Capability Gap Analysis for Newbuild Offshore CO_2 Pipeline Transportation Systems

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North Sea Transition Authority

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Contents

List of Figures

List of Tables

Abbreviations

The following abbreviations are used in this document.

ACS	Automated Control System
ACTL	Alberta Carbon Trunk Line
AFLAS	Tetrafluoroethylene/propylene elastomer
AGI	Above Ground Installation
AI	Artificial Intelligence
ALARP	As Low As Reasonably Practicable
API	American Petroleum Institute
ART	Acoustic Resonance Technology
ASME	American Society of Mechanical Engineers
ATR	Autothermal Reforming
BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department for Business, Energy and Industrial Strategy
BOC	British Oxygen Company
BOOT	Build-Own-Operate-Transfer
BTCM	Battelle Two-Curve Method
BTEX	Benzene, Toluene, Ethylbenzene and Xylenes
CAPEX	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
CCSA	Carbon Capture and Storage Association
CCUS	Carbon Capture, Utilisation and Storage
CFD	Computational Fluid Dynamics
CFR	Code of Federal Regulations
CH	Carbon-Hydrogen
CH4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COS	Carbonyl Sulphide
CP	Cathodic Protection
CSNP	Centralised Strategic Network Plan
DAC	Direct Air Capture
DAR	Design Accidental Release
DAS	Distributed Acoustic Sensing
DBFO	Design-Build-Finance-Operate
DBTT	Ductile-to-Brittle Transition Temperature
DCO	Development Consent Order
DCS	Distributed Control System
DESNZ	Department for Energy Security and Net Zero
DHSV	Downhole Safety Valve
DIAL	Differential Absorption LiDAR
DNV	Det Norske Veritas
DPA	Dispatchable Power Agreement
DSS	Distributed Strain Sensing
DTS	Distributed Temperature Sensing
EA	Environment Agency (England)
ECC	East Coast Cluster
EET	Essar Energy Transition
EGIG	European Gas Pipeline Incident Data Group
EIA	Environmental Impact Assessment
EMAT	Electromagnetic Acoustic Transducer
EOR	Enhanced Oil Recovery

EOS	Equation of State
EPC	Engineering, Procurement and Construction
EPCI	Engineering, Procurement, Construction and Installation
EPCM	Engineering, Procurement and Construction Management
ERF	Energy Recovery Facility
ESD	Emergency Shutdown
ESDV	Emergency Shutdown Valve
ESV	Emergency Shutoff Valve
ETS	Emissions Trading Scheme
EU	European Union
FAT	Factory Acceptance Test
FEED	Front End Engineering Design
FFKM	Perfluoroelastomer
FID	Final Investment Decision
FKM	Fluoroelastomer
FOAK	First of a Kind
GAP	Gap Analysis
GB	Great Britain
GC	Gas Chromatograph
GERG	Groupe Europeen de Recherches Gazieres
GGR	Greenhouse Gas Removal
GPG	Good Practice Guide
GRE	Glass-Reinforced Epoxy
H_2	Hydrogen
H20	Water
H_2S	Hydrogen Sulphide
H2T	H2 Teesside
HCCP	Humber Carbon Capture Pipeline
HDD	Horizontal Directional Drilling
HDPE	High-density polyethylene
HIPPS	High-integrity pressure protection systems
HNBR	Hydrogenated Nitrile Butadiene Rubber
HNO	Nitroxyl
HS2	High Speed 2
HSC	Hydrogen stress cracking
HSE	Health and Safety Executive
HSL	Health and Safety Laboratory
HVAC	Heating, Ventilation and Air Conditioning
IARC	International Agency for Research on Cancer
ICC	Industrial Carbon Capture
ICD	Inflow Control Device
IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
ILI	In-Line Inspection
IMO	International Maritime Organization
IR	Infrared
ISO	International Organization for Standardization
JIP	Joint Industry Project
JT	Joule–Thomson
LNG	Liquefied Natural Gas
LOGGS	Lincolnshire Offshore Gas Gathering System
LPG	Liquefied Petroleum Gas
LUP	Land Use Planning
LTCS	Low Temperature Carbon Steel
MAH	Major Accident Hazard
MAHP	Major Accident Hazard Pipeline

MAOP	Maximum Allowable Operating Pressure
MAPD	Major Accident Prevention Document
MDEA	Methyldiethanolamine
MFL	Magnetic Flux Leakage
MMR	Monitoring and Reporting Regulations
MMV	Monitoring, Measurement and Verification
MP	Management Plan
$MtCO_2$/yr	Million tonnes of carbon dioxide per year
N_2	Nitrogen
NDE	Non-Destructive Examination
NDIR	Non-Dispersive Infrared
NDT	Non-Destructive Testing
NEP	Northern Endurance Partnership
NESO	National Energy System Operator
NO	Nitric Oxide
NOx	Nitrogen Oxides
NPAI	Not Permanently Attended Installation
NPT	Non-Pipeline Transport
NUI	Normally Unmanned Installation
NSIP	Nationally Significant Infrastructure Project
NSTA	North Sea Transition Authority
NZT	Net Zero Teesside
O_2	Oxygen
OPEX	Operating Expenditure
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning
OREDA	Offshore Reliability Data Handbook
OSD	Offshore Safety Division
PAC	Public Accounts Committee
PEEK	Polyether Ether Ketone
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIMS	Pipeline Integrity Management System
PPE	personal protective equipment
PSIG	Pipeline Simulation Interest Group
PSR	Pipelines Safety Regulations
PSV	Pressure Safety Valve
PTFE	Polytetrafluoroethylene
QA	Quality Assurance
QC	Quality Control
QRA	Quantitative Risk Assessment
RDF	Running Ductile Fracture
RIG	Regulatory Instructions and Guidance
ROV	Remotely Operated Vehicle
ROW	Right of Way
RP	Recommended Practice
RTP	Reinforced thermoplastic pipe
RTTM	Real-Time Transient Model
SAT	Site Acceptance Test
SC	Supercritical
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SCM	Subsea Control Module
SEPA	Scottish Environment Protection Agency
SLOD	Significant Likelihood of Death
SLOT	Specified Level of Toxicity
SMR	Steam Methane Reforming

SO	Sulphur Oxide
SOHIC	Stress-Oriented Hydrogen-Induced Cracking
SOx	Sulphur Oxides
SSC	Sulphide Stress Cracking
SSEP	Strategic Spatial Energy Plan
SSIV	Subsea isolation valves
SSSI	Sites of Special Scientific Interest
SWIC	South Wales Industrial Cluster
SWIR	Short-Wave Infrared
T&S	Transport and Storage
T&SCo	Transport and Storage Company
TBC	To Be Confirmed
TDLAS	Tunable Diode Laser Absorption Spectroscopy
TEG	Triethylene Glycol
TR	Technical Report
TRL	Technology Readiness Level
UAV	Unmanned Aerial Vehicle
UK	United Kingdom
UK ETS	United Kingdom Emissions Trading Scheme
UKOPA	United Kingdom Onshore Pipeline Operators' Association
UN	United Nations
USA	United States of America
USV	Unmanned Surface Vessel
UT	Ultrasonic Testing
UTCD	Ultrasonic Crack Detection
VOC	Volatile Organic Compound

1. EXECUTIVE SUMMARY

The UK is progressing the development of large-scale Carbon Capture and Storage (CCS) networks to support the decarbonisation of industrial clusters and power generation. Central to this is the reliable, safe and commercially viable transport of CO_2 from multiple emitters to offshore storage sites. This study assesses the maturity of CO_2 transport technologies and systems, with particular focus on new-build offshore pipeline transport under UK-specific conditions.

The assessment concludes that there are no fundamental or blocking technology barriers to the deployment of CO_2 transport systems in the UK. The core technologies required for pipeline design, construction and operation are well established, with many components at Technology Readiness Level (TRL) 8–9. However, deployment at the scale and configuration required for UK CCS, particularly multi-emitter networks operating with variable CO_2 compositions and connected to offshore storage, introduces a set of less-mature system-integration challenges.

Where lower TRLs are observed (typically TRL 6–8), they do not reflect deficiencies in underlying hardware but rather limited system-level validation and operational experience, particularly under realistic operating envelopes, including offshore and subsea deployment conditions. These challenges arise from the need to integrate thermodynamics, fracture control, corrosion management, transient behaviour, control systems and commercial arrangements within a single, coordinated network. Deployment and FID readiness are primarily constrained by six categories of integration challenge:

1. CO_2 specification and composition management, including impurity limits, compatibility with transport and storage, and alignment across multiple emitters
2. Transient flow behaviour and decompression, particularly for dense-phase CO_2 with variable compositions
3. Fracture control and pipeline integrity, where validation datasets for CO_2 mixtures and different pipe sizes and manufacturing methods remain limited
4. Measurement, sampling and custody transfer, including calibration standards and uncertainty for dense-phase CO_2 mixtures
5. System operability and multi-emitter network control, including composition tracking, metering, balancing, turndown and start-up/shutdown behaviour
6. Integration with storage systems, including pressure constraints, injectivity and whole-system operating envelopes

While these constraints span the full CCS value chain, their impact on project sanction is not equal.

In practice, only a subset of these challenges materially influences project sanction and early delivery. The most critical determinants of Final Investment Decision (FID) readiness are:

1. Demonstration of safe and predictable transient and decompression behaviour in dense-phase CO_2 systems
2. A clearly defined CO_2 specification, supported by reliable measurement, sampling and custody transfer frameworks
3. Confidence in fracture control performance for impurity-variable CO_2 mixtures
4. Confidence in inspection, monitoring and integrity assurance strategies, particularly for crack detection and long-term operation in impurity-variable CO_2 systems

These areas underpin safety-case acceptance, regulatory confidence and commercial agreements across multi-user networks. Where they are not sufficiently defined or validated, projects are likely to experience extended assurance cycles, conservative design assumptions, and delays to FID and commissioning.

More broadly, the identified gaps reflect integration and validation challenges rather than technology deficiencies. In practice, CO_2 transport systems can and will be deployed using conservative design assumptions, enhanced monitoring, and staged commissioning approaches. However, this may result in reduced operational flexibility, higher cost, and longer ramp-up periods during early project phases.

Ongoing research programmes and Joint Industry Projects (JIPs), including large-scale testing initiatives such as DNV's Project Skylark at Spadeadam, are actively addressing key uncertainties in areas such as dispersion, decompression behaviour, fracture control and impurity effects. These programmes are improving the evidence base required for design and regulatory acceptance, although full integration of their outputs into standards and routine engineering practice is still in progress.

The key constraint to UK CCS transport deployment is therefore not a lack of engineering capability, but the need for confidence in system integration, validation under representative conditions, and alignment across technical, commercial and regulatory interfaces. A further challenge is the limited operational experience available from large-scale offshore CO_2 transportation systems, particularly under the multi-emitter, impurity-variable conditions anticipated for UK CCS networks. As a result, many design assumptions, operating philosophies, integrity management approaches, and emergency response strategies continue to be derived from a combination of hydrocarbon pipeline experience, modelling studies, and targeted testing programmes, rather than from extensive operational feedback from comparable CCS systems. Addressing these areas early in project development will be critical to achieving timely FID, establishing industry best practice, and enabling the successful large-scale deployment of CCS infrastructure in the UK.

2. INTRODUCTION

2.1 Purpose of Work

The North Sea Transition Authority (NSTA) plays an essential role in, amongst other things, enabling the UK's carbon storage ambitions by stewarding offshore carbon storage licenses, developing a robust carbon storage (CS) opportunity portfolio, and engaging with project developers and government to support the evolution of safe and efficient carbon storage opportunities. In pursuit of this, the NSTA commissioned a study to assess the technology requirements for new offshore pipeline carbon dioxide (CO_2) transportation systems, covering both gas and dense-phase operations.

The NSTA regulates the UK's offshore carbon dioxide transport and storage industry and maintains the carbon storage public register on behalf of the UK Secretary of State for Energy Security and Net Zero. When exercising its functions under the Energy Act 2016, the NSTA is required, so far as is relevant, to have regard to the development and use of facilities for the storage of carbon dioxide and to anything else (including pipelines) needed in connection with the development and use of such facilities.

The core objectives of the study are to set the scene regarding UK CO_2 transportation projects; and, for offshore transportation, define the status of technology, research, lessons learned, guidance, standards, and regulatory frameworks; and identify any gaps that, if filled, would accelerate the development of new offshore CO_2 transportation infrastructure.

2.2 Project Overview

2.2.1 Scope of work

The study covers the full life cycle of new offshore CO_2 pipeline transportation systems, supplied by single-emitter and multi-emitter systems, primarily offshore, connected to platform-based or subsea wells. The study battery limits extend from the gathering system interface to the storage interface at either end of the offshore transportation system, including all facilities, equipment, and operational practices required within these limits. Only gaps specific to offshore CO_2 transportation and interfaces with gathering facilities, topsides and subsea sequestration facilities are addressed.

2.2.2 Methodology

A targeted desktop research activity was conducted, drawing on Penspen's direct experience with CCS projects, complemented by selective industry engagement.

2.2.3 Foreword

CCS refers to the capture of CO_2, typically from large, concentrated industrial sources such as power generation facilities, cement plants, steelworks, refineries, and hydrogen production (SMR, or ATR), and its permanent storage in deep geological formations [1,4]. These sectors are prioritised because they emit significant volumes of CO_2 from fixed locations, making capture technically and economically feasible at scale[4]. Importantly, in several industries, particularly cement and certain chemical processes, a substantial proportion of emissions arises from inherent chemical reactions rather than energy use alone[3]. These process emissions cannot be eliminated solely through electrification or fuel switching, positioning CCS as one of the few viable abatement options capable of delivering deep decarbonisation in hard-to-abate sectors[1, 2].

[1] IPCC. AR6 Working Group III Mitigation of Climate Change – Technical Summary. 2022. Available: IPCC_AR6_WGIII_TechnicalSummary.pdf [Accessed 02 March 2026].
[2] Climate Change Committee. The Sixth Carbon Budget – The Uk's path to Net Zero. 2020. Available: The-Sixth-Carbon-Budget-The-UKs-path-to-Net-Zero.pdf [Accessed 02 March 2026].

Following capture, CO_2 is compressed and transported via pipelines to be injected into saline aquifers or depleted oil and gas reservoirs for permanent storage[3,4]. The UK Continental Shelf offers extensive and well-characterised geological storage capacity, with formations that have retained hydrocarbons over geological timescales[5,6]. Established monitoring, measurement and verification technologies provide confidence in long-term containment[7] although technology in this space is evolving rapidly. The development of shared transport and storage (T&S) infrastructure within industrial clusters is central to achieving economies of scale, reducing unit costs, and enabling multiple emitters to decarbonise efficiently[8].

CCS is widely recognised within the UK and international decarbonisation pathways as a critical enabler of net-zero[9,10]. It underpins the decarbonisation of hard-to-abate industries, supports dispatchable low-carbon power generation, and enables low-carbon hydrogen production, particularly at scale in the near to medium term[8,10]. While green hydrogen, produced via electrolysis powered by renewable electricity, will play an important long-term role, its expansion is constrained by the pace of renewable deployment, grid capacity, and electrolyser scale-up[11]. CCS-enabled hydrogen production offers a complementary pathway that can deliver large volumes of low-carbon hydrogen at scale during the transition, supporting industrial demand and system resilience[8].

The strategic importance of CCS is reflected in the UK Government's cluster sequencing approach, including the Track 1 and Track 2 initiatives, which prioritise the phased development of industrial carbon capture clusters and associated transport and storage infrastructure[8,12]. These programmes are designed to catalyse private investment, reduce delivery risk, and establish the UK as a global leader in carbon storage and the low-carbon industry[8]. Net-zero modelling consistently indicates that excluding CCS from national decarbonisation strategies significantly increases overall system costs, narrows viable pathways to net-zero, and places greater pressure on alternative technologies to scale at unprecedented rates[9,10].

CCS materially expands the portfolio of credible decarbonisation options available to the UK. Within the context of industrial competitiveness, energy security, and legally binding carbon budgets, CCS is a foundational component of a balanced, deliverable net-zero strategy aligned with the Government's Track 1 and Track 2 cluster development framework[8,13].

There are material gaps in CCUS thinking that delay deployment[11,14]. In particular, unresolved network integration challenges present critical barriers to scaling projects, alongside gaps in commercial frameworks and cross-chain coordination[8,9]. The development of shared CO_2 transport and storage (T&S) systems has been widely identified as essential to cost reduction and timely deployment, yet it remains dependent on coordinated investment, regulatory clarity, and risk allocation mechanisms[11].

To understand the transport challenges and associated technological gaps, it is essential to clearly define the concept of a CO_2 project and the distinct process steps within the CCS value chain, from capture and

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[3] IPCC. Special Report on Carbon Dioxide Capture and Storage – Technical Summary. **2005**. Available: srccs_technicalsummary-1.pdf [Accessed 02 March 2026].
[4] IEA. CCUS in Clean Energy Transitions. **2020**. Available: CCUS in Clean Energy Transitions – Analysis - IEA [Accessed 02 March 2026].
[5] BEIS. Cluster Sequencing for Carbon Capture Usage and Storage Deployment: Phase 1. **2021**. Available: Cluster Sequencing for Carbon Capture Usage and Storage Deployment: Phase-1 - background and guidance for submissions [Accessed 02 March 2026].
[6] NSTA. Carbon Capture and Storage (CCS) is critical to the UK achieving net zero. Available: Carbon Capture and Storage - The Move to Net Zero - The North Sea Transitioning Authority [Accessed 02 March 2026]
[7] IPCC. Special Report on Carbon Dioxide Capture and Storage – Technical Summary. **2005**. Available: srccs_technicalsummary-1.pdf [Accessed 02 March 2026].
[8] HM Government. Net Zero Strategy: Build Back Greener. **2021**. Available: net-zero-strategy-beis.pdf [Accessed 02 March 2026].
[9] IPCC. AR6 Working Group III Mitigation of Climate Change – Technical Summary. **2022**. Available: IPCC_AR6_WGIII_TechnicalSummary.pdf [Accessed 02 March 2026].
[10] Climate Change Committee. The Sixth Carbon Budget – The Uk's path to Net Zero. **2020**. Available: The-Sixth-Carbon-Budget-The-UKs-path-to-Net-Zero.pdf [Accessed 02 March 2026].
[11] IEA. CCUS in Clean Energy Transitions. **2020**. Available: CCUS in Clean Energy Transitions – Analysis - IEA [Accessed 02 March 2026].
[12] DESNZ. Cluster Sequencing for Carbon Capture Usage and Storage (CCUS) - Track 2 guidance. 2023. Available: Cluster Sequencing for Carbon Capture Usage and Storage (CCUS): Track-2 guidance [Accessed 02 March 2026].
[13] UK Parliament. Climate Change Act 2008. **2008**. Available: Climate Change Act 2008 [Accessed 02 March 2026].
[14] National Infrastructure Commission. The Second National Infrastructure Assessment. **2023**. Available: CD6.3.5 National Infrastructure Assessment (October 2023).pdf [Accessed 02 March 2026].

conditioning through compression, transport, injection and long-term storage[15]. A structured, whole-chain perspective is necessary to identify where constraints arise and how they interact across the system, particularly in cluster-based deployment models, where interdependencies among emitters, transport operators, and storage providers are commercially and technically significant[16].

Although the term CCS is used throughout this report, carbon capture is not part of its primary focus. A more accurate term would be Offshore Carbon Transportation and Storage (aligned with the NSTA's responsibilities), but CCS is used as shorthand, as it is more generally referred to (along with CCUS) when describing carbon sequestration systems.

2.3 Overview of CO_2 Transportation Challenges

CO_2 transport is a critical component of CCS, providing the essential link between capture facilities and permanent storage sites. For efficiency, CO_2 can be transported via pipelines in gaseous or dense-phase (including supercritical) conditions in both onshore and offshore environments. Dense-phase transport is typically preferred for large-scale systems because it provides higher fluid density and improved hydraulic efficiency. However, maintaining dense-phase conditions over long distances requires tight control of pressure, temperature, and composition. This introduces additional technical, operational, and regulatory complexities, particularly in relation to phase stability, impurity management, transient behaviour, and integrity assurance, all of which can directly influence project design, operability, cost, and schedule..

2.3.1 Phase behaviour and impurity management

In its dense phase condition, CO_2 behaves like a liquid in terms of density but may retain some gas-like properties. It occurs at high pressure, typically above about 74 bar, and at temperatures above or below the critical temperature, depending on conditions. In this state, CO_2 has high density (close to that of a liquid), lower volume than gaseous CO_2, improved transport efficiency, and more stable flow behaviour in pipelines.

Transporting CO_2 as a dense fluid significantly reduces the required pipeline diameter; however, it requires more initial compression energy than gaseous transport. Compression of CO_2 from near-atmospheric conditions to dense-phase pipeline pressures (~100–150 bar) typically requires on the order of 90–120 kWh per tonne of CO_2 (≈0.3–0.4 GJ/tCO_2), depending on process configuration and efficiency[17,18].

By comparison, transport in the gaseous phase operates at lower pressures and therefore requires materially less initial compression energy, typically on the order of two to four times lower, depending on the target pressure, as compression work increases strongly with final pressure[18]. However, gaseous transport results in significantly lower fluid density, higher volumetric flow rates, and increased frictional losses, often requiring larger pipelines and/or intermediate recompression.

As a result, dense-phase transport is generally preferred for large-scale and long-distance CO_2 pipelines due to its superior overall transport efficiency and economics, despite the higher upfront compression energy requirement[17,19,20].

Pure CO_2 becomes supercritical when it exceeds its critical point: for pure CO_2, the critical temperature is ~31°C, and the critical pressure is ~73.8 bar. Above both values, CO_2 is neither a typical gas nor a typical liquid. Instead, it becomes a supercritical fluid, which has a liquid-like density and a gas-like viscosity, with no distinct phase boundary between liquid and gas. This makes it highly suitable for pipeline

[15] IEA. CCUS in Clean Energy Transitions. **2020**. Available: CCUS in Clean Energy Transitions – Analysis - IEA [Accessed 02 March 2026].
[16] IPCC. Special Report on Carbon Dioxide Capture and Storage – Technical Summary. **2005**. Available: srccs_technicalsummary-1.pdf [Accessed 02 March 2026].
[17] IPCC Special Report on Carbon Dioxide Capture and Storage. Cambridge University Press, Cambridge, UK, 2005
[18] CO_2 Pipeline Infrastructure. Report No. 2011/02. International Energy Agency Greenhouse Gas R&D Programme (IEAGHG), Cheltenham, UK.
[19] Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage. U.S. Department of Energy, Office of Fossil Energy, 2019
[20] DNV-RP-F104: Design and Operation of Carbon Dioxide Pipelines. DNV, Norway, 2021

transport because it combines efficient volumetric transport (like a liquid) with relatively good flow characteristics (like a gas).

The presence of impurities in the CO_2 stream significantly influences transport behaviour, material performance, and overall system integrity. Common impurities may include water (H_2O), hydrogen sulphide (H_2S), sulphur oxides (SO_x), nitrogen oxides (NO_x), oxygen (O_2), nitrogen (N_2), methane (CH_4), carbon monoxide (CO) and hydrogen (H_2), depending on the capture source and process. Even small concentrations of water can form carbonic acid, increasing the risk of corrosion in pipelines and associated infrastructure. Impurities alter phase behaviour by shifting the critical point, thereby creating a multiphase region that affects density, pressure requirements, and decompression characteristics. Certain combinations may also increase the risk of fracture propagation risk, or complicate compression and dehydration requirements. Even small/trace impurities can also have an impact see Table 5-2 . As a result, strict CO_2 quality specifications, dehydration standards, monitoring and management of impurity limits are essential to ensure safe, efficient and reliable CCS transport operations.

Maintaining CO_2 in a dense or supercritical state maximises the mass transported per unit volume, reduces compression and operating costs, and improves hydraulic stability. However, this requires tight control of pressure, temperature and composition of the fluid provided by the various emitters. If pressure drops below critical levels, CO_2 can revert to a two-phase fluid. In rapid decompression scenarios, it can form solid CO_2 (dry ice), which introduces material and safety challenges. In summary, use of dense/supercritical transport is essential for the economic operation of CCS pipelines, but it introduces thermodynamic and integrity-management complexities that must be carefully engineered and controlled.

2.3.2 Onshore vs offshore challenges

CO_2 pipeline challenges differ materially between onshore and offshore environments, with additional distinctions offshore between platform-based and purely subsea configurations. Onshore pipelines face routing constraints, land access negotiations and heightened public and planning scrutiny due to dense CO_2 dispersion characteristics. However, they benefit from easier access for inspection, maintenance and emergency response, with generally lower intervention cost and simpler construction logistics.

Offshore pipelines involve higher capital cost and operational complexity. Installation requires specialist vessels and weather windows, while repair and intervention are slower and more expensive. Longer tie-backs increase inventory and complicate depressurisation and restart, and seabed conditions influence phase stability and monitoring requirements.

Platform-based systems provide surface access for pigging, metering, compression and manual intervention, improving inspectability and operational flexibility but increasing capital cost, safety-case complexity and personnel exposure. Purely subsea systems minimise surface infrastructure and manning but shift risk toward remote control, intervention logistics, and transient management, with greater dependence on the reliability of monitoring and the performance of subsea equipment.

2.3.3 Integrated risk landscape

The principal challenges in CO_2 pipeline transport arise not from any single technical issue, but from the interaction of multiple tightly coupled factors. These can be broadly grouped into four interrelated domains: the unique physical properties of CO_2; phase-behaviour sensitivity and corrosion control; flow assurance and pipeline integrity management; and safety, cost, and regulatory compliance requirements. The integration challenge lies in the fact that decisions in one domain directly affect performance and risk in the others. As a result, CO_2 transport infrastructure must be designed and operated as a whole system, with thermodynamics, materials selection, transient behaviour, operational control philosophy and commercial governance aligned across the entire CCS value chain rather than optimised in isolation.

2.3.4 Economies of scale

Scale and volume can influence which constraints become dominant, especially as systems evolve from single-user or limited-user configurations to shared, open-access networks. Governance, planning and standardisation requirements become increasingly important as networks expand. Pipelines in particular benefit from economies of scale, where maximum utilisation of the pipeline justifies its dominating capital costs[21].

2.3.5 Comparison with hydrocarbons

A CO_2 transportation project differs from conventional hydrocarbon pipeline transportation projects because transport performance is tightly coupled to CO_2 phase behaviour and stream composition, hazard potential and constraints imposed by the end storage site. The project objective is not simply to convey a commodity between two points but to deliver CO_2 into a storage system that can accept injection only within defined pressure, temperature and composition limits, which can become the binding constraint on throughput and operability[22, 23]. Hazard and consequence considerations differ from typical flammable-gas pipeline streams because CO_2 presents an inhalation hazard primarily as a simple asphyxiant, displacing oxygen in the air at high concentrations, but it also has direct physiological effects at elevated levels. As CO_2 concentration increases, it stimulates breathing and leads to hypercapnia (raised blood CO_2), causing headaches, dizziness and shortness of breath. At higher concentrations, CO_2 can induce respiratory acidosis, confusion, loss of consciousness and, in extreme cases, rapid incapacitation or death. Very high concentrations may cause collapse within seconds due to the combined effects of oxygen displacement and acute hypercapnia. Releases from high-pressure systems require a detailed hazard assessment (Quantitative Risk Assessment, or QRA) that considers topography, routing, and dispersion modelling. Operational considerations that may be less prominent in conventional projects can be central in CO_2 projects. Water content must be carefully controlled to manage corrosion and hydrate formation risk, which influences infrastructure design and operation. Maintenance access, turndown, restart philosophy and pigging are also affected, each forming a part of the design basis. Issues can be amplified where multiple emitters connect to shared infrastructure. Off-spec events, balancing, and curtailment rules must be governed by agreed-upon processes.

2.3.6 Development phases

A CO_2 project development lifecycle can be described using the following phases, beginning with concept selection from the emitter to the store, and identifying critical interfaces to ensure viability. Pre-FEED and FEED then develop the selected concept into a defined basis for technical assurance and delivery planning, including specification regimes, control philosophies, and the integration of onshore and offshore facilities consistent with the end-to-end chain in
Figure 4-1.
Planning and DCO applications, where applicable, address consents for onshore infrastructure, while regulatory approvals and assurance gate reviews provide structured checkpoints for demonstrating readiness and compliance across the regulated elements of the chain. Permitting and seabed leases provide assurance for offshore infrastructure development. Procurement and contracting strategies then determine how the scope will be packaged and delivered. Common project execution models include EPC (Engineering, Procurement and Construction), EPCI (Engineering, Procurement, Construction and Installation), EPCM (Engineering, Procurement and Construction Management), multi-contract strategies, alliance or integrated project delivery models, and Build–Own–Operate–Transfer (BOOT)/ Design–Build–Finance–Operate (DBFO) structures after which operations, maintenance and system integrity management sustain safe performance over the operating life. Decommissioning and end-of-life activities then address asset retirement.

[21] Orchard, K. (Element Energy). CO_2 transport: The role of CO_2 shipping. 2019. Available: CO2 transport: The role of CO2 shipping [Accessed 04 March 2026].
[22] HSE. The Storage of Carbon Dioxide Regulations - General - 8.1c. 2010. Available: The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010 [Accessed 05 March 2026].
[23] BEIS. Endurance Storage Development Plan – Key Knowledge Document. 2022. Available: Endurance Storage Development Plan [Accessed 05 March 2026].

3. SCENE SETTING

3.1 Regulatory Framework

The regulatory framework governing CO_2 pipelines and transport systems in the UK is structured around five complementary pillars: pipeline safety, environmental protection, storage integrity and licensing, network operation and economic regulation, and emissions accounting. These pillars are administered by different regulatory bodies but operate in combination to ensure that CO_2 transport and storage systems are safe, environmentally compliant, commercially robust, and consistent with the objectives of carbon capture and storage.

Pipeline safety is primarily administered and enforced by the Health and Safety Executive (HSE), which acts as the competent authority under the Pipeline Safety Regulations 1996 (PSR) and, more broadly, for major hazard regulation. HSE enforces compliance through statutory duties placed on operators, including requirements for hazard identification, risk assessment, integrity management and emergency planning, supported by inspection, audit and investigation activities. In addition, HSE provides statutory advice to local planning authorities on developments near major hazard pipelines and installations through its Land Use Planning (LUP) function. Enforcement powers include the ability to issue improvement and prohibition notices, and to pursue prosecution where regulatory requirements are not met. For offshore infrastructure, HSE operates under the Safety Case regime, requiring duty holders to demonstrate that major accident risks are identified and controlled. Together, these mechanisms ensure that pipeline operators demonstrate that risks are reduced as low as reasonably practicable (ALARP) and that appropriate safeguards are maintained throughout the asset lifecycle.

Environmental protection is overseen offshore by the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED), part of the Department for Energy Security and Net Zero (DESNZ). OPRED is responsible for environmental permitting, monitoring and assurance, including the assessment of environmental impacts associated with CO_2 transport and storage activities. This includes ensuring that operations minimise emissions, protect the marine environment, and comply with relevant environmental legislation and permitting regimes.

Storage integrity and licensing are governed by the Energy Act 2008 and associated regulations, with DESNZ responsible for the overall policy and regulatory framework. The North Sea Transition Authority (NSTA) acts as the licensing authority for offshore CO_2 transportation and storage, granting and administering storage licences and ensuring compliance with storage permit conditions, including the requirement to demonstrate that there is no significant risk of leakage. This pillar establishes the regulatory basis for long-term containment and underpins the requirement that transported CO_2 must be suitable for safe and permanent storage.

Network operation and economic regulation are delivered through the CCS Network Code and the economic regulatory framework overseen by the Office of Gas and Electricity Markets (Ofgem). Ofgem regulates Transport and Storage Companies (T&SCos), embedding the CCS Network Code within licence conditions and enforcing compliance through licence obligations, performance monitoring and enforcement powers. The Code establishes the technical, commercial and operational rules governing multi-user CO_2 transport and storage networks, including requirements for CO_2 specification, system operability, capacity allocation and coordinated network management. This pillar ensures that shared infrastructure operates efficiently, transparently, and in a manner that supports fair access and system integrity.

The fifth pillar is emissions accounting and trading, delivered through the UK Emissions Trading Scheme (UK ETS) and associated Monitoring, Reporting and Verification (MRV) requirements. While the ETS does not directly regulate pipeline design or operation, it imposes requirements on the accurate quantification and reporting of CO_2 quantities captured, transported, injected, and released. These requirements introduce a direct dependency on reliable metering, composition analysis, and mass-balance reconciliation throughout the CCS chain. Measurement uncertainty, venting, or leakage therefore have direct implications for carbon credit allocation, regulatory compliance, and commercial positions.

Together, these five pillars pipeline safety (HSE/PSR), environmental protection (OPRED), storage integrity (NSTA/Energy Act), network operation and economic regulation (Ofgem/CCS Network Code), and emissions accounting (UK ETS/MRV) form a layered regulatory framework in which responsibilities are distributed but interdependent. Effective CCS deployment requires coordinated compliance across all pillars, with particularly strong interdependencies between measurement performance, environmental outcomes, and commercial operation.

3.1.1 Pipeline Safety (HSE)

If a pipeline is classified as a Major Accident Hazard Pipeline (MAHP) under the Pipeline Safety Regulations (PSR)[24], the operator assumes enhanced legal duties. These include preparing and maintaining a documented arrangements demonstrating that major accident hazards have been identified, risks assessed and control measures implemented (MAPD) demonstrating that hazards have been identified, risks assessed and control measures implemented; establishing and exercising emergency procedures in coordination with local authorities and emergency responders; notifying HSE of relevant pipeline details and safety measures; maintaining robust integrity management systems covering inspection, monitoring and maintenance; and demonstrating that risks have been reduced as low as reasonably practicable (ALARP). A MAHP also triggers the need for Land Use Planning (LUP) assessments in the pipeline's vicinity. HSE's Land Use Planning Team (part of Hazardous Installations Directorate – HID) undertakes this assessment using a tool/process known as PADHI (Planning Advice for Developments near Hazardous Installations). HSE does not make the planning decision but provides advice (e.g. "Advise Against" or "Do Not Advise Against"). The local planning authority makes the final decision. For offshore infrastructure, this is primarily delivered through the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015, under which duty holders must prepare and maintain an accepted Safety Case demonstrating control of major accident hazards.

The Health and Safety Executive (HSE) has a statutory role in advising local planning authorities on developments near major hazard installations and pipelines. For MAHPs, HSE defines consultation distances and associated inner, middle and outer zones, within which development proposals are assessed against risk-based criteria. Local planning authorities are required to consult HSE before approving developments within these zones. If CO_2 pipelines are classified as MAHPs, this would directly influence route selection, setback distances, permissible nearby development and overall planning timelines.

Historically, CO_2 has not been treated as a dangerous substance under PSR, as it is classified internationally by the UN as a non-flammable, non-toxic gas (Class 2.2) and primarily presents an asphyxiation hazard rather than chemical toxicity. However, for dense-phase, high-pressure CO_2 pipelines associated with CCS, HSE has recognised that CO_2 can present a major accident hazard potential due to operating pressure and release behaviour. Dense-phase CO_2 releases differ materially from methane, and consequence modelling requires specific treatment. As a result, high-pressure CO_2 pipelines may fall within the MAHP regime depending on operating pressure, diameter, inventory and modelling outcomes. In practice, large CCS trunklines are likely to meet MAHP criteria.

HSE (March 2026) is actively reviewing and refining the regulatory treatment of CO_2 pipelines as CCS deployment progresses. This includes clarifying how PSR applies to CO_2, determining classification thresholds, developing appropriate LUP methodologies and updating hazard assessment guidance to reflect dense-phase behaviour. Consultation has taken place through technical working groups and engagement with industry stakeholders, and guidance continues to evolve alongside early cluster development.

For UK CCS deployment, the practical implication is that high-pressure CO_2 pipelines will likely be regulated as MAHPs, requiring comprehensive safety documentation, emergency planning and engagement with HSE on LUP matters. These requirements may influence routing, consenting and project schedules, making early regulatory engagement essential.

A further consideration is the relationship with the Control of Major Accident Hazards (COMAH) Regulations 2015. COMAH applies to fixed onshore establishments holding specified dangerous

[24] The Pipelines Safety Regulations 1996 (SI 1996/825)

substances above defined thresholds and is based on the Seveso III Directive. It does not apply to offshore installations which are regulated under the offshore Safety Cas regime. Pure CO_2 is not listed as a dangerous substance and is not typically classified as toxic or flammable for COMAH purposes, meaning that CO_2 alone would not normally bring a site into COMAH scope. However, in CCS applications, the transported CO_2 stream may contain impurities (e.g., H_2S, CO, or hydrocarbons) that, if present in sufficient quantities, could trigger COMAH classification. In addition, CO_2 compression, dehydration, and conditioning facilities associated with pipelines may form part of larger installations that fall within COMAH due to other hazardous inventories. It is also important to note that pipelines themselves are explicitly excluded from COMAH and are instead regulated under the Pipeline Safety Regulations (PSR). As such, there is a regulatory interface whereby CO_2 pipelines (classified as MAHPs under PSR) connect to onshore installations that may be subject to COMAH, requiring coordination of safety management systems, emergency planning and risk assessments across both regimes.

3.1.2 Environmental Protection (OPRED / DESNZ)

Environmental protection for offshore CO_2 transport and storage activities is overseen by the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED), part of the Department for Energy Security and Net Zero (DESNZ). OPRED is responsible for environmental permitting, monitoring and assurance, ensuring that CO_2 transport and storage operations are conducted in a manner that protects the marine environment and complies with applicable environmental legislation.

Operators are required to undertake environmental impact assessments and obtain the necessary permits prior to construction and operation. This includes demonstrating that potential impacts associated with pipeline installation, operation, venting, and decommissioning are understood and appropriately mitigated. Particular consideration is given to the potential for CO_2 releases, dispersion behaviour, and interactions with the marine environment.

OPRED also oversees monitoring and reporting requirements, including emissions to atmosphere and discharges to sea, ensuring alignment with broader environmental and climate objectives. These requirements operate alongside, but are distinct from, emissions accounting under the UK Emissions Trading Scheme (UK ETS), with OPRED focused on environmental protection and permitting, and ETS regimes focused on carbon accounting and compliance.

3.1.3 CO_2 Storage Licensing (Energy Act 2008 and Licensing Regulations)

The EU CCS Directive (2009/31/EC) includes provisions relevant to CO_2 pipelines, but its treatment of transport is limited compared with its detailed requirements for storage. For pipelines, the Directive primarily addresses third-party access, requiring that CO_2 transport networks be made available on a non-discriminatory basis to support the development of integrated CCS infrastructure. It also sets requirements on the composition of the CO_2 stream, stipulating that it must consist predominantly of CO_2, with impurities controlled so they do not compromise transport integrity, storage security, or pose risks to human health or the environment. However, the Directive does not establish detailed pipeline design, safety, or risk assessment standards, leaving these matters to national regulatory frameworks. A central principle of the Directive is that CO_2 storage sites must demonstrate “no significant risk of leakage”, which places an implicit requirement on the wider CCS chain, including pipelines, to ensure that CO_2 quality and handling do not undermine long-term containment integrity.

In the UK, the Directive was transposed into domestic law primarily through the Energy Act 2008 and the Storage of Carbon Dioxide (Licensing etc.) Regulations 2010, which together establish the legal framework for CO_2 storage and aspects of transport, including access provisions. Following the UK’s exit from the EU, these requirements were retained in UK law, meaning that, while the Directive itself no longer applies directly, its core principles continue to operate through this legislation. This is particularly relevant for offshore CO_2 pipelines connecting to storage sites, where the integrity of the transported CO_2 stream is critical to meeting the storage permit conditions. While the Directive (and its UK equivalents) does not directly regulate offshore pipeline design, operators must demonstrate that pipeline operation—including control of impurities, pressure, and phase behaviour—supports the overarching requirement of secure, permanent storage with no significant risk of leakage. In practice, the design, construction, and operation of offshore CO_2 pipelines are governed by existing UK offshore safety and environmental regimes, but must align with storage regulatory expectations, creating a functional link between transport performance and storage compliance.

3.1.4 Network Operation and Commercial Regulation (CCS Network Code / Ofgem)[25]

To provide a clear and enforceable framework governing the operation of shared CO_2 transport and storage networks operate in a regulated, multi-user environment, the Department for Energy Security and Net Zero (DESNZ) led the development and production of the CCS Network Code. This was undertaken in partnership with industry stakeholders, expert advisors, and the Department for Business, Energy and Industrial Strategy (BEIS). The Code governs the commercial, technical, and operational relationships between CO_2 network Users and Transport and Storage companies (T&SCos). Although developed by the government, the Code is implemented and maintained by Ofgem. A consultation on the draft heads of terms was held in late 2023, and the initial full-form Code was published in January 2026. A summary of the objectives and implications is included below.

In the context of offshore pipelines connecting to CO_2 storage sites, the Code is particularly important as it provides the framework through which multiple emitters can access and utilise shared offshore transport infrastructure leading to licensed storage complexes. It establishes requirements around CO_2 specification, pressure and flow conditions, capacity allocation, and system operability, all of which are critical to ensuring that offshore pipelines can reliably deliver CO_2 to storage sites without compromising integrity or storage performance. While the physical design and safety regulation of offshore pipelines remain governed by existing UK offshore safety and environmental regimes, the Network Code ensures that their operation within a multi-user system is coordinated and consistent with storage permit conditions, including the overarching requirement for secure, permanent containment (i.e. no significant risk of leakage). In this way, the Code links commercial access arrangements to the technical constraints of offshore transport and storage infrastructure, supporting the safe and efficient scaling of CCS networks.

3.1.4.1 Objectives of the CCS Network Code

Establish a binding governance framework to provide a consistent, enforceable rulebook for access and operations: The Code establishes the legal, commercial and technical framework governing CO_2 transport and storage networks. It is maintained under the T&SCo Licence and sets out the commercial and technical rules between T&SCos and Users. It legally binds parties via Code Agreements or Code Accession Agreements. It covers the connection of Users to a T&S Network, the delivery of CO_2 at Delivery Points, transportation and storage, operation and maintenance, and the interface between different T&S Networks. It protects the integrity and safety of the T&S Network by preventing corrosion, phase change, fracture, hazardous release, and system damage. It sets detailed CO_2 quality specifications, including >95 mol% CO_2 and <4 mol% non-condensables, together with strict controls on water, impurities, corrosion, fracture, solids, and hazard risks. It requires risk-based monitoring plans, defined exceedance thresholds and non-compliance rules, and immediate isolation for certain categories of non-compliance. It defines monitoring, verification, and transparency requirements to ensure reliable data, accountability, and operational control. It requires continuous or periodic monitoring, depending on component risk; early warning systems and pre-exceedance alarms; independent verification of measurement equipment; and defined communication timeframes for non-compliance. It allocates connection responsibilities to clearly define technical, legal and cost responsibilities at the interface. Any connection requires a Connection Agreement, a Construction Agreement and a Code Accession Agreement. Physical works are split between T&SCo Works (the network side of the Delivery Point) and User Works (the facility side).

3.1.4.2 Implications for CO_2 transporters (T&SCos)

Transport and Storage Companies carry strong integrity and availability obligations under the Network Code. In the event of non-compliance, they must assess and manage risks to the network, including impacts on pipeline integrity, corrosion, phase behaviour such as condensation or free water formation, acid generation, and potential hazards to operators and the public. They are required to act as a Reasonable and Prudent Operator, minimise the duration of any isolation, and meet licence-based availability requirements, effectively holding system-wide responsibility for both safety and uptime. In addition, any proposed modification to the Code must consider impacts on network operations, capital and operating costs, existing and future Users, and overall cost allocation, ensuring that system evolution

[25] UK Carbon Dioxide Transport and Storage Network Code (DESNZ)

does not disadvantage new connectors or undermine efficiency. The T&SCo also validates measurement systems, may require enhanced monitoring, and enforces isolation procedures where necessary, positioning it as the gatekeeper for CO_2 quality compliance and operational discipline across the network.

3.1.4.3 Implications for parties wishing to connect (Users)

Users are subject to a mandatory contractual framework requiring entry into a Connection Agreement, a Construction Agreement and a Code Accession Agreement, ensuring that access to the network is formally structured rather than informal. They must comply with strict CO_2 quality specifications, meeting detailed impurity and composition limits and installing required online analysers, including for CO_2, water, oxygen and relevant acid gases, together with early-warning alarm systems. Where specified thresholds are exceeded, certain categories of non-compliance require immediate isolation, meaning capture facilities must incorporate high-quality gas treatment, redundancy and rapid shut-in capability. In cases of non-compliance, Users may be required to cease flow immediately and notify the T&SCo, and resumption is permitted only once compliance is demonstrated, placing operational and revenue risk primarily on the user in the event of quality breaches. Users are also responsible for providing independently verifiable measurement systems, implementing risk-based monitoring plans, and complying with defined exceedance and averaging rules, resulting in a significant requirement for metering, laboratory, and compliance infrastructure.

3.1.4.4 How it becomes legally binding

The CCS Network Code becomes legally binding when it is incorporated into a T&SCo's licence and when relevant parties accede to it through the required contractual arrangements.

Under the UK CCUS regulatory model, T&SCos are granted licences (regulated by Ofgem) under the Energy Act framework. The licence conditions require the T&SCo to comply with and administer the CCS Network Code. Once the Code is in force under the licence, it becomes binding on the licensed T&SCo itself; and any User (e.g. capture project) that signs a Code Accession Agreement and related Connection and Construction Agreements. In practice, this means the Code is legally binding once the T&S licence containing the Network Code obligation is active, and a User has formally acceded to the Code.

With respect to Track 1 projects, HyNet (Liverpool Bay CCS) and the Northern Endurance Partnership (NEP) for the East Coast Cluster, both are intended to operate as regulated T&S networks under the UK CCUS regime. As licensed T&SCos, they are expected to be governed by the CCS Network Code once their licences are in effect and the Code is designated as applicable. Capture projects connecting to these networks will be required to accede to the Code as part of their connection process.

In summary, the CCS Network Code is not merely guidance; it becomes legally enforceable through licence conditions and accession agreements. HyNet and Northern Endurance, as regulated T&S networks, are intended to operate under this framework once their licences and Code arrangements are formally in force.

3.1.4.5 Capability implications

Table 3-1– CCS Network Code Implications below identifies the capability implications for T&SCo and Users.

Table 3-1– CCS Network Code Implications

Area	Implications for Capability and Technology
System-Level Technical Capability Requirements	The Code establishes a regulated utility-style CO_2 transport system. This drives the need for high-integrity dense-phase CO_2 pipeline design capability, including fracture control, corrosion management, impurity interaction modelling, and phase behaviour analysis. Whole-system process modelling capability, covering transient operations, start-up/shutdown scenarios, and impurity impacts across onshore and offshore systems. Advanced materials engineering expertise, particularly relating to hydrogen-enhanced cracking, aqueous phase corrosion, and acid formation risks. Integrated network control capability, ensuring operational safety while meeting availability targets. The emphasis on preventing corrosion, phase change, fracture, and hazardous release requires transporters to possess deep expertise in thermodynamics, chemistry, and materials, supported by validated modelling tools.
CO_2 Quality Control and Treatment Technology	The strict CO_2 specification requirements (>95 mol% CO_2, <4 mol% non-condensables, water and impurity controls) imply that capture and conditioning systems must include high-performance

	dehydration systems, advanced gas purification technologies, robust impurity-removal processes (e.g., O_2, NOx, SOx management), and solid and liquid management systems. This pushes Users toward more sophisticated gas treatment trains, tighter process control, and redundancy in conditioning systems to avoid isolation events.
Monitoring and Measurement Technology Capability	The Code's monitoring and verification requirements imply the need for continuous online analysers for key components (minimum: CO_2, H_2O, O_2, NOx, SOx), cyclic and laboratory-based analytical capability, high-reliability instrumentation with rapid response times, pre-exceedance alarm systems integrated with control systems, and independent verification-ready metering systems. Both T&SCos and Users must deploy advanced flow measurement systems, gas chromatography and spectroscopic analysers, data acquisition and supervisory control systems (SCADA/DCS integration), and automated reporting interfaces (including regulatory data interfaces). Technology must be sufficiently robust to support enforcement, audit and independent validation.
Isolation and Rapid Response Capability	The requirement for immediate isolation in certain exceedance cases implies automated shutdown logic integrated with monitoring systems, fast-acting isolation valves, emergency response systems, and operational procedures supported by digital workflow systems. Users must design facilities with rapid shut-in capability, controlled depressurisation systems, and minimal upset propagation to upstream processes. This shifts facility design toward resilience and controllability rather than purely steady-state optimisation.
Data Management and Digital Infrastructure	Given the requirements for monitoring, verification, communication, and transparency, there is a strong implication for high-integrity digital infrastructure, secure data exchange platforms between Users and T&SCos, automated compliance reporting systems, and data validation and anomaly-detection tools. Capability is required not just in instrumentation, but in cybersecurity, digital audit trails, regulatory reporting frameworks, and data governance and retention systems.
Network Integrity and Asset Management Capability (T&SCos)	T&SCos must demonstrate capability in risk-based integrity management, corrosion monitoring technologies (e.g. corrosion probes, inspection tools), in-line inspection (ILI) and pigging systems, reservoir monitoring technologies (for offshore storage systems), and availability modelling and performance optimisation. The need to balance safety and availability requires predictive maintenance tools and digital twin-style modelling of network behaviour.
Engineering and Commercial Interface Capability	Because responsibilities are split between T&SCo Works and User Works, both parties must have clear boundary definitions and interface management capabilities, detailed FEED-level engineering integration, commissioning and performance testing protocols, and the capability to demonstrate compliance before flow commencement. This increases the importance of systems integration engineering capability.
Financial and Technology Risk Implications	From a technology perspective, isolation risk places a premium on process reliability engineering, monitoring obligations increase capital expenditure on instrumentation, compliance risk encourages redundant or conservative technology selection, and network operators require scalable and future-proof designs to accommodate future connectors. The Code, therefore, indirectly drives higher technical specification standards, reduced tolerance for experimental or marginal technologies, and preference for proven, bankable technology platforms.
Overall Capability and Technology Implication	The CCS Network Code effectively transforms CO_2 transport into a regulated, high-integrity infrastructure sector comparable to gas transmission. This creates a need for advanced process engineering capability, strong instrumentation and digital systems capability, sophisticated integrity management capability, high-reliability plant design capability, and integrated commercial–technical governance capability. For transporters, this means operating as regulated infrastructure utilities with advanced engineering, integrity and digital systems capability. For Users, this means designing capture and conditioning facilities to utility-grade specifications, with robust quality-control, redundancy, and compliance infrastructure built in from the outset.

3.1.5 Emissions Trading and Measurement Requirements (UK ETS / MRV)

The UK Emissions Trading Scheme (UK ETS) provides the regulatory framework for accounting of greenhouse gas emissions, including the treatment of captured, transported and permanently stored CO_2. While the ETS is not directly responsible for pipeline design or operation, it establishes requirements for the monitoring, reporting and verification (MRV) of CO_2 quantities, including the mass of CO_2 captured, transported, injected, and, where applicable, released to the atmosphere. These requirements are set out in the Measurement, Monitoring and Reporting (MMR) regulations and enforced by the relevant environmental regulators.

For CO_2 transport and storage systems, this introduces a direct dependency on accurate and auditable measurement of CO_2 flows and composition. Metering systems must meet defined uncertainty thresholds (typically ≤±2.5%, with lower targets anticipated for commercial CCS applications) and support full mass-balance reconciliation across the CCS chain. Venting, leakage, or measurement uncertainty can therefore have direct implications for emissions accounting, carbon credit allocation, and regulatory compliance. As a result, emissions-trading requirements impose additional constraints on metering system design, calibration, and verification, thereby linking regulatory compliance directly to measurement performance.

3.2 Properties of CO_2

Carbon dioxide comprises two oxygen atoms covalently double-bonded to a single carbon atom, with an O=C=O angle of 180°. In chemical processing industries, it is used to control reactor temperatures (in its supercritical phase)[26], to neutralise alkaline effluents, and to purify or dye polymer, animal, or vegetable fibres[27]. In the food and beverage industries, CO_2 is used to carbonate beverages such as soft drinks, mineral water, and beer[28]. It is also used for packaging foodstuffs as a cryogenic fluid in chilling or freezing operations, or as dry ice for temperature control during food distribution.

If pressure or temperature conditions move outside the dense-phase region, CO_2 may enter a two-phase region where liquid and vapour coexist. Two-phase flow significantly complicates pipeline operation. It can lead to unstable hydraulics, pressure oscillations, uneven flow distribution, slugging, and an inability to achieve the required flow-rate uncertainty levels. In dense-phase pipelines, maintaining a sufficient margin from the phase boundary under steady-state and transient conditions (such as start-up, shutdown or rapid depressurisation) is therefore a key design objective. The risk of entering the two-phase region is particularly important during pressure drops along long pipelines or during rapid decompression events.

At lower pressures, CO_2 behaves as a gas. Gas-phase transport is possible and has been used in some applications, but it requires larger diameters for equivalent throughput and is more sensitive to pressure drop. Several UK stores will be low-pressure initially, so gas-phase injection must be used to build reservoir pressure before transitioning to dense-phase operation, but this requires pipelines and compression systems capable of safely accommodating both regimes.

CO_2 also has a solid phase (dry ice). The triple point of CO_2 occurs at approximately 5.2 bar and −56.6°C. See Figure 3-1. During rapid depressurisation of high-pressure CO_2 pipelines, significant Joule–Thomson (JT) cooling can occur, potentially driving local conditions below the sublimation temperature and causing solid CO_2 formation. Solid formation can create blockages in valves and vents, and cause restrictions, increasing mechanical stress and complicating restart procedures. This behaviour is particularly relevant for blowdown and emergency isolation design.

Impurities materially influence CO_2 phase behaviour and its impact on pipelines. Non-condensable gases such as nitrogen (N_2), oxygen (O_2), hydrogen (H_2) and methane (CH_4) shift the phase envelope, typically raising the pressure required to maintain single-phase dense operation and broadening the two-phase region. This reduces operating margin and can necessitate higher design pressures or tighter specification limits. Reactive impurities such as water, sulphur oxides (SOx), nitrogen oxides (NOx) and hydrogen sulphide (H_2S) can affect both phase behaviour and corrosion risk. Even very small amounts of water can form carbonic acid in the presence of CO_2, increasing the risk of corrosion in carbon steel pipelines. Hygroscopic contaminants (e.g., glycols or amines) can promote liquid-phase formation at lower overall water contents, altering expected dew-point behaviour.

Impurities also influence decompression characteristics and fracture control. The presence of certain gases can alter decompression wave speed and the shape of the pressure–temperature path during rupture, affecting running ductile fracture behaviour. Consequently, fracture-control design and operating envelopes must account for realistic impurity ranges rather than idealised pure CO_2.

In summary, CO_2 phase behaviour under pipeline conditions spans dense phase (supercritical or liquid-like), two-phase, gas and solid regimes, and transitions between these states can occur under realistic operating and transient scenarios. Impurities modify the phase envelope, corrosion potential, and decompression response, directly influencing pipeline design pressure, material selection, fracture-control requirements, and operational control philosophy. Effective CO_2 pipeline integration, therefore,

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[26] Xiao, Y. et al. Research Advances in the Application of the Supercritical CO_2 Brayton Cycle to Reactor Systems: A Review. *Energies*. 2023. Available: [Research Advances in the Application of the Supercritical CO2 Brayton Cycle to Reactor Systems: A Review | MDPI] [Accessed 05 March 2026].
[27] Goñi, M.; Gañán, N.; Martini, R. Supercritical CO2-assisted dyeing and functionalization of polymeric materials: A review of recent advances (2015–2020). *Journal of CO2 Utilization*. Volume 54. 2021. Available: [Supercritical CO2-assisted dyeing and functionalization of polymeric materials: A review of recent advances (2015–2020) - ScienceDirect] [Accessed 05 March 2026].
[28] Sure Purity. What is Carbon Dioxide Used For in Drinks Industry?. 2025. Available: [What Is Carbon Dioxide Used For in Drinks Industry?] [Accessed 10 March 2026].

requires managing thermodynamics, materials performance and transient behaviour as a coupled system rather than in isolation.

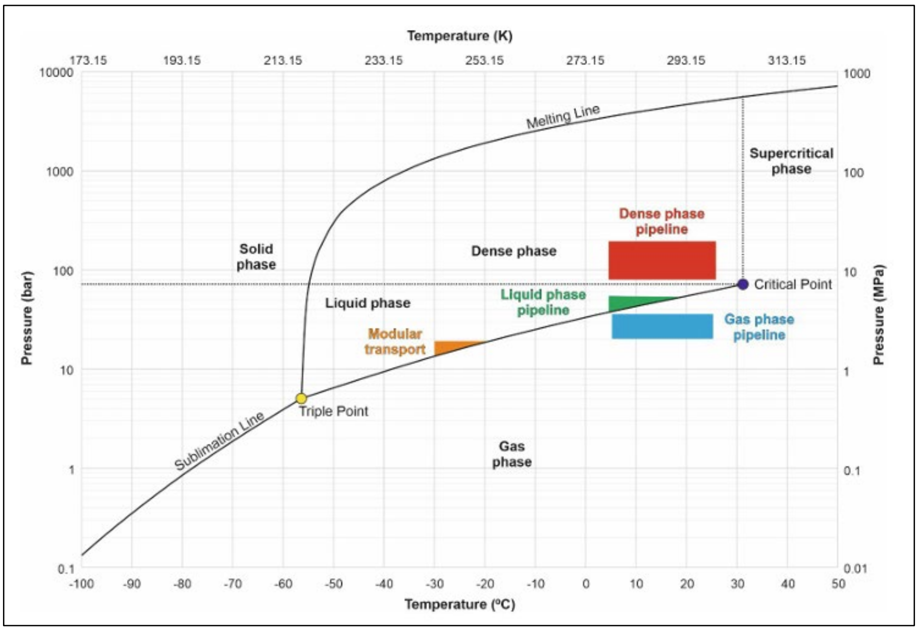

Figure 3-1 – CO_2 Phase Diagram with Typical Transport Conditions [29]

3.3 Existing CO_2 Pipelines

Existing CO_2 pipelines total over 5,000 miles (>8,000 km) globally, with the majority in the United States for enhanced oil recovery (EOR). Examples include the Cortez Pipeline (~800 km, 30-inch diameter), which transports naturally sourced CO_2 from McElmo Dome in Colorado to oil fields in the Permian Basin and is one of the longest and highest-capacity CO_2 pipelines globally. The Sheep Mountain Pipeline (~1,050 km, 24-inch diameter) carries naturally occurring CO_2 from Colorado into Wyoming and Nebraska for enhanced oil recovery (EOR). The Central Basin Pipeline (~430 km) and the Bravo Dome pipeline system in New Mexico also supply CO_2 to Permian Basin EOR operations. In addition, the Denbury Green Pipeline (~515 km) and the Denbury Gulf Coast Pipeline (~375 km) transport anthropogenic CO_2 captured from industrial sources to EOR fields along the US Gulf Coast, demonstrating both natural and industrial CO_2 transport at scale.

