An Integrated and Resilient North Sea

Offshore Energies UK

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TABLE OF CONTENTS

1 EXECUTIVE SUMMARY 1
1.1 Scope and Approach 1
1.2 Key System Insights 1
1.3 Resilience as a Design Principle 2
1.4 Economic Implications 2
1.5 Findings and Conclusions 2

2 INTRODUCTION 4
2.1 Approach 5
2.2 Scope Boundary 5

3 UNDERSTANDING THE LANDSCAPE: CCS AND HYDROGEN IN THE NORTH SEA REGION 6
3.1 CCS Project Landscape 6
3.2 The Role of Hydrogen 10

4 DEFINING A RESILIENT NORTH SEA SYSTEM 13
4.1 The Four Dimensions of Resilience 13
4.2 Critical elements to unlock the Resilient North Sea Scenario 14

5 AN INTEGRATED AND RESILIENT NORTH SEA SCENARIO 41
5.1 CCS Transport and Storage Systems 41
5.2 Hydrogen Networks and Assets 45

6 ECONOMIC OVERVIEW 49
6.1 CCS Infrastructure Assets 49
6.2 Hydrogen Infrastructure Assets 55

7 FINDINGS AND CONCLUSIONS 59
7.1 Economic Conclusions 59
7.2 System-Level Challenges and Pathways Forward 59

1 EXECUTIVE SUMMARY

The North Sea is emerging as a cornerstone of Europe's net-zero transition, with a uniquely concentrated opportunity to deliver large-scale carbon capture and storage (CCS), low-carbon hydrogen production, and cross-border energy integration. Driven by ambitious national and EU-level climate targets, accelerating industrial decarbonisation, and increasing energy-security concerns, governments and industry across the region are rapidly advancing CO_2 transport and storage systems and hydrogen networks. However, the pace, scale, and fragmentation of development risk locking in inefficiencies unless infrastructure is designed and governed as an integrated, resilient system from the outset.

This study examines what an Integrated and Resilient North Sea energy system could look like across the medium- and long-term, focusing specifically on CO_2 transport and storage infrastructure and pure hydrogen transport. Rather than assessing individual projects in isolation, the analysis adopts a system-level perspective, recognising that long-term value, affordability, and security of supply will depend on how assets interact across borders, technologies, and time.

1.1 Scope and Approach

The study covers the UK, Norway, the Netherlands, Germany, Belgium, and France, with broader European demand and supply dynamics considered where relevant. Carbon capture installations and onshore hydrogen production are outside scope; however, their anticipated locations, volumes, and ramp-up trajectories are reflected in transport and storage requirements.

A structured methodology was applied combining:

- Infrastructure mapping across hydrogen and CCS across medium- and long-term evolution,
- A resilience framework spanning technical, operational, regulatory, and economic dimensions, and
- A high-level economic assessment of transport and storage assets to explore utilisation, tariffs, and payback dynamics.

The objective is not to predict a single outcome, but to identify the design principles, enabling actions, and strategic choices that determine whether North Sea infrastructure evolves into a fragmented set of national systems or a coherent, scalable regional network.

1.2 Key System Insights

CCS deployment in Europe is entering a scale-up phase, with capture capacity expected to grow rapidly from the early 2030s onward. While CO_2 transport and storage capacity is currently advancing ahead of capture, this imbalance is likely temporary. The apparent surplus of CO_2 storage capacity in the near-term project pipeline may reverse as capture deployment accelerates, unless additional storage sites are licensed and brought into development.

The North Sea's geological resource places the UK and Norway in a strategically pivotal role as long-term storage providers for Europe. Shorter shipping distances between major industrial clusters in Northwest Europe and the UK Southern North Sea, compared with Norwegian sites, offer potential cost and resilience advantages. Realising this opportunity, however, depends on early appraisal, permitting certainty, and the proactive development of transport corridors rather than project-by-project routing.

Hydrogen demand is expected to grow more gradually and unevenly, with long-term volumes driven primarily by industry, transport fuels, and dispatchable power. Supply–demand imbalances across regions imply a growing need for cross-border hydrogen transport and large-scale storage. The study highlights the importance of hydrogen backbones such as Project Union in Great Britain and the European Hydrogen Backbone, being designed with mutual compatibility in mind to avoid costly retrofits and barriers to future interconnection.

1.3 Resilience as a Design Principle

A central objective of the study is the articulation of four dimensions of resilience that together seek to define a robust North Sea system:

Technical resilience, ensuring infrastructure is physically capable of scaling under the system with interoperable specifications, consistent pressure regimes, redundancy, and expandability.

Operational resilience, enabling reliable day-to-day functioning through diversified routes, multimodality, bidirectional flows, and adequate buffer capacity.

Regulatory resilience, providing stable, interoperable governance across borders, including ETS alignment, London Protocol arrangements, custody transfer rules, and coherent network regulation.

Economic resilience, recognising that large-scale transport and storage are long-life, capital-intensive assets whose value emerges over decades, requiring stable revenue frameworks, tariff transparency, and mechanisms to manage early underutilisation.

While these dimensions are interlinked, they are not realised simultaneously. Technical and regulatory considerations shape the system from the outset, determining future optionality and investability, while operational and economic resilience are progressively realised as infrastructure is used, scaled, and interconnected. Regulatory resilience is foundational: it provides the system's permission to operate by defining liabilities, access rights, cross-border rules, and long-term stewardship. Without robust and credible regulation, technical solutions are unlikely to secure investment, revenue models remain unviable, and operational optimisation has limited impact.

Although out of scope of this study, embedding security in design is increasingly important. As CCS and hydrogen systems scale, exposure to physical and cyber threats may influence decisions on siting, routing, and required levels of redundancy and protection.

1.4 Economic Implications

The economic assessment shows that both CCS and hydrogen transport and storage infrastructure exhibit long payback periods of around 20–30 years, driven by high upfront capital costs and the need to build ahead of demand. System-level viability is achievable, but only under conditions of sustained utilisation growth, stable policy frameworks, and coordinated planning.

Tariffs in the early years are highly sensitive to utilisation assumptions, which points to the need for targeted support mechanisms during the build-out phase, including regulated or utility-style revenue models and approaches to socialise early costs where infrastructure delivers wider societal value through emissions reduction and energy security. Over time, as utilisation stabilises and markets mature, this could transition toward a more competitive merchant-based model.

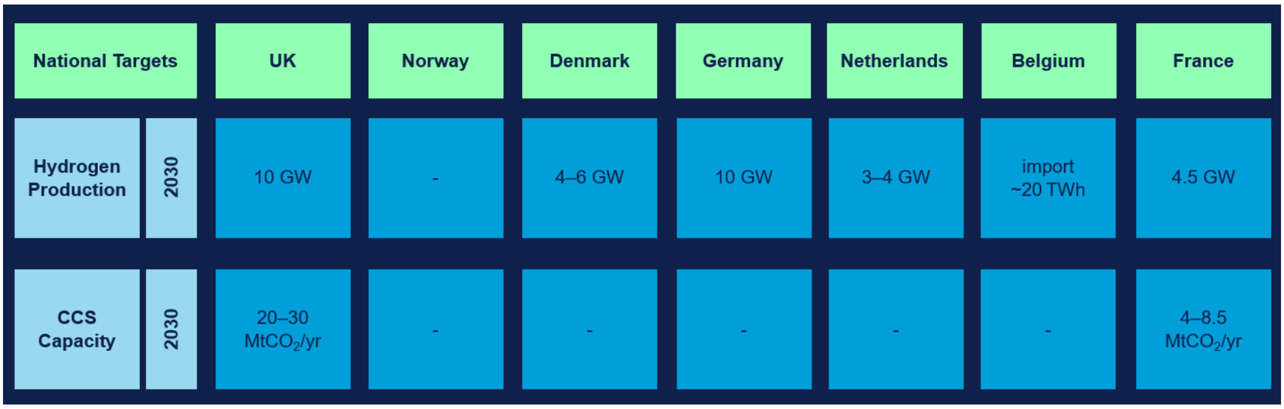
1.5 Findings and Conclusions

- The North Sea is well-positioned to play a central role in supporting Europe's decarbonisation targets, particularly through the development of CO_2 transport and storage and cross-border hydrogen networks; however, achieving this potential may depend on how effectively infrastructure evolves from individual projects into coordinated, system-level networks.
- Early-stage development is often shaped by project-level requirements, including funding constraints and competitiveness, which may not always align with longer-term system needs such as interoperability, scalability, and resilience within a fully integrated network.
- From an operational perspective, as infrastructure systems become more interconnected, overall performance will depend increasingly on effective coordination and flexibility across the network, reinforcing the need to consider system-level requirements beyond individual project optimisation.

- From an economic perspective, CCS and hydrogen infrastructure are characterised as capital-intensive, long-term investments, where deployment may depend not only on project-level viability but also on confidence in the broader system environment, including policy stability, demand growth, and risk allocation. Infrastructure development is also subject to significant demand uncertainty and coordination challenges across production, transport, and end-use sectors, creating “chicken-and-egg” dynamics that may constrain timely and efficient system build-out.
- Across both CCS and hydrogen, the study finds that early underutilisation and apparent overcapacity are not inefficiencies. Infrastructure sized only to initial projects risks future bottlenecks, higher lifetime costs, and constrained optionality. From a system perspective, building technical headroom and redundancy upfront is a rational response to uncertainty and a prerequisite for delivering reliable, affordable performance over the full asset life.
- Delivering an integrated and resilient North Sea system may require a shift toward more coordinated, system-level approaches to infrastructure planning, including early consideration of interoperability, scalability, and cross-border alignment, supported by appropriate governance and investment frameworks.

2 Introduction

The North Sea is emerging as one of the most critical regions for Europe's energy transition, with potential to accelerate large-scale CO_2 transport and storage, low-carbon hydrogen production and use, and cross-border collaboration. National hydrogen targets vary across the region: the UK, Germany, Denmark, France, and the Netherlands have set clear electrolyser capacity goals, whereas Belgium and Norway focus instead on developing import hubs and progressing individual projects rather than defining national capacity numbers. For CCS, only the UK and France have published explicit 2030 capture targets, while countries such as Norway, Denmark, Germany, the Netherlands, and Belgium have not set national $MtCO_2$/year goals but are nevertheless advancing significant CCS projects, including Longship, Northern Lights, Porthos, and Aramis. In this context, the Net-Zero Industry Act's requirement for at least 50 $MtCO_2$/year storage availability functions as Europe's de-facto CCS deployment target for 2030, anchoring investment decisions even in the absence of explicit national capture targets.[1]



National Targets		UK	Norway	Denmark	Germany	Netherlands	Belgium	France
Hydrogen Production	2030	10 GW	-	4–6 GW	10 GW	3–4 GW	import ~20 TWh	4.5 GW
CCS Capacity	2030	20–30 $MtCO_2$/yr	-	-	-	-	-	4–8.5 $MtCO_2$/yr

Figure 2-1 National targets for CCS capacity and hydrogen production[2]

These infrastructure developments sit within the broader context of Europe's Nationally Determined Contributions (NDCs), which require rapid and sustained emissions reductions over the next decade. The UK must deliver an 81% reduction against 1990 levels by 2035, Norway targets a 70–75% reduction by 2035, and EU Member States, including Denmark, Germany, the Netherlands, Belgium, and France, are collectively bound to a 55% emissions cut by 2030 under the EU-level NDC. Meeting these steep decarbonisation trajectories will require both substantial industrial CO_2 abatement and the scaling of clean hydrogen as a fuel and feedstock, making CCS and hydrogen deployment key strategies.

Table 2-1 Nationally Determined Contributions[3]

Country	Latest NDC Target	Target Year	Notes
UK	81% reduction vs 1990	2035	Independent NDC
Norway	70–75% reduction vs 1990	2035	Independent NDC; joint implementation with EU
Denmark	55% (EU)	2030	EU-level NDC applies
Germany	55% (EU)	2030	EU-level NDC; stricter national law but not an NDC
Netherlands	55% (EU)	2030	EU-level NDC applies
Belgium	55% (EU)	2030	EU-level NDC applies
France	55% (EU)	2030	EU-level NDC; national ambitions evolving

Deploying CCS at scale in Europe will require CO_2 transport networks, initially made up of regional or national links between capture sites and nearby storage locations. These early local clusters will form the foundation for broader shared infrastructure, gradually expanding as more emitters and storage sites come online. Over time, this localised build-out can

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[1] **European Union**. 2024. Regulation (EU) 2024/1735 of the European Parliament and of the Council establishing a framework of measures for strengthening Europe's net-zero technology manufacturing ecosystem (Net-Zero Industry Act), Chapter III: CO_2 Injection Capacity, Article 20 – Union level objective of CO_2 injection capacity. Official Journal of the European Union, L 1735, 28 June.

[2] Hydrogen and CCS targets reflect published national strategies where available.

[3] **United Nations Framework Convention on Climate Change (UNFCCC)**. 2024. Nationally Determined Contributions (NDCs). UN Climate Change.

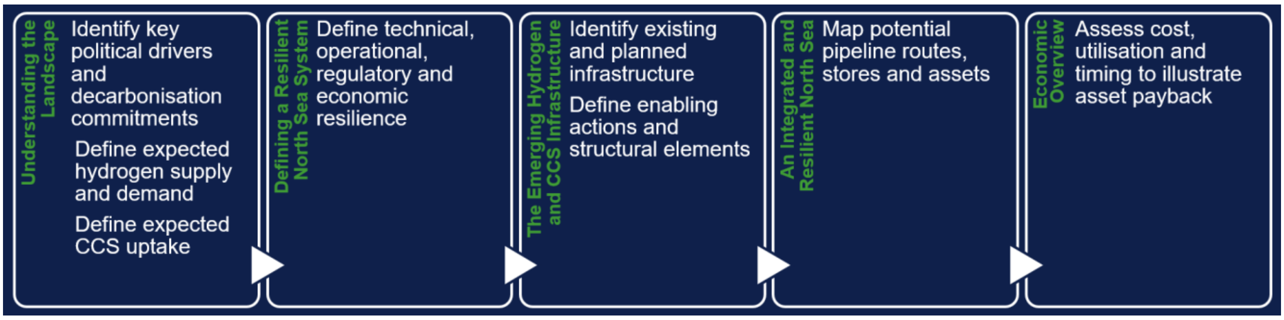
mature into a larger, interconnected European CO_2 transport network, similar in concept to existing electricity and gas transmission systems.

In parallel, European hydrogen strategies are also driving the creation of cross-border hydrogen corridors, with countries developing new and repurposed pipelines, import hubs, and regional hydrogen backbones that increasingly require interoperability between national systems. As hydrogen demand, supply, and imports scale, these emerging networks will need to connect across borders to support a flexible, integrated European hydrogen market.

This study therefore assumes a future in which both CO_2 and hydrogen networks evolve from national and regional projects into coordinated, cross-border, multimodal systems. The objective of the study is to describe what an 'Integrated and Resilient North Sea' could look like across medium- and long-term time horizons. The study brings together infrastructure mapping to illustrate a North Sea infrastructure network to meet the defined resilience principles. This shows what an interconnected regional network for both hydrogen and CCS could look like and provides an assessment of enabling actions, infrastructure requirements, and system-wide challenges and risks that need to be addressed to achieve an interconnected regional network for both CCS and hydrogen

2.1 Approach

The study adopted a structured, multi-stage methodology designed to produce a scenario of what an integrated and resilient North Sea system could look like in the medium- to long-term. The approach comprised five core components, each focused on generating the evidence, principles and insights required to develop a coherent network concept.



2.2 Scope Boundary

The geographic scope of the infrastructure considered in the study include the following countries, although for demand or supply considerations (especially from NPT/shipping), the rest of Europe will be considered.

- UK (including west coast)
- Norway
- Netherlands
- Germany
- Belgium
- France

In terms of assets, the study focusses on CO_2 transport and storage and pure hydrogen transport, highlighting opportunities across the North Sea for:

- CO_2 pipelines (offshore)
- CO_2 storage (offshore)
- Shipping, including ship-to-store
- CO_2 import/export terminals
- Cross-border hydrogen pipelines
- Shared offshore electrolysis and storage

Carbon capture infrastructure is considered out of scope for this study; however, it is recognised that the location of major emission sources and carbon capture installations will inherently influence transport infrastructure routings and anticipated capacity requirements. Similarly, hydrogen production onshore is out of scope, however supply and demand volumes will be evaluated to provide evidence for the requirement of cross-border transport of low-carbon hydrogen.

3 UNDERSTANDING THE LANDSCAPE: CCS AND HYDROGEN IN THE NORTH SEA REGION

3.1 CCS Project Landscape

From the early 2030s DNV's ETO forecasts that capture capacity across Europe will undergo rapid acceleration, as the region becomes one of the world's fastest growing CCS markets.[4] DNV identifies the late 2020s as a turning point, with global capture and storage capacity expected to quadruple by 2030, driven increasingly by rapid scale up in Europe and North America. Beyond 2030, Europe is projected to shift from pilot scale activity to large scale industrial deployment, with CCS expanding into hard-to-abate sectors such as steel, cement, chemicals, and hydrogen production. This growth will need to be underpinned by maturing project pipelines, emerging CO_2 transport networks, and accelerating investment in offshore storage capacity across the North Sea.

Carbon pricing is a mechanism whereby emitters incur a cost per tonne of CO_2 emitted. It creates a sustained economic incentive, especially in high-price regions like Europe, that makes carbon capture the most practical and scalable solution for decarbonising existing industrial systems while maintaining competitiveness.

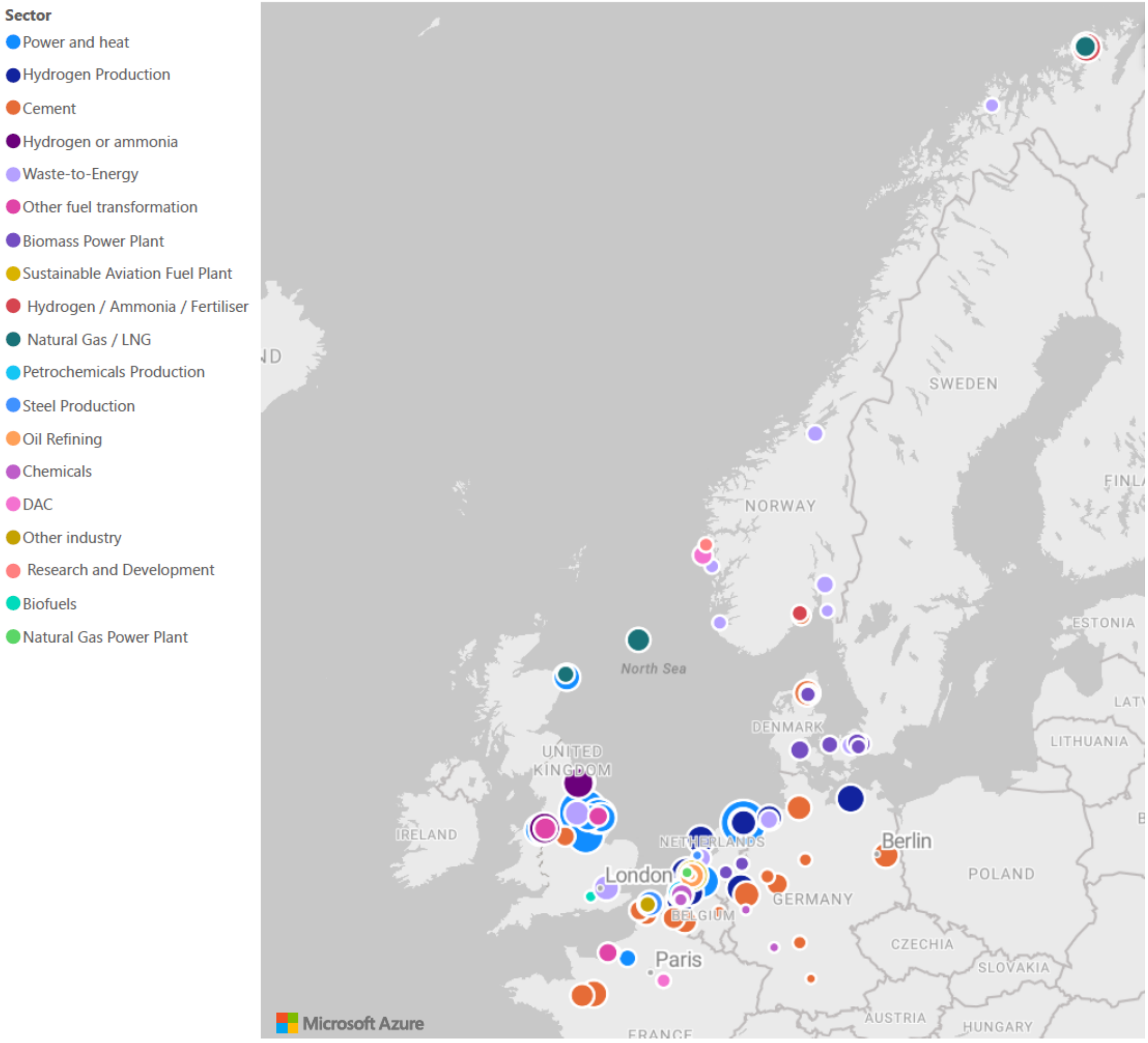


Figure 3-1 Carbon Capture Projects in the North Sea Region, by 2035

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[4] **DNV.** Energy Transition Outlook.

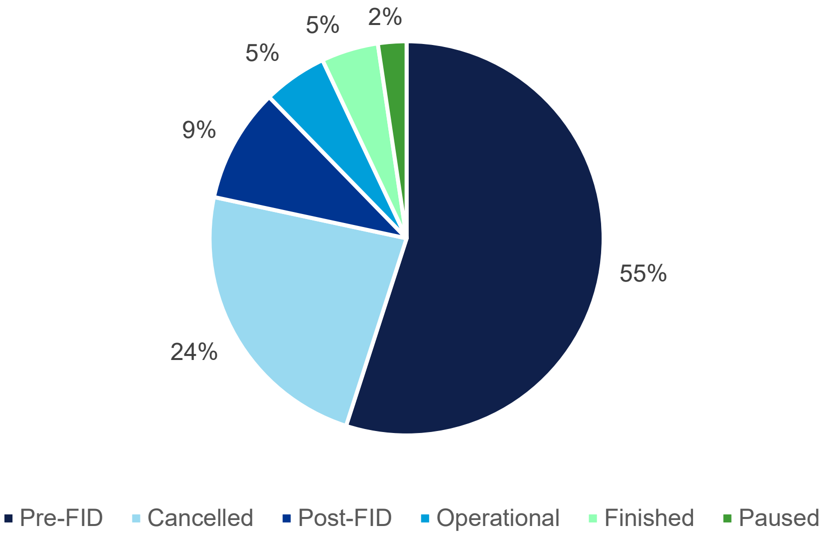

Figure 3-2 Carbon Capture Project Stage, at Present

The project stage pie chart indicates that 55% of current CCS projects are pre-FID, demonstrating a substantial pipeline of early-stage developments. A further 23% have progressed past FID, while 9% are operational and 7% have been completed, signalling that CCS in Europe is moving beyond demonstration and into a scaling phase. These maturity indicators reflect a market in transition with early commercial deployment underway, while the majority of projects are focusing on raising capital, securing permitting, and integrating into future CO_2 networks.

As shown in Figure 3-3,CO_2 storage capacity increases rapidly to the early–mid 2030s but then plateaus, falling short of forecast capture capacity in Figure 3-5. Additional CO_2 storage sites will need to be licensed and developed to accommodate future capture volumes. Planned and future CO_2 storage licensing rounds are therefore expected to be critical in enabling new storage projects and closing the emerging capacity gap. The heat map (right) of offshore CO_2 storage sites illustrates the concentration of prospective and active storage locations in the North Sea.