These systems operate at high pressure in dense or supercritical phases to transport CO_2 safely, with a limited but growing network. In Canada, the 240 km Alberta Carbon Trunk Line (ACTL) has been in operation since 2020, transporting CO_2 for EOR. In general CO_2 pipelines have a strong safety record over several decades, with no recorded fatalities in the US in the last 20 years.

3.4 UK CCS Perspective and Progress

Within the UK's net-zero pathway, CCS is positioned as critical enabling infrastructure for sectors where emissions are difficult or costly to eliminate, particularly for carbon-intensive industrial processes. At the time of writing (May 2026), the government laid plans for four CCUS clusters by 2030, aiming to capture 10 million tonnes of CO_2 per year ($MtCO_2$/yr), with two clusters to be in place by the mid-2020s[30]. The Cluster Sequencing Process was used to select and sequence the first CCUS projects to receive government support. In the first phase, the government assessed bids from cluster organisations and selected clusters best placed to be operational in the mid-2020s as Track-1. These had to credibly demonstrate their

[29] Alcalde, J. (CSIC); Johnson, G. (Drax). Transportation of CO2. **2025**. Available: DR1907-6_Transportation-of-CO2_GB_V002.pdf [Accessed 04 March 2026].
[30] BEIS. Cluster Sequencing for Carbon Capture Usage and Storage Deployment: Phase-1 Background and guidance for submissions. **2021**. Available: Cluster Sequencing for Carbon Capture Usage and Storage Deployment: Phase-1 - background and guidance for submissions [Accessed 10 March 2026].

operability by 2030 and comprise a T&S network with an associated first phase of at least two CO_2 capture projects. In the second phase, the government assessed bids from individual capture projects seeking to connect to the Track-1 cluster and selected projects for negotiations to secure support. Track-2 clusters were also selected with a longer delivery timeline than Track-1. The UK planned industrial clusters are shown in Figure 3-2 – Planned Industrial Clusters .

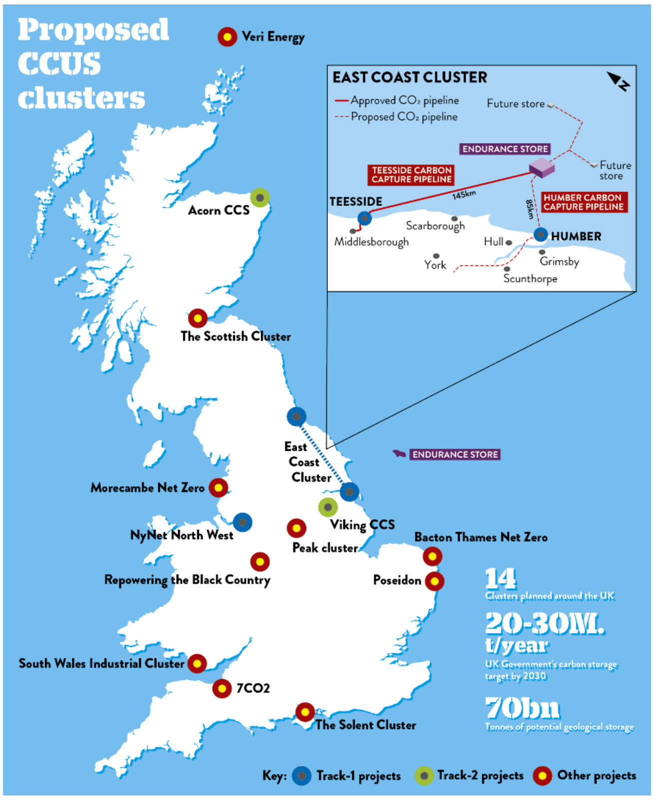

Figure 3-2 – Planned Industrial Clusters [31]

Track-1 comprises the HyNet and East Coast Clusters, fully backed by the Government's funding envelope of £21.7 billion over 25 years, announced in 2024[32]. Net Zero Teesside Power CCS and the Northern Endurance Partnership (NEP) T&S two East Coast Cluster (ECC) projects reached financial close in December 2024[33], followed by HyNet's Liverpool Bay T&S in April 2025[34]. These two clusters have since transitioned from planning into delivery, with additional projects currently in negotiations to join the HyNet cluster under the Government's Track-1 expansion (T1x) plan[35]. Track-2 comprises the Viking and Acorn clusters, with Acorn also designated as the Track-1 reserve[36]. The government has committed development funding to accelerate both clusters towards 2030 and beyond, announcing £200 million for Acorn in June 2025, subject to business case review, with more to follow post Spending Review process[37].

[31] Smith, K. (New Civil Engineer). What do the UK's carbon capture and storage plans mean for the civil engineering sector? 2025. Available: What do the UK's carbon capture and storage plans mean for the civil engineering sector? [Accessed 11 March 2026].
[32] DESNZ. Government reignites industrial heartlands 10 days out from the International Investment Summit. 2024. Available: Government reignites industrial heartlands 10 days out from the International Investment Summit - GOV.UK [Accessed 10 March 2026].
[33] Equinor. Equinor and partners approve execution of UK's first carbon capture and storage projects. 2024. Available: Equinor and partners approve execution of UK's first carbon capture and storage projects - Equinor [Accessed 10 March 2026].
[34] ENI. Eni and the UK Government reach Financial Close for the Liverpool Bay CCS project. 2025. Available: Eni and the UK Government reach Financial Close for the Liverpool Bay CCS project [Accessed 10 March 2026].
[35] DESNZ. HyNet expansion: project negotiation list. 2025. Available: HyNet expansion: project negotiation list - GOV.UK [Accessed 10 March 2026].
[36] DESNZ. Notice: Update to industry on conclusion of the CCUS Cluster Sequencing Track-2 expression of interest. 2023. Available: Update to industry on conclusion of the CCUS Cluster Sequencing Track-2 expression of interest - GOV.UK [Accessed 10 March 2026].
[37] DESNZ. Funding secured for Britain's industrial future, Government backs 2 major Carbon Capture projects in Aberdeenshire and the Humber. 2025. Available: Funding secured for Britain's industrial future - GOV.UK [Accessed 10 March 2026].

Remaining projects not selected through the Track-1 and Track-2 Cluster Sequencing Process are increasingly using new development pathways as the government seeks to broaden participation beyond the slower, resource-intensive Track framework. In November 2025, the Department for Energy Security and Net Zero (DESNZ) confirmed it is developing a new East Coast Cluster (ECC) Teesside competitive selection process to launch in early 2026, based on summer 2025 market engagement. The selection process aims to build on prior learning and provide a proportionate and accessible approach to eligibility and assessment. This includes broadening participation in projects expected to be commercially viable without typical long-term government revenue support, and exploring the extent to which non-pipeline transport (NPT) projects could be made eligible[38].

In parallel, the government has stated it is working with the South Wales Industrial Cluster (SWIC) to assess viable decarbonisation pathways that encompass CCUS deployment, including potential NPT and storage solutions. SWIC, along with many other clusters, has benefited from backing via the Industrial Decarbonisation Challenge, a research and innovation programme that provided funding to help clusters plan and invest in decarbonisation[39], and is also being assessed as part of the Track-1 expansion process[40]. These examples illustrate ongoing CCUS developments outside Track 1 and Track 2. A consolidated overview of current and planned UK CCUS projects, at the time of writing (May 2025), is provided in Table 3-2. Of the projects proposed under Track 1 and Track 2, only a subset have reached financial close or construction.

Table 3-2 – UK CCUS Projects

Cluster / Region	Project	Value Chain Element	Track / Pathway	Current Stage (Feb 2026)	Key Public Milestone(s)	Target In-service / Next Milestone	Stated Capacity ($MtCO_2$/yr)
East Coast Cluster (Teesside)	Endurance store / NEP T&S (Net Zero North Sea Storage / NEP)	Transport & Storage	Track-1	Post-award/delivery (pre-injection)	Storage permit awarded 10 Dec 2024	First injection from 2027 (per permit)	4.0 (permitted injection rate); 100 Mt total over 25 years
East Coast Cluster (Teesside)	Net Zero Teesside Power (NZT Power)	Capture (power CCUS)	Track-1	Post-financial close/delivery	"Work set to begin in 2025"; NZT power targeted from 2028	2028 (target)	~2.0 (capture)
East Coast Cluster (Teesside)	Teesside Hydrogen CO_2 Capture (BOC)	Capture (industrial / hydrogen)	Track-1	In negotiations /development	Selected to Track-1 negotiations list (Mar 2023)	TBC (not stated publicly in cited sources)	>0.2 (capture)
East Coast Cluster (Teesside)	H2Teesside (bp)	Capture (CCS-enabled hydrogen)	Track-1 (originally)	Withdrawn/ stopped	FEED announced (Aug 2024); project later withdrawn (Dec 2025)	N/A	>2.0 (planned capture)
HyNet (NW England / N Wales)	Liverpool Bay CCS (Eni) – HyNet T&S	Transport & Storage	Track-1	Post-financial close/construction	Financial close 24 Apr 2025; "enters construction phase"	Initial operations c. 2027 (stated expectation in DESNZ guidance)	~4.5 (initial T&S capacity)
HyNet	Hydrogen Production Plant 1 (HPP1) (EET Hydrogen)	Capture (CCS-enabled hydrogen)	Track-1	In negotiations (FEED complete)	FEED completed Sep 2021	2027 (expected production start)	0.6 (capture)

[38] DESNZ. CCUS East Coast Cluster: Teesside selection process. **2025**. Available: CCUS East Coast Cluster: Teesside selection process - GOV.UK [Accessed 10 March 2026].
[39] UKRI. Area of investment and support: Industrial decarbonisation. **2026**. Available: Industrial decarbonisation – UKRI [Accessed 10 March 2026].
[40] UK Parliament. Carbon Capture and Storage: South Wales – Question for DESNZ. **2025**. Available: Written questions and answers - Written questions, answers and statements - UK Parliament [Accessed 10 March 2026].

HyNet	Hydrogen Production Plant 2 (HPP2) (EET Hydrogen)	Capture (CCS-enabled hydrogen)	Track-1 expansion (T1x)	In negotiations (deliverability passed)	Listed in T1x negotiations (Aug 2025)	2028 (expected production start)	1.9 (capture)
HyNet (N Wales)	Hanson Padeswood Cement Works CCS (Heidelberg Materials)	Capture (industrial)	Track-1	Post-FID/execution	FID announced 25 Sep 2025	Operational by 2029	~0.8 (capture; "nearly all" site CO_2)
HyNet (Cheshire)	Protos ERF CCS (Encyclis)	Capture (waste / EfW)	Track-1	In development (pre-operations)	Project update / agreements public (2025)	Operational by mid-2029	~0.37 (capture)
HyNet (Cheshire)	InBECCS (Evero)	GGR / BECCS (capture)	Track-1 expansion (T1x)	In negotiations (priority)	Selected to negotiations Aug 2025	Retrofit by 2029 (stated aim)	0.217 (removals/ capture)
HyNet (NW England)	Connah's Quay Low Carbon Power (Uniper)	Capture (power CCUS)	Track-1 expansion (T1x)	In negotiations (priority)	Selected to T1x negotiations (Aug 2025)	TBC	Up to 3.7 (capture at full load)
HyNet (Cheshire)	EET Industrial Carbon Capture (Stanlow) (EET Fuels)	Capture (industrial)	Track-1 expansion (T1x)	In negotiations (standby)	Selected to T1x negotiations (Aug 2025)	TBC	~1.0 (capture)
HyNet (N Wales)	Parc Adfer EfW ICC (Enfinium)	Capture (waste / EfW)	Track-1 expansion (T1x)	In negotiations (standby)	Selected to T1x negotiations (Aug 2025)	TBC (not stated publicly in cited sources)	Up to 0.12 (capture/removals)
HyNet (Cheshire)	Viridor Runcorn Carbon Capture	Capture (waste / EfW)	Track-1 (then T1x standby)	Paused (per developer update)	FEED completed summer 2025; developer states it will not proceed to planning submission	N/A (paused)	0.9 (capture; incl. biogenic fraction)
HyNet (Derbyshire)	Buxton Lime Net Zero (Tarmac/ partners)	Capture (industrial/ process)	Track-1	Early development / due diligence	Selected to Track-1 negotiations list (Mar 2023)	TBC	0.02 (capture)
HyNet	Silver Birch (Climeworks)	GGR / DAC (planned)	Track-1 expansion (T1x)	In negotiations (standby)	Selected to T1x negotiations (Aug 2025)	TBC	TBC (not stated publicly in cited sources)
Humber / Viking	Viking CCS T&S	Transport & Storage	Track-2	Pre-FID (FEED complete; consenting achieved)	FEED complete Q1 2025; DCO granted Q2 2025	Construction from 2028; storage ramp early 2030s	4 in early 2030s; line of sight to 10 by 2035
Scotland / St Fergus	Acorn CCS	Transport & Storage	Track-2	Pre-FID (development funded)	Track-2 status confirmed (govt process)	Targeting progress toward FID "in this Parliament"	≥5 by 2030 (stated); storage licences cover ~240 Mt resource

Figure 3-3, from the latest Carbon Capture and Storage Association (CCSA) industry survey, further illustrates some of CCS projects in various stages of development (which do not include all ongoing projects in the UK due to developer permissions). Currently around 20 percent of the projects shown, with a combined capture capacity of 12.65 Mtpa, are targeted to be commercially operational by 2031 at the earliest. By 2036 this number is planned to increase to around 30 percent of all projects. On average, project timelines have been extended by 2 years and around one third of surveyed projects have paused spending on development in the UK[41]. There are more than 100 CCUS projects in development in the

[41] CCSA. CCUS Delivery Plan Update 2025. **2025**. Available: PowerPoint Presentation [Accessed 06 March 2026].

UK with a combined capture and storage capacity of 77 Mtpa but without a step change in key enablers such as key policy decisions and reliable funding, the number of projects cancelled may continue to rise from the current 27 since 2023[41].

The currently progressing projects represent approximately 13 $MtCO_2$/yr of potential near-term capacity, materially below the previously stated 20–30 $MtCO_2$/yr ambition. This reinforces the importance of ensuring utilisation certainty before further expanding transport infrastructure.

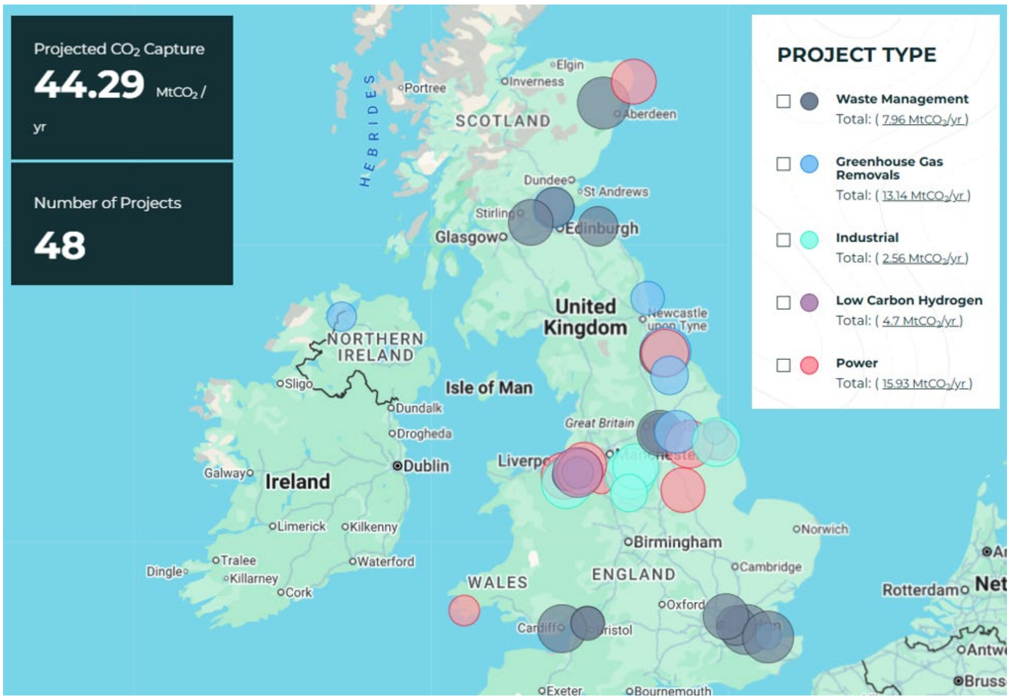

Figure 3-3 – UK Carbon Capture Project Pipeline [42]

The UK CCUS network cannot progress solely based on engineering and financial readiness. Projects must also secure the necessary offshore carbon storage licenses to store the CO_2 they capture, as well as seabed leases. The NSTA plays an essential role, amongst other things, in granting critical carbon storage licenses that allow a project to move towards injection. Concurrently, developers must also be granted seabed leases through The Crown Estate (England, Wales, Northern Ireland waters) or The Crown Estate Scotland[43]. The Northern Endurance Partnership (NEP) predates the UK's first carbon storage licensing round and was established to develop the Endurance saline aquifer as part of the East Coast Cluster. Subsequently, in December 2024, NEP was granted a carbon storage permit for the Endurance store, located approximately 75 km off the north-east coast of England. This permit enables the commencement of offshore installation works and progression toward injection, which is currently targeted for 2027. The Endurance store is expected to support Track-1 East Coast Cluster projects, with an initial permitted injection rate of ~4 $MtCO_2$ per year and a total storage capacity of up to 100 Mt over 25 years. The partnership had to satisfy criteria such as site eligibility assessment, safety and environmental risk, financial security, and technical competency. Under the UK's first CO_2 storage licensing round, concluded in 2023, the North Sea Transition Authority (NSTA), working with The Crown Estate and Crown Estate Scotland, awarded over 20 carbon storage licences across the UK Continental Shelf. In December 2025, the NSTA opened its second licensing round, offering 14 locations for exploration and appraisal. These additional stores could add up to 2 gigatonnes of CO_2 storage capacity to the planned UK network[44]. Should these early projects prove successful, further contracts could be awarded to develop access to the

[42] *By express permission of the CCSA.* CCSA. UK Carbon Capture Project Pipeline. **2025**. Available: CCUS in the UK - CCSA [Accessed 06 March 2026].
[43] NSTA. NSTA launches UK's second carbon storage licensing round, **2025**. Available: NSTA launches UK's second carbon storage licensing round [Accessed 10 March 2026].
[44] NSTA. NSTA launches UK's second carbon storage licensing round, **2025**. Available: NSTA launches UK's second carbon storage licensing round [Accessed 10 March 2026].

UK's estimated 78 gigatons of offshore CO_2 storage capacity, predominantly composed of saline aquifers[45].

Similarly, public opinion can have a dramatic effect on infrastructure development. Public attitudes toward CCUS vary, and for many people, it is not a high-profile issue. DESNZ's Public Attitudes Tracker showed that in Spring 2025, 44 per cent of the public supported CCS, with 12 per cent opposed and a substantial share neutral or unsure, indicating limited awareness or confidence to take a clear stance[46]. Support is most often linked to climate benefits, but it can weaken if the technology is perceived as expensive or if delivery appears uncertain. Public opinion is crucial because cost and schedule delays have undermined trust in major UK infrastructure projects, with HS2 frequently cited as an example.

Large onshore CO_2 pipelines in England are likely to qualify as Nationally Significant Infrastructure Projects (NSIPs) under the Planning Act 2008 and therefore require consent through a Development Consent Order (DCO) rather than local planning permission. In Scotland, an equivalent NSIP regime does not apply; instead, onshore pipelines are typically consented under the Town and Country Planning (Scotland) Act 1997, with determination by the relevant planning authority or Scottish Ministers, depending on scale and strategic importance.

For offshore pipelines, the primary consenting regime is separate, with approvals granted under the Energy Act 2008 (e.g. via a CO_2 storage licence and associated pipeline works authorisation), and, where relevant, marine licensing requirements. However, even for predominantly offshore developments, the short onshore section (e.g. landfall, valve stations, and tie-ins) will still require onshore planning consent. In England, this onshore element may fall within the DCO regime if it forms part of a project that meets NSIP thresholds or is included within a wider nationally significant development; otherwise, it may be consented through the local planning system. In Scotland, the onshore elements would be addressed through the standard planning framework noted above.

This means that, while offshore pipelines are primarily governed by offshore regulatory regimes, a hybrid consenting approach is typically required, with offshore consents complemented by onshore planning approvals for landfall infrastructure, even where the onshore footprint is relatively limited.

The DCO process, administered by the Planning Inspectorate on behalf of the Secretary of State, includes an extensive pre-application phase involving environmental surveys, Environmental Impact Assessment (EIA), statutory consultation and route refinement; a 28-day acceptance stage; a six-month examination by an appointed Examining Authority; and subsequent recommendation and ministerial decision. While the statutory post-submission process typically takes 12–18 months, the pre-application phase can extend the total programme duration to several years. For CO_2 pipelines, delays can arise from public and planning sensitivity to dense-phase dispersion risks, environmental and habitat constraints along long linear routes, complex land acquisition and compulsory purchase processes, interaction with HSE's Major Accident Hazard and Land Use Planning requirements, evolving project scope (e.g., additional emitters or storage changes), and cumulative impacts with other infrastructure. Although the DCO regime provides a consolidated consent mechanism, schedule risk primarily arises from route uncertainty, environmental survey timing, safety case refinement, and iterative redesign during consultation, making early integration of engineering, safety, environmental, and stakeholder strategy critical to avoiding programme delays.

As such, CCUS will be judged not only on overall emissions impact but also on value for money and adherence to stated delivery timelines, including whether key milestones such as FID, construction start, and first injection are achieved as planned. This further increases the importance of clear deliverables, timelines, and costs.

With the context for CCUS in the UK established, the obvious question is why, despite its long-term strategic importance and broad but tentative public support, deployment is not advancing faster. The answer is largely economic: CCUS remains expensive, and in many cases, current market indicators are insufficient to justify private investment without policy support.

[45] CO2 Stored. Project FAQs. CO2 Stored FAQ [Accessed 10 March 2026].
[46] DESNZ. DESNZ Public Attitudes Tracker: Headline findings, Spring 2025, UK. **2025**. Available: DESNZ Public Attitudes Tracker: Spring 2025 - GOV.UK [Accessed 10 March 2026].

A second key contributor is capability gaps across the end-to-end value chain, including supply chain capacity, delivery expertise, and the technical and operational readiness needed to rapidly scale capture, transport, and storage.

3.5 Role of CCS as Defined by the National Energy System Operator (NESO)

The National Energy System Operator (NESO) is the independent public body responsible for planning and operating Great Britain's (GB) electricity system and for delivering whole-system strategic planning across electricity and hydrogen[47]. It leads long-term system planning to ensure energy security, affordability and decarbonisation, operating independently of generation and network asset ownership while providing system-wide coordination and strategic advice to government. One of its key responsibilities is producing the Strategic Spatial Energy Plan (SSEP), which sets out a spatially coordinated framework for the future development of GB's electricity and hydrogen infrastructure. The SSEP uses economic modelling and geospatial analysis to identify optimal locations for generation and storage, develop and compare multiple credible system pathways, ensure a strategic spread of technology mixes, and balance economic viability, deliverability and spatial impact. It does not approve projects; instead, it provides a structured comparison of future system configurations to guide infrastructure and policy decisions.

The SSEP works alongside the Centralised Strategic Network Plan (CSNP), with distinct but complementary roles: SSEP identifies where and what technologies are likely to be deployed, while the CSNP determines how the transmission network should be built or reinforced to connect generation to demand efficiently. Within SSEP modelling, Gas with CCS is explicitly treated as a low-carbon dispatchable power technology, grouped with nuclear, bioenergy with carbon capture and storage (BECCS), hydrogen-to-power and biomethane under themes focused on higher levels of low-carbon dispatchable capacity. CCS is therefore positioned as a provider of firm, controllable generation that supports security of supply and reduces reliance on unabated gas. Its role varies across pathways, expanding where higher levels of dispatchable low-carbon power are required and contracting in scenarios that emphasise renewables or reduced reliance on newer technologies, reflecting both its strategic importance and recognised deployment risks[48].

3.6 Carbon Pricing

Within this evolving energy transition landscape, UK and European carbon pricing mechanisms play a material role in shaping the commercial viability and investment case for CCUS[49, 50]. The UK Emissions Trading Scheme (ETS), established in 2021 following departure from the EU ETS, places a price on carbon emissions from power generation, heavy industry and aviation[51]. As emitters face a rising carbon price, the economic case for capturing and storing CO_2 strengthens, as avoided emissions reduce the need to purchase allowances[52]. In principle, a sufficiently high and predictable carbon price can narrow the cost gap between unabated production and CCS-enabled operations, thereby reducing reliance on direct government subsidy[53]. However, carbon price volatility and uncertainty over long-term trajectories limit its effectiveness as a sole investment signal for capital-intensive infrastructure with multi-decade lifetimes[54].

[47] NESO. National Energy System Operator launches today. **2024**. Available: National Energy System Operator launches today | National Energy System Operator [Accessed 05 March 2026].
[48] NESO. NESO outlines new timelines for Strategic Energy Plans. **2025**. Available: NESO outlines new timelines for Strategic Energy Plans | National Energy System Operator [Accessed 10 March 2026].
[49] DESNZ. The Long-Term Pathway for the UK Emissions Trading Scheme. **2023**. Available: The long-term pathway for the UK Emissions Trading Scheme - GOV.UK [Accessed 10 March 2026].
[50] European Parliamentary Research Service. Revision of the EU emissions trading system. **2026**. Available: Revision of the EU emissions trading system [Accessed 10 March 2026].
[51] DESNZ. UK Emissions Trading Scheme (UK ETS): a policy overview. **2026**. Available: UK Emissions Trading Scheme (UK ETS): a policy overview - GOV.UK [Accessed 10 March 2026].
[52] Climate Change Committee. Sixth Carbon Budget. **2020**. Available: Sixth Carbon Budget - Climate Change Committee [Accessed 10 March 2026].
[53] Murfet, C. (Global CCS Institute). Perspective – Carbon Contracts for Differences in Europe. **2025**. Available: Carbon-Contracts-for-Differences-in-Europe-Global-CCS-Institute.pdf [Accessed 10 March 2026].
[54] IPCC. Climate Change 2022, Mitigation of Climate Change, Technical Summary - AR6 Working Group III. **2022**. Available: IPCC_AR6_WGIII_TechnicalSummary.pdf [Accessed 10 March 2026].

In the European Union, the EU ETS has undergone successive reforms, including tightening the cap and expanding the Innovation Fund, leading to higher allowance prices and stronger incentives for industrial decarbonisation[55]. The EU's Carbon Border Adjustment Mechanism (CBAM) further reinforces this framework by imposing a carbon price on certain imported goods, aiming to prevent carbon leakage and protect domestic low-carbon investments[56]. Together, these mechanisms increase pressure on carbon-intensive industries operating in Europe to decarbonise or face rising compliance costs[49]. For UK industry, divergence between the UK ETS and EU ETS creates both risk and opportunity: misalignment in carbon prices may affect competitiveness and cross-border trade, while linkage between the schemes, if pursued, could improve liquidity and reduce price volatility[57].

Carbon pricing also influences the relative attractiveness of different decarbonisation pathways. For example, higher and more stable carbon prices improve the business case for CCS-enabled blue hydrogen and industrial capture, particularly where capture rates are high, and storage is permanent[52]. Conversely, if renewable electricity costs fall more rapidly than expected, green hydrogen pathways may become increasingly competitive without exposure to residual carbon costs[52]. In both cases, the carbon price functions as a system-wide signal that shapes technology choice, sequencing and scale[49].

Despite this, carbon pricing alone has not historically been sufficient to unlock CCS at scale in the UK, as evidenced by the cancellation of earlier competitions in 2011 and 2016[58]. The current cluster model, therefore, combines carbon pricing with long-term contractual support mechanisms, such as Industrial Carbon Capture (ICC) contracts and Dispatchable Power Agreements (DPAs) to provide revenue certainty alongside ETS-driven incentives[59, 60]. The interaction between regulated transport and storage returns, carbon pricing, and government-backed contracts is central to determining overall programme affordability for taxpayers and consumers, a concern highlighted by the PAC[61].

Ultimately, the trajectory of carbon pricing in the UK and Europe will materially influence the pace and scale of CCS deployment. A credible, rising and stable carbon price can reduce subsidy requirements, support private investment, and strengthen the competitiveness of CCS-enabled industrial production [62, 63]. Conversely, persistent volatility, policy divergence, or weak price signals may prolong dependence on direct fiscal support and complicate delivery against future capture targets[64].

3.7 UK-Wide CCS Network

Against this regulatory, technical, and economic backdrop, the question arises: should the UK move toward a fully integrated national CO_2 transport network or continue with a phased, cluster-based approach?

There is a defensible strategic case for a UK-wide CCS platform, but not for building a fully interconnected national backbone ahead of proven demand. The economics of CO_2 transport infrastructure are driven primarily by utilisation rather than geography. While a national platform would standardise access, enable

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[55] European Parliamentary Research Service. Revision of the EU emissions trading system. **2026**. Available: Revision of the EU emissions trading system [Accessed 10 March 2026].
[56] European Commission. Carbon Border Adjustment Mechanism (CBAM). **2026**. Available: Carbon Border Adjustment Mechanism - Taxation and Customs Union [Accessed 10 March 2026].
[57] UK ETS Authority. Developing the UK ETS: Main Response. **2023**. Available: Developing the UK Emissions Trading Scheme: main government response [Accessed 10 March 2026].
[58] National Audit Office, Value for Money, Carbon capture and storage: lessons from the competition for the first UK demonstration. **2012**. Available: Carbon capture and storage: lessons from the competition for the first UK demonstration - NAO report [Accessed 10 March 2026].
[59] HM Government. Net Zero Strategy: Build Back Greener. **2021**. Available: net-zero-strategy-beis.pdf [Accessed 02 March 2026].
[60] DESNZ. The Long-Term Pathway for the UK Emissions Trading Scheme. **2023**. Available: The long-term pathway for the UK Emissions Trading Scheme - GOV.UK [Accessed 10 March 2026].
[61] Public Accounts Committee. Carbon capture: High degree of uncertainty whether risky investment by Govt will pay off. **2025**. Available: Carbon capture: High degree of uncertainty whether risky investment by Govt will pay off - Committees - UK Parliament [Accessed 10 March 2026].
[62] IEA. CCUS in Clean Energy Transitions. **2020**. Available: CCUS in Clean Energy Transitions – Analysis - IEA [Accessed 02 March 2026].
[63] Climate Change Committee. The Sixth Carbon Budget – The Uk's path to Net Zero. **2020**. Available: The-Sixth-Carbon-Budget-The-UKs-path-to-Net-Zero.pdf [Accessed 02 March 2026].
[64] IPCC. AR6 Working Group III Mitigation of Climate Change – Technical Summary. **2022**. Available: IPCC_AR6_WGIII_TechnicalSummary.pdf [Accessed 02 March 2026].

regional decarbonisation, and aggregate North Sea storage resources, long-distance trunklines built in advance of contracted volumes would expose consumers and taxpayers to the risk of underutilisation. Given revised capture ambitions, project withdrawals, and ongoing affordability scrutiny, the economically rational approach is to expand high-load regional clusters first and interconnect only where utilisation thresholds justify the capital investment. This preserves long-term optionality while protecting affordability.

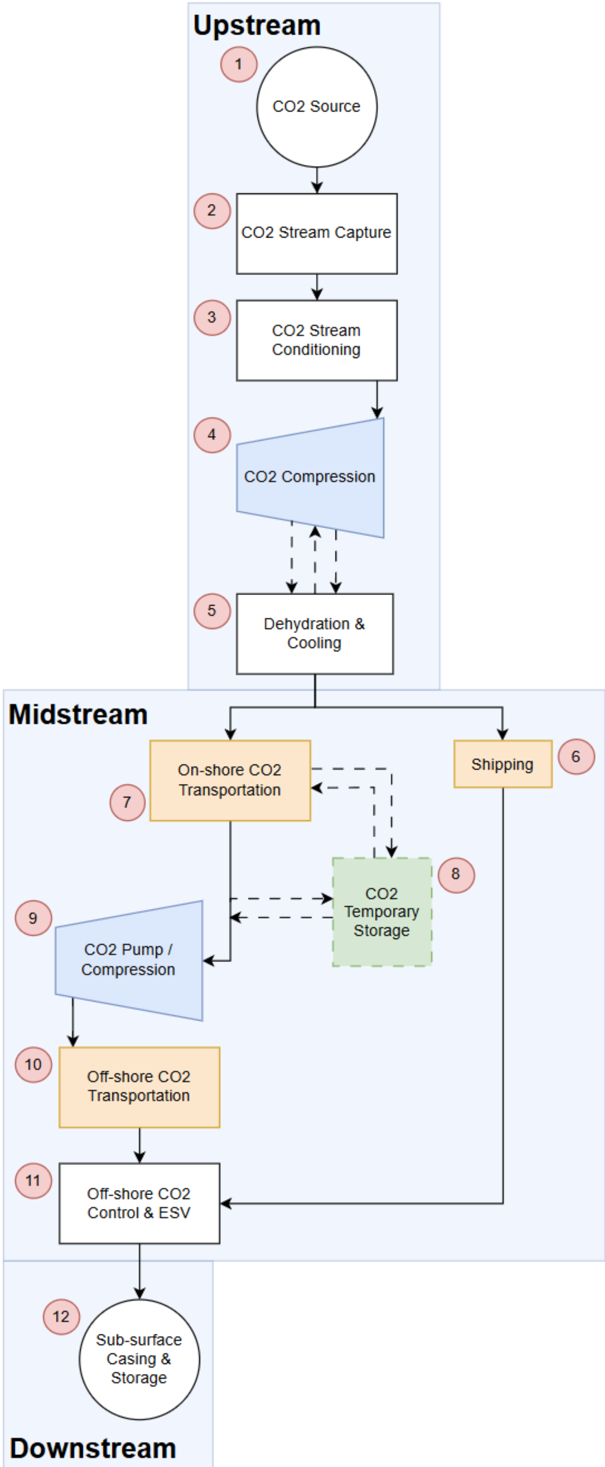
3.8 CCS Scale-up

A simple comparison of scale illustrates the structural challenge facing UK CCUS deployment. The Government's 2030 ambition is to achieve 20–30 $MtCO_2$ per year of capture and storage. By contrast, currently progressing capacity remains materially below this level. The Endurance store, which underpins the East Coast Cluster, has a permitted injection rate of 4 $MtCO_2$ per year, while Viking CCS is expected to deliver a similar order of transport and storage capacity in the early 2030s. In parallel, the second UK storage licensing round alone offers access to approximately 2,000,000 Mt of potential storage capacity. This equates to less than 3 percent of total estimated UK offshore geological storage potential (approximately 78,000,000 Mt).

The contrast is striking. The UK does not face a fundamental shortage of geological storage resource. Instead, the gap lies between long-term storage potential and near-term deliverable annual throughput. The constraint is therefore not storage capacity in principle, but the pace at which transport and injection infrastructure can be developed, integrated and brought into operation at scale.

4. CCS PROJECT DEFINITION

A CO_2 project requires three core components: (1) an emitter package that captures CO_2 and prepares it for export, (2) a transport pathway that maintains operability within a defined specification and operating envelope, and (3) a permitted storage sink capable of accepting injection within defined limits. This section details a complete end-to-end CO_2 process chain from capture to sequestration in reference to Figure 4-1 – CCS Process Chain.



#	Process Step	Key Technologies
1	CO_2 source facility and tie-in point (defined battery limits)	Tie-ins; utilities/controls; emissions metering
2	Capture CO_2 from flue/process gas to an initial spec	Capture plant (DAC, pre/post combustion, amine, oxyfuel, industrial processes); integration/monitoring
3	Condition CO_2 to the T&S export specification (impurities/phase)	Impurity removal; filtration; dehydration trim; spec verification
4	Compress CO_2 to export pressure for transport	Compression/pumping; intercooling; pressure protection
5	Dehydrate CO2 and cool to meet water/hydrate and corrosion limits	Dehydration; aftercooling; hydrate/corrosion control
6	Optional: Liquefy & ship CO_2 between terminals	Liquefaction; CO_2 tanks; loading arms; custody metering; COMAH safety systems
7	Transport CO2 onshore via gathering/trunk pipeline(s) to hub/injection interface	Dense-phase pipeline; block valves/ESD; SCADA/leak detection; CP/coatings
8	Buffer storage at hub/terminal to manage outages and stabilise flow	Pressurised/liquid tanks; transfer pumps & booster compression; metering/monitoring; ESD/relief/SCADA
9	Boost stream pressure as required to manage pressure drop & operating envelope	Booster pump/compressor; pressure control; metering; pigging
10	Transport offshore via export line/risers/tie-ins to injection area	Offshore line/risers; subsea isolation; integrity/corrosion protection
11	Offshore isolation, ESD and control to manage inventory and enable safe operations	ESD/PSD/SIS; HIPPS (as needed); isolation valves; blowdown/depressurisation; remote SCADA telemetry & control
12	Inject into permitted geological store via wells; operate within agreed limits and monitor performance	Injection wells/completions; MMV; well integrity; conformance/containment

Figure 4-1 – CCS Process Chain

4.1 Upstream

A CO_2 project starts at an emitter or collection point where a defined facility boundary and tie-in point establish responsibility for interfaces, measurement, and operational control. The objective is to produce a CO_2 stream that is sufficiently characterised and conditioned to enter the wider T&S network under an agreed specification[65]. In practice, this begins with integrating capture facilities with flue gas or process streams, including any necessary pretreatment steps to make the inlet gas compatible with the selected capture process. The capture unit can take different forms depending on the source and selected concept, including, but not limited to, pre-combustion, post-combustion and oxy-fuel capture configurations. Solvent-based systems are also typical industrial capture options. The common requirement is that the capture plant consistently delivers CO_2 of a quality suitable for downstream conditioning and export[66].

Following capture, upstream conditioning purifies the CO_2 to a set export specification using filtration and impurity removal processes. A key operability driver is that CO_2 phase behaviour is sensitive to pressure, temperature and composition. Relatively small variations can affect whether the stream remains within the acceptable operating envelope, so specification definition and compliance become a central design input[67]. Phase selection influences the definition of a common specification and network logistics across the CO_2 process chain, with both dense-phase and gaseous-phase operation potentially relevant. Conditioning systems deployed for either phase significantly affect operability and the ability to manage abnormal conditions without creating off-spec deliveries to shared infrastructure, which is a recurring theme in multi-user CO_2 systems under emerging network governance frameworks[68].

Compression and/or pumping with intercooling are then used to achieve export conditions. Downstream of compression, dehydration and cooling are commonly applied to manage water content, which dominates corrosion and flow assurance risks. In CO_2 service, controlling water content is critical as dissolved water can form carbonic acid and drive corrosion in carbon steel systems[69]. Water and other contaminants can also contribute to hydrate or solid formation under certain transient conditions, leading to restricted flow and upset conditions. The upstream element typically culminates at the emitter "battery limit," where metering, sampling, and quality confirmation support measurement, custody transfer, and compliance monitoring at the point of entry into the wider network.

Effective and uniform upstream processes are critical to envisioned multi-emitter networks where each emitter would capture and condition its own CO_2 to a common specification before transferring custody at its battery limit. Multiple entry streams would feed a shared onshore gathering system that aggregates the CO_2 into a pipeline (trunkline[70]), supported by pressure management and integrity systems. CO_2 networks will require credible compliance evidence at these interfaces as a prerequisite for multi-party governance and operation[71].

Upstream facilities also require supporting systems like utilities and controls integration, chemical supply and handling, waste and vent management, and relief and blowdown provisions. These systems are consequential for safety and reliability because they influence the ability to operate safely under abnormal conditions and to manage planned and unplanned outages without creating off-spec events that propagate into shared infrastructure or necessitate venting off-spec CO_{22}.

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[65] IPCC. Special Report on Carbon Dioxide Capture and Storage – Technical Summary. **2005**. Available: srccs_technicalsummary-1.pdf [Accessed 02 March 2026].
[66] IPCC. Guidelines for National Greenhouse Gas Inventories. Volume 2: Energy - Section 5.3. **2006**. Available: Microsoft Word - V2_Ch5_CCS_Final.doc [Accessed 02 March 2026].
[67] ISO. ISO 27913:2024 Carbon dioxide capture, transportation and geological storage – Pipeline transportation systems. **2024**. Available: ISO 27913:2024 - Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems [Accessed 02 March 2026].
[68] DESNZ. Carbon capture and storage (CCS) Network Code – Consultation on the CCS Network Code Heads of Terms (Pg. 37). **2024**. Available: CCS Network Code Heads of Terms: consultation [Accessed 02 March 2026].
[69] IPCC. Special Report on Carbon Dioxide Capture and Storage – Technical Summary. **2005**. Available: srccs_technicalsummary-1.pdf [Accessed 02 March 2026].
[70] Cole, S.; Itani, S. The Alberta Carbon Trunk Line and the Benefits of CO2 (Section 1.2). *Energy Procedia Volume 37*. **2013**. Available: The Alberta Carbon Trunk Line and the Benefits of CO2 - ScienceDirect [Accessed 02 March 2026].
[71] Suvanmani, V. Impurities in CO2 streams for a multi-user CCS hub. *Australian Energy Producers Journal* 65. **2025**. Available: Impurities in CO2 streams for a multi-user CCS hub | Australian Energy Producers Journal | ConnectSci [Accessed 02 March 2026].

4.1.1 Source

The CO_2 project begins at a defined tie-in between an emitting source and a capture plant. The boundary matters because downstream equipment and operating rules depend on what is delivered and because multiple parties may share responsibility at that interface[72,73]. Key technologies are the physical tie-ins, utilities and control integration, and measurement provisions needed to quantify and track what is transferred into the chain. Common challenges are practical integration at a live industrial site, data quality for measured flows, and ensuring the boundary conditions are stable enough that capture and downstream processing are not forced into frequent upset operation[74,75].

4.1.2 Stream capture

Stream capture separates CO_2 from a flue or process gas stream, producing a CO_2 stream for downstream processing. The process step boundary includes the capture plant and the integrations needed to run it safely alongside the host process. Key technologies include solvent/adsorbent processes, membranes and other separation configurations, plus plant monitoring and controls. Typical challenges include achieving stable capture performance across variable host operations, managing the energy and utility demands of capture, and producing a CO_2 stream that can be reliably conditioned to meet transport entry requirements[76,77,78,79].

4.1.3 Stream conditioning

Stream conditioning covers the processing required to bring captured CO_2 into an export specification suitable for T&S. The process step boundary is the set of treatment steps between capture output and transport entry conditions, with the objective of managing impurities and phase behaviour so that the CO_2 stream is compatible with the selected transport mode and downstream operational envelope. In a multi-emitter context, the importance of controlled aggregated delivery conditions cannot be overstated, as reflected in the CCS network code. Impurity removal, filtration, and verification technologies are critical to the success of this process step. These technologies support achieving and confirming an exportable CO_2 quality prior to compression, dehydration and transport entry. Where pipeline transport is envisaged, UK safety guidance highlights that CO_2 may be conveyed as a gas, a dense or supercritical phase fluid[80] and that stream conditioning is critical to success[81,82].

4.1.4 Compression

The compression process step increases CO_2 pressure to the conditions defined by the T&S network. The boundary includes the compression duty needed to reach the chosen export pressure and to support stable downstream conveyance. Compression or pumping, intercooling, and pressure protection technologies will be employed to deliver the required export conditions while controlling temperature rise and safeguarding against overpressure. The facility must handle variability in inlet pressure, temperature, flowrate, and composition as sources ramp and trip. This increases turndown requirements and the risk

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[72] ISO. ISO 27913:2024 Carbon dioxide capture, transportation and geological storage – Pipeline transportation systems. **2024**. Available: ISO 27913:2024 - Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems [Accessed 02 March 2026].

[73] CCSA. CCSA Pre-Capture Metering Position & Comments on Excessive Carbon Creation. **2022**. Available: Resources - CCSA [Accessed 03 March 2026].

[74] TUV SUD National Engineering Laboratory. Flow Measurement in Support of Carbon Capture, Utilisation and Storage (CCUS), **2021**. Available: Report / Proposal [Accessed 03 March 2026].

[75] NPL. Measurement needs for carbon capture, usage and storage. **2021**. Available: Measurement needs for carbon capture, usage and storage - NPL [Accessed 03 March 2026].

[76] UKCCSRC. Carbon capture. Available: UKCCSRC - Carbon Capture & Storage (CCS) Carbon capture - UKCCSRC [Accessed 03 March 2026].

[77] IEA. Timely advances in carbon capture, utilisation and storage. Available: Timely advances in carbon capture, utilisation and storage – The role of CCUS in low-carbon power systems – Analysis - IEA [Accessed 03 March 2026].

[78] IEA. About CCUS. **2021**. Available: About CCUS – Analysis - IEA [Accessed 03 March 2026].

[79] Zhang, R. et al. Recent advancements in integrating CO_2 capture from flue gas and ambient air with thermal catalytic conversion for efficient CO_2 utilization. *Journal of CO2 Utilization*. **2024**. Available: Recent advancements in integrating CO2 capture from flue gas and ambient air with thermal catalytic conversion for efficient CO2 utilization - ScienceDirect [Accessed 03 March 2026].

[80] Supercritical CO_2 exists above its critical temperature and pressure. "Dense phase" is a broader term describing high-pressure CO_2 with liquid-like density, whether supercritical or liquid-like below the critical temperature. Thus, all supercritical CO_2 is dense phase, but not all dense-phase CO_2 is supercritical.

[81] HSE. Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects. Available: Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects - HSE [Accessed 02 March 2026].

[82] Bilio, M. et al. The CO2PipeHaz Good Practice Guidelines for CO2 pipeline safety. **2014**. Available: (PDF) The CO2PipeHaz Good Practice Guidelines for CO2 pipeline safety [Accessed 03 March 2026].

of off-design operation, surge/recycle, and unstable discharge pressure if controls and train configuration are not robust. Impurity and moisture variability can also reduce phase margin during transients and increase the risk of corrosion and solids during start-up, shutdown, and depressurisation. Changing downstream backpressure, from linepack or injection constraints, can further complicate stable export control[83].

4.1.5 Dehydration & cooling

Dehydration and cooling technologies manage CO_2 water content and temperature to meet defined limits prior to transport. Specifications for water content in CO_2 transport pathways are necessarily very tight, as low as 30 or 50 parts per million (ppm)[84, 85]. The process boundary is the set of treatment steps required to bring the now elevated pressure and temperature CO_2 into a stable condition for the selected transport mode, with the objective of reducing risks that can arise from water and subsequent corrosion[86]. Maximum water content must be managed so that, under any upset conditions, no free water may occur[87]. Dehydration is expected prior to the captured CO_2 entering the T&S network to separate the 'wet' system from the 'dry' system, inclusive of integrity protection systems to ensure the operational security of the T&S network[88, 89]. Dehydration systems such as triethylene glycol (TEG) and molecular sieves can reduce water content to below 10 parts per million by volume (ppmv)[90]. Interstage cooling will take place during the multi-stage compression process, but some additional cooling (aftercooling) may be required to condition the stream to the set transport specification[91]. Dehydration, aftercooling, and hydrate/corrosion control are key technological elements of this process step, managing phase and corrosion risks that could affect transport integrity and operability.

4.2 Midstream

The midstream element of a CO_2 project comprises the onshore and offshore transport infrastructure and associated interfaces that convey CO_2 from capture export points to the injection area, typically through multi-user gathering and hub arrangements. The midstream is designed to deliver CO_2 within the pressure, temperature and composition envelope required by the downstream storage system and by the network's operational rules. The boundary for the midstream is the pig trap interfaces at the emitter and the offshore storage location, whether sited subsea or on a surface installation such as a platform.

Onshore gathering and hub facilities provide pressure-management functions when multiple sources connect to the shared system. They also include intermediate compression or "booster stations" to manage pressure drop and operating envelope over distance[92]. These onshore facilities will face heightened scrutiny in their approach to integrity management and CO_2-specific safety considerations, especially regarding batch logistics[93], from variable linepack and possible non-pipeline transport (NPT)

[83] Martynov, S.B. et al. Estimating the line packing time for pipelines transporting carbon dioxide. *Carbon Capture Science & Technology*. Volume 11. **2024**. Available: Estimating the line packing time for pipelines transporting carbon dioxide - ScienceDirect [Accessed 10 March 2026].
[84] Northern Lights JV. How to store CO2 with Northern Lights – Liquid Specification. Available: How to store CO2 with Northern Lights - Northern Lights [Accessed 03 March 2026].
[85] Northern Endurance Partnership (NEP). 3018090-ARC-XX-XX-RP-ZB-0008-1-Preliminary Environmental Information Report – Volume 2 – Chapters (Pg. 104). **2025**. Available: Documents - Northern Endurance Partnership (NEP) [Accessed 03 March 2026].
[86] HSE. Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects. Available: Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects - HSE [Accessed 02 March 2026].
[87] DNV. Design and Operation of CO2 Pipelines (Section 4.8.3). **2010**. Available: DNV-RP-J202: Design and Operation of CO2 Pipelines [Accessed 03 March 2026].
[88] Barnes, J. (PACECCS). How to Manage the Wet/Dry Interface in an Operational CCS Cluster. **2023**. Available: PowerPoint Presentation [Accessed 03 March 2026].
[89] CCUS Insight Accelerator. CO2 Compression and Dehydration Technologies. **2025**. Available: CO2 Compression and Dehydration Technologies | CCS Knowledge Centre [Accessed 03 March 2026].
[90] Kemper, J. et al. Evaluation and analysis of the performance of dehydration units for CO_2 capture. **2014**. Available: Evaluation and Analysis of the Performance of Dehydration Units for CO2 Capture [Accessed 03 March 2026].
[91] BEIS. Drax BECCS Project – CO2 Compression and Dehydration Unit Report (Section 5.4.2). **2021**. Available: CO2 compression and dehydration unit report [Accessed 04 March 2026].
[92] Diabate, M. et al. Analyzing the Impact of Pipeline Length and CO_2 Mass Flow Rate on the Transportation Cost Based on the Required Number of Booster Pumps: A Case Study of Houston. *SPE Journal 29*. **2024**. Available: Analyzing the Impact of Pipeline Length and CO2 Mass Flow Rate on the Transportation Cost Based on the Required Number of Booster Pumps: A Case Study of Houston | SPE Journal | OnePetro [Accessed 02 March 2026].
[93] Considering some emitters operate batch processes

modes like shipping that necessitate onshore intermediate storage systems. In operation, the safety case for CO_2 pipelines depends on maintaining dense-phase transport conditions and managing transients.

CO_2 transport differs from many conventional pipeline services in its hazard profile. Guidance highlights that dense or supercritical CO_2 pipelines warrant a hazard assessment approach comparable in rigour to that used for high-pressure natural gas pipelines, while also recognising the distinct consequences associated with CO_2 release and dispersion[94, 95]. As a result, route risk assessment, emergency planning, segmentation and blowdown philosophies can become prominent design drivers, particularly where pipelines are routed through areas of potential public exposure. These issues are reinforced by CO_2 pipeline safety guidance and research outputs that highlight ongoing developments in dispersion understanding and the need for robust evidence to underpin consequence modelling in CO_2 contexts.

Coastal landfall and terminal interfaces are commonly required where transport transitions from onshore pipelines to offshore export systems or, in some concepts, to NPT. At these interfaces, projects typically define receiving and dispatch functions, metering and quality confirmation, and the duty holder boundary between onshore and offshore operations. This interface is driving UK policy direction toward shared, regulated networks where interoperability and clearly defined operational rules are prerequisites for multi-user access.

4.2.1 Shipping

The process chain illustrated in
Figure 4-1 includes both pipeline transportation and an optional non-pipeline pathway in which captured CO_2 is moved by ship between terminals. NPT, which encompasses shipping, road, rail and barge transport pathways, is widely regarded as an important element of achieving UK CCS ambitions[96, 97]. The boundary of this process step extends from the export terminal interface, post-dehydration and conditioning to the offshore CO_2 control and emergency shutdown (ESD) isolation interface, where the stream is received into the offshore system for controlled transfer onward to subsurface injection and storage. Shipping is commonly positioned as the primary enabling NPT option for the UK where capture sites are dispersed, where early-phase volumes require flexibility and may not yet justify dedicated pipelines, and or where shipping can connect emitters to developing, shared T&S networks via coastal terminals[98]. Unlike continuous pipeline operating envelopes, CO_2 shipping terminals require additional key enabling technologies. These include liquefaction and or regasification; temporary storage sized to ship loading cycles; loading arms or hose systems; custody transfer and metering arrangements; suitable cargo vessels; and corresponding receiving facilities to unload, store and transfer CO_2 onward into the downstream transport and injection system[99]. The key requirement is that CO_2 is conditioned and managed into a transport state that is compatible with the selected shipping method and remains within specification at each interface, including the export terminal, any intermediate hubs, and the receiving terminal that connects to the downstream T&S network. Additional conditioning steps may also be required to manage received or exported CO_2 composition and phase behaviour at hubs, all of which add cost to the value chain[100]. There are, however, similarities with established liquefied gas carriage principles and technologies, such as liquified natural gas (LNG), that could be employed[101, 102]. Shipping

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[94] Bielka, P. et al. Risks and Safety of CO2 Pipeline Transport: A Case Study of the Analysis and Modeling of the Risk of Accidental Release of CO2 into the Atmosphere. *Energies.* **2024**. Available: Risks and Safety of CO2 Pipeline Transport: A Case Study of the Analysis and Modeling of the Risk of Accidental Release of CO2 into the Atmosphere | MDPI [Accessed 02 March 2026].
[95] HSE. Major hazard potential of CCS. Available: Major hazard potential of CCS - HSE [Accessed 02 March 2026].
[96] DESNZ. CCUS: Call for evidence on non-pipeline transport and cross-border CO2 networks. **2024**. Available: Carbon capture, usage and storage (CCUS): non-pipeline transport and cross-border CO2 networks - call for evidence [Accessed 04 March 2026].
[97] Southern Marine & Maritime Institute (SMMI). Carbon capture, usage and storage (CCUS); non-pipeline transport and cross-border CO2 networks. **2024**. Available: DESNZ_CfE_Transport of CO2_SMMI_Jul2024_Final [Accessed 04 March 2026].
[98] DESNZ. CCUS: consultation on non-pipeline transport (NPT). **2026**. Available: Carbon capture, usage, and storage (CCUS): consultation on non-pipeline transport (NPT) (accessible webpage) - GOV.UK [Accessed 04 March 2026].
[99] Alcalde, J. (CSIC); Johnson, G. (Drax). Transportation of CO2. **2025**. Available: DR1907-6_Transportation-of-CO2_GB_V002.pdf [Accessed 04 March 2026].
[100] Element Energy. Shipping CO2 – UK Cost Estimation Study. **2018**. Available: Shipping CO2 - UK cost estimation study [Accessed 04 March 2026].
[101] Baroudi, H. et al. A review of large-scale CO2 shipping and marine emissions management for carbon capture, utilisation and storage. **2021**. Available: A review of large-scale CO2 shipping and marine emissions management for carbon capture, utilisation and storage - ScienceDirect [Accessed 04 March 2026].
[102] SIGTTO. Carbon Dioxide Cargo on Gas Carriers. **2024**. Available: sigtto-carbon-dioxide-cargo-on-gas-carriers.pdf [Accessed 04 March 2026].

typically has higher operational and lower capital costs compared to pipelines[103]. It is particularly well-suited to transporting smaller volumes of CO_2 over longer distances and can be flexible to new emitter tie-ins to the CCS network. Road, rail and barge NPT pathways are also expected to support UK CCS initiatives, but specific emphasis is being placed on the role of CO_2 shipping in deployment[104].

4.2.2 Onshore transportation

Onshore trunk pipeline transportation of captured CO_2 is primarily driven by capital costs and thus benefits from economies of scale and high utilisation. Pipelines form the basis for the vast majority of existing global CO_2 transport capacity[105] and are generally the lowest overall cost, most scalable solution for continuous, high-volume transport over long distances on land, supported by decades of operating experience and established engineering standards[106, 107].

Non-pipeline transport (NPT) options, such as road, rail, and shipping, involve higher levels of handling, intermediate storage, and operational coordination. For road and rail, this typically limits their application to smaller volumes and shorter distances. However, shipping represents an important exception: it is well suited to medium-to-large volumes over long distances, particularly for offshore storage or where pipeline routing is constrained (e.g. cross-border transport or early-phase cluster development). While shipping generally incurs higher operating costs and requires liquefaction, storage, and port infrastructure, it can be more flexible and lower risk in early project phases, and in some cases cost-competitive with pipelines at lower throughputs or where utilisation is uncertain.

The process step boundary of the onshore transportation process step covers from the pig trap or tie-in interface at the individual CO_2 emitter, including gathering and trunklines with their associated operational controls, up to the coastal landfall interface where the stream is either recompressed and transported offshore or decanted into temporary storage tanks. Key enabling technologies include isolation and block valves, ESD/ESDV, supervisory control and data acquisition (SCADA), leak detection, and coatings/corrosion protection systems. Collectively, these technologies provide isolation, monitoring, and remote operation, as well as integrity protection across the onshore network.