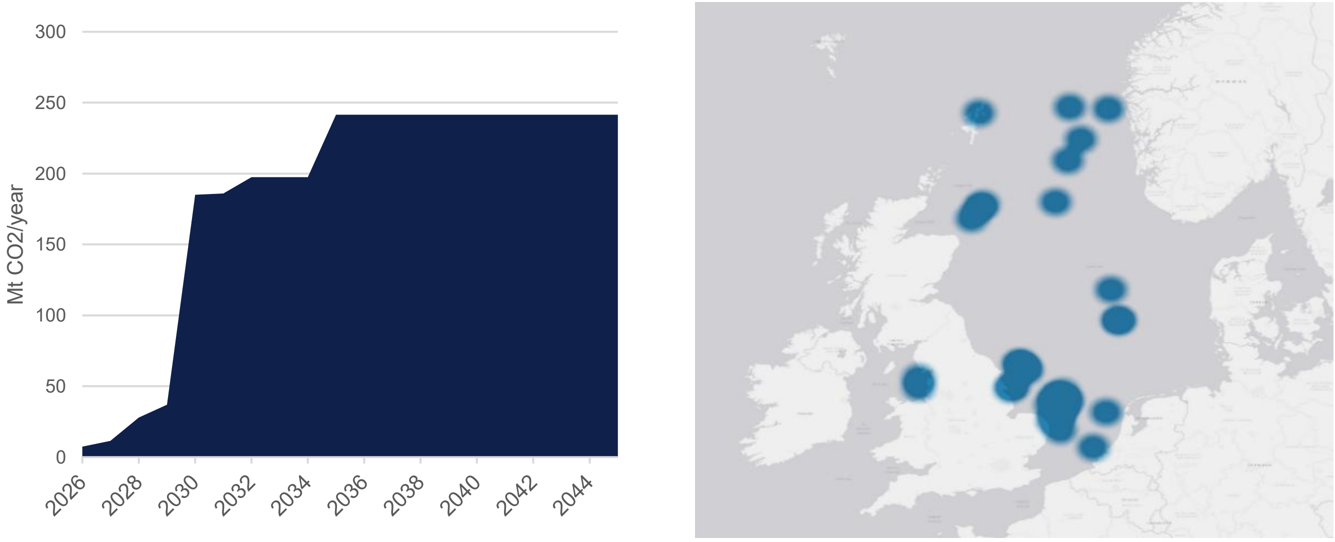

Figure 3-3 (Left) Currently planned CO_2 storage Capacity.[5] (Right) Heatmap of CO_2 Stores in the North Sea Region

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[5] Based on publicly announced plans

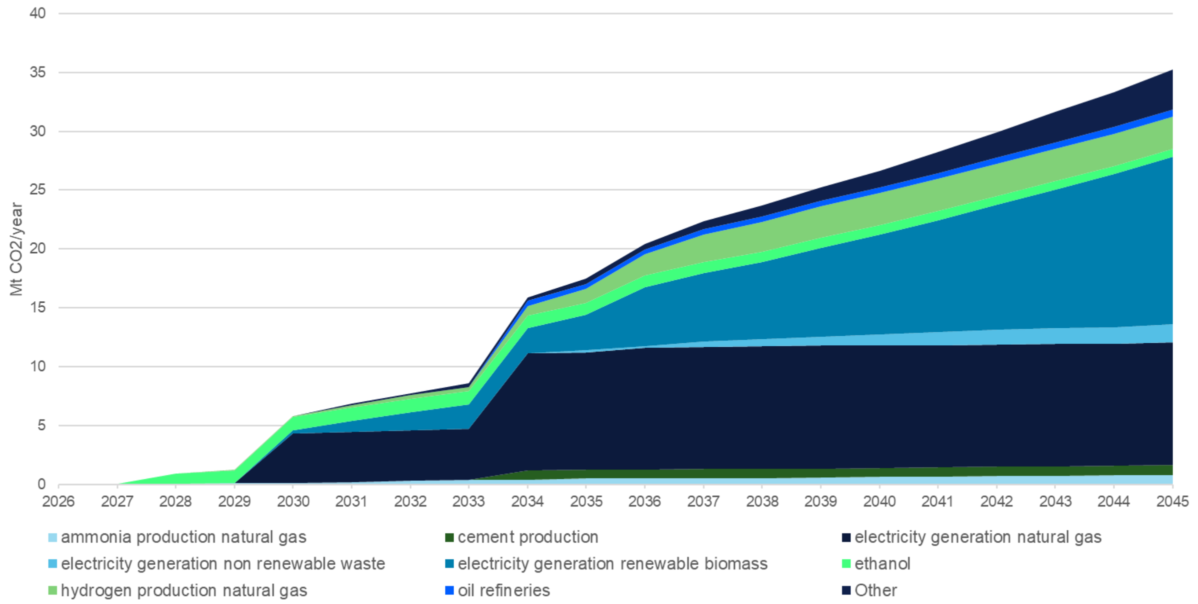

Figure 3-4 UK Capture Capacity by Sector, DNV UK ETO 2026

The UK capture capacity is forecast to have a steady growth to around 35–40 $MtCO_2$/yr by 2045, driven predominantly by three major segments:

- Electricity generation (natural gas with CCS) provides the first wave of large-scale capture, forming the backbone of early CCS deployment through the 2030s.
- Electricity generation from biomass (BECCS) grows rapidly in the late 2030s and 2040s, reflecting its role in delivering negative emissions to meet net zero in 2050.
- Hydrogen production from natural gas with CCS becomes a significant contributor, consistent with the UK's emerging hydrogen economy.

Smaller but increasingly important contributions arise from industrial sectors such as chemicals, cement, oil refining, waste-to-energy, and other manufacturing segments. The UK trajectory therefore reflects a strong energy-system orientation, with CCS enabling dispatchable low-carbon power, negative-emissions technologies, and hydrogen supply.

In contrast, generally EU capture capacity expands more broadly and at a larger scale, reaching approximately 300 $MtCO_2$/yr by 2045. While electricity generation (both natural gas and biomass) plays a role similar to the UK in early deployment, Europe's long-term trajectory is driven increasingly by hard-to-abate industrial sectors:

- Cement becomes one of the largest contributors to capture volumes.
- Chemicals, steel, and hydrogen production all exhibit substantial growth.
- A wide array of manufacturing and process industries contribute smaller but collectively significant volumes.

This reflects the EU's broader industrial base and its strong policy focus on decarbonising energy intensive sectors under the Emissions Trading System (ETS). Whereas the UK's early uptake is energy led, the EU's is more diversified, with CCS playing a central role in industrial transformation.

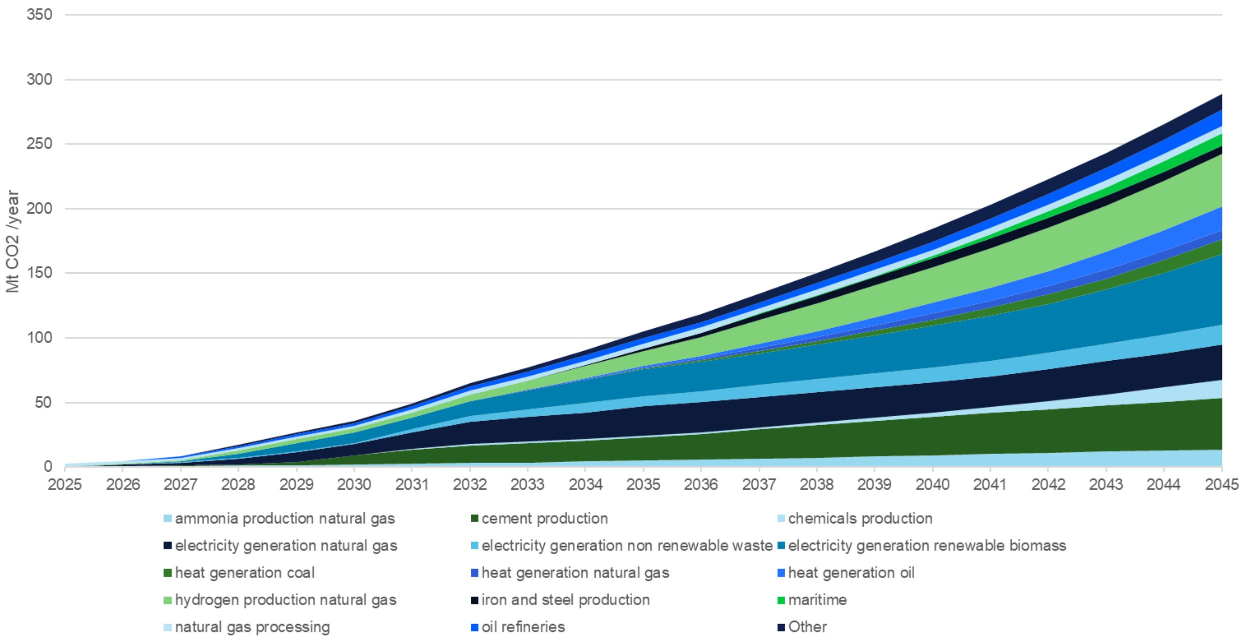

Figure 3-5 EU Capture Capacity by Sector, DNV ETO 2025

3.2 The Role of Hydrogen

Hydrogen has been embedded for many years in industrial sectors such as oil refining and chemical manufacturing. It is typically produced on site from hydrocarbons using processes such as steam methane reforming and therefore has significant associated carbon emissions. While the production and use of this “grey” hydrogen are locally balanced, decarbonising these industries will require a change in how hydrogen is produced and, in some cases, importing low-carbon hydrogen to replace existing supplies.

Other sectors where hydrogen can support decarbonisation are iron and steel, green ammonia production, and transport (mainly in the form of e-fuels and ammonia, for aviation and maritime respectively).

As defined under the EU Hydrogen and Gas Market Directive, low carbon hydrogen needs to reach a threshold of 70% greenhouse gas emission savings compared to the use of unabated fossil fuels. Low-carbon hydrogen can be produced through several pathways, including natural gas reforming with carbon capture and storage and electrolysis of water powered by low-carbon electricity.[6]

DNV forecasts a total hydrogen demand of ~13 MtH$_2$/year by 2030 and ~27 MtH$_2$/year by 2045 in the EU region (see Figure 3-6). The main driver for long-term demand is the increasing need for hydrogen and its derivatives in the transport sector and in manufacturing.

Hydrogen is forecast to predominantly come from domestic EU production, however some imports via shipping and pipeline (between EU counties and from the UK, particularly from Scotland) are also expected to contribute to the overall supply.

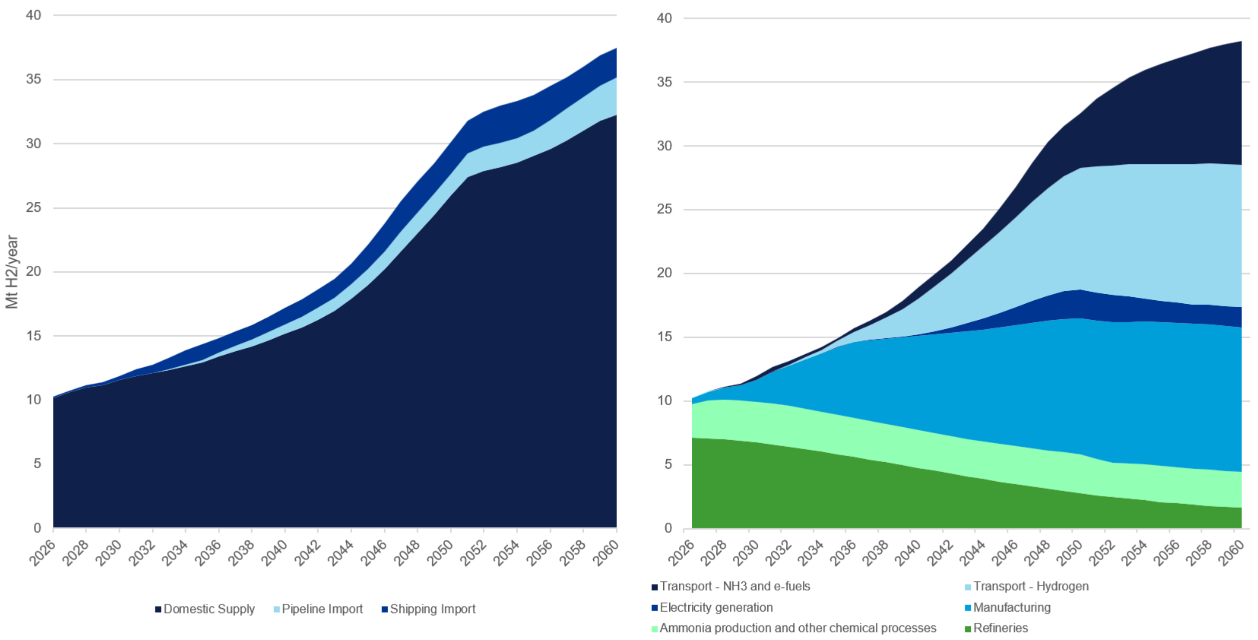

Figure 3-6 EU H_2 supply (left) and demand (right) forecast, DNV ETO 2025

In the UK, total hydrogen demand is forecast to rise gradually from just under 1 MtH$_2$/year in 2026 to around 3.3–3.5 MtH$_2$/year by 2060, with most of the increase occurring after 2040 (see Figure 3-7). The DNV UK ETO shows a relatively flat demand in traditional hydrogen sectors (like refineries) but strong long-term growth driven mainly by transport fuels based on ammonia and e-fuels; these become the largest contributors to UK hydrogen consumption by 2060.

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[6] **European Commission.** 2025. Press release, **IP/25/1743**.

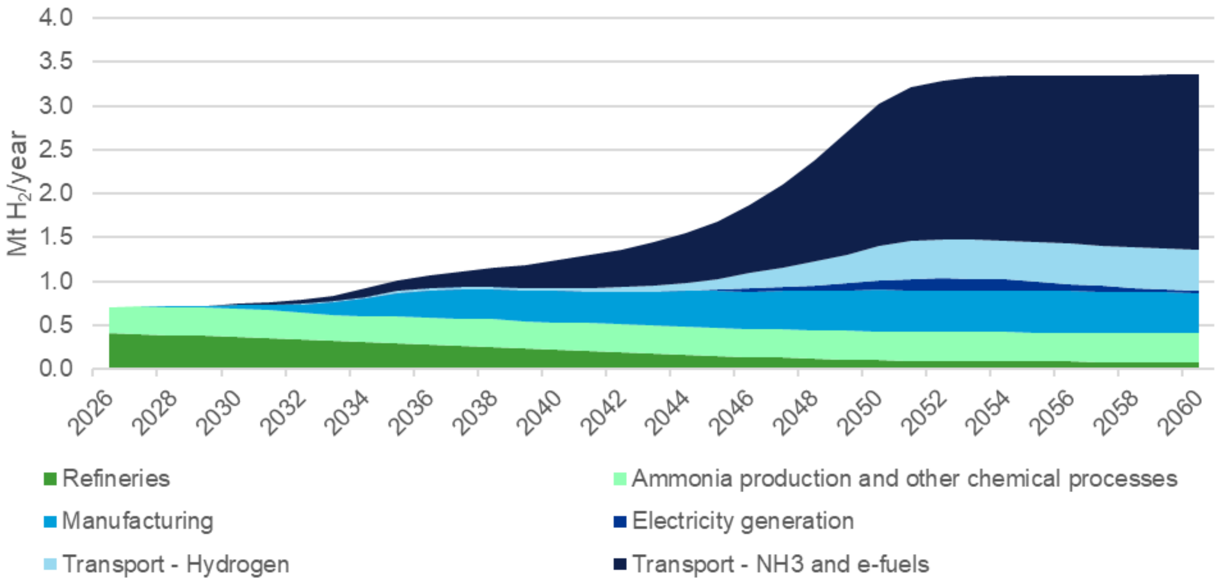

Figure 3-7 Demand for Hydrogen and its derivatives by sector, DNV UK ETO 2026 [7]

Even as renewable penetration grows, gas/H_2 fired installed capacity remains present all the way to 2050, reflecting a structural need for firm, fast responding thermal generation in the UK. This trend reinforces the need for secure, large scale domestic hydrogen storage, because power sector hydrogen usage will be time critical and highly variable.

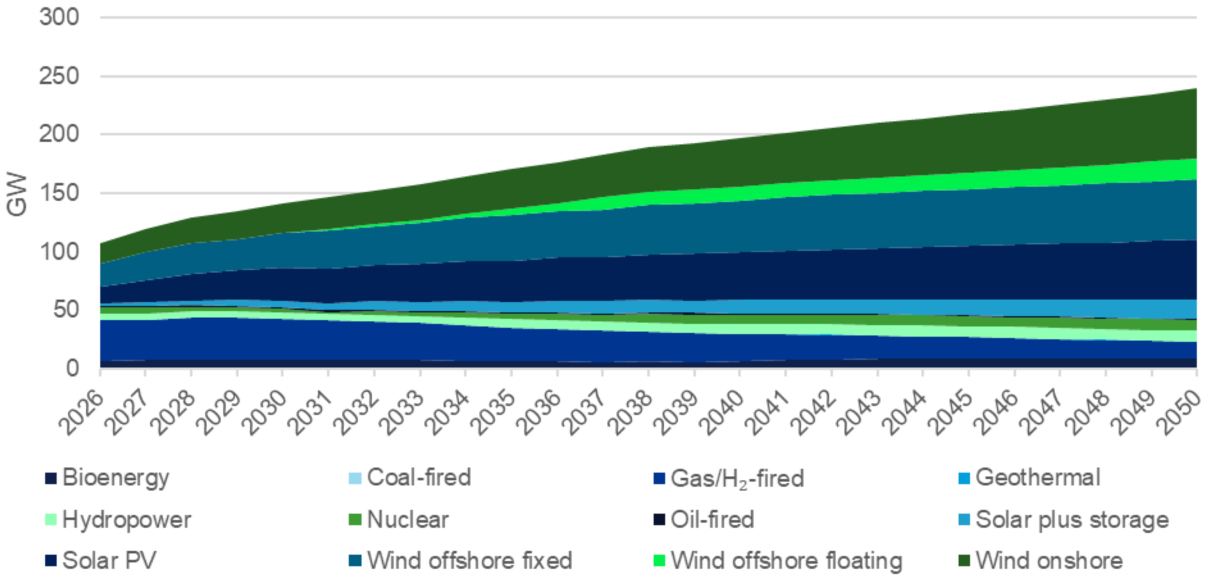

Figure 3-8 Utility-scale installed capacity, DNV UK ETO 2026

Connectivity across Europe allows for hydrogen to be produced in regions with greater renewable resources and lower costs which is then delivered to demand centres around the continent.

A coordinated, cross-border hydrogen network could significantly enhance Europe's energy resilience by balancing supply across regions and time periods, especially when coupled with large-scale storage that allows excess production to be stockpiled for later use. It also enables countries lacking suitable geological formations to access shared large-scale hydrogen storage, improving system flexibility and reducing exposure to geopolitical risks. Moreover, by integrating

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[7] The latest UK ETO differs from the previous one because it now projects much lower hydrogen deployment, mainly to the high cost of hydrogen compared with alternatives.

multiple supply sources, routes, and storage options, such a network strengthens overall energy-system robustness and security of supply.

Across the UK and Europe there are differences in the hydrogen supply-demand balance. The UK has the potential to be a net exporter of hydrogen, with most of the supply coming from Scotland's vast renewable energy resources. The Scottish Hydrogen Assessment estimated that by 2050 around 94 TWh/year (~2.8Mt H_2/year) could be exported from Scotland to the UK and other European markets.[8]

Error! Reference source not found. shows the supply-demand balances across various regions in Europe. Central Europe (in particular Germany) is a region that will likely require significant imports of green hydrogen to satisfy demand. Competitiveness of UK-produced hydrogen in export markets is uncertain, particularly where competing suppliers (e.g. Norway) may benefit from lower production and transport costs, which could further influence demand realisation and investment confidence.

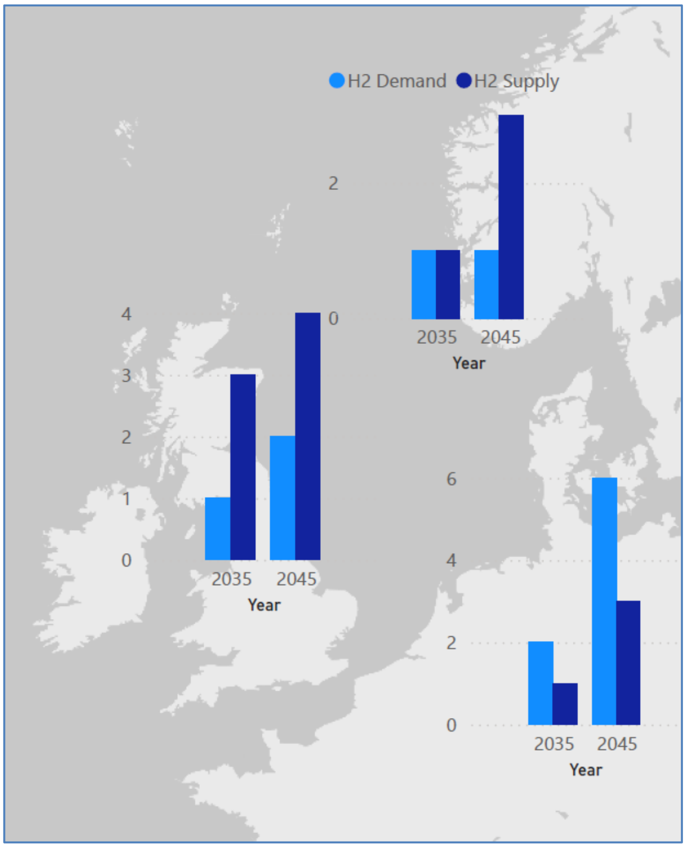

Figure 3-9 Regional H_2 Supply/Demand Mt Hydrogen/year (Based on UK ETO 2026/Scottish H_2 Assessment [8], Norway ETO 2025, Germany ETO 2025)

The latest UK ETO model does not consider imports and exports of hydrogen, however there are various studies that can be drawn upon to demonstrate the potential production of low carbon hydrogen in the UK, in particular in Scotland, and the availability of export capacity to mainland Europe.[9] [10] For the purposes of this study, it is assumed that green hydrogen

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[8] **Scottish Government.** 2020. *Scottish Hydrogen Assessment: Report*. Edinburgh: Scottish Government.

[9] **Net Zero Technology Centre (NZTC).** 2023 Hydrogen backbone link report 3. Aberdeen: Net Zero Technology Centre.

[10] **Department for Energy Security and Net Zero & Federal Ministry for Economic Affairs and Climate Action**. 2025. *UK–Germany Joint Hydrogen Export Study*.

for EU export will be generated in Scotland, although actual export routes could be located at strategic points along the coastline bordering the North Sea connecting from the Project Union infrastructure.[11]

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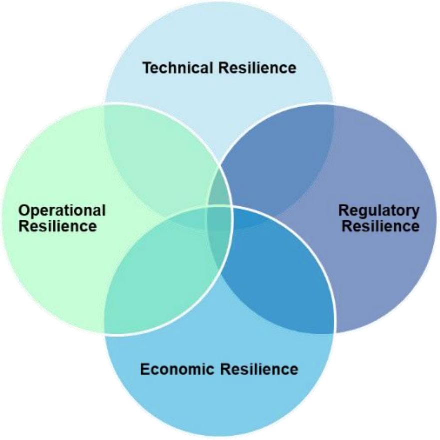
[11] **National Gas**. Project Union – Energising Britain.

4 DEFINING A RESILIENT NORTH SEA SYSTEM

4.1 The Four Dimensions of Resilience

The "Resilient North Sea Scenario" is built around four core dimensions of resilience, defined in Figure 4-1. Together, these dimensions provide a high-level view of the qualities that underpin a robust North Sea hydrogen and Carbon Capture and Storage (CCS) system, bringing technical, operational, regulatory, and economic factors into a single, coherent framework.

This framework sets the foundation for identifying the structural elements the system will require, as well as the enabling actions needed to support a resilient, cross-border network.



Technical resilience = how the system is built
A focus on ensuring redundancy in H_2 and CO_2 transport routes and interoperability of pipeline specifications.

Operational resilience = how the system is physically run
A focus on reliability and flexibility to manage H_2 supply/demand fluctuations and CO_2 export through diversified routing and storage options.

Regulatory resilience = how the system is governed
A focus on ensuring aligned and interoperable policy and regulatory frameworks that support cross-border H_2 and CO_2 transport and storage.

Economic resilience = how the system sustains itself economically
Ensuring the North Sea CCS and H_2 system stays financially viable, competitive, and adaptable to market fluctuations.

Figure 4-1 Four Dimensions of Resilience

Building on this framework, the four dimensions are used to identify what a resilient North Sea system must physically include and what must be in place to enable it. This involves:

Structural elements that physically deliver resilience, such as cross-border pipelines, diversified routing options, interconnection points through bidirectional hydrogen flows, shared trunklines, cluster-to-cluster links.

Enabling actions that support the development of a resilient network, such as harmonised regulation, coordinated investment mechanisms and technology interoperability.

While out of scope for this study, incorporating security and resilience considerations at the design stage is likely to become increasingly important for system optimisation and risk mitigation. As CCS and hydrogen scale into large, networked energy systems, exposure to physical attack and cyber threats may influence key decisions on siting, routing, clustering, and the level of redundancy and protection required.

4.1.1 Sequencing and Interaction of System Resilience Dimensions

The dimensions of resilience are interlinked, but they are not co-dependent in time. Technical, regulatory, and operational considerations interact from the outset. For example, anticipated needs for reverse flow, alternative routing, or intermodal operation directly influence upfront design choices. The full value of operational and economic resilience is progressively realised as these capabilities are exercised, and the system develops and scales.

Regulatory resilience provides the system's permission to exist. It defines liabilities, access rights, cross-border rules, and long-term stewardship arrangements, and underpins investor confidence over multi decadal horizons. Without robust and credible regulation, technical solutions are unlikely to secure investment, revenue models remain unviable, and operational optimisation has limited impact.

Technical resilience determines whether the system is physically capable of scaling under uncertainty. Reservoir appraisal, injectivity margins, redundancy, and interoperability determine future optionality, including the ability to add new users or manage uneven ramp-up profiles. From this perspective, spare capacity and redundancy are not inefficiencies but deliberate design features. Once storage infrastructure becomes constrained, expansion is slow and costly, making early headroom a rational risk management choice.

Operational resilience reflects how effectively the system performs in practice, including its ability to manage variability, outages, and interdependencies. Many operational capabilities, such as reverse flow, alternate routing, or intermodal flexibility, depend directly on prior regulatory and technical decisions. Operational resilience is therefore realised through use, but only within constraints established earlier.

Economic resilience is an emergent system outcome rather than a starting condition. Early-stage infrastructure will often appear underutilised and high cost on a unit basis. However, long term economic resilience depends on regulatory durability, technical headroom, and reliable operation at scale. While individual projects must be bankable to proceed, bankability itself is shaped by confidence in the wider system, not by near term utilisation alone.

From a system perspective, early underutilisation should therefore be understood not as inefficiency, but as a consequence of designing infrastructure to scale credibly, avoid future bottlenecks, and deliver value over its full operating life.

4.2 Critical elements to unlock the Resilient North Sea Scenario

4.2.1 CCS Infrastructure Resilience

4.2.1.1 Technical Resilience

Harmonised quality specifications to avoid border reconditioning and support pipeline compatibility.

Harmonised CO_2 quality specifications are important to avoid border reconditioning and ensure compatibility across different pipeline systems, shipping operations, intermediate storage facilities, and ultimately, geological storage sites. In theory, aligning CO_2 quality expectations supports the long-term development of a North Sea transport network. However, current practice remains fragmented, for example, national regulations differ and CO_2 streams from various capture technologies exhibit inherently varying impurity profiles.

While standards are essential for strengthening industry practice, overly stringent or uniform purity thresholds can introduce avoidable costs, especially where certain transport or storage systems do not require such high levels of conditioning. The challenge is finding a balance between aligning specifications where it is functionally necessary, while avoiding requirements that exceed what specific operations actually need. In addition, purity standards must remain practical. In some cases, specified impurity thresholds are set at levels so low that they are beyond the capability of commercially available measurement equipment, creating challenges for verification and compliance.

This issue is the focus of extensive joint industry work, including the Wood -led JIP that convened more than 18 partners to develop fit-for-purpose specifications across the capture–transport–storage chain[12], and the upcoming DNV-led CO_2 SpecChain[13] JIP, which aims to create a unified, transparent framework for defining and managing stream compositions across the full CCS value chain.

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[12] **Wood Group**, *"Industry Guidelines for Setting the CO_2 Specification in CCUS Chains."*

[13] **DNV.** 2026. *CO_2 SpecChain Joint Industry Project: Developing a unified framework for CO_2 composition across the CCS value chain.*

In the early stages of CCS deployment, flexibility is vital for enabling investment and accelerating the build-out of infrastructure. Introducing a rigid, sector-wide specification too early risks limiting market participation and raising costs, whereas allowing operators to negotiate specifications case by case helps maintain competitive advantage for those who can accommodate a broader range of CO_2 qualities. Flexibility should, however, be bounded by a system-wide, risk-based assessment of how impurities impact performance, integrity, and safety across the full value chain.

At the same time, maintaining a basic level of interoperability remains important: avoiding unnecessarily strict or divergent requirements ensures that captured CO_2 can be redirected to alternative storage sites when needed, whether due to outages, capacity limits, or commercial decisions. Striking the right balance means enabling enough compatibility to ensure system resilience while avoiding prescriptive rules that could constrain early development and deter investment.

At present, generic specifications are broader because they aim to cover multiple scenarios, while project-specific ones (e.g., Northern Lights, Porthos, Aramis) are much tighter because they are engineered to a specific transport method, storage reservoir and injection pressure. Table 4-1 summarises the current CO_2 specifications for a range of projects and broader industry recommendations.

Table 4-1 Various CO_2 Specifications (ppm-mol) [14] [15]

	Dynamis	NETL Design (2013)	Longannet (2014)	Goldeneye / Peterhead (2014/2016)	CarbonNet Project (2016)	NETL Design (2019)	Porthos (2021)	Fluxys Gas (2022)	TES OGE (2022)	PACE-CCS Ltd (2022)	Aramis: Pipeline (2023)	Aramis: Ship (2023)	AMPP Tentative (2023)	Northern Lights (2024)
Type	Generic	Generic	Project-specific	Project-specific	Project-specific	Generic	Project-specific	Project-specific	Project-specific	Generic	Project-specific	Project-specific	Generic	Project-specific
H_2O	500	500	50	50	100	500	70	40	30	50	70	30	100	30
H_2S	200	100	0.5	0.5	100	100	5	5	10		5	5	10	9
CO	2000	35	10	10	900–5000	35	750	750	100	2000	750	1200	1000	100
O_2	<40000	10	1	1	20000–50000	10	40	40	30	10	40	10	20	10
SOx	100	100	10	10	250–2500	100		<0.1	1	50		10	10	10
Sulphur compounds						20 (a)		30 (c)	5 (f)	20 (b)		20/60 (d)		
NOx	100	100	10	10	200–2000	100	5	5	1	50	2.5	1.5	2.5/10 (e)	1.5
MeOH							620	620		500	620	40		30
NH_3		50	5			50	3	3	10	1500	3	10		10
Amine			2				1	1	1		1	10		10

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[14] Notes
a. Total sulphur-contained compounds (COS, dimethyl sulphide, H_2S, SO_x, mercaptan), of which $H_2S \leq 5$ ppm
b. H_2S + COS + SO_x + dimethyl sulphide
c. Total sulphur
d. H_2S + SO_x + COS, concentration may be increased to 60 ppm-mol if NO_2 is not present
e. 2.5 ppm is suggested for lower operating temperatures (seabed)
f. H_2S + COS
g. $SO_3 \leq 0.1$ ppm-mol

[15] Adapted from **Wood Group,** *"Industry Guidelines for Setting the CO_2 Specification in CCUS Chains."*

Consistent pressure ratings and pipeline diameters to minimise booster station requirements.

While a harmonised CO_2 quality specification primarily addresses fluid composition, consistent (where technically and economically feasible) pressure ratings and pipeline diameters are equally critical engineering considerations for the development of an integrated North Sea CO_2 transport network. Harmonisation in these design parameters reduces unnecessary pressure drops across interconnected pipeline systems, thereby minimising the need for intermediate booster or recompression stations and supporting more cost effective and scalable network expansion.

The importance of diameter–pressure alignment is well documented in the CO_2 pipeline design literature, including DNV's recommended practice.[16] Pipeline diameter and operating pressure are the dominant variables influencing frictional pressure losses, flow velocity, and overall hydraulic performance of CO_2 transport systems. Sub optimal diameter selection can result in excessive pressure drops, forcing the installation of additional booster stations, whereas oversized pipelines increase capital costs without proportional operational benefits.[17]

Recent work by Fraunhofer Institute reinforces this through a detailed techno-economic analysis of CO_2 transport infrastructure. Their study demonstrates that pipeline diameter choice and pressure drop directly determine compressor spacing, number of booster stations, and total transport cost.[18]

Extendable transport routes supported by proactive extension planning.

Due to the "chicken-and-egg" challenge in CCS deployment, CO_2 pipelines may need to be built ahead of capture projects; network design should therefore enable proactive, expandable route planning for these future emitters.

A study by the European Commission's Joint Research Centre (JRC) shows that Europe will require a large, integrated and highly international CO_2 transport network to meet its climate-neutrality targets.[19] In the offshore-only scenario (B2), where all captured CO_2 must be stored in offshore sites, Europe develops the largest and most extensive CO_2 transport networks of any scenario assessed. By 2050, the network length reaches up to 19,000 km, driven by the need to route CO_2 from inland regions to limited offshore storage hubs. Although the study demonstrates expandability for onshore routes, the principle is transferable to North Sea pipeline infrastructure, where future offshore corridors will similarly need to accommodate new emitters and evolving network demands.

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[16] **DNV.** 2021. DNV-RP-F104: Design and operation of carbon dioxide pipelines. Recommended Practice, February 2021, amended September 2021.

[17] **Peletiri, S. P., Rahmanian, N., & Mujtaba, I. M**. 2018. CO_2 Pipeline Design: A Review. Energies, 11(9), 2184

[18] **Fraunhofer-Gesellschaft.** 2024. Pipeline infrastructure for CO_2 transport: Cost analysis and design optimisation. Journal article.

[19] **European Commission, Joint Research Centre (JRC).** 2024, *Shaping the future CO_2 transport network for Europe*.

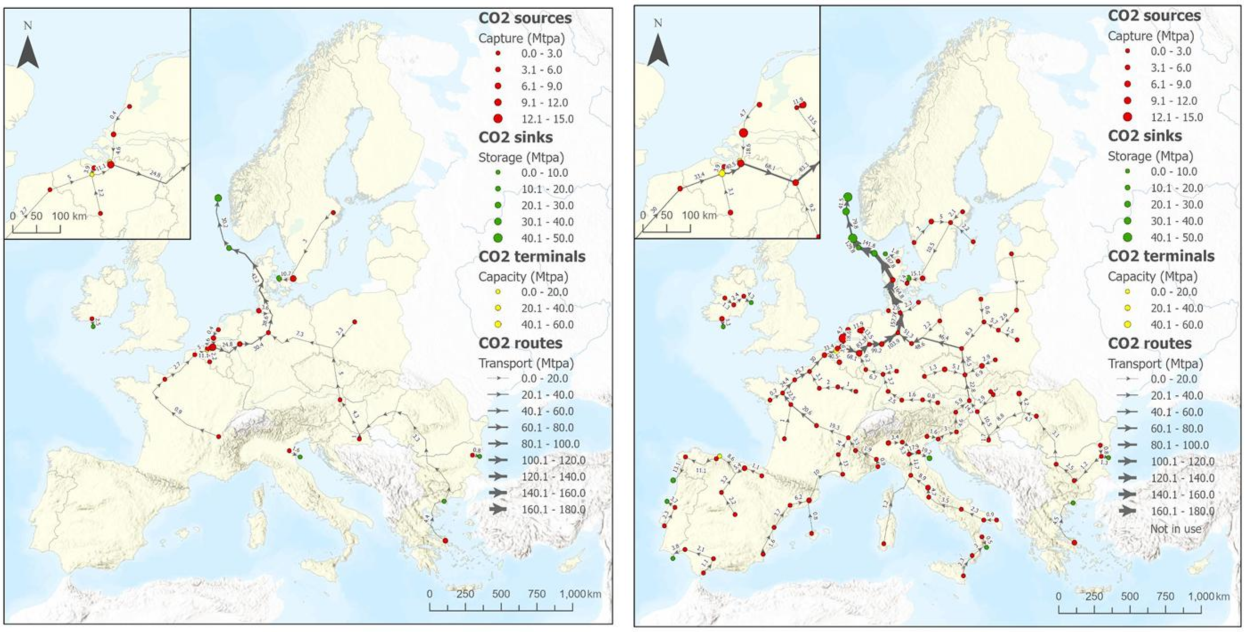

Figure 19. Scenario B2 - CTP 2040 & Offshore only (EU+NO+UK), year 2030

Source: JRC, 2024

Figure 20. Scenario B2 - CTP 2040 & Offshore only (EU+NO+UK), year 2040

Source: JRC, 2024

Figure 4-2 Scenario B2 2030 and 2040 from ref. 19

This scenario also produces high levels of cross-border offshore CO_2 flows, with the North Sea emerging as the dominant storage basin due to its scale, maturity and availability of suitable geological formations. As a result, major offshore pipeline corridors function as continent-spanning CO_2 transport "superhighways", linking dispersed emitters to a number of high-capacity offshore stores. The findings demonstrate that in regions lacking adequate geological storage, offshore pipelines become the essential backbone of the European CO_2 management system.

Although transferable learnings can be drawn, direct interconnection between the UK and mainland Europe or Norway is not represented, as cross-border CO_2 transport beyond the assessed regions falls outside the scope of the JRC study.

4.2.1.2 Operational Resilience

Alternate export/import routes to enable the flows if one corridor goes offline.

Pipeline-based CO_2 transport systems are inherently rigid when they connect a source (or cluster) to a single storage site. Pipelines gain operational flexibility once they are interconnected through branching, multi-hub systems, shared trunklines, or regional backbone networks. These interconnections enable routing options similar to gas networks, allowing CO_2 flows to be diverted when stores are constrained or routes are offline. However, achieving this level of flexibility requires significant investment into new or repurposed infrastructure and coordinated planning.

Europe's CO_2 network is expected to rely on shipping and the terminal facilities at ports, given the inherent flexibility Non-Pipeline Transport (NPT) provides. NPT is not tied to fixed linear corridors, so it enables emitters to access multiple offshore storage sites rather than relying on a single pipeline-linked store. Multi-store accessibility reduces the operational risks associated with constrained or temporarily unavailable storage sites and prevents emitters from becoming dependent on a single pipeline or hub.

The Netherlands provides one of the strongest real-world examples of how pipeline flexibility only emerges when multiple transport corridors and storage sites are interconnected. Five major Dutch CO_2 infrastructure projects (Porthos, Aramis, CO_2next, Delta Rhine Corridor, and Delta Schelde CO_2nnection) are purposefully coordinating to form a single, integrated cross-border CO_2 transport and storage network for Northwest Europe.

Figure 4-3 Cross-border CO_2 Transport (Porthos)

1. Porthos provides a trunkline from the Port of Rotterdam to offshore storage under the North Sea.
2. Aramis introduces additional offshore storage capacity and routing optionality.
3. CO_2next develops export terminal capacity at Rotterdam, enabling shipping-based access to multiple stores.
4. Delta Rhine Corridor connects Rotterdam's industrial cluster with Germany, providing a cross-border pipeline link and the potential to reroute CO_2 eastwards.
5. Delta Schelde CO_2nnection links Rotterdam to Antwerp, creating a hub-to-hub corridor between two major industrial clusters.

Ref: **Offshore Energy.** *Dutch CO_2 quintet paving the way for Northwest Europe's cross-border CCS network.*

Inter-modality: the ability to switch between pipeline and ship if needed.

An interconnected European CCS system may require CO_2 to move across several transport modes in series. Each transition introduces interfaces where the CO_2 may need to be heated, cooled, compressed, depressurised, or purified. The table from the CCUS Forum Expert Group on CO_2[20] summarises the level of compatibility between modes.

Table 4-2 Full combination of transfers as outlined in ref.20

To From	Gas phase pipeline	Dense phase pipeline	MP shipping (14-17.5 bar)	LP shipping (6.5-8 bar)	Rail and truck
Gas phase		Fully compatible	Purification	Purification	Not likely
Dense phase	Exceptional		Purification	Purification	Not likely
MP shipping	Not likely	Fully compatible		Unexplored	Fully compatible
LP shipping	Not likely	Fully compatible	Unexplored		Fully compatible
HP shipping	Unexplored	Unexplored	Unexplored	Unexplored	Unexplored

As shown in Table 4-2, transitions between different CO_2 transport modes frequently require additional purification, especially when moving into MP or LP shipping, which demand very strict purity and low water content, or when shifting from gas-phase to dense-phase transport. To enable these transitions, purification units such as drying and sulphur-removal systems must be strategically located at hubs and terminals, with shared facilities helping to avoid duplication.

Capture and value chain interdependencies

Another critical dimension of operational resilience lies in the management of interdependencies across the CCS value chain. Because transport networks rely on steady, predictable flows, any delay, shortfall, or under-performance in upstream capture projects can lead to lower-than-expected volumes entering the system, undermining utilisation assumptions and affecting the commercial viability of shared transport assets. Similarly, downstream constraints, such as storage sites that are not fully commissioned, face injection limitations, or experience temporary outages will disrupt CO_2 capture or transport upstream.

Understanding interdependencies across the full CCS and hydrogen value chain will be critical given the complexity of these systems, where performance or availability issues in one segment can have wider impacts across the network. This highlights the value of system-level reliability, availability, and maintainability (RAM) analysis in informing design, contingency planning, and operational strategies.

According to ING Research data, projections indicate that by 2030, Europe will possess far more transport and storage capacity than captured CO_2 volumes.[21] While it is expected that infrastructure must be in place before emitters commit, the scale of the emerging imbalance signals the need for more coordinated action. Closing this gap in the coming years will be essential to ensure that investments in CO_2 transport and storage are fully utilised and aligned with sufficient capture deployment. Although the Net Zero Industry Act (NZIA) sets a binding EU wide target of 50 Mt/year of operational CO_2 storage injection capacity by 2030 under Article 23, current project delivery trajectories indicate that progress is falling short of this target.[22] The NZIA 2030 target can play a crucial role in providing confidence to emitters by trying to address the imbalance between CO_2 transport and storage capacity and captured volumes by providing a unifying, time-bound framework for coordination across the value chain.

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[20] **CCUS Forum Expert Group on CO2 Specifications.** 2023. An Interoperable CO2 Transport Network – Towards Specifications for the Transport of Impure CO2. European Commission.

[21] **ING Research.** 2026. Energy Outlook 2026.

[22] **Article 23 Watch**. 2026.

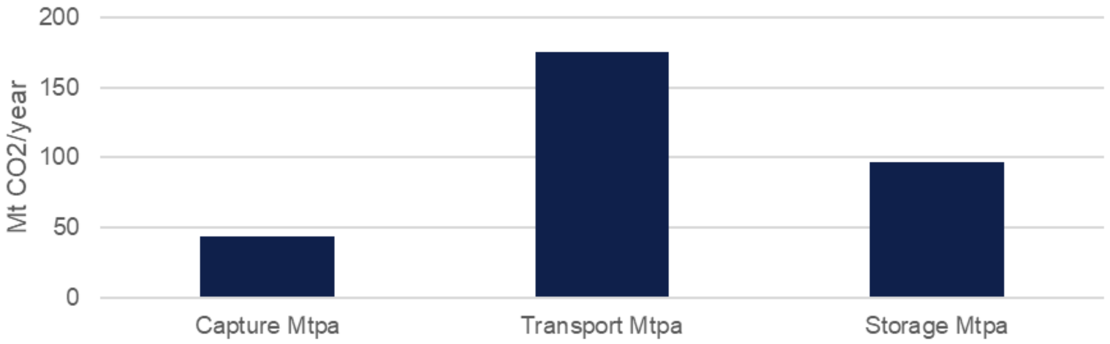
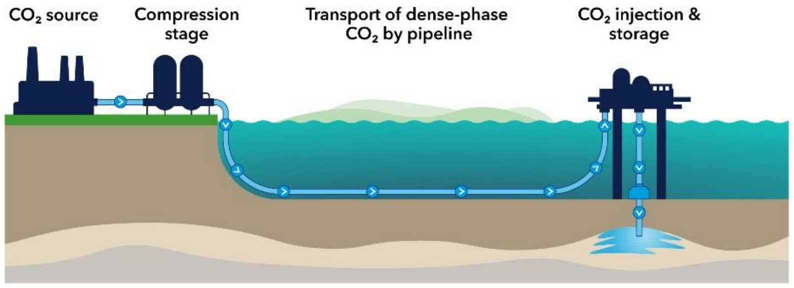


Figure 4-4 CCS estimates along the value chain, by 2030 for Belgium, France, Germany, Denmark, Netherlands, United Kingdom and Norway, based on ING Research (ref. 21)

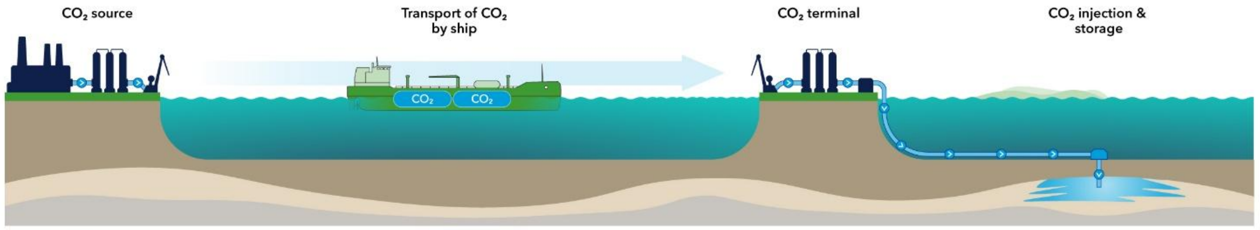
Buffer/holding storage sites for operational smoothing and contingency management.

Buffer or intermediate storage plays a crucial role in maintaining operational continuity, flexibility, and resilience in integrated CO_2 transport systems, particularly in a potential multi modal North Sea network. These facilities which are to be located at emitter sites, ports or pipeline injection points act as shock absorbers that smooth out the natural variability in CO_2 capture, transport, and injection operations.

Buffer capacity must be sized appropriately for the expected batch delivery frequency and volumes, enabling stable downstream operation even when supply patterns fluctuate. Figure 4-5 shows typical CCS value chains; buffer storage is required for operational resilience and would typically be located at the port or CO_2 source.



Transport - pipeline-based



Ship-based transport

Figure 4-5 Typical CCS value chains (DNV)

4.2.1.3 Regulatory Resilience

EU ETS/UK ETS linking to align carbon pricing and crediting rules to enable interaction between systems.

An Emissions Trading System (ETS) is a cap-and-trade mechanism that reduces greenhouse gas emissions by setting a limit on total emissions and issuing tradable allowances. Each allowance authorises the emission of one tonne of CO_2-equivalent. Companies that cut emissions can sell surplus allowances, while those exceeding their limit must buy more. This creates a financial incentive to reduce emissions cost-effectively, and as the emissions cap tightens over time, total emissions fall in a predictable, market-driven way.[23]

The UK ETS, introduced after Brexit, mirrors the core design principles of the EU ETS. It similarly aims to deliver sustained decarbonisation through a declining emissions cap and a market-based mechanism for trading allowances.