4.2.3 Temporary storage

Linepacking, a well-understood short-term method of increasing the total volume of gas in a pipeline to balance throughput, is proven in CO_2 pipelines but likely to be insufficient to accommodate the flexibility required for some cases and incurs additional compression costs[108]. Thus, an alternative method is required to manage batch CO_2 deliveries, from NPT pathways, and or variations in supply and demand in the T&S pipeline network. Temporary CO_2 storage at a hub or landfall terminal may be required to act as a buffer, allowing the network to keep running despite variable capture rates, interruptions, or brief constraints on the downstream injection system. The process step boundary sits at the handover point between the onshore and offshore pipelines, helping to keep system flow steady. Tanks, transfer pumps, metering, ESD/ESDV, SCADA and overpressure provisions are key technologies supporting temporary storage. These technologies enable safe custody of CO_2 inventory, controlled transfer between systems, and remote monitoring and isolation capability. Purification, regasification, and liquefaction systems will also be required at this interface to manipulate the CO_2 for storage and subsequent onward transport in line with defined operating specifications[109]. Northern Lights' onshore intermediate (buffer) storage at the Øygarden terminal consists of two full-containment liquid CO_2 tanks, each with a capacity of

[103] Orchard, K. (Element Energy). CO_2 transport: The role of CO_2 shipping. **2019**. Available: CO2 transport: The role of CO2 shipping [Accessed 04 March 2026].
[104] DESNZ. CCUS: Call for evidence on non-pipeline transport and cross-border CO_2 networks. **2024**. Available: Carbon capture, usage and storage (CCUS): non-pipeline transport and cross-border CO2 networks - call for evidence [Accessed 04 March 2026].
[105] Gillespie, A. (Global CCS Institute). Needs, Opportunities and Prospects for CO_2 Shipping in CCS Projects. **2025**. Available: Global-CCS-Institute-Needs-Opportunities-and-Prospects-for-CO2-Shipping-in-CCS-Projects.pdf [Accessed 04 March 2026].
[106] Zero Emissions Platform. The Costs of CO_2 Transport – Post-demonstration CCS in the EU. **2011**. Available: (PDF) The cost of CO2 Transport [Accessed 04 March 2026].
[107] Exxon Mobil. CO_2 pipelines. Available: CO_2 pipelines [Accessed 04 March 2026].
[108] IEAGHG. Components of CCS Infrastructure – Interim CO_2 Holding Options. **2023**. Available: 2023-04 Components of CCS Infrastructure - Interim CO2 Holding Options.pdf [Accessed 04 March 2026].
[109] DNV. Industrial Decarbonisation – Getting ready for Non Pipeline Transport. **2024**. Available: IUK-181124-IndustrialDecarbonisationGettingReadyNonPipelineTransport.pdf [Accessed 04 March 2026].

approximately 7,500 m³, giving a total buffer storage volume of about 15,000 m³. The CO_2 is stored in refrigerated liquid form (around −26°C and ~15 bar) prior to being pumped and transported offshore[110].

4.2.4 Booster compression

Pressure boosting may be required at the interface of the onshore and offshore pipelines to set the offshore line's inlet conditions and provide sufficient pressure margin for transport and injection. UK projects are being developed with onshore compression technologies immediately feeding offshore pipelines and subsea injection systems[111,112].

4.2.5 Offshore transportation

Offshore transportation conveys CO_2 from the onshore export boundary to the offshore injection site via pipelines, risers, platforms and subsea tie-ins. UK licensing and permitting requirements for offshore CO_2 storage mean that offshore transport is typically developed in conjunction with the authorised storage project it supplies, so that T&S boundaries align operationally and regulatorily[113]. For both surface and subsea pipelines, risers, tie-ins, inspection and pigging[114], isolation, integrity and corrosion provisions are key technologies required for the success of this complex process step. These technologies reflect the need for reliable isolation and inspection capability, particularly subsea, to support integrity management and T&S network operation.

4.3 Downstream

The downstream portion of a CO_2 project begins at the injection interface into a permitted geological storage site, supported by monitoring and verification systems. Offshore export systems typically comprise offshore pipelines, risers, and tie-ins to the injection area together with isolation and segmentation philosophies, subsea isolation valves and monitoring and communications systems. The design emphasis in offshore settings is often shaped by operability constraints and intervention limitations, which can make shutdown, cooldown and restart behaviour a key determinant of system configuration and control philosophy.

Depending on the selected concept, additional offshore facilities may be provided via a hub platform or a subsea distribution system using manifolds, jumpers, and control umbilicals integrated with well control and barrier management. Regardless of configuration, the objective of these elements is to safely manage delivery and inventory of CO_2 to the wells within defined operating limits, recognising that the injection system can become the binding constraint on throughput and operability for the entire chain.

The subsurface storage and injection system includes injection wells and completions, well flow control, reservoir management, and a monitoring, measurement, and verification (MMV) programme designed to demonstrate performance and long-term containment. International standards for geological storage systems provide a lifecycle framework for storage project requirements, while UK offshore guidance sets expectations for the content and evidence needed to support carbon storage permit applications. For the UK, this technical lifecycle operates within an evolving regulatory and governance structure for CO_2 Transport and Storage (T&S) systems and geological storage, which includes statutory provisions and the economic regulation approach outlined by Ofgem. The CCS Network Code translates these requirements into operational, technical, and commercial rules for connecting to and managing shared networks. This emphasises the practical importance of compliance with specifications, metering to required uncertainty levels, and clear processes for handling off-spec events and curtailment in multi-user settings.

[110] GASSNOVA. CO2 transport and storage: Northern Lights. Available: CO2 transport and storage | The Northern Lights project [Accessed 04 March 2026].
[111] BEIS. Net Zero Teesside & Northern Endurance Partnership Technology Plan – Key Knowledge Document. 2021. Available: Net Zero Teesside and Northern Endurance Partnership Technology Plan [Accessed 05 March 2026].
[112] Saipem. Saipem: awarded a contract by Eni for Carbon Capture and Storage in the UK. 2025. Available: Saipem: awarded a contract by Eni for Carbon Capture and Storage in the UK | Saipem [Accessed 05 March 2026].
[113] NSTA. Guidance on the Application for a Carbon Dioxide Appraisal and Storage Licence. 2025. Available: Guidance on the Application for a Carbon Dioxide Appraisal and Storage Licence [Accessed 05 March 2026].
[114] NOV. Subsea Automated Pig Launcher. Available: Subsea Automated Pig Launcher | NOV [Accessed 05 March 2026].

4.3.1 Offshore control & ESV

Offshore control and emergency shutoff valve (ESV) functions provide the means to monitor and isolate the offshore CO_2 transportation system to manage inventory and respond to upset conditions or emergencies. The process step boundary includes the shutdown and isolation philosophy, remote control and telemetry systems, and associated safety functions between the offshore pipeline and the injection site. ESD systems, high-integrity pressure protection systems (HIPPS)[115, 116] where required, isolation valves, blowdown/depressurisation functions, and remote SCADA systems[117] are key technologies. These technologies form the critical architecture required for compliant[118], redundant and efficient sequestration of captured CO_2. Dependent on the design concept these technologies can be installed on surface platforms or subsea, with considerable implications in both cases.

4.3.2 Injection well construction and completion

The final process step of the CO_2 chain is injection into the offshore storage site. The injection well and completion is the furthest downstream process step in which CO_2 is injected into a permitted geological store. The boundary includes the injection wells and geological storage site, both of which are highly regulated assets, with the objective of injecting to agreed specifications and volumes, and monitoring performance to demonstrate containment. In the UK, a carbon storage licence and seabed lease are required to begin construction and injection, establishing a clear regulatory boundary for proposed projects[119]. Injection wells and completions, measurement, monitoring and verification (MMV), well integrity, and conformance/containment assurance technologies are critical. There is emphasis on the development of metering and measurement standards to comply with the UK ETS requirements, permitting accurate assessment of T&S performance with respect to captured and stored emissions[120].

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[115] Proserv. Subsea HIPPS System & Controls. Available: HIPPS Subsea System and Controls | Proserv [Accessed 05 March 2026].
[116] HSE. Safety instrumented systems for the overpressure protection of pipeline risers. 2014. Available: SPC/TECH/OSD/31 - Safety instrumented systems for the overpre... [Accessed 05 March 2026].
[117] Khisty, V. SCADA Systems in Oil and Gas: Driving Innovation and Efficiency in the Digital Age. *IJRASET*. 2024. Available: scada-systems-in-oil-and-gas-driving-innovation-and-efficiency-in-the-digital-age [Accessed 05 March 2026].
[118] HSE. The Pipelines Safety Regulations 1996 - Regulation 19 (Schedule 3). 1996. Available: The Pipelines Safety Regulations 1996 [Accessed 05 March 2026].
[119] NSTA. NSTA launches UK's second carbon storage licensing round. 2025. Available: NSTA launches UK's second carbon storage licensing round [Accessed 05 March 2026].
[120] OEUK. Carbon Capture & Storage in the UK: Accelerating Towards the Merchant Model. 2025. Available: OEUK-CCUS-Market-Transition-Report-2025-j6pqfr.pdf [Accessed 05 March 2026].

5. TECHNOLOGY AND TRL STATUS

This section assesses the current technology status of CO_2 transport systems within a defined "trap-to-trap" scope, extending from the pig trap interface at the emitter facility to the corresponding pig trap interface at the offshore storage location. Capture technology and subsurface reservoir behaviour beyond the injection interface are considered only where they materially influence transport system requirements.

The assessment examines the maturity, integration challenges and operational risks associated with transporting CO_2 under both dense-phase and gas-phase conditions, recognising that while many individual components are mature in adjacent sectors such as natural gas transmission and offshore hydrocarbons, their combined application in impurity-sensitive, multi-emitter CCS networks introduces additional complexity. Attention is given to impurity management, phase-behaviour control, corrosion mechanisms, fracture and materials performance, monitoring and digital integration, and safety management and inspection technologies across both operating regimes.

The TRL (Technology Readiness Level) standard used is the conventional 1–9 TRL scale, originally developed by NASA[121]. TRLs are referenced where appropriate to distinguish between well-established engineering practices and areas where system-level validation, impurity interaction data or large-scale operational experience remain limited. The objective is not simply to assess component maturity, but to evaluate the degree to which integrated CO_2 transport systems can be deployed reliably at scale within the UK CCS framework.

5.1 Summary

The technology readiness profile indicates no fundamental technology gaps in dense-phase CO_2 transmission systems. Most core hardware elements, including pipe, valves, construction methods, block valves, pig traps, cathodic protection, SCADA systems, compressors and fracture mechanics principles, are assessed at TRL 8–9. This confirms that the UK does not lack the underlying engineering capability to design, construct, and operate dense-phase CO_2 transport infrastructure where the physics is understood, the equipment exists, and the relevant standards frameworks are mature.

Where lower TRLs appear, they are not due to basic hardware immaturity but to system integration at scale. The lowest readiness levels, typically in the TRL 6–7 range, are observed in multi-emitter network balancing, crack detection in the presence of hydrogen, subsea pigging in dense-phase CO_2 service, commissioning under impurity-variable conditions, integrated network control strategies, and large-scale decommissioning of CCS trunklines.

A further integration constraint arises in long-distance subsea control and operation. While individual subsea control components, including umbilicals, valves and control systems, are mature, system-level performance becomes increasingly uncertain as tieback distance increases. At shorter distances, typically below 50–100 km, conventional subsea control architectures are well proven. However, at extended distances of approximately 150–300 km, which are relevant for UK CCS developments, hydraulic response times, pressure losses, power delivery, signal latency and overall system reliability become more challenging, particularly for safety-critical functions such as isolation and emergency shutdown.

Emerging all-electric subsea control systems and electric trees may help mitigate some of these constraints by reducing dependence on hydraulic actuation and improving diagnostics, monitoring and response performance over extended tieback distances. However, while individual electrical control and actuation technologies are relatively mature, their application in long-distance CCS subsea systems remains less proven and is more appropriately assessed at approximately TRL 6–8, reflecting limited large-scale operational experience and the need for further system-level validation of reliability, redundancy and safety-critical performance.

As a result, while no fixed technical limit exists, long-distance subsea operation should be viewed primarily as an integration challenge rather than a component limitation. Overall maturity is likely to fall in the TRL

[121] NASA Systems Engineering Handbook, NASA/SP-2016-6105 Rev. 2.

7–8 range, and in some cases TRL 6–7, depending on the selected architecture, tieback distance and validation basis. These effects are most pronounced in fully subsea configurations and may influence system design choices, including the adoption of alternative control architectures or intermediate facilities.

Overall, these limitations reflect constrained operational datasets, limited validation under realistic impurity envelopes, and the complexity of integrating thermodynamics, fracture control, corrosion management, and automated control in large-scale networks. The maturity gap is therefore one of integration confidence rather than component capability.

A consistent pattern emerges across the assessment: the presence of impurities, hydrogen and dynamic operating conditions reduces overall readiness. Remove impurity variability and readiness increases; introduce hydrogen, multi-emitter variability or subsea integration and readiness decreases. The most integration-sensitive domains are those combining dense-phase operation with subsea hardware and transient behaviour, where intervention is more difficult, and validation datasets are more limited. Inspection and monitoring technologies are largely mature, particularly for metal loss and dent detection, but crack detection in hydrogen-containing CO_2 environments and CCS-specific system validation remain less mature due to limited empirical experience.

Decommissioning presents a similar pattern. While individual component technologies such as isolation, purging and pigging are mature, integrated dense-phase CO_2 trunkline decommissioning at UK CCS scale remains in the TRL 6–7 range due to limited precedent and lack of regulatory clarity. Overall, Section 4 demonstrates that dense-phase CO_2 transport is technically feasible using mature engineering hardware, but successful large-scale deployment will depend on strengthening confidence in validation and integration in impurity-variable, multi-emitter, and subsea environments rather than on overcoming fundamental technological barriers.

If CO_2 were transported in the gas phase, many of the integration challenges associated with dense-phase thermodynamics, decompression behaviour and phase stability would be reduced. As a result, several technology areas currently assessed at TRL 6–8 would increase to TRL 7–9. However, this reflects reduced system complexity rather than fundamentally different technology and does not offset the reduced efficiency and increased infrastructure requirements associated with gas-phase transport.

Calibration standards for dense-phase CO_2 mixtures, particularly under varying impurity compositions, are an area of active development. While core metering technologies are mature, ongoing work by organisations such as TÜV SÜD National Engineering Laboratory and related metrology programmes aims to establish traceable reference materials and to improve confidence in measurement accuracy and uncertainty for CCS applications.

An overall technology readiness level CO_2 pipeline transportation is provided in Table 5-1.

Table 5-1 –Technology Readiness Level CO_2 Pipeline Transportation (gas phase in brackets)

Technology Area	TRL	Notes
Management of Impurities – System Integration	7–8 (8-9)	Chemistry mature; multi-impurity transient validation limited at CCS trunkline scale
Dense vs Gaseous Phase Control	8–9	Fundamentals mature; impurity-sensitive envelope mgmt. integration-dependent
EOS Validation – CO_2 Mixtures with Impurities	7-8	EOS methods are available and widely used, but confidence depends on validation against representative CCS impurity envelopes. Publicly available data and model parameters may not cover all expected UK multi-emitter mixtures, particularly under transient dense-phase conditions.
Blowdown & Venting	7–8 (8-9)	Hardware TRL 9; decompression/solid behaviour in mixed impurities less validated
Multi-Emitter Network Balancing	6–7 (7-8)	Gas balancing TRL 9; dense-phase optimisation at scale less mature
Metering (topsides)	7–8 (8-9)	Coriolis, differential-pressure, and ultrasonic meters are TRL 9 at component level, but application to dense-phase, impurity-variable CO_2 introduces uncertainty in density, viscosity, and composition. Achieving ETS-compliant accuracy requires robust calibration, representative sampling, and reliable EOS integration. Traceable calibration for CO_2 mixtures remains under development, with programmes such as MetCCUS improving confidence but not yet fully resolving system-level validation.
Metering (subsea)	6-7(7-8)	Direct measurement is typically limited to differential-pressure (Venturi) meters. Subsea deployment introduces constraints in access, calibration, and representative sampling, with limited intervention capability and higher reliance on redundancy. Measurement uncertainty and verification confidence are therefore lower than in topside systems, and system-level validation remains limited.
Intermediate Storage – Onshore	8–9	Established pressure vessel practice
Intermediate Storage – Offshore	6–7	Integration and operational precedent limited
Linepack Management	7–8	Pressure management mature; impurity-coupled phase control less validated
Fracture Control – CO_2 Arrest Methodology	7–8 (8-9)	Limited CO_2-specific validation dataset
Full-Scale Fracture Testing	8–9	Established practice; applied selectively
Cryogenic Materials – Materials	9	Metallurgy mature
Cryogenic Materials – System Integration	7–8	Validation under dense-phase transients required
Onshore Routing (Process)	9	Established PD 8010 / QRA process
CO_2-Specific Consequence Modelling	7–8	Dispersion integration still evolving
Offshore Routing	9	Established hydrocarbon practice
Offshore Safety Case & Major Hazard Assessment (CO_2 Systems)	7-8 (9)	The Safety Case process, ALARP methodology, and regulatory framework are fully mature (TRL 9). CO_2-specific application relies on evolving evidence for dispersion, decompression, consequence modelling and system-level CCS validation.
Platform-Based Pigging	9	Fully mature
Subsea Pigging	6–7 (7-8)	CCS-scale integration validation limited
Platform Monitoring & Control	9	Mature offshore practice
Subsea Control	7–8	CO_2 transient/impurity integration sensitivity. 6-7 for long-distance tiebacks
All-Electric Subsea Control Systems / Electric Trees	6-8	Individual electrical actuators, sensors, communications and subsea electronics are mature (TRL 8–9), but long-distance CCS deployment remains limited. Potential to reduce hydraulic control constraints and umbilical complexity, although system-level validation of reliability, redundancy, power distribution and safety-critical isolation functions is still evolving.
Subsea Isolation Valves (SSIV)	9	Mature technology
300 km subsea dense-phase CO_2 tie-back	6-7 (8-9)	Intervention logistics, reliability expectations increase operational risk
CO_2 Dispersion Modelling (Advanced/CFD)	8–9	Mature modelling; validation improving
CO_2 Large-Scale Dispersion Validation (Impurities)	7–8 (8-9)	Empirical dataset still developing

Subsea CO_2 Release Modelling	7–8 (8-9)	Integrated plume + surface breakthrough modelling evolving
Core Pipeline Construction	9	Fully mature
Drying & Dehydration	9	Mature technologies
Dense-Phase Commissioning (Single Emitter)	8–9	Mature but thermodynamically sensitive
Multi-Emitter Commissioning	6–8 (7-9)	Integration-driven complexity
Nitrogen / Fracture Commissioning Implications	6–7 (7-8)	Limited empirical validation
SCADA Leak Detection	9	Mature
Acoustic Leak Detection	9	Mature
Fibre Optic	7–8 (8-9)	CCS-specific validation limited
Satellite CO_2 Detection (Climate)	9	Mature for global monitoring
Satellite CO_2 Detection (Pipeline Safety)	6–8	Limited suitability for rapid leak detection
UAV-Based Monitoring	7–8	Demonstrated; not primary safety layer
Integrated Real-Time Monitoring	7–8 (7-9)	System integration maturity
Digital Twin – Hydraulics	8–9	Mature modelling
Digital Twin – Integrated CO_2 Integrity	6–8	CCS-scale integration evolving
Automated Control – Hardware	9	Mature
Integrated Multi-Emitter Control	6–8	Validation under CCS-specific conditions required
ILI – Metal Loss (Core)	9	Mature
ILI – Metal Loss (Dense CO_2)	8–9	Application validated but limited CCS dataset
ILI – Dent Detection	9	Fully mature
ILI – Crack Detection (No Hydrogen)	7–8	CO_2 validation limited
ILI – Crack Detection (Hydrogen Present)	6–7	Limited empirical experience
ILI – Tool Survivability	7–8 (8-9)	CO_2-specific material qualification required

5.2 Technology Readiness Level (TRL) Framework and Application

The TRL (Technology Readiness Level) standard used is the conventional 1–9 TRL scale, originally developed by NASA[122] and now widely adopted across government, industry and international programmes. This scale provides a consistent way to describe technology maturity, where:

TRL 1–3 represent early research and proof of concept
TRL 4–6 represent validation and demonstration in relevant environments
TRL 7–8 represent system-level demonstration and qualification in operational conditions
TRL 9 represents a fully proven system in real-world operation

The TRL framework is being applied from a systems engineering context rather than a pure component context. This is important, since many of the individual technologies (e.g., pipelines, valves) are already at TRL 9, but when integrated into CO_2 multi-emitter offshore impurity-variable networks, the effective TRL is reduced to 6–8 due to limited full-scale operational validation.

5.3 Management of Impurities

5.3.1 Impact of CO_2 impurities on T&S systems

Captured CO_2 streams are rarely pure. Depending on the capture technology and source (post-combustion, pre-combustion, oxyfuel, industrial process), contaminants may include H_2O, N_2, O_2, Ar, H_2, CO, SOx, NOx, H_2S, amines, glycols, methanol, hydrocarbons, and particulates. These impurities significantly influence thermodynamics, materials performance, safety, and operational integrity. Table 5-2 details potential impurities in the CO_2 stream. The wide variety reflects the capture technology and industrial process used to capture the CO_2. The implications are discussed in the following sections.

Table 5-2 – Implications of Impurities on Operability, Integrity, and Health and Safety

Impurity	Operability Implications	Integrity Implications	Health & Safety Implications
Water / Hygroscopic Liquids (glycols, alcohols, amines)	Liquid drop-out; dew point shift; formation of aqueous phase under transients	Carbonic acid formation (pH ~3.5); aqueous corrosion; under-deposit corrosion	Generally low toxicity, but corrosion-induced failure presents a major hazard

[122] NASA Systems Engineering Handbook, NASA/SP-2016-6105 Rev. 2.

Nitrogen / Argon	Increase bubble point; enlarge two-phase region; affect depressurisation speed	Aggravate the running ductile fracture (RDF) risk	Asphyxiant if released in high concentrations
Hydrogen (H_2)	Raises bubble point; increases two-phase risk; concentrates in gas bubbles	Hydrogen stress cracking (HSC); SOHIC; embrittlement; increased RDF risk	Flammable; contributes to asphyxiation hazard in release scenarios
Oxygen (O_2)	Shifts phase behaviour; may encourage microbial activity	Corrosion in the presence of water.	Supports combustion; contributes to oxidative degradation products
Carbon Monoxide (CO)	Affects bubble point; increases two-phase risk	Contributes to CO_2 stress corrosion cracking; crack initiation	Highly toxic; binds haemoglobin preferentially over oxygen
Methane / Ethane (C1–C2)	Increase bubble point; broaden two-phase zone	Increased fracture risk via phase effects	Flammable; contributes to explosion hazard
Propane & heavier hydrocarbons (C3+)	Liquid formation; droplet accumulation; operating issues	Potential for deposit formation	Flammable; VOC exposure risk
NOx / SOx	Hydrolyse even below water saturation; acid formation	Strong acid formation; rapid carbon steel corrosion; reservoir degradation	Highly toxic; respiratory harm
Hydrogen Sulphide (H_2S)	Affects dew point; injectivity reduction due to salt precipitation	Sulphide stress cracking (SSC); stress corrosion cracking (SCC)	Highly toxic; acute respiratory hazard
Carbonyl Sulphide (COS)	Hydrolyses to $CO_2 + H_2S$; impacts dew point	Produces H_2S, leading to sour service cracking risk	Highly toxic; respiratory hazard
Amines (e.g., MDEA, piperazine)	Shift phase envelope; aqueous phase formation	Aqueous corrosion; degradation to harmful by-products	Formation of nitrosamines/nitramines (carcinogenic potential)
BTEX	Typically, low phase impact at trace levels	Limited integrity impact at low levels	Benzene is toxic and has long-term health risk implications
Methanol	Liquid phase formation; increases water dew point	Can induce rapid corrosion with water	Toxic; ingestion and inhalation hazard
Ash / Dust / Particulates	Equipment fouling; injection plugging; flow issues	Under-deposit corrosion, erosion, and carbonate formation	Dust inhalation risk; mechanical hazard
Metals (Hg, Pb, Cd, etc.)	Solid formation; deposition	Mercury embrittlement (material dependent); corrosion risk	Toxic; some potentially radioactive
Volatile Organic Compounds (VOCs)	Potential aqueous phase at high concentration	Minor direct integrity impact unless polar	Chronic health effects and presents a respiratory risk
Glycols (e.g., TEG)	Alters the phase envelope; promotes aqueous phase	Aqueous corrosion; liquid accumulation	Low toxicity; indirect risk via corrosion
Dioxins / Furans	Typically trace; minimal phase impact	No major pipeline integrity effect	Highly toxic; carcinogenic; bioaccumulative
Nitrosamines / Nitramines	Formed from amine degradation	No major direct integrity effect	Carcinogenic potential (IARC 2A/2B classification)

5.3.2 Emissions

Under UK ETS rules, an emitter can deduct CO_2 from its reported emissions only if the CO_2 is accurately measured, transported for permanent geological storage, and the transfer is verified. If the transported stream contains significant non-CO_2 components such as N_2, O_2, H_2 or CH_4, only the CO_2 fraction qualifies for deduction. Mass flow meters measure the total stream volume or mass, so accurate, continuous composition analysis is essential. If impurity levels fluctuate and monitoring is inadequate, companies risk a regulatory breach. If elevated impurities lead to rejection of off-spec gas, venting, flaring or reprocessing losses, those CO_2 volumes may remain reportable under the UK ETS and require surrender of allowances, increasing compliance exposure.

Impurities can also complicate compliance with broader regulatory obligations. Some components, such as CO, CH_4 or H_2, may oxidise during venting or flaring, potentially triggering additional greenhouse gas reporting requirements beyond CO_2.

Fugitive emissions may trigger exceedances of workplace exposure limits, environmental permit reporting requirements, air quality monitoring obligations, and increased inspection and enforcement risk. Where impurities significantly elevate toxicity, installations may require enhanced hazardous-area classification, additional gas-detection and monitoring systems, personal protective equipment (PPE) protocols, and reassessment of emergency planning zones.

5.3.3 Phase behaviour and required operating pressure

CO_2 transport pipelines may be designed to operate in either dense phase (supercritical or liquid-like state) or gas phase, depending on project requirements, distance, throughput, and integration with capture and storage systems. Dense-phase operation is typically preferred for high-capacity trunklines as it maximises volumetric efficiency and supports stable, single-phase flow, whereas gas-phase operation may be appropriate for shorter distances, lower pressures, or specific integration constraints.

Impurities, particularly non-condensable gases (N_2, O_2, H_2, Ar), significantly affect the critical point, phase envelope, and saturation pressure compared with pure CO_2. These effects are particularly important for dense-phase systems, where maintaining single-phase conditions requires operation above the shifted phase boundary. In gas-phase systems, impurities influence density, compressibility, and dispersion behaviour, but generally have a less severe impact on phase stability.

It is important to design and operate the pipeline to remain in a single phase—either dense or gas—throughout the operating envelope, as the presence of two phases significantly complicates operations. Two-phase flow can lead to unstable hydraulics, unpredictable pressure drop, and operational challenges. Avoiding two-phase conditions may result in tighter impurity tolerances and/or higher operating pressures, particularly for dense-phase systems. Therefore, impurity control directly determines minimum operating pressure, operating margins, and overall pipeline design requirements.

5.3.4 Corrosion risk

Pure, dry CO_2 is non-corrosive to carbon steel. Corrosion arises when free water is present, forming carbonic acid. Acid gases (SO_2, NO_2, H_2S) dissolve in water, and chemical reactions can also produce strong acids. Key corrosion mechanisms include Carbonic acid corrosion (CO_2 + H_2O), Sulphuric acid formation (SO_2 + H_2O + O_2), Nitric acid formation (NO_2 + H_2O), mixed acid systems accelerating pitting, and localised corrosion from condensed water films. Therefore, water content must be kept below levels that allow free water formation under steady-state and transient cooling conditions.

Hygroscopic substances such as glycols, amines and methanol have a strong affinity for water and can materially alter the behaviour of moisture in a CO_2 stream. Even at low concentrations, they can absorb water from the CO_2 phase, form a liquid microphase, lower the effective water activity threshold, and create stable liquid films or droplets. As a result, a separate liquid phase can form at overall water concentrations below the normal CO_2 saturation limit, introducing a corrosion risk under conditions where pure CO_2–water systems would be expected to remain single-phase. This is why CO_2 specifications often limit solvent carryover. Meeting a water ppm limit alone is not always sufficient if hygroscopic contaminants are present. Even trace levels of SOx/NOx in the presence of water can dramatically increase corrosion rates.

5.3.5 Interaction between contaminants

Impurities do not act independently. Interaction effects include $SO_2 + O_2 + H_2O \rightarrow H_2SO_4$, $NO_2 + H_2O \rightarrow HNO_3$, H_2S oxidation to sulphur or sulphuric acid, and reaction products forming solid sulphates or nitrates. These reactions may produce corrosive liquid films, solid particulates, deposits that trap moisture, under-deposit corrosion sites, polar solvents (amines, methanol, glycols) that can retain water, and increased aqueous-phase stability and modified corrosion chemistry. Thus, compositional limits must consider combined chemical effects, not just individual thresholds.

5.3.6 Hydrate formation

A hydrate is a solid, ice-like crystalline compound in which water molecules form a cage-like lattice that traps gas molecules inside it. In pipelines, the most common are gas hydrates, in which gases such as CO_2, methane, or H_2S become trapped in water cages under high-pressure, and low-temperature conditions. In CO_2 transport systems, hydrates matter because even small amounts of water, combined with cooling during pressure drops or transients, can form these solids and potentially block valves, vents, instrumentation lines, or restrictions, creating flow assurance and safety risks. Impurities shift the hydrate equilibrium conditions. Even if bulk water content is low, localised condensation during expansion or transients can trigger hydrate formation.

5.3.7 Fracture, integrity and hydrogen embrittlement

Hydrogen (H_2) produces embrittlement in pipeline steels. This affects fracture toughness and ductility, which determines the pipeline material's tolerance to cracks and fatigue. The driving force is partial pressure, which, at low concentrations under dense-phase operating conditions, would be sufficient to cause embrittlement. The presence of hydrogen, if not sufficiently removed by the capture plant, will imply a credible susceptibility to cracking and drive injection requirements to allow early detection. Also, if H_2 is present in significant concentrations, pipeline steels must be assessed for hydrogen compatibility through environmental fracture mechanics testing. This is regularly done for new-build and repurposed hydrogen pipelines.

5.3.8 Solid formation and particulates

Solid risks include the formation of dry ice during rapid decompression, precipitated sulphur, corrosion product debris, catalyst fines or carryover from capture processes. Solids can cause erosion, damage valves, block instrumentation, and reduce injection well permeability in the geological storage.

5.4 Managing a Wider Network

5.4.1 Balancing pipeline integrity with emitter processing burden

There is an inherent tension between the transporter's need for a stable, non-corrosive, fracture-safe CO_2 stream and the emitter's desire to minimise costly purification and conditioning.

The transporter Perspective is dense-phase stability, low corrosion risk, controlled fracture propagation, avoidance of hydrates, minimal solid formation, long asset life, and regulatory and safety compliance. From this perspective, tighter composition limits reduce integrity risk, simplify operations, lower long-term maintenance cost, and increase network availability. However, tighter specifications may: increase capture plant CAPEX and OPEX, reduce project bankability for emitters, and limit participation of diverse sources.

The Emitter (User) Perspective aims to minimise the number of purification stages, avoid deep dehydration costs, avoid complex acid-gas polishing systems, and avoid additional compression to compensate for stricter pressure limits. Excessively tight specifications may increase energy penalties, require additional solvent regeneration, reduce net CO_2 capture efficiency, and increase project cost per tonne captured.

5.4.2 The practical balance

A workable CO_2 specification must: prevent phase instability under all operating scenarios, avoid free water formation with a margin, limit reactive impurity combinations, not just individual species, set hydrogen limits aligned with fracture design and void unnecessary over-purification where system risk is negligible.

This balance is typically achieved by: Risk-based impurity categorisation, Threshold + exceedance logic, Monitoring-based compliance rather than absolute purity, allowing derogations where system-specific risk is low, and designing pipelines for realistic impurity envelopes.

5.4.3 Strategic interpretation

An overly restrictive CO_2 specification will increase emitter costs and may reduce the scale of CCS deployment. An overly permissive specification increases pipeline integrity risk, raises lifetime maintenance and outage costs, and reduces system reliability.

The optimal composition envelope is therefore: a risk-managed compromise that protects system integrity while enabling economically viable capture projects.

In regulated CO_2 networks, this balance is typically embedded in entry specifications, monitoring requirements, isolation procedures and risk-based modification frameworks.

5.4.4 How the CO_2 Network Code controls impurities

Under the CO_2 Network Code, a User may not deliver CO_2 into the T&S Network unless a Connection Agreement is in force that specifies the applicable Entry Provisions. The Entry Provisions comprise Carbon Dioxide Specifications and measurement Requirements. The Carbon Dioxide Specifications are set out in Annexure B of The Entry Provisions and must ensure protection of health and safety, corrosion management and avoidance, environmental protection, predictable flow conditions, and reservoir impact management. This establishes the composition envelope as a contractual and regulatory condition of entry. Composition is defined by explicit threshold limits. Each impurity component has a defined limit, an exceedance threshold, and a defined monitoring frequency

Non-compliance is defined using averaging periods, maximum allowable exceedance durations, exceedance frequency, and risk-based categorisation of components. This prevents both transient spikes and systematic composition drift. Continuous and risk-based monitoring is mandatory. Calibration accuracy of equipment must match impurity limits and operating conditions. An agreed quality Monitoring Procedure establishes sampling techniques, testing frequencies, early warning systems, and categorisation of components by risk. Monitoring types include online continuous, online cyclical, and offline laboratory sampling. This creates a layered technical control system.

Non-Compliance Triggers Isolation. The User must immediately cease delivery under defined conditions. An isolation Procedure governs response and flow cessation. Reconnection requires evidence that the compliant conditions have been restored. The T&SCo may require increased monitoring, temporary flow restrictions, or full or partial cessation based on risk. Thus, composition control is enforceable operationally, not just contractually.

5.5 Routing

5.5.1 Onshore Routing

The routing of an onshore dense-phase CO_2 pipeline in the UK is typically undertaken in accordance with PD 8010, which provides guidance on route selection, design factors, risk assessment and proximity to populated areas. The process begins with high-level corridor identification, considering constructability, environmental designations, existing infrastructure crossings, and strategic tie-in points at emitter and storage interfaces. Early-stage screening aims to minimise interaction with densely populated areas and sensitive receptors. PD 8010 requires that proximity to occupied buildings be explicitly assessed, typically through a combination of separation distance guidance and QRA, particularly where the pipeline may qualify as a MAHP under the Pipeline Safety Regulations.

For high-pressure CO_2 pipelines, MAHP classification is likely due to operating pressure and inventory, even though CO_2 is not classified as a toxic gas under UN transport rules. Once MAHP status is established, routing must consider consultation distances derived from QRA outputs. The QRA integrates failure frequency assumptions with consequence modelling to generate individual risk contours and, where required, societal risk metrics. For CO_2 systems, consequence modelling introduces additional uncertainty compared with natural gas because dense CO_2 releases may produce ground-hugging dispersion influenced strongly by terrain, atmospheric stability and impurity composition. Modelling assumptions regarding phase transition, decompression behaviour, and toxic load criteria (such as specified level of toxicity (SLOT) and significant likelihood of death (SLOD) thresholds) can materially affect predicted hazard distances. These uncertainties often drive conservative routing decisions or increased separation from buildings.

Individual risk contours are used to inform HSE's LUP advice. HSE establishes consultation distances around MAHPs, typically segmented into inner, middle and outer zones. Local planning authorities must consult HSE when new developments are proposed within these zones. Consequently, routing must consider not only current building proximity but also potential future development pressure. In areas near industrial emitters, where capture plants are often located within or adjacent to established industrial zones that may have residential interfaces nearby, finding a compliant corridor that balances constructability, land access, and acceptable risk contours can be challenging.

The Development Consent Order process under the Planning Act 2008 introduces additional complexity for pipelines qualifying as NSIP. The pre-application stage requires extensive consultation with local authorities, statutory consultees, landowners and the public, supported by EIA. Environmental constraints such as protected habitats, watercourses, heritage assets and agricultural land classification may require route deviations or mitigation design, increasing length and cost. Land acquisition and easement negotiation across multiple parcels can be protracted, and objections can lead to compulsory purchase challenges. Interaction with local planning policy, existing utilities, transport corridors and community concerns regarding CO_2 safety can further extend timelines. While the statutory examination period is fixed, pre-application iteration and route refinement often dominate programme duration.

Interfaces with local authorities and landowners are therefore a critical component of onshore routing. Authorities focus on emergency planning, land use compatibility and community safety, while landowners are concerned with access rights, compensation and reinstatement. Transparent communication of QRA assumptions, hazard distances and integrity management measures is essential to maintain stakeholder confidence.

In contrast, offshore routing is not subject to the same building proximity and land-use planning constraints, which simplifies certain aspects of corridor selection. Offshore routing focuses instead on seabed geohazards, existing subsea infrastructure conflicts, shipping lanes, fishing activity, cable crossings and environmental sensitivities such as protected marine habitats. While offshore pipelines avoid the density of development challenges seen onshore, they introduce technical challenges related to bathymetry, free-span management, trenching feasibility, installation weather windows and inspection accessibility. Permitting involves marine licences and seabed leases rather than DCOs, and while stakeholder engagement is still required, public opposition is generally less intense than for onshore routes.

From a TRL perspective, the routing process itself, including PD 8010 application, QRA methodology, MAHP classification and LUP interface, is mature and would generally be assessed at TRL 9, as these processes are well established for high-pressure gas and liquid pipelines. However, the application of dense-phase CO_2-specific consequence modelling within QRA, particularly regarding impurity effects and terrain-sensitive dispersion, may be better characterised as TRL 7 to 8, reflecting integration and validation challenges rather than immaturity of the underlying regulatory framework. Offshore routing processes are similarly mature in the hydrocarbon sector, also TRL 9, though the integration of dense-phase CO_2-specific hazard modelling and long-term CCS network planning remains at the system-integration level rather than fundamental technological uncertainty.

5.5.2 Offshore Routing

Offshore CO_2 pipeline routing follows a structured corridor development process broadly aligned with established offshore oil and gas practice, with an emphasis on technical feasibility, constructability, and seabed interaction rather than land-use constraints. The process typically begins with regional-scale corridor identification linking landfall locations to offshore storage sites, considering bathymetry, seabed conditions, existing infrastructure, and designated marine areas. This is followed by progressively detailed route engineering, incorporating geophysical and geotechnical survey data to refine alignment, minimise intervention requirements, and reduce installation and lifecycle risks.

A primary consideration in offshore routing is the management of seabed geohazards. These include shallow gas, pockmarks, mobile sediments, sand waves, slope instability, and glacial features, all of which can affect pipeline stability and integrity. Routing seeks to avoid or mitigate these hazards where practicable, although some residual exposure is often unavoidable and must be addressed through design measures such as wall thickness selection, trenching, rock placement, or mechanical protection. Free-span formation due to seabed irregularities is a key design constraint, requiring careful route optimisation and span assessment to ensure acceptable fatigue performance.

Interaction with existing subsea infrastructure is another major driver of routing. Offshore corridors in mature basins such as the North Sea are often congested with pipelines, cables, wells, and structures. Route selection must minimise crossings where possible and ensure that unavoidable crossings are engineered with appropriate separation, protection, and regulatory approval. Cable crossings require coordination with telecommunications and power asset owners. Routing must also consider proximity to offshore installations, anchor patterns, and exclusion zones.

Human activity constraints influence routing, particularly shipping and fishing. High-density shipping lanes are typically avoided where possible, or crossings are designed to minimise exposure to anchor damage. Fishing activity, especially bottom trawling, introduces the risk of external interference; routing may therefore favour burial or protective measures in high-activity areas. These considerations are balanced against installation feasibility and cost, as deeper burial or protection increases project complexity.

Environmental considerations play a significant role in offshore routing. Sensitive receptors may include marine protected areas (MPAs), benthic habitats, spawning grounds, and designated conservation zones. Environmental impact assessment (EIA) is required to evaluate routing alternatives and define mitigation measures. While offshore routing generally encounters fewer direct stakeholder conflicts than onshore, regulatory scrutiny remains high, particularly in environmentally sensitive regions.

From a flow assurance and operability perspective, offshore routing must also consider thermal and hydraulic behaviour, especially for dense-phase CO_2 systems. Long subsea tie-backs are subject to seabed temperature conditions that can promote cooling during turndown or transient operation, increasing the risk of approaching the phase boundary. Routing and burial depth can influence thermal performance, and in some cases, insulation or operational constraints may be required to maintain single-phase conditions. Low points along the route may act as potential accumulation zones in two-phase scenarios, reinforcing the need for careful elevation profiling and transient analysis.

Permitting for offshore pipelines is undertaken under the Energy Act 2008, supported by marine licensing and seabed leasing arrangements with The Crown Estate or Crown Estate Scotland. Compared to onshore routing, the process involves fewer land ownership constraints but requires coordination with multiple regulators, including environmental bodies, maritime authorities, and infrastructure owners. Stakeholder engagement is still necessary, particularly with fisheries organisations, shipping authorities, and offshore operators, but public opposition is generally less pronounced.

From a TRL perspective, offshore routing methodologies, including survey techniques, geohazard assessment, and corridor engineering, are TRL 9, reflecting decades of application in the offshore hydrocarbon sector.

5.5.3 Landfalls

A pipeline landfall is the point at which an offshore pipeline makes transition from the seabed to the onshore environment, typically at or near the coastline. A shore crossing refers more specifically to the engineered section that passes beneath the beach, dunes, intertidal zone or coastal defences to connect offshore and onshore pipeline segments. Together, these represent one of the most technically and environmentally sensitive elements of a CO_2 transport system linking offshore storage to onshore emitters.

Landfalls and shore crossings are typically achieved using trenchless installation methods to minimise environmental disturbance. The most common technique is Horizontal Directional Drilling (HDD), where a bore is drilled from onshore to an offshore exit point beneath the seabed, and the pipeline is then pulled through the drilled tunnel. Alternatives include microtunnelling, direct pipe installation or, in some cases, open-cut trenching where environmental constraints allow. HDD is preferred in environmentally sensitive areas because it avoids excavation across beaches, dunes or protected habitats. Offshore tie-in then connects the drilled section to the seabed pipeline via a nearshore spool or welded connection.

Environmental challenges at landfall locations are significant. Coastal zones often include protected habitats such as dunes, salt marshes, mudflats or Sites of Special Scientific Interest (SSSI). There may be archaeological constraints, flood defence structures, unstable soils, or erosion-prone shorelines. Intertidal construction windows may be restricted by marine ecology, fisheries and navigation requirements. HDD itself carries risk of drilling fluid returns (“frac-outs”) into sensitive environments, which must be managed through geotechnical investigation and monitoring. Landfalls are also focal points of public scrutiny during consenting because they serve as visible interfaces between offshore infrastructure and communities.

Landfall engineering techniques such as HDD are TRL 9, as they are widely used in oil, gas and utility infrastructure. The application of these techniques to dense-phase CO_2 pipelines is also effectively TRL 9 from a construction standpoint, though project-specific environmental integration and repurposing assessments may involve lower system-integration maturity depending on site conditions and asset history.

5.5.4 Repurposing

Repurposing existing infrastructure can substantially reduce the complexity of a landfall. Where legacy hydrocarbon pipelines already exist, these corridors may be reused, avoiding new shoreline disturbance and reducing consenting risk. Viking CCS proposes to reuse existing offshore pipelines and infrastructure in the southern North Sea, reducing the need for new coastal crossings. The Liverpool Bay CCS (HyNet) project similarly leverages existing offshore assets and pipelines associated with historic gas production, limiting new seabed and landfall works. The NEP (serving the ECC) uses established offshore infrastructure corridors in the North Sea, though new onshore connections are still required. Acorn CCS in Scotland proposes to reuse existing pipelines associated with the St Fergus gas terminal, again reducing the environmental and planning burden of new shore crossings. Repurposing offers advantages in reduced capital cost, shorter consenting timelines, lower environmental impact and improved stakeholder acceptance, although it introduces technical challenges around material requalification, corrosion history and suitability for dense-phase CO_2 service.

5.6 Operation Issues

5.6.1 Dense phase vs. gaseous phase

There are two main strategies for storing carbon dioxide in depleted gas fields, each with distinct operational requirements. One involves injecting dense phase CO_2 from the start, provided the depleted field pressure is high enough to support dense-phase conditions. The alternative approach begins with gaseous CO_2 injection, gradually increasing reservoir pressure until it can sustain a dense phase CO_2 column within the wellbore. Saline aquifers that are sufficiently deep generally have formation pressures close to hydrostatic and are typically capable of dense-phase injection from the start, whereas depleted gas fields may begin at significantly reduced pressure and may require an initial gas-phase period or a pressure build-up strategy before dense-phase conditions can be sustained. This distinction is why project-specific storage development plans and permit submissions discuss phase and operability rather than assuming it from licence status alone. As a result, pipeline designers must account for the possibility of transporting both gaseous and liquid (dense phase) CO_2, including managing the transition between these phases, which have significantly different physical properties and risk profiles.

5.6.2 Blowdown and venting

Blowdown and venting systems are required for planned maintenance, emergency isolation, depressurisation prior to inspection, and decommissioning. In dense-phase CO_2 pipelines, decompression behaviour differs significantly from natural gas. Rapid depressurisation can result in Joule–Thomson (JT) cooling, phase transitions, and the formation of solid CO_2 (dry ice). Vent systems (e.g. vent stacks or cold flares) therefore require low-temperature-resistant materials, controlled depressurisation valves, and staged blowdown procedures to manage these effects. Impurities further influence phase behaviour and solid formation conditions, increasing uncertainty during venting. If not properly controlled, decompression may lead to solid CO_2 formation, blockage, or, in extreme cases, ductile fracture. As a result, blowdown operations are typically rate-limited and, for long pipelines, may extend over prolonged durations to maintain temperatures within allowable limits.

In gas-phase CO_2 pipelines, decompression behaviour is generally less severe. JT cooling still occurs, but the absence of phase change reduces the risk of solid formation and extreme temperature drops. Blowdown can therefore typically be achieved more rapidly and with fewer temperature constraints, although asphyxiation risk and dispersion behaviour remain important considerations. Where pressures, compositions, or ambient conditions approach the phase boundary, localised condensation or transient two-phase behaviour may still occur and must be considered in design and procedures.

Under the Pipeline Safety Regulations (PSR), operators must ensure CO_2 pipelines are designed, operated, and maintained safely, including during depressurisation. Blowdown is permitted where justified for safe operation (e.g. emergency isolation, maintenance, integrity management), but must be supported by appropriate risk assessment. Operators are expected to demonstrate, typically through QRA and consequence modelling, that venting does not pose unacceptable risk to people, with particular attention to hazard distances given the potential for dense CO_2 to form ground-hugging dispersions. Venting systems must avoid hazardous accumulation (asphyxiation risk) and manage low temperatures and potential solid formation. HSE expectations include minimising releases so far as reasonably practicable (ALARP), implementing controlled depressurisation procedures, and accounting for topography and meteorological conditions in dispersion modelling. While blowdown is an accepted safety measure, routine or poorly controlled venting—particularly for large inventories—is unlikely to meet ALARP expectations.

Although CO_2 is not classified as a toxic gas for transport purposes, venting has direct environmental implications, as any release constitutes a loss of stored CO_2 to the atmosphere. Accordingly, CO_2 transport projects may be subject to environmental permitting (e.g. EA or SEPA) and monitoring, reporting, and verification (MRV) requirements. In practice, routine venting is strongly discouraged, and operators must demonstrate that any releases are unavoidable, minimised, and fully accounted for.

Under the emerging UK CCS transport and storage regulatory regime, blowdown and venting also carry direct commercial implications. CO_2 is treated as a contracted stream with associated tariffs and service obligations; venting, therefore, represents a loss of transported volume and may constitute a breach of commitments to emitters. Vented CO_2 may also be attributed within emissions accounting frameworks to either the capture plant or the T&S operator, affecting carbon compliance positions and creating potential financial and reputational exposure. The Ofgem regulatory model is expected to incentivise high availability and efficient operation, discouraging unnecessary losses. Consequently, operators are driven to minimise the frequency and volume of blowdown events and to invest in mitigation measures such as recompression, capture, or temporary storage. The CCS Network Code is expected to treat venting and blowdown as tightly controlled operational events, subject to notification requirements, loss allocation rules, and coordinated system operation across users.

As a result, routine blowdown cannot be considered a neutral operational tool in CO_2 transport systems. Instead, it is treated as a last-resort action for safety or maintenance, carrying both commercial and environmental penalties. This drives system design toward a no-routine-venting philosophy, with increasing reliance on buffer storage, recompression, and controlled displacement methods (e.g. nitrogen purging) during maintenance and intervention.

In addition to safety, environmental and commercial considerations, accurate quantification of vented CO_2 is required for emissions reporting and commercial reconciliation. Venting events must be measured or reliably estimated with sufficient accuracy to ensure compliance with ETS monitoring, reporting and verification (MRV) requirements and to avoid distortion of overall mass balance calculations. This introduces reliance on metering systems during transient and non-steady-state conditions, which are more challenging to characterise than steady-state flow. Uncertainty in vent measurements may contribute to discrepancies in reported emissions and commercial allocations among system users, reinforcing the importance of robust measurement and agreed-upon accounting methodologies.

Blowdown systems are mature for hydrocarbon service (TRL 9), which is broadly applicable to gas-phase CO_2. However, dense-phase CO_2 decompression modelling and solid management under impurity-variable conditions remain at lower maturity (TRL 7–8), depending on project-specific validation. These behaviours remain an active area of research (see Section 5.19), particularly for impurity-variable CO_2 streams under transient conditions.

5.6.3 Multi-emitter network balancing and flow control

CO_2 trunklines may serve multiple emitters with varying flow rates and impurity profiles. Pressure management, backflow prevention, and composition blending must be controlled to maintain dense-phase stability. Unlike point-to-point pipelines, multi-user networks introduce compositional variability and transient pressure interactions. Linepack control must prevent localised two-phase formation and compositional excursions.

Advanced network simulation tools, automated pressure and blending controls, and impurity-forecasting capabilities pose challenges for coordinated scheduling between emitters, avoiding phase instability under variable inflow, and ensuring fair allocation while preserving integrity margin. See section 5.6.9.

Gas network balancing is mature (TRL 9), but multi-emitter dense-phase CO_2 network optimisation is closer to TRL 6–7 at large scale.

5.6.4 Metering

Any party seeking to explore for or utilise a geological formation for the long-term storage of carbon dioxide in a UK offshore area must hold a Carbon Dioxide Appraisal and Storage Licence ("CS Licence") under section 18 of the Energy Act 2008 (the "Act"). Under such a licence, the Licensee must obtain a storage permit from the North Sea Transition Authority (NSTA) to construct and operate facilities for the injection and permanent storage of CO_2 within the licensed area. As part of the storage permit application, the Licensee is required to demonstrate how it will meet the NSTA's expectations regarding the measurement of CO_2. NSTA provide guidance with respect to this[123].

There are two distinct regulatory requirements for the measurement of bulk quantities of CO_2 transported to and injected into offshore reservoirs:

- For financial accounting and emissions trading purposes, the mass of CO_2 sequestered must be quantified to an uncertainty level defined by the applicable scheme (e.g. the UK Emissions Trading Scheme, "UK ETS"), from which carbon credits are derived. This is achieved in two stages: measurement of bulk fluid quantities (herein referred to as rich CO_2) and determination of CO_2 concentration to quantify the mass of pure CO_2.
- In addition, the quantities of CO_2 delivered at each injection point must be measured with sufficient precision to meet the requirements of reservoir modelling. Injection rate is a key input to these models, governing pressure evolution, plume behaviour and containment; consequently, inadequate measurement accuracy reduces confidence in storage performance and regulatory compliance.

Measurement of the bulk fluid composition must also be determined at all necessary stages so that the fluid's phase behaviour remains consistent with the relevant equation of state and is properly understood for reservoir management. The presence of contaminants may be identified to ensure the integrity of pipelines and the associated plant.

Measurement of quantities of pure CO_2 sequestered must satisfy the uncertainty criteria of the Measurement, Monitoring and Reporting Regulations (MMR) of the relevant Emissions Trading Scheme (ETS). The UK-ETS generally requires a measurement uncertainty of less than ±2.5% in mass of CO_2, but it is envisaged that for commercial CCUS applications, the uncertainty requirement may be ±1.5% (mass of CO_2; i.e. including the uncertainty in determining the proportion of CO_2 in the rich fluid via sampling and analysis) or less. Allocation metering may be required where shared transportation systems are used to deliver CO_2 to multiple offshore injection hubs. Where the process plant has the capability to vent quantities of CO_2, for example, during planned maintenance activities, these quantities must be determined with an uncertainty level that does not cause the overall determination of CO_2 stored quantities to exceed the limit set by the trading scheme.

The measurement uncertainty mentioned above (±2.5% of the mass of CO_2) is only achievable if the measurement is performed on a single-phase fluid. The metering station should therefore be situated in the process plant at a location where this condition is guaranteed, taking account of the predicted phase behaviour of the rich CO_2. The measurement of CO_2 may present technical challenges. Under typical process conditions, CO_2 may exist in the gas, liquid or supercritical phase. At or near the 'critical point',

[123] North Sea Transition Authority (2024). Guidance for Measurement of Carbon Dioxide for Carbon Storage Permit Applications. Published 28 March 2024

very large variations in density may occur as the fluid shifts between these phases. Relatively small amounts of impurities may cause significant changes in the fluid's phase behaviour; two-phase flow with different compositions in each phase may result. The concentration and nature of any impurities may differ from one application to another, depending on the original source of CO_2. Accordingly, accurate determination of fluid composition, combined with an appropriate Equation of State, is required to reliably predict phase behaviour.

Ongoing metrology programmes, such as MetCCUS, are addressing several of the identified challenges associated with CO_2 measurement. These include the development of traceable calibration methods for CO_2 flow measurement, improved reference materials for CO_2 mixtures, and enhanced approaches to sampling and uncertainty quantification. While the underlying measurement technologies are mature, these programmes are improving confidence in their application to dense-phase and impurity-variable CO_2 systems. The impact is primarily on reducing uncertainty and improving traceability, rather than on introducing new measurement technologies, and therefore represents an increase in system-level confidence rather than a step change in fundamental capability. See section 5.19.

To meet these requirements, the NSTA guidance identifies three principal bulk-flow metering technologies for measuring rich CO_2: differential-pressure meters, Coriolis meters, and ultrasonic meters. Selection should be made on a case-by-case basis, taking account of phase state, pressure drop, installation constraints, calibration strategy, access for verification, and whether the meter is required for fiscal accounting, allocation or reservoir management.

For topside and onshore measurement stations, Coriolis meters are generally considered a strong candidate where line size, pressure drop and mechanical installation constraints are acceptable. Their principal strength is direct mass-flow measurement, which reduces reliance on separate density determination and makes them attractive where CO_2 composition may vary. They are relatively tolerant of installation effects and do not require extensive upstream flow conditioning. However, their limitations include relatively high pressure drop, increasing size and weight at larger diameters, and the need to confirm performance under dense-phase or supercritical conditions and across expected impurity envelopes.

Differential-pressure meters, particularly Venturi meters, are robust, well-understood and suitable for large-diameter applications. Their strengths include simplicity, proven offshore application, suitability for subsea deployment, and relatively low cost where multiple injection points require metering. Their limitations include dependence on accurate density and viscosity determination, with viscosity uncertainty contributing to overall measurement uncertainty, and the need for flow calibration to achieve the required accuracy. Unless otherwise agreed with the NSTA, Venturi meters should be flow calibrated.

Ultrasonic meters offer low pressure drop and advanced diagnostic capability, making them attractive for topside or onshore gas-phase or liquid-phase CO_2 measurement where suitable calibration facilities are available. However, their application is constrained by the requirement for CO_2-specific calibration, as calibration using natural gas or air is not transferable, and their performance in dense or supercritical CO_2 service may be limited by the fluid's acoustic properties, including reduced signal strength and sensitivity to density and composition.

For subsea injection-point measurement, the NSTA guidance indicates that direct measurement is effectively limited to differential-pressure technologies, with Venturi meters being the most practical solution. Their strengths are robustness, compatibility with subsea service and relative simplicity. However, their limitations include restricted access for inspection and recalibration, reliance on accurate density determination, and significant challenges associated with subsea sampling. As a result, the use of dual or triple instrumentation is typically required as a baseline design approach to provide redundancy and maintain measurement confidence.

Where direct measurement is difficult, particularly in subsea applications, virtual metering may be considered as a supplementary approach. While it can provide useful inferred flow data following calibration against physical measurements, it is not a substitute for validated direct metering without agreement with the NSTA and requires a reliable calibration basis.

Across all technologies, the metering location should be selected to ensure the CO_2 stream is single-phase, as required to achieve the stated measurement uncertainty. In addition, the provision of a final measurement station immediately prior to offshore transport is strongly beneficial, particularly in multi-emitter systems, as it reduces reliance on weighted averages from variable contributor streams and improves confidence in the total quantity of CO_2 delivered for injection.

This creates a direct linkage between measurement performance, regulatory compliance under UK ETS, and commercial settlement between network participants.

The underlying metering technologies (Coriolis, differential-pressure, and ultrasonic meters) are mature and widely deployed in hydrocarbon service and are therefore assessed at TRL 9 at the component level. However, their application to dense-phase, impurity-variable CO_2 systems, particularly in multi-emitter networks and subsea environments, introduces additional uncertainty associated with phase behaviour, calibration, and system integration. As such, overall metering systems for CCS applications are more appropriately characterised at TRL 7–8, reflecting mature hardware but reduced confidence at the integrated system level. Subsea metering and composition measurement remain constrained by access, calibration, and sampling challenges, and are typically assessed at TRL 6–7.