As outlined in the EU–UK Summit's "Common Understanding," it's agreed to pursue a formal linkage of the emissions trading systems, setting out the framework, principles, and next steps for aligning the EU ETS and UK ETS.[24]

A linked market would help deliver clearer, more consistent carbon price signals across jurisdictions, supporting investor confidence and enabling more coordinated decarbonisation planning for companies operating in both regions. EU emitters would be able to store carbon in the UK and vice versa, reducing uncertainty about legal recognition of stored CO_2 units. One of the key benefits of linking is the creation of a more robust and stable carbon price. Stable carbon pricing is critical for long-term industrial transformation, particularly for capital-intensive sectors that rely on predictable policy frameworks when making investment decisions.

Linking would also help safeguard competitiveness across European industrial value chains. When carbon prices or allocation rules diverge between systems, businesses operating across borders can face inconsistent compliance costs, potentially distorting competition. Harmonising the markets through linkage would reduce these disparities, creating a level playing field and helping to mitigate carbon leakage risks for energy-intensive industries.

CO_2 cross-border legality (London Protocol)

Article 6 of the Basel Convention regulates cross-border CO_2 movement and was originally designed to prevent waste exports, effectively prohibiting the export of CO_2 for offshore storage.[25] In 2019, Parties adopted a resolution allowing provisional application of the amendment through bilateral agreements, even before its formal entry came into force, enabling signatories to progress CCUS via such arrangements. Countries including Norway, Belgium, the Netherlands, Denmark, and Sweden have since established multiple bilateral deals under this mechanism. However, the amendment remains unratified globally, meaning the export ban technically still applies unless countries rely on these bilateral workarounds.

Table 4-3 is a consolidated status table for European countries, based on the latest IMO reports and internal briefing notes. The 2009 amendment has not yet entered into force because only 14 acceptances have been deposited, far short of the 36 required for ratification. Provisional application therefore serves as the key legal workaround, enabling projects such as Northern Lights to import CO_2 from other countries despite the amendment's pending status.

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[23] Carbon Gap. 2026. EU Emissions Trading System (EU ETS).

[24] A renewed agenda for European Union – United Kingdom cooperation Common Understanding

[25] Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal

Table 4-3 London Protocol Status Overview

Country	Date of Ratification	Accepted Article 6 Amendment	Provisional Application Declared	Bilateral Agreements
Belgium	2007-01-05	Yes	Yes	BE–DK (2022)[26], NO–BE (2024) [27]
Denmark	2006-12-22	Yes	Yes	BE–DK (2022)[26], NO–DK (2024)[28], DK-SE (2024)[29], FR-DK (2024)[32], NL-BE (2023)[34]
Estonia	2007-01-05	Yes	No	
Finland	2007-01-05	Yes	Yes	FI-NO (2025)[30]
France	2007-01-05	Yes	Yes	FR-NO (2025)[31], FR-DK (2024)[32]
Netherlands	2007-01-05	Yes	Yes	NO–NL (2024)[33], NL-BE (2023)[34]
Norway	2007-01-05	Yes	Yes	NO–NL (2024)[33], NO–BE (2024)[27], NO–DK (2024)[28], NO–SE (2024)[35] , FI-NO (2025)[30], FR-NO (2025)[31]
Sweden	2007-01-05	Yes	Yes	NO–SE (2024)[35], DK-SE (2024)[36]
Switzerland	2007-01-05	Yes	Yes	
United Kingdom	2007-01-05	Yes	Yes	

Custody Transfer and metering - standardised measurement and verification rules for cross-border handover of CO_2.

There is no harmonised EU framework for cross-border CO_2 custody-transfer metering and verification. Measurement practices instead rely on national regulations, emerging industry standards, and contractual agreements. EU rules cover storage and ETS reporting, and technical guidance exists, but custody-transfer metering and CO_2 purity standards remain unstandardised.

In shared CO_2 transport networks, robust chain-of-custody arrangements are essential to ensure accountability, regulatory compliance, and confidence among multiple system users. A potential approach is based on mass balance principles, drawing on practices established in other multi-user pipeline systems, such as natural gas networks. Key principles include:

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[26] Offshore Energy - Denmark and Belgium sign landmark agreement for CO_2 transport [2022]

[27] MoU Between Norway and Belgium [2024]

[28] MoU Between Denmark and Norway [2024]

[29] MoU Between Denmark and Sweden [2024]

[30] MoU Between Norway and Finland [2025]

[31] MoU Between Norway and France [2025]

[32] MoU Between France and Denmark [2024]

[33] MoU Between Norway and Netherlands [2024]

[34] MoU Between Belgium and Netherlands [2023]

[35] MoU Between Norway and Sweden [2024]

[36] MoU Between Denmark and Sweden [2024]

- **Clear definition of system boundaries**

  The physical and functional extent of the shared CO_2 transport chain should be explicitly defined, including all assets and interfaces that form part of the common system.

- **Identification and classification of entry and exit points**

  All points at which CO_2 enters or leaves the shared system should be clearly identified and categorised according to their function (e.g. capture facilities, transfer points, storage or utilisation sites).

- **Compliance of interface points with regulatory and operator requirements**

  Entry and exit points must satisfy applicable regulatory, safety, and technical requirements and be designed, constructed, and operated in accordance with specifications approved by the network operator.

- **Comprehensive metering and quality measurement**

  Reliable metering that is traceable to international standards and, where required, compositional analysis should be implemented at all entry and exit points to support mass balance calculations, allocation of CO_2 volumes, and verification of custody transfer.

The report on "Toward standardized measurement of CO_2 transfer in the CCS chain" also concludes that expanding calibration and testing infrastructure, improving impurity measurement capability, and developing validated thermophysical models are critical steps toward creating a transparent and interoperable CCS measurement framework.[37]

Compatibility of the commercial operational requirements for cross-border transport as part of the regulatory framework.

Compatibility in the regulatory approach to CO_2 transport and storage is essential for effective network regulation, a point reinforced by the Energy Transition Expertise Center (EnTEC).[38] Table 4-4 provides an overview of key regulatory elements that must be considered when developing integrated CCS infrastructure.

Table 4-4 Regulatory Elements

Regulatory Element	Description
Network Regulation and Regulator	Pan-European oversight supported by national regulators to ensure consistent rules for access, tariffs, and transparency.
Network Planning	EU-level planning and future-proofing, including corridor identification, volume forecasting, pipeline repurposing, and multimodal integration.
Third Party Access	Fair, transparent, and technically feasible access to CO_2 networks, underpinned by harmonised cross-border rules on CO_2 quality, tariffs, and capacity.

EnTEC also highlights that no single regulatory model will suit all CCS circumstances, as the appropriate approach depends on factors such as geography, proximity to storage, market maturity, and national regulatory cultures. While there

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[37] **Chinello, G., Arellano, Y., Span, R., van Putten, D., Abdulrahman, A., Joonaki, E., Arrhenius, K. & Murugan, A.** 2024. *Toward standardized measurement of CO_2 transfer in the CCS chain.* Nexus, 1, 100013.

[38] **EnTEC.** 2023. EU regulation for the development of the market for CO2 transport and storage. Prepared for the European Commission, DG ENER (Contract No. ENER/C2/2019-456/SI2.840317).

is a need for a common framework to ensure harmonisation and the smooth functioning of the internal market, this framework must also remain flexible, allowing Member States to adapt rules to their specific contexts.[38]

The position held by Zero Emissions Platform (ZEP) is that CO_2 infrastructure and environmental governance are inseparable as environmental rules determine what counts as real emissions reductions and ensure permanence and safety, while climate goals cannot be met without the infrastructure to transport and store CO_2. Because these aims depend on each other, ZEP supports using a dual legal basis under Articles 192 and 194 TFEU.[39]

This interdependence directly underpins the need for harmonised rules across borders, for example, to count CO_2 as "not emitted" under the EU ETS, all segments of a cross-border chain must follow common MRV, leakage, and permanence standards.

The interaction with carbon pricing mechanisms, including the Carbon Border Adjustment Mechanism (CBAM), will also be an important consideration, as misalignment could expose the system to carbon leakage risks and affect the competitiveness of domestic low-carbon production.

Permitting Resilience Through Repurposing

In offshore CO_2 storage projects, a benefit of repurposing existing natural gas pipelines lies in permitting and development acceleration. Established pipeline routes already possess seabed rights, landfall approvals, and a well-understood environmental and safety footprint. By avoiding new offshore corridors, coastal landings, and seabed disturbance, repurposed pipelines significantly reduce regulatory friction and shorten critical-path timelines, shifting the permitting challenge from greenfield consent to technical fitness-for-service reassessment.

While not cost-led, regulatory resilience translates into economic resilience through increased schedule certainty.

4.2.1.4 Economic Resilience

Ensure bankability through stable revenue models

CCS revenue models are inherently complex often combining transport fees, storage fees, carbon credits and tax incentives, each carrying different risk profiles, and therefore must be structured to provide lenders with confidence in long-term repayment capability.[40]

A report by Global CCS Institute underlines that bankability increasingly hinges on robust risk-management frameworks, including insurance for long-term storage liabilities, which lenders view as essential before committing capital to projects.[41]

Insurance helps translate uncertain technical and environmental risks, such as leakage, long-term containment, construction delays, contractor risks, and post-closure obligations, into quantifiable exposures that lenders can accept. A constraint is the lack of long-term storage performance data, which makes it difficult for insurers to price critical risks such as leakage and post-closure liability. Because CO_2 storage risks are long-duration and high-impact, insurers remain cautious about potential environmental and health consequences that may emerge decades after injection.

Ability to adapt to uncertain market conditions

As outlined in DNV's CCS to 2050 Energy Transition Outlook 2025, the key conditions for medium- and long-term scale-up (projects, policy frameworks, capital availability, and corporate action) are now aligning, signalling that the sector is at an inflection point. However, political and economic uncertainty remain the biggest risks to widening the gap between

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[39] **Zero Emissions Platform**. 2026. *ZEP's response to the public consultation on CO_2 markets and transportation infrastructure: Appendix to survey responses.*

[40] **Howden.** 2025. Carbon capture and storage: How insurance can address the financing challenges of CCS.

[41] **Global CCS Institute.** 2025. *Insurance for carbon capture and storage: State of the market.*

expected and required volumes for large-scale decarbonisation. This highlights the need for business models that remain viable across a wide range of future market scenarios.[42]

Build affordability into system design

Affordability depends heavily on design choices across the capture–transport–storage chain, with major cost reductions achievable through economies of scale, modular or standardised system design, repurposing existing pipelines, and optimisation of compression, liquefaction and transport technologies.

A Global CCS Institute report looks at advancements in CCS technologies and costs. It shows that dense-phase CO_2 pipelines offer significant cost advantages because their higher fluid density allows for smaller pipe diameters, reduced steel tonnage and therefore lower construction costs. However, achieving and maintaining dense-phase conditions requires appropriate processing, typically managed at entry points such as capture sites or terminals. While pipeline transport itself may predominantly occur offshore, the associated onshore facilities would introduce additional design, siting, and permitting considerations which may influence overall system cost and development timelines.

Economies of scale are also strong as the cost per tonne of CO_2 transported decreases substantially once throughput exceeds around 1 Mt/year, with most cost efficiencies achieved between 1–3 Mt/year. Beyond approximately 5 Mt/year, however, additional cost reductions become marginal, indicating that the greatest affordability gains come from designing systems that operate within this optimal capacity range.

Shipping cost efficiency is influenced by a wide set of design factors, including shipping pressure choices, ship sizing strategies, intermediate storage requirements, and liquefaction optimisation. These findings are also explored in more detail in the Global CCS Institute report.[43]

Affordability also improves when systems are built for future volume, as oversizing pipelines and injection infrastructure at the outset is far cheaper than retrofitting later; modular compression trains can then be added incrementally as capacity grows. Minimising pressure changes across the chain is another major cost driver. Each transition (between compression, liquefaction, shipping and injection) introduces additional capital and energy costs. Aligning shipping pressures with injection requirements, reducing unnecessary throttling or reheating, and integrating dense-phase pipeline strategies with downstream shipping and storage operations all help simplify the system and cut costs over the project lifetime.

While reusing existing natural gas pipelines can reduce upfront capital costs and accelerate the development of a CO_2 transport network, repurposing introduces uncertainty that affects both operational constraints and bankability.

In terms of affordability to the network user, tariff transparency will be key as it reduces investment uncertainty for emitters, strengthens confidence that charges are fair and cost-reflective, and supports predictable revenue streams that enable efficient network development and expansion. By clearly signalling how costs are structured and recovered, it encourages early participation that improves utilisation and lowers per-tonne charges, while also enabling market benchmarking and competition where possible.[44]

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[42] **DNV.** 2025. Energy Transition Outlook: CCS to 2050.

[43] **Barlow, H., Shahi, S.M.S. & Kearns, D.T.** 2025. *Advancements in CCS Technologies and Costs.* Global CCS Institute.

[44] **Zero Emissions Platform (ZEP)** 2026, *ZEP's response to the public consultation on CO_2 markets and transportation infrastructure: Appendix to survey responses*, Zero Emissions Platform, 9 January 2026.

4.2.1.5 CCS Summary

CCS Infrastructure Resilience Summary

Technical Dimension	
Core Focus	**Technical resilience: how the system is built** A focus on ensuring redundancy in CO_2 transport routes and interoperability of pipeline specifications.
What Enables Resilience	• Fit-for-purpose CO_2 quality specifications (harmonised where possible) • Consistent pressure/diameter pipeline design • Expandable, corridor-based network design
Risks / Challenges	• Misaligned or overly rigid CO_2 purity specifications driving unnecessary conditioning cost and limiting market participation. • Premature standard-setting locking in specifications before the market stabilises. • Misalignment in pipeline diameter and pressure regimes creating inefficiencies at network interfaces, often necessitating additional compression to maintain flow performance.
Pathway Forward	Near/Medium-term: Define minimum viable CO_2 quality envelopes and indicative pressure regimes that enable early interoperability without premature standard lock-in. Long-term: Progress towards harmonised specifications and expandable corridor designs as operational experience and network interconnection increase. Lead actors: T&S developers and pipeline operators, coordinated via JIPs and supported by standards bodies and regulators.
Operational Dimension	
Core Focus	**Operational resilience: how the system is physically run** A focus on reliability and flexibility to manage CO_2 export through diversified routing and storage options.
What Enables Resilience	• Multi-route, multi-hub networks • Pipeline and shipping inter-modality • Buffer/holding storage
Risks / Challenges	• High interdependency risk: delays in capture, permitting, shipping availability, or storage readiness causing full-chain disruption. • Port and terminal readiness emerging as bottlenecks in a shipping-dominated system. • Lack of multi-store access leading to a dependency on single corridors or single storage sites. • Frequent purification requirements at inter-modal transitions without coordinated planning. • Insufficient buffer capacity to absorb variability in capture or shipping schedules.

Pathway Forward	Near/Medium-term: Plan hub-based systems with optionality for multi-route and multi-store access, including early provision for buffer and intermediate storage. Long-term: Integrate pipeline and shipping operations into coordinated dispatch and routing frameworks, reducing single-point dependencies and inter-modal friction. Lead actors: Hub and network operators, port authorities, and shipping providers, with coordination support from public infrastructure planners.
Regulatory Dimension	
Core Focus	**Regulatory resilience: how the system is governed** A focus on ensuring aligned and interoperable policy and regulatory frameworks that support cross-border CO_2 transport and storage.
What Enables Resilience	• EU–UK ETS linkage • Bilateral agreements under London Protocol • Standardised custody transfer, measurement
Risks / Challenges	• Unharmonised metering and custody-transfer frameworks, risking inconsistent accounting of CO_2 across borders. • London Protocol amendment still not ratified, relying on bilateral workarounds. • Inconsistent Third-Party Access and tariff frameworks across jurisdictions. • Absence of unified European-level network planning governance, risking incompatible national systems.
Pathway Forward	Near/Medium-term: Advance interim cross-border arrangements (bilateral agreements, aligned MRV principles) to enable early projects while broader frameworks mature. Long-term: Establish interoperable MRV, custody transfer, and Third-Party Access regimes, supported by coordinated regional or EU-level network planning. Lead actors: National regulators and governments, EU and UK institutions (European Commission, DESNZ etc.) and permitting authorities.
Economic Dimension	
Core Focus	**Economic resilience: how the system sustains itself economically** Ensuring the North Sea CCS system stays financially viable, competitive, and adaptable to market fluctuations.
What Enables Resilience	• Stable, predictable revenue frameworks (transport + storage fees, carbon credits) • Insurance and risk-management solutions for long-term liability • Cost-efficient system design choices (aligned pressure regimes, minimised phase transitions, optimised compression/liquefaction strategy) • Economies of scale

	- Future-proof infrastructure sizing (oversizing pipelines early where cost-effective) - Standardisation and modularisation across the chain to suppress CAPEX/OPEX
Risks / Challenges	- Insurability barriers due to limited long-term storage performance data, constraining bankability. - Affordability risks from misaligned design choices (pressure mismatches, suboptimal pipeline sizing, unnecessary phase changes). - Repurposed gas pipelines introducing operational constraint and bankability uncertainty. - Mismatch between capture deployment and T&S build-out, risking underutilised assets and stranded capacity. - Exposure to policy and carbon-price volatility. - Insufficient tariff transparency delaying emitter commitments.
Pathway Forward	Near-term: Improve tariff transparency, clarify risk-sharing arrangements, and align early design choices to reduce avoidable CAPEX and OPEX. Medium-term: targeted support and regulated frameworks to enable cluster development and scale-up. Long-term: transition to larger, more commercially driven systems with declining subsidy intensity. Lead actors: Governments (policy and risk frameworks), T&S developers (design and tariffs), financial institutions and insurers, and committed emitters.

4.2.2 Hydrogen Infrastructure Resilience

4.2.2.1 Technical Resilience

Harmonised quality specifications to avoid border reconditioning and support pipeline compatibility.

Hydrogen purity is a complex topic, that has led to many different hydrogen standards across jurisdictions. This is largely due to the variation in purity that comes from the variety of hydrogen production methods coupled with the variation in purity requirements for different applications. For example, for hydrogen fuel cell applications, both for transport and stationery power require extremely high purity, particularly for concentrations of carbon monoxide, sulphur compounds and ammonia. This is specified by ISO 14687 (grade D), it is likely that hydrogen transported in bulk via pipelines will be of lower purity, due to the cost of purification and the lower purity requirements of most applications.[45] In the North Sea region, several countries are developing standards for hydrogen transport in pipelines, as part of their energy transition strategy.

The ability to smoothly transport hydrogen within the North Sea and between adjoining countries requires standardisation of the hydrogen purity specifications, such that the gas can be transported between regions without the need for additional process steps. Table 4-5 shows a cross section of hydrogen pipeline standards in the North Sea region.

Contaminants such as CO_2, sulphur compounds alongside the presence of water are key components that will affect the longevity of the pipeline and the risk of accelerated corrosion.

UK standards (e.g. IGEM/H/1) allow higher CO_2 concentrations and specify a lower overall hydrogen purity (~98%) compared to many European standards (~99.5%). This reflects the UK's pragmatic approach to the costs and benefits of further purification for most users of hydrogen transported by pipelines and for hydrogen blending with natural gas.

In contrast, there is a move within the EU to harmonise hydrogen specifications at around 99.5% purity. This level is considered a practical compromise between industrial requirements and the cost of purification. [46]

If 99.5% becomes the European norm, the UK may need to align with this standard to enable cross-border transport via interconnectors.

Water specifications are broadly similar across the UK and EU, aiming to prevent liquid water formation under normal operating conditions and thereby reduce corrosion risk. European standards also typically impose lower CO_2 limits, further mitigating corrosion risk, whereas in the UK this is managed primarily by controlling water content.

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[45] **International Organization for Standardization (ISO).** 2025. ISO 14687: Hydrogen fuel quality - Product specification.

[46] EASEE-gas study Optimum Hydrogen Purity in Europe - EASEE-gas

Table 4-5 Hydrogen standards and their respective specifications for several impurities

Component	IGEM/H/1 (UK)[47]	Unit	Dutch Ministry[48]	Unit	HyNetwork Netherlands[49]	Unit
Year published	2023		2023		2022	
Hydrogen	98	% (cmol/mol)	> 99.5	mol%	> 99.5	mol%
Water						
Oxygen	≤0.2	% (cmol/mol)	< 10	mol ppm	< 10	µmol/mol
Nitrogen (inerts)			< 0.5	mol%	< 0.5	mol%
$Ar+N_2+He$	≤ 2	% (cmol/mol)			< 0.5	mol%
Hydrocarbons inc CH_4			< 0.5	mol%		
CH_4+CO_2+ total hydrocarbons	≤ 1	% (cmol/mol)			<0.5	mol%
Carbon dioxide			< 20	mol ppm	< 20	µmol/mol
Carbon monoxide	20	ppm (µmol/mol)	< 20	mol ppm	< 20	µmol/mol
Formic acid			< 10	mol ppm	< 10	µmol/mol
Ammonia			< 10	mol ppm	< 10	µmol/mol
Formaldehyde			< 10	mol ppm	< 10	µmol/mol
H_2S	≤ 5 ≤ 3.5	mg/m^3 ppm (mol/mol)				
Total sulphur (inc H_2S)	≤ 50 ≤ 35	mg/m^3 ppm (mol/mol)	< 3	mol ppm	< 3	µmol/mol
Halogens			<50	mol ppb	<0.05	µmol/mol
Hydrocarbon dew point	≤ –2	°C at any P up to 85 bar	< –2	C at P up to 70 bar	< -2	C at 1-70 bar
Water dew point	≤ –10	°C at 85 bar	< –8	C at P 70 bar	< –8	C at P 70 bar
Wobbe Number	42–46	MJ/m^3			45.99 – 48.35	MJ/m3 (n)
Other impurities	None that are detrimental					

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[47] WP2 - Hydrogen quality standards - Hy4Heat

[48] DNV and Kiwa. 2023. A follow-up study into the Hydrogen Quality Requirements

[49] Indicative quality and temperature specification for Hydrogen Network Netherlands - hynetwork

Extendable transport routes supported by proactive extension planning.

For the import and export side of the North Sea to be truly resilient and future proofed – transport routes should be designed such that they can be extended beyond the initial reach. This means ensuring that the domestic transporters of gas within each relevant jurisdiction are on board and planning for connections across the countries. In the case of the UK, Project Union intends to connect clusters on the east coast initially, with the intention to extend the network further across the UK in later years – this is discussed in more detail in Section 5.2. In Europe, the European Hydrogen Backbone (EHB) initiative brings together a host of European infrastructure operators to collaborate on the development of a transport network across multiple European countries that integrates with proposed coastal and offshore infrastructure. Continued development of this initiative and involvement of regulatory and government bodies is key to ensuring access to a diverse range of hydrogen supply and demand via a well-connected network. Accessing a broader set of regions enables shifts of demand peaks and troughs and therefore better integration and utilisation of assets.

Capacity buffers to absorb demand or supply shocks.

In the natural gas network, resilience is enhanced by large scale storage of gas across the network. This is done in large quantities in geological storage facilities such as salt caverns and depleted offshore fields the UK and across Europe. LNG terminals also provide critical storage. Additional diurnal storage is also achieved by the use of 'Linepack' within the gas networks themselves; the pressure is cycled in the pipelines within limits so as not to age the pipelines prematurely. Linepack is considered to offer limited applicability to hydrogen systems for several reasons:

- Lower energy density – volumetric energy density of hydrogen is ~ 1/3 of that of natural gas
- Potential to accelerate fatigue crack growth in hydrogen systems

Geological storage of hydrogen, in salt caverns, lined rock caverns, aquifers and depleted fields is generally expected to be feasible. There are however several key considerations that need to be thought through to enable their effective use:

- Geography – depleted fields only exist in certain regions, salt caverns require underground salt deposits, aquifers are only in certain locations. Lined rock caverns can be more flexible, but are smaller scale and require significant investment in their formation.
- Timeline – Depleted fields are only available at specific timelines based on cessation of production, and salt caverns for example take multiple years to create, although it is likely that natural gas caverns can be repurposed to hydrogen.

Due to the scale, required investment and long development timelines, large scale hydrogen storage will require concerted industry effort and government support. This is a key aspect of the future hydrogen economy, its use as an energy vector, and its application in inter-seasonal storage and to support whole energy system resilience across the region. While the hydrogen supply and demand landscape may take time to develop, early decisions on the development of large-scale hydrogen storage – in advance of the scale up of the hydrogen economy - will be key to ensure sufficient storage does not become a bottleneck to the development of an integrated and resilient hydrogen economy across the North Sea region. It is of note that current large scale hydrogen storage plans are onshore.

4.2.2.2 Operational Resilience

Alternative export/import routes to enable the flows if one corridor goes offline.

The resilience of gas and electricity networks is achieved through means such as system redundancy and multiple alternative pathways for the flow of energy.

In the case of hydrogen, this can be replicated between and within countries by creating a network with sufficient redundancy that if a pipeline is offline, transport can be maintained via alternative routes. Currently this is maintained with natural gas via several parallel pipelines that cross the North Sea to offer capacity and redundancy to maintain availability of transport options.

It is unlikely that shipping of gaseous hydrogen will form a credible alternative to hydrogen pipeline transport as the volumes that can be shipped in the gas phase are quite low. Inter-regionally, it is expected that hydrogen will be shipped either in the liquid phase, or bound into a hydrogen carrier (such as ammonia or liquid organic hydrogen carrier (LOHC)). The shipping will transport hydrogen (derivatives) as an energy vector from regions with abundant and cheap renewable energy to those with less available energy. It is also less likely that these more transportable forms of hydrogen will be made in significant quantities in Europe due to the high price of energy.

Operational resilience and redundancy of transport routes should therefore consider the tried and tested strategies used in the current natural gas network within and across the North Sea and in the adjacent jurisdictions. It remains to be determined which of these strategies can be applied to the nascent hydrogen network, and what new approaches may need to be developed.

Reverse flow H_2 pipelines to accommodate supply and demand shifts, multiple routes to support resilience

The North Sea acts as a region of great potential for production and transport of energy throughout the energy transition, however, it also adds complexity, with potential geographic and political barriers to the transfer of energy between countries.

At the present time, this is managed by interconnectors between the UK, Ireland and mainland Europe that are designed to deliver energy either electrical, or natural gas across the North Sea.

The natural gas interconnector between Bacton in the UK and Zeebrugge in Belgium was originally designed to transport natural gas from the UK to Belgium – and wider continental Europe[50]. It was however designed and built with sufficient flexibility that bidirectional transport could be enabled in the future. Since it became operational in 1998 it has been capable of bi-directional flow, with an increase in Belgium to UK flow implemented in 2005. Further expansion in 2010 was completed with a parallel pipeline. A separate pipeline (BBL pipeline[51]) connects Bacton and the Netherlands, operated by BBL, a joint venture of Gasunie, Uniper and Fluxys. This pipeline was initially designed for uni directional flow, but upgraded to bidirectional flow later. These pipelines work alongside the Langeled pipeline operated by Gassco between Nyhamna in Norway and Easington in the UK[52], this also passes through the Sleipner offshore facilities, which enable connection to other pipelines and other countries. Between them, these pipelines offer significant gas transport capacity via multiple routes between the UK and several countries across the North Sea. This sets up significant redundancy that supports resilience in the system.

A similar strategy will need to be employed for hydrogen transport between the UK and Europe. Fluxys Belgium and National Gas in the UK have signed a memorandum of understanding to explore the benefits of a hydrogen interconnector between the planned infrastructure in the respective geographies. In addition, an MOU between Hydrogen Scotland and AquaVentus has been signed to intensify exploration into North Sea hydrogen.[53]

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[50] **Bacton – Zeebrugge pipeline** - Interconnector

[51] **BBL Pipeline** - BBL Company

[52] **Gassco** *Langeled North.*

[53] **AquaVentus Förderverein e.V.** 2025. Bridges across the North Sea: AquaVentus cooperates with Hydrogen Scotland.

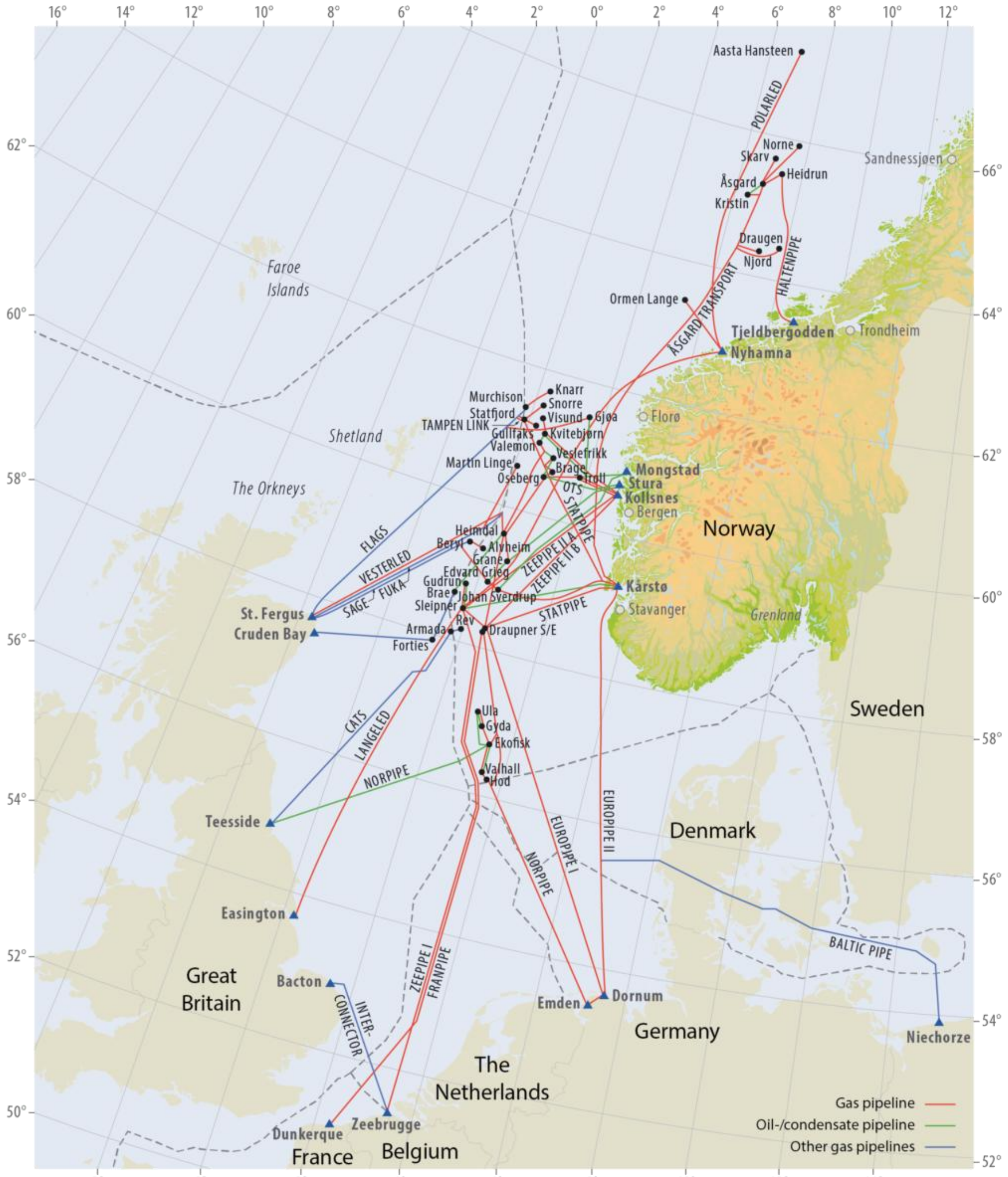

Figure 4-6 Schematic of major pipelines within and across the north sea[54]

Diversified hydrogen offtake to reduce vulnerability from reliance on a small number of customers or sectors.

Coordination across the North Sea, between the UK, Norway, and the EU, has historically supported stable and diversified natural gas markets, enabling investment in infrastructure. As the region transitions to renewable energy, similar coordination will be critical. Access to multiple markets and sectors will increase utilisation of renewable assets, reduce

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[54] **Norwegian Petroleum Directorate.** 2022. The oil and gas pipeline system.

curtailment, and improve security of supply, helping deliver benefits similar to those seen in existing energy markets, as highlighted in a 2024 study by Baringa[55].

This integrated approach also supports hydrogen development. Strong links between renewable energy and hydrogen systems will enable higher production, better asset utilisation, and greater resilience. A well-connected North Sea, through multipurpose hubs and flexible export routes such as interconnectors and hydrogen pipelines, would allow surplus electricity to be redirected to hydrogen production, improving efficiency and reducing costs. Further discussion of where offshore hydrogen production may offer the greatest benefits is provided in Section 5.2.

However, demand for hydrogen, particularly in hard-to-abate sectors, remains uncertain in the medium term. Expanding hydrogen use cases will therefore be critical to underpin investment in transport infrastructure.

In the UK, hydrogen blending into the gas network is being considered as a fallback option (offtaker of last resort) to stimulate early demand and reduce investment risk. Extending similar approaches across the North Sea could help build confidence in the demand for 100% hydrogen infrastructure and support its long-term development.

4.2.2.3 Regulatory Resilience

Network codes, Custody Transfer and metering - standardised measurement and verification rules for cross-border handover of H_2

At present, the low carbon hydrogen market is at an early stage of development, however learnings can be taken from the current landscape for natural gas transport between the EU and UK. Since Brexit, the UK has continued to adopt EU network codes to facilitate the cross-border transfer of gas. These codes include capacity allocation mechanisms (CAM NC), balancing (BAL NC) interoperability and data exchange and tariffs. These codes are all incorporated into the bilateral interconnector agreement (IA) that governs gas transport between TSOs across the interconnector pipelines. The rules around interoperability govern aspects such as gas quality, measurement requirements and data exchange, ensuring these adhere to international standards and help to ensure the gas transported can be accepted by the receiving party without issue. All these rules support the resilience and security of supply of natural gas to both sides of the North Sea by aligning requirements, ensuring that the gas keeps flowing and it adheres to the specifications required for integrity of all assets.

Within the interconnector agreement, custody transfer metering, and any associated settlement, is governed by energy flow (kWh) rather than gas volume flow. This ensures fair commercial treatment regardless of the natural gas source and its potentially varying composition. As the composition of natural gas varies by source, its energy density also varies; therefore, both volume flow rate and calorific value are measured in order to calculate the energy flow rate in kWh/h.

In the case of pure hydrogen, this process may be comparatively simplified, as variation in calorific value is typically more limited where hydrogen purity is sufficiently high; however, calorific value must still be measured and incorporated into energy calculations.

Where existing interconnectors are repurposed, or where new direct connections are constructed, similar principles to the current arrangements will apply. Alignment on custody transfer metering and gas quality requirements, robust data sharing, and close collaboration between parties at both ends of the pipeline will continue to be key factors for successful operation.

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[55] Baringa - 2024 - Beyond borders - Unlocking the power of UK-EU offshore wind coordination

Example: The Statfjord System

There are currently examples of offshore production facilities that are (or are capable of) exporting hydrocarbons to multiple countries, these tend to lie on the geographic borders between jurisdictions such as the UK and Norway. The Statfjord system (Figure 3-7) was originally designed to export gas to Norway, but in 2007, capability was introduced to export gas to the UK via the ‘Tampen link’ to the FLAGS pipeline which connects into St Fergus. Gas flow and quality is metered on the Statfjord B platform, on entry to the FLAGS pipeline and at St Fergus. The metering rules, such as calibration in adherence with entry rules to the gas networks were agreed between counterparties that operated the systems, in this case, Shell and Equinor.

The different sections of the system are owned and operated by different entities in jurisdictions with different rules. Transfer of gas between these different sections is therefore measured in several places, including directly on the offshore platform. This posed technical issues with calibration of the meters on the offshore facility (6 monthly laboratory calibrations were not deemed feasible) that were overcome by close collaboration and integration between separate entities.

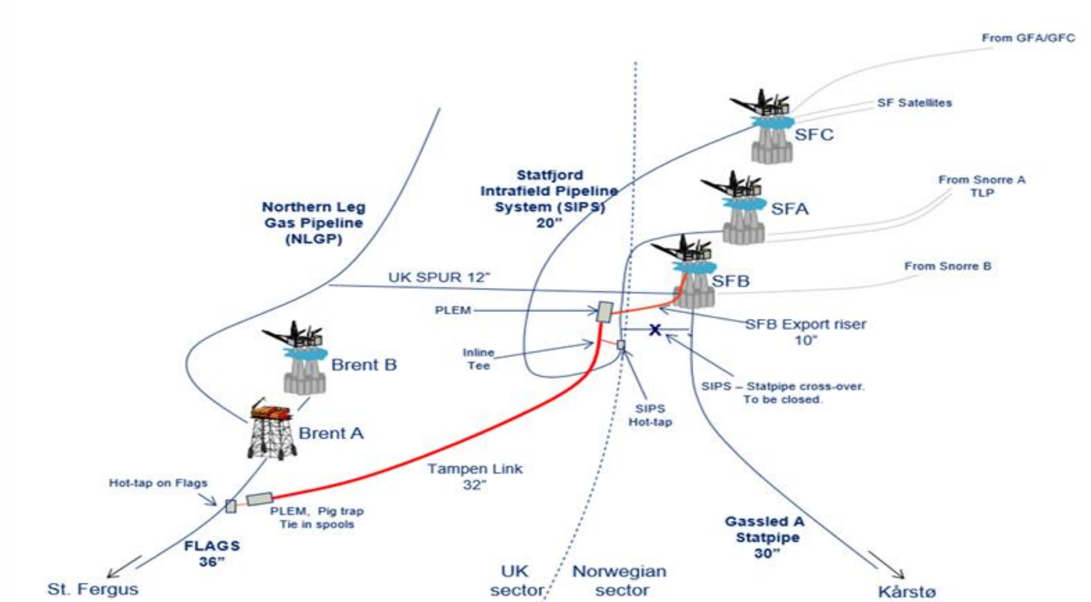

Figure 4-7. Schematic of the Statfjord system and its connections to the UK and Norway pipeline systems

Ref: Steiner Fosse (Norwegian Petroleum Directorate) and Martin Lillo (Equinor) “A field comparison of a fiscal USM gas metering station with a conventional orifice metering station”

Future offshore hydrogen interfaces will also need to build upon learnings from these cross-border oil and gas facilities. Regulations on gas quality, metering rules and calibration will need to be aligned and developed in a pragmatic way to ensure facilities do not become overcomplicated and are compatible with all jurisdictions around the North Sea. While this type of installation has operated successfully in the past, it is key to properly consider how offshore facilities that deal with hydrogen may differ in their requirements and how proper alignment between jurisdictions could potentially simplify the custody transfer processes and reduce complexity and cost of offshore facilities.

As part of future North Sea hydrogen development, a cross-border rule book should be developed to ensure that future proofed decisions can be made on cross-border transport, custody transfer and aligned purity requirements. This should include rules on interface management, what measurements should happen at each interface (e.g. landfall/pipeline/ production facility) and to what standards each component should be designed.

Compatibility of the commercial operational requirements for the interconnector as part of the regulatory framework.

Beyond metering and gas quality requirements, there is currently no full alignment between the UK and EU on the definition of ‘low-carbon’ hydrogen, which has direct implications for cross-border hydrogen transport.

The UK requires hydrogen to be produced with a greenhouse gas intensity of less than 20g of CO_2 or equivalent across the full life cycle. This can include feedstock extraction, electricity use, production process, CCS and fugitive emissions. The standard is agnostic of hydrogen production methodology as long as the emissions remain below the stated value. In the EU, renewable hydrogen defined by the Renewable Energy Directive (RED III) must be produced via electrolysis, and the renewable electricity supply needs to meet strict matching rules. In 2025, the EU published a delegated act on low carbon hydrogen that includes other hydrogen production methods and is more closely aligned with the UK version. Fundamentally, these regulations will require further alignment between jurisdictions and decisions on whether to keep several different standards in order to facilitate and simplify cross-border hydrogen transport.

4.2.2.4 Economic Resilience

Ensure bankability through stable revenue models

Large offshore hydrogen pipelines must be built at significant scale to be economic, yet early hydrogen supply and demand projects are unlikely to support such capacity on a purely commercial basis. This creates a coordination bottleneck that is likely to necessitate government support or state-led delivery models. In jurisdictions such as Norway, a potential approach is for offshore hydrogen transport infrastructure to be developed and owned by a state-backed entity, enabling pipelines to be sized for long-term system needs rather than individual project requirements and reducing risk to early market participants.

The UK government, to support the development of onshore hydrogen transport and storage infrastructure, has committed £500M to establish the first regional hydrogen transport and storage network, operational by 2031. The Hydrogen Transport and Storage Business Model award is due in 2027, however the UK Hydrogen market development has stalled due to delays in the publication of the UK Hydrogen Strategy and so impacting revenue certainty for H2 production developments for example. This underlines the importance of stable, timely and consistent revenue frameworks to unlock investment.

Similar schemes exist across the EU, such as Germany’s Hydrogen Core Network initiative, while in the Netherlands, state support is provided through state ownership of Gasunie. Offshore pipelines and interconnectors are mostly not yet included, with a few notable exceptions, such as the first section of the AquaDuctus pipeline that is already approved as part of the German Core Hydrogen Network. This is designed to import hydrogen to the German grid from the North Sea. Further interconnections across the North Sea, including to the UK, are under consideration but remain at an early development stage and do not yet have confirmed funding frameworks.

Ability to adapt to uncertain market conditions

Hydrogen demand across Europe remains subject to significant uncertainty across multiple sectors, including industrial decarbonisation, dispatchable power generation, and heavy transport. While these sectors are expected to represent the core sources of demand, their timing, scale, and geographic distribution will depend on evolving policy, technology development, and market conditions.

In the power sector, the use of hydrogen for dispatchable generation introduces an additional layer of variability, as demand will be driven by intermittent and weather-dependent system needs rather than steady-state consumption.

Further uncertainty arises from the potential role of hydrogen in space and commercial heating. Although current expectations suggest limited deployment in this sector, even partial adoption could materially increase overall demand given the scale of the heating market.

This range of uncertainties reinforces the importance of a resilient North Sea system with transport and storage infrastructure that is sufficiently flexible and scalable to accommodate demand pathways that may not yet be fully defined.

4.2.2.5 Hydrogen Summary

Hydrogen Infrastructure Resilience Summary

Technical Dimension	
Core Focus	**Technical resilience: how the system is built** A focus on ensuring extendable H_2 transport routes, sufficient storage and interoperability of pipeline specifications.
What Enables Resilience	• Alignment of hydrogen quality rules to enable seamless transition between regions. • Urgency in the development of large-scale storage. • Consideration of future hydrogen routes extended further inland to access diversified demand.
Risks / Challenges	• Misalignment of pipeline specifications based on historical differences. • Long development time for large scale infrastructure – particularly H_2 storage, leading to delays in development of capacity buffers.
Pathway Forward	Near/medium term: Proactive, public sector led decisions to build storage capacity in key geographic regions, and early alignment on hydrogen purity/ pipeline standards. Continued extension of pipeline routes inland to diversify offtake and broaden demand. Long term: A self-sustaining hydrogen market supported by cross-border flows and integrated regional networks and stores. Lead actors: Government and regulatory bodies and T&S developers.
Operational Dimension	
Core Focus	**Operational resilience: how the system is physically run** A focus on reliability and flexibility to manage H_2 supply/demand fluctuations through diversified routing, demand and integration with other industries.
What Enables Resilience	• Redundancy and flexibility of transport routes, multiple options, bidirectional flow and future proofing. • Diversification of hydrogen demand across industry to enable earlier utilisation of assets. • Integration with other North Sea infrastructure to enable synergies such as improved RES utilisation and multiple energy export options.

Risks / Challenges	• Infrastructure built slowly and potential demand has already shifted to other decarbonised options.
Pathway Forward	Near/medium term: Consideration of future increases/ changes in the supply and demand landscape to ensure future proofed design decisions are made. Long term: Large scale deployment of T&S infrastructure informed by sound early decision making, including bidirectional flow capabilities. Lead actors: Pipeline developers and operators, Industry actors with potential hydrogen demand, supported by government and regulators.
Regulatory Dimension	
Core Focus	**Regulatory resilience: how the system is governed** A focus on ensuring aligned and interoperable policy and regulatory frameworks that support cross-border H_2 transport and storage.
What Enables Resilience	• Alignment of rules on custody transfer, gas quality, calibrations, interfaces between jurisdictions. • Agreement on the definition of low carbon/ renewable hydrogen.
Risks / Challenges	• Differing legacy rules for network entry risks increasing complexity of offshore installations. • Mismatched 'low carbon' hydrogen standards blocking transport of hydrogen between regions.
Pathway Forward	Near/medium term: The development of cross-border regulatory rule book. Long term: Streamlined rules to simplify design of facilities while ensuring reliability of measurement and cross-border compatibility with networks and consumers. Lead actors: Production and T&S developers and cross-border regulators, supported by consumers as well as JIPs and working groups made up of these key stakeholders and the wider industry.
Economic Dimension	
Core Focus	**Economic resilience: how the system sustains itself economically** Ensuring the North Sea H_2 system stays financially viable, competitive, and adaptable to market fluctuations.
What Enables Resilience	• Alignment of business models across jurisdictions to ensure cross-border compatibility and stable predictable support frameworks. • Regulatory alignment to reduce complexity, reduce requirement for purification compression, measurement and increase standardisation and enable economies of scale.
Risks / Challenges	• Uncertainty on economic viability of large-scale infrastructure reduces appetite to invest. • Misalignment between jurisdictions and industries may favour investment in certain sectors. • Lack of harmonisation of regulatory regimes may complicate cross-border transport.

Pathway Forward	Near/medium term: Ensure cross industry and cross-border alignment on government support and business models, including strategy and timeline. Long term: Ensure industry continues to develop and is able to operate in the future without financial support. Lead actors: Governments, national and EU and regulatory bodies.

5 AN INTEGRATED AND RESILIENT NORTH SEA SCENARIO

The scenario is intentionally scoped to physical assets and assumes an enabling regulatory framework, including the effective implementation of relevant London Protocol provisions. As a result, all proposed resilience elements are assumed to apply, and the analysis focuses on physical and operational asset resilience rather than regulatory uncertainty.

5.1 CCS Transport and Storage Systems

The North Sea is becoming the central hub for carbon capture and storage, supported by an expanding network of CO_2 shipping corridors, offshore storage sites, and new/repurposed pipeline infrastructure.

CO_2 Storage

Where industrial emitters lack access to dedicated CO_2 pipelines, non-pipeline transport has emerged as a critical component of CCS deployment, enabling delivery of captured carbon to regions with access to offshore CO_2 stores.

The UK and EU are licensing and developing a network of offshore CO_2 storage sites, with increasing volumes of capacity expected to come online through the 2030s as appraisal, permitting, and infrastructure build-out accelerate.

Recent literature on UK CO_2 storage potential highlights the significant scale of geological storage resources on the UK Continental Shelf, as well as the strategic opportunity for the UK to act as a storage provider for European industrial emissions. According to the British Geological Survey's 2025 assessment, the UK holds an estimated 78 Gt of theoretical CO_2 storage capacity, comparable to Norway's 83 Gt, distributed mostly across offshore saline aquifers and depleted hydrocarbon fields. Despite this large theoretical storage, the proportion of storage units that are appraised and close to operational readiness remains limited, with most units historically at low Storage Readiness Levels (SRLs)[56] prior to the first major carbon storage licensing round in 2022.[57]

The BGS storage availability model analyses the portfolio of licensed UK storage sites (awarded in 2022–23) to assess when, and to what extent, appraised capacity will be available. Under a "Base Case" where all licensed sites progress to operation on current indicative timelines, the UK has just enough capacity to meet domestic storage needs through to 2050, though early-stage constraints are expected. Storage availability lags capture requirements between 2025–2027, as no licensed stores are expected to begin injection before 2027. From the early 2030s, storage availability increases substantially as Track-1, Track-2 and additional licensed stores come online, assuming no significant permitting or construction delays.