5.6.5 Intermediate storage

Intermediate buffer storage may be required for flow smoothing, particularly in offshore or long-distance transport. Storage may be pressurised vessels or pipeline linepack utilisation.

Intermediate storage options for CO_2 transport depend on the phase in which the CO_2 is being handled and the function of the storage within the value chain, whether for linepack balancing, buffering between capture and injection, or conditioning prior to non-pipeline transport such as shipping.

For dense-phase CO_2 in pipeline systems, intermediate storage is typically achieved either through pipeline linepack or through high-pressure buffer vessels. Linepack storage uses the compressibility of the pipeline contents to temporarily store additional inventory by raising operating pressure within allowable limits, providing short-term balancing between emitters and injection capacity. Where additional buffering is required, above-ground pressurised vessels or bullet tanks can be used, designed for dense-phase conditions. These systems operate at high pressure, require robust materials selection and pressure control, and must account for phase stability and transient cooling effects. Dense-phase storage is generally best suited for short-duration balancing rather than large-volume, long-term storage due to cost and pressure vessel size constraints.

For gaseous-phase CO_2, intermediate storage can be provided in lower-pressure gas holders, pressure vessels, or potentially depleted reservoirs in specific configurations. Gas-phase storage reduces pressure vessel design demands but requires significantly larger volumetric capacity for equivalent mass storage. It may be used during early-stage injection into depleted fields where reservoir pressure is initially too low to sustain dense-phase injection. However, large-scale gaseous storage above ground is generally space-intensive and less efficient, making it more suitable for temporary balancing rather than high-throughput buffering.

For liquefied CO_2 prior to non-pipeline transport, particularly shipping, refrigerated storage tanks are the standard solution. CO_2 is typically liquefied at moderate pressure (for example, around 6–20 bar depending on temperature) and stored at low temperature in insulated tanks similar to LPG storage systems. These tanks may be full-containment or semi-refrigerated designs and can store significant volumes at relatively compact footprints compared with gas-phase storage. This configuration is widely used in food-grade CO_2 supply chains and is being adopted for CCS shipping hubs, where captured CO_2 is conditioned, liquefied, stored in intermediate tanks, and then loaded onto vessels for offshore transport. Refrigerated liquid storage introduces requirements for thermal management, boil-off control, materials compatible with low temperatures, and robust transfer systems.

In summary, dense-phase intermediate storage is typically limited to high-pressure buffering and linepack, gaseous storage offers lower pressure but much larger volume requirements and limited economic attractiveness at scale, and liquefied CO_2 storage is the preferred solution where CO_2 must be accumulated prior to shipping or other non-pipeline transport. The choice depends on integration with transport mode, required buffer duration, pressure regime, impurity tolerance, and overall system economics.

The challenges are managing thermal cycling, maintaining dense-phase conditions, and avoiding impurity stratification (due to gravity). There is limited operational experience in large-scale dense-phase CO_2 intermediate storage outside EOR contexts. Onshore pressurised storage is TRL 8–9; offshore buffer integration is closer to TRL 6–7.

5.6.6 Linepack management and pressure-control philosophy

Dense-phase CO_2 pipelines use pressure as the primary stability control parameter. Linepack provides short-term balancing but has tighter operating margins than natural gas. Phase envelope sensitivity reduces operational flexibility. The challenges are avoiding the approach to the saturation curve, managing transient cooling events, and maintaining margin during outages

Pipeline pressure management is mature; impurity-sensitive phase envelope control is TRL 7–8.

5.6.7 Scheduling and flow-allocation

In a regulated, multi-user CO_2 network, allocation mechanisms define how transport and storage capacity is shared between Users, establishing both rights to flow and responsibilities for system impacts. Under the CCS Network Code, allocation is not purely volumetric; it is explicitly linked to compliance with defined CO_2 quality specifications and operational constraints. Users are granted capacity entitlements through contractual arrangements, but those rights are conditional upon meeting entry specifications, monitoring obligations, and network operating requirements. As a result, access to the system is governed by both quantity and quality.

Unlike natural gas networks, where allocation is typically based on nominated volumes and balancing tolerances, CO_2 networks must incorporate composition-driven constraints into allocation logic. Variations in impurity levels can affect phase stability, corrosion risk, fracture margins, and storage injectivity. The Network Code, therefore, requires monitoring, exceedance thresholds and defined non-compliance responses, including partial restriction or isolation. This means that a user's failure to meet specification can affect not only its own flows but also system integrity and other Users' capacity. Allocation frameworks must therefore incorporate curtailment rules, blending logic and priority sequencing that reflect both hydraulic and compositional risk.

The practical challenge is balancing contractual fairness with integrity protection. From a user perspective, bankability depends on predictable access to contracted capacity and transparent curtailment rules. From a T&SCo perspective, maintaining system integrity and regulatory compliance requires the ability to restrict flows rapidly when compositional or pressure limits are approached. The Network Code addresses this through defined exceedance categories, risk-based isolation procedures, and structured modification processes, but tensions remain where network constraints are driven by a single user's impurity profile or transient behaviour.

In multi-emitter networks, allocation mechanisms must therefore integrate quality-weighted rights, real-time monitoring data, and clear governance for dispute resolution. The system must ensure that no user gains advantage through relaxed compliance, while also avoiding over-conservative curtailment that unnecessarily restricts throughput. Achieving this balance requires transparent operating rules, robust measurement and verification systems, and a control philosophy capable of distinguishing between routine variability and integrity-threatening excursions. Ultimately, allocation in CO_2 networks is not simply a question of volume sharing, but of coordinated risk management across interconnected participants operating within a common regulatory framework.

5.6.8 Fugitive emissions

Fugitive emissions are unintended releases from equipment, systems or infrastructure, rather than controlled discharges through vents, flares or stacks. In pipeline and process systems, they typically arise from leaks at flanges, valves, seals, compressor seals, instrument fittings, and connections. They are usually low-rate, diffuse releases rather than catastrophic failures.

In the context of CO_2 operations, fugitive emissions can occur along transport pipelines, at compressor stations, metering skids, intermediate storage facilities, injection sites and connection points. While CO_2 is not flammable, fugitive releases can create asphyxiation risks in confined spaces and may trigger occupational exposure limits. Where impurities such as hydrogen sulphide, carbon monoxide, volatile organic compounds, or acid gases are present, even small leaks can introduce additional toxicity or environmental concerns.

From a regulatory perspective, fugitive CO_2 emissions have several implications. Under the UK ETS, only CO_2 that is permanently stored in an approved geological formation can be deducted from an emitter's reported emissions. CO_2 lost through fugitive leakage may remain reportable, potentially requiring the surrender of allowances and creating financial exposure. Operators must therefore ensure accurate measurement and monitoring to distinguish transported and stored volumes from losses.

Fugitive emissions may also trigger environmental permit reporting obligations, workplace exposure monitoring requirements, and, in some cases, air-quality or greenhouse-gas reporting thresholds. If impurity levels elevate toxicity, installations may require enhanced gas detection systems, hazardous area classification, emergency planning updates and inspection regimes.

In addition, from a safety case perspective, fugitive emissions contribute to the overall risk profile used in QRA. Although individual leaks are low consequence compared to full-bore ruptures, their higher frequency and cumulative probability must be considered in integrity management planning.

In summary, fugitive emissions represent a combination of operational, regulatory and reputational risk in CO_2 systems. Effective management requires robust sealing design, inspection and maintenance programmes, continuous monitoring where appropriate, rapid repair protocols and accurate accounting aligned with carbon market rules.

5.6.9 Pressure reduction/heating requirements

Typical pressures in North Sea saline aquifers are close to hydrostatic, as these formations are water-filled and have not been significantly depleted prior to CO_2 injection. A useful offshore rule of thumb is a hydrostatic gradient of approximately 1 bar (~0.1 MPa) per 10 metres of depth, meaning that at 800 m depth formation pressure is roughly 80 bar, at 1,000 m around 100 bar, at 1,500 m about 150 bar, at 2,000 m approximately 200 bar, and at 3,000 m around 300 bar. Most UK saline aquifers targeted for CCS lie between about 800 and 2,500 m subsea, corresponding to initial formation pressures of roughly 80–250 bar. Unlike depleted gas fields, these aquifers remain near hydrostatic pressure, so injection occurs against a relatively high native pressure. Maximum injection pressure is constrained by the fracture gradient, typically 0.18–0.23 bar per metre, implying fracture pressures of 30–50% above hydrostatic at depth. Because most target formations are deeper than 800 m, pressures are generally sufficient to maintain CO_2 in the dense phase within the wellbore and near-well region, reducing or eliminating the need for significant pressure reduction at the injection interface, making saline aquifer storage hydraulically simpler in early project life than depleted gas-field storage.

However, typical low pressures for depleted North Sea oil and gas reservoirs may range from roughly 10 to 80 bar, depending on depth and production history. Therefore, for some storage configurations, dense-phase CO_2 trunklines will operate at pressures significantly above initial reservoir pressure. Under these circumstances, a pressure reduction may be required at or near the injection interface to align with wellhead, tubing or reservoir constraints. CO_2 exhibits strong JT cooling during expansion, so substantial throttling will result in marked temperature drops, potentially leading to two-phase behaviour, hydrate or dry-ice formation, and exposing wellhead or subsea equipment to temperatures below their design limits. Injection wells and associated completion hardware in hydrocarbon service are typically not designed to tolerate sustained cryogenic conditions. Where these factors coincide, provision of controlled pressure reduction with thermal management may be necessary to ensure phase stability and protect equipment integrity. Use of alternative materials may also be necessary.

The requirement to provide significant offshore heating to manage large pressure reductions from dense-phase CO_2 to lower wellhead pressures is credible in principle but is not generally the preferred design approach. The most robust and likely scenario in practice is to avoid large offshore pressure letdown altogether by adopting an operating philosophy that maintains phase stability at the injection interface. This may include operating in gas phase during early field life, where reservoir pressure is low, and transitioning to dense-phase injection as reservoir pressure increases, thereby reducing or eliminating the need for substantial heating duty at the offshore end. HyNet (Liverpool Bay CCS) is designed to work in this way. Where pressure reduction with thermal management is unavoidable, the provision of heating is technically feasible on a platform-based installation. Topsides facilities can accommodate line heaters, electrical heating systems, or heat-exchanger arrangements, and offer the space, power availability, control systems and maintainability required to manage low-temperature transients reliably. However, the source of heat supply introduces additional design considerations, including fuel or power availability, environmental impact, and cost. Where heating is derived from electrification or renewable sources (e.g. offshore wind), issues of intermittency and reliability must be addressed, potentially requiring buffering, hybrid power systems, or operational constraints to ensure consistent thermal performance. In such cases, heating to protect wellhead equipment and prevent phase instability can be engineered using established offshore process design practices but must be integrated with a robust and reliable energy supply strategy.

By contrast, implementing significant heating in a purely subsea configuration is considerably more challenging. Subsea systems operate in a cold seawater environment that acts as a continuous heat sink, and high-duty electrical heating introduces complexity, reliability concerns and intervention risk. While localised subsea heating or insulation to protect specific components is credible and established in hydrocarbon service, reliance on sustained, large-scale subsea heating to manage routine pressure letdown is generally unattractive from both a cost and reliability perspective.

Alternative approaches may be adopted to manage pressure reduction more gradually and locally within the well system, thereby mitigating extreme Joule–Thomson cooling. These include the use of restricted tubing sizes to distribute pressure drop along the wellbore, allowing partial heat recovery from the geothermal gradient, and the application of inflow control devices (ICDs) to localise pressure reduction at or near the perforations. Such approaches can reduce the severity of temperature drops at any single location and help maintain more stable thermodynamic conditions during injection.

Consequently, the preferred engineering solution is typically to minimise or eliminate the need for major offshore pressure reduction at a single control point, combining system-level pressure management with well design features that distribute pressure drop, rather than relying on subsea heating as a primary mitigation measure.

5.6.10 Intermittency

Intermittency presents a structural challenge for CO_2 transport networks because both capture sources and injection systems favour steady, continuous operation. Certain industrial emitters, such as cement and lime plants, operate batch or cyclic processes that produce variable CO_2 flow. Gas-fired power stations, which are expected to play an increasingly dispatchable role in high-renewable electricity systems, may ramp output frequently or operate for limited periods. These operating patterns contrast with the preferred operating conditions of dense-phase CO_2 pipelines, compressors and injection wells, which are optimised for stable pressure, temperature and flow conditions.

Dense-phase CO_2 pipelines must operate above the bubble-point pressure to remain in single phase. If pressure falls toward saturation conditions during low-flow periods, the system may enter the two-phase region, creating instability, increased pressure drop, and potential control difficulties. In practical terms, two-phase operation can lead to phase slip and flow stratification, causing non-uniform velocity profiles and erratic pressure gradients along the pipeline. This may manifest as oscillating or poorly damped pressure responses, difficulty maintaining compressor set points, and challenges in flow metering accuracy. In inclined or undulating pipelines, local accumulation of liquid or dense-phase CO_2 can occur in low points, increasing the risk of intermittent slugging or transient surges when flow conditions change.

These effects can complicate start-up and restart procedures, increase the likelihood of control system instability, and lead to conservative operating margins being applied. Repeated transitions across the phase boundary can therefore complicate hydraulic behaviour and increase operational risk.

In addition, injection wells and tubing are not well-suited to frequent thermal cycling and start-stop operation. Rapid depressurisation and re-pressurisation can induce temperature swings, stress cycling and possible scaling or corrosion risks within the wellbore. Compressors are also most efficient and mechanically stable when operating near defined set points; frequent ramping reduces efficiency, increases wear and complicates control.

As a result, CO_2 Transport and Storage (T&S) systems benefit from the smoothing of supply variability. One solution is network aggregation: connecting multiple emitters into a wider trunkline network so that fluctuations from one source are dampened by steadier flows from others. A geographically broader network reduces the impact of any single intermittent emitter on overall system pressure and injection rate. This approach requires sufficient network capacity and coordinated scheduling but improves hydraulic stability and asset utilisation.

Linepack can also provide short-term buffering. By allowing pressure to increase modestly during high inflow and decrease during low inflow, the pipeline itself acts as a temporary storage vessel. However, linepack flexibility in dense-phase CO_2 systems is more constrained than in natural gas networks because operating margins to the phase boundary are narrower. Excessive drawdown risks approaching the saturation curve, so linepack must be managed conservatively.

Intermediate storage offers greater buffering capability. This may take the form of high-pressure dense-phase storage vessels onshore, low-temperature liquid CO_2 tanks for shipping interfaces, or utilisation of short pipeline segments as controlled buffer volumes. Such storage can decouple capture variability from injection stability, but it introduces additional capital cost, footprint and operational complexity.

Variable-speed compression or pumping provides another mitigation mechanism. Adjustable-speed drives allow compressors to respond more flexibly to changing inflow conditions while maintaining required discharge pressures. This reduces the need for blowdown or recycling during partial-load operation. However, the underlying thermodynamic constraints of phase stability remain; variable-speed drives improve control but do not eliminate the need to remain above minimum dense-phase pressure.

Operational coordination between capture and storage is therefore essential. In the early life of a storage site, where reservoir pressure may be low, gas-phase injection may be more tolerant of intermittency, with transition to dense-phase injection as reservoir pressure builds. Over the longer term, maintaining steady injection rates is typically preferred to preserve well integrity, optimise injectivity and minimise thermal cycling.

In summary, intermittency in CO_2 transport systems arises from the mismatch between variable capture sources and the steady-state preferences of pipelines, compressors and wells. Dense-phase operation imposes additional constraints because pressure cannot fall below saturation without risking two-phase instability. Practical mitigation strategies include network aggregation to smooth flows, conservative use of linepack, provision of intermediate storage, flexible compression, and coordinated operating modes between capture and storage. Effective system design must therefore consider intermittency not as an exception but as an inherent operating condition in future decarbonised energy systems.

5.7 Flow Modelling

5.7.1 Transient Analysis

Accurate transient modelling is a core enabler for designing and operating CO_2 transport networks because CO_2 systems are often run close to phase boundaries and are strongly affected by pressure/temperature transients, linepack changes, and storage backpressure. Unlike natural-gas systems, dense-phase CO_2 can cross into two-phase behaviour during routine operations (start-up, shutdown, ramping, blowdown), and during decompression it can exhibit a phase-change “plateau” that materially changes depressurisation dynamics and integrity-related loadings. Published work shows the chosen thermodynamic model/equation of state (EOS) can dominate predicted decompression timing and behaviour, which is directly relevant to safe operating envelopes and fracture-control assumptions.

Impurities such as N_2, O_2, H_2, CH_4, Ar and trace polar components shift the critical point and phase envelope, often narrowing the "safe" dense-phase operating region and increasing sensitivity to small P–T changes. This creates three modelling challenges. First, the simulation must capture phase equilibrium and property accuracy (density, speed of sound, JT coefficient, Cp/Cv) because these drive hydraulics and transients. Second, solvers must remain stable across steep property gradients near phase boundaries (where numerical instability is common). Third, networks are coupled systems: storage injectivity/backpressure, compressor control, linepack, and multi-emitter blending create interacting transients that can push local segments toward two-phase conditions.

Most transient pipeline and network simulators model CO_2 flow by solving one-dimensional conservation equations for mass, momentum and energy for a compressible fluid. The energy equation is particularly important for CO_2 because temperature changes directly influence phase behaviour and can trigger phase transitions. These partial differential equations are closed using an appropriate EOS together with transport-property correlations for viscosity and thermal conductivity. A numerical solution is typically obtained using finite-volume or finite-difference schemes with implicit or semi-implicit time stepping in small increments to ensure numerical stability. For CO_2 mixtures, both stability and predictive accuracy depend critically on how the solver handles phase appearance and disappearance, heat transfer and elevation effects, and the evaluation of thermodynamic and transport properties across steep phase boundaries.

5.7.2 Equations of state (EOS)

Cubic EOS, such as Peng–Robinson and Soave–Redlich–Kwong, are widely used in transient pipeline modelling because they are computationally efficient and numerically robust, but their density and phase accuracy for CO_2-rich mixtures can be limited unless carefully tuned with binary interaction parameters or volume shifts. In CCS applications, methodologies have emerged that benchmark against high-accuracy reference models such as GERG-2008 and then optimise cubic EOS parameters to better match density and viscosity behaviour across the relevant CCS operating envelope. GERG-2008 itself is an ISO-adopted, high-accuracy mixture EOS widely used for natural-gas-like mixtures and often employed as a reference where composition falls within its validated range. For pure CO_2, the Span–Wagner equation of state provides highly accurate thermodynamic properties, although its direct implementation in transient solvers can be computationally intensive, prompting the development of adapted or reduced-order formulations. Within specialised transient multiphase tools, additional numerical treatment is often required because conventional pressure–temperature–composition formulations that perform well for hydrocarbons can struggle near the narrow and highly sensitive phase boundaries characteristic of near-pure CO_2 and low-level impurity mixtures.

5.7.3 Practical Application of Modelling and Digital Tools

In design (FEED and detailed design), transient modelling tools are best used to define the safe operating envelope for CO_2 networks, including minimum pressure margins to maintain single-phase flow, compressor control philosophy, linepack management strategy, blowdown and depressurisation procedures, and sensitivity to impurity excursions. Platforms such as Schlumberger's OLGA, including its CCS-focused solver developments, are designed to provide numerically stable and reliable solutions for multiphase CO_2 transportation and injection, supporting both system design and operational procedure development. Kongsberg Digital's LedaFlow is similarly positioned to multiphase-simulate CO_2 networks, enabling design optimisation and performance assessment of continuous-flow systems. In parallel, process simulators such as Aspen or HYSYS-type workflows are widely used to develop and validate fluid property packages and steady-state hydraulic conditions, where appropriate equation-of-state selection and tuning, often based on Peng–Robinson with CCS-specific calibration, are critical inputs to the broader transient modelling framework.

For operations planning and procedures, software is required to validate start-up/shutdown sequences, manage storage backpressure changes, determine curtailment logic, predict where two-phase risk emerges during transients, and specify monitoring/alarm thresholds. Here, transient models are used to generate operating rules (minimum pressures, ramp rates, valve sequencing), and to justify that procedures keep the network within the required integrity envelope.

For real-time operations, a "digital twin" is required for decision support (not a full physics replacement), such as forecasting phase margin in near real time, anticipating constraint-driven backpressure transients, and triggering preventive control actions. In real time, the practical constraint is computational. Operators typically run a calibrated reduced-order or faster-running model in parallel with SCADA, or a "fast transient" configuration with simplified thermodynamics and bounded scenarios and periodically reconcile against higher-fidelity runs. AI and machine learning potentially have an important role in this.

5.7.4 TRL assessment

The available solutions are assessed to have TRLs as follows:

- Transient multiphase simulation platforms as a class (oil & gas heritage) and steady-state pipeline hydraulics using standard EOS approaches - TRL 9.
- Dense-phase CO_2 + impurities transient modelling in large networks, because accuracy depends on EOS tuning/validation for the specific impurity envelope and on proven numerical robustness near phase boundaries. Evidence of targeted CCS solver development and long-running research programmes supports this maturity level - TRL 7–8.
- Closed-loop, real-time network optimisation that integrates impurity analytics, transient hydraulics, and automated control decisions across multi-emitter systems. This is generally feasible with today's tools but is still limited by plant-to-network data integration, validation under realistic impurity variability, and governance of automated actions - TRL 6–7.

These modelling limitations are the subject of ongoing research and validation programmes (see Section 5.19), particularly in relation to impurity-sensitive transient behaviour.

5.8 Pipeline Materials

5.8.1 Fracture control

Running ductile fracture (RDF) is a high-consequence failure mode in which a through-wall defect transitions into a rapidly propagating longitudinal crack, driven by the internal pressure of the escaping fluid. Because a propagating ductile crack can run along the pipeline for many pipe lengths if the driving force remains above the material's arrest capability, fracture control is a fundamental part of high-pressure pipeline design, alongside initiation control.

To manage RDF in gas transmission pipelines, empirical and semi-empirical design methods were developed and validated against extensive full-scale testing. The best-known approach is the Battelle two-curve method (BTCM), originating in Battelle's work in the 1970s and subsequently applied widely to natural gas pipelines. The method compares a decompression curve for the pipeline fluid with a material/fracture curve describing crack-propagation behaviour to determine whether a running crack will arrest.

Dense-phase CO_2 differs from natural gas primarily because of its decompression behaviour. When a dense-phase CO_2 pipeline ruptures, the decompression path can intersect the two-phase region, leading to a pronounced pressure "plateau" associated with phase change. This plateau sustains a relatively high crack-driving pressure over a wider range of crack speeds than typical natural gas decompression, increasing susceptibility to long-running ductile fracture unless toughness (or other arrest measures) is significantly higher.

A growing body of work has re-examined BTCM for CO_2-rich mixtures, prompted by the recognition that methods calibrated for natural gas do not necessarily translate to dense-phase CO_2. Published research specifically notes that the BTCM, originally developed for natural gas, has been shown to be non-conservative for CO_2 unless the fluid and material treatments are appropriately adapted, and multiple programmes since the early 2010s have reported full-scale propagation testing aimed at validating arrest predictions in CO_2 service.

ISO 27913:2016 explicitly included guidance on the use of a modified BTCM (Annexe D), reflecting the then-available evidence base and the need to adapt natural-gas-derived concepts for CO_2 service. The latest ISO edition (ISO 27913:2024) supersedes the 2016 version and states that "latest findings in fracture arrest design" abandons the Battelle Two-Curve Model, and mirrors DNV-RP-F104.

In parallel, DNV-RP-F104 (Edition 2021, amended 2021-09) provides a CO_2-specific framework for design and operation, including structural assessment and fracture control. Recent work linked to DNV-RP-F104 presents a CO_2-focused empirical arrest model expressed as a relationship between normalised decompressed stress level and normalised toughness, drawing on full-scale test interpretation and providing an engineering pathway beyond the direct transplantation of natural gas BTCM assumptions. Despite progress, a persistent constraint is that the number of publicly documented full-scale CO_2 burst/propagation tests remains small (although this is being expanded through ongoing Joint Industry Projects, see Section 5.19), and available data cover a limited envelope of pipe sizes, wall thicknesses, grades, and CO_2 mixture compositions. This makes it difficult to claim the full generality of any single engineering model across all anticipated CCS operating envelopes. Accordingly, DNV-RP-F104 sets the expectation that where the combination of pipeline materials and CO_2 stream lies outside the range of available full-scale test data, a full-scale test should be conducted to provide confidence in fracture arrest performance.

DNV-RP-F104 CO_2-specific fracture arrest methodology, including empirical arrest relationships, provides formalised guidance and improves calibration, but remains bounded by the limited full-scale dataset and its applicability range - TRL 7–8. Full-scale fracture propagation/burst testing as a qualification route for CO_2 pipelines is a well-established test practice, but it is expensive and used selectively; it remains a key requirement when extrapolating beyond validated envelopes (TRL 8–9).

Current Joint Industry Projects and large-scale testing programmes (see Section 5.19) are expanding the empirical basis for CO_2-specific fracture control design.

5.8.2 Cryogenic materials

Dense-phase CO_2 pipelines are more prone to low-temperature conditions than conventional natural gas pipelines because of the thermodynamic behaviour of CO_2 during pressure reduction. When high-pressure dense-phase CO_2 expands, whether through a control valve, restriction, or full-bore rupture, it undergoes significant JT cooling and may cross into the two-phase region. The decompression path can approach the triple point of CO_2, creating local temperatures below −50 °C and, in extreme cases, dry ice formation. Natural gas systems also cool during depressurisation, but methane does not exhibit the same phase-change plateau or solid formation risk in typical transmission conditions. As a result, dense-phase CO_2 systems experience a higher likelihood of very low transient temperatures during blowdown, venting, rapid isolation, compressor trips, start-up sequencing, and emergency release scenarios.

Cryogenic or low-temperature-tolerant materials may therefore be required at specific locations where rapid pressure drops or phase change are credible. These typically include blowdown and vent systems, cold flare stacks, isolation valves and valve bodies (particularly where trapped volumes may warm and re-pressurise), pig traps and launcher/receiver systems, pressure control valves and throttling devices, relief valves, injection chokes, and sections immediately downstream of emergency shutdown valves. In offshore systems, subsea isolation valves, manifolds, and control modules may also require low-temperature qualification due to depressurisation or cold CO_2 inflow. In addition, equipment such as small-bore instrument lines, drain and vent connections, and elastomeric seals can be vulnerable to rapid cooling and embrittlement if not specified appropriately.

Cryogenic or low-temperature metals in this context generally refer to materials with demonstrated toughness and ductility at sub-zero temperatures. Common examples include austenitic stainless steels (such as 304L and 316L), which retain toughness at very low temperatures; nickel-alloy steels; and certain fine-grain carbon-manganese steels designed for low-temperature service (e.g., grades qualified under impact testing at −40 °C or lower). In some cases, 9 % nickel steel or aluminium alloys are used for refrigerated liquid CO_2 storage systems. Material selection is guided by standards such as ASME B31.4 and B31.8 for pipeline design, ISO 27913 for CO_2 transportation systems, DNV-RP-F104 for CO_2 pipelines, and relevant material standards specifying Charpy impact testing at defined minimum design metal temperatures. European pressure equipment standards (e.g., EN 13445) and offshore codes also require demonstration of adequate fracture toughness at the lowest credible metal temperature.

From a TRL perspective, cryogenic materials themselves are mature, generally TRL 9, having long-standing application in LNG, LPG, industrial gas and refrigerated CO_2 service. Their application in dense-phase CO_2 pipelines is therefore not novel at the material level. However, system-level validation of impurity-influenced decompression temperatures and transient behaviour in CCS networks may be considered TRL 7–8, reflecting the integration challenge rather than uncertainty in the fundamental metallurgy. In summary, the need for cryogenic materials in dense-phase CO_2 pipelines arises primarily from rapid depressurisation and phase behaviour effects, and while the materials are mature, their application requires careful transient modelling and design validation specific to CO_2 service.

5.8.3 Non-metallic materials

Non-metallic materials are widely used in oil and gas pipelines for functions that do not require primary structural strength. These include elastomeric seals and O-rings in valves and pig traps, flange gaskets, internal linings, external corrosion coatings, composite repair systems, thermoplastic liners and components within subsea umbilicals. In conventional hydrocarbon service, these materials are selected based on chemical compatibility, pressure and temperature rating, and resistance to rapid gas decompression.

In dense-phase CO_2 service, additional challenges arise. High-pressure CO_2 can permeate elastomers and polymers, and rapid depressurisation may cause blistering or cracking because of gas decompression. JT cooling during blowdown can expose materials to very low temperatures, increasing brittleness and reducing sealing performance. If water and reactive impurities such as SOx, NOx, or H_2S are present, acidic micro-environments can form, accelerating the degradation of certain polymers and gasket materials. These factors make material qualification more critical than in conventional methane systems.

Suitable materials for dense-phase CO_2 typically include high-performance elastomers such as FKM, HNBR, AFLAS and FFKM when properly qualified for rapid gas decompression and low-temperature service. Thermoplastics such as PEEK and PTFE can be appropriate in certain applications, and standard external coatings such as fusion-bonded epoxy and three-layer polyethene systems remain suitable because external corrosion mechanisms are not fundamentally altered by CO_2 transport. However, lower-grade nitrile rubbers, some polyurethane formulations and certain fibre-based gasket materials may exhibit excessive swelling, permeability or degradation and therefore require careful evaluation or avoidance.

The key to successful use of non-metallic materials in CO_2 pipelines lies in disciplined specification and validation. Rapid gas decompression testing, low-temperature qualification, impurity control and appropriate venting of trapped volumes are essential design measures. When these practices are followed, non-metallic materials can be used reliably in dense-phase CO_2 transmission systems, but the tolerance margins are narrower, and material selection must be more conservative than in conventional natural gas service.

5.8.4 Non-metallic pipelines

Non-metallic pipes are used in oil and gas systems in a range of applications where corrosion resistance, weight reduction or ease of installation provide advantages over carbon steel. These include glass-reinforced epoxy (GRE) pipe for produced water and low-pressure service, reinforced thermoplastic pipe (RTP) for flowlines and gathering systems, high-density polyethylene (HDPE) pipe for low-pressure water or gas distribution, and flexible composite pipes used in certain offshore applications. In conventional hydrocarbon service, these materials are selected based on pressure rating, temperature limits, chemical compatibility and long-term creep performance.

GRE pipelines made using filament-winding are suitable for CO_2 service, with pressure capabilities up to 120 bar, with reasonably large diameters. They have excellent corrosion resistance and fracture properties at low temperatures, offering considerable advantages.

For high-pressure, long-distance, dense-phase CO_2 transmission, carbon steel remains the dominant material because it provides predictable mechanical performance, fracture-control capability, and compatibility with established design codes. Where non-metallic pipe systems are considered, the principal gaps relate to long-term performance data under dense-phase CO_2 exposure, and validation of failure data required to undertake QRA required for regulatory acceptance. In practice, non-metallic pipes may play a role in low-pressure distribution, temporary works or specific corrosion-prone segments, but they are unlikely to replace steel in primary dense-phase CO_2 export pipelines without substantial additional validation.

5.9 Pipeline Equipment

This category includes the mainline pipe, girth welds, bends, tees, reducers and branch connections that form the pressure-retaining envelope. In dense-phase CO_2 service, fracture control is a central design consideration because decompression behaviour differs from methane and may sustain crack-driving pressure for longer. Wall thickness and steel toughness may therefore be governed by fracture-arrest requirements rather than by pressure containment alone. Minimum design metal temperature must account for rapid JT cooling during rupture or blowdown, and material compatibility must consider the potential presence of hydrogen and impurity effects. TRL: 8–9, reflecting mature pipeline materials and design practice with additional validation required for CO_2-specific fracture behaviour.

5.9.1 Block valves (sectionalising valves)

Mainline block valves, emergency shutdown valves and, where applicable, subsea isolation valves are used to segment inventory and limit release duration. In CO_2 service, valves must be qualified for closure under flowing dense-phase conditions and for exposure to rapid cooling during depressurisation. Trapped volumes between double-block arrangements can re-pressurise as temperature rises, requiring vented cavities. Seal materials must be resistant to CO_2 permeation and rapid gas decompression effects, and isolation philosophy must reflect asphyxiation-driven hazard rather than flammability. TRL: 8–9, with hardware fully mature but requiring CO_2-specific qualification for low-temperature and decompression effects.

5.9.2 Pressure safety valves (PSVs) and relief devices

Pressure safety valves (PSVs), rupture discs and thermal relief valves protect against overpressure conditions. In dense-phase CO_2 pipelines, relief sizing must account for two-phase discharge and extreme cooling. Vent systems may experience dry ice formation, requiring careful design to prevent blockage. Discharge dispersion modelling focuses on asphyxiation hazard rather than fire or explosion, and relief headers must avoid configurations that allow solid accumulation. TRL: 8–9, as relief technology is mature, but application to dense-phase CO_2 requires thermodynamic and materials validation.

5.9.3 Pig traps (launchers and receivers)

Pig traps allow cleaning, gauging and in-line inspection. In CO_2 service, depressurisation before opening can generate very low temperatures and potential solid formation. Stagnant cavities may accumulate acidic condensate if water and reactive impurities are present. Elastomer seals must be qualified for CO_2 exposure and rapid decompression, and phase stability must be maintained during pigging runs to preserve inspection tool performance. TRL: 8–9 for topside systems; 7–8 for subsea applications in dense-phase CO_2, reflecting integration and validation challenges.

5.9.4 Flanges and mechanical connections

Flanged joints, gaskets and bolting systems represent potential leak paths. CO_2 can permeate certain gasket materials and rapid cooling can induce differential contraction between components. Bolting materials must maintain adequate toughness at low temperature. Although the mechanical design principles are conventional, leak consequence considerations focus on asphyxiation and dispersion rather than flammable vapour cloud explosion. TRL: 9, with mature technology requiring CO_2-compatible material selection.

5.9.5 Cathodic protection (CP) systems

Cathodic protection (CP) and external coatings control external corrosion threats. While the electrochemical principles are unchanged from hydrocarbon service, thermal cycling and installation stresses may influence coating performance. CO_2 itself does not alter external corrosion mechanisms, but overall integrity strategy must still incorporate coating condition and CP performance monitoring. TRL: 9, fully mature and transferable from hydrocarbon practice.

5.9.6 Supports and anchors

Pipe supports, anchors and expansion loops manage mechanical loads and thermal expansion. Rapid cooling during depressurisation can create contraction stresses, and in cold climates frost heave may be a secondary consideration. Structural design must account for transient thermal loads as well as steady-state operating conditions. TRL: 9, reflecting established structural engineering practice.

5.9.7 Coatings and internal linings

External coatings protect against soil corrosion, and internal linings may be applied in specific cases. In CO_2 pipelines, internal surfaces must tolerate potential acidic microphases where water and impurities coexist. Elastomeric materials and bonded coatings must be compatible with dense-phase CO_2 and resistant to rapid decompression effects. TRL: 8–9, mature technology with CO_2-specific material qualification requirements.

5.9.8 Subsea components (where applicable)

Subsea valves, manifolds and control modules are used in offshore transport systems. These components must be qualified for high-pressure, low-temperature transients and impurity exposure. Intervention and maintenance are more complex than in topside systems, and materials must be selected to resist CO_2-specific thermal and chemical effects. Isolation philosophy and control reliability are critical because access for repair is limited. TRL: 7–8, reflecting mature offshore hardware with integration and validation challenges in dense-phase CO_2 service.

5.10 Pipeline Integrity Management

Pipeline Integrity Management Systems (PIMS) are structured, risk-based frameworks that ensure pipelines remain fit for service throughout their operational life. They integrate engineering design assumptions, inspection data, operational controls, maintenance practices and risk assessment to manage threats systematically rather than reactively. The core objective of a PIMS is to prevent loss of containment by identifying hazards, understanding degradation mechanisms, monitoring conditions, prioritising mitigation and demonstrating that risks are reduced to an acceptable level. A well-implemented PIMS provides traceability from threat identification through inspection planning, defect assessment, repair decisions and performance verification, and is central to regulatory compliance and public assurance.

The concept and structure of integrity management are well-established in international standards. API 1160 (Managing System Integrity for Hazardous Liquid Pipelines) and ASME B31.8S (Managing System Integrity of Gas Pipelines) set out risk-based methodologies for threat identification, data integration, inspection planning, mitigation, reassessment intervals and continual improvement. These standards emphasise that integrity management must begin with a clear understanding of pipeline-specific hazards and credible degradation processes. They require operators to characterise threats such as corrosion, cracking, material defects, third-party interference and geotechnical movement, and to select inspection and monitoring tools aligned to those threats. In conventional oil and gas service, this framework is assessed at TRL 9, reflecting decades of application and regulatory embedding.

For dense-phase CO_2 pipelines, the PIMS framework itself remains mature, but its application requires a nuanced understanding of CO_2-specific degradation mechanisms.

In summary, pipeline integrity management systems are mature and standardised through API 1160 and ASME B31.8S, but effective application in dense-phase CO_2 service requires a detailed understanding of CO_2-specific hazards, phase behaviour, impurity interactions and fracture mechanics. The framework remains at TRL 9, while certain degradation mechanisms, particularly impurity-driven corrosion and hydrogen-related cracking, require careful validation and conservative management to ensure long-term system integrity.

5.10.1 Corrosion

Internal corrosion risk is primarily governed by water management. Dry CO_2 is not corrosive to carbon steel, but the presence of free water leads to carbonic acid formation and potential corrosion. Where impurities such as SOx, NOx or H_2S are present, stronger acids can form, accelerating corrosion rates and potentially altering pitting morphology. Hygroscopic contaminants such as glycols or amines can modify water behaviour, increasing the likelihood of localised aqueous phase formation even when bulk water levels appear compliant. Integrity management must therefore integrate dehydration performance, impurity monitoring, transient thermal modelling and internal inspection data to ensure that free water does not form under steady-state or blowdown conditions.

External corrosion mechanisms are similar to those in hydrocarbon pipelines and are governed by coating integrity, cathodic protection performance, and soil environment. However, rapid depressurisation and low-temperature transients may affect coating performance or induce differential thermal stresses that compromise adhesion. External corrosion management, therefore, remains within established practice but must account for CO_2-specific operating conditions.

Ongoing research programmes (Section 5.19) are improving understanding of impurity interactions and transient corrosion mechanisms.

5.10.2 Cracking

Crack management introduces additional nuance. Where hydrogen is present as an impurity, there is potential for hydrogen-assisted cracking or embrittlement, particularly under cyclic pressure conditions. Even low hydrogen partial pressures may influence crack growth behaviour over time. As a result, integrity management for CO_2 systems may require enhanced crack-detection intervals, tighter defect-growth modelling, and integration of inspection results with fracture-mechanics assessments that account for CO_2-specific decompression characteristics.

5.10.3 Third party

Dents and third-party interference remain major threats in onshore pipelines. The fundamental mechanism—external mechanical damage from excavation or ground movement—does not change in CO_2 service. However, the consequence environment differs because a rupture in dense-phase CO_2 may produce a ground-hugging dispersion cloud rather than a flammable vapour cloud. Integrity management must therefore maintain strong damage prevention programmes, right-of-way surveillance and geometry inspection capability to manage deformation threats, while recognising that societal risk contours may be driven more by inhalation hazards than by explosion potential.

5.10.4 Leak to full-bore rupture progression

A leak in a dense-phase CO_2 pipeline can, under certain conditions, escalate into a full-bore rupture through the combined effects of rapid decompression cooling, reduced material toughness, and fracture propagation. The mechanism differs in detail from methane pipelines but follows the same fracture mechanics principles.

When a dense-phase CO_2 pipeline develops a through-wall defect, for example, from corrosion, external damage, or a dent with cracking, high-pressure CO_2 begins escaping through the opening. As it expands from the dense phase to the gas phase, it undergoes JT cooling. For CO_2, this cooling can be substantial, often driving local temperatures well below 0°C and, in some cases, below −40 °C. The escaping jet also causes rapid depressurisation of the pipe section near the defect.

Two coupled effects occur. First, the pipe wall in the vicinity of the leak experiences intense local cooling. Carbon steels used in pipelines have a ductile-to-brittle transition temperature (DBTT), below which fracture toughness decreases significantly. If the steel temperature drops into or below this transition region, its resistance to crack growth decreases, allowing the crack to grow.

In the case of the 2020 Satartia, Mississippi incident, publicly available investigations indicate that the failure was initiated due to ground movement associated with a landslide, which imposed bending stresses on the pipeline. The rupture of the dense-phase CO_2 pipeline resulted in rapid decompression and the release of a large volume of CO_2. While the primary initiating mechanism was mechanical ground movement rather than JT-induced embrittlement, the thermodynamic behaviour of dense-phase CO_2 likely influenced the escalation.

In summary, a leak in a dense-phase CO_2 pipeline can escalate to full-bore rupture if rapid JT cooling lowers steel toughness while decompression behaviour sustains sufficient crack-driving force for fracture propagation. The Satartia incident primarily resulted from external ground movement, but the dense-phase CO_2 decompression characteristics likely influenced the rupture dynamics and the scale of release once failure occurred.

5.10.5 Frost heave

Frost heave may be a secondary integrity consideration for onshore dense-phase CO_2 pipelines, where transient or sustained low pipe wall temperatures can freeze moisture in frost-susceptible soils. Rapid depressurisation events can generate significant JT cooling, and if local ground temperatures fall below freezing, ice lens formation may induce upward soil movement and impose additional bending or axial stresses on the pipe. While this risk is generally limited in temperate climates under steady-state operation, it should be assessed using coupled thermal–geotechnical modelling, shallow-burial conditions, or, where frequent blowdown events are anticipated, which is unlikely given the proposed CO_2 transportation system. Mitigation measures include appropriate burial depth, non-frost-susceptible backfill, controlled depressurisation rates and, where necessary, thermal management.

5.11 Inline Inspection (ILI)

In-line inspection (ILI) is a mature capability in oil and gas pipelines but reported global experience specifically for dense-phase/high-pressure CO_2 transport at the scale anticipated for CCS remains limited, as reflected in industry guidance aimed at managing the risks and uncertainties of CO_2 pipeline transport. As CO_2 networks expand, ILI becomes a critical enabler of integrity assurance because dense-phase CO_2 systems can be sensitive to fracture propagation behaviour, impurity-driven degradation mechanisms, and operating transients.

Inspection underpins the ability to demonstrate ongoing fitness-for-service by detecting metal loss and wall thinning, dents and deformation, and cracking and crack-like features (including weld-related anomalies). This is particularly important where wall thicknesses can be substantial (e.g., ~25 mm) and where design margins depend on verified wall thickness and defect growth rates. In CCS, inspection also supports operational decision-making (repair, pressure restriction, requalification) and provides evidence to regulators and stakeholders that integrity risks remain under control throughout the pipeline's life.

If hydrogen is present as an impurity, inspection emphasis shifts toward crack detection and crack growth management, because hydrogen can degrade fracture and fatigue behaviour even at relatively low partial pressures in dense-phase CO_2 mixtures[124]. This drives stronger requirements for crack-focused ILI runs such as with (Section UTCD 5.11.2), and EMAT (Section 5.11.4) configurations at defined intervals, higher confidence in sizing and repeatability (to support growth rate assessment), tighter data quality management and validation (correlation digs / NDE), and integration of ILI results with fracture mechanics-based integrity assessment and pressure cycling history.

High-pressure CO_2 service can challenge the construction and reliability of ILI tools. Dense-phase CO_2 can interact with some polymers, elastomers, seals, adhesives, cable jackets and coatings through swelling, permeability and rapid decompression effects, and can influence lubrication and tribology in moving components. These issues can be exacerbated by impurities (water, hydrocarbons, solvent carryover) and by low-temperature transients during depressurisation events. Consequently, CCS ILI programmes typically require CO_2-compatible elastomers and seal materials, qualified for pressure, temperature, and decompression cycles, robust pressure housings for electronics and battery systems, defined limits for temperature excursion, differential pressure, and tool speed, pre-run testing in representative CO_2 conditions (pressure/temperature/composition) and post-run inspection of tool components.

[124] Bezensek, B. et al. Influence of the H2 Impurity on the Fatigue Crack Growth and Fracture in a Dense Phase CO_2 Pipeline. 2024. Available: Influence of the H2 Impurity on the Fatigue Crack Growth and Fracture in a Dense Phase CO2 Pipeline | AMPP Annual Conference | Association for Materials Protection and Performance [Accessed 10 March 2026].

Internal inspection of dense-phase CO_2 pipelines naturally draws heavily on established in-line inspection (ILI) technologies from the oil and gas sector, but application in CO_2 service requires careful consideration of phase behaviour, material compatibility and defect mechanisms specific to CO_2 and its potential impurities.

5.11.1 Ultrasonic tools (UT)

Ultrasonic in-line inspection tools use high-frequency sound waves transmitted through a liquid or dense fluid medium to measure wall thickness and characterise defects. In conventional oil pipelines, UT tools are widely used to assess metal loss with high accuracy and, in specialised configurations, to detect and size crack-like defects such as axial stress-corrosion cracking or seam weld flaws. UT is particularly advantageous where accurate through-wall sizing is required, including for thicker-wall pipelines typical of high-pressure CO_2 trunklines. Because UT relies on effective acoustic coupling between the transducer and the pipe wall, it is not suitable for dry gas pipelines without a liquid couplant; however, dense-phase CO_2 provides a continuous, liquid-like medium that can support ultrasonic propagation, making UT technically viable in this service, provided the pipeline remains in single phase during the inspection run. Performance depends on stable flow conditions, absence of two-phase behaviour, tool centralisation, internal surface cleanliness, and robust data quality control. In CO_2 pipelines, particular attention must be paid to maintaining phase stability during operation to avoid flashing or local solid formation, which could degrade signal quality. When properly configured and validated, UT is commonly regarded as a leading option for accurate metal-loss sizing and crack assessment in dense-phase CO_2 pipelines.

5.11.2 Ultrasonic Crack Detection (UTCD) In-Line Inspection Tools

Ultrasonic crack detection (UTCD) in-line inspection tools represent the current benchmark for reliable detection, identification, and sizing of crack-like defects in pipelines, particularly where high integrity requirements apply. In CO_2 service, and especially in systems containing small amounts of hydrogen, the reduction in fracture toughness increases the criticality of detecting and accurately sizing cracks and crack-like anomalies. As a result, high-performance UTCD tools are often required to support probabilistic integrity assessments and to ensure that defect populations are fully characterised prior to and during service.

UTCD tools, like UT tools, rely on liquid coupling to transmit ultrasonic energy into the pipe wall, enabling the use of high-frequency shear waves and advanced techniques such as tip diffraction for accurate crack sizing. Modern ultra-high resolution UTCD systems incorporate large numbers of sensors (on the order of thousands), significantly improving the probability of detection (POD), the probability of identification (POI), and sizing accuracy. These tools can distinguish between true crack-like defects and benign features such as weld geometry, which has historically been a key challenge in seam-welded pipelines. Reported sizing accuracies on the order of ±1 mm provide a strong basis for engineering critical assessments and repair planning.

However, the application of UTCD tools in CO_2 pipelines introduces important operational and material challenges. The requirement for liquid coupling conflicts with the need to maintain a dry pipeline environment to avoid the formation of carbonic acid. While UTCD inspections can be performed using water batches isolated by inert gases (e.g., nitrogen), this approach can be operationally complex, particularly in large-diameter or long-distance pipelines, and may result in significant downtime. Consequently, the use of UTCD in CO_2 service often requires careful planning, including drying procedures and post-inspection conditioning to restore pipeline conditions.

From a tool construction perspective, UTCD pigs must be designed to accommodate liquid handling while maintaining compatibility with CO_2 service constraints. This includes the use of materials resistant to both corrosion and low-temperature effects, as depressurisation and fluid handling can result in significant cooling. Sealing systems must maintain integrity during batching operations, while electronic and sensor components must be protected from both moisture ingress and temperature extremes.

Despite these challenges, UTCD remains the most effective technology for high-resolution crack inspection and is often required when stringent acceptance criteria apply, such as during pipeline repurposing for CO_2 or CO_2/H_2 service. In situations where operational constraints limit the use of liquid-coupled systems, alternative low-operational-disruption technologies such as EMAT or gas-coupled ultrasound may be considered; however, these generally do not yet match the detection and sizing performance of UTCD. Therefore, UTCD tools continue to play a critical role in ensuring pipeline integrity in demanding service conditions, albeit with additional operational considerations in CO_2 environments.

5.11.3 Magnetic flux leakage (MFL)

MFL inspection tools operate by magnetising the pipe wall and detecting leakage fields caused by metal loss. MFL is a well-established and robust technology for detecting general corrosion, pitting, and wall thinning, and it does not require a liquid coupling medium, making it suitable for both liquid and gas pipelines. In CCS applications, MFL remains an important baseline inspection technology for wall-loss threats, including corrosion potentially driven by water ingress or acidic impurity combinations. While MFL is highly effective for volumetric metal-loss detection, its capability for direct crack detection and sizing is more limited compared with crack-focused ultrasonic or EMAT tools. In dense-phase CO_2 service, MFL tools must still be qualified for high pressure, potential low-temperature transients and compatibility of tool materials with CO_2 and impurities, but the underlying detection principle is not fundamentally altered by the transported fluid.

5.11.4 Electromagnetic acoustic transducer (EMAT)

EMAT technology generates ultrasonic waves within the pipe wall using electromagnetic interaction rather than requiring direct acoustic coupling through a liquid medium. This allows EMAT tools to operate in gas pipelines and in conditions where conventional UT coupling would be difficult. EMAT tools are commonly configured to detect and characterise crack-like features, including stress-corrosion cracking, seam-weld anomalies, and other planar defects. For dense-phase CO_2 pipelines, particularly where hydrogen or other impurities may increase susceptibility to environmentally assisted cracking, EMAT provides a valuable inspection modality focused on crack detection rather than volumetric metal loss. However, signal interpretation can be more complex than with conventional UT, and field verification through correlation digs and non-destructive examination is typically required to confirm defect characterisation.

5.11.5 Acoustic resonance technology (ART)

Acoustic Resonance Technology (ART) represents a distinct inspection approach that uses low-frequency acoustic resonance rather than high-frequency ultrasonic reflection. ART tools excite the pipe wall and analyse resonance patterns to infer wall thickness and detect anomalies. Because resonance-based measurements rely on global vibrational characteristics rather than point-by-point echo timing, ART can provide rapid coverage and is less sensitive to surface conditions compared with conventional UT. ART is typically focused on detecting and sizing general corrosion and wall thinning rather than detailed crack characterisation. In dense-phase CO_2 pipelines, ART may offer advantages for efficiently surveying long lengths for corrosion-related degradation, particularly when phase stability is maintained and internal cleanliness is controlled. However, as with other technologies, applications require consideration of the effects of pressure, temperature, and impurities on tool materials and of measurement repeatability.

5.11.6 Material selection for ILI tools for CO2 service

The presence of CO_2 in pipelines significantly influences material selection and pigging equipment design, primarily due to the requirement to maintain a dry operating environment. CO_2 pipelines must remain free of water to prevent the formation of carbonic acid, which is highly corrosive to both pipeline steel and pig components. As a result, pig materials must exhibit very low water absorption and must not introduce or retain moisture, effectively limiting the use of liquid-based pigging systems such as gel or batching pigs. This constraint drives the selection toward dry-compatible materials, such as low-absorption polyurethanes and elastomers, and requires careful control of operational practices.

In addition, the avoidance of liquid batching means that pigs must operate under dry gas conditions, placing greater demands on material performance. Without the benefit of liquid lubrication, pig components such as discs and cups must provide reliable sealing while also exhibiting high abrasion resistance and low friction characteristics. This typically leads to more robust construction, including thicker or harder elastomer components and the use of wear-resistant materials to ensure durability over longer runs. The need to minimise operational disruption further reinforces the preference for dry-running pigging systems and long-life materials.

Material selection must also consider the potential for corrosion, even with small amounts of water present. In such cases, carbonic acid can form and attack metallic components, necessitating the use of corrosion-resistant materials such as coated or stainless steels for mandrels, springs, and brush elements. Non-metallic materials must likewise be compatible with occasional exposure to acidic conditions. Furthermore, the behaviour of dense-phase CO_2, including significant pressure-induced density changes, introduces additional mechanical challenges. Pig materials and construction must therefore accommodate variable drag forces and pressure cycling, requiring dimensional stability, fatigue resistance, and the ability to maintain sealing performance under changing conditions.

A further important consideration is the very low temperatures that can be experienced during pig trap depressurisation or blowdown. Rapid expansion of CO_2 can result in significant Joule–Thomson cooling, potentially reaching sub-zero or even cryogenic temperatures. This imposes additional constraints on material selection, as elastomers and polymers used in pig components must retain flexibility and toughness at low temperatures and avoid embrittlement or cracking. Similarly, metallic components must be suitable for low-temperature service to prevent brittle fracture. These conditions can also affect seals and interfaces, increasing the risk of leakage or mechanical damage if inappropriate materials are used. Finally, the potential presence of small amounts of hydrogen in CO_2 streams introduces an additional consideration for material integrity, particularly for metallic components that may be susceptible to hydrogen-related degradation mechanisms. Overall, CO_2 service conditions necessitate a shift toward dry-compatible, corrosion-resistant, and mechanically robust pig designs, capable of withstanding both demanding mechanical conditions and transient low-temperature events, with material selection playing a critical role in ensuring reliable performance and maintaining pipeline integrity.

5.11.7 TRL assessment

Inspection technology status is inseparable from operational capability. High-pressure CO_2 systems require pigging and ILI operating procedures that control pressure/temperature transients and avoid two-phase conditions during runs, maintenance readiness for pig traps, valves, and launcher/receiver systems (seal management, venting/drain systems, instrumentation calibration), intervention planning for stuck tools (retrieval strategy, safe depressurisation sequencing, contingency spares, mobilisation plans for offshore/subsea systems), data management controls: quality thresholds, reporting standards, anomaly confirmation process, and integration into a pipeline integrity management system. Where access is constrained (offshore/subsea), inspection feasibility and intervention logistics can become a principal driver of overall integrity strategy.

UT, MFL, EMAT and ART each address different defect classes and inspection objectives. For dense-phase CO_2 pipelines, UT provides high-accuracy metal-loss and crack sizing where stable single-phase conditions can be maintained; MFL offers robust baseline corrosion detection; EMAT targets crack-like features without reliance on liquid coupling; and ART provides an alternative resonance-based method for efficient wall-thickness assessment. Effective integrity management in CCS trunklines often involves a complementary deployment of these technologies, selected according to expected degradation mechanisms, operating envelope and impurity profile.

Metal-loss detection in dense-phase CO_2 pipelines, using MFL, UT wall thickness and ART, represents the most mature ILI function, with core metal-loss detection capability assessed at TRL 9 and application in dense-phase CO_2 trunklines at CCS scale assessed at TRL 8–9, the slight reduction reflecting limited long-term CCS operational datasets rather than any limitation in detection principles. Dent and deformation detection using geometry tools, MFL geometry combinations and UT geometry is fully mature and directly transferable, with dent detection in dense-phase CO_2 assessed at TRL 9, as the mechanical deformation detection principles and sizing reliability are unchanged, with only operational adaptations required. Crack detection using UT crack tools and EMAT is more complex; while the underlying technologies are mature in hydrocarbon service, validation in dense-phase CO_2 environments remains less developed, giving crack detection in dense-phase CO_2 without hydrogen a TRL of 7–8, and with hydrogen present a TRL of 6–7 due to limited hydrogen-in-CO_2 field data and smaller empirical growth-rate datasets. Tool survivability and system integration under high-pressure, low-temperature and impurity-variable CO_2 conditions are assessed at TRL 7–8, reflecting engineering adaptation and CCS-scale validation requirements. Overall, volumetric metal-loss detection is mature and transferable, dent detection is fully mature, and crack detection maturity is constrained primarily by system-level validation and data confidence rather than hardware capability.

5.12 Long-distance Subsea Tiebacks

5.12.1 UK Storage Geography and Tieback Distances

The most distant potential CO_2 sequestration sites on the UK Continental Shelf are generally located in the Northern North Sea and West of Shetland regions. These areas are substantially farther offshore than the early UK cluster projects in the Southern North Sea and East Irish Sea, which were prioritised in part due to their proximity to major industrial emitters and existing infrastructure.

For comparison, HyNet (Liverpool Bay CCS) storage sites are typically located approximately 20–40 km offshore. Viking CCS in the Southern North Sea lies approximately 120–150 km offshore, while the Northern Endurance Partnership (East Coast Cluster) is also in the range of 100–150 km offshore. Acorn CCS, targeting the Central North Sea, is located approximately 100 km from the Scottish coastline.

By contrast, several Central and Northern North Sea saline aquifers are situated between 150 and 250 km offshore, and West of Shetland fields may be located 200–300 km from the nearest landfall, depending on the specific licence area. These distances represent the upper bound of likely CO_2 transport requirements for UK CCS deployment.

At these scales, tieback length becomes a primary system design constraint, rather than a secondary consideration, influencing architecture selection, control philosophy, intervention strategy, and overall project risk.

5.12.2 Design Implications of Increasing Distance

Increasing offshore distance directly affects transmission system design. Longer tiebacks lead to larger pipeline inventories, greater hydraulic complexity, and higher capital expenditure. They may also drive the need for intermediate compression, boosting, or offshore hub facilities, depending on system configuration.

At distances approaching 300 km, the pipeline behaves as a high-inventory system, where any operational upset—such as trips, isolation events, or restarts requires the management of large CO_2 inventories, long pressure equalisation times, and careful control of the phase envelope. This is particularly important for dense-phase CO_2 systems with impurities, where pressure and temperature excursions can result in phase transition or solid formation.

Hydraulic and thermal performance become more sensitive to seabed temperature, elevation profile, and localised pressure losses. There is reduced tolerance for operating close to saturation conditions, as local cooling or pressure drops at valves or restrictions can lead to two-phase flow, hydrate or dry ice formation. Fracture control and blowdown philosophy also become more critical, as decompression behaviour and valve spacing directly influence consequence distances and restart complexity.