The study finds that, if "Base Case" storage develops as planned, the UK could have meaningful surplus storage capacity during the early-to-mid 2030s. In this window, the UK could accept up to ~14 Mt/yr of CO_2 imported from Europe, equivalent to >5% of Europe's 2050 storage needs, while still meeting domestic requirements. This aligns with the EU's 2024 Industrial Carbon Management strategy, which forecasts 147–243 Mt/yr of CO_2 storage demand by 2040, rising to ~247 Mt/yr by 2050, offering a potentially substantial export market.

The UK has the underlying geological potential to become a major storage provider for Europe, but realising this opportunity depends on accelerating appraisal, permitting, and development of storage sites. Early operational bottlenecks, storage under-performance, or licensing delays could significantly constrain both domestic decarbonisation and the UK's ability to participate in a future integrated European CO_2 storage market.

It is also important to consider the geographical efficiency of connecting emitters to potential storage sites. While the availability of storage capacity is a critical enabler, the transport distance between emitter clusters and storage hubs is a key determinant of cost, resilience, and operational feasibility. In this context, the UK Southern North Sea (SNS) emerges

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[56] As defined in the BGS report which was commissioned by IDRIC (ref. 57)

[57] **Industrial Decarbonisation Research and Innovation Centre (IDRIC)**. 2025 MIP 4.4: Quantification of the UK CO_2 storage export potential to drive down the cost of CCS.

as a strategically located storage province not only for UK industrial clusters but also for major emitters in France, Belgium, and the Netherlands.

Across Northwest Europe, the highest concentration of industrial CO_2 sources is located near the coast, for example Dunkirk and Calais in France; Antwerp, Ghent, and Zeebrugge in Belgium; and Rotterdam, Terneuzen, and the broader Rijnmond area in the Netherlands. From a purely geographic standpoint, these emitting regions are substantially closer to the UK SNS storage province than to Norwegian offshore storage sites such as Smeaheia or the Northern Lights complex. For example, typical shipping distances from northern France to the UK SNS are on the order of 300–450 km, while equivalent shipping journeys to Norwegian storage sites extend to 800–1,300 km.

Distance advantages offer several system-level implications. Shorter transport routes translate into lower operating costs, increased vessel productivity, and reduced weather exposure, all of which improve system resilience. For emitters relying on shipped CO_2, voyage length directly affects achievable throughput, required fleet size and buffer storage requirements, as well as the carbon intensity of the transport component. By contrast, long-distance shipping to Norway, while entirely feasible and already planned by multiple projects, introduces greater variability in cycle time and higher energy consumption.

Early CCS projects are not necessarily emerging in the locations with the shortest shipping distances, but in jurisdictions where the foundations for reliable investment and project execution are already in place. For example, Yara’s Sluiskil plant, in the Netherlands, has already entered into a 15-year binding CO_2 transport and storage agreement with Northern Lights, off the coast of Norway, covering around 800,000 tCO_2 per year. Heidelberg Materials also has a long-term agreement with Northern Lights covering approximately 400,000 tCO_2 per year from its Brevik cement plant.

CO_2 Transport

Across the CCS Projects of Common and Mutual Interest (PCIs/PMIs) (13.2 Aramis, 13.4 Bifrost, 13.8 EU2NSEA, 13.13 Northern Lights, 13.14 Nautilus), most integration occurs through NPT-type networks and connected hubs, and many Member States rely on shipping-based collection terminals or enabling infrastructure rather than continuous cross-border CO_2 pipelines.

This contrasts heavily with H_2 PCIs, which depend on major cross-border trunk pipelines as physical point-to-point interconnection is central to hydrogen market integration.

Among the current set of CCS PCIs/PMIs,PCI 13.8 – EU2NSEA is one of the few examples that incorporates a genuinely large-scale cross-border CO_2 pipeline system. The project establishes a major offshore transport corridor linking Zeebrugge in Belgium and Wilhelmshaven in Germany to geological storage sites on the Norwegian continental shelf, with the offshore pipeline infrastructure extending over 1,000 kilometres. This fixed cross-border system is designed to carry significant injection volumes to large-capacity storage formations, positioning EU2NSEA as the most substantial physical transmission project within the CCS PCI portfolio.

Despite this strong physical component, the EU2NSEA system is not a fully interconnected trans-European CO_2 pipeline network. It retains a hybrid system that relies heavily on shipping-based transport to bring captured CO_2 to the pipeline injection hubs. CO_2 from Denmark, Latvia, Poland, Sweden, and parts of eastern Germany must first be transported by barge, often via the Kiel Canal, to Wilhelmshaven, where it is then injected into the offshore pipeline. This means that although the project includes a major cross-border trunkline, most participating countries do not have direct pipeline connections. Instead, they depend on national-level CO_2 collection networks and export terminals, which serve as feeder points rather than cross-border links.

Consequently, while EU2NSEA stands out as the strongest and most extensive pipeline-based CCS project, its overall integration model still differs markedly from the meshed, point-to-point pipeline systems seen in hydrogen PCIs. It illustrates that even the most advanced CCS infrastructure in Europe remains anchored in a hub-and-spoke architecture, with shipping acting as the primary cross-border transport mode and the offshore pipeline operating more as a consolidated export corridor than a continent-wide transmission network.[58]

Some projects, such as Greensand and Havstjerne, are looking at using direct injection (ship to store) which refers to a CO_2 transport and storage configuration in which liquefied CO_2 is transported by dedicated vessels and injected directly into offshore geological storage formations, without transfer to an intermediate onshore terminal or permanent offshore buffer storage.

5.1.1 Medium-term view

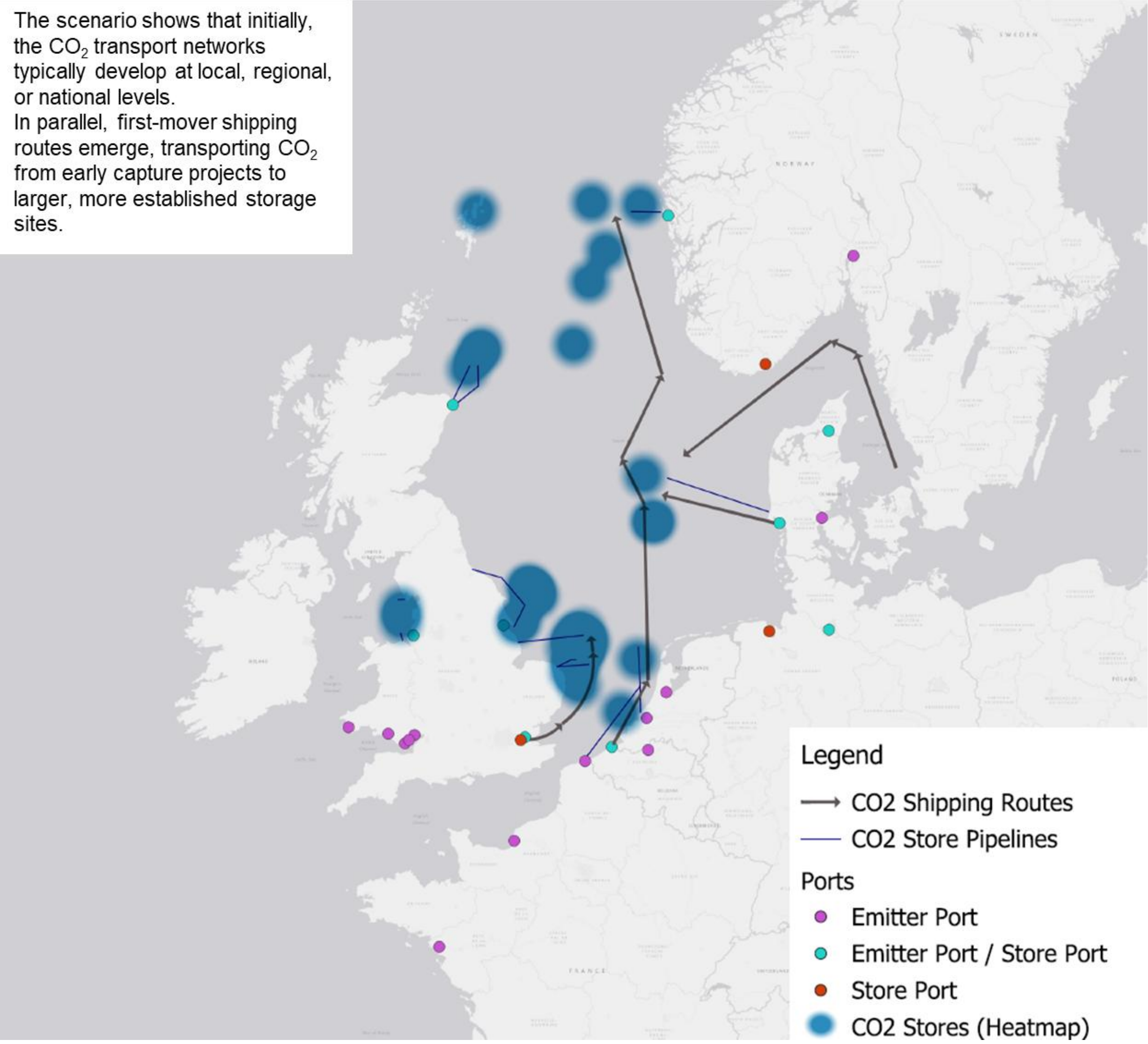
The scenario shows that initially, the CO_2 transport networks typically develop at local, regional, or national levels.
In parallel, first-mover shipping routes emerge, transporting CO_2 from early capture projects to larger, more established storage sites.

Figure 5-1 CCS Medium-term view[59]

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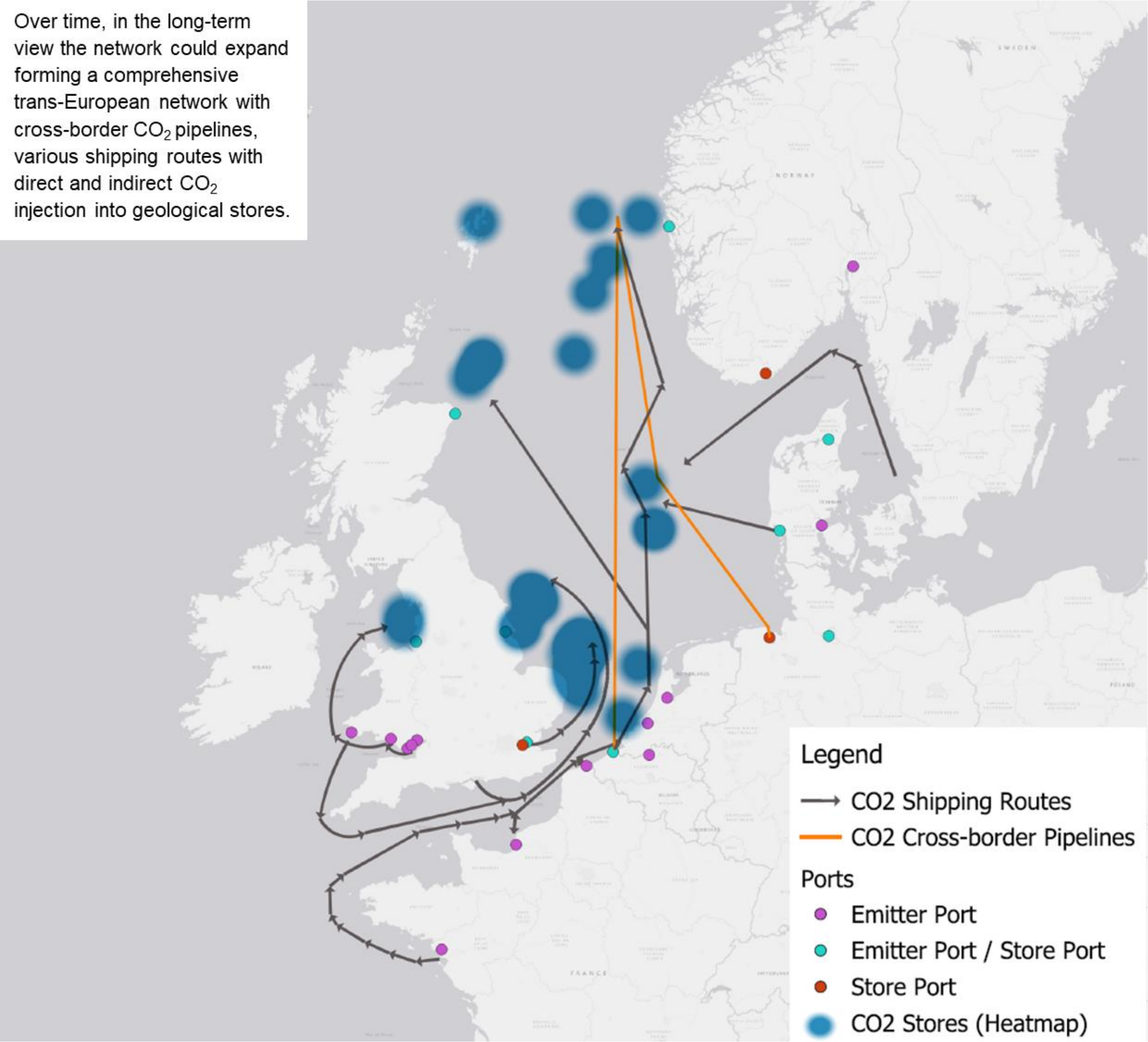
[58] **European Commission.** *Projects of Common Interest – Energy Infrastructure Transparency Platform.*

[59] Indicative routes and infrastructure shown are illustrative and non-exhaustive. Cross-border flows may evolve over time, and alternative configurations are possible, including the potential for CO_2 captured in continental Europe to be transported to UK storage sites.

5.1.2 Long-term view



Over time, in the long-term view the network could expand forming a comprehensive trans-European network with cross-border CO_2 pipelines, various shipping routes with direct and indirect CO_2 injection into geological stores.

Figure 5-2 CCS Long-term view[60]

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[60] Indicative routes and infrastructure shown are illustrative and non-exhaustive. Cross-border flows may evolve over time, and alternative configurations are possible, including the potential for CO_2 captured in continental Europe to be transported to UK storage sites.

5.2 Hydrogen Networks and Assets

Within Great Britain, Project Union is expected to play a central role in establishing a national hydrogen transport backbone, linking hydrogen supply and demand across all major industrial clusters by the early 2030s. The proposed network is designed to connect strategic hydrogen production locations with key industrial demand centres, while also providing optionality for future interconnection with continental European hydrogen infrastructure.

The Project Union concept focuses on the development of a low-cost, high-capacity hydrogen backbone, linking industrial clusters at Teesside, Humberside, Grangemouth, Southampton, the Northwest and South Wales to hydrogen production and import hubs, notably St Fergus and Bacton. These locations have been selected due to their proximity to existing industrial demand, access to offshore energy resources, and the availability of legacy gas transmission and landing infrastructure suitable for repurposing. Current estimates suggest that a proportion of the existing National Transmission System could be suitable for conversion to hydrogen service, subject to detailed integrity assessment, safety case development, and regulatory approval.

Progress to date has been concentrated in early-stage development, with Ofgem funding supporting multiple phases of Front-End Engineering Design studies for the proposed hydrogen backbone (including Union phases 1, 2, and 3). These studies are focused on enabling connections between key industrial clusters, including Teesside, Humberside, North West England, and Scotland. The design studies are expected to conclude in the late 2020s to inform subsequent investment and regulatory decisions. At present, there remains limited clarity on infrastructure development beyond these regions.

The development of initial regional hydrogen transport networks (e.g. through the Hydrogen Transport Business Model (HTBM) and Hydrogen Storage Business Model (HSBM)) will be a key precursor to national-scale infrastructure. However, selection processes for early projects are not expected to conclude before approximately 2027, with initial operational capability likely to follow in the early 2030s.

As a result, while the early 2030s remain a plausible timeframe for the emergence of a regional 100% hydrogen network, delivery timelines will depend on the pace of regulatory approvals, funding mechanisms, and coordinated development across production, transport, and end-use sectors.

A defining characteristic of Project Union is its emphasis on strategic coastal terminals. While the initial focus is domestic hydrogen connectivity, the inclusion of established natural gas entry terminals such as Bacton and St Fergus provides a credible pathway for future offshore hydrogen export or cross-border interconnection. These sites already serve as major gas landing points and are well positioned to host future hydrogen compression, metering, and export infrastructure, should market demand and regulatory frameworks support hydrogen trade with mainland Europe.

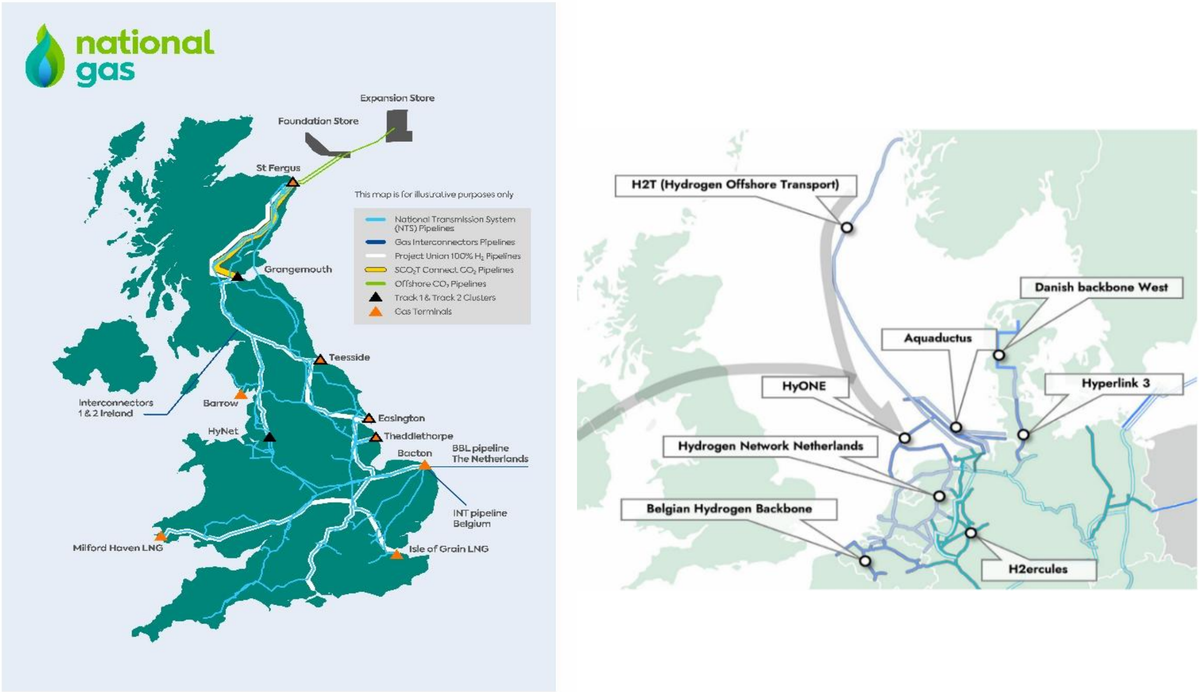

Figure 5-3: (Left) Proposed Project Union 100% hydrogen pipelines in Great Britian[61] (Right) European Hydrogen Backbone Corridor C – North Sea[62]

In parallel, the European Hydrogen Backbone initiative is progressing plans for a pan-European hydrogen transport network. The initiative began in 2020 with 11 Transmission System Operators (TSOs) and has since expanded to 31 gas infrastructure companies across 28 countries. The EHB vision is to establish a hydrogen backbone spanning Europe through the repurposing of existing natural gas pipelines, complemented by targeted investments in new dedicated hydrogen pipelines and compressor stations.

The proposed European backbone is intended to enhance security of hydrogen supply, reduce energy dependence, and provide a cost-effective solution for large-scale hydrogen transport across national borders. From a UK perspective, future offshore interconnection between Project Union and the European Hydrogen Backbone represents a longer-term strategic opportunity rather than a near-term commitment. Potential connections would most likely utilise established offshore corridors in the Southern North Sea, building on historic gas interconnection routes and existing landing points on both sides of the UK–EU boundary.

Early consideration of compatibility between Project Union and the European Hydrogen Backbone could reduce future retrofit requirements. As hydrogen markets mature, the interconnection could support export of surplus UK hydrogen, provide import flexibility, and strengthen system resilience across both UK and European hydrogen networks.

Offshore hydrogen PCIs and PMIs identified under the TEN-E Regulation form a critical interface between offshore hydrogen production, national hydrogen backbones, and cross-border transport in the North Sea.[63] In particular, PCI 9.8 (AquaDuctus) and PMI 9.25 (CHE Pipeline) demonstrate how offshore hydrogen infrastructure is being designed as part of an integrated European system, rather than as isolated point-to-point export routes. These projects provide a framework for future connectivity between hydrogen supply in the North Sea, continental European demand, and potential UK hydrogen networks, including Project Union.

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[61] **National Gas.** *Project Union: Energising Britain.*

[62] **European Hydrogen Backbone (EHB).** 2023. *European Hydrogen Backbone: Implementation Roadmap – Part 1.*

[63] **European Commission.** *Projects of Common Interest – Energy Infrastructure Transparency Platform.*

AquaDuctus is a modular offshore hydrogen backbone within the German EEZ, linking offshore hydrogen production such as hydrogen derived from offshore wind electrolysis to onshore Germany at Wilhelmshaven, with onward connection to the wider European Hydrogen Backbone. Its design explicitly allows for tie-ins from adjacent offshore hydrogen pipelines, including potential future connections from the UK and Norway. PMI 9.25 (CHE Pipeline) complements this approach by evaluating multiple routing options for transporting hydrogen from Norway to Germany, including direct integration into the AquaDuctus system. This reinforces a hub-and-trunk model in which offshore pipelines function as shared transmission assets rather than standalone bilateral links.

While neither project currently includes a confirmed UK landing point, both are structured to accommodate future UK offshore connections. Together, they create a clear conceptual pathway for integration with Project Union, particularly via UK east coast hydrogen hubs.

Hydrogen infrastructure projects were additionally identified using the H_2 Infrastructure Map, which provides a consolidated overview of planned and proposed hydrogen pipeline backbones across Europe, including offshore and cross-border linkages relevant to UK–EU integration.[64]

Offshore Hydrogen Production

In addition to the AquaVentus offshore hydrogen production ambition, the placement of offshore hydrogen production points within the North Sea reflects the spatial and techno-economic conclusions of the DNV *Specification of a European Offshore Hydrogen Backbone* study.[65] The selected points correspond to offshore areas where hydrogen production from wind power is assessed to be both system-efficient and cost-effective at scale.

For offshore wind farms located at distances greater than approximately 100 km from shore, the increasing cost and complexity of HVAC and HVDC cable transmission significantly erode competitiveness. In contrast, hydrogen pipelines scale efficiently with capacity and deliver lower overall transport costs at longer distances. In the longer-term view the hydrogen production points are therefore located predominantly in far-offshore zones rather than in near-shore wind areas that are more economically suited to grid-connected electricity export.

The most significant concentrations occur in the central North Sea, including Dogger Bank and adjacent offshore zones, as well as further north towards offshore areas approaching the Shetland region. While actual deployment will depend on national policy choices, grid development trajectories, and market evolution, the spatial rationale for these locations is consistent with current planning frameworks.

The development of offshore hydrogen production hubs and energy island concepts has also been assessed by National Grid, examining the role of offshore assets in supporting large-scale hydrogen production, aggregation, and transmission. The study highlights the potential for energy islands or offshore hubs to co-locate renewable generation, electrolysis, and compression, reducing the need for multiple individual export cables or pipelines and enabling more efficient integration with onshore hydrogen transmission networks.[66]

While these configurations highlight clear system-level benefits, there remain significant technical, safety, and economic challenges associated with offshore hydrogen production at scale. Offshore electrolysis, compression, and transport systems introduce additional complexity compared to onshore installations, including integration with variable renewable generation and offshore operational risks.

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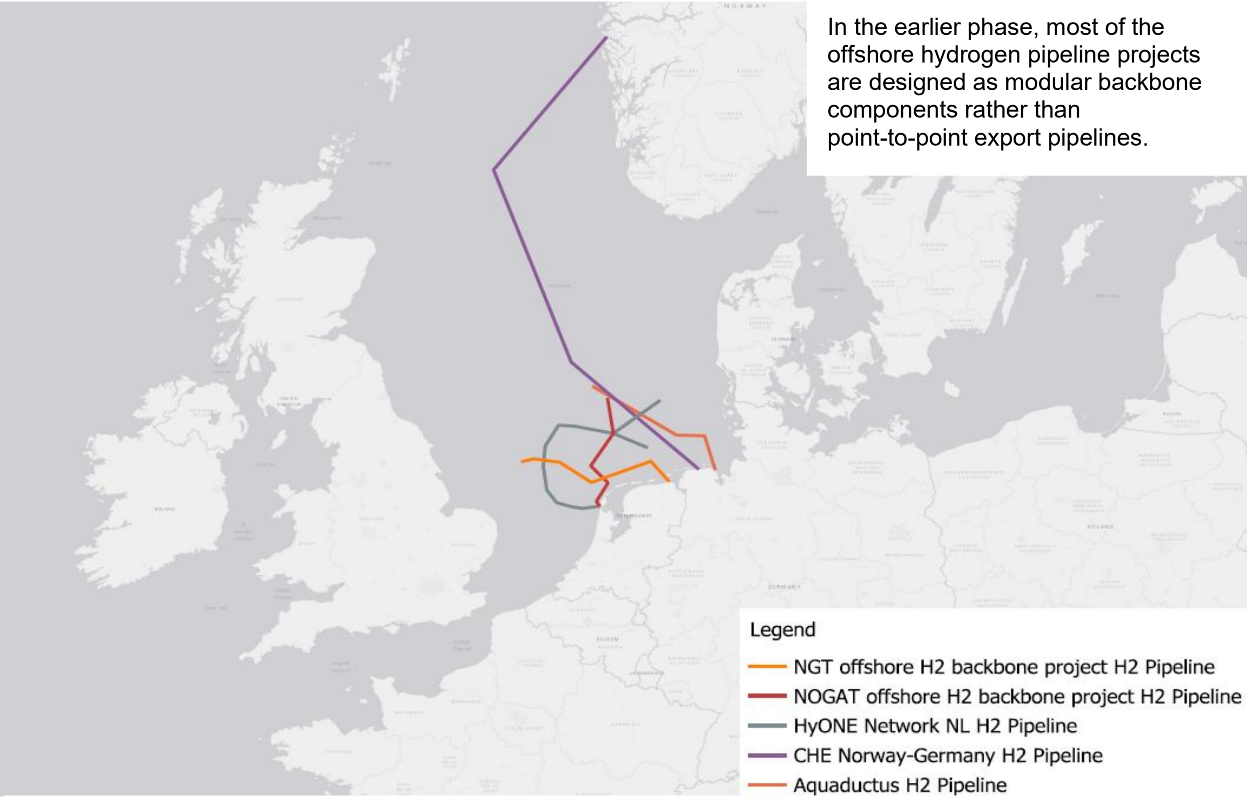
[64] **H2 Infrastructure Map** *European hydrogen infrastructure map.*

[65] **DNV.** 2023 *Specification of a European Offshore Hydrogen Backbone*. Report prepared for GASCADE and Fluxys.

[66] **National Grid.** 2025. LookNortH2 Alpha. *Study on offshore hydrogen production and energy island concepts.*

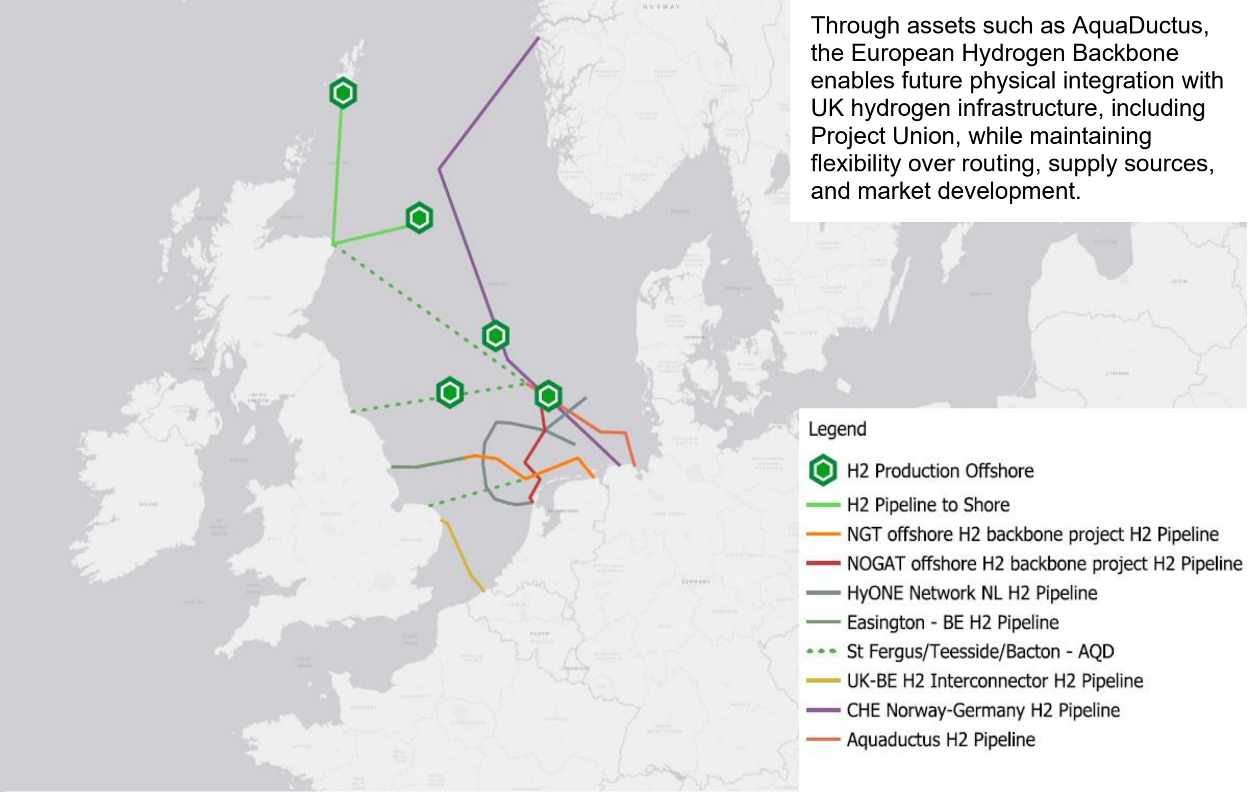
5.2.1 Medium-term view



In the earlier phase, most of the offshore hydrogen pipeline projects are designed as modular backbone components rather than point-to-point export pipelines.

Figure 5-4 H_2 Medium-term view

5.2.2 Long-term view



Through assets such as AquaDuctus, the European Hydrogen Backbone enables future physical integration with UK hydrogen infrastructure, including Project Union, while maintaining flexibility over routing, supply sources, and market development.

Figure 5-5 H_2 Long-term view

6 ECONOMIC OVERVIEW

This chapter provides a high-level economic assessment of the hydrogen and carbon capture and storage infrastructure considered in this study, based on Figure 5-2 and Figure 5-5. The purpose of the assessment is to illustrate the timing of cost recovery for large-scale transport and storage assets and to examine how indicative capital expenditure (CAPEX), operating expenditure (OPEX), and tariff assumptions translate into long-term economic performance.

The analysis adopts a system-level perspective, using simplified representations of infrastructure scale, deployment phasing, utilisation, and charging structures. Cumulative discounted costs and revenues are assessed over the asset lifetime to identify indicative payback periods and sensitivities to key drivers such as throughput and tariffs. The results therefore reflect the structural economic characteristics of hydrogen and CCS infrastructure rather than detailed, project-specific investment cases.

Given the capital-intensive nature of these assets and the expectation that capacity is developed ahead of demand, the assessment highlights prolonged periods of negative net value in the early years of operation and a reliance on sustained utilisation over long asset lifetimes to achieve economic viability.

The transport and storage tariffs estimated in this study represent bottom-up cost-of-service estimates of CCS and hydrogen infrastructure, derived from engineering-based capital and operating cost assumptions. These tariffs are intended to reflect the underlying costs required to design, construct, finance, and operate transport and storage assets, rather than the prices that emitters would necessarily pay in practice. The business models are designed to optimise cost and risk allocation between developers and the state, using regulated returns and government support mechanisms to enable investment.[67] A 7% discount rate is applied, consistent with UK and European energy infrastructure modelling. The appraisal is undertaken on a commercial basis; accordingly, the discount rate reflects investor cost of capital rather than the lower social discount rate prescribed by the Green Book.

6.1 CCS Infrastructure Assets

6.1.1 Assumptions and Scope

6.1.1.1 Infrastructure Scale and Commissioning Range

The assessed CCS network is comprised of a combination of cross-border CO_2 pipelines, shipping capacity, and associated onshore compression and storage infrastructure, commissioned between 2025 and 2040. This phased development reflects the expectation that transport and storage capacity will need to be established ahead of capture demand, while allowing infrastructure availability to scale in line with the ramp-up of CO_2 capture across Europe.

At full deployment, the system includes approximately 1,000 km of cross-border CO_2 pipelines and peak shipping activity of around 3,430 trips per year.

Table 6-1 Key parameters used in the model (CCS)

Parameter	Value	Unit
Total cross-border pipelines[68]	1,000	km
Peak store injection capacity	333.6	Mtonnes/year
Peak shipping trips	3,430	Trips/year
Commissioning date range	2025 - 2040	

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[67] **Clean Air Task Force.** 2024. Risk allocation and regulation for CO_2 infrastructure: A UK case study.

[68] This excludes pipelines associated with individual stores, which are included as part of the CO_2 store cost estimates.

6.1.1.2 CO_2 Store Development Timeline

CO_2 storage is not a flexible, on-demand service that can be readily scaled up or down in line with capture deployment. Instead, it constitutes strategic, long-term national infrastructure, the availability of which is a prerequisite for investment across the wider CCS value chain.

The development of geological storage sites is characterised by long lead times. The development of a CO_2 storage site follows a structured, multi-phase lifecycle defined by regulatory requirements and technical risk management. The timeline below summarises this lifecycle into a set of simplified phases, taking a CO_2 storage project from initial assessment through to full operation.

In this context, early underutilisation of CO_2 storage is a feature of system design rather than a failure of economic optimisation.

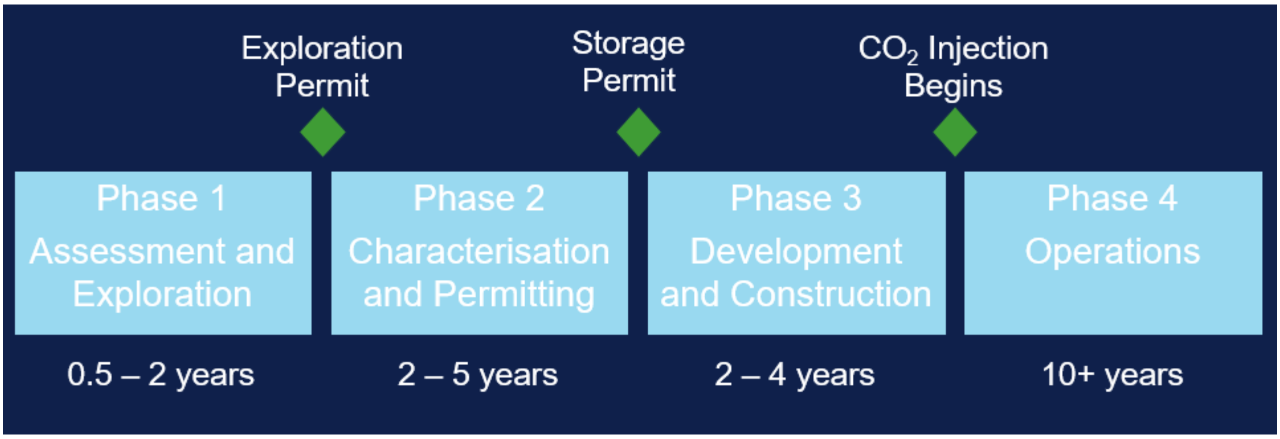

Figure 6-1 Indicative CO_2 store development timeline (based on the European Commission Guidance Document 1: CO_2 storage life cycle and risk management framework[69])[70]

6.1.1.3 Forecasted Capacity

Figure 6-2 compares planned total CO_2 store injection capacity with the EU capture capacity forecast set out in the DNV Energy Transition Outlook through to 2050. The chart illustrates that a substantial volume of injection capacity could be developed well in advance of expected demand.

While this overcapacity is necessary from a system-planning and security-of-supply perspective, it has important commercial implications. Storage infrastructure is characterised by high upfront capital expenditure and revenues that depend on throughput; when capacity is built ahead of demand, utilisation is initially low despite a largely fixed cost base.

This leads to extended payback periods for storage investments and, unless costs are socialised or smoothed over time, higher tariffs for early users. Early capture projects may therefore bear a disproportionate share of system costs until utilisation increases. This highlights a structural tension between the need to overbuild injection capacity to enable long-term capture growth and the challenge of financing and pricing underutilised infrastructure in the early years, pointing to a potential role for policy and regulatory mechanisms to mitigate first-mover disadvantage.

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[69] **European Commission, Directorate-General for Climate Action.** 2025. *Guidance document 1: CO_2 storage life cycle and risk management framework.* Luxembourg: Publications Office of the European Union.

[70] The development timeline is broadly consistent with the UK context.

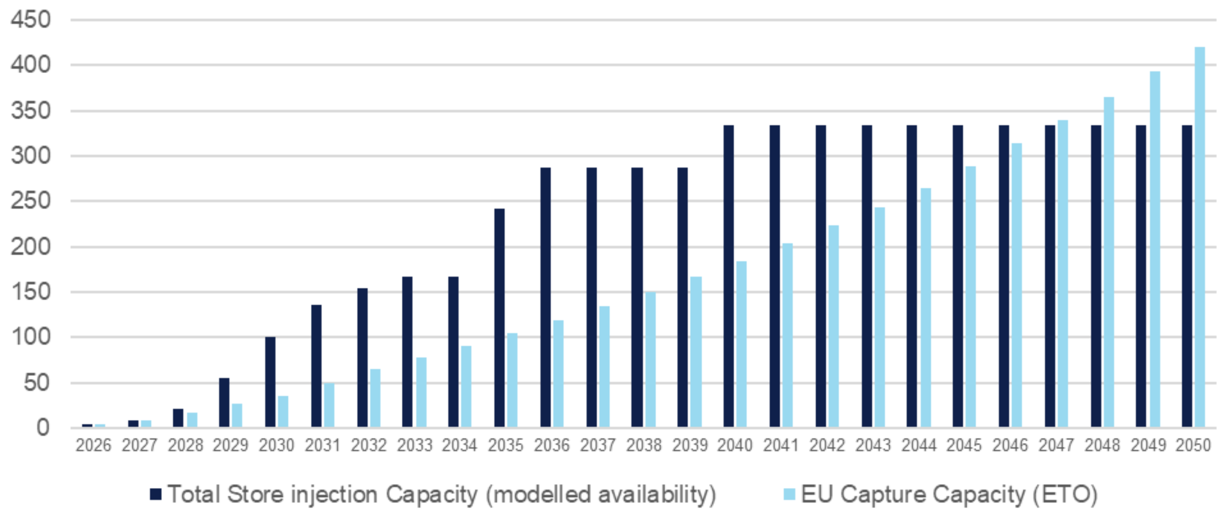

Figure 6-2 Injection Capacity vs ETO Capture Capacity (million tonnes CO_2/ year)

1. Storage capacity grows faster than capture capacity, at least initially

From roughly 2026 through the late 2030s, Europe's planned CO_2 storage capacity could grow significantly faster than capture capacity. Throughout this period, projected injection capacity[71] consistently exceeds anticipated capture volumes, for example, around 2035 storage capacity reaches about 240 Mt CO_2 /year compared with roughly 105 Mt CO_2 per year of capture, widening further by 2040 to approximately 335 Mt CO_2 /year of storage versus 185 Mt CO_2 /year of capture.

2. Risk of underutilised storage in the 2030s

As capture capacity lags well behind storage development, a substantial share of Europe's planned CO_2 storage capacity is likely to remain unused during the 2030–2040 period. This indicates that the primary constraint on CCS deployment is not storage, but rather the pace of capture project development and associated pipeline infrastructure. The gap highlights persistent policy, cost, and project-delivery challenges on the capture side, while also creating potential commercial risk for storage developers if CO_2 supply fails to ramp-up in line with current storage plans.

3. Capture begins to close the gap after ~2040

From the early to mid-2040s onward, capture capacity is projected to accelerate and increasingly converge with available storage. By around 2046–2050, capture rises to approximately 420 Mt CO_2 per year, while planned storage capacity appears to plateau at roughly 330–340 Mt CO_2 /year. If these ETO capture projections materialise, the current balance reverses, and storage could become a limiting factor for CCS deployment in the late 2040s unless additional storage projects are sanctioned or existing sites are able to increase injection rates beyond current plans.

6.1.1.4 Tariff/Charging Estimates

The analysis represents the CO_2 transport and storage system as a single, integrated CCS network with a uniform tariff applied across the system. In practice, CCS infrastructure is expected to comprise multiple independent operators, each responsible for discrete elements of the value chain, including CO_2 transport pipelines, offshore transport, and storage sites. Each operator would set tariffs based on project-specific capital costs, operating costs, financing structures, risk profiles, and required rates of return.

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[71] Storage capacity is based on project announcements related to awarded appraisal licenses as well as data from **Industrial Decarbonisation Research and Innovation Centre (IDRIC)**. 2025 MIP 4.4: Quantification of the UK CO_2 storage export potential to drive down the cost of CCS.

Aggregating the CCS network into a single notional system simplifies the economic assessment. However, this approach abstracts from the commercial reality of CCS deployment, where tariffs are likely to differ by route, location, utilisation levels, and operator.

As a result, the analysis may under-represent:

- Tariff stacking effects where CO_2 passes through multiple independently priced assets,
- Localised cost heterogeneity across transport corridors and storage hubs, and
- Differences in investment incentives and payback periods between individual CCS projects.

Future project-level assessments would need to disaggregate the system and explicitly model operator-specific tariffs and contractual arrangements to reflect realistic commercial delivery models for CCS infrastructure.

6.1.1.5 Scope of Assets

The scope of assets included in the CCS cost model covers the principal transport and storage infrastructure required to enable large-scale CO_2 capture and permanent storage at a system level. The model includes cross-border CO_2 pipelines, CO_2 shipping, CO_2 compression and onshore handling facilities, and CO_2 storage assets, including both buffer storage and geological storage sites.

These assets represent the core capital-intensive components of the CCS value chain and are the dominant drivers of system-level CAPEX, OPEX, and tariff requirements. Together, they define the economic performance of CCS infrastructure where revenues are strongly dependent on throughput and utilisation over long asset lifetimes.

The CCS system is modelled as an integrated transport and storage network, with costs aggregated across individual asset types, rather than project-specific ownership structures.

Where project announcements indicate a ship-to-store CO_2 transport configuration, a cost adjustment factor is applied to reflect differences in transport cost structure relative to dedicated pipeline transport. This approach is informed by the IEA GHG study “The Status and Challenges of CO_2 Shipping Infrastructures”.[72]

Table 6-2 Asset type included in the model

CCS Infrastructure Assets	Included in the model
CO_2 Cross-border pipelines	✓
CO_2 Shipping	✓
CO_2 Storage (buffer/geological)[73] [74]	✓
CO_2 Compressors	✓
Carbon Capture	✗

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[72] **IEA Greenhouse Gas R&D Programme (IEA GHG)**. 2020. *The status and challenges of CO_2 shipping infrastructures*. Report 2020-10. Cheltenham: IEA Greenhouse Gas R&D Programme.

[73] Costs related to individual CO_2 storage pipelines and on-site buffer storage are included as part of the storage cost estimate.

[74] For the ship-to-store (direct injection) cases, a cost adjustment factor of 0.5 has been applied to the storage project costs to account for direct injection.

6.1.2 Results

6.1.2.1 Tariffs and Payback Period

Figure 6-3 illustrates the discounted economic performance of the CCS transport and storage infrastructure over the period 2026–2050, showing cumulative discounted costs, cumulative discounted revenues, and the resulting net value at a system level.

The results indicate that the CCS network is characterised by high upfront capital expenditure, with cumulative discounted costs rising steadily through the early deployment phase as transport and storage capacity is developed ahead of full utilisation. During this period, revenues remain comparatively low, reflecting the gradual ramp-up of CO_2 capture volumes and system throughput. Consequently, the net value declines sharply during the late 2020s and early 2030s, reaching a minimum in the mid-to-late 2030s.

From the late 2030s onward, cumulative discounted revenues increase at a faster rate as utilisation of the CCS infrastructure improves and captured CO_2 volumes approach planned capacity levels. This leads to a sustained recovery in net value through the 2040s. By the end of the assessment period, cumulative discounted revenues materially close the gap with cumulative discounted costs, and the net value approaches breakeven by 2050 (~25 year payback period).

Overall, the results suggest that CCS infrastructure can achieve long-term economic viability at a system level, but only over extended asset lifetimes and under conditions of steadily increasing utilisation. The prolonged period of negative net value highlights the importance of early-stage support mechanisms, long-term contractual arrangements, or regulated revenue frameworks to manage investment risk during the initial deployment phase.

Key Implications

- CCS transport and storage infrastructure exhibits a long economic payback period, driven by capital-intensive development and delayed revenue generation.
- System-wide viability is highly dependent on timely ramp-up of CO_2 capture volumes to avoid prolonged underutilisation.
- The economic profile reinforces the role of CCS infrastructure as strategic enabling infrastructure, where value is realised primarily through enabling emissions reduction rather than short-term financial returns.

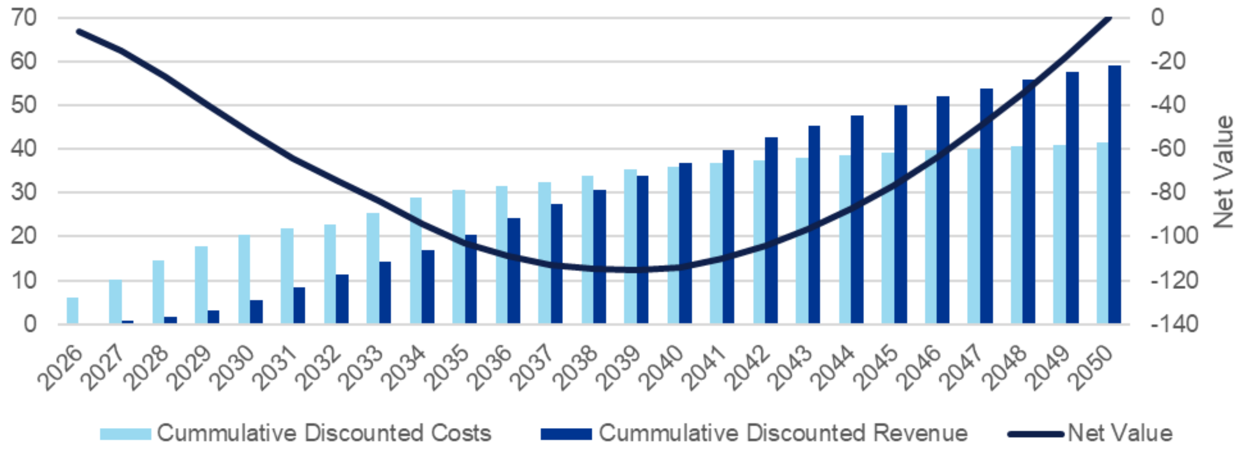

Figure 6-3 Discounted economic performance of CCS infrastructure (£b)

In this base-case, revenues are modelled assuming full utilisation of the available CCS transport and storage infrastructure. In practice, early-year utilisation is likely to be lower due to slower ramp-up of CO_2 capture capacity. This may result in overestimation of realised revenues and an optimistic payback period, particularly in the initial years of operation. This is explored in the utilisation sensitivity in 6.1.2.2, which uses the forecasted EU capture capacity shown in Figure 6-2.