As offshore tieback distance increases, the dominant technical constraints and corresponding mitigation strategies evolve. At around 100 km, hydraulic behaviour is generally manageable within established design practice, and standard subsea configurations are typically sufficient. At approximately 200 km, control complexity and restart management become more significant, requiring more conservative operating margins, enhanced control strategies, and careful transient management. At distances approaching 300 km, umbilical performance, intervention capability, and overall system reliability become primary constraints, often driving the need for platform-based or hybrid architectures to maintain control responsiveness, enable intervention, and reduce operational risk.

5.12.3 Construction and Commissioning Considerations

From a construction perspective, long-distance subsea pipelines are well within the established capabilities of offshore engineering. Pipelines of approximately 300 km are routinely constructed in the oil and gas sector. However, increased length introduces logistical complexity, longer installation campaigns, and greater exposure to weather windows, thereby increasing programme risk.

The primary construction and commissioning challenges are associated with drying and moisture control over long distances. Demonstrating compliance with stringent water specifications across a large pipeline volume is technically demanding. In addition, commissioning must be carefully managed to avoid low-temperature excursions during venting or depressurisation, which could lead to hydrate or dry ice formation in localised regions, particularly at valves or restrictions.

5.12.4 Operability, Control and Reliability

From an operational perspective, long-distance CO_2 pipelines behave as slow, tightly coupled systems. Disturbances at one end of the pipeline propagate over extended timescales, and stable operation depends on careful management of linepack, backpressure, and compression or pumping setpoints. Control strategies must be designed to avoid operation near the phase boundary, particularly under transient conditions.

Instrumentation and monitoring systems are technically feasible; however, the limited accessibility of subsea infrastructure places increased reliance on robust, redundant measurement systems and well-tuned control logic. In multi-emitter networks, long export pipelines amplify the impact of flow variability and compositional changes, requiring stronger operating rules and often more conservative design margins.

Intervention and recovery also become more challenging at these scales. Faults typically require vessel mobilisation, and access may be delayed by weather conditions. Restart times are extended due to the large pipeline inventory and the need for controlled pressure equalisation. The system behaves as a high-inertia hydraulic system, where pressure and flow changes propagate slowly, requiring careful tuning of control logic and response dynamics.

While long subsea tiebacks are not unprecedented, the comparison with hydrocarbon systems highlights important differences. For example, Shell's Mensa development in the Gulf of Mexico achieved a subsea tieback of approximately 110 km, driven primarily by reservoir pressure and involving relatively low liquid content (i.e. only mildly two-phase flow). In contrast, CO_2 pipelines are actively driven systems, where flow is determined by compression and pipeline design, but they must manage more complex phase behaviour and tighter operational constraints.

At distances approaching 300 km, control system architecture, intervention strategy, and restart philosophy become key design considerations. These challenges are manageable within established offshore engineering practice but require conservative design margins, robust control systems, and clearly defined operational procedures.

5.12.5 Control Umbilicals: Manufacture, Installation and Operation

Control umbilicals are a critical enabling system for long-distance subsea CO_2 tiebacks, providing hydraulic power, electrical supply, fibre-optic communications and chemical injection capability between the host facility (onshore or platform) and subsea valves, actuators and monitoring systems. For extended tiebacks in the 150–300 km range, umbilical design and performance become a key system-level constraint rather than a standard subsea component.

Umbilicals are complex, multi-core assemblies that combine steel tubes, electrical conductors, and fibre optics within a protective sheath. While manufacturing processes are mature (TRL 9) for conventional offshore applications, very long umbilicals introduce challenges in terms of continuous-length production, reel capacity, material handling, and quality assurance over extended lengths. Long-length umbilicals may require factory joints, increasing complexity and potential reliability considerations. Material selection must also account for CO_2-specific service risks, including low-temperature exposure during blowdown and compatibility with injected chemicals.

Installation of long umbilicals is well-established in subsea developments but becomes more demanding as length increases. Key challenges include vessel capacity, lay tension control, routing alongside pipelines, seabed interaction, and protection against damage. Installation campaigns are sensitive to weather windows and can become critical path activities for project delivery. For very long tiebacks, the installation strategy must also consider segmentation, jointing offshore, and integration with subsea structures, increasing execution risk relative to shorter systems.

Operationally, long-distance umbilicals impose constraints on signal transmission, power delivery, and hydraulic response times. Electrical and fibre-optic systems are generally scalable to long distances, although redundancy and fault tolerance become increasingly important. Hydraulic control systems, however, may experience pressure losses, slower actuation, and reduced efficiency over long distances, particularly when multiple subsea valves must be operated reliably, leading to slower valve response times and challenges in achieving rapid or coordinated isolation over long distances. This has direct implications for emergency shutdown philosophy and isolation times in safety-critical scenarios.

For CO_2 systems, these challenges are compounded by the need for high reliability and limited intervention, particularly in fully subsea configurations where access is restricted. Umbilical failure or degradation can directly affect the ability to isolate, control or safely depressurise the pipeline, making redundancy, monitoring and fault detection essential design considerations.

At distances approaching 200–300 km, umbilical performance and reliability can become a driver for system architecture selection, influencing the decision between fully subsea systems and platform-based solutions. Platform-based configurations can shorten umbilical lengths, improve control responsiveness, and enhance maintainability, albeit at higher cost and complexity.

5.12.6 All Electric Subsea Control Systems

An additional consideration for long-distance subsea CCS developments is the potential use of all-electric subsea control systems and electric trees as an alternative to conventional electro-hydraulic architectures. By replacing hydraulic actuation with electrically actuated valves and distributed control electronics, these systems can reduce or eliminate many of the limitations associated with extended tiebacks, including hydraulic pressure losses, slow actuation response, and large-volume control-fluid systems. They also offer the potential for improved diagnostics, enhanced condition monitoring, reduced umbilical complexity and faster response times over long distances.

However, while electric tree technology has advanced significantly within the offshore oil and gas sector, its operational track record remains relatively limited compared with conventional electro-hydraulic systems, particularly for long-duration service and safety-critical isolation functions. Furthermore, the adoption of electric trees introduces a different set of integration challenges, including power distribution, redundancy, cybersecurity, qualification of subsea electronics and long-term reliability assurance.

Electric subsea tree technology is generally assessed at TRL 7–8, reflecting successful demonstration and early deployment in offshore applications. For long-distance CCS tiebacks in the range of 150–300 km, however, the overall maturity is more appropriately characterised as TRL 6–7, as system-level validation under representative CCS operating conditions remains limited. Consequently, electric trees should currently be regarded as a promising enabling technology that may help overcome some long-distance control constraints, rather than a fully established replacement for conventional subsea control architectures.

5.12.7 Technology Maturity (TRL Assessment)

Long-distance offshore CO_2 tiebacks of up to approximately 300 km are technically feasible using established offshore pipeline technology; however, at these distances, tieback length becomes a primary design and operability constraint rather than a secondary consideration. The principal challenges relate to system integration, control, intervention, and phase management, particularly for dense-phase, impurity-variable CO_2 systems. These factors drive more conservative design, influence architecture selection, and increase the importance of early validation of the full system operating envelope.

From a construction, materials and installation perspective, long-distance subsea pipelines are mature (TRL 8–9) and do not represent a fundamental barrier. At the integrated system level, however, a 300 km subsea dense-phase CO_2 tieback is more appropriately characterised as TRL 7–8. This reflects limited operational precedent for long-distance, impurity-variable CO_2 transport under dense-phase conditions, and the challenges of integrating hydraulics, phase behaviour, control systems, umbilicals, intervention strategies, and restart management at scale.

Conventional electro-hydraulic subsea control systems remain the most mature option and are generally assessed at TRL 8–9 at the component level. However, their application to very long tiebacks is increasingly constrained by hydraulic response times, pressure losses, power delivery limitations and overall system complexity. As a result, the effective maturity of integrated long-distance electro-hydraulic control systems is more appropriately characterised at TRL 7–8, and in some cases TRL 6–7, where tieback distances approach the upper end of the anticipated UK CCS range.

All-electric subsea control systems and electric trees offer a potential means of overcoming some of these limitations by reducing dependence on hydraulic actuation and simplifying umbilical architectures. Individual electrical components, including actuators, sensors, communications systems and subsea electronics, are generally mature and have been successfully demonstrated in offshore oil and gas applications. Electric tree technology is therefore typically assessed at TRL 7–8. However, the application of fully electric architectures to long-distance CCS tiebacks remains less mature, with limited operational experience and a continuing requirement for system-level validation of reliability, redundancy, cybersecurity, power distribution and safety-critical isolation functions. Consequently, their application to long-distance CCS developments is more appropriately characterised at TRL 6–7.

A platform-based architecture can increase overall system maturity toward the upper end of these ranges by improving access, control, responsiveness, intervention capability and maintainability. A fully subsea configuration at these distances remains feasible but represents the upper boundary of current integration maturity rather than routine, fully de-risked practice.

At the longest tieback distances, the preferred architecture may increasingly depend on a balance among conventional electro-hydraulic systems, emerging all-electric control systems, and intermediate facilities to maintain operability and reliability. The selection of control architecture is therefore becoming a key system-level design decision rather than a secondary equipment choice.

Accordingly, tieback length is not simply a routing parameter but a primary determinant of system architecture, control philosophy, operability and overall project risk in UK CCS developments.

5.13 Platforms vs Subsea

CO_2 export pipelines connecting onshore emitters to offshore storage may terminate either at an offshore platform (fixed or floating) or at a fully subsea tie-in arrangement, such as a subsea manifold, wellhead, or template. The choice materially affects operability, inspection access, intervention philosophy, maintenance logistics, manning, and long-term integrity management.

Platform tie-ins provide surface access for pigging, isolation, instrumentation, maintenance, heating, and pressure boosting before flow passes via the wellhead and tubing to the reservoir. Well tubing would generally be fitted with a Down Hole Safety Valve (DHSV). Subsea tie-ins reduce surface infrastructure and offshore manning requirements, but rely more heavily on remote actuation, subsea controls, umbilicals, and vessel-based intervention.

5.13.1 Offshore Safety Case Requirements

All offshore CO_2 transport and storage developments on the UK Continental Shelf involving pipelines connected to offshore installations fall within the UK offshore major accident hazard regime. This is governed principally by the Offshore Installations (Safety Case) Regulations 2015 (SCR2015), supported by the Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995 (PFEER) and relevant provisions of the Pipeline Safety Regulations 1996 (PSR). Although CO_2 is non-flammable, PFEER remains relevant because it applies more broadly to major accident hazards on offshore installations, including hazardous releases and emergency response, rather than only to flammable fluids.

Duty holders are required to prepare and submit a Safety Case to the Health and Safety Executive (HSE) for acceptance before operations commence. The Safety Case must demonstrate that credible major accident hazards have been identified, assessed, and controlled, and that risks have been reduced to As Low As Reasonably Practicable (ALARP).

For CO_2 systems, this includes consideration of hazards such as asphyxiation, low-temperature effects arising from Joule–Thomson cooling and phase change, high-momentum releases, impurity-driven corrosion, and the behaviour of dense-phase CO_2 during depressurisation and blowdown. It must also demonstrate that the overall design philosophy, including isolation, control, monitoring, verification, and emergency response arrangements, is appropriate for the identified hazards.

Accordingly, Safety Case requirements directly influence the choice between platform and subsea configurations, particularly regarding manning, inventory isolation, structural escalation risk, intervention strategy, and control system design.

From a technology readiness perspective, the offshore Safety Case process, ALARP methodology, major accident hazard assessment, and associated regulatory framework are fully mature and are therefore assessed at TRL 9. However, the application of these established processes to large-scale dense-phase CO_2 transport and storage systems is more appropriately characterised at TRL 7–8, reflecting ongoing development of the evidence base for CO_2-specific consequence modelling, dispersion behaviour, decompression effects, and system-level validation under representative CCS operating conditions.

5.13.2 Pigging Facilities

The principal distinction for pigging is accessibility. Platform installations allow conventional pig traps to be accessed for inspection, cleaning, batching, gauging, and intelligent pigging, as well as for direct visual inspection, manual valve operation, and comparatively straightforward retrieval of stuck pigs. Routine maintenance of traps, seals, and valves can be carried out without marine intervention, which improves inspection readiness and operational flexibility.

Subsea tie-ins reduce surface infrastructure requirements and can avoid permanent offshore manning, but pigging becomes more operationally complex. Where pig traps are located subsea, loading, launching, retrieval, and recovery depend on hydraulic or electric actuation, subsea control systems, umbilicals, and ROV-assisted intervention. Recovery from a stuck pig is inherently more constrained, and intervention is subject to vessel availability and weather windows.

In dense-phase CO_2 service, subsea pigging introduces additional technical considerations. These include the potential for dry ice or hydrate formation during depressurisation, thermal shock to subsea components, impurity-driven corrosion in trap cavities, and reduced ability to manually clear blockages. These factors do not render subsea pigging infeasible, but they increase system integration and operability demands relative to platform-based systems.

Platform pigging systems are assessed as TRL 9. They are long-established in offshore high-pressure service, and their application to dense-phase CO_2 does not introduce fundamental technology uncertainty. Subsea pig trap systems are generally TRL 8–9 in offshore hydrocarbon service, but subsea pigging in dense-phase CO_2 with realistic impurity envelopes is more appropriately assessed at TRL 6–7, reflecting more limited system-level validation under CO_2-specific transient, thermal, and corrosion conditions.

5.13.3 Controls and Monitoring

The key difference in controls and monitoring is direct access versus remote dependence. Platforms allow installation of direct-access instrumentation, redundant pressure and temperature transmitters, real-time composition monitoring, local control panels, safety shutdown systems, and manual override capability. This supports active monitoring and rapid response to composition excursions or pressure instability.

Subsea systems rely on subsea control modules, hydraulic or electric actuation, fibre-optic or multiplexed umbilical communications, remote leak detection, mass-balance systems, and automated isolation logic. While these systems are well established, failures may require vessel mobilisation and intervention, increasing the likelihood and duration of downtime.

For CO_2 service, subsea control hardware must also be shown to tolerate rapid depressurisation, low-temperature transients, CO_2 exposure, and impurity-related degradation of seals, elastomers, and localised wetted components.

Platform-based monitoring and control systems are assessed at TRL 9 in both conventional offshore service and dense-phase CO_2 applications. Subsea control systems are likewise TRL 9 in general hydrocarbon service. However, where these systems are applied to dense-phase CO_2 trunklines with rapid depressurisation, cryogenic transient effects, and impurity-related corrosion risks, the overall system integration is more appropriately assessed at TRL 7–8.

5.13.4 Intervention and Maintenance

The main consequence of the architecture choice is the difference in intervention logistics and outage duration. Platform-based systems support routine valve inspection and refurbishment, pig trap seal replacement, instrument recalibration, inspection of corrosion-prone cavities, and manual drain and vent operations with relatively straightforward access. Intervention times are shorter, and downtime is generally lower.

Subsea intervention typically requires ROV or light intervention vessel mobilisation, specialist tooling, depressurisation and isolation procedures, and environmental assessment prior to blowdown. Maintenance intervals may be extended due to logistics and cost constraints, and unplanned failures in subsea pig traps, valves, or control modules can lead to prolonged outages caused by mobilisation delays and weather constraints.

As a result, subsea configurations place greater emphasis on predictive maintenance, high-integrity condition monitoring, digital modelling of pressure and corrosion risks, and early-warning diagnostics. There is also increasing interest in the use of Unmanned Surface Vessel (USV) which are remotely operated or uncrewed surface vessels to support offshore inspection and basic intervention activities, which may reduce intervention cost over time, but does not remove reliance on remote recovery methods.

5.13.5 Intermediate Platforms

Intermediate platforms between an onshore trunkline and an offshore storage site are not the default configuration for CO_2 transport, but may be justified where hydraulic, operational, or infrastructure constraints cannot be managed through a direct subsea tie-back.

One driver is the hydraulic management of very long tiebacks. Where offshore distance is substantial and pressure losses are high, intermediate boosting, heating, or flow conditioning may be required to maintain dense-phase conditions and avoid phase boundary crossing during steady-state or transient operation. This is more likely where impurity levels narrow the phase envelope or where reservoir backpressure fluctuates.

A second potential driver is storage architecture. Where multiple offshore storage sites are clustered, an intermediate hub platform could provide manifold, metering, flow-switching, blending, or monitoring functions at a single node. Flow metering is required to allocate ETS-relevant quantities among offshore storage sites, with traceability back to the primary custody-transfer measurement onshore.

A third case is repurposing. Where existing hydrocarbon infrastructure lies favourably along the route, a legacy platform may offer a practical location for pigging, metering, or flow control if re-use avoids significant new subsea fabrication and installation. In such cases, the attraction is often strategic rather than purely technical.

This may support phased development, although many of these functions can be delivered using subsea manifolds and templates, avoiding the need for permanent surface infrastructure. However, the addition of an intermediate manned platform introduces additional Safety Case obligations, including inventory isolation, escalation risks under CO_2 release scenarios, evacuation arrangements, and potentially the need for subsea isolation valves. Even for normally unattended installations, robust remote isolation and control must be demonstrated.

In practice, intermediate platforms are expected to remain the exception rather than the norm in most UK CCS trunkline-to-storage developments. They are most likely justified by extreme tieback distances, network hub requirements, or favourable legacy infrastructure.

5.13.6 Integrity and Risk Considerations

Subsea configurations reduce permanent offshore manning and remove surface structures, thereby lowering personnel exposure to major accident hazards and reducing visual and navigational impact. In that sense, they offer clear advantages in terms of societal and occupational risk.

These advantages are offset by greater dependence on remote systems for inspection, control, and recovery. Compared with platform-based systems, subsea arrangements rely more heavily on subsea control modules, actuation systems, umbilicals, communications links, and vessel-based intervention. Failures are therefore generally slower and more costly to diagnose and recover, with mobilisation delays and weather windows often dominating outage duration.

The result is a shift in risk profile rather than a simple increase or decrease in risk. Platform-based systems concentrate equipment and personnel at an accessible surface location, making intervention easier but increasing exposure to manned-installation hazards. Subsea systems reduce direct exposure but place greater weight on remote operability, recovery resilience, materials qualification, and predictive monitoring.

Accordingly, subsea configurations require a design philosophy that emphasises redundancy, validated transient modelling, robust material selection, and reliable condition-monitoring systems to maintain integrity throughout the asset's life.

5.13.7 Subsea Isolation Valves (SSIV)

A Subsea Isolation Valve (SSIV) is a remotely operated pipeline valve installed on the seabed, typically near a platform or riser base, to isolate a pipeline in an emergency. In CO_2 service, its relevance depends mainly on whether the pipeline connects to a manned or normally attended offshore installation.

Dense-phase CO_2 does not present a flammability hazard, but a high-pressure release can create asphyxiation risk, high jet momentum, and severe low-temperature effects. Where a CO_2 export or import line connects to a manned platform, the offshore regulatory framework is likely to require explicit consideration of whether pipeline inventory should be limited by an SSIV or equivalent arrangement. Even for a Normally Unmanned Installation (NUI), regulators would still expect a demonstration that significant inventory can be isolated following structural damage or vessel impact.

In fully subsea tie-back systems without a manned installation, the isolation philosophy may instead rely on in-line block valves along the trunkline rather than on an SSIV at the riser base. The design requirement is therefore not CO_2-specific legislation as such, but the broader expectation under the Safety Case regime that major accident hazards and escalation pathways are appropriately controlled.

SSIVs cannot be assumed to be perfectly leak-tight, and a small amount of leakage across a closed valve is normal in design terms. In CO_2 service, this may cause localised Joule–Thomson cooling downstream of the valve. In practice, expected leakage rates are very small and the associated cooling effects are generally limited and localised. These effects are normally addressed through material selection, low-temperature design qualification, and confirmation that more severe depressurisation and blowdown cases bound the thermal conditions.

Where necessary, additional mitigation may include tighter shut-off classes, double isolation or bleed arrangements, and inspection and maintenance measures to maintain valve performance.

SSIV hardware and control systems are assessed as TRL 9. Their use in dense-phase CO_2 service does not introduce fundamental technology uncertainty, although material compatibility, decompression effects, and low-temperature tolerance remain project-specific design considerations.

5.13.8 Platform Structural Integrity

A large-diameter dense-phase CO_2 riser rupture at or near a manned platform is physically credible in principle, although it represents a low-probability, high-consequence scenario whose severity depends strongly on configuration and design. Rapid depressurisation of dense-phase CO_2 can produce significant Joule–Thomson cooling, phase-change effects, and potentially very low local temperatures, along with a dense, high-momentum jet capable of mechanical loading and local erosion.

If structural members not qualified for the resulting temperatures were exposed while under stress, brittle fracture could, in principle, initiate. However, modern offshore platforms are generally designed with accidental load cases in mind, incorporate structural redundancy and progressive collapse resistance, and typically use steels with suitable low-temperature performance in critical areas. Catastrophic collapse resulting solely from CO_2 impingement would therefore be unlikely in a modern installation, though the issue may merit closer scrutiny for older or repurposed assets.

From a regulatory perspective, this scenario is relevant not because collapse is expected, but because the Safety Case must demonstrate that escalation risks have been assessed and reduced to ALARP. For a high-pressure CO_2 riser connected to a manned platform, this would typically include assessments of low-temperature effects, structural response, release duration, and inventory limitations.

Mitigation measures may include structural shielding, riser guards or deflectors, specification of low-temperature-qualified steels in potential impingement zones, transient modelling to predict minimum metal temperatures, careful riser routing away from critical structural nodes, and segmentation of line inventory through block valves or SSIVs. The role of SSIVs in limiting release duration and escalation potential should therefore be considered as part of the overall isolation philosophy, as discussed in Section 5.12.7.

5.13.9 Strategic Trade-Off

The choice between platform and subsea architecture is not simply a technical preference, but a broader trade between accessibility and remote dependence, with implications for cost, regulation, operability, and risk allocation.

Platform tie-ins support an intervention-led integrity model. They provide easier access for pigging, inspection, monitoring, maintenance, and fault recovery, thereby making operational assurance easier to demonstrate. They are particularly attractive where frequent inspection is required, where impurity variability increases the need for intervention, or where suitable legacy infrastructure can be repurposed. Their disadvantages include higher CAPEX and fixed OPEX, topsides and structural constraints, increased exposure to offshore manning, and greater Safety Case complexity for manned installations.

Subsea architectures support a reliability-led integrity model. They reduce surface footprint, avoid permanent offshore manning, and remove many platform-related escalation concerns. They are therefore well-suited to new offshore storage developments where no legacy platform exists and where minimising visible surface infrastructure is a project objective. Their disadvantages are greater dependence on subsea controls, remote diagnostics, vessel mobilisation, and recovery planning, with a corresponding increase in outage uncertainty and a stronger reliance on validated materials performance and predictive monitoring.

From a regulatory perspective, platforms tend to make assurance easier to evidence but harder to justify in major accident terms, whereas subsea systems reduce direct manned hazard exposure but require stronger justification of remote integrity assurance and recovery capability. Where a manned platform is retained or repurposed, this is likely to reinforce the case for a strong isolation philosophy, including consideration of SSIVs, not because CO_2 is flammable, but because release duration, low-temperature effects, and asphyxiation consequences must be shown to be controlled to ALARP.

Commercially, the decision can be understood as a CAPEX-OPEX and risk-transfer choice. Platforms generally have higher upfront and fixed operating costs but allow faster inspection and recovery. Subsea systems may reduce visible surface infrastructure cost and routine manning burden but can increase the probabilistic cost of failures because repair times depend more heavily on logistics, vessel availability, and weather.

Overall, the preferred solution is context-specific. The choice should be framed against the impurity envelope, the required inspection frequency, the manning philosophy, the availability targets, the repurposing opportunities, the hydraulic constraints, and the regulator’s expectations for credible isolation and escalation prevention.

5.14 Safety, Risk & Environmental Management

5.14.1 Dense Phase vs. Gas Phase

Dense-phase CO_2 presents a different safety profile than gas-phase CO_2 due to its higher density and stored energy. In dense phase (typically at high pressure and moderate temperature), CO_2 behaves more like a liquid, meaning a release can result in rapid decompression, formation of solid CO_2 (dry ice), and very low temperatures. This can cause material embrittlement, cold burns, and ductile fracture in pipelines. Additionally, CO_2's heavier-than-air nature means it can accumulate in low-lying areas, increasing the risk of asphyxiation. In contrast, gas phase CO_2 releases tend to disperse more readily, reducing the likelihood of prolonged accumulation, although asphyxiation remains a hazard in confined or poorly ventilated spaces. Overall, dense phase systems require more stringent controls on pressure containment, fracture propagation, and emergency depressurisation than gas phase systems.

5.14.2 Hazardous properties of CO_2

Carbon dioxide is widely used and is not flammable, but at elevated concentrations, it poses a significant hazard due to its toxicity and potential to cause asphyxiation. HSE notes that CO_2 has long been recognised as a workplace hazard and that, at CCS scale, it can become a Major Accident Hazard because of the very large inventories involved.

The main hazardous properties relevant to CCS are that CO_2 is denser than air and can accumulate in low-lying areas, it can exist as a dense-phase fluid (liquid-like or supercritical) at high pressure, and its harmful effects depend on both concentration and exposure duration. HSE also emphasises that CO_2 can become life-threatening at concentrations where oxygen displacement alone does not fully explain the severity of effects, reflecting its direct toxicological impact at higher concentrations.

Physiologically, CO_2 affects the body by driving respiratory acidosis and impairing cardiovascular and central nervous system function. HSE highlights that effects escalate quickly with concentration. Around 3% (30,000 ppm) can cause headache after about an hour, while above roughly 7% people become particularly sensitive and relatively small increases can rapidly shift outcomes from distress to loss of consciousness and death. HSE also notes that the concentration difference between outcomes associated with 1–5% lethality and 50% lethality is relatively small, meaning the transition from serious harm to widespread fatality can occur over a narrow concentration range.

For routine occupational exposure, HSE workplace limits under EH40 set a long-term Workplace Exposure Limit (WEL) of 5,000 ppm (0.5%) and a short-term (15-minute) limit of 15,000 ppm (1.5%). These are designed to prevent adverse physiological effects in normal work and sit far below major accident hazard levels, which is why CO_2 monitoring and ventilation controls are particularly important in confined or poorly ventilated locations where concentrations can rise quickly.

For major accident assessment and land-use planning, HSE does not rely on a single concentration threshold. Instead, it uses the concept of Dangerous Toxic Load, which combines concentration with exposure duration, reflecting that harm depends on how much CO_2 is inhaled and for how long. Within this approach, HSE defines two key endpoints: the SLOT, associated with severe distress for almost everyone exposed, a substantial fraction of whom require medical attention, and a possible lethality of 1–5%; and the SLOD, defined as 50% lethality from a single exposure over a known time period. HSE provides time-dependent SLOT and SLOD values, illustrating that at high concentrations, the margin between serious harm and mass fatality is relatively narrow.

Regulators expect these endpoints to be used in a structured way. Workplace compliance is managed against the WELs, while major accident risk assessment relies on QRA that combines failure frequency with consequence modelling and uses SLOT and SLOD to determine hazard distances. Those hazard distances inform land-use planning through consultation distances, and they also feed Safety Case demonstrations offshore and onshore, where operators must show that major accident hazards are identified, escalation is prevented or mitigated, and risks are reduced ALARP. HSE's analysis indicates that large CO_2 inventories can generate hazardous distances from tens to hundreds of metres depending on inventory, temperature and weather conditions, with colder releases generally producing larger hazard ranges, and it concludes that CCS-scale CO_2 inventories can constitute a Major Accident Hazard requiring appropriate regulatory control.

Beyond inhalation toxicity, HSE also flags additional hazards associated with dense-phase CO_2 releases, including cryogenic burns, pipe embrittlement and structural cooling, dry ice formation, and "grit blasting" type effects. These are particularly relevant for blowdown, vessel rupture and pipeline release scenarios where rapid depressurisation can create very low temperatures and multiphase conditions.

Overall, the regulatory framing is that CO_2 is relatively benign at low concentrations but becomes highly dangerous above around 7%, that harm is governed by toxic load rather than concentration alone, and that SLOT and SLOD provide the benchmarks for major hazard assessment and land-use planning. Workplace limits protect routine operations, but at the CCS scale, the combination of large inventories and dense-phase behaviour means CO_2 can credibly present major accident hazards that must be assessed and managed through formal risk assessment, safety case arguments and proportionate regulatory controls[125].

5.14.3 Transient overpressure

When a dense-phase CO_2 pipeline ruptures, the internal high pressure is released almost instantaneously at the breach. This produces two distinct but related phenomena: an internal decompression wave and an external pressure wave associated with the rapid expansion of the escaping fluid into the surrounding atmosphere. The mechanism differs from hydrocarbon explosions because the driving force is stored mechanical energy from compressed fluid rather than combustion.

Externally, the sudden release generates a high-velocity jet and a transient overpressure pulse close to the rupture. For dense-phase CO_2, the expansion involves strong JT cooling and phase change. The decompression path may cross the two-phase region, producing a sustained pressure plateau that influences crack propagation, but it does not produce the flame acceleration or detonation observed in natural gas vapour cloud explosions. Therefore, while a localised mechanical overpressure is generated at the rupture site, there is no secondary combustion-driven blast amplification.

Overpressure is evaluated using source term modelling and blast calculations. The key parameters include pipeline pressure, diameter, wall thickness, rupture geometry and inventory between isolation valves. Modelling tools estimate the peak overpressure and impulse near the rupture, typically expressed in bar or kPa, and compare these values to established damage thresholds for people and structures. For dense-phase CO_2, predicted overpressures decrease rapidly with distance and are generally limited to the immediate vicinity of the rupture. Unlike natural gas explosions, there is no large flammable cloud ignition event that would generate widespread blast loading.

In terms of human effects, mechanical overpressure can cause injury if sufficiently high. Typical thresholds indicate that eardrum rupture may occur around 35 kPa (0.35 bar) and more severe lung damage at higher levels. However, CO_2 pipeline rupture overpressures tend to fall below these thresholds at relatively short distances from the rupture. The more significant human hazard is usually not the blast itself but the subsequent formation of a dense, ground-hugging CO_2 cloud that can displace oxygen and produce toxicological effects. Therefore, the inhalation hazard generally dominates risk contours beyond the immediate rupture zone.

For buildings and structures, transient mechanical loading from a CO_2 rupture may cause minor damage very close to the rupture, such as shattered windows or cladding damage, depending on the distance and orientation. Structural collapse from overpressure alone would be unlikely except at very close proximity. Again, this contrasts with natural gas pipelines, where delayed ignition of a vapour cloud can produce much larger blast waves capable of significant structural damage over wider areas.

Compared with natural gas, dense-phase CO_2 rupture scenarios are characterised by lower blast-escalation potential but higher asphyxiation and toxic-load potential. Natural gas hazards are dominated by flammability, whereas CO_2 hazards are dominated by toxicological exposure and gravity-driven dispersion. In dense-phase CO_2 service, the mechanical pressure wave is important for fracture

[125] HSE. Major hazard potential of CCS. Available: [Major hazard potential of CCS - HSE] [Accessed 02 March 2026].

propagation assessment and local structural impact, but the primary public risk driver in QRA is typically inhalation rather than blast.

In summary, a dense-phase CO_2 pipeline rupture produces a transient mechanical overpressure due to rapid decompression, but without combustion amplification, the blast hazard is generally localised. The dominant off-site hazard is the formation and dispersion of a cold, dense CO_2 cloud capable of causing asphyxiation or toxicological harm, which typically governs land-use planning and emergency response considerations. In contrast, a gas-phase CO_2 pipeline rupture typically results in a lower initial overpressure and less pronounced decompression cooling, as no phase change occurs and the stored energy is lower. The released gas is still denser than air under most ambient conditions and can accumulate in low-lying or poorly ventilated areas, but it generally disperses more readily and over shorter distances than a dense-phase release. Consequently, while asphyxiation remains the principal hazard for gas-phase systems, the extent and persistence of hazardous concentrations are usually reduced, and the associated safety considerations are more focused on ventilation, detection, and confined space risks rather than large-scale dispersion and fracture-related effects.

5.14.4 Subsea releases

Subsea CO_2 release modelling introduces a different but equally nuanced set of consequence behaviours compared with onshore dispersion. When dense-phase CO_2 is released underwater, the immediate behaviour is governed by high-pressure jet expansion, rapid cooling, phase transition and buoyant plume formation within a denser surrounding medium. Unlike atmospheric releases, where CO_2 is heavier than air and tends to slump, subsea releases typically form a rising gas or multiphase plume because CO_2 is less dense than seawater once in gaseous form. However, the behaviour is highly sensitive to temperature, pressure, water depth and impurity composition.

At depth, hydrostatic pressure influences phase behaviour and bubble size distribution. A deepwater release may initially produce liquid CO_2 droplets or solid CO_2 particles, depending on temperature and pressure conditions, but in all cases, even at 3000m, the CO_2 is less dense than the surrounding water. As the plume rises, decreasing hydrostatic pressure causes further expansion, potential phase change and accelerated bubble growth. This affects plume velocity, seawater entrainment, dissolution rates, and eventual surface breakthrough. Lower water temperatures increase gas solubility and may initially reduce plume buoyancy, while also influencing the potential for hydrate or solid formation. The depth of release is therefore critical: shallow releases are more likely to reach the surface quickly and form a hazardous gas cloud; deep releases may experience greater dissolution and dispersion before surfacing, though large inventories can still break through with significant mass.

The consequences for floating surface vessels and platform occupants depend on whether the plume reaches the surface in sufficient concentration to create an asphyxiation hazard. CO_2 emerging at the surface can accumulate in depressions on deck, in enclosed modules, or in temporary refuges, particularly under low-wind conditions. While CO_2 is not flammable, high concentrations can impair visibility and reduce oxygen levels, posing a risk to personnel during evacuation or emergency response. For floating vessels, dynamic positioning systems, ventilation intakes and enclosed machinery spaces may be affected if gas is drawn into air systems. On fixed platforms, surface breakthrough may produce a cold, dense cloud that can pool in sheltered areas. However, unlike hydrocarbon releases, subsea CO_2 releases do not pose a jet-fire or explosion-escalation risk.

Modelling subsea releases requires coupling of multiphase flow, bubble dynamics, dissolution kinetics and surface dispersion. Simplified integral plume models can provide screening-level estimates of rise height and surface concentration, but accurate prediction of plume behaviour in stratified or current-influenced waters often requires computational fluid dynamics (CFD) or specialised plume models incorporating mass transfer and phase change. Surface dispersion modelling must then consider atmospheric stability and platform geometry, similar to onshore modelling but with the added uncertainty of plume breakthrough conditions. Water depth, temperature gradients, salinity and current shear can materially influence results.

The TRL for undertaking subsea CO_2 consequence assessment can be characterised as follows. The underlying plume modelling and multiphase CFD techniques are mature in oil and gas blowout and gas release assessment, typically TRL 8–9. However, dense-phase CO_2-specific validation datasets are more limited, particularly for very large-scale releases and mixed impurity compositions. Integration of underwater plume modelling with validated surface breakthrough and atmospheric dispersion for CCS-scale inventories is therefore more appropriately assessed at TRL 7–8. The tools exist and are technically robust, but full empirical validation for large dense-phase CO_2 releases under varied depth and temperature conditions remains comparatively limited.

5.14.5 Failure frequency (probability)

QRA depends critically on credible failure-frequency data to estimate the likelihood of hazardous events and, when combined with consequence modelling, to derive individual and societal risk metrics. For pipelines and associated components such as valves, flanges, pig traps, compressors, and isolation systems, these data inform assumptions about rupture, leak, and small-hole frequencies; event and fault-tree probabilities; escalation modelling, including crack propagation; assessment of mitigation barrier effectiveness; and optimisation of integrity management and inspection intervals. Without defensible failure-rate inputs, QRA becomes largely sensitivity-driven rather than evidence-based.

For high-pressure CO_2 transport systems, the need for reliable failure data is heightened because dense-phase CO_2 behaves differently from methane on release, including gravity-driven dispersion and phase-change effects. Impurities such as hydrogen, hydrogen sulphide and water may introduce additional degradation mechanisms, running ductile fracture behaviour differs from natural gas, and toxicity may be influenced by non-CO_2 components. Failure frequency assumptions must therefore reflect not only mechanical integrity but also thermodynamic and compositional complexity.

In practice, CO_2 pipeline QRA draws on a range of surrogate datasets, including natural gas transmission databases such as EGIG, PHMSA, and UK HSE statistics, oil pipeline performance data, US EOR CO_2 pipeline experience, generic component reliability databases such as OREDA and DNV, and any available project-specific operational information. However, the transferability of these data to dense-phase CO_2 service is limited. Natural gas datasets do not capture CO_2-specific decompression behaviour or impurity-driven corrosion mechanisms; the global installed base of long-distance dense-phase CO_2 pipelines remains relatively small, limiting statistical confidence; operating envelopes and wall thicknesses may differ materially; and impurity-related degradation mechanisms, particularly hydrogen-assisted cracking, are rarely disaggregated in legacy datasets. Component-level data similarly may not reflect CO_2-induced elastomer swelling, rapid decompression effects or subsea pig trap configurations.

These limitations are significant because QRA outcomes are sensitive to failure frequency inputs. Sparse or non-representative datasets widen uncertainty bounds and can bias results, potentially leading to over-conservative land-use restrictions or, conversely, underestimation of public risk. Regulators typically expect clear justification when surrogate datasets are used, and explicit recognition of transfer limitations is essential to a defensible assessment.

Accordingly, good practice for CO_2 pipeline QRA includes transparent use of surrogate methane data with documented adjustment factors, sensitivity analysis across credible failure-rate ranges, explicit modelling of fracture propagation scenarios, inclusion of impurity-specific threat mechanisms within integrity assessment, conservative bounding cases where hydrogen is present, and periodic updating of assumptions as CCS operational data accumulate. While natural gas experience provides a starting point, it is not a perfect proxy for dense-phase CO_2. As CCS networks expand, systematic collection and publication of CO_2-specific failure data will be essential to narrow uncertainty, improve integrity management, support proportionate land-use planning decisions and strengthen public confidence in the safety of CO_2 infrastructure.

5.14.6 CO_2 dispersion modelling (consequences)

Accurate dispersion modelling is critical in the design and regulation of CO_2 transport systems because dense CO_2 releases behave very differently from lighter-than-air gases. Historical incidents such as Nyos

(Cameroon, 1986)[126] and Satartia (Mississippi, 2020)[127] demonstrate the consequences of poorly understood or inadequately predicted dispersion. At Nyos, a large CO_2 release accumulated in low-lying terrain, displacing oxygen and causing widespread fatalities. At Satartia, a dense CO_2 cloud from a pipeline rupture travelled along topography and settled in depressions, leading to hospitalisations and emergency response challenges. Both incidents highlight that CO_2 is colourless, odourless, and heavier than air under release conditions, and that its dispersion behaviour is strongly influenced by terrain, atmospheric stability, and phase-change effects. For CCS networks, robust dispersion modelling underpins safety case development, emergency planning zones, hazardous area classification, and public risk assessments.

Modelling heavier-than-air gases presents specific challenges. Unlike buoyant gases, dense CO_2 clouds can slump, pool, channel along valleys, and persist in stagnant atmospheric conditions. Rapid depressurisation can also create complex multi-phase jets, including flashing liquid, dry ice formation, and strong evaporative cooling, all of which affect initial plume dynamics. Simplified consequence tools such as DNV PHAST use integral and semi-empirical models that are efficient for screening studies and regulatory submissions but may struggle to capture complex terrain interactions, building effects, transient wind shifts, and gravity-driven pooling behaviour in detail. CFD approaches provide much higher spatial resolution and can model terrain, obstacles and transient flow more realistically, but they require detailed input data, are computationally intensive, and remain sensitive to turbulence modelling assumptions, atmospheric stability parameters, and phase-change representation. Both approaches, therefore, involve trade-offs between practicality, conservatism and physical fidelity.

DNV's Project Skylark is particularly important in this context because it addresses the validation gap for large-scale dense CO_2 release modelling. Historically, most dispersion models were calibrated using lighter-than-air hydrocarbon data, with limited full-scale validation for dense-phase CO_2 releases. Project Skylark involves controlled large-scale CO_2 release trials to generate high-quality experimental data for model validation. This improves confidence in consequence modelling tools, supports refinement of dispersion correlations, and helps regulators and operators better understand how dense CO_2 behaves under realistic pipeline rupture scenarios. By strengthening the empirical basis for PHAST and CFD models, Skylark contributes directly to more reliable safety distances, emergency response planning, and risk quantification for CCS infrastructure.

Advanced CFD modelling TRL 8–9; impurity-modified dispersion validation TRL 7–8.

Ongoing large-scale validation programmes, including DNV's Project Skylark (see Section 5.19), are addressing these uncertainties by generating empirical datasets for dense-phase CO_2 release behaviour.

5.14.7 Block valves

Block valves play a critical role in CO_2 pipeline safety because they directly limit the inventory available for release in the event of a rupture or major leak. By dividing a long pipeline into shorter isolated segments, block valves reduce the maximum mass that can be discharged before isolation is achieved. In dense-phase CO_2 systems, where rapid depressurisation can generate large, ground-hugging clouds, limiting inventory significantly reduces potential dispersion distances, exposure duration, and environmental impact. In an accidental blowdown scenario, block valves allow operators to segregate the damaged section, preventing continued feed from upstream and downstream segments and protecting unaffected portions of the network. This limits both the scale of the release and the extent of pipeline damage, reducing repair scope, downtime, and long-term asset loss.

However, this benefit introduces a safety paradox. Every block valve is itself a mechanical assembly with flanges, seals, actuators and instrumentation, all of which create additional potential leak paths. Over the

[126] Tanyileke, G. et al. 30 years of the Lakes Nyos and Monoun gas disasters: A scientific, technological, institutional and social adventure. *Journal of African Earth Sciences*. Volume 150. 2019. Available: [30 years of the Lakes Nyos and Monoun gas disasters: A scientific, technological, institutional and social adventure - ScienceDirect] [Accessed 10 March 2026].
[127] Mathews, W.; Ruhl, C. (DOT, PHMSA, OPS). Failure Investigation Report – Denbury Guld Coast Pipelines LLC: Pipeline Rupture/Natural Force Damage. 2022. Available: [Failure Investigation Report - Denbury Gulf Coast Pipeline.pdf] [Accessed 10 March 2026].

pipeline's lifetime, the cumulative probability of small leaks increases with the number of fittings. While each individual valve reduces the consequences of a full-bore rupture, it marginally increases the probability of lower-rate releases. From a societal risk perspective, this creates a dichotomy: segmentation reduces high-consequence, low-frequency events (major ruptures with large inventories), but increases the number of components that could contribute to more frequent, smaller leaks. The design challenge, therefore, becomes one of optimisation: balancing valve spacing to reduce maximum credible release volumes without materially increasing overall leak frequency. This requires quantitative risk assessment, reliability analysis of valve systems, and consideration of inspection, maintenance and remote actuation reliability to ensure that the risk reduction from inventory limitation outweighs the incremental leak probability introduced by additional hardware.

Valves not designed for liquid CO_2 service can explode when trapped CO_2 warms and vaporises. Valves with vented interspaces, designed for CO_2 service, must be specified at the design stage.

5.14.8 Emergency response planning

Emergency response planning is a critical barrier in the risk management of MAHPs because it provides the structured, pre-agreed actions needed to minimise consequences to public health and safety in the event of a low-frequency, high-consequence pipeline emergency[128, 129]. UKOPA's MAHP, Emergency Response Plan, Guidance on Testing[128] links emergency planning directly to the Pipelines Safety Regulations (PSR) 1996, which place duties on pipeline operators to have emergency procedures (Regulation 24) and on Local Authorities to prepare emergency plans for MAHPs (Regulation 25)[128]. The same guidance emphasises that emergency plans must "dovetail" across operator arrangements and Local Authority plans to provide a comprehensive response, and that exercising has three purposes—validation, training, and testing—to ensure communications, roles, and response coverage function as intended[128] . This role of structured testing is reinforced by the UKOPA emergency plan template, which reiterates that Local Authorities have explicit responsibilities under PSR to prepare emergency plans, and that major emergencies may require multi-agency coordination at strategic, tactical and operational levels[130].

Local Authorities have an essential role because they are responsible for developing and coordinating the off-site emergency plan, convening relevant responders, and ensuring that community protection measures (warning and informing, evacuation/shelter advice, access control, recovery planning) are workable in the local context[128, 130]. UKOPA/GPG/010 explicitly states that before any test is conducted, the Local Authority should agree the scale and scope with the operator and consider involving all relevant parties, including strategic stakeholders[128] . This is important for pipelines because they are long, linear assets that cross boundaries, are often remote and unmanned, and may not be obvious to the public, characteristics that directly affect resourcing, communications, rendezvous points, access routes, and command arrangements in an emergency[128]. The implication is that emergency response planning for MAHPs is not a paper exercise: it requires a tested system of multi-agency interoperability, clear ownership of decisions, and an auditable programme of exercises and learning capture to demonstrate ongoing readiness[128].

CO_2 introduces important nuances that materially shape emergency preparedness and initial response. Unlike methane, CO_2 is an asphyxiant and, when released from high pressure, can produce a visible vapour cloud, accumulate in low-lying areas (e.g., valleys and ditches) during cool, humid, low-wind conditions, and significantly reduce visibility, making movement through the release area hazardous[131]. The API Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document: Best Practice Guidelines for Preparedness and Initial Response to a Pipeline Release of Carbon Dioxide (CO_2) is explicitly framed as an

[128] UKOPA. Good Practice Guide - Major Accident Hazard Pipeline, Emergency Response Plan, Guidance on Testing. **2025**. Available: Major Accident Hazard Pipeline, Emergency Response Plan, Guidance on Testing - UKOPA [Accessed 10 March 2026].
[129] UK Government. The Pipeline Safety Regulations 1996. **2023**. Available: The Pipelines Safety Regulations 1996 [Accessed 09 March 2026].
[130] UKOPA. Good Practice Guide - Major Accident Hazard Pipeline, Emergency Response Plan, Guidance on Testing. **2025**. Available: Major Accident Hazard Pipeline, Emergency Response Plan, Guidance on Testing - UKOPA [Accessed 10 March 2026].
[131] API. Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document. **2023**. Available: co2-tactical-guidance.pdf [Accessed 10 March 2026].

operational field guide to assist response to CO_2 pipeline releases, and it highlights the need for rapid provision of key information from the operator, actions being taken, initial evacuation distances, and options to shelter-in-place, so that local emergency managers and responders can make time-critical decisions[Error! Bookmark not defined.]. CO_2 releases can also present dermal cold-burn hazards close to the release p oint due to very low temperatures, and response may include consideration of controlled venting scenarios in certain conditions (e.g., long distances between isolation valves or smaller releases), further emphasising the need for coordinated tactical planning between operators and local responders (API CO_2 Tactical Guidance Document). In practice, these CO_2-specific behaviours make emergency response planning and tested, locally tailored procedures especially important: the hazard footprint can be strongly influenced by topography and weather, safe approach routes and control points must be planned, and public protection actions must be delivered quickly and coherently through Local Authority-led coordination[132, 133].

5.15 Digital, Monitoring and Control

5.15.1 CO_2 sensing technology

The principal remote CO_2 sensing technologies are based on optical absorption principles, primarily exploiting the strong infrared absorption bands of carbon dioxide. These systems can be deployed from satellites, aircraft, UAVs, or ground-based platforms and are designed to detect elevated atmospheric CO_2 concentrations from a distance rather than through point-contact sampling.

The most widely used technology is infrared (IR) absorption sensing, which relies on the fact that CO_2 strongly absorbs radiation in specific mid-wave and long-wave infrared wavelengths, particularly around 4.3 μm and 15 μm. Non-dispersive infrared (NDIR) sensors are commonly used in fixed and portable instruments; they measure attenuation of IR light across a defined optical path and are highly mature for point detection. For remote and open-path applications, tunable diode laser absorption spectroscopy (TDLAS) and related laser-based techniques are used. These systems transmit a laser beam across a path and measure absorption at CO_2-specific wavelengths, enabling high sensitivity and fast response.

For longer-range and aerial detection, open-path[134] infrared imaging systems and hyperspectral infrared cameras are used. These instruments detect differential absorption across many wavelengths to identify and visualise CO_2 plumes against the atmospheric background. Hyperspectral imaging can be deployed from aircraft or satellites and allows mapping of concentration anomalies over wide areas, although resolution and detection thresholds depend on altitude, atmospheric conditions and background variability.

Light Detection and Ranging (LiDAR) systems adapted for gas detection are also used. Differential Absorption LiDAR (DIAL) emits laser pulses at CO_2-absorbing and non-absorbing wavelengths and measures backscatter differences to quantify gas concentration along the beam path. DIAL systems can provide spatially resolved plume mapping and can operate from ground, airborne, or mobile platforms.

Satellite-based CO_2 monitoring typically uses shortwave infrared (SWIR) and thermal infrared spectrometers to measure column-integrated CO_2 concentrations by analysing reflected sunlight or emitted thermal radiation. These systems are effective for detecting large or persistent plumes but are less sensitive to small, short-duration leaks due to atmospheric mixing and resolution constraints.

UAV-mounted systems commonly combine miniaturised NDIR or laser-based sensors with real-time telemetry to map near-field plume dispersion during emergency response or verification surveys.

[132] UKOPA. Good Practice Guide - Major Accident Hazard Pipeline, Emergency Response Plan, Guidance on Testing. **2025**. Available: Major Accident Hazard Pipeline, Emergency Response Plan, Guidance on Testing - UKOPA [Accessed 10 March 2026].
[133] API. Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document. **2023**. Available: co2-tactical-guidance.pdf [Accessed 10 March 2026].
[134] “open-path” refers to a gas detection system where the sensing beam travels through open air between a transmitter and a receiver, rather than sampling gas inside a closed chamber.

In summary, the principal remote CO_2 sensing technologies are infrared absorption (including NDIR and open-path IR), laser-based spectroscopy such as TDLAS and DIAL, hyperspectral imaging and satellite-based infrared spectrometry. All rely fundamentally on the characteristic infrared absorption features of CO_2, with differences in deployment scale, sensitivity, spatial resolution and suitability for continuous safety-critical monitoring versus supplementary verification.

Point NDIR CO_2 sensors are fully mature, widely used for fixed gas detection in industrial, HVAC and confined space applications, and are assessed at TRL 9 with well-established calibration standards and field performance. Open-path infrared systems are also mature in industrial safety applications and are assessed at TRL 8–9 for CO_2 use, although high-background atmospheric CO_2 conditions require careful configuration. TDLAS is similarly highly mature and widely deployed for gas detection, including CO_2 monitoring, and is assessed at TRL 8–9; integration into pipeline-specific leak detection systems is somewhat less widely demonstrated. DIAL is technically mature for atmospheric gas studies and spatial plume mapping but is less commonly used as a primary safety-critical detection layer in pipeline systems and is assessed at TRL 7–8 for CO_2 pipeline applications. Airborne hyperspectral infrared imaging is mature for environmental monitoring and large-scale plume detection, but limited for small leak detection, and is assessed at TRL 7–8 in the CCS context. Satellite-based CO_2 monitoring is operational and mature for regional and global carbon assessment but not optimised for small, transient industrial leaks, and is therefore assessed at TRL 6–8 for safety-critical CCS leak detection, although TRL 9 for climate monitoring purposes. UAV-mounted CO_2 sensing systems rely on mature sensor technologies and have increasingly been demonstrated for environmental compliance and methane surveys but are not yet standard as primary CCS monitoring tools and are assessed at TRL 7–8. At the system level, while individual technologies are generally TRL 8–9, their integration as primary, safety-critical monitoring frameworks for dense-phase CO_2 trunklines is more appropriately characterised at TRL 7–8, reflecting limited large-scale CCS deployment experience, dependence on meteorological variability, elevated atmospheric background CO_2 concentrations and the need for further validation under realistic dense-phase CO_2 release scenarios.

These systems are being actively evaluated in current research programmes (see Section 5.19), particularly under realistic CO_2 release conditions.

5.15.2 Pipeline integrity monitoring systems

The increasing regulatory and public focus on demonstrating active management of societal risk, and the complexity of CO_2 phase equilibria with compositions likely from multi-user systems, is driving a shift from passive design-only safety measures toward continuous, real-time monitoring in CO_2 pipeline systems. Traditional risk assessments assume conservative release scenarios and rely on static design margins, block valve spacing, periodic inspection and surveillance. However, regulators and communities now expect operators not only to design for low-probability events, but also to demonstrate the ability to detect, respond to, and mitigate abnormal conditions in real time. For dense-phase CO_2 pipelines where releases may produce ground-hugging clouds with delayed detection, early identification of substantial leaks, third-party interference, ground movement or abnormal thermal behaviour materially reduces escalation risk. Real-time monitoring, therefore, strengthens safety cases, supports ALARP demonstration, shortens emergency response time, and provides defensible evidence of proactive risk management.

Several monitoring technologies are available. SCADA-based pressure/flow imbalance systems are mature (TRL 9), widely deployed, and capable of detecting moderate-to-large leaks by identifying mass-balance discrepancies. They are reliable and cost-effective but may struggle with small leaks, complex terrain, or transient operating conditions that mask imbalances. Acoustic leak detection systems (external or internal) can identify rapid decompression events, and high-frequency rupture signatures are more effective for sudden, high-rate releases than for slow seepage. Fibre-optic distributed sensing systems (including Distributed Temperature Sensing (DTS), Distributed Acoustic Sensing (DAS), and Distributed Strain Sensing (DSS)) represent a more advanced, increasingly deployed solution. These are installed alongside or integrated into the pipeline, fibre-optic cables can detect temperature anomalies from JT cooling during a leak, acoustic signatures from third-party intrusion or rupture, and strain changes from ground movement or geohazards. Their strengths include continuous coverage over long distances, high spatial resolution, passive operation (no power along the route), and multi-threat detection capability. Weaknesses include higher capital cost, sensitivity to environmental noise (for DAS), complex data interpretation requiring advanced analytics, and potential performance degradation if fibre installation quality is poor. False positives can also increase operational burden if filtering and validation algorithms are not robust.

Emerging monitoring technologies, such as satellite-based plume detection, UAV-mounted gas sensors, and fixed ground-based monitoring networks, provide additional layers of surveillance beyond conventional pipeline instrumentation. Satellite-based systems use hyperspectral or infrared imaging to detect elevated atmospheric CO_2 concentrations over broad areas, identifying large or persistent plumes from space. These systems are most effective for detecting substantial releases and post-event verification, rather than small, transient leaks, due to spatial resolution and atmospheric interference constraints. UAV-mounted sensors, typically equipped with infrared or laser-based gas analysers, can be rapidly deployed over a suspected leak area to map plume extent, confirm concentration gradients, and support emergency response. Fixed ground-based monitoring networks consist of distributed CO_2 detectors installed near high-consequence areas, such as road crossings, populated zones or sensitive environmental receptors, providing continuous local concentration measurements and early warning capability. These provide supplementary layers but are generally better suited for verification rather than primary detection. Fibre optics, when combined with SCADA and automated valve actuation, offers the most comprehensive integrated approach.

From a societal risk perspective, the value of these systems lies not only in leak detection but in demonstrable reduction in time-to-isolation, documented proof of continuous surveillance, and enhanced transparency with regulators and stakeholders. As expectations for infrastructure resilience increase, real-time monitoring, based on projects to-date, is evolving from a discretionary enhancement to a core element of modern CO_2 pipeline risk management strategy.

The shift from passive, design-only safeguards to continuous, real-time monitoring in dense-phase CO_2 pipelines reflects a change in risk management philosophy rather than a fundamental technological advance. Core monitoring technologies such as SCADA-based pressure and flow imbalance systems and acoustic leak detection are fully mature at TRL 9, with proven performance in oil and gas transmission. Fibre-optic distributed sensing systems, including DTS, DAS and DSS, are generally assessed at TRL 8–9 in hydrocarbon service, but their integrated application to dense-phase CO_2 trunklines where JT cooling, impurity-sensitive phase behaviour and ground-hugging dispersion alter release characteristics is more appropriately characterised at TRL 7–8 due to the need for CO_2-specific validation and calibration. Emerging technologies such as satellite-based plume detection, UAV-mounted sensors, and fixed ground-based monitoring networks typically fall within TRL 6–8 for CO_2 applications and are better suited as supplementary verification layers. Integrated configurations that combine SCADA, fibre-optic sensing, and automated block valve actuation into a coordinated mitigation framework are best assessed at TRL 7–8 for dense-phase CO_2 service, reflecting system-integration and validation maturity rather than hardware limitations. Overall, real-time monitoring for dense-phase CO_2 pipelines can be described as TRL 8 at the system level: mature in principle and demonstrated in related sectors, but still undergoing CCS-specific optimisation and operational validation as networks expand and regulatory expectations evolve.

5.15.3 Above-ground installations (AGI)

Unlike long-buried pipelines, where releases may go undetected for a period, and dispersion may be terrain-driven, above-ground installations benefit from direct access, visible infrastructure and closer integration of instrumentation. Detection of abnormal conditions is therefore generally faster and more reliable, but the proximity of equipment, valves, flanges, pig traps, metering skids and compression modules introduces a greater density of potential leak points. In dense-phase CO_2 service, where releases can generate cold, ground-hugging clouds and rapid temperature excursions, regulators increasingly expect operators to demonstrate not only that equipment is designed to appropriate standards, but that abnormal pressure, temperature, composition or containment events can be detected and mitigated in real time. Continuous monitoring strengthens the Safety Case, supports ALARP demonstration and reduces the likelihood of escalation from small equipment failures into wider site events.

Monitoring technologies in above-ground installations are generally mature and well established. Fixed gas detection systems, including point infrared CO_2 detectors and open-path systems, are widely deployed and assessed at TRL 9, providing rapid detection of elevated concentrations in process areas, enclosed modules and near ventilation intakes. Pressure, temperature and flow instrumentation integrated into

SCADA systems are likewise at TRL 9 and enable real-time identification of leaks through imbalance detection, rapid decompression signatures, or abnormal thermal behaviour. Acoustic detection can identify high-rate rupture events, while localised vibration monitoring may indicate mechanical distress. Because equipment is accessible, additional safeguards, such as visual inspection, handheld gas detection, and thermal imaging, can be deployed during commissioning and routine surveillance, further improving detection confidence relative to buried pipelines.

Above-ground systems also allow easier implementation of redundancy and layered detection strategies. Continuous composition monitoring ensures compliance with impurity specifications, while automated shutdown and isolation logic can be directly linked to gas detection alarms and ESD systems. The principal challenges are less about detectability and more about ensuring appropriate alarm management, avoiding false positives that trigger unnecessary shutdowns, and maintaining calibration accuracy in corrosive or impurity-variable environments. In dense-phase CO_2 service, particular attention must be given to sensors exposed to low-temperature excursions during blowdown, elastomer compatibility and the reliability of detection systems in confined or partially enclosed areas.

Emerging technologies such as drone-mounted sensors, fixed perimeter monitoring arrays and enhanced plume modelling tools may supplement primary detection, but in above-ground contexts, these typically serve as verification layers rather than first-line protection. From a societal risk perspective, the principal value of above-ground monitoring lies in demonstrably short detection-to-isolation times, auditable alarm records and visible control measures that reinforce regulatory confidence. Given the maturity of fixed detection, SCADA integration, and automated shutdown systems in industrial settings, above-ground CO_2 monitoring and control strategies are generally assessed at TRL 9, with system-integration considerations more related to operational discipline and impurity management than to fundamental technological uncertainty.

5.15.4 Digital twins for predictive maintenance

The case for deploying a digital twin for CO_2 pipeline systems is rooted in the growing expectation that operators demonstrate not only robust design, but continuous, predictive management of integrity and societal risk. A digital twin integrates real-time operational data (pressure, temperature, flow, composition), material properties, corrosion models, and thermodynamic phase behaviour into a live simulation environment that mirrors the physical asset. Rather than relying solely on static design envelopes or periodic inspection, the twin enables operators to simulate transient events such as start-up, shutdown, depressurisation, seasonal temperature changes, or composition excursions and assess whether operating conditions approach thresholds for two-phase flow, hydrate formation, aqueous phase development, and hydrogen concentration. In effect, it converts compliance from a retrospective audit exercise into an active integrity management tool.

From a pressure and temperature perspective, a digital twin can model real-time dense-phase stability, identify areas approaching the bubble point, predict localised cooling during flow changes, and flag conditions that increase the risk of phase transformation. When linked with composition monitoring, it can dynamically assess corrosion risk by calculating acid-forming potential and dew-point margins under current operating conditions. By incorporating corrosion kinetics and material response models, the twin can calculate corrosion risk and drive inspection frequency. This enables risk-based maintenance, improved isolation decision-making, and stronger ALARP demonstrations to regulators. It also provides traceable evidence of active monitoring increasingly important in demonstrating societal risk management.

The strengths of a digital twin include real-time risk visibility across the entire asset, predictive capability rather than reactive detection, integration of thermodynamics, hydraulics, fracture mechanics, and corrosion models, enhanced emergency response modelling (e.g., simulating blowdown consequences before execution), and improved regulatory defensibility through documented continuous assessment.
However, limitations must be recognised. A digital twin is only as reliable as its input data and calibration. Measurement uncertainty, sensor failure, or composition variability can propagate into modelling error. Complex multiphase and impurity interactions may exceed the fidelity of embedded thermodynamic models. Corrosion models require assumptions about local chemistry and flow regimes that may not fully reflect micro-scale behaviour. There is also a risk of overconfidence if the twin is not periodically validated

against physical inspection and testing data. Implementation requires significant integration effort, cybersecurity safeguards, and skilled interpretation of outputs.

Digital twin frameworks for pipeline hydraulics and pressure modelling are generally TRL 8–9 in conventional gas systems. Real-time integration of corrosion risk modelling linked to compositional variability in dense-phase CO_2 pipelines is typically TRL 6–8, depending on model complexity and validation dataset. Full integration of fracture mechanics, phase envelope prediction, corrosion chemistry, and live data analytics into a unified operational decision platform remains at the upper end of the demonstration phase at TRL 6–7 but is rapidly maturing.

Overall, the digital twin represents a shift from static compliance to dynamic integrity assurance, providing a powerful mechanism to anticipate, simulate and mitigate pressure, temperature and corrosion risks in real time, provided its limitations are understood and managed.

5.15.5 Automated control systems

An automated control system (ACS) in a dense-phase CO_2 pipeline serves as the real-time operational safeguard, keeping the system within defined thermodynamic and integrity limits and executing protective actions without operator delay. In networks where impurity variability, hydrogen effects, phase stability and multi-emitter balancing interact dynamically, static operating envelopes are insufficient; automation provides continuous margin management and rapid intervention.

The primary functions of an ACS are operational and protective. It maintains phase stability by controlling pressure and compressor setpoints to preserve adequate bubble-point margin and prevent two-phase conditions. It manages impurity excursions by comparing real-time composition against defined thresholds and triggering graduated responses, from controlled restriction to automatic isolation where required. It manages multi-emitter balancing to prevent compositional-related risks and maintain integrity-safe allocation. Where abnormal conditions are detected, the ACS executes predefined isolation logic to minimise inventory release time and limit escalation.

The principal benefits are faster isolation, reduced consequence magnitude, improved availability through controlled transient management, and demonstrable ALARP compliance through auditable, repeatable protective logic. Automation optimises block valve use, reduces reliance on manual intervention, and ensures consistent enforcement of network operating rules across multiple Users.

The underlying technologies, such as SCADA, pressure and flow control, and automated valve actuation, are mature and generally assessed at TRL 9 in conventional gas transmission systems. However, their integrated application to dense-phase, impurity-sensitive CO_2 trunklines is more appropriately characterised at TRL 6–7, reflecting that while the constituent systems are proven, full-scale validation under representative CO_2 compositions and operating conditions remains limited.

Limitations include dependence on accurate models and sensor integrity, the risk of false positives leading to unnecessary shutdowns, cybersecurity exposure, and limited large-scale CCS validation relative to natural gas systems.

Automation does not replace conservative design, fracture control, or inspection; rather, it functions as the system's dynamic risk governor. In both dense-phase and gas-phase CO_2 networks, the core challenge lies not in hardware capability but in validating integrated control strategies under realistic operating conditions. For dense-phase systems, this is driven by sensitivity to impurities, phase behaviour, and transient decompression effects, while for gas-phase systems it is more focused on dispersion behaviour, pressure transients, and confinement risks. In both cases, ensuring that control responses are reliable, proportionate, and defensible requires robust validation against representative compositions, operating envelopes, and credible upset scenarios.

5.16 Construction

The construction of CO_2 pipelines, both onshore and offshore, is fundamentally based on the same engineering methods used for oil and gas transmission. Trenching, welding, coating, hydrotesting, lowering-in, backfilling, and offshore lay techniques such as S-lay and reel-lay are all mature practices.

However, CO_2 service, whether dense-phase or gas-phase, introduces several important nuances compared with conventional hydrocarbon pipelines. For dense-phase systems, these are particularly associated with fracture control, decompression behaviour, and sensitivity to impurities and moisture, which can influence material performance and running fracture risk. For gas-phase systems, the challenges are generally less severe but still require careful attention to materials compatibility, corrosion control, and operational cleanliness. In both cases, appropriate materials qualification, moisture management, and specification control remain critical to ensuring safe and reliable operation.

Offshore construction introduces additional considerations related to temperature and pressure. Dense-phase CO_2 pipelines may experience lower minimum design metal temperatures during blowdown or depressurisation than hydrocarbon lines. As a result, material selection, weld procedure qualification and coating systems must be validated for low-temperature performance and resistance to rapid decompression effects. Elastomers, seals and coatings may require compatibility assessment specific to CO_2 permeation and decompression. Where pipelines connect to platforms or subsea templates, the isolation philosophy and riser integrity must account for CO_2-specific decompression cooling and asphyxiation hazards rather than flammability escalation.

In both onshore and offshore contexts, impurity management is more tightly integrated into the design and commissioning processes. Construction tolerances must support maintaining single-phase stability and avoiding internal debris that could promote corrosion or deposition. Cleanliness standards may be higher than for oil service, particularly if multi-emitter networks introduce composition variability. For repurposed pipelines, additional inspection and metallurgical assessment are required to confirm suitability for dense-phase CO_2 service, including evaluation of existing welds, coatings and susceptibility to fracture propagation.

Despite these nuances, no fundamentally new construction technologies are required for CO_2 pipelines. The differences lie primarily in specification, validation, and the integration of thermodynamic and materials behaviour into established pipeline practices. Techniques such as hydrotesting, non-destructive testing (NDT), offshore lay methods, subsea tie-ins, and drying are well-established in the hydrocarbon industry. However, post-hydrotest dewatering and drying requirements are typically more stringent for CO_2 service than for conventional hydrocarbon pipelines, reflecting the need to achieve very low residual water contents and avoid free water under all operating conditions. As a result, greater emphasis is placed on drying effectiveness, verification, and preservation prior to commissioning. This is covered in Section 5.17.1.

From a Technology Readiness Level perspective, core pipeline construction methods for CO_2 are TRL 9, as they are directly derived from decades of oil and gas practice. The additional CO_2-specific requirements, such as impurity envelope validation, fracture arrest modelling integration, and low-temperature transient qualification, are more appropriately characterised at TRL 7–8, reflecting integration maturity rather than lack of fundamental capability. Overall, CO_2 pipeline construction is a mature engineering activity, with incremental complexity driven by thermodynamics and material performance rather than by novel construction technologies.

5.17 Commissioning

5.17.1 Pre-commissioning, dewatering, drying, and integrity testing

One of the principal CO_2-specific challenges is moisture management. Unlike natural gas, dry CO_2 is non-corrosive, but even small quantities of free water can form carbonic acid and cause rapid corrosion. Construction, therefore, requires stringent drying and dewatering after hydrotesting, often to water ppm levels below those typical of gas service.

DNV-RP-F104 establishes a clear principle for CO_2 pipeline operation: avoiding free water is fundamental to corrosion control. The guidance emphasises that internal corrosion mitigation is primarily achieved through dehydration, and that conventional pipeline design assumptions remain valid only where free water is absent. If water is present, the service environment changes significantly, introducing corrosive conditions that require different design and operational considerations. Importantly, DNV highlights that

water solubility in CO_2 is not fixed, but varies with pressure, temperature, and composition, meaning acceptable limits must be assessed on a case-by-case basis for the specific CO_2 stream.
This position is reinforced by broader DNV and CCS guidance, which treats water as one component within a wider impurity envelope. Rather than prescribing a single allowable value, the approach recognises that impurities—including water—interact and influence phase behaviour and corrosion risk. As a result, water limits cannot be defined in isolation but must be considered as part of an integrated compositional specification for safe transport. ISO 27913 aligns with this approach, requiring strong dehydration of the CO_2 stream and specifying that operating conditions must avoid the formation of any aqueous phase, without defining a universal numerical limit.

This contrasts with natural gas pipeline practice, where drying requirements are more standardised and prescriptive. Established codes such as IGEM/TD/1 or ASME B31.8 typically correspond to water contents of ~50–150 ppmv (depending on pressure and temperature), often expressed as fixed dew-point limits (e.g., −10 °C to −20 °C at line pressure). These limits are primarily set to control hydrate formation and conventional corrosion mechanisms and are broadly applicable across typical gas compositions.

In CO_2 systems, by contrast, water content is more tightly constrained because even small amounts can lead to carbonic acid formation and, in the presence of impurities, potentially aggressive corrosion regimes. Consequently, allowable water levels must be derived from thermodynamic and chemical modelling rather than fixed code limits. In practice, this has led to commonly adopted engineering targets, typically on the order of 10–50 ppmv water for dense-phase CO_2 systems, with potentially higher limits in well-controlled gas-phase systems. While there is some overlap with natural gas ranges, CO_2 specifications are generally more conservative and composition-sensitive, reflecting the need to ensure that no free water forms across the full operating envelope.

Achieving ultra-low ppm water levels in long offshore pipelines is technically demanding, particularly in ensuring uniform drying and verification over large volumes. Drying technologies themselves are mature (TRL 9); however, confidence in achieving and maintaining these low water contents under CO_2 service conditions—particularly where impurity carryover and phase behaviour effects are relevant—is better characterised at TRL 7–8.

5.17.2 Commissioning sequences for CO_2 service

Commissioning dense-phase CO_2 pipelines shares many steps with oil and gas pipelines, but tighter tolerances apply because CO_2 phase behaviour is highly sensitive to temperature, pressure and composition, and because small amounts of water or non-condensables can shift the phase envelope and create risks of two-phase or solid formation. Hydrocarbon pipelines can often be commissioned assuming single-phase behaviour across a relatively wide operating window, whereas CO_2 commissioning must be deliberately engineered to avoid crossing the saturation boundary and to avoid conditions that promote dry ice or hydrates and severe temperature drops, while also achieving very low residual water content before first CO_2 introduction.

Moisture control is more critical than in typical gas pipeline commissioning. Dry CO_2 is non-corrosive, but the formation of even small amounts of free water can create carbonic acid corrosion and, where SOx, NOx or H_2S are present, far more aggressive acids. Drying acceptance criteria and “no free water under transients” margins therefore need to be more stringent. Because CO_2 cools strongly during depressurisation, any residual water can condense locally during blowdown or start-up, creating temporary aqueous phases and hydrate risk.

Thermal and phase transients dominate commissioning risk management. Dense-phase CO_2 can flash into two-phase conditions and may form solids under rapid pressure changes, so blowdown, venting and early start-up require controlled rates, staged pressurisation and, in some cases, pre-warming or heat management, particularly offshore. Many natural gas pipelines tolerate wider JT cooling margins without encountering solid formation concerns.

Composition management is part of commissioning, especially for multi-emitter networks. Commissioning readiness is not limited to pressure and flow proving, but includes CO_2 quality compliance through impurity limits, monitoring availability, alarm functionality and isolation logic. This requires functional testing of analysers, averaging and exceedance logic, and isolation sequencing, resembling the commissioning of a regulated network rather than a point-to-point hydrocarbon pipeline.

Onshore commissioning generally benefits from easier access to pig traps, instrumentation, vents and isolation valves, enabling incremental proving steps such as short pigging runs, repeat drying cycles and simpler analyser calibration and sampling. The principal onshore constraint is proximity to receptors, meaning venting and controlled depressurisation attract greater scrutiny because a CO_2 cloud is a credible hazard under low-wind, stable atmospheric conditions.

Offshore commissioning is typically more challenging because long tiebacks and seabed cooling reduce thermal margins and increase inventory. More conservative sequencing is often required to avoid low-temperature excursions at subsea restrictions, risers and valve cavities, and there are fewer intervention options if pigging issues arise or an analyser fails. Where a manned platform is involved, the Safety Case and isolation philosophy, including SSIV logic where applicable, are normally embedded in the commissioning plan, with emphasis on minimising time in unstable phase regions and demonstrating shutdown and isolation performance.

A typical phase-aware commissioning sequence comprises mechanical completion and pre-commissioning, including hydrotest (or alternative), dewatering, cleaning and gauging, followed by drying using air and desiccant, vacuum drying or dry-gas drying to a defined low water specification supported by sampling evidence. The acceptance basis should address not only steady-state ppm water but also transient cooling margins where local condensation could occur. This is followed by inerting and leak testing with a non-condensable gas, typically nitrogen, to prove tightness and instrumentation while operating in gas phase and validating controls, ESD functions, valves and communications. Controlled CO_2 introduction then follows, maintaining pressure and temperature within a defined safe region. This is commonly achieved by initially introducing CO_2 in gas phase and ramping pressure in stages, or introducing conditioned CO_2 and raising pressure above the minimum dense-phase requirement while managing temperature, including heat input if needed offshore. The critical requirement is avoidance of rapid depressurisation or pressurisation steps that cross into two-phase or solid regions, particularly at restrictions, dead legs and valves. Finally, transition to normal operating envelope occurs once stable single-phase operation is established, commissioning integrity monitoring, analysers, metering and network logic under flowing conditions, and validating emergency blowdown procedures, often through modelling rather than full-scale blowdown trials.

During commissioning transients, the practical rule is to keep the line either clearly gaseous or clearly dense phase, avoid operating close to the saturation line, minimise residual water, and manage depressurisation rates to avoid deep JT cooling and solid formation. If the system enters the two-phase region, even gradually, several adverse effects can arise. The formation of gas–liquid mixtures leads to unstable, non-uniform flow, with phase slip, stratification, or slugging depending on the inclination and velocity. This can result in erratic pressure and temperature behaviour, reduced predictability of hydraulic performance, and challenges for control systems and metering. Localised cooling during phase change may promote condensation of water or impurities, increasing the risk of corrosion or, in colder conditions, the formation and deposition of solid CO_2 (dry ice), which can restrict flow or damage equipment. Even a “gentle” entry into the two-phase region can therefore degrade operability and introduce uncertainty in system response.

Recovery from two-phase conditions requires actively moving the system back into a single-phase envelope, which, in practice, involves adjusting pressure and/or temperature throughout the entire pipeline. Returning to the dense phase typically requires increasing pressure (e.g., via compression or restricting outflow) and/or increasing temperature to ensure that all fluid is above the saturation line. Returning to the gas phase requires reducing pressure and/or increasing temperature sufficiently to fully vaporise any liquid. In long pipelines, this is not instantaneous: pressure and temperature changes propagate over time, and pockets of liquid may persist in low points, making full reversion to single-phase conditions operationally challenging. As a result, avoiding entry into the two-phase region is strongly preferred, as recovery can require coordinated control actions, stable boundary conditions, and sufficient time to re-establish uniform single-phase flow throughout the system.

Non-condensables such as nitrogen broaden the two-phase region, shift the phase envelope and can change decompression behaviour. Fracture control depends on the decompression curve relative to the material's crack-arrest capability, and some mixtures can sustain higher crack-driving pressure for longer, increasing susceptibility to long-running ductile fracture if margins are already tight. During nitrogen inerting, the line is typically at a lower pressure and in the gas phase, so stored energy and crack-driving forces are often lower than in dense-phase operation. The most relevant risk window is the transition period, as the CO_2/N_2 mixture is taken toward dense-phase conditions. If elevated nitrogen content remains and operation proceeds near the dense-phase boundary, decompression and phase behaviour can become less forgiving than for the intended specification. Nitrogen can therefore worsen fracture-relevant decompression behaviour if present in meaningful concentrations during dense-phase operation, but whether it increases the risk of ductile fracture during running depends on pressure, temperature, nitrogen fraction, and the fracture-control basis. Mitigation includes defining allowable temporary nitrogen concentration and purge requirements, avoiding operation near the saturation line during the mixed-gas period, and treating the commissioning mixture as a separate fluid case for transient, decompression and fracture checks. Typically, onerous conditions can be avoided by inerting the pipeline with Nitrogen at low pressures (~ 4 barg), purging the pipeline with gas phase CO2 and then building pressure to the operating pressure, gas phase or dense phase. This means the CO2/N2 mixing only occurs at very low pressure.

The commissioning of dense-phase CO_2 pipelines builds on fully mature oil and gas practices such as hydrotesting, dewatering, drying, pigging and inerting, which are assessed at TRL 9; however, when these techniques are applied to single-emitter dense-phase CO_2 systems with tight thermodynamic control requirements, overall maturity is more appropriately characterised as TRL 8–9 due to increased sensitivity to phase behaviour and transient cooling. For multi-emitter, impurity-variable CCS trunklines operating under regulated network conditions with composition monitoring, staged pressurisation and strict phase-margin management, the integrated commissioning approach is better assessed at TRL 7–8, reflecting system-level complexity and limited large-scale operational precedent rather than fundamental technical gaps. Where nitrogen or other non-condensables are present during transition to dense-phase operation and fracture behaviour must be reassessed against modified decompression curves, the commissioning-phase fracture implications are most appropriately characterised at TRL 6–7, as empirical validation under realistic CCS impurity envelopes remains comparatively limited despite well-understood underlying fracture mechanics.

5.18 Decommissioning

Decommissioning a CO_2 transmission pipeline requires providing an end-to-end method that is safe, regulator-acceptable, environmentally compliant, and practical at scale. The UK has limited onshore pipeline decommissioning precedent relative to its operating base, and essentially no CCS-era experience for dense-phase CO_2 trunklines. The main technical issues are residual inventory management, avoiding dry ice/hydrate blockages during depressurisation, preventing corrosion/acid formation during any "wet" phases, and demonstrating that any remaining CO_2 is either captured or rendered non-hazardous before final abandonment. At the system level, the gap is the lack of established UK practice, guidance and "standard method statements" specific to dense-phase CO_2, particularly for long lines with multiple low points and tie-ins.

5.18.1 Residual CO_2 removal and depressurisation

A no routine venting approach is credible, but it requires designing the decommissioning method around capture or transfer rather than free release. Practically, residual CO_2 can be removed by isolating the pipeline into manageable sections (using existing block valves), then displacing CO_2 to a receiving system via controlled pushing and pumping. The receiving system could be a live CO_2 network, a temporary recovery plant, or a ship-loading interface where available.

Displacement is typically undertaken using an inert gas such as nitrogen. In principle, pipeline pigs can be used to provide a physical interface between CO_2 and nitrogen, minimising mixing and maintaining a relatively sharp front, which can be beneficial where downstream processing or specification limits are tight. However, in long pipelines and particularly offshore systems, pigging during decommissioning can be operationally complex and not always necessary or practicable.

In many cases, a controlled level of mixing at the CO_2–N_2 interface is acceptable, provided the receiving system and compression facilities are designed to handle a gradually changing composition. This results in a transition zone rather than a sharp interface, with CO_2 concentration decreasing over time. The displaced stream is then routed to compression and temporary storage, re-injection, or capture for reuse, with facilities sized and operated to accommodate this compositional variation.

The key is managing phase behaviour during pressure reduction: rapid blowdown risks deep JT cooling and dry ice formation at restrictions and vents, so depressurisation is staged, heat-managed where necessary, and routed through equipment designed for two-phase and potential solid-tolerant handling. If "full capture" is mandated, the practical gap is infrastructure: a destination is needed for the recovered CO_2, along with temporary compression and storage capacity sized to the pipeline inventory, displacement method (pigged or non-pigged), and allowable duration of the operation.

5.18.2 Pipeline cleaning, purging and inerting

Cleaning and making the line inert is a distinct step from CO_2 recovery. Once CO_2 is displaced to low residual levels, the line is typically purged with nitrogen until CO_2 concentrations are below a defined threshold and oxygen ingress is controlled. For CO_2 service, the nuance is to avoid creating a corrosive aqueous phase: if any water is present, CO_2 + water forms carbonic acid, and impurities can form stronger acids. Therefore, "dry" inerting is preferred, with dew point control and verification at multiple locations, particularly at low points. Pigging may be used to remove debris and any liquids, followed by drying/inerting to a stable condition. A further nuance is that decommissioning may leave behind pockets in dead legs, tees, valve cavities and low points, so the verification plan (sampling points, purge modelling, acceptance criteria) becomes the critical element rather than the purge gas itself.

5.18.3 Long-term abandonment

For onshore pipelines, the typical end-state is abandonment in situ unless there is a clear driver for removal (land redevelopment constraints, contamination risk, third-party requirements, or major crossings). "Making safe" typically means eliminating the pipe's ability to become a future confined-space hazard, migration pathway, or subsidence risk, and ensuring it is clearly identified and managed in land records. Options include leaving the line inert and isolated, filling with an inert gas at low pressure, or filling with a solid medium. Grout or foamed grout is often discussed because it prevents collapse/void formation and eliminates the possibility of gas accumulation; it can also reduce the risk of third-party interference during future excavations by limiting "unexpected void" behaviour. The trade-off is logistics, cost, and emissions: grout volumes for large-diameter trunklines are substantial, require access for injection at multiple points, and need management of displaced gas during filling (which must be captured/treated). For small diameter laterals, leaving in place and isolating/venting safely may be acceptable, but for large trunklines, the long-term liability and "unknown future disturbance" arguments tend to push toward a more robust end-state, particularly near populated areas, road/rail crossings, or sensitive ground conditions. The gap for CO_2 is not whether grout works—it's agreeing what "good practice" looks like for CO_2 pipelines under UK regulatory expectations and landowner/local authority constraints.

5.18.4 TRL assessment

Key gaps to highlight are limited UK precedent and therefore limited accepted practice for decommissioning long onshore pipelines, lack of CO_2-specific end-to-end procedures that demonstrate low/zero atmospheric release, including temporary recovery/compression logistics, limited guidance on phase-managed depressurisation and purge verification for dense-phase CO_2 systems with impurities, uncertainty on abandonment end-states (inert only vs grout/foam grout) and what regulators and land authorities will expect for large-diameter CO_2 trunklines, and need for clear acceptance criteria and records management so "leave in situ" does not become a future uncontrolled risk.

Most enabling technologies are mature individually (isolation valves, nitrogen purging, pigging, drying, temporary compression), but the system-level decommissioning method for dense-phase CO_2 trunklines in the UK is best characterised as TRL 6–7: technically feasible with proven components, but with limited CCS-specific full-scale execution experience, limited standardisation, and significant dependence on integration, permitting and demonstration of environmental performance.

5.19 Ongoing Research and Joint Industry Initiatives

A significant proportion of the identified technology gaps for CO_2 transportation systems do not arise from a lack of fundamental engineering capability, but from limited large-scale validation under representative CCS conditions. As a result, a substantial body of ongoing research, much of it delivered through Joint Industry Projects (JIPs), is focused on generating empirical data, validating models, and improving confidence in system-level behaviour.

These initiatives are particularly important for dense-phase CO_2 systems, where thermodynamic behaviour, impurity interactions, and transient conditions differ materially from conventional hydrocarbon pipelines. Most of the current research effort is therefore concentrated on areas identified in this report as TRL 6–8, including decompression behaviour, fracture propagation, dispersion modelling, and impurity effects.

A key contributor to this effort is DNV, which operates a dedicated research and testing facility at Spadeadam in Cumbria. This site hosts large-scale experimental programmes designed to replicate realistic CO_2 pipeline conditions, including high-pressure releases, transient decompression, and impurity-variable mixtures. These experiments provide critical validation data that cannot be obtained through modelling alone.

One of the most significant current programmes is Project Skylark, which focuses on large-scale testing of CO_2 releases to improve understanding of dispersion behaviour and consequence modelling. The project is generating high-quality empirical datasets for dense-phase CO_2 releases, enabling validation and refinement of both integral models (e.g. PHAST-type tools) and advanced CFD simulations. This work directly addresses one of the key uncertainties identified in this report: predicting hazard distances and dispersion characteristics for CO_2 releases under realistic conditions.

Beyond dispersion, ongoing JIPs and research programmes are addressing several other critical areas:

- Decompression and fracture control: Large-scale testing and modelling are improving understanding of CO_2 decompression curves, including the effects of impurities on the characteristic pressure plateau that governs running ductile fracture behaviour.
- Impurity effects and phase behaviour: Research is refining equations of state and validating thermodynamic models for multi-component CO_2 streams, particularly under transient conditions relevant to CCS networks.
- Transient flow assurance: Experimental and modelling work is improving the prediction of low-temperature behaviour during blowdown and restart, including dry ice formation and hydrate risks.
- Monitoring and leak detection: Programmes are evaluating the performance of sensing technologies and detection methodologies under CO_2-specific release conditions.

Collectively, these research efforts are reducing uncertainty and enabling the transition from component-level maturity to system-level confidence. However, it is important to recognise that many of these programmes are still ongoing, and their outputs are not yet fully embedded in standards, design practices, or regulatory frameworks.

As a result, while ongoing research is actively closing key knowledge gaps, current CCS projects must often proceed using conservative assumptions and partial datasets. This contributes directly to the integration and assurance challenges identified throughout this report, reinforcing the need for continued coordination between research programmes, standards development, and project delivery.

The following examples illustrate how these research themes are being addressed in practice:

- Project Skylark – large-scale CO_2 release and dispersion validation, led by DNV
- CO_2SafePipe – pipeline design, impurities, and fracture control, led by DNV

- MetCCUS and related metrology programmes - Measurement and calibration of CO_2 mixtures, led by European metrology institutes (e.g. RISE, NPL, TÜV SÜD NEL),
- CATO – A national CCS research programme covering the full value chain and industry guidelines for setting the CO2 Specification in CCUS Chains. It focuses on setting the CO_2 specification in CCUS chains. It covered thermodynamics, chemical reactions, materials and corrosion, safety and environment, capture and conditioning, compression and pumping, metering & sampling, pipeline transport, ship transport, geological storage and economics, led by TNO (Netherlands Organisation for Applied Scientific Research)

These build on earlier programmes, including CO_2PipeHaz, COOLTRANS, CO_2Pipetrans, COSHER, CO_2SafeArrest and CO_2QUEST, which collectively underpin current engineering practice but are still being extended through new large-scale validation work.

6. GAP ANALYSIS

6.1 Summary

This section identifies the principal integration and validation gaps that could stall the development of UK CO_2 Transport and Storage (T&S) system infrastructure. It also details the practical impacts of each gap and outlines targeted measures to accelerate deployment. Table 6-1 summarises the performed gap analysis, highlighting the key barriers identified across the CO_2 process chain together with the principal onshore and offshore factors that influence each. Delivery risks and potential solutions are also discussed for each identified gap. The table is intended to support navigation and prioritisation by highlighting where gaps are most likely to drive schedule, cost, and risk, with the detailed discussion that follows setting out the underlying rationale and implications for UK CO_2 Transport and Storage (T&S) system deployment. The following sections provide supporting detail.

Table 6-1 –T&S Gap Analysis Considering Onshore and Offshore Factors

#	Transport Gap	Description	Onshore Factors	Offshore Factors	Delivery Risk	Potential Solutions
1	CO_2 Quality & Specification	Network entry specs, impurity limits, standardisation across UK clusters, purity monitoring and re-conditioning at hubs/terminals, impacts on operability and storage acceptance	More emitters/entry points mean more variability; easier access for sampling & conditioning skids	Fewer access points but harder to access; subsea/remote sampling constraints; tight interface at landfall/platform	Off-spec events trigger curtailment, disputes, redesign and delayed commissioning	Establish a coherent spec + verification + off-spec governance regime: align entry conditions with storage acceptance; define sampling/analyser expectations and uncertainty treatment; define blending/compositional tracking rules; and enforce off-spec management pathways (diversion/waivers/remediation) to reduce redesign and contractual stand-offs
2	Phase Behaviour & Flow Assurance	Phase envelope management, two-phase risks, hydrates/ice/dry ice, low-temperature blockage risks, operating window control, thermal management (esp. blowdown / transient cooling)	Temperature swings + shutdown/startup events; venting/blowdown constraints near population	Cold seabed + hydrate/ice risks at subsea/landfall; depressurisation harder to manage; insulation/thermal design critical	Blocked vents/valves and unstable restart behaviour extend outages and drive conservative operating envelopes	Use improved transient modelling and validated decompression curves for realistic compositions; design staged blowdown/venting procedures and cold-resistant vent hardware; assess insulation/burial and (if needed) boosting together with sizing/inlet conditions
3	Materials & Corrosion	Water/impurity-driven corrosion mechanisms, materials compatibility, corrosion management, external corrosion, inspection and materials selection for dense/liquid CO_2 service	Soil-driven external corrosion + third-party damage risk; easier inspection/repair	Seawater exposure + deepwater fatigue; subsea corrosion protection & inspection complexity; repair costly/logistically difficult	Integrity uncertainty forces material re-qualification, additional conditioning scope, and delayed readiness to operate	Make water control a primary safeguard (dehydration/cooling to keep “wet” out of the network); qualify non-metallics and seals for pressure/temperature/decompression cycles and impurity envelope; integrate corrosion threat models with inspection and operating transients
4	Hydraulics, Transients & Decompression	Steady-state hydraulics, transient operations, depressurisation behaviour, decompression curves, crack arrest/fracture control	More tie-ins/valves/crossings mean transient complexity; emergency isolation easier access	Longer subsea segments mean large inventories; isolation/venting constraints; decompression/fracture	FEED iteration and redesign if transient envelope and decompression/fracture controls are not proven early	Validate a full-life “system envelope” (capture variability + linepack + compressors + wells) including transients and trip recovery; apply CO_2-specific emergency depressurisation design (staged blowdown, isolation philosophy, toughness)

#	Transport Gap	Description	Onshore Factors	Offshore Factors	Delivery Risk	Potential Solutions
		design, surge/ linepack management		consequences harder to intervene		
5	Compression & Dehydration Reliability	Compression/dehydration system design, rotating equipment reliability and maintainability, impurity impacts on performance, availability planning for network service	Typically, easier maintenance access; footprint/noise planning constraints	Offshore topsides space/weight limits; access windows drive high reliability & redundancy expectations	Trips/intermittency reduce utilisation and can trigger repeated re-baselining of the delivery plan	Design around abnormal operation: integrate utilities/controls, chemical handling, vent management and blowdown as core reliability systems; validate start/stop and turndown behaviour; ensure operating procedures prevent off-spec propagation into shared infrastructure
6	Safety, Leak Detection & Response	Integrity, QRA, dispersion/consequence modelling for dense CO_2 releases, routing, detection/isolation philosophy, emergency response planning and interfaces with local authorities/operators	Higher public exposure means consequence modelling scrutiny; emergency response coordination with local services	Lower public exposure but remote detection/response; subsea leak localisation difficult; marine response logistics	Iterative consenting and late design changes (valve spacing, venting, route/layout) if QRA basis is not robust	Establish a QRA methodology and governance early (assumptions, uncertainty, acceptability); tailor third-party interference management for CO_2 service; agree emergency planning early with authorities; use monitoring that shortens time-to-isolation (e.g., fibre/DAS) with robust analytics
7	Measurement & Custody Transfer	Sampling/analysis, metering accuracy, allocation in shared systems, custody transfer rules, data quality and auditability.	More custody points and third-party metering; access facilitates calibration/inspection	Fewer points but harsher conditions; offshore metering maintenance and verification more challenging/costly	Commissioning delay and disputes if calibration drifts under composition change or impurity spikes are missed.	Use metering designed for mass flow + composition with explicit calibration strategy for density/compressibility changes; detect transient impurity spikes; align uncertainty requirements with accounting/verification needs and data governance.
8	Network Operations	Multi-shipper/at scale integration, controllability, nominations/dispatch, batch vs continuous operation, balancing/curtailment, redundancy philosophy, outage coordination, operating rules (network code-type requirements), SCADA, cybersecurity, metering/allocation accuracy and data integrity, digital twinning	More nodes mean complex dispatch/linepack management; easier operational access for interventions	Fewer physical access options: offshore outages have bigger capacity impacts; remote ops resilience critical	Poor controllability increases curtailment and slows ramp-up to stable utilisation	Deploy advanced network simulation tools and automated pressure/blending controls; add impurity forecasting; codify batching tolerance and rules; develop an integrated operating envelope and operating playbook (start-up/shutdown/re-entry)
9	Onshore Delivery Challenges	Routing constraints, construction logistics, third-party crossings, public interface, land access constraints, stakeholder acceptance impacts on schedule/design	Dominated by crossings, utilities, stakeholders, population proximity; construction disruption	N/A (covered under Offshore Delivery)	Late route/layout changes and schedule slip if assessment methods and messaging are inconsistent	Align early on CO_2-specific QRA methodology and emergency planning approach; implement CO_2-tailored third-party interference management and clear public emergency messaging to reduce consenting iteration

#	Transport Gap	Description	Onshore Factors	Offshore Factors	Delivery Risk	Potential Solutions
10	Offshore Delivery Challenges	Subsea tie-ins, platforms/monopoles/subsea structures, marine operations, inspection/repair constraints, weather windows, offshore HSE and consenting complexity	N/A (covered under Onshore Delivery)	Weather windows, vessel availability, installation complexity; subsea intervention is slow and expensive	Longer outages and conservative design bases due to intervention limits and isolation/blowdown constraints	Treat offshore distance as hydraulic-thermal breakpoints: manage phase margin (diameter, inlet pressure, insulation/burial, boosting) and isolation/blowdown strategy (staged procedures, vent/relief design); justify platform/NPAI vs subsea architecture based on operability/intervention and safety-case needs
11	Long-Distance Subsea Control (Umbilical Limits)	Subsea control of pipelines and associated equipment via umbilicals over very long distances (e.g. >150–200 km) approaches or exceeds typical oil and gas practice. Challenges include hydraulic pressure losses, slow actuation response, power delivery constraints, signal latency, and reduced reliability for critical functions such as isolation and emergency shutdown.	Control systems are typically located close to assets with minimal distance constraints; easier access for maintenance, testing and redundancy implementation	Very long umbilicals required; hydraulic efficiency decreases with distance; slower valve response times; limited intervention access; higher consequence of control system failure; integration with subsea structures and pipeline control more complex	Inability to achieve timely or coordinated isolation and control under fault or emergency conditions; increased safety case challenge; requirement for redesign of control architecture late in project; reduced system reliability and operability	Adopt alternative control architectures such as electro-hydraulic or all-electric systems (e.g. electric actuators on valves) to reduce reliance on long hydraulic lines; consider distributed control nodes or intermediate platforms to shorten umbilical lengths; design redundancy and fault-tolerant control systems; validate response times and isolation performance early through system-level modelling and testing
12	Storage Interface Constraints	Injection pressure/temperature constraints, ramp rates, backpressure management into the transport network, operational coordination with storage, storage acceptance criteria	Onshore hub buffering (Linepack /intermediate storage) can smooth variability; interface equipment accessible	Storage is offshore so platform/subsea interface; injectivity/backpressure directly constrains trunkline throughput	Prolonged assurance cycles and chronic curtailment if interface envelope is not validated across life-of-field scenarios	Develop a validated system envelope coupling capture variability, linepack, compressor control and well/reservoir constraints; assess staged strategies early (e.g., initial gas-phase injection transitioning later); define batching rules and stress-test against well/reservoir models
13	Monitoring, Measurement & Verification (MMV)	Pipeline-focused MMV covering leak detection, containment assurance, flow and composition monitoring, and verification of transported CO_2 volumes and quality between custody transfer points (pig trap to pig trap). This includes integration of metering, sampling, SCADA, and data governance systems to support safe operation, emissions accounting, and regulatory compliance. Excludes subsurface storage	Easier access for installation, calibration and maintenance of metering, sampling and leak detection systems; greater flexibility for inspection, repair and system upgrades	Limited physical access; reliance on remote sensing (e.g. pressure/flow balance, fibre-optic/DAS, subsea monitoring); higher cost and complexity of intervention and verification activities	Delayed commissioning, regulatory challenge or commercial disputes if leak detection performance, measurement accuracy or data integrity are not demonstrated; uncertainty in emissions accounting and custody transfer under variable composition or transient conditions	Define a transport-specific MMV architecture early, aligned with safety case and custody transfer requirements; deploy robust leak detection (e.g. pressure/flow analytics, fibre-optic/DAS) with validated performance; integrate metering, sampling and data governance systems; define verification thresholds, alarm logic and response procedures; ensure alignment with regulatory reporting and emissions accounting frameworks

#	Transport Gap	Description	Onshore Factors	Offshore Factors	Delivery Risk	Potential Solutions
		MMV (e.g. plume monitoring, reservoir verification), which is addressed under storage regulation.				
14	Harmonised Standards	Most standards from O&G, few address dense phase behaviour or impurity-driven risks, no current harmonisation	Inconsistent requirements across routes/regions complicate design and approvals; multiple local authority interfaces	Offshore standards must align with marine regs and O&G legacy practice; harmonisation needed for cross-cluster reuse	Rework and prolonged assurance due to inconsistent codes/basis assumptions between Users and T&SCo	Adopt and apply a coherent standards stack across the chain (including CO_2 pipeline standards and composition guidance), and translate it into enforceable spec/verification/off-spec rules to reduce redesign and disputes
15	Permitting & Access Rights	Consenting/planning pathways (onshore and offshore), permitting timelines and compliance requirements (incl. environmental assessments), plus land/right-of-way acquisition, easements, marine/seabed rights, crossing agreements, co-location constraints, and third-party negotiations—often collectively driving route selection, schedule, and constructability	ROW/landowner agreements; planning risk often schedule-critical; strong stakeholder sensitivity	Marine licences, seabed rights, landfall consents; co-location with wind/fishing/oil & gas/shipping lanes drives route complexity	Delayed permissions prevent surveys, freeze of route/landfall, and mobilisation	Reduce iteration by agreeing QRA methodology/governance early and aligning it with planners and regulators; build the evidence base for permits and leases in parallel with concept selection
16	Cost & Economic Viability	CAPEX/OPEX and economies of scale, utilisation/throughput risk, regulated model impacts (tariffs/returns), FOAK contingency and financing constraints	Lower install cost, but higher social/land/interface costs; easier OPEX access	Very high install and intervention costs; fewer intervention options drive conservative design and higher contingency	FID delays or repeated re-baselining if utilisation ramp-up assumptions are not credible	Tighten utilisation assumptions and risk allocation: define capacity allocation/nominations processes; integrate charging and capacity arrangements with realistic capture availability and storage performance; recognise FOAK financing friction and apply revenue-support mechanisms where applicable
17	Non-Pipeline & Intermodal Transport	CO_2 shipping/road/rail interfaces, terminal design, liquefaction and intermediate storage, loading/unloading operations, multimodal logistics and constraints	Truck/rail feasible for small volumes; local permitting/traffic constraints at terminals	Shipping-led systems need port/jetty infrastructure including storage; marine ops reliability and boil-off/conditioning management	Interface unreliability (liquefaction/storage/loading/unloading) drives repeated shutdowns and delays scale-up	Treat NPT as an engineered system: define interface standards and operating playbooks; specify consistent receiving/transfer conditions; design storage and schedules around disruption scenarios; integrate boil-off/conditioning and quality management; for road/rail define practical terminal/permitting solutions and throughput limits with a clear transition plan to higher-capacity transport.
18	Decommissioning & End-of-Life	Decommissioning processes and liability, asset reuse vs abandon decisions,	Land restoration and third-party agreements;	Subsea decommissioning expensive; long-term	Late-stage scope/uncertainty increases contingent	Define decommissioning philosophy early: plan for safe depressurisation without dry ice blockage; pipeline cleaning/purging/inerting, and internal

#	Transport Gap	Description	Onshore Factors	Offshore Factors	Delivery Risk	Potential Solutions
		decommissioning standards and funding provisions, closure planning	easier physical access for removal	seabed obligations and marine permitting complexity	liability and can slow approvals/financing decisions	condition assessment prior to abandonment; build decommissioning evidence and provisions into lifecycle planning
19	Competency & Capability	Skills, procedures, organisational readiness for dense and gas-phase CO_2 operations, integrity management capability, emergency response competency, training requirements	Broader workforce availability: training needed for dense and gas-phase CO_2 hazards and multi-shipper ops	Specialist offshore competence required; limited personnel access windows (weather constrained); strong reliance on proven offshore procedures	Commissioning and early operations are delayed by immature procedures/skills, especially around transients, pigging, and emergency response	Establish CO_2-specific operating procedures for pigging/ILI runs that avoid two-phase conditions; build intervention plans for stuck tools with safe depressurisation sequencing; implement data quality thresholds and anomaly confirmation processes; agree emergency planning early with relevant authorities and embed into operating procedures

6.2 CO_2 Quality & Specification

A persistent delivery constraint for shared UK CO_2 transportation networks is the lack of a consistently applied, end-to-end approach to CO_2 stream quality that aligns capture outputs with transport operability and storage acceptance. Captured CO_2 streams are not compositionally uniform and can vary with capture plant operating mode, intermittent operation and non-steady events, leading to changes in phase behaviour and increasing the likelihood of two-phase conditions or solid formation under certain operating scenarios. This is particularly relevant for networks designed to operate at elevated pressures where dense-phase or supercritical transport may be favoured for capacity and efficiency, but where transient conditions such as start-up, shutdown, turndown and upset response can push operating points into more challenging regimes. UK safety guidance recognises that CO_2 may be conveyed as a dense phase and emphasises the need for operators to understand hazards and failure mechanisms, noting continuing uncertainties for dense/supercritical conveyance in CCS contexts[135, 136]. In practice, where specifications and verification processes are not harmonised across emitters and clusters, operators and developers are incentivised to take conservative positions, narrowing operating envelopes and reducing flexibility to ensure that composition swings do not compromise flow assurance, integrity or compression performance.

This challenge becomes more pronounced in multi-user systems because the number of emitters and entry points increases compositional variability and the probability of off-spec excursions[137]. Onshore networks may experience a greater diversity of entry streams and therefore greater variability but typically allow more straightforward physical access for sampling and conditioning equipment at hubs and terminals. Offshore networks may have fewer access points but face greater challenges to sampling and intervention, including subsea or remote constraints and tighter operational interfaces at landfalls or platforms. These practical differences do not reduce the need for common specifications; rather, they strengthen the requirement for clear, enforceable rules on measurement, verification and off-spec management that work across both onshore and offshore operating environments.

The gap is not simply technical; it is also institutional and contractual. Economic regulation and network governance in the UK are evolving to support transport and storage networks, including licensing and operational oversight by Ofgem and NESO[138, 139]. The CCS Network Code establishes commercial and technical arrangements between transport and storage companies and network Users, including connection and operational arrangements[140]. Separately, government consultation activity highlights the policy intent to facilitate transparent, non-discriminatory access to CO_2 infrastructure and to ensure regulatory arrangements are fit for a developing market[141]. A harmonised, operationally grounded national approach to CO_2 quality is required, including entry specifications, measurement and verification requirements, and clear handling of upset events. Without this, shared infrastructure faces increased interface friction, higher dispute potential and a tendency for projects to adopt incompatible design assumptions that delay approvals and drive redesign.

[135] HSE. Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects. Available: Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects - HSE [Accessed 02 March 2026].
[136] HSE. Major hazard potential of CCS. Available: Major hazard potential of CCS - HSE [Accessed 02 March 2026].
[137] Suvanmani V. Impurities in CO2 streams for a multi-user CCS hub. *Australian Energy Producers Journal* 65. 2025. Available: Impurities in CO2 streams for a multi-user CCS hub | Australian Energy Producers Journal | ConnectSci [Accessed 09 March 2026].
[138] Ofgem. How we regulate carbon dioxide transport and storage networks. Available: How we regulate carbon dioxide transport and storage networks | Ofgem [Accessed 09 March 2026].
[139] NESO. What we do – National Energy System Operator. 2024. Available: What we do | National Energy System Operator [Accessed 09 March 2026].
[140] CCS Network Code. Network Code – Current Version. 2026. Available: Network Code – Carbon Capture and Storage Network Code [Accessed 09 March 2026].
[141] DESNZ. Carbon capture, usage and storage (CCUS): Ensuring fair access to CO2 infrastructure. 2026. Available: Carbon capture, usage and storage (CCUS): Ensuring fair access to CO2 infrastructure (accessible webpage) - GOV.UK [Accessed 09 March 2026].

International standards and guidance provide a basis for structuring this harmonisation effort. ISO 27913 defines requirements and recommendations for pipeline transportation systems for CO_2 streams, explicitly covering onshore and offshore pipelines, conversion of existing pipelines, transportation in gaseous and dense phases, and aspects of stream quality assurance and the convergence of streams from different sources[142]. Complementing this, ISO/TR 27921 describes compositional characteristics of CO_2 streams downstream of capture and discusses purification options, offering a structured reference point for understanding likely stream constituents and variability[143]. Recommended practices and guidelines also seek to provide an "internationally acceptable framework" for the design, construction and operation of CO_2 pipelines in both onshore and offshore settings[144], with Energy Institute guidance addressing repurposing and design considerations for CO_2 pipeline service across onshore and offshore assets[145]. The importance of coherent CO_2 specifications at a network level, rather than solely project-by-project, is also emphasised in sector briefings and targeted insight publications that frame specification as an enabling condition for safe and effective transport and for managing corrosion and operational risk[146, 147].

Closing this gap requires moving from fragmented assumptions to a nationally coherent framework that is explicit about both steady-state and transient operability expectations. A UK CO_2 specification regime that aligns transport entry conditions with storage acceptance criteria, supported by mandatory measurement and verification standards covering sampling locations, analyser or laboratory performance expectations, uncertainty treatment and data governance, would reduce disputes and enable more predictable network operations. This should be complemented by defined rules for blending and compositional tracking in multi-emitter hubs to make mixed-stream behaviour more predictable and to support robust phase behaviour assessments under realistic operating scenarios. Finally, an enforceable off-spec management and liability approach is needed so that curtailment, diversion, waivers and remediation pathways can be applied consistently, reducing the risk that specification disagreements translate into curtailment events, commissioning delays or contractual stand-offs. When implemented together, these measures would reduce the incentive for each project to over-design in isolation and strengthen interoperability, operability, and investment confidence as UK CO_2 Transport and Storage (T&S) systems at network scale.

Overall, accelerating UK CO_2 Transport and Storage (T&S) system deployment depends on moving from project-specific assumptions to a consistent national specification, verification and off-spec governance framework that enables interoperable, safely operable shared infrastructure and reduces redesign, dispute and commissioning delay risk across multi-user networks.

In addition to national alignment, there is increasing importance in ensuring consistency with emerging European CO_2 transport specifications, particularly as cross-border transport and shared offshore storage networks develop. Several European initiatives, including CCS projects in the North Sea basin and EU-funded studies, are working toward convergence on CO_2 quality ranges, impurity limits, and verification approaches. However, like the UK, these efforts remain partially harmonised, with specifications often defined at the project or cluster level. Misalignment between UK and European specifications could introduce barriers to interoperability, particularly for ship-based transport, future interconnectors, or shared storage resources. A UK framework developed with

[142] ISO. ISO 27913:2024 Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems. 2024. Available: ISO 27913:2024 - Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems [Accessed 09 March 2026].
[143] ISO. ISO/TR 27921:2020 Carbon dioxide capture, transportation, and geological storage — Cross Cutting Issues — CO2 stream composition. 2020. Available: ISO/TR 27921:2020 - Carbon dioxide capture, transportation, and geological storage — Cross Cutting Issues — CO2 stream composition [Accessed 09 March 2026].
[144] DNV. DNV-RP-F104 Design and operation of carbon dioxide pipelines. 2021. Available: DNV-RP-F104 Design and operation of carbon dioxide pipelines [Accessed 09 March 2026].
[145] Energy Institute. EI 3545 Repurposing and design guidelines for carbon dioxide pipelines. 2023. Available: Repurposing and design guidelines for carbon dioxide pipelines | Energy Institute [Accessed 09 March 2026].
[146] CCUS Projects Network. Briefing on carbon dioxide specifications for transport. 2019. Available: Microsoft Word - Briefing-CO2-Specs-FINAL-v1.docx [Accessed 09 March 2026].
[147] Burnard, K. (IEAGHG). Insight Paper: The Role and Importance of CO2 Specification on Transport and Storage Networks. 2025. Available: 2025-IP01 The Role and Importance of CO2 Specification on Transport and Storage Networks.pdf [Accessed 09 March 2026].

reference to European standards, guidance, and project practice would support future integration, reduce the risk of re-specification, and enhance the network's long-term flexibility. Alignment does not necessarily require identical limits, but should ensure compatibility of operating envelopes, measurement approaches, and off-spec handling philosophies.

6.3 Phase Behaviour & Flow Assurance

A material flow assurance gap for CO_2 Transport and Storage (T&S) systems is the limited availability of predictive, validated methods (partially addressed through ongoing research programmes, see Section 5.19) and practical operating guidance for low-temperature transients, particularly during depressurisation of dense-phase CO_2 systems. Depressurisation can drive rapid cooling through JT and auto-refrigeration effects, taking local conditions into regimes where solid CO_2 can form and deposit and, where water is present, where ice or CO_2 hydrates may form[148, 149]. Experimental and modelling literature on CO_2 depressurisation in pipework identifies dry-ice formation as a credible phenomenon during depressurisation, including at locations such as bends and valves where solids may accumulate and pose a blockage risk[150]. From a UK safety perspective, national guidance on conveying CO_2 recognises material hazards associated with CO_2 transport and stresses the importance of understanding corrosion mechanisms, including the role of water content, which is directly relevant where low temperatures and residual or ingress water coincide[151].

These low-temperature risks concentrate at restrictions, valves and vent or blowdown systems, and at low points where cold fluid or solids can collect. The operational consequence is that vents and emergency depressurisation pathways can become vulnerable to blockage or impaired performance, potentially increasing reinstatement time, inspection burden and downtime following trips or commissioning activities. More broadly, the hazard is not limited to steady-state design conditions. The credible envelope for depressurisation and restart can be materially colder than normal operation, requiring explicit transient assessment and well-defined operational controls. Evidence from experimental datasets and associated analyses highlights that predicting the coupled pressure–temperature evolution is essential to identifying key phenomena such as dry-ice formation and duration during pipeline depressurisation[152, 153]. This reinforces the underlying gap identified for UK projects: where validated tools and reference datasets are limited for realistic impurity mixes and transient events, developers default to conservative assumptions, extensive assurance cycles and additional instrumentation or materials measures; increasing cost and schedule risk.

Network context amplifies these challenges. Onshore systems may experience temperature swings associated with shutdown and start-up events and may face constraints on venting and blowdown arrangements near populated areas. This can narrow the acceptable depressurisation and restart strategies and increase the importance of robust thermal management and operability planning. Offshore export lines and long-distance networks add further thermal and transient complexities: cold seabed environments, long cooldown periods during shutdown, and heat-transfer limits during warm-up and restart can push conditions into low-temperature or two-phase regions not

[148] Tweed, L.E.L.; Bickle, M.J.; Neufeld, J.A. Transient Joule–Thomson cooling during CO2 injection in depleted reservoirs. *Journal of Fluid Mechanics*. 2024. Available: Transient Joule–Thomson cooling during CO2 injection in depleted reservoirs | Journal of Fluid Mechanics | Cambridge Core [Accessed 09 March 2026].
[149] Log, A.M. et al. Temperature response during rapid depressurization of CO2 in a pipe: Experiments and fluid-dynamics modelling. *International Journal of Multiphase Flow*. Volume 192. 2025. Available: Temperature response during rapid depressurization of CO2 in a pipe: Experiments and fluid-dynamics modelling - ScienceDirect [Accessed 09 March 2026].
[150] Qiao, F. et al. Experimental study on the safety of dry ice freeze plugging by throttling effect during pressure relief of industrial CO2 pipeline. *Process Safety and Environmental Protection*. Volume 197. 2025. Available: Experimental study on the safety of dry ice freeze plugging by throttling effect during pressure relief of industrial CO2 pipeline - ScienceDirect [Accessed 09 March 2026].
[151] HSE. Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects. Available: Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects - HSE [Accessed 02 March 2026].
[152] Log, A.M. et al. Temperature response during rapid depressurization of CO2 in a pipe: Experiments and fluid-dynamics modelling. *International Journal of Multiphase Flow*. Volume 192. **2025**. Available: Temperature response during rapid depressurization of CO2 in a pipe: Experiments and fluid-dynamics modelling - ScienceDirect [Accessed 09 March 2026].
[153] SINTEF. Understanding CO2 Depressurization in Pipes. **2025**. Available: Understanding CO2 Depressurization in Pipes – SINTEF Blog [Accessed 09 March 2026].

encountered in steady-state design. In this context, the need for insulation and thermal design becomes critical, and the feasibility of depressurisation and restart can be dominated by line length and thermal inertia. Established guidance for CO_2 pipeline systems seeks to provide a structured framework for design and operation across onshore and offshore CO_2 pipelines, supporting the use of consistent engineering practice to manage integrity and operability challenges that arise in these environments[154]. UK-specific safety-oriented guidance also positions CO_2 pipeline hazards and decision support in the context of knowledge gaps and appropriate use of methods, which is consistent with the need to treat transient behaviour and low-temperature phenomena as first-order design and operational considerations[155].

Addressing this gap requires a shift from typical pipeline depressurisation practices to CO_2-specific transient flow assurance and operating philosophy across the full lifecycle, including start-up, shutdown, trips, blowdown and restart. A practical acceleration measure is to treat venting and blowdown as a specialist CO_2 service, with a defined design basis and depressurisation philosophy aligned to credible transient scenarios and the risk of solid formation. Publicly available engineering studies of handling CO_2-rich streams in vent and flare systems explicitly frame the risk of solid CO_2 formation during depressurisation to atmospheric conditions and show that temperatures may fall below thresholds associated with dry-ice formation during such events, illustrating the need for deliberate vent system design and modelling[156]. The complementary operational requirement is a coherent operating envelope that sets minimum temperatures and pressures, ramp rates, shutdown and restart sequences, and water-management actions that remain consistent across the CO_2 chain, so that interface decisions do not reintroduce low-temperature or plugging risks at system boundaries.

For offshore systems, early inclusion of shutdown and restart thermal studies and associated mitigations is essential to avoid late-stage design change. Cold ambient conditions, long cooldowns and slow warm-up, insulation, heating requirements, drainability and low-point management, and fit-for-purpose monitoring can all materially influence whether restart strategies remain within acceptable operability limits. Finally, because the core technology gap relates to predictive confidence under realistic conditions, a UK-wide validation and data-sharing programme supported or enabled by government would accelerate deployment by benchmarking solid CO_2 and hydrate/ice prediction methods against representative pipeline sizes, layouts and impurity envelopes, and by translating that evidence base into consistent engineering and operational guidance. Ongoing research is being undertaken to address this, see section 5.19.

In summary, UK CO_2 network deployment is at risk without reliable availability and efficient operability of CO_2-specific transient flow assurance techniques that credibly capture low-temperature depressurisation behaviour, translating validated prediction methods into robust vent and blowdown design philosophies and operator practices across onshore and offshore environments.