Table 6-3 Indicative Tariff's for a 25 year payback period

Tariff	Study Result	Benchmarks	Unit
Cross- border Pipeline	9.00	6.70 (scaled from ZEP reference)	£/tonne
Storage	19.86	35.00 (CCSA/XODUS)	£/tonne
Shipping	17.93	16.80 (scaled from ZEP reference)	£/tonne

CO_2 cross-border pipelines and shipping costs are benchmarked against published estimates for 20 Mt/year networks that include liquefaction and terminal infrastructure. The study's shipping tariff is derived by scaling these benchmarks to reflect higher throughput and longer transport distances.[75]

The €41/t (£35/tonne) benchmark represents an estimated cost to emitters of offshore CO_2 transport and storage, reflecting a user-facing charge rather than a pure infrastructure cost.[76] The storage tariff estimated in this study (£19.86/tonne) represents a bottom-up cost-of-service estimate for storage infrastructure (including the source-to-store pipeline) under high-utilisation assumptions.

6.1.2.2 Sensitivities

Utilisation Sensitivity

The base case assumes full utilisation of the CO_2 transport and storage infrastructure, which results in an optimistic revenue profile in the early years of operation. In reality, utilisation is expected to ramp-up more slowly, reflecting the phased deployment of CO_2 capture capacity.

For the utilisation sensitivity, the ETO capture capacity forecast is applied as the effective asset utilisation profile, reducing throughput and revenues in the initial years compared with the base case. To ensure consistency with the base-case investment case, transport and storage tariffs are increased in this sensitivity such that the overall project payback period is maintained.

The higher value tariffs reflect the need to develop substantial injection capacity ahead of demand, combined with low utilisation in the early years of deployment. It should therefore be interpreted as a system-wide average cost under early-stage conditions, rather than a long-run cost-reflective tariff.

Table 6-4 Indicative tariffs after reduced utilisation of assets

Tariff	Value	Unit
Cross- border Pipeline	17	£/tonne
Storage	150	£/tonne
Shipping	50	£/tonne

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[75] **Zero Emissions Platform (ZEP).** 2025. The costs of CO_2 capture, transport and storage: Post-demonstration CCS in the EU. Brussels: Zero Emissions Platform.

[76] **Carbon Capture & Storage Association (CCSA).** 2024. Accelerating a Europe-wide CO_2 storage market. London: Carbon Capture & Storage Association.

Tariff – Payback Period Sensitivity

A 10% decrease in tariff extends the payback period by approximately 5 years, while a 20% increase in tariff shortens the payback period by around 5 years. This assumes the base-case infrastructure utilisation, i.e. full utilisation.

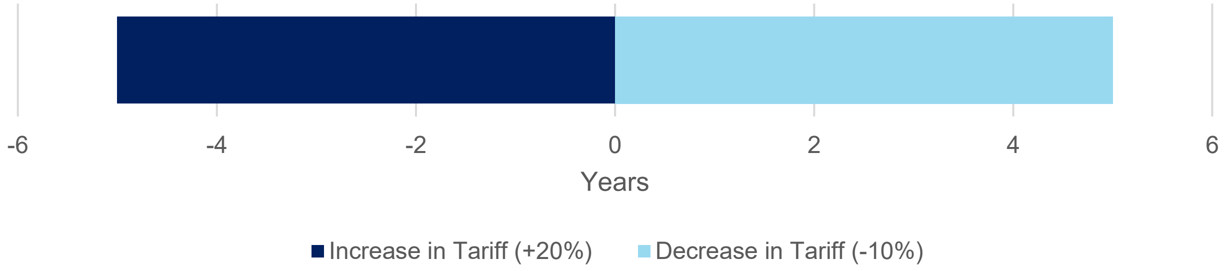

Figure 6-4 Tariff- Payback period sensitivity

6.2 Hydrogen Infrastructure Assets

6.2.1 Assumptions and Scope

6.2.1.1 Infrastructure Scale and Commissioning Range

The proposed network comprises approximately 1,795 km of hydrogen pipelines, commissioned between 2028 and 2045 (see Figure 5-5). This phased rollout aligns infrastructure availability with expected growth in hydrogen production and demand, helping to mitigate the risk of underutilised assets in the early years.

At full development, the network is capable of transporting up to 34 million tonnes of hydrogen per year, representing a large-scale backbone system intended to support industrial decarbonisation and regional hydrogen markets.

Table 6-5 Key parameters used in the model (H_2)

Parameter	Value	Unit
Maximum H_2 throughput	34	Mtonnes/year
Total pipelines	1,795	km
Commissioning date range	2028 - 2045	

6.2.1.2 Scope of Assets

The scope of assets included in the hydrogen cost model is limited to the core transport infrastructure required to enable large-scale hydrogen transmission. Specifically, the model includes hydrogen transmission pipelines and associated compression infrastructure, which together represent the dominant drivers of capital expenditure and operating costs for hydrogen networks.

Onshore hydrogen storage facilities and offshore hydrogen production assets are excluded from the scope of this assessment. These assets are characterised by distinct cost structures, ownership models, and commercial drivers, and are more closely linked to production and end-use system design rather than transport infrastructure economics. Excluding these elements allows the analysis to focus on the economics of hydrogen transport as a regulated, shared network asset.

Where repurposed oil and gas pipelines are proposed for hydrogen transport, a cost reduction factor of 50% relative to new-build pipeline capital costs is applied. This assumption is based on evidence from the Re-Stream study undertaken by IOGP Europe, which assessed the technical and economic feasibility of re-using existing European oil and gas pipeline infrastructure. The study finds that reuse of existing pipelines can deliver cost reductions of approximately 53–82% compared to construction of new pipelines, depending on asset condition, location (onshore or offshore), and scope of required refurbishment.[77]

Table 6-6 Asset type included in the model

Hydrogen Infrastructure Assets	Included in the model
Hydrogen pipelines (offshore)	✓
Hydrogen compressors	✓
Hydrogen stores	✗
Offshore hydrogen production	✗

6.2.2 Results

6.2.2.1 Tariffs and Payback Period

Figure 6-5 presents the discounted economic performance of the proposed hydrogen transport infrastructure over the period 2026–2050. The analysis considers cumulative discounted capital and operating costs, cumulative discounted revenue from transport tariffs, and the resulting net value over the project lifetime.

The results show that the hydrogen pipeline network requires substantial upfront investment during the early deployment phase. Cumulative discounted costs rise rapidly from first commissioning around 2026, reflecting phased construction and commissioning across the network. During this period, revenues remain limited due to relatively low initial hydrogen throughput, resulting in a negative net value in the early years of operation.

As utilisation increases through the 2030s and early 2040s, cumulative discounted revenues grow steadily, driven by rising hydrogen flows and a transport tariff of £270/tonne. The net value reaches its minimum in the late 2020s before improving progressively as revenues begin to offset capital recovery. The analysis has set a payback period of approximately 25 years, with the project moving towards breakeven in the mid-2040s and generating a positive net value by 2050.

By the end of the assessment period, cumulative discounted revenues approach cumulative discounted costs, indicating that the infrastructure becomes financially sustainable over the long term, albeit with limited margin. This reflects the capital-intensive nature of hydrogen transport infrastructure and the importance of long asset lifetimes and stable utilisation for economic viability.

Key Implications

Overall, the results indicate that hydrogen transport infrastructure can achieve long-term economic viability under the assumed tariff and utilisation trajectory, but requires:

- Long-term commitment to hydrogen demand growth,
- High and sustained throughput levels over the asset lifetime, and
- Stable regulatory and policy frameworks to reduce revenue uncertainty during the early years of operation.

The relatively long payback period highlights that hydrogen pipelines could be viewed as strategic enabling infrastructure, rather than short-term commercial investments, with value derived primarily from supporting system-wide decarbonisation

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[77] **IOGP Europe**. 2021 *Re-Stream: Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe*. Brussels: IOGP Europe.

rather than standalone financial returns.

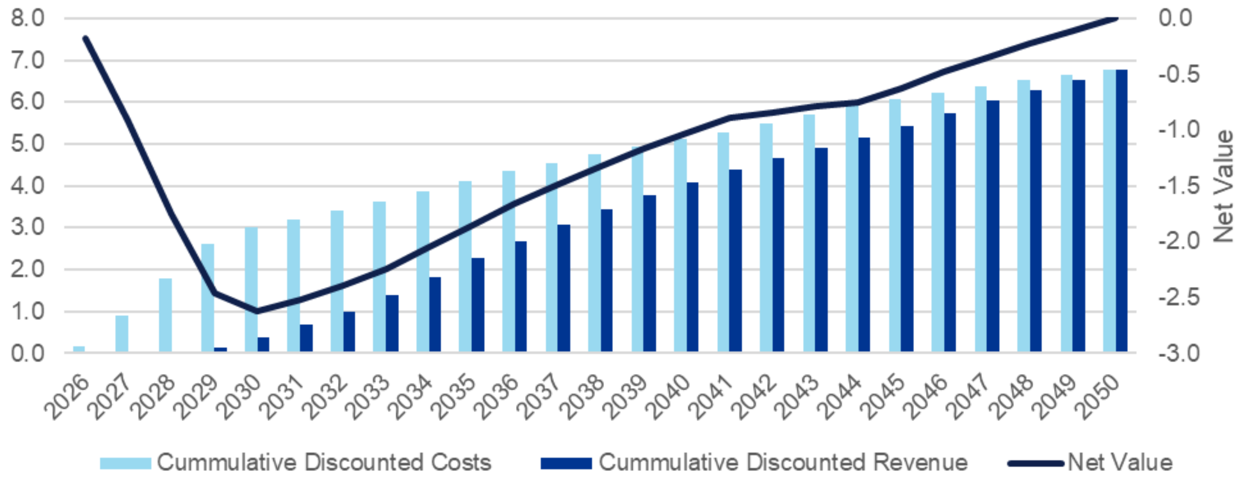

Figure 6-5 Discounted economic performance of hydrogen infrastructure (£b)

To achieve the 25 year payback period, the hydrogen transport tariff was found to be £270/tonne. This aligns well with the EHB willingness-to-pay benchmark, in Figure 6-6.

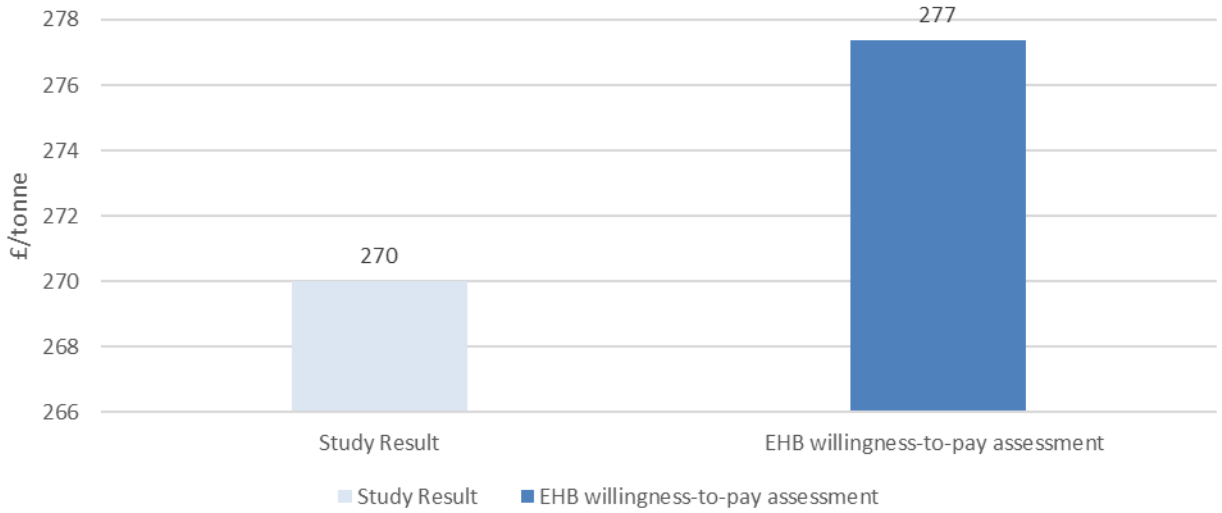

Figure 6-6 Hydrogen Transport Tariff Benchmarking[78]

For comparison, cross-border natural gas transmission via regulated European interconnectors typically results in transportation charges of the order of €2–4/MWh, equivalent to approximately £25–55 per tonne of methane transported. Hydrogen transport tariffs appear high when compared to natural gas, but this reflects fundamental differences in network maturity, utilisation, and capital recovery rather than inefficiency.[79] In addition, on an energy or mass basis, hydrogen has a much lower volumetric density than methane, meaning significantly larger pipeline diameters (or higher compression) are required to deliver equivalent quantities. This drives higher capital costs per unit transported, which is reflected in tariffs.

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[78] **European Hydrogen Backbone (EHB).** 2024. Implementation roadmap: Public support as catalyst for hydrogen infrastructure. European Hydrogen Backbone Initiative.

[79] **Bortoni, G.P.P.** 2024. Inefficient interactions among gas trades and gas tariffs in the EU's market: does the new Gas Package spur towards market efficiency? Presentation delivered at the 8th AIEE Energy Symposium – The gas role in the transition: natural gas, hydrogen and other renewable gases, Padova, 29 November 2024.

6.2.2.2 Sensitivities

Utilisation Sensitivity

This section presents a sensitivity analysis on hydrogen throughput/utilisation, in which total operating capacity is constrained to 50% of the base-case level. The purpose of this assessment is to understand the impact of reduced utilisation on project economics and, specifically, to determine the hydrogen tariff required to maintain the same payback period as the full-capacity case. Under this reduced-capacity scenario, an increase in the hydrogen charge is necessary to offset the loss of throughput and ensure sufficient revenue recovery. The analysis indicates that a tariff uplift to £383.90 per tonne is required to compensate for the lower utilisation and maintain the same payback period as the full-capacity case.

Tariff – Payback period Sensitivity

A 10% decrease in tariff extends the payback period by approximately 7 years, while a 20% increase in tariff shortens the payback period by around 9 years. This assumes the base-case infrastructure utilisation, i.e. high hydrogen throughput.

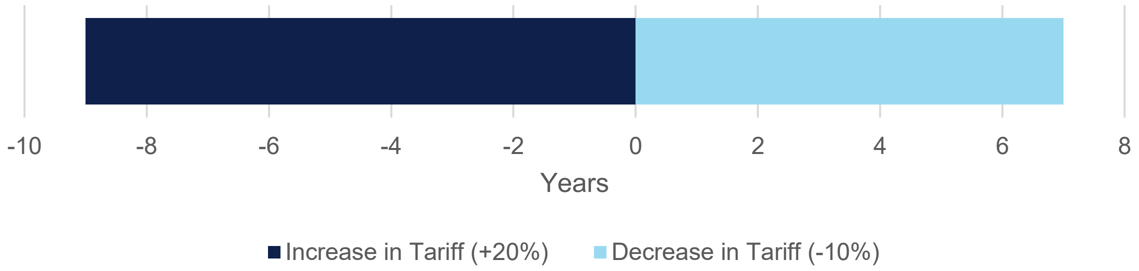

Figure 6-7 Tariff - Payback Period Sensitivity

7 FINDINGS AND CONCLUSIONS

The North Sea has the potential to become Europe's backbone for both CO_2 management and hydrogen transport, but this outcome is not guaranteed. Without deliberate coordination, early design choices on specifications, routing, regulation, and sizing could lock in fragmentation, higher costs, and reduced resilience for decades.

This study demonstrates that resilience must be embedded upfront to enable a system that can absorb uncertainty, scale efficiently, and deliver long term value. The findings point to a clear need for coordinated action by governments, regulators, and infrastructure developers to treat CO_2 and hydrogen networks as strategic regional and/or national systems rather than collections of standalone projects.

7.1 Economic Conclusions

CCS and hydrogen transport infrastructure are capital-intensive, long-life assets that require significant upfront investment and experience prolonged periods of low utilisation, resulting in extended payback periods. Economic viability depends critically on sustained throughput growth, while early deployment phases are characterised by negative returns, underutilisation, and first-mover disadvantage. As a result, these systems function as strategic enabling infrastructure and require policy support, regulated revenue models, and coordinated system planning to ensure successful deployment.

While hydrogen and CCS infrastructure share many economic characteristics with traditional network infrastructure, they are distinguished by significantly higher levels of uncertainty and coordination complexity. Demand is not yet fully established and depends on evolving decarbonisation pathways, creating both timing and fundamental demand risk. In addition, these systems require simultaneous development across multiple sectors (production, transport, and end use), increasing market development challenges beyond those typically seen in conventional infrastructure.

7.2 System-Level Challenges and Pathways Forward

The challenges identified across the technical, operational, regulatory, and economic dimensions consistently cluster around a small number of recurring system-level issues. The categorisation below consolidates these challenges to highlight common root causes across CO_2 and hydrogen infrastructure, distinguishing what the challenges are and from where they manifest. These recurring challenges form the basis for the pathway forward, which focuses on how infrastructure design, coordination, and governance approaches can evolve to mitigate these system-level risks.

7.2.1 Standards and specification misalignment

- Some current technical specifications (e.g., purity thresholds, pressure ranges, pipeline design assumptions) reflect legacy practices or early project-level decisions, which may not fully align with emerging system-wide requirements.
- Regulatory approaches to network entry, custody transfer, and access conditions vary across jurisdictions, creating potential interoperability challenges and increased administrative complexity.
- Infrastructure path dependency means that once assets are built, modifying specifications or aligning standards can become costly and operationally disruptive, though not impossible.
- Where misalignment persists, it can introduce additional costs (e.g., conditioning, contractual complexity) and may limit flexibility for cross-network integration or market participation.

System-level implication:

Early divergence in technical and regulatory standards can create path dependencies that constrain interoperability over time, particularly if alignment mechanisms (e.g., harmonisation frameworks or commercial workarounds) are not established early.

Pathway forward:

- Maintain early-stage flexibility in technical specifications while defining clear pathways toward longer-term harmonisation, supported by regulators and standardisation bodies.
- Introduce early alignment mechanisms (e.g., common standards development, interface agreements, or commercial bridging solutions), facilitated through industry collaboration (e.g., joint industry projects, standard-setting forums).
- Support increasing regulatory coordination across jurisdictions, particularly for network access, custody transfer, and permitting, led by governments and regulatory authorities.

7.2.2 Long lead times and timing mismatch

- Infrastructure development timelines (e.g., for storage, transport corridors, and offshore interfaces) are typically long relative to the pace of supply and demand formation, particularly in early market phases where project dynamics can shift quickly.
- Market signals and investment decisions (e.g., upstream production or industrial offtake) can evolve on shorter time horizons, creating potential misalignment with fixed infrastructure delivery schedules.
- Once major assets are committed or constructed, options for rapid capacity expansion or reconfiguration are more constrained, although incremental upgrades may still be possible.
- Where timing mismatches occur, they can result in temporary underutilisation or capacity constraints, depending on how demand materialises relative to infrastructure availability.

System-level implication:

Differences in development timescales between infrastructure and market actors can create coordination challenges, increasing the risk of either capacity shortfalls or underutilised assets, particularly where planning is closely tied to near-term signals rather than informed by longer-term system needs.

Pathway forward:

- Base infrastructure planning on long-term system outlooks and scenario-based demand projections, supported by government-led system planning.
- Improve coordination and visibility across project pipelines through industry collaboration mechanisms (e.g., joint industry projects, shared data platforms) to better align infrastructure delivery with evolving supply and demand.
- Adopt phased and modular development approaches, led by project developers and network operators, to retain flexibility where future demand is uncertain.

7.2.3 Infrastructure sizing and future optionality

- Initial infrastructure sizing decisions are often anchored to early project volumes or first-wave demand, which may not reflect longer-term system evolution.
- Design choices (e.g., pressure, diameter, routing, and layout) are sometimes optimised for near-term utilisation rather than incorporating expandability or corridor-based development approaches.
- Where flexibility is limited, future capacity expansion or integration of new demand centres may require higher-cost retrofits or parallel infrastructure.
- These design constraints, if not considered early, can introduce additional CAPEX and OPEX over time and reduce the system’s ability to adapt to changing demand patterns.

System-level implication:

While early projects are typically optimised on an individual basis to remain competitive and secure funding, this approach may conflict with wider system requirements. Infrastructure decisions made at the project level can prioritise short-term viability over long-term flexibility, potentially constraining future expansion and leading to higher system-wide costs.

Pathway forward:

- Prioritise scalable and corridor-based infrastructure design, rather than strict optimisation for initial utilisation, led by project developers and network operators.
- Incorporate future demand scenarios into early design decisions, supported by government-led system planning and strategic network design.
- Enable coordination on sizing and routing through industry collaboration (e.g., joint industry projects, shared planning frameworks) to support more coherent system expansion.

7.2.4 Interdependency and coordination risk

- System components (e.g., production, transport, storage, ports, and demand) are highly interdependent, meaning delays, outages, or underperformance in one segment can propagate across the wider value chain.
- Network configurations that rely on single routes, hubs, or storage sites can increase exposure to operational disruptions, particularly in early system build-out phases.
- Limited buffer or redundancy capacity (e.g., storage, alternative routing, flexibility mechanisms) can reduce the system’s ability to absorb variability in supply or demand.
- Where coordination across actors and interfaces is weak, mismatches in timing, capacity, or operational conditions can amplify these risks and increase system fragility.

System-level implication:

As systems become more interconnected, their ability to operate reliably depends on how well variability and disruption are managed across the whole network, rather than within individual components.

Pathway forward:

- Design networks with system-level redundancy and multiple routing pathways to reduce reliance on single points of failure, led by network operators and system planners.
- Incorporate buffer capacity and flexibility mechanisms (e.g., storage, linepack, operational margins) to manage variability and absorb disruptions, implemented by infrastructure developers and operators.

7.2.5 Cross-border and governance fragmentation

- Infrastructure networks often span multiple jurisdictions, while regulatory frameworks, planning processes, and market rules remain primarily defined at a national level.
- Early-stage arrangements (e.g., bilateral agreements or project-specific frameworks) can enable initial deployment, but may not provide a consistent basis for long-term system integration.
- Differences in regulatory approaches (e.g., permitting, access conditions, tariff structures) can introduce complexity and create potential barriers to interoperability across borders.
- In the absence of coordinated planning, national infrastructure development may evolve in ways that are not fully compatible or optimised at a wider system level.

System-level implication:

Fragmentation in governance and regulatory frameworks can increase coordination complexity and regulatory risk, potentially constraining interoperability and leading to less efficient cross-border infrastructure development over time.

Pathway forward:

- Promote alignment of regulatory frameworks and market rules across jurisdictions, led by governments and regulatory authorities.
- Transition from project-specific or bilateral arrangements to more standardised cross-border frameworks, supported by regional coordination bodies and multilateral agreements.
- Enable coordinated cross-border infrastructure planning, facilitated by government-led initiatives and regional planning institutions.

7.2.6 Bankability, affordability, and investment risk

- Large-scale infrastructure investments face uncertainty around long-term utilisation, revenue stability, and the durability of supporting policy and regulatory frameworks.
- Variability or lack of clarity in support mechanisms (e.g., tariffs, revenue models, liability and insurability provisions) can increase perceived risk and deter investment, particularly in early market phases.
- Risk allocation across stakeholders (e.g., between public and private actors, or along the value chain) is often not fully defined, contributing to financing challenges.

System-level implication:

Investment decisions are shaped not only by project-level economics but by confidence in the broader system environment, with uncertainty around long-term demand, policy stability, and risk allocation potentially constraining capital deployment or increasing financing costs.

Pathway forward:

- Establish stable and transparent policy and regulatory frameworks, led by governments and regulators, to improve long-term investment confidence.
- Define clearer risk allocation across the value chain (e.g., utilisation, policy, liability), supported by public–private frameworks and contractual mechanisms.
- Develop coordinated revenue and support mechanisms to balance investor certainty with system-wide efficiency, enabled by governments and system operators.

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