6.4 Materials & Corrosion

Corrosion and materials integrity risk in CO_2 transport and storage networks is driven by the challenge of maintaining sufficiently dry conditions across the full system lifecycle. Even small amounts of free water can enable carbonic acid formation and rapid internal corrosion, but end-to-end assurance of "dry" conditions is difficult to sustain across transient operations, deadlegs and low points, and during recommissioning following shutdown. Published research and guidance on dense-phase CO_2 transport consistently reinforces that internal corrosion risk is closely linked to water availability and the behaviour of impurities under transport conditions and highlights the continuing need to define safe operating windows under realistic conditions (see Section 5.19 for ongoing research in this

[154] DNV. DNV-RP-F104 Design and operation of carbon dioxide pipelines. **2021**. Available: DNV-RP-F104 Design and operation of carbon dioxide pipelines [Accessed 09 March 2026].
[155] Bilio, M. (HSE) et al. The CO2PipeHaz Good Practice Guidelines for CO2 pipeline safety. **2014**. Available: (PDF) The CO2PipeHaz Good Practice Guidelines for CO2 pipeline safety [Accessed 03 March 2026].
[156] Fulchini, F. (Siemens) et al. Design Considerations for Pressurised Flare and Vent Systems for EfficientCO2 Management. **2025**. Available: fabio-fulchini-siemens-industry-software-21920.pdf [Accessed 09 March 2026].

area)[157, 158]. In the UK context, national safety guidance for conveying CO_2 in pipelines also frames safe conveyance in terms of understanding hazards and degradation mechanisms, including corrosion control and the implications of transport conditions for integrity management[159].

A second driver of uncertainty is that trace reactive contaminants can materially change corrosion mechanisms and outcomes compared with nominally dry CO_2 service. In the presence of water, impurities such as sulphur and nitrogen oxides and oxygen can alter aqueous chemistry, promote localised attack and complicate the definition of an acceptable impurity envelope. Experimental work demonstrates that when depressurisation leads to the formation of a separate liquid phase, certain impurities can preferentially accumulate in that phase and increase acidity and reactivity, with corrosion rates elevated under the conditions investigated[160]. This evidence aligns with the practical concern that corrosion exposure is not governed solely by steady-state composition limits, but also by how impurities and water partition during transients, including low-flow periods, temperature gradients and depressurisation events that can promote local condensation and water dropout in pockets. The resulting integrity risk can drive additional pigging and monitoring, longer commissioning and restart windows, and unplanned outages where water management is not demonstrably robust through the full range of operating modes.

These internal corrosion and impurity effects directly influence materials selection decisions, where dense-phase CO_2 with contaminants is not equivalent to conventional dry natural gas service. Rules for when carbon steel is acceptable versus when corrosion-resistant alloys, linings, or cladding are required remain uneven and are often sensitive to uncertainties in impurity control and transient behaviour. Research in this area continues to investigate the effects of impurities and water on carbon steel corrosion under dense-phase CO_2 conditions and to characterise how different contaminant species influence corrosion responses, reflecting that evidence gaps persist for defining robust operating windows and material performance boundaries[161]. Where such evidence is incomplete, projects tend to apply conservative design margins, expand qualification and testing scope, and add monitoring and mitigation systems with predictable impacts on procurement lead times, capital cost, and the timing of final investment decisions.

The interface dimension is particularly important for shared infrastructure because a nominal "dryness" condition demonstrated at capture plant battery limits may not be sufficient to protect transport and storage assets if transients and hold-up mechanisms can still create free water locally within the wider system. This mismatch can become a source of contractual and operational friction, including disputes over liability for corrosion damage and downtime, and can drive late changes if transport and storage operators require additional assurance measures, conditioning scope or materials upgrades after front-end assumptions have already been embedded. In this respect, governance arrangements and industry guidance emphasising coherent design and operational practice for CO_2 pipeline systems provide a useful foundation, but practical implementation still depends on consistent interpretation and evidence-based decision-making rules shared across stakeholders.

Accelerating UK project delivery, therefore, requires treating water control as a system-wide integrity requirement rather than a capture-only specification, with explicit end-to-end assurance that accounts for transients, restart procedures and hold-up management in deadlegs and low points. A coherent monitoring and verification strategy for water and relevant impurities, including data

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[157] Dugstad, A. (Institute for Energy Technology) et al. Corrosion in Dense Phase CO2 Pipelines - Three Reasons for Concern. **2011**. Available: [Dense phase CO2 transport – when is corrosion a threat?] [Accessed 09 March 2026].

[158] Patchigolla, K.; Oakey, J.E.; Anthony, E.J. (Teesside University). Understanding dense phase CO2 corrosion problems. *Energy Procedia.* Volume 63. **2014**. Available: [Understanding dense phase CO2 corrosion problems - Teesside University's Research Portal] [Accessed 09 March 2026].

[159] HSE. Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects. Available: [Guidance on conveying carbon dioxide in pipelines in connection with carbon capture and storage projects - HSE] [Accessed 02 March 2026].

[160] Dugstad, A. (Institute for Energy Technology) et al. Corrosion in dense phase CO2 – the impact of depressurisation and accumulation of impurities. *Energy Procedia.* Volume 37. **2013**. Available: [Corrosion in Dense Phase CO2 – the Impact of Depressurisation and Accumulation of Impurities - ScienceDirect] [Accessed 09 March 2026].

[161] NETL, ExxonMobil, DNV, US DOE. Corrosion of Carbon Steel in Dense Phase CO_2 with Impurities. **2024**. Available: [Master Cover Title] [Accessed 09 March 2026].

governance and defined operational responses to excursions, would reduce uncertainty and improve alignment across all interfaces. In parallel, developing a UK-appropriate materials selection and qualification guideline for dense-phase CO_2 with plausible impurity envelopes and operating modes would provide consistent decision rules and reduce late-stage changes that drive cost and schedule escalation. Finally, embedding operability and layout requirements that minimise water accumulation and enable effective drainage and pigging, together with a clear liability and off-spec regime for corrosion-related excursions, would reduce interface risk and improve investment confidence for shared networks.

UK CO_2 Transport and Storage (T&S) systems risk not achieving reliable, scalable deployment until corrosion assurance is consistent through transients and interfaces, supported by monitoring, evidence-based materials rules and operable integrity strategies across onshore and offshore assets.

6.5 Fracture Management

Hydraulics, transient behaviour and decompression performance represent a material source of design and delivery uncertainty for dense-phase CO_2 networks, because rapid depressurisation from dense phase is inherently coupled to phase change. In contrast to natural gas, where decompression behaviour is typically treated as a single-phase gas expansion over much of the relevant range, dense-phase CO_2 can exhibit a characteristic saturation plateau in the decompression curve that materially affects the crack-driving force and the ability to arrest a running ductile fracture. Figure 6-1 illustrates the interaction between pipeline material resistance and fluid decompression behaviour during a rupture. The solid line represents the material curve, where fracture speed is governed by pipe toughness (e.g. CVN), while the fluid curves show how pressure decays behind a propagating crack. For natural gas, pressure decreases rapidly with crack speed, allowing the decompression curve to intersect the material curve relatively early, enabling fracture arrest at moderate toughness levels. In contrast, CO_2 exhibits a decompression plateau due to phase change effects, maintaining higher pressure over a range of crack speeds. This sustains the driving force for fracture propagation, shifting the intersection with the material curve to higher pressures and requiring significantly greater toughness to achieve arrest. As a result, CO_2 pipelines are more susceptible to long-running fractures during blowdown unless material properties and design are carefully controlled.

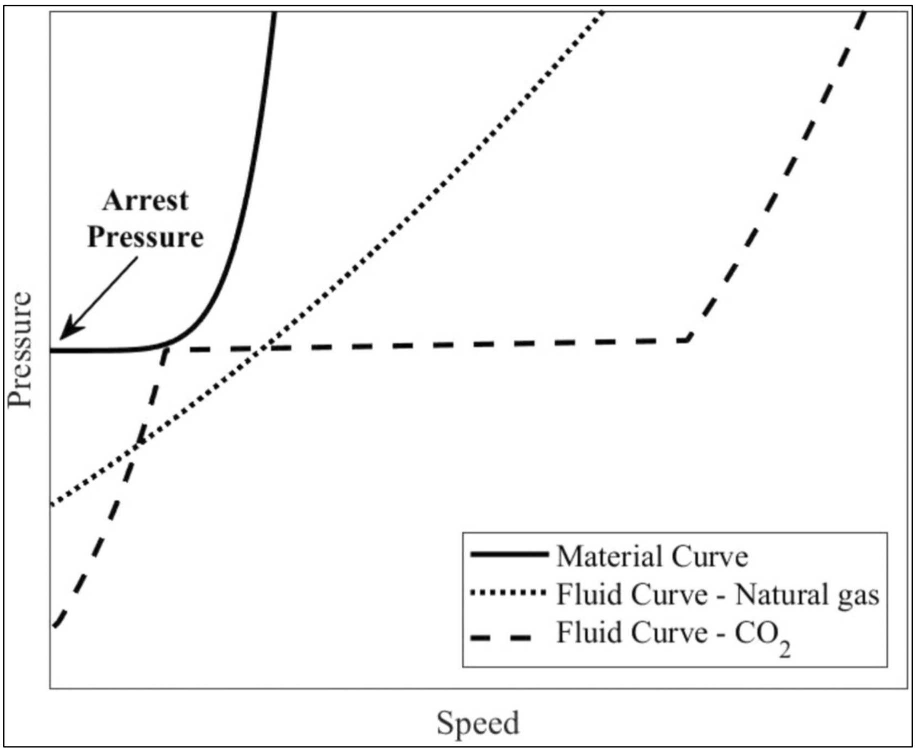

Figure 6-1 - Decompression and Material Resistance Curves for CO_2 and Natural Gas Pipelines

Operator-focused evidence has highlighted that the key difference between natural gas and dense-phase CO_2, in fracture propagation terms, is this decompression behaviour and its long plateau, which changes the relationship between arrest pressure and required toughness[162]. Industry research has similarly documented that decompression curves for CO_2 in liquid or dense phase can display a long plateau and that fracture control methods must explicitly consider the interaction between decompression wave speed and fracture speed[163]. This behaviour is also reflected in broader research, which notes that dense-phase CO_2 pipelines can require significantly higher fracture resistance than pipelines transporting lean or rich natural gas because the decompression plateau can sustain a substantial driving force even at relatively low fracture velocities[164].

The consequence is that ductile fracture control and decompression assurance for CO_2 systems tends to be more sensitive to modelling choices and input uncertainty, driving conservatism and increasing iteration during design. Evidence from research programmes addressing fracture prevention in CO_2 pipelines indicates that dense-phase decompression can be more severe than natural gas in terms of fracture propagation susceptibility, emphasising the need for CO_2-specific approaches rather than direct transfer of natural gas assumptions[165]. Where EOS selection, impurity property representation, and fracture-mechanics inputs are not consistently standardised or benchmarked, developers face additional third-party review, supplementary testing, and increased uncertainty in decompression curves (partially addressed through ongoing large-scale testing programmes, see Section 5.19) and crack-driving-force calculations. Work aimed at developing practical engineering tools for running ductile fracture prediction in CO_2 pipelines reinforces that reliable fracture assessment is

[162] Cooper, R.; Barnett, J. (National Grid Carbon). Fracture Propagation in Dense Phase CO2 Pipelines from an Operator's Perspective. 2016. Available: hazards-26-poster-17-fracture-propagation-in-dense-phase-co2-pipelines-from-an-operator-s-perspective.pdf [Accessed 09 March 2026].
[163] Cosham, A. et al. The decompressed stress level in dense phase carbon dioxide full-scale fracture propagation tests - paper 11. 2022. Available: The Decompressed Stress Level in Dense Phase Carbon Dioxide Full-Scale Fracture Propagation Tests | IPC | ASME Digital Collection [Accessed 09 March 2026].
[164] Michal, G. et al. An Empirical Fracture Control Model for Dense-Phase CO2 Carrying Pipelines. 2020. Available: An Empirical Fracture Control Model for Dense-Phase CO2 Carrying Pipelines | IPC | ASME Digital Collection [Accessed 09 March 2026].
[165] Biagio, D.M. et al. Fracture propagation prevention on CO2 pipelines: full scale experimental testing and verification approach. 2017. Available: Microsoft Word - 2017 - 3R -Di Biagio et al - Fracture in CO2 Pipelines.docx [Accessed 09 March 2026].

foundational to CCS pipeline deployment and must reflect CO_2-specific decompression behaviour[166]. More detailed coupled models explicitly combine dense-phase flow modelling (including appropriate CO_2 equation-of-state treatment) with structural fracture propagation modelling, underlining both the technical complexity and the dependence on model fidelity and data availability[167].

6.6 Transients and Decompression

Operationally, transient events create two-phase conditions and significant temperature drops that are not fully represented by steady-state design points. Trips, rapid depressurisation, ESD blowdown, and restart following shutdown can all produce strong transient gradients and low temperatures that require explicit operability constraints, low-temperature material checks, and a revised blowdown philosophy and control logic to avoid unacceptable excursions. Transient behaviour is further complicated in shared systems where batch changes in composition occur due to multi-emitter blending and mixing variability, altering hydraulics, the speed of sound, transient response, and compressor performance, and increasing the scope of dynamic simulation and controls assurance required to achieve consistent handovers.

Network configuration and geography influence the scale and consequences of these issues. Onshore systems often include more tie-ins, valves, and crossings, which increases transient complexity but can offer comparatively easier physical access for emergency isolation. Offshore and longer subsea segments typically hold larger inventories and face more constrained isolation and venting options, while the consequences of decompression or fracture propagation may be harder to mitigate and intervene on once initiated. These factors underscore the importance of defining an operable transient and decompression envelope early in the design, rather than attempting to retrofit controls, instrumentation, or operational limitations later in the project lifecycle.

Closing this gap requires a more consistent UK-aligned approach to decompression and transient assurance for CO_2 transport and storage networks, supported by clearer minimum expectations for modelling scope, acceptance criteria and independent verification where appropriate. A government-supported validation and benchmarking programme would directly address the shortage of representative test data by enabling shared decompression and fracture-model benchmarking against UK-relevant design cases and impurity envelopes, thereby reducing over-conservatism, preventing late-stage design changes, and improving schedule certainty.

Dense-phase CO_2 decompression and transient hydraulics introduce phase-change-driven behaviours that materially alter decompression curves and fracture arrest performance compared with natural gas, and without better standardisation and UK-relevant validation data, fracture control and transient assurance are likely to remain drivers of conservative design, redesign cycles and commissioning delays.

6.7 Compression & Dehydration Reliability

Reliability in compression and conditioning is a material development gap for CO_2 transport networks because CO_2 compression trains are not straightforward analogues of natural gas service. CO_2 compression commonly follows a transcritical pathway, moving from subcritical conditions at the inlet to supercritical or dense-phase conditions at discharge, and this pathway can be sensitive to composition and impurities in ways that materially affect compressor performance and stability margins. Technical literature describing CO_2 compression technologies for carbon capture and storage explicitly characterises this as a transcritical compression process and frames it as a distinct design and operability challenge set, rather than a simple extension of conventional gas compression

[166] Skarsvåg, H.L. et al. Towards an engineering tool for the prediction of running ductile fractures in CO2 pipelines. *Process Safety and Environmental Protection*. Volume 171. 2023. Available: [Towards an engineering tool for the prediction of running ductile fractures in CO2 pipelines - ScienceDirect] [Accessed 09 March 2026].
[167] Aursand, E. et al. Fracture propagation control in CO2 pipelines: Validation of a coupled fluid–structure model. *Engineering Structures*. Volume 123. 2016. Available: [Fracture propagation control in CO2 pipelines: Validation of a coupled fluid–structure model - ScienceDirect] [Accessed 09 March 2026].

practice[168]. In operational terms, this sensitivity increases the importance of validating compressor performance and control behaviour over the expected range of operating modes.

A key delivery risk arises from compressor surge and anti-surge performance under operating point shifts. Changes in density and thermodynamic behaviour across interstage cooling and separation, particularly near critical regions, can alter the compressor's proximity to surge and increase the complexity of anti-surge philosophy and controls tuning. Work focused on anti-surge systems for CO_2 compressors in CCS service describes the compression stage as central to CCS performance, outlines the multi-stage quasi-isothermal approach commonly used, and focuses on the control considerations required to manage compressor stability during operation[169]. When this is combined with the project reality that CO_2 networks may ramp, cycle and experience trips during early operations, the consequence is an increased requirement for dynamic studies, vendor iterations and commissioning validation to reduce the likelihood of trips during ramping and cycling.

Impurity variability and multi-source aggregation amplify this challenge by changing the thermophysical properties that underpin compressor maps and performance tests. Where the inlet composition varies due to multi-source blending or batch changes, the resulting shifts in head, efficiency and surge line location can erode surge margin and lead to re-rating requirements, performance test disputes or throughput derating during start-up and early operations. The practical implication for UK networks is that compressor and control validation should be undertaken against the credible composition envelope rather than a single nominal case, with explicit acceptance criteria that protect operability across realistic variability.

Rotating equipment reliability is also exposed by the sensitivity of seals and auxiliary systems to contamination and wet or dirty gas conditions. Where seal gas quality is compromised by particulates, condensables or inadequate dryness, seal degradation risk and unplanned outages can increase. The resulting mitigations often expand the scope of filtration and separation and extend the qualification and commissioning effort. Maintainability and access constraints can be decisive: onshore installations generally allow easier maintenance access but can face footprint and noise planning constraints, while offshore installations (including topsides platforms and subsea-integrated systems) are typically limited by space, weight and access windows, increasing expectations for high reliability and redundancy in rotating equipment and dehydration systems. These constraints make early specification of seal gas quality, contamination control and maintainability requirements an enabling condition for reliable operations in both onshore and offshore environments.

The dehydration element of the train is a second major source of network operability risk because achieving consistently very low water content is not solely a steady-state design problem. Cycling, low flows, regeneration upsets, and transient conditions can drive water breakthrough risk, and dehydration technology selection and integration become lifecycle operability decisions. The IEAGHG technical report on dehydration units emphasises the criticality of low moisture content for minimising corrosion and hydrate formation and examines dehydration process characteristics and integration within CCS systems, underscoring that dehydration is an integrity-critical function[170]. This supports the delivery concern that maintaining ultra-low water specifications across wide operating ranges, including cycling, can be challenging and can drive additional polishing steps, redundancy, control complexity, and increased utility demand, with associated capital and schedule implications.

A further acceleration barrier is that the qualification of equipment and materials for realistic impurity envelopes, including compressor internals, seals and auxiliaries, remains uneven across projects and suppliers. Where standards and qualification expectations are not clear for defined impurity ranges, projects tend to adopt conservative materials and qualification programmes, lengthening procurement lead times and assurance cycles and delaying final investment decisions. These gaps

[168] Taher, M. Carbon Capture: CO_2 Compression Challenges and Design Options. **2022**. Available: Carbon Capture: CO2 Compression Challenges and Design Options | GT | ASME Digital Collection [Accessed 09 March 2026].
[169] Diez, N.G. (TNO). Anti-surge system for CO_2 compressor. **2013**. Available: CATO2-WP2.1-D15c-v2013.12.21-Anti-serge-for-CO2-compressor - Public [Accessed 09 March 2026].
[170] IEAGHG. Evaluation and analysis of the performance of dehydration units for CO2 capture. **2014**. Available: 2014-04 Evaluation and analysis of the performance of dehydration units for CO2 capture.pdf [Accessed 09 March 2026].

are likely to be most acute for aggregated multi-source networks, because the credible operating envelope is broader and the consequences of under-qualification are higher in shared infrastructure.

Closing this gap requires aligning network-level conditioning requirements with measurable acceptance criteria and embedding envelope-based validation into design and procurement from the outset. Compression and control validation should cover the expected composition envelope and operating modes, including start-up, turndown and cycling, with explicit testing and verification of anti-surge logic and recovery from credible trip scenarios, consistent with the focus in CCS-specific anti-surge work on control philosophy and compressor stability. Dehydration technology should be selected based on lifecycle operability under cycling, with defined regeneration performance, redundancy, monitoring, and safeguards against water breakthrough, reflecting the integrity and hydrate-avoidance roles emphasised in dehydration guidance. Finally, reliability and qualification should be accelerated through shared validation and learning at cluster or UK level, reducing bespoke rework between projects and enabling vendors and operators to converge on robust impurity-envelope assumptions for compressors, seals and dehydration systems.

CO_2 compression and dehydration trains are highly sensitive to transcritical behaviour, composition variability and ultra-low water management under cycling, so UK network readiness depends on envelope-based performance validation and faster, shared qualification of rotating equipment and dehydration designs for realistic impurity ranges to avoid trips, redesign and schedule delays.

6.8 Safety, Leak Detection & Response

CO_2 releases present a different hazard profile to methane and therefore require distinct design and emergency planning assumptions. CO_2 is an asphyxiant and can accumulate where oxygen is displaced; this risk applies to both dense-phase and gas-phase CO_2, although it is more pronounced for dense-phase releases. CO_2 is heavier than air and, following a pressurised release—particularly from dense-phase conditions—can be significantly colder than the surrounding air, increasing the likelihood of accumulation in low-lying outdoor areas as well as confined or partially confined spaces such as pits and sumps. In gas-phase releases, dispersion may be somewhat more rapid, but the gas can still accumulate under low-wind or stable atmospheric conditions. This density-driven behaviour can produce hazard footprints that are less intuitive than those associated with buoyant methane dispersion, underscoring the importance of explicitly considering terrain channelling, low-lying accumulation, and the interaction between release conditions and local topography when defining separation distances, evacuation planning, and community response arrangements. Current research highlights the need to evaluate release and dispersion behaviour systematically.

Because dense-phase operation and transient events can increase the complexity of release conditions, consequence assessment and emergency planning are particularly critical for dense-phase systems, although gas-phase systems also require careful evaluation. The CO_2PipeHaz programme and its associated good practice guidance emphasise that numerical outflow calculations combined with CFD for near-field and far-field dispersion provide the most accurate approach for consequence modelling of CO_2 pipeline releases, reflecting the sensitivity of hazard outcomes to release regime, phase behaviour and atmospheric dispersion dynamics. This supports the delivery concern that dispersion and consequence modelling often requires greater effort than for methane (with ongoing validation work, including Project Skylark, described in Section 5.19), with additional scrutiny during permitting and safety assurance, and with potential for late-stage layout changes if modelling outcomes are not embedded early enough in design. In onshore settings, higher public exposure typically increases the level of scrutiny of consequence modelling and the need to coordinate emergency response planning with local services. Offshore, public exposure may be lower, but detection coverage, access constraints, and marine response logistics can increase the risk of time-to-detect and time-to-intervene, driving more conservative operating constraints and potentially greater redundancy expectations, consistent with the onshore/offshore differences highlighted in Table 6-1.

A further safety dimension arises where impurities are present in the transported stream. The base CO_2 hazard is asphyxiation, but contaminants can introduce additional toxicological considerations and may also influence compatibility and degradation risks for non-metallic components, thereby expanding the scope of hazard identification and materials assurance. This increases the value of network-level specification and verification arrangements that prevent late discovery of incompatible impurity envelopes and avoid interface-driven delays when responsibility for monitoring and compliance is unclear.

Leak detection and isolation performance is particularly challenging for dense-phase systems operating through frequent transients. Property changes, linepack effects and the potential for two-phase behaviour during disturbances can complicate model-based detection approaches and the tuning of sensitivity versus false positives, increasing commissioning and validation effort and raising the risk of nuisance trips or curtailment during ramp-up. Recent work presented through the Pipeline Simulation Interest Group (PSIG) demonstrates the development of real-time transient model (RTTM) approaches for dense-phase or supercritical CO_2 pipelines for leak detection purposes and explicitly identifies both thermodynamic model selection and computational speed as key constraints for effective live detection systems[171]. This aligns with the operational reality that leak detection must remain reliable under transient operations, not only under stable conditions, and that validation against expected operating modes is necessary to maintain both safety assurance and availability.

Venting and blowdown design is also safety critical for CO_2 service because it must manage cold plumes, potential phase change and the risk of dry ice or ice formation near restrictions, all of which can affect both dispersion outcomes and the integrity of emergency vent paths. Experimental and modelling literature on dense or supercritical CO_2 leakage describes complex jet and cloud behaviour, including phenomena associated with dry ice particle accumulation near an orifice, which illustrates why vent and blowdown arrangements must be treated as specialised CO_2 service rather than treated as directly analogous to natural gas[172]. This is particularly important where temporary emergency venting may occur from less favourable configurations than permanent vents. Permanent vents are commonly designed with height and dispersion performance in mind, whereas temporary emergency vent scenarios can be constrained by location, set-up and local controls, which can increase consequence potential and require additional justification and readiness planning to ensure risks are controlled to a tolerable level.

Addressing this gap requires treating CO_2 dispersion and emergency response as primary design drivers. Validated dispersion modelling should be used to inform layout, vent locations and heights, access control and evacuation planning, and to ensure community emergency planning aligns with credible dispersion and accumulation behaviours under pressurised release conditions. Leak detection should be specified against a CO_2-appropriate performance basis, including alarm strategy and transient-handling logic, and validated through commissioning tests representative of start-up, shutdown, trip and blowdown conditions, consistent with the evidence base for real-time transient modelling approaches in dense-phase CO_2 pipelines. Finally, emergency blowdown and vent design should be underpinned by a CO_2-specific philosophy that explicitly addresses low-temperature effects and blockage risk and distinguishes permanent venting arrangements from temporary emergency vent scenarios, supported by dispersion modelling and clear deployment and control procedures informed by credible release behaviour.

CO_2 pipeline safety depends on accurately characterising dense-gas dispersion and accumulation, delivering leak detection performance that remains reliable under transients, and implementing CO_2-specific venting and emergency response arrangements including for temporary emergency vents so that credible upsets do not escalate into major response events with material schedule and availability impacts.

[171] Vishrut, G. et al. Real Time Leak Detection Systems for Supercritical CO_2 Pipelines. **2025**. Available: Real Time Leak Detection Systems for Supercritical CO2 Pipelines | PSIG Annual Meeting | OnePetro [Accessed 09 March 2026].
[172] Guo, X. et al. Flow characteristics and dispersion during the leakage of high pressure CO2 from an industrial scale pipeline. *International Journal of Greenhouse Gas Control*. Volume 73. **2018**. Available: Flow characteristics and dispersion during the leakage of high pressure CO2 from an industrial scale pipeline - ScienceDirect [Accessed 09 March 2026].

6.9 Measurement & Custody Transfer

Measurement and custody transfer for CO_2 networks remains a material gap because representative sampling and accurate quantification of both composition and flow are more challenging than in conventional hydrocarbon systems. These challenges are most pronounced under dense-phase and near-critical conditions, where small changes in pressure and temperature can drive large changes in fluid properties, complicating stable measurement conditions and potentially biasing both sampling and metering if phase behaviour is not tightly controlled. In gas-phase CO_2 systems, measurements are generally more stable and align with established natural gas practices; however, challenges arise when operating conditions approach the phase boundary or when compositional variability affects density and compressibility. Across both regimes, the presence of trace impurities remains operationally significant: the metrology burden extends (with ongoing metrology programmes addressing these gaps, see Section 5.19) beyond measuring bulk CO_2 to detecting and quantifying low-level components with sufficient sensitivity and traceable uncertainty to support operability, integrity, and storage acceptance decisions.

Representative sampling is particularly difficult in dense-phase systems, where phase slip, condensation, or density sensitivity can lead to non-representative samples or inconsistent results between parties. While gas-phase sampling is typically more straightforward, it can still be affected by condensation or compositional gradients under certain conditions. These issues create a direct pathway to specification disputes, repeated testing, and interface delays at commissioning and handover. Current metrology initiatives explicitly identify sampling integrity as a key challenge for CCUS and are developing good-practice guidance covering sampling plans, material compatibility for sampling lines and vessels, and practical considerations for online and offline analysis. This reflects that, particularly for dense-phase CO_2 but also to a lesser extent for gas-phase systems, sampling and custody transfer are not yet treated as fully mature, standardised disciplines equivalent to hydrocarbon practice.[173].

The risk of measurement uncertainty translating into operational and commercial friction is heightened because very low impurity levels can still materially affect corrosion, flow assurance, fiscal and allocation measurements, and storage acceptance, which drives the need for higher-sensitivity measurements, improved calibration approaches, and stronger QA/QC expectations. This requirement is directly reflected in metrology development work under CCUS-focused programmes that are producing certified reference materials and calibration support for impurity measurement in CO_2, explicitly targeting the traceable measurement of impurities with stated uncertainties to underpin instrument calibration and method validation[174]. In the UK, measurement and calibration capability for CCUS is also being positioned as a deployment enabler, with a specific emphasis on measurement needs and the role of national measurement expertise in supporting confidence in CCUS technologies and impurity effects on analyser performance[175].

Online analysers and metering systems introduce a further gap because packages and sampling systems designed for hydrocarbon service may not be robust in CO_2 service without explicit attention to condensation control, temperature management, deadlegs and maintainability. Where these issues are not addressed early, bias and drift can increase downtime and drive rework to analyser shelters, heating and conditioning during late design or commissioning, with associated operational cost and acceptance testing delays. Measurement performance in the CCUS chain requires distinguishing custody transfer and fiscal needs from plant measurement and emphasising the importance of appropriate specifications and quality assurance regimes[176].

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[173] Arrhenius, K. (RISE) et al. Good practice guide for the sampling of CO2 for capture, transport storage, conversion, utilisation and recycling. **2024**. Available: 21GRD06-MetCCUS_A3.2.5_RISE_Report_final.pdf [Accessed 09 March 2026].
[174] MetCCUS. Publishable Summary for 21GRD06 MetCCUS Metrology Support for Carbon Capture Utilisation and Storage. **2023**. Available: EMRP-template (document) [Accessed 09 March 2026].
[175] NPL. Energy transition: Measurement needs for carbon capture, usage and storage. **2021**. Available: NPL Energy Transitions report - Measurement needs for carbon capture, usage and storage [Accessed 09 March 2026].
[176] Chinello, G. et al. Toward standardized measurement of CO2 transfer in the CCS chain. *Nexus.* Volume 1. **2024**. Available: Nexus: Nexus [Accessed 09 March 2026].

Multi-source aggregation increases both technical and governance complexity. Blending uncertainty and batch changes increases variability, leading to more frequent measurement, data reconciliation and compliance verification. This raises the likelihood of contractual disputes if the custody transfer and data governance framework is not established early with clear rules on traceability, calibration, auditing, uncertainty requirements and responsibility allocation at battery limits. The onshore/offshore distinction adds an additional dimension. Onshore networks may have more custody points and a greater incidence of third-party metering, but they can benefit from easier physical access for calibration and inspection. Contrastingly, offshore systems may have fewer measurement points, but harsher conditions and access windows can make metering, maintenance, and verification more challenging and costly, increasing the importance of a robust maintainability philosophy and clear verification pathways from the outset.

Closing this gap requires standardising sampling, analysis and metering requirements at network level for dense-phase service, with explicit control of temperature and pressure conditions to avoid phase slip and condensation, and with clear uncertainty and QA expectations that reduce room for dispute. A risk-based impurity monitoring strategy is needed because no single analyser covers all relevant impurities, and the required sensitivity varies by impurity and by potential impact on operability and integrity. Custody transfer governance should be developed early, including common data standards, traceability requirements, calibration and audit regimes and agreed actions for off-spec events and measurement uncertainty. Finally, accelerated UK-wide validation and standardisation, ideally supported by national measurement institute capability and aligned with ongoing metrology programmes developing reference materials, sampling guidance and traceable methods, would provide the practical underpinning required for custody transfer arrangements analogous to hydrocarbon service, reducing duplicated effort and shortening the time to stable operations.

Without standardised, field-proven sampling and custody-transfer metrology that is demonstrably reliable in dense-phase and near-critical CO_2 service, measurement uncertainty is likely to translate into specification disputes, conservative design assumptions and prolonged commissioning and handover across multi-source UK networks.

6.10 Network Operations

Operating a multi-shipper, open-access CO_2 transport and storage network requires a more codified approach to controllability and interoperability than is typical in point-to-point systems because operational flexibility is constrained by dense-phase behaviour, impurity sensitivity and tighter phase-management requirements. In dense-phase service, linepack and short-term balancing dynamics can behave differently from those in more compressible gas systems, reducing the range of available levers to accommodate supply swings from capture plants or short-term storage injection constraints. Research addressing linepack explicitly positions linepacking as a critical element of pipeline operation and notes that both detailed flow models and simplified correlations are used to understand linepack capacity and linepacking time, reflecting its role in balancing and controllability strategies for long pipelines and networks[177]. This means that, without a network-wide operational basis that reflects dense-phase constraints and realistic capture intermittency, early operations can be characterised by tighter operating envelopes, more frequent curtailment and slower ramp-up to stable availability. Ongoing research and development activity, including modelling, monitoring and digital-twin-enabled approaches, is helping to improve confidence in these operating strategies, but this has not yet matured into fully standardised network operation practice (see Section 5.19)

A second delivery-critical gap is the maturity and consistent application of interoperability rules across multiple capture plants, transport assets and storage constraints. For open-access networks, operating outcomes depend on enforceable provisions covering entry and exit compliance, blending and batching rules, curtailment hierarchy, venting policies, waiver and off-spec processes, and re-

[177] Martynov, S.B. et al. Estimating the line packing time for pipelines transporting carbon dioxide, *Carbon Capture Science & Technology*. Volume 11. 2024. Available: [Estimating the line packing time for pipelines transporting carbon dioxide - ScienceDirect] [Accessed 09 March 2026].

entry criteria following excursions. The UK CCS Network Code is explicitly intended to provide the commercial and technical rules and arrangements between CO_2 Transport and Storage (T&S) Companies and network Users for connection and use of T&S networks, reflecting the policy intent to standardise these arrangements across the regulated regime. However, where these rules are not consistently embedded in front-end engineering design and operating philosophies across stakeholders, the likely outcome is interface friction, incompatible assumptions, and longer commissioning and handover periods.

Off-spec events are a practical stress test for any multi-shipper network because they require rapid, coordinated decision-making across multiple parties and assets to avoid escalation from local deviation to network-wide disruption. Excursions such as wetter CO_2 or elevated oxygen levels from one capture plant can require isolation, diversion, or controlled shutdown actions, and clear criteria for re-entry once conditions are restored. This is operationally and organisationally nontrivial, particularly offshore, where physical access and intervention windows can be constrained and where the consequences of conservative decisions may be higher due to limited alternative routing and slower response. These realities place greater weight on pre-defined contingency architectures, including valving, tie-ins and blowdown philosophy, and on clear allocation of decision rights and liabilities so that responses are consistent and proportionate. The table extract supports this operational framing, highlighting that more nodes and tie-ins increase dispatch and linepack management complexity onshore, while offshore outages can have larger capacity impacts and remote operational resilience becomes critical.

The need for a defined system-operator role is therefore central to controllability and multi-shipper performance. In a network context, the system operator must be able to coordinate nominations and dispatch, manage linepack, apply curtailment hierarchies, approve or reject waivers, and coordinate start-up and shutdown across shippers and storage constraints with speed. The regulatory context recognises that CO_2 transport and storage (T&S) systems operate under an economic licensing regime and that regulated entities are subject to governance and reporting obligations intended to support effective oversight and administration of the regime[178]. While economic regulation and network code arrangements establish important foundations, the operational gap remains the translation of these frameworks into an empowered control room capability, forecasting and coordination processes, and offshore-specific operating and emergency procedures that can be executed under real-world variability.

Multi-source aggregation and batching can further increase operational complexity by driving variability in composition, hydraulics and transient response. This increases the requirement for real-time monitoring, forecasting and coordinated control actions, and expands the scope of metering and analytics needed to support safe, efficient dispatch. Work reviewing monitoring system challenges for CO_2 pipelines highlights the need to adapt monitoring approaches to CO_2 pipeline characteristics and to consider network topology when optimising monitoring strategies, pointing toward a need for CO_2-specific monitoring and potentially digital-twin-enabled approaches as networks scale[179]. This supports the practical delivery point that commissioning and validation cycles can be extended when monitoring and control systems are expected to handle a broad range of operating modes and compositions without an agreed-upon network-wide performance basis.

Finally, capture availability profiles and maintenance practices must be treated as central planning inputs. The cost and feasibility of achieving high capture reliability, and the reality of planned turnarounds and unplanned outages, will influence whether capacity booking and curtailment mechanisms are workable in practice. If network utilisation assumptions do not match plausible operating profiles, the outcome can be inefficient utilisation, commercial friction between reserved capacity and actual delivery, and delays to stable operations as coordination mechanisms are adjusted. The government's CCUS Future Network Strategy call for evidence underscores the focus on

[178] Ofgem. Carbon dioxide transport and storage: regulatory instructions and guidance (RIGs). 2025. [Carbon dioxide transport and storage: regulatory instructions and guidance (RIGs) | Ofgem] [Accessed 09 March 2026].
[179] Xu, Teke et al. Monitoring systems for CO2 transport pipelines: a review of optimisation problems and methods. 2024. Available: [PowerPoint Presentation] [Accessed 09 March 2026].

how CO_2 networks may need to evolve to meet strategic objectives and implies a continuing policy interest in ensuring that network arrangements are fit for growth and market development[180].

Closing the gap, therefore, depends on implementing an operating framework that makes interoperability rules executable, supported by a clearly defined system operator (NESO). Building on the CCS Network Code, an effective framework would codify entry and exit compliance processes, blending and batching rules, curtailment hierarchy, venting policy, waiver and off-spec processes and re-entry criteria in a way that can be directly translated into control logic, operational studies, commissioning tests and operating manuals. It would also require network-wide FEED studies—covering linepack management, transient response, capture intermittency and storage injectivity constraints—and conversion of those results into practical operating envelopes that reduce the likelihood that routine disturbances become network-wide curtailment or outages. In parallel, standardised off-spec isolation and diversion architectures, combined with aligned liabilities and incentives, would reduce interface disputes and support faster recovery after excursions, particularly in offshore contexts where intervention constraints can otherwise drive overly conservative approaches.

Multi-shipper CO_2 networks require enforceable interoperability rules and a clearly empowered system operator to manage linepack, transient constraints, off-spec events and capture variability, enabling open-access operation without turning routine upsets into network-wide curtailment.

6.11 Onshore Delivery Challenges

Onshore CO_2 pipelines face distinctive development constraints because routing and consenting are strongly influenced by public and stakeholder perceptions of risk, as well as the physical hazard characteristics of CO_2 releases. CO_2 is an asphyxiant and, when released, can form a cold, dense cloud that can accumulate in low-lying areas and be channelled by local terrain, which can make hazard footprints less intuitive and more sensitive to topography than for buoyant gas releases. These characteristics increase the likelihood that route selection, setback distances and emergency planning become dominant design drivers, particularly where routes pass near populations or sensitive receptors.

A core delivery gap is that quantified risk assessment (QRA) approaches and land-use planning expectations for CO_2 are less mature and less consistently codified than for established pipeline fluids, which increases uncertainty during optioneering and consent. Industry work focused specifically on routing dense-phase CO_2 pipelines in the UK highlights that applying individual-risk-based distances for routing is complicated by CO_2-specific design features and the current state of CO_2 routing methodologies, and it describes the development of QRA-based routing methods using evidence from CO_2 transport research programmes[181]. In parallel, HSE's design codes and standards guidance reinforces that UK pipeline design under the Pipelines Safety Regulations must consider the operating regime, conveyed fluid conditions and environmental context, and points to ongoing work and standards development relevant to CO_2 pipeline design and assessment[182]. Where CO_2-specific expectations for consultation distances, modelling assumptions and acceptability criteria are not established early, project teams can face iterative safety case work, repeated regulator and planning authority queries, and schedule risk prior to consent and final investment decision.

Onshore delivery is also disproportionately affected by the risk of third-party interference. Construction and excavation damage remains a dominant threat to buried pipelines, and this risk can be more challenging to communicate for CO_2 because the hazard is perceived as "invisible" and is primarily associated with asphyxiation rather than fire or explosion. The result is often a need for enhanced surveillance, protection measures, stakeholder interface management and public

[180] DESNZ. Future Network Strategy for CO2 Transport and Storage - Call for evidence on CCUS Future Network Strategy. 2025. Available: CCUS future network strategy: call for evidence [Accessed 09 March 2026].
[181] Cooper, R. (National Grid Carbon) et al. Routeing of Dense Phase CO2 Pipelines in the UK. *Energy Procedia*. Volume 63. 2014. Available: (PDF) Pipelines for transporting CO2 in the UK [Accessed 09 March 2026].
[182] HSE. Pipeline design codes and standards for use in UK CO2 Storage and Sequestration projects. Available: Pipeline design codes and standards for use in UK CO2 Storage and Sequestration projects - HSE [Accessed 09 March].

communications, with a higher likelihood of late mitigation measures being requested if third-party risk and emergency messaging are not addressed proactively.

Emergency planning and response requirements frequently become a pacing factor for route approval and readiness to operate. Onshore systems typically require clear arrangements for cordons, evacuation zones, access control and liaison with local authorities, and these requirements are closely linked to how hazard distances are derived and communicated. UK pipeline industry guidance on hazard distances provides a reference point for how hazard distance concepts are treated within established pipeline good practice, and it illustrates the role such guidance can play in supporting consistent planning assumptions and communication, even where CO_2-specific translation remains an area of development[183]. Where projects must demonstrate that risks are reduced to as low as reasonably practicable (ALARP) and define practical emergency hazard distances for high-consequence rupture scenarios, additional consequence modelling effort is commonly required, often including terrain-informed dispersion assessment to address dense-gas accumulation behaviour. If this work is not embedded into early routing and facility optioneering, it can lead to late changes to route alignment, above-ground installation locations or emergency access arrangements, driving schedule and cost impacts.

Addressing these onshore-specific constraints requires treating routing and societal risk as primary design drivers from the outset, integrating dense-gas dispersion-informed route selection, emergency access planning and community interface considerations into early optioneering. A clearly defined QRA methodology and governance approach—covering modelling assumptions, data sources, uncertainty treatment and acceptability criteria—should be established early and aligned with planners and regulators to reduce iteration and improve predictability through consent. Third-party interference management should be tailored to CO_2 service with clear public communications, marker and signage strategy, structured liaison with utilities and construction stakeholders, and explicit emergency messaging that reflects the asphyxiation and accumulation hazards. Finally, emergency planning requirements should be agreed early with local authorities and embedded in design and operating procedures, using and adapting established UK pipeline risk frameworks and good-practice guidance, while closing CO_2-specific gaps through project evidence, validation, and standard setting.

For onshore CO_2 pipelines, routing, public acceptability and defensible, consistently applied QRA and emergency planning can drive programme critical path as much as technical design, so early alignment on CO_2-specific assessment methods and clear, evidence-based risk communication is essential to avoid iterative consenting and late route or layout changes.

6.12 Offshore Delivery Challenges

Offshore CO_2 transport and injection systems are typically constrained more by operability and practicality of interventions than by steady-state capacity design. Dense-phase operation and the need for safe depressurisation and restart can create extremely low temperatures and phase changes that are difficult to manage at subsea hardware. During depressurisation, JT and auto-refrigeration cooling can drive conditions into regimes where solids or two-phase behaviour becomes credible, which in turn increases the risk of dry ice, ice, or hydrate formation at subsea restrictions and low points such as valves, jumpers, and riser bases. Experimental and modelling studies of CO_2 pipe depressurisation emphasise that predicting pressure and temperature evolution during depressurisation requires capturing non-equilibrium two-phase effects, reinforcing that transients can be materially different from simplified steady-state assumptions and can directly influence low-temperature exposure and operability outcomes[184]. This is one of the areas where ongoing large-scale validation and modelling programmes are particularly relevant, as discussed in Section 5.19.

A central offshore delivery challenge is that subsea isolation and restart philosophy is inherently non-trivial because segmentation, depressurisation and re-pressurisation decisions must be compatible

[183] UKOPA. Good Practice Guide – Pipeline Hazard Distances. **2024**. Available: Good Practice Guide [Accessed 09 March 2026].
[184] Log, A.M. et al. Depressurization of CO2 in a pipe: Effect of initial state on non-equilibrium two-phase flow. *International Journal of Multiphase Flow*. Volume 170. **2024.** Depressurization of CO2 in a pipe: Effect of initial state on non-equilibrium two-phase flow - ScienceDirect [Accessed 09 March 2026].

with the avoidance of solids formation and two-phase slugging at subsea restrictions, while still achieving credible emergency shutdown performance. In practice, this means that valve strategy, closure behaviour, inventory management and re-entry criteria become tightly coupled to transient thermo-hydraulic behaviour and to the availability of intervention. Because subsea intervention is slow and expensive, and weather windows and vessel availability can determine when recovery actions can be executed, recovery after trips can take longer and downtime consequences can be higher than for comparable onshore systems. These realities align with emerging subsea CCS-specific guidance, which frames subsea CCS projects as comparatively new and emphasises the need for dedicated design guidance to address risks and decisions unique to subsea CCS systems[185].

Pigging and integrity management present an additional offshore-specific constraint because subsea systems often need pigging for corrosion/degradation monitoring, yet topsides space, pig trap availability and operational windows can materially limit what is feasible in practice. Where pigging systems are a late addition, offshore projects face either costly topsides modifications or restricted pigging frequency, both of which can increase integrity risk or drive late cost and schedule impacts during tie-in or shutdown campaigns. This is one reason offshore architecture decisions that appear "mechanical" at concept stage can become decisive drivers of lifecycle risk and operability.

Tie-in architecture—subsea tie-ins versus platform tie-ins—is therefore a critical early design decision with long-lived implications for operability, maintainability and intervention burden. Subsea tie-ins can reduce the scope of topsides integration but tend to increase subsea system complexity and reliance on vessel-based intervention, whereas platform tie-ins may simplify operability and access for maintenance and monitoring but can require heavier topsides modifications and integration work. Because late architecture changes offshore are typically expensive and schedule-disruptive, this decision benefits from being treated as a gated choice supported by lifecycle analysis, instead of a detail resolved late in FEED.

Tie-back length can further dominate controllability and restart practicality, particularly in the UK context, where distances to offshore storage sites can approach ~300 km. Longer subsea segments increase the inventory that must be managed during isolation and depressurisation, extend cooldown and warm-up durations, and slow hydraulic response and transient propagation through the system. For long-distance tiebacks of this scale, the pipeline behaves as a large, slow-responding system, with pressure and flow changes taking significant time to stabilise. As tie-back length increases, systems typically require enhanced automation, broader instrumentation coverage, robust telemetry, and continuous condition monitoring to maintain safe, stable operation in environments with limited routine access and long intervention lead times.

Technology maturity also remains an enabling constraint for subsea CO_2 injection, monitoring, and well-control packages, especially where long-duration reliability, barrier-testing philosophies, and subsea measurement and analytics must be demonstrated under offshore access constraints. Where evidence is weak, projects tend to adopt conservative design and expanded qualification and testing, which can lengthen procurement and acceptance timelines and increase the risk that operability-driven changes emerge late.

Reducing these offshore delivery risks requires making tie-in architecture an early, lifecycle-based decision; requiring offshore-specific transient and restart studies and converting them into a validated operating envelope and restart playbook; and defining a subsea isolation and segmentation philosophy that is explicitly designed to avoid solids and two-phase slugs at subsea restrictions. Pigging and integrity management should be embedded in the concept design, and monitoring and control requirements for long tiebacks should be specified and qualified against the realities of offshore access. Where empirical evidence is limited, a structured qualification plan aligned with recognised guidance and targeted project-specific testing provides a pragmatic route to reducing uncertainty while maintaining delivery momentum.

[185] IOGP. Guidance for Subsea CCS Systems. **2024.** Available: Subsea CCS guidance | IOGP [Accessed 09 March 2026].

Offshore CO_2 systems are defined by limited access and the consequences of low-temperature transients during depressurisation and restart, so early tie-in architecture choices supported by CO_2-specific transient studies, a robust subsea isolation and restart philosophy, and concept-led integrity and monitoring design are essential to avoid integrity-driven redesign and extended offshore downtime.

6.13 Storage Interface Constraints

Storage interface constraints arise because transport and storage systems optimise to different operating envelopes. A pipeline and compressor train may be designed to deliver CO_2 within defined pressure, temperature, and composition limits at the battery limit, whereas injection wells and reservoirs typically operate within narrower and more sensitive constraints, including phase state, wellhead and wellbore pressure and temperature, and acceptable impurity content. This mismatch creates a systemic delivery risk: in early operations, the well–reservoir system is often the limiting element, meaning transport capacity cannot be fully utilised and ramp-up to nameplate throughput may be slower and more susceptible to curtailment.

This effect differs between onshore and offshore configurations. Onshore systems may benefit from hub buffering or intermediate storage, providing limited decoupling between transport and injection and some operational flexibility. In contrast, offshore storage interfaces, whether platform-based or subsea, tend to impose more direct constraints on trunkline throughput due to injection-system capacity, backpressure limits, and limited intervention capability, making the transport system more tightly coupled to storage performance.

A key gap is the shortage of integrated tools and validated operating envelopes that couple capture variability, pipeline and compressor transients and well–reservoir injection limits. In the absence of a system-level envelope, projects often treat the pipeline and storage domains separately, which can lead to inconsistent assumptions, duplicated modelling, and boundary disputes, and to late design changes once the true coupled constraints become apparent. Technical work focusing on injection and storage performance highlights that well deliverability and injectivity are sensitive to operational conditions and can be constrained by both mechanical integrity limits and reservoir behaviour, reinforcing the need for integrated assessment[186].

Ongoing research programmes are improving the underlying transport-side evidence base, particularly around transients, phase behaviour and impurity effects, but integrated transport-storage operating envelopes remain project-specific and not yet fully standardised (see Section 5.19).

Impurity management is a central component of this interface because impurities that may be manageable from a pipeline operability perspective can still create material storage-related risks and constraints. The effects include wellbore integrity concerns, such as tubular corrosion and compatibility issues with well cement, as well as geochemical interactions that may influence near-well permeability and longer-term storage integrity. The IEAGHG technical report on impurities in geological storage explicitly evaluates how different impurities can influence storage behaviour and risks, supporting the premise that storage acceptance criteria must be linked to demonstrated impacts on well and reservoir performance[187]. This creates a practical interface requirement: transport entry specifications and storage acceptance limits must be consistent, and where there is uncertainty, a risk-based monitoring and verification approach is needed to avoid either unnecessary constraint or unmanaged risk.

Transient coupling is frequently under-addressed in project development, even though it is a primary pathway for storage interface exceedances. Capture cycling, pipeline linepack swings, compressor

[186] Nikolai, A. et al. Coupled CO_2 Injection Well Flow Model to Assess Thermal Stresses under Geomechanical Uncertainty. 2023. Available: Coupled CO2 Injection Well Flow Model to Assess Thermal Stresses under Geomechanical Uncertainty | SPE Reservoir Simulation Conference | OnePetro [Accessed 09 March 2026].
[187] IEAGHG. Effects of Impurities on Geological Storage of CO2. 2011. Available: 2011-04 Effects of Impurities on Geological Storage of CO2.pdf [Accessed 09 March 2026].

trips and start/stop sequences can drive fluctuations in wellhead conditions that move outside safe windows, increasing the complexity of control philosophy and shutdown and restart procedures and increasing the likelihood of availability losses after trips. This is particularly acute offshore, where depressurisation and re-pressurisation actions can be constrained by limited access and where thermal behaviour can dominate, including the practical challenge that blowdown and subsequent repressurisation may demand significant heat input to avoid low-temperature risks and phase instabilities. When early-life reservoir pressure is low, the injection system can be further constrained, potentially necessitating a staged operational strategy. In such cases, transitioning from initial gas-phase injection to dense-phase injection as reservoir pressure builds may be a pragmatic approach to maintaining injectability and operability without excessive compression and thermal management burden, but if this is identified late, it can drive major FEED iterations and equipment reselection.

Batching tolerance is another cross-domain uncertainty for multi-source networks. If a transport network experiences batch-like changes in composition or phase behaviour due to multi-source blending variability, intermittent injectors or process upsets, storage sites may require procedural controls and additional monitoring to manage the injectivity and integrity consequences. Technical literature examining CO_2 injection and the influence of operational variability reinforces that injectivity behaviour can be sensitive to near-well conditions and fluid properties, which supports the need to define batching rules and mitigations that are tested against well and reservoir models[188]. The consequence of leaving batching tolerance undefined is increased likelihood of operating restrictions, interface delays and reduced network utilisation.

Regulatory guidance in the UK reinforces that storage performance and measurement assurance are central to permitting and, therefore, to project schedules. The NSTA provides specific guidance on applications for a carbon storage permit and related measurement expectations, indicating that storage permitting is tightly linked to the evidence base for storage performance, monitoring and compliance[189]. This means that uncertainty in impurity acceptance, operating envelopes and transient behaviour at the storage interface can translate directly into extended assurance cycles, iterative regulator queries and delayed readiness to operate.

Closing the gap therefore requires developing an integrated system envelope for each transport and storage system that explicitly couples capture variability, pipeline hydraulics and linepack, compressor control and well–reservoir constraints into a single validated operating envelope and operating playbook, including transient scenarios, trip recovery, start-up and shutdown and re-entry criteria. Impurity acceptance criteria should be aligned with demonstrated impacts on wellbore integrity and reservoir behaviour, with monitoring and verification proportionate to the risk and consistent with storage permitting expectations. Where initial reservoir pressure is low, staged operational strategies should be assessed early, including offshore thermal management and the practicality of depressurisation and re-pressurisation without creating low-temperature or phase instability problems. Batching rules should be defined and stress-tested against injectivity and integrity models, and well-centric operability limits should be embedded into pipeline and compression design, so that the storage site does not become a chronic constraint on network availability.

Storage performance is set by the coupled pipeline–compressor–well–reservoir system so UK CCUS delivery depends on integrated, validated operating envelopes and interface rules that manage transients, impurity acceptance, and early-life low-pressure constraints without persistent curtailment, redesign, or prolonged assurance cycles.

[188] Mohammadi, B.T. et al. A review of modeling approaches for CO2 injection into depleted gas reservoirs: Coupling transient wellbore and reservoir dynamics. *International Journal of Greenhouse Gas Control*. Volume 145. 2025. Available: [A review of modeling approaches for CO2 injection into depleted gas reservoirs: Coupling transient wellbore and reservoir dynamics - ScienceDirect] [Accessed 09 March 2026].
[189] NSTA. Guidance for Measurement of Carbon Dioxide for Carbon Storage Permit Applications. 2024. Available: [Guidance for Measurement of Carbon Dioxide for Carbon Storage Permit Applications] [Accessed 09 March 2026].

6.14 Monitoring, Measurement & Verification

Monitoring, Measurement and Verification (MMV) in the context of CO_2 transport pipelines serves a distinct but complementary purpose to storage MMV. For pipelines, MMV underpins system integrity, containment assurance, operational control, and commercial accountability, ensuring that CO_2 is transported safely between custody transfer points (e.g. pig trap to pig trap) without loss, degradation of quality, or undetected leakage. It supports regulatory compliance under the Pipeline Safety Regulations (PSR), enables effective leak detection and response, and provides the measurement basis for flow, composition, and custody transfer within multi-user networks.

The technical challenge is that CO_2 transport, particularly under dense-phase conditions, introduces measurement and monitoring complexities not typically encountered in conventional gas systems. Dense-phase and near-critical CO_2 is highly sensitive to pressure and temperature, meaning small variations can significantly affect density, flow measurement accuracy, and phase stability. This complicates the design and operation of metering systems, leak detection algorithms, and transient monitoring. In gas-phase systems, measurement is generally more stable, but compositional variability and proximity to the phase boundary can still introduce uncertainty. Across both regimes, the presence of impurities and the need to maintain tight compositional control increase the burden on measurement accuracy, sampling integrity, and data validation.

From an integrity and safety perspective, pipeline MMV must also address leak detection and localisation, particularly for offshore systems where access is limited, and detection may be delayed. CO_2 releases behave differently from natural gas, with potential for cold, dense, ground-hugging dispersion, making early detection and accurate quantification critical. Conventional leak detection methods (e.g. pressure/flow balance, negative pressure wave) remain applicable, but their performance can be affected by long tie-back lengths, slow transient propagation, and compositional variability. Offshore pipelines introduce additional constraints, including limited access for inspection, reliance on remote sensing and subsea instrumentation, and longer response times for intervention.

Operationally, MMV must also support network-level coordination in multi-emitter systems. This includes tracking flow and composition across multiple entry points, managing blending effects, and ensuring that off-spec conditions can be identified and attributed. Inadequate measurement or inconsistent verification approaches can lead to custody transfer disputes, uncertainty in emissions accounting, and reduced confidence in system operability, particularly where pipelines interface with storage systems that impose stricter acceptance criteria.

The key gap is therefore not the absence of individual monitoring technologies, many of which are mature, but the lack of an integrated, standardised MMV framework for CO_2 transport pipelines. This includes:

- Consistent approaches to flow and composition measurement under dense-phase conditions
- Robust and validated leak detection methodologies tailored to CO_2 behaviour
- Standardised requirements for sampling, verification, and uncertainty management
- Clear integration of monitoring data into operational decision-making and regulatory reporting

Without such a framework, projects are forced to adopt conservative, project-specific solutions, increasing costs, reducing interoperability, and introducing the risk of late-stage redesign or regulatory challenges. Addressing this gap requires early integration of MMV into pipeline design, alignment with custody transfer and network code requirements, and development of practical, deployable monitoring strategies that are robust across both onshore and offshore environments.

6.15 Regulation & Harmonised Standards

UK CO_2 transport and storage (T&S) system projects are being developed within a regulatory landscape that is still consolidating, while the technical basis for design and operation often draws heavily on established oil and gas pipeline and offshore practices. Many existing standards originate from conventional hydrocarbons, comparatively few explicitly address dense-phase CO_2 behaviour or impurity-driven risks, and there is not yet a fully harmonised approach across regions and routes. In practice, this creates a material integration challenge for open-access and multi-source systems, because the basis of design, assurance expectations and interface requirements can vary between projects even where the intent is to develop interoperable networks[190].

On the transport side, UK safety regulation for pipelines sits within a mature framework, including the Pipelines Safety Regulations 1996, which establish duties for pipeline operators and define requirements for major accident hazard pipelines. While these regulations provide a common baseline for pipeline safety management, they do not in themselves supply a CO_2-specific technical "playbook" for dense-phase behaviour, impurity effects or cross-chain interoperability, so duty holders must demonstrate that risks are reduced so far as is reasonably practicable through appropriate application of good practice and sound engineering judgement within the regulatory framework[191]. In parallel, HSE has developed CO_2-specific guidance for conveying carbon dioxide in pipelines in connection with CCS projects, which positions the safe design and operation of CO_2 pipelines within existing legal duties while explicitly acknowledging that dense or supercritical CO_2 service introduces distinctive considerations and remaining uncertainties that must be addressed through good practice at the design stage. HSE also publishes guidance on pipeline design codes and standards relevant to CO_2 storage and sequestration projects, noting that design may draw on established pipeline codes and highlighting the importance of supporting chosen standards with appropriate good practice, which is an explicit signal that consistent interpretation and application remain critical to demonstrate an adequate risk position[192].

A separate but equally important dimension is economic and access regulation for CO_2 transport and storage networks, which has been evolving to support open access and coordinated network development. Ofgem's regulatory instructions and guidance for CO_2 transport and storage licensees provide a mechanism for directing how licensees collect and provide information needed to administer licence conditions, supporting an emerging governance framework for licensed CO_2 transport and storage networks[193]. At the network-operating-rule level, the UK CCS Network Code has been established to set the commercial and technical arrangements for how Users connect to a transport and storage network and how the network is operated and maintained, including interfaces between transport and storage companies and Users[194]. This is a material step toward harmonised operation for open-access networks, but it also highlights the remaining need to align technical standards, interface specifications and assurance practices across clusters if the UK is to avoid project-specific fragmentation.

The lack of harmonisation is particularly visible where technical standards are required to address dense-phase CO_2 behaviour and impurity-driven risks in a way that is consistent across the value chain. International standards exist that are explicitly framed for CO_2 transport and storage, including standards for pipeline transportation systems for CO_2 streams and for geological storage project requirements. ISO 27913, updated in 2024, covers pipeline transportation systems for CO_2 streams across gaseous and dense phases and explicitly includes aspects such as CO_2 stream quality assurance and converging streams from different sources, directly addressing the multi-source

[190] SMMI. Carbon capture, usage and storage (CCUS): non-pipeline transport and cross-border CO2 networks. **2024**. Available: DESNZ_CfE_Transport of CO2_SMMI_Jul2024_Final [Accessed 09 March 2026].
[191] UK Government. The Pipeline Safety Regulations 1996. **2023**. Available: The Pipelines Safety Regulations 1996 [Accessed 09 March 2026].
[192] HSE. Pipeline design codes and standards for use in UK CO2 Storage and Sequestration projects. Available: Pipeline design codes and standards for use in UK CO2 Storage and Sequestration projects - HSE [Accessed 09 March].
[193] Ofgem. Carbon dioxide transport and storage: regulatory instructions and guidance (RIGs). 2025. Carbon dioxide transport and storage: regulatory instructions and guidance (RIGs) | Ofgem [Accessed 09 March 2026].
[194] CCS Network Code. Network Code – Current Version. 2026. Available: Network Code – Carbon Capture and Storage Network Code [Accessed 09 March 2026].

network context that legacy hydrocarbon codes were not designed around[195]. On the storage side, ISO 27914 establishes requirements and recommendations for geological storage of CO_2 streams and recognises that permitting and approval will be required through the project lifecycle, reinforcing that storage constraints and assurance cannot be treated as an afterthought to transport design[196]. In addition, industry-recommended practices such as DNV-RP-F104 aim to provide an internationally applicable framework for design, construction and operation of onshore and offshore CO_2 pipelines, offering CO_2-focused guidance that can supplement or inform the application of legacy pipeline standards[197]. However, the presence of these resources does not automatically deliver harmonisation at national level; UK deployment still requires consistent adoption pathways, aligned interpretations and integration with UK regulatory expectations and licensing frameworks.

Where project teams and authorities apply differing expectations for design basis, risk assessment methodology, emergency planning assumptions or interface requirements, the result is often iterative design and assurance cycles and slower consenting and investment decisions. Offshore projects commonly inherit established offshore integrity management and marine-operability assumptions, while CO_2 service introduces additional low-temperature transient, phase behaviour and impurity considerations that are not uniformly captured in legacy practices. This combination can lead to divergence between offshore and onshore expectations unless a deliberate harmonisation effort bridges CO_2-specific technical guidance and the UK's safety, environmental and economic regulatory frameworks.

Closing this gap, therefore, requires more than adding another guidance document: it requires a coherent, UK-aligned framework that connects the regulatory regime, the Network Code operating rules and a consistent technical standards "stack" that explicitly covers dense-phase CO_2 behaviour, impurity-driven risks and multi-source interoperability. Without that integration, the risk is that projects will continue to rely on conservative, bespoke interpretations of legacy standards, driving inconsistent requirements between regions and compounding uncertainty in design and consenting, particularly as the UK moves from single-project developments toward interconnected, open-access networks spanning multiple clusters and offshore storage hubs.

The UK has core safety regulation and emerging economic and network governance for CO_2 transport and storage, but the delivery gap is consistent harmonisation of the technical standards and interpretations needed for dense-phase and impurity-sensitive CO_2 service across routes, regions and offshore interfaces; resolving this is essential to avoid fragmented design bases, repeated assurance cycles and reduced interoperability between clusters.

6.16 Permitting & Access Rights

Permitting and access rights are a programme-defining constraint for CO_2 transport and storage because the delivery of pipelines, landfalls and offshore routes depends on securing multiple consents Permitting and access rights are a programme-defining constraint for CO_2 transport and storage because the delivery of pipelines, landfalls and offshore routes depends on securing multiple consents and legal rights that are often interdependent and sequential.

Onshore, a central risk driver is that linear infrastructure frequently crosses many land parcels and interfaces with numerous third parties, each with their own constraints and negotiating positions. Securing the necessary rights typically involves a combination of voluntary agreements and, where applicable, the use of statutory powers linked to the consenting route. Where landowner agreements, rights negotiation and interface management are not progressed early and in parallel with

[195] ISO. ISO 27913:2024 Carbon dioxide capture, transportation and geological storage – Pipeline transportation systems. 2024. Available: ISO 27913:2024 - Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems [Accessed 02 March 2026].
[196] ISO. ISO 27914:2017 Carbon dioxide capture, transportation and geological storage — Geological storage. 2017. Available: ISO 27914:2017 - Carbon dioxide capture, transportation and geological storage — Geological storage [Accessed 09 March 2026].
[197] DNV. DNV-RP-F104 Design and operation of carbon dioxide pipelines. 2021. Available: DNV-RP-F104 Design and operation of carbon dioxide pipelines [Accessed 09 March 2026].

engineering, programmes are exposed to schedule risk that can be difficult to recover later because route certainty is a prerequisite for detailed design, surveys and procurement.

Consenting route and governance also influence programme risk. Larger energy infrastructure projects may fall within nationally significant infrastructure pathways, where a DCO provides a single consenting mechanism that integrates multiple permissions and land powers instead of relying solely on local planning permission. UK Government planning guidance provides structured requirements across pre-application, acceptance, examination and decision stages for nationally significant infrastructure, reinforcing that evidence requirements and procedural steps are substantial and can become pacing items if not planned and resourced appropriately[198].

Offshore, permitting and access complexity shifts toward marine licensing, seabed rights and co-location with other marine uses. Marine works typically require specific permissions under the marine licensing regime, and UK Government guidance is explicit that marine licensing is a separate consent and that applicants must determine what licence, exemption or additional permissions apply to the activity and location[199]. This consent layer can be schedule-critical because it depends on complete applications, consultation and potential conditions, and must be coordinated with other project approvals and with practical constraints such as weather windows and vessel availability.

A further offshore delivery driver is the need to secure and manage seabed access in a congested environment. Route selection and landfall siting may be constrained by existing infrastructure, designated areas, shipping lanes, and the rapid expansion of offshore wind and associated survey and construction activity, all of which can create co-location constraints and complicate routing. Offshore consenting must contend with marine licences and seabed rights, while co-location with wind and fishing or shipping lanes can shape routing and construction windows. Even where technical feasibility is clear, the programme can be driven by the time required to resolve co-location issues, agree crossing arrangements, and demonstrate that environmental and navigation impacts have been assessed and mitigated through the consenting process.

Reducing this gap requires treating consenting and access rights as primary design inputs from the outset. Onshore, this involves progressing a land and rights acquisition strategy in parallel with route optioneering, with a clear link between the chosen consenting pathway and the powers and processes required to secure the necessary rights and crossings. Offshore, it requires early identification of the applicable marine licensing requirements and a co-location strategy that accounts for other seabed Users and the practicalities of marine construction windows. Across both environments, front-loading surveys, stakeholder engagement and evidence development can reduce iteration and rework later, because permitting, land and seabed rights, and third-party negotiations collectively determine whether routes and landfalls remain viable through to consent and construction.

Permitting and access rights are not secondary “process steps” for CO_2 infrastructure; they are often the defining determinants of route selection and schedule, onshore and offshore, and early alignment of the consenting pathway, land and seabed rights strategy, and co-location management is essential to prevent avoidable rework and programme delays.

6.17 Cost & Economic Viability

Cost and economic viability are defining constraints for CO_2 transport and storage because project economics are shaped as much by utilisation and regulatory arrangements as by engineering design. Government policy describing the CO_2 transport and storage regulatory investment model indicates that a licence is expected to determine the allowed revenue an operator may receive, reflecting

[198] UK Government. National Infrastructure Planning Guidance Portal. 2024. Available: National Infrastructure Planning Guidance Portal - GOV.UK [Accessed 09 March 2026].
[199] UK Government. Get Permission for Marine Work. 2025. Available: Get permission for marine work - GOV.UK [Accessed 09 March 2026].

efficient costs and a reasonable return, and that this underpins the ability to charge network Users for delivering and operating the network[200].

A practical consequence is that the economic case depends on the interaction between regulated revenue allowances and real-world throughput. Even if the allowed revenue model is designed to support efficient investment, project delivery can still be exposed to utilisation risk: if capture volumes ramp more slowly than expected, if capture plants experience intermittency, or if storage injection is constrained, network utilisation can fall below the level implicitly assumed in investment cases. This is particularly material in early operations where utilisation and availability tend to be most uncertain and where first-of-a-kind contingency and financing constraints are most acute. The UK regulatory investment model explicitly recognises this early-market challenge by providing for Exchequer-funded revenue support to be available in certain circumstances to support the first transport and storage networks, reflecting a policy intent to provide revenue certainty during initial deployment and scale-up. In parallel, government material on CCUS business models provides the broader policy framing for the commercial frameworks intended to support transport and storage and other parts of the CCUS value chain, reinforcing that the economic architecture is being actively developed to enable investment at scale[201].

Economies of scale are another structural driver. Shared networks can reduce unit costs as infrastructure is expanded and as multiple emitters share common trunklines, compression and storage access, but those benefits are only realised if the network can sustain high utilisation over time. This creates a tension: networks sized to unlock future scale economies may carry higher early-life costs and require stronger confidence in future volumes, while networks sized tightly around initial anchor volumes may reduce early financing exposure but risk costly retrofits and constrained growth later. This is one reason throughput risk and capacity allocation arrangements become central to cost viability. The CCS Network Code provides the underlying framework for the commercial and technical arrangements between transport and storage companies and Users, including aspects of connection and network operation, which in turn influences how capacity rights, curtailment and operational coordination affect utilisation and therefore economic performance.

The onshore/offshore split highlights a further delivery reality: cost drivers differ materially by environment. Onshore delivery can benefit from lower installation costs and generally easier access for operations and maintenance but may carry higher societal and land/interface costs that can indirectly drive CAPEX through route length, crossing complexity and mitigation measures. Offshore systems, by contrast, typically face very high installation and intervention costs, and fewer intervention options once assets are in service. These constraints tend to drive more conservative design bases and higher contingency allowances, because the consequences of unplanned intervention are more expensive and less predictable. Offshore intervention constraints are also tightly linked to weather windows and vessel availability, which can translate into both higher OPEX and higher indirect economic risk from downtime and deferred availability. While the regulatory model can provide a framework for cost recovery and reasonable returns, these offshore-specific risk factors still affect financing and procurement because they influence the probability distribution of cost and schedule outcomes, not only the central estimate.

Finally, first-of-a-kind status increases financing friction even within a regulated model. Early networks face heightened uncertainty in utilisation profiles, technology-integration performance across capture–transport–storage interfaces, and the maturity of operating rules and metrology that enable transparent charging and performance testing. The government has explicitly positioned revenue support as a mechanism to provide investor certainty for first networks, which indicates recognition that the “bankability gap” is not solely technical but also commercial and financial. The remaining delivery gap is therefore the practical integration of regulatory allowances, network charging and capacity arrangements, and realistic assumptions on capture availability and storage

[200] UK Government. Energy Security Bill factsheet: Carbon dioxide transport and storage regulatory investment model. 2023. Available: Energy Security Bill factsheet: Carbon dioxide transport and storage regulatory investment model - GOV.UK [Accessed 09 March 2026].
[201] UK Government. Carbon Capture, Usage and Storage - Industrial Carbon Capture Business Models Update. 2025. Available: Industrial Carbon Capture Business Models Update (November 2025) [Accessed 09 March 2026].

performance so that investors and Users can align around credible utilisation trajectories and risk allocation without repeated re-baselining during development.

UK CO_2 transport and storage cost viability depends on more than lowering CAPEX; it requires an investable balance between regulated allowed revenue and charging arrangements, realistic utilisation and ramp-up assumptions, and environment-specific risk management, particularly offshore, where intervention costs and limited options drive conservative design and higher contingency.

6.18 Non-Pipeline & Intermodal Transport

Non-pipeline and intermodal transport become important in UK CCUS where early projects, smaller emitters, or geographically dispersed sources need a credible route to a shore terminal and onward offshore storage before a full pipeline network is available. For shipping-led value chains, the system behaves fundamentally differently from a pipeline network because capture is typically continuous while shipping is batched. This creates a need for intermediate storage and careful terminal operations to buffer flow and maintain stable loading schedules.

The delivery gap is therefore interfaced reliably across liquefaction, storage, loading arms/hoses, metering, sampling, and transfer procedures. This includes managing the thermodynamic state of CO_2 consistently across the liquefaction plant, storage tanks, and ship cargo systems, and ensuring that terminal designs are compatible with ship operating envelopes. Industry perspectives stress that shipping, terminals and offshore receiving units need to be developed as an integrated system, reflecting a broader gap in cross-chain standardisation and assurance practices for this emerging segment[202].

Reliability and operability risks are particularly important for shipping-led systems because stoppages or delays propagate quickly through a batch logistics chain. Marine operations introduce additional constraints, including port and jetty availability, shipping slot management, weather windows and marine safety requirements, which can reduce operational resilience compared to a fully pipelined system. These requirements add design and operational compliance demands that must be addressed early, particularly for novel CO_2 carrier designs and new terminal concepts.

Onshore, road and rail are feasible for small volumes but are subject to local permitting and terminal traffic constraints. In practice, this means intermodal solutions can be helpful for bridging early projects, dispersed emitters, or interim phases, but terminal siting and operations can become the limiting factor rather than the transport mode itself. Traffic management, safety cases, and local stakeholder acceptance can constrain operating hours and throughput, and small-volume transport can also intensify measurement and custody considerations because frequent loading and unloading cycles increase the number of custody points and opportunities for quality drift (for example, warming, condensation or contamination during handling). Where intermodal is used to support offshore storage through a shore terminal, interface risks become tightly coupled to offshore availability: terminal storage and scheduling must be resilient enough to avoid extended capture shutdowns when ships are delayed, or offshore injection constraints arise.

Closing this gap requires specifying consistent storage and transfer conditions, designing terminal storage and loading/unloading operations around realistic schedules and disruption scenarios, and ensuring that boil-off/conditioning and quality management are integrated into the operability concept. For road and rail, the priority is to define practical terminal and permitting solutions for small-volume transport, including safe loading operations and realistic throughput limits, while maintaining a clear transition pathway to higher-capacity transport solutions as networks scale. Across all intermodal options, the key enabling need is harmonised specifications, metering and operational rules at the interfaces so that CO_2 quality, transfer safety and scheduling can be managed predictably between capture sites, terminals and offshore receiving hubs.

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[202] DNV. CO2 Shipping: Design, safety, and regulatory considerations for an emerging fleet. **2025**. Available: [DNV-CO2_Shipping_White_paper_2025.pdf] [Accessed 09 March 2026].

Non-pipeline and intermodal transport can enable early and dispersed CO_2 capture to connect into offshore storage via shore terminals, but the delivery gap is the reliability and standardisation of liquefaction, intermediate storage and loading/unloading interfaces—particularly for shipping chains where batch logistics, port infrastructure and conditioning requirements can become the binding constraints on availability and scale-up.

6.19 Decommissioning & End-of-Life

Decommissioning and end-of-life planning is a delivery-relevant gap for UK CCUS because CO_2 transport and storage assets must ultimately be closed out in a manner that is safe, legally compliant and financially provisioned, yet the value chain spans infrastructure types with different end-state expectations.

Offshore, decommissioning requirements are underpinned by established UK oil and gas decommissioning law and practice. The Petroleum Act 1998 provides the statutory basis under which the Secretary of State can require submission and implementation of decommissioning programmes for offshore installations and pipelines, and it enables the allocation of decommissioning responsibility to relevant parties[203]. The Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) provides guidance and oversight for decommissioning programmes, and its published materials set out processes and expectations for decommissioning submissions, consultation and approvals[204]. While CCUS introduces new asset types and operating purposes, offshore CO_2 transport and injection systems are likely to interact with this established regulatory environment, particularly where infrastructure is repurposed from oil and gas service or where subsea pipelines and structures create comparable seabed and navigational considerations.

Storage introduces a further end-of-life dimension that differs from conventional pipeline and facility decommissioning because the storage site's closure is governed by a permitting framework and long-term containment obligations. UK guidance on applications for a carbon storage permit sets expectations for storage site development and regulation, including the need for evidence across the project lifecycle and the steps required to obtain and maintain permissions[205]. In parallel, UK implementation of geological storage requirements under retained EU-derived regulations includes provisions for closure and post-closure obligations, which implies that end-state planning must address not only physical decommissioning but also the monitoring, verification and handover conditions associated with long-term storage stewardship[206]. In practice, this means projects need a clear closure plan that ties together well-plugging and abandonment strategy, monitoring cessation criteria, evidence for long-term containment, and the financial arrangements that underpin those obligations.

Emphasis is placed on asset reuse versus abandonment decisions where project developers may seek to repurpose existing oil and gas pipelines, platforms or wells to reduce upfront costs and accelerate schedules. Repurposing can be beneficial, but it complicates end-of-life decisions because the decommissioning baseline, remaining life, and standards applicable to repurposed assets may differ from those of newly built infrastructure, and responsibility may span multiple parties and historical owners. Where these issues are not resolved early, they can become a material barrier to commercial close: investors and counterparties typically need clarity on who carries end-of-life liabilities and how decommissioning funding is secured, particularly in regulated network contexts where Users may be exposed to costs through tariffs over time. Offshore oil and gas practice commonly uses decommissioning security arrangements to ensure funds will be available when required; although the detailed approach for CO_2 transport and storage networks will be shaped by the applicable

[203] UK Government. Petroleum Act 1998. **2026.** Available: [Petroleum Act 1998] [Accessed 09 March 2026].
[204] UK Government. Oil & Gas: decommissioning of offshore installations & pipelines. **2026**. Available: [Oil & Gas: decommissioning of offshore installations & pipelines - GOV.UK] [Accessed 09 March 2026].
[205] NSTA. Guidance on the Application for a Carbon Dioxide Appraisal and Storage Licence. **2025**. Available: [Guidance on the Application for a Carbon Dioxide Appraisal and Storage Licence] [Accessed 05 March 2026].
[206] UK Government. The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010. **2010**. Available: [The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010] [Accessed 10 March 2026].

licences and commercial frameworks, the underlying investor concern—certainty of liability allocation and funding—remains the same.

Onshore, end-of-life obligations are typically shaped by landowner agreements, planning conditions and environmental requirements, and the practicalities of physical access for removal. When routes and sites are acquired through agreements that anticipate decades of operation, decommissioning provisions can be overlooked in early negotiations; this can create future uncertainty and may drive additional costs or disputes at closure if end-state expectations differ between parties.

Offshore, long-term seabed obligations and the complexity of marine permitting reflect two intersecting issues. First, subsea removal or remediation can be technically difficult and expensive, and decisions on whether to remove, leave in situ, or partially remove infrastructure must consider safety, navigation, environmental impacts and regulatory expectations. Second, marine consents and environmental assessments can continue to apply during decommissioning campaigns, meaning that end-of-life work can require permitting effort comparable in complexity to installation—often under tighter operational windows because of offshore logistics and weather constraints.

Closing this gap requires integrating end-of-life thinking into concept selection and commercial structuring. For transport networks, this includes defining decommissioning standards and end-state assumptions for new build and repurposed assets, and embedding these assumptions into licence, tariff and commercial arrangements so liabilities are transparent and fundable. For storage, it includes clear closure planning that aligns with storage-permitting expectations and defines post-closure monitoring and stewardship pathways, along with associated funding provisions. Across onshore and offshore, early clarity on reuse versus abandonment decisions can avoid late-stage disputes and reduce the risk that decommissioning uncertainty constrains investment decisions or complicates consenting and stakeholder negotiations.

Decommissioning and end-of-life planning are enabling requirements for UK CCUS inevitability: without early clarity on reuse versus abandonment, liability allocation, and secure funding provisions, especially offshore, where removal is costly and permitting is complex, projects risk avoidable commercial friction and regulatory delays, even before construction begins.

6.20 Competency & Capability

Competency is a programme-critical gap for UK CCUS, as operational success depends on controlling and responding to CO_2 behaviours that differ materially from those in natural gas and conventional process operations. Dense-phase CO_2 behaviour, impurity sensitivity, low-temperature transients, and asphyxiation hazards introduce failure modes and decision points that require tailored knowledge, operating discipline, and consistent procedures across capture, transport, and storage. In parallel, the shift toward multi-shipper, open-access networks increases the operational burden because interoperability rules, entry and exit compliance, curtailment and off-spec handling require coordinated actions and clear decision rights across multiple parties, which is the type of operating environment the UK's evolving network governance arrangements are designed to support.

The key risk is not simply that individual organisations may lack awareness of CO_2 hazards, but that sector-wide, role-based competency standards and consistent operating procedures are not yet uniformly established across the UK CCUS value chain. Where competency expectations differ among operators, contractors, and interfaces, readiness-to-operate reviews can be prolonged and inconsistent, and commissioning and handover can be delayed while training and procedural gaps are addressed. This is particularly relevant to abnormal operations, where CO_2-specific events such as two-phase or solid formation during depressurisation, cold plume behaviour, dense-gas dispersion, off-spec excursions and compressor trips demand clear, practised responses. Without mature, consistently applied procedures and re-entry criteria, the operational consequence is often either conservative shutdowns that extend downtime or incorrect responses that increase safety and integrity risk, both of which reduce early availability and slow ramp-up.

Multi-emitter network operation further increases the competency burden because the operational "system" extends beyond any single asset. Effective response to off-spec events and transient upsets requires coordinated procedures that define who act, who decides and how priorities are applied across capture plants, transport systems and storage constraints. Where operational governance and decision rights are unclear, there is an increased likelihood of interface disputes, curtailment events and inefficient utilisation, particularly during early-life operations when the learning base is limited and control philosophies and alarm settings often require tuning and iteration. The onshore and offshore distinction reinforces this point: onshore contexts may benefit from broader workforce availability but still require training tailored to dense-phase CO_2 hazards and multi-shipper operations, while offshore contexts typically have more limited personnel windows and a stronger dependency on proven procedures because remote access and intervention constraints make recovery from errors slower and more costly, consistent with the factors highlighted in Table 6-1.

Emergency response readiness is a further competency-critical area because CO_2 releases require CO_2-specific preparedness, including recognition of asphyxiation risk, the potential for low-lying accumulation and the implications of temporary emergency venting and dispersion. UK guidance emphasises that employers must have appropriate emergency procedures and that arrangements should be planned, communicated and practised, which becomes particularly important where emergency response depends on coordinated actions with external responders and where the hazard behaviour may not be intuitive to non-specialists[207].

Addressing this gap requires a UK CCUS competency framework that is explicitly role-based and spans normal and abnormal CO_2 operations across capture, transport and storage, aligned with UK safety expectations and the operational arrangements envisaged for multi-user networks. It also requires the development and adoption of standard operating and abnormal and emergency procedures that cover start-up and shutdown, blowdown and venting, compressor trips, off-spec receipt, restart after shutdown, isolation and diversion logic and clear re-entry criteria. To make these procedures operationally effective, scenario-based training and drills should be embedded, including control-room simulation where appropriate, and joint exercises should be conducted with emergency services so that CO_2 release scenarios are understood and practised across the responding organisations. Practical training provision is already emerging through industry and academic capability-building initiatives, but the remaining need is to translate these into consistent minimum expectations for competence assurance across operators and contractors and to maintain an industry learning loop that updates procedures and training content as operational experience grows[208, 209].

Without consistent CO_2-specific competency standards and proven normal and abnormal operating procedures—covering transients, off-spec events, emergency response and multi-shipper governance—UK CCUS projects are likely to experience slower commissioning and elevated early-life safety and availability risk as networks transition from construction into operations.

[207] UK Government. The Pipeline Safety Regulations 1996. 2023. Available: The Pipelines Safety Regulations 1996 [Accessed 09 March 2026].
[208] UKCCSRC. CCS Training. Available: UKCCSRC - Carbon Capture & Storage (CCS) CCS Training - UKCCSRC [Accessed 10 March 2026].
[209] OPITO. Introduction to Carbon Capture, Utilisation and Storage. Available: Introduction to Carbon Capture, Utilisation and Storage - OPITO [Accessed 10 March 2026].

7. RISK ASSESSMENT

Table 7-1 summarises the principal delivery risks associated with large-scale CO_2 transmission infrastructure and identifies the key technologies implicated, the underlying challenge in each case, and practical measures that may reduce delay or programme disruption. While Section 5 demonstrates that most individual technologies required for CO_2 transport are mature, delivery risk arises primarily from system integration, regulatory scrutiny, public confidence, multi-party interfaces and first-of-a-kind deployment at network scale.

For clarity, Table 7-1 – Project Delivery Risks also identifies those risks that fall within, or are closely connected to, the North Sea Transition Authority's (NSTA's) scope, noting that the NSTA is the licensing authority for offshore carbon storage and grants carbon storage permits, while Ofgem regulates the economic operation of CO_2 transport and storage networks under the Energy Act 2023. Accordingly, the risks most directly relevant to NSTA are those associated with offshore storage performance, storage permitting, containment, MMV, and assurance of the offshore transport/storage interface, rather than with wider onshore planning, public acceptance, or general project finance matters. Within the table, Direct is clearly within NSTA storage/permit/offshore interface scope; Interface is not solely NSTA-controlled but likely relevant to NSTA assurance or permit confidence; and Indirect/Outside primary scope is mainly Ofgem, DESNZ, HSE, local planning, or commercial matters.

The risks listed span the full value chain, from onshore routing and community confidence through fracture control, impurity management and compression reliability, to storage injectivity, metering integrity, shared transport dependencies and long-term stewardship. In many cases, the core technologies are proven; however, integration at scale, evidence requirements for assurance bodies, and coordination across multiple Users introduce complexity that can delay approvals, Final Investment Decision (FID) or commissioning. The table, therefore, focuses not only on technical failure modes but also on those risks that most directly affect schedule, cost certainty, and deliverability.

For each risk, the associated technologies are highlighted to demonstrate where system integration pressure is greatest, and practical mitigation measures are identified. These solutions emphasise early optioneering, conservative design margins, robust monitoring, staged commissioning, clear contractual frameworks and transparent stakeholder engagement. Collectively, this risk register illustrates that the principal barriers to the timely deployment of CO_2 transmission networks are more often linked to coordination, validation and confidence at scale than to fundamental engineering feasibility.

Table 7-1 – Project Delivery Risks

#	Delivery Risk	Key Technologies Implicated	Challenge	Solutions to Reduce Delay	NSTA Scope
1	Public confidence impacting approvals (perceived CO_2 hazard)	Community engagement, emergency response systems, monitoring	Objections delay DCO/planning; perception shaped by incidents	Transparent risk comms; drills; local engagement	Indirect
2	Planning/DCO & corridor delivery for onshore CO_2 pipelines	Pipeline route, valve stations, pig traps, ESD systems, construction methods	Linear consenting and objections drive re-routing	Early optioneering; stakeholder plan; flexible crossing designs	Indirect
3	CO_2 spec/impurities control in multi-emitter networks	Impurity removal, filtration, dehydration trim, online analysers, sampling systems	Variable feeds; off-spec events cause curtailment & redesign	Clear spec + off-spec handling; robust monitoring at entry	Interface
4	Dense-phase fracture propagation & saturation pressure modelling	Fracture control design, arrestors, decompression models, toughness specs	CO_2 decompression plateau + saturation pressure effects are tricky	Early fracture/decompression programme; conservative design margins	Interface
5	Corrosion / materials compatibility incl. non-metallics	Dehydration units, corrosion monitoring, material qualification, seals/elastomers	Water + impurities drive corrosion; material compatibility uncertainty	Tight water control; qualification testing; monitoring strategy	Interface
6	Loss-of-containment modelling & emergency response readiness	Dispersion modelling tools, detectors, ESD/blowdown, responder tactics	Dense CO_2 dispersion; responder training; access constraints	Site-specific dispersion models; drills; tactical playbooks	Interface

7	FOAK performance & evidence packs (technology maturity at scale)	Capture plants, compression/dehydration trains, dense-phase pipelines, MMV toolchain	Not enough operating evidence at required scale; assurance rework	Conservative design; independent verification; progressive commissioning	Interface
8	Storage injectivity & pressure evolution	Injection wells, wellheads/trees, downhole gauges, pressure management, reservoir models	Rate may be lower than assumed; pressure constraints bind chain	Early appraisal; staged ramp-up; backup wells/portfolio	Direct
9	Compression + dehydration package reliability (FOAK integration risk)	Multi-stage compressors, intercoolers, dehydration skids, controls, PSVs	Trips/turndown/heat management; start-up instability	Dynamic studies; redundancy philosophy; rigorous FAT/SAT	Interface
10	Liability/insurance & long-term stewardship	Monitoring/closure plans, verification tech, data retention	Contracting slows if long-term obligations unclear	Clear liability handoffs; robust closure strategy and MMV	Direct / Interface
11	Policy / affordability / continuity	Contracting model, funding mechanisms, programme sequencing (not hardware)	Stop–start decisions pause FID and procurement	Multi-year commitments; standard contracts; staged commitments aligned to readiness	Indirect
12	MMV toolchain maturity and data credibility	Seismic surveys, pressure monitoring, plume models, seabed monitoring	Evidence burden; data integration; attribution across Users	Baseline surveys; fit-for-purpose monitoring plan; data governance	Direct
13	Shared T&S dependency (system-of-systems)	Interfaces, metering points, compressor/terminal tie-ins, commissioning integration	One late element blocks many; interface rework	Integrated master schedule; hard interface control; phased tie-ins	Interface
14	Capture technology performance risk in hard-to-abate sectors	Solvents/adsorbents/membranes, heat integration, solvent management	Lower-than-expected capture rates; integration complexity	Sector-specific pilots; conservative performance assumptions	Indirect
15	Cybersecurity and SCADA resilience	SCADA, telemetry, remote isolation control, data platforms	Multi-party connectivity; remote ops; assurance rework	Security-by-design; segmentation; supplier assurance	Interface
16	Metering, allocation & custody transfer in dense-phase CO_2	Flow meters, sampling trains, analysers, allocation algorithms/data systems	Dense-phase metering uncertainty; sampling representativeness	Redundant metering; calibration regime; clear allocation basis	Interface
17	CO_2 shipping/NPT chain buildout (terminals + logistics)	Liquefaction, refrigerated storage, loading arms, CO_2 carriers, unloading terminals	Batch logistics + more interfaces; terminal permitting/integration	Phased terminals; standard interfaces; proven cargo-handling practices	Interface
18	Supply chain constraints for specialist equipment	Compressors, large valves, analysers, subsea hardware, drilling rigs	Long-lead items; limited suppliers; fabrication slots	Early long-lead ordering; standardisation; framework agreements	Indirect
19	Workforce/competency (design, ops, emergency response)	Control room ops, emergency response training, integrity teams	Shortage of competent personnel delays readiness & approvals	Training pipelines; cross-project resource planning	Interface
20	Network capacity allocation & curtailment rules	Dispatch/nomination systems, telemetry, metering, contractual rules	Constraints require fair curtailment; disputes stall new connections	Transparent rules; constraint products; staged connection windows	Indirect

8. APPLICABLE CODES, STANDARDS AND GUIDANCE

The development and deployment of dense-phase CO_2 transportation systems is supported by a growing body of international standards, recommended practices, regulatory guidance and collaborative industry research. Unlike conventional hydrocarbon pipelines, where decades of operational precedent underpin well-established codes, CCS infrastructure is evolving within a framework that blends mature oil and gas standards with CO_2-specific adaptations and new technical guidance. This section summarises the principal standards, regulatory references and Joint Industry Projects (JIPs) that inform the design, construction, operation and assurance of CO_2 transport and storage systems.

The ISO 2791x series provides the overarching international framework for CCS, covering geological storage, quantification and verification, lifecycle risk management, CO_2 stream composition, injection operations and flow assurance. These standards define terminology, risk-based principles and cross-cutting technical issues relevant to integrated CCS projects. Complementing these, industry-specific guidance such as DNV-RP-F104 and API RP 1192 addresses the design and operation of CO_2 pipelines, incorporating fracture control, decompression behaviour, materials selection and operational considerations unique to CO_2 service.

Regulatory guidance, particularly from the UK Health and Safety Executive (HSE), provides the safety-case and hazard assessment context in which CCS infrastructure must operate. Publications addressing the major hazard potential of CO_2, workplace exposure limits, and the regulation of CCS installations frame the expectations for risk management, dispersion modelling, emergency planning and integrity assurance. The Energy Institute has also issued targeted guidance on CO_2 repurposing, plant design and hazard analysis, bridging oil and gas practice with CCS-specific requirements.

In parallel, a series of Joint Industry Projects over the past two decades has significantly advanced understanding of dense-phase CO_2 transport risks. Programmes such as CO_2PIPEHAZ, CO_2PIPETRANS, COOLTRANS and CO_2SAFEARREST have generated experimental data on release behaviour, fracture propagation and safety distances. More recent initiatives, including CO_2SafePipe and industry guidelines on CO_2 specification, continue to refine best practice in impurity management, phase selection and long-term integrity. Together, these standards and research efforts provide the technical foundation for CCS transmission systems, while highlighting areas where validation at scale remains ongoing.

8.1 ISO Standards

- ISO 27914:2017 Carbon dioxide capture, transportation and geological storage — Geological storage[210]
- ISO/TR 27915:2017 Carbon dioxide capture, transportation and geological storage — Quantification and verification
- ISO 27916:2019 Carbon dioxide capture, transportation and geological storage — Carbon dioxide storage using enhanced oil recovery (CO_2-EOR)
- ISO 27917:2017 Carbon dioxide capture, transportation and geological storage — Vocabulary — Cross cutting terms
- ISO/TR 27918:2018 Lifecycle risk management for integrated CCS projects
- ISO/TR 27921:2020 Carbon dioxide capture, transportation, and geological storage — Cross Cutting Issues — CO_2 stream composition
- ISO/TR 27923:2022 Carbon dioxide capture, transportation and geological storage — Injection operations, infrastructure and monitoring
- ISO/TR 27925:2023 Carbon dioxide capture, transportation and geological storage — Cross cutting issues — Flow assurance

[210] ISO 27914:2017 Carbon dioxide capture, transportation and geological storage — Geological storage. 2017. Available: [ISO 27914:2017 - Carbon dioxide capture, transportation and geological storage — Geological storage] [Accessed 09 March 2026].

- ISO/TR 27926:2024 Carbon dioxide capture, transportation and geological storage — Carbon dioxide enhanced oil recovery (CO_2 EOR) — Transitioning from EOR to storage

8.2 Other Standards

- DNV RP F104 (2021-09) Design and Operation of CO_2 Pipelines[211]
- RP 1192 American Petroleum Institute Recommended Practice, Transportation of Carbon Dioxide by Pipeline, Dec 2025[212]

8.3 General Guidance

- Regulating CCS[213]
- General Hazards of Carbon Dioxide[214]
- EH40/2005 Workplace exposure limits[215]
- Assessment of the major hazard potential of carbon dioxide (CO_2) A paper by: Dr Peter Harper, Health and Safety Executive (HSE) Advisers: Ms Jill Wilday (HSL) and Mr Mike Bilio (OSD)[216]
- Energy Institute – Repurposing and design guidelines for carbon dioxide, December 2023[217]
- Energy Institute – Good Plant Design for Offshore and Onshore Carbon Capture Facilities and Pipelines, Second Edition, April 2024[218]
- Energy Institute – Hazard Analysis for Onshore and Offshore Carbon Capture Installations and Pipelines, Second Edition, April 2024[219]

8.4 Joint Industry Projects

The following JIPs are referenced in Section 5.19, where their relevance to current technology gaps and TRL limitations is discussed.

- Project Skylark (Ongoing) – large-scale CO_2 release and dispersion validation, led by DNV
- MetCCUS (Ongoing) and related metrology programmes, including measurement and calibration of CO_2 mixture, led by European metrology institutes (e.g. RISE, NPL, TÜV SÜD NEL)
- CATO (2004-Ongoing) – A national program which includes complete studies in all aspects of CCS, led by TNO (Netherlands Organisation for Applied Scientific Research) - Industry Guidelines for Setting the CO2 Specification in CCUS Chains. It focuses on setting the CO_2 specification in CCUS chains. It covered thermodynamics, chemical reactions, materials and corrosion, safety and environment, capture and conditioning, compression and pumping, metering & sampling, pipeline transport, ship transport, geological storage and economic

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[211] DNV. DNV-RP-F104 Design and operation of carbon dioxide pipelines. 2021. Available: DNV-RP-F104 Design and operation of carbon dioxide pipelines [Accessed 09 March 2026].
[212] API. API Recommended Practice 1192 (RP 1192), Transportation of Carbon Dioxide by Pipeline. 2025. American Petroleum Institute | API | API Recommended Practice 1192 (RP 1192), Transportation of Carbon Dioxide by Pipeline [Accessed 10 March 2026].
[213] HSE. Regulating CCS. Available: Regulating CCS - HSE [Accessed 10 March 2026].
[214] HSE. General hazards of Carbon Dioxide. Available: General hazards of Carbon Dioxide - HSE [Accessed 10 March 2026].
[215] HSE. EH40/2005 Workplace exposure limits. 2020. Available: EH40/2005 Workplace exposure limits - HSE [Accessed 10 March 2026].
[216] Harper, P. (HSE); Wilday, J. (HSL); Bilio, M. (OSD). Assessment of the major hazard potential of carbon dioxide (CO2). 2011. Available: Assessment of the major hazard potential of carbon dioxide [Accessed 10 March 2026].
[217] Energy Institute. EI 3545 Repurposing and design guidelines for carbon dioxide pipelines. 2023. Available: Repurposing and design guidelines for carbon dioxide pipelines | Energy Institute [Accessed 09 March 2026].
[218] Energy Institute. EI 3554 Good plant design and operation for onshore and offshore carbon capture installations and pipelines. 2024. Available: Good plant design and operation for onshore and offshore carbon capture installations and pipelines | Energy Institute [Accessed 10 March 2026].
[219] Energy Institute. EI 3553 Hazard analysis for onshore and offshore carbon capture installations and pipelines. 2024. Available: Hazard analysis for onshore and offshore carbon capture installations and pipelines | Energy Institute [Accessed 10 March 2026].

- CO_2SafePipe (2023-Ongoing) – This project considers the benefits and disadvantages of transporting CO_2 in the gas phase compared to the dense phase and how the chosen phase impacts the design or re-qualification process for existing CO_2 pipelines. The JIP will further investigate increasing the acceptable level of impurities without raising the risk of corrosion and material degradation
- CO_2PIPEHAZ (2009-2013) – Small-scale to medium-scale test to improve the understanding of the hazards represented by CO_2 releases
- CO_2Europipe (2009-2011) – To define the road towards large-scale CO_2 transport infrastructure
- CO_2RISKMAN (2011-2012) – Publicly available guidance document on MAH risk management of the CO_2 stream within a CCS project
- CO_2SAFEARREST (2016-2019) – Full-scale burst tests research program. Two full-scale tests with buried pipeline (CO_2-N2 mixture), 24 inches
- COSHER (2011-2015) – Large-scale test to obtain data to support the development of models to determine safety zones/consequence distances
- CO_2PIPETRANS (2009-2015) – Medium-scale to large-scale test to fill the knowledge gap identified in the DNV-RP-J202. The results of the project were included in DNVGL-RP-F104 (2017)
- COOLTRANS (2011-2015) – Large-scale test to identify and propose solutions to key issues relating to the safe routing, design, construction and operation of onshore CO_2 pipelines in the UK
- CO_2QUEST (2013-2016) – Small-scale to medium-scale test to study the impact of the quality of CO_2 on storage and transport.

9. CONCLUSIONS

The study aimed to identify gaps which, if addressed, would accelerate the development of new CO_2 transportation infrastructure. The gap analysis indicates that the principal delivery-acceleration constraints are as follows:

9.1 Critical Technology Gaps Affecting FID and Early Operations

While this study concludes that there are no fundamental technology barriers to CO_2 transport deployment, several system-level technology gaps, typically in the TRL 6–8 range, remain sufficiently immature that, if not adequately addressed, they have the potential to impact Final Investment Decision (FID), commissioning, and early operational performance.

These gaps do not inherently prevent project sanction; however, they directly influence confidence in deliverability, operability, and regulatory approval. As a result, they can drive conservative design assumptions, extended assurance cycles, increased contingency, and, in some cases, delays to FID or start-up where evidence is insufficient.

The most critical technology areas in this respect are:

1. Dense-phase transient behaviour and decompression modelling - Limited validation of decompression curves, particularly for impurity-variable CO_2 mixtures, introduces uncertainty in fracture control design, blowdown strategy, and restart procedures. Where not resolved early, this can drive FEED iteration, additional testing requirements, and delayed safety-case acceptance.
2. Fracture control and crack arrest behaviour for CO_2 mixtures - While methodologies exist, the empirical dataset remains limited. Projects operating outside validated envelopes may require additional analysis or full-scale testing, which can impact design finalisation and schedule.
3. Multi-emitter network control and system integration - Integrated control strategies for impurity-variable, multi-source networks remain at lower TRL due to limited operational precedent. This can affect confidence in operability, curtailment logic, and network stability during early operations.
4. Metering, sampling and custody transfer for dense-phase CO_2 mixtures - Although metering hardware is mature, calibration standards and traceable reference materials for CO_2 mixtures are still developing. This can delay commissioning and create commercial risk if measurement uncertainty is not resolved.
5. Long-distance subsea control and tieback operability - At extended distances (≈150–300 km), system-level validation of control response, umbilical performance, and restart behaviour remains limited. This can influence architecture selection and increase reliance on conservative design margins.
6. Integrated monitoring, leak detection and MMV systems - While individual technologies are mature, integrated system validation under realistic CO_2 release conditions is still developing. This may affect safety-case confidence and regulatory approval timelines.
7. Decommissioning of dense-phase CO_2 trunklines at scale - The absence of established UK precedent introduces uncertainty in closure planning and long-term liability, which may influence investor confidence and commercial structuring.

Collectively, these gaps represent integration and validation challenges rather than technology deficiencies. In practice, projects can and do proceed by adopting conservative design, enhanced monitoring, and staged commissioning strategies. However, where these gaps are not addressed through early validation, testing, or design allowances, they can impact:

- FID timing, through increased uncertainty and extended assurance requirements

- Commissioning duration, due to additional testing and conservative ramp-up
- Early operational performance, including reduced availability, tighter operating envelopes, and higher curtailment

Ongoing research programmes and Joint Industry Projects (Section 5.19), including large-scale testing initiatives such as Project Skylark, are actively reducing these uncertainties. However, full integration of their outputs into standards and routine engineering practice remains in progress.

9.2 FID-Critical Priorities for CO_2 Transport Systems

Building on the critical gaps identified above, while multiple technology and integration gaps have been identified in this study, only a subset is likely to materially influence the timing and confidence in the Final Investment Decision (FID). These "FID-critical" priorities are those that directly affect the ability to demonstrate safe, operable, and regulator-acceptable system performance at the project sanction stage.

In practice, FID readiness for CO_2 transport systems is driven less by individual component maturity and more by the availability of validated system-level evidence, particularly under realistic operating and transient conditions. The following areas represent the most significant FID-critical priorities:

1. Validated transient and decompression behaviour (dense-phase CO_2) - The ability to demonstrate predictable pressure–temperature behaviour during start-up, shutdown, and blowdown is fundamental to the acceptance of the safety case and to fracture control design. Limited validation of decompression curves for impurity-variable CO_2 mixtures can lead to extended assurance cycles, additional modelling and testing requirements, and delayed FID where evidence is insufficient.
2. Fracture control and pipeline integrity assurance - Confidence in crack arrest performance for CO_2 mixtures remains dependent on a limited empirical dataset. Where project conditions fall outside validated envelopes, additional testing or conservative design measures may be required, directly impacting design finalisation, cost, and schedule prior to FID.
3. CO_2 specification, measurement, and custody transfer framework - A clearly defined and enforceable CO_2 specification, supported by reliable measurement and calibration methods, is essential for multi-user networks. Uncertainty in impurity limits, sampling, and metering accuracy can create commercial and regulatory risk, potentially delaying FID where allocation, compliance, and liability frameworks are not fully resolved.
4. Integrated system operability (multi-emitter networks) - Demonstrating that a network can operate reliably under variable inflow conditions, including impurity variability and capture intermittency, is critical for investor and regulator confidence. Limited operational precedent for multi-emitter dense-phase CO_2 networks means that system-level operability must be validated through modelling, operating philosophy, and defined control strategies prior to FID.
5. Storage interface definition and whole-system envelope validation - Transport systems must be designed within the constraints of storage injectivity, pressure limits, and operational flexibility. Without a validated "whole-system envelope" linking capture, transport, and storage, projects risk late-stage redesign, curtailment, or under-utilisation. This interface is therefore a key determinant of FID readiness.
6. Long-distance subsea operability and control (where applicable) - For projects involving extended offshore tiebacks, system-level validation of control response, restart behaviour, and intervention strategy becomes critical. While not a universal constraint, this can become FID-critical where distances exceed typical operating experience and influence architecture selection.

Collectively, these priorities define the minimum evidence base required to support FID. Projects that address these areas early through integrated modelling, validation, and design alignment are more likely to achieve timely sanction and efficient delivery.

Conversely, where these issues remain unresolved at FID stage, projects are likely to experience extended assurance and regulatory review cycles, conservative design and increased contingency, and
delayed commissioning and constrained early operations.

It is therefore recommended that these FID-critical areas be explicitly addressed during concept selection and FEED, rather than deferred to later project phases.

In practice, the most critical determinants of FID readiness are demonstration of safe transient and decompression behaviour, confidence in fracture-control performance within the defined operating envelope, and a fully defined and agreed CO_2 specification, measurement, and custody-transfer framework. These areas typically form the core of safety-case acceptance, commercial agreement, and investor confidence, and therefore represent the highest priority for early resolution.

9.3 CO_2 Quality Specification and Governance Maturity Risk

End-to-end CO_2 quality and specification governance is supported by the CCS network code, but is not yet fully mature for multi-user networks, risking off-spec curtailment, disputes, rework, and delayed commissioning where entry conditions, verification processes, and off-spec pathways are unclear or inconsistently applied.

9.4 Phase Behaviour and Transient Flow Assurance Uncertainty

Phase behaviour and flow assurance experience remains limited for realistic impurity mixtures and transient scenarios, particularly during low-temperature blowdown and restart (hydrate, ice and dry-ice risks), driving conservative operating envelopes and extending outage and commissioning recovery times.

9.5 Limited Operational Flexibility and Buffering Capacity

While linepacking provides short-term flexibility in CO_2 pipelines, it may be insufficient to manage variability from batch deliveries and supply demand fluctuations and can increase compression requirements. As a result, temporary CO_2 storage at hubs or landfall terminals may be needed to buffer the system and maintain stable, continuous operation.

9.6 Corrosion and Materials Compatibility Risk

Water- and impurity-driven corrosion, together with material compatibility (including seals and non-metallic components), are important risks to manage, especially under transient conditions and in offshore, access-constrained contexts, thereby increasing qualification scope and delaying operational readiness.

9.7 Hydraulic and Fracture Control Design Uncertainty

Hydraulics, transients, and decompression/fracture control continue to drive FEED iteration, where the full-life operating envelope, encompassing capture variability, linepack, compression, and well constraints, is not validated at an early stage.

9.8 Safety Case and Consequence Modelling Maturity Risk

Safety case development, QRA, dispersion modelling and emergency response evidence are critical items for routing and consenting; weak early evidence bases could result in late changes to valve spacing, venting strategy, route layout and monitoring requirements, directly impacting programme schedules.

9.9 Measurement and Custody Transfer Standardisation Gap

Measurement and custody transfer arrangements (mass flow, composition and auditability) are not yet consistently standardised for dense-phase, mixed-composition CO_2 service, creating the possibility of commissioning delays and commercial friction where calibration approaches and impurity excursions are contested.

While the underlying metering technologies (e.g. Coriolis, differential-pressure and ultrasonic meters) are mature at the component level (TRL 9), system-level maturity for CO_2 applications is lower (TRL 7–8) due to challenges associated with dense-phase behaviour, calibration, and composition measurement. Subsea metering remains less mature (TRL 6–7), with constraints on access, calibration and sampling reducing measurement confidence and increasing reliance on redundancy.

Ongoing metrology initiatives (e.g. MetCCUS) are improving calibration traceability, composition measurement and uncertainty quantification for CO_2 mixtures. However, these developments primarily increase confidence in measurement accuracy rather than resolving system-level standardisation and integration challenges. As such, measurement remains a key area of risk for ETS compliance and commercial alignment across multi-party CO_2 transport and storage systems.

9.10 Multi-Emitter Network Operations and Control Maturity

Multi-emitter network operations covering dispatch, balancing, blending, linepack philosophy, cybersecurity and operating rules are not mature at scale, increasing curtailment risk and slowing ramp-up to stable utilisation.

9.11 Onshore and Offshore Delivery Constraints

Onshore delivery is constrained by access rights, stakeholder acceptance and the absence of consistently applied CO_2-specific assessment methodologies, while offshore delivery is constrained by intervention limitations, isolation and blowdown practicality, and architecture choices (platform/NPAI versus subsea); both contexts drive conservative design and increased outage risk.

9.12 Storage Interface and Throughput Constraint Risk

Storage interface constraints, including backpressure, injectivity and ramp-rate limits, can become binding throughput constraints; without an integrated system envelope, projects may experience chronic curtailment and prolonged assurance cycles.

9.13 MMV Deployment and Integration Risk

Monitoring, Measurement and Verification (MMV) for CO_2 transport pipelines primarily relates to leak detection, flow and composition measurement, and verification of transported volumes and quality between custody transfer points, rather than subsurface storage monitoring. For pipeline systems, MMV supports integrity management, emissions accounting, and compliance with regulatory and commercial requirements.

The scope and deployment of these systems, particularly offshore, can drive late-stage redesign and schedule or cost growth if not aligned early with permitting expectations, custody transfer requirements, and data/reporting workflows. Challenges include demonstrating measurement accuracy under dense-phase and variable composition conditions, integrating leak detection with control and isolation systems, and ensuring that monitoring approaches are practical in offshore and subsea environments with limited access.

As a result, early definition of a transport-specific MMV architecture, aligned with safety case requirements, custody transfer arrangements, and regulatory reporting, is essential to avoid rework and to support timely commissioning and operation.

9.14 Regulatory and Standards Alignment Risk

Regulation and standards harmonisation, together with permitting and access pathways, remain material non-technical accelerators; inconsistent interpretation and sequential approvals can delay surveys, freeze route and landfall decisions and defer mobilisation.

9.15 Intermodal and Non-Pipeline Interface Reliability Risk

Non-pipeline and intermodal interfaces, particularly shipping terminals, are reliability-critical; interface unreliability can propagate repeated shutdowns and delay scale-up.

9.16 Workforce Competency and Operational Readiness Risk

Competency development and CO_2-specific operating procedures, including management of transients, pigging and in-line inspection, and emergency response, are not yet consistently embedded, delaying commissioning and early operations.

10. RECOMMENDATIONS

The following recommendations are prioritised according to their impact on Final Investment Decision (FID) readiness and early operational risk. The first three are considered FID-critical.

Across all recommendations, the central requirement is the definition, validation, and control of an integrated CO_2 system operating envelope spanning capture, transport, and storage.

10.1 FID-Critical Recommendations

10.1.1 Define and validate the full-chain CO_2 system operating envelope

Establish a fully integrated operating envelope covering capture variability, linepack, compression, transport, and storage constraints. This must explicitly include transient scenarios (start-up, shutdown, trip, and restart) and be validated against realistic impurity compositions. The envelope should be used as the primary design and assurance basis across all interfaces.

10.1.2 Strengthen transient behaviour, decompression, and fracture control design

Treat transient thermo-hydraulic behaviour as a primary design basis. Apply validated decompression models to representative CO_2 mixtures and ensure that the fracture-control design is aligned with CO_2-specific decompression characteristics. Define isolation philosophy, material toughness requirements, and staged blowdown strategies to prevent running ductile fracture and uncontrolled low-temperature excursions.

10.1.3 Establish a nationally consistent CO_2 specification and measurement framework

Define and enforce a common CO_2 composition specification, supported by robust sampling, metering, and custody transfer arrangements. Measurement systems must account for dense-phase behaviour, impurity variability, and compressibility effects, with clear uncertainty requirements aligned to regulatory and commercial frameworks. Governance for off-spec conditions, including isolation, curtailment, and re-entry, must be established early.

10.2 Early Design and FEED Priorities

10.2.1 Implement water control as a system-level integrity requirement

Treat dehydration and water management as the primary corrosion control barrier across the full CCS chain. Demonstrate that no free water can form under steady-state or transient conditions. Integrate impurity effects, corrosion modelling, and inspection strategy into a single integrity management framework.

10.2.2 Establish a regulator-aligned QRA and consequence modelling basis early

Define and agree on QRA methodology, dispersion modelling assumptions, uncertainty treatment, and acceptability criteria at the concept stage, aligned with HSE expectations. Embed these into routing, layout, and emergency planning decisions to avoid late-stage redesign.

10.2.3 Enhance network controllability and define operating governance

Develop network-level control capability supported by transient simulation, pressure and composition management, and clear operating rules. Define enforceable arrangements for batching tolerance, curtailment, and off-spec handling. Establish an integrated operating playbook covering start-up, shutdown, and re-entry, validated for offshore constraints and multi-emitter operation.

10.2.4 Front-load routing and system architecture decisions

Treat onshore routing, landfall selection, and offshore tie-in architecture as early gated decisions. Onshore, align with CO_2-specific QRA and stakeholder requirements. Offshore, design against hydraulic and thermal constraints, ensuring isolation, blowdown, and restart strategies are compatible with high inventory and limited intervention capability.

10.2.5 Define storage interface constraints within the system envelope

Integrate well, reservoir, and injection constraints into the overall operating envelope. Validate pressure, temperature, and compositional limits across the full lifecycle, including early-life low-pressure conditions and transient coupling between transport and storage.

10.3 Enablers for Delivery and Scale-Up

10.3.1 Standardise metering, data governance, and verification systems

Implement consistent approaches to measurement, sampling, and data management across the network. Ensure traceability, auditability, and alignment with emissions accounting and commercial frameworks to minimise disputes and commissioning delays.

10.3.2 Engineer non-pipeline transport and intermodal interfaces as integrated systems

Design shipping and intermodal transport chains (liquefaction, storage, loading/unloading) as complete, reliability-qualified systems with defined interface conditions, operating procedures, and disruption management strategies.

10.3.3 Close competency and operational readiness gaps prior to first CO_2 introduction

Establish CO_2-specific operating procedures covering transient management, pigging, inspection, and emergency response. Define intervention strategies (including safe depressurisation and recovery scenarios), implement robust data validation processes, and demonstrate readiness through scenario-based training and system testing as a formal operational gate.

10.3.4 Accelerate standardisation and validation through coordinated programmes

Support UK-aligned validation of decompression behaviour, dispersion modelling, impurity effects, and metrology through coordinated research, standards development, and data-sharing initiatives to reduce conservatism and shorten assurance cycles.

APPENDICES

Appendix A: Sample Entry-Level Specifications

This appendix summarises selected publicly published entry specification parameters[220] for the Liverpool Bay T&S (HyNet)[221, 222], HCCP[223, 224] and the Northern Lights project[225].

Table A-1 – Example CO_2 Entry Specification for HyNet, HCCP and Northern Lights

Parameter	CCS Project & Parameter Value			Design Significance
	Liverpool Bay T&S (HyNet)	NEP / HCCP	Northern Lights	
CO_2 Purity	≥ 95 mol-%	≥ 96 mol-%	≥ 99.81 mol-%	Sets baseline for phase behaviour and transport efficiency; limits non-condensables
Non-condensables (Combined)	≤ 4 mol-%	≤ 4 mol-%	≤ 4 mol-%	(N_2, Ar, CH_4, etc.) Affect density, phase envelope, and minimum pressure for single-phase flow
Water (H_20)	≤ 50 ppm-mol	≤ 50 ppm-mol	≤ 30 ppm-mol	Core corrosion and hydrate/solid risk control; drives dehydration requirements upstream
Oxygen (O_2)	≤ 10 ppm-mol	≤ 10 ppm-mol	≤ 10 ppm-mol	Limits corrosion and compatibility issues with downstream materials/storage
H_2S	≤ 5 ppm-mol	≤ 5 ppm-m ol	≤ 1 ppm-mol	Controls toxicity/corrosion risk and compatibility with storage/reservoir chemistry
Operating Pressure (Users)	Gas Phase (5-82 barg) Dense Phase (88-147 barg)	Design pressure - 150 barg MAOP - 136 barg Minimum - 90 barg	Not specified, must be brought to specific pressure before being collected for shipping	Maintains dense-phase conditions and outlet pressure margin; defines pump/compressor requirements
Operating Temperature (Users)	Gas Phase (0-50°C) Dense Phase (13-16°C)	Maximum +40°C, Minimum +5°C	Not specified, must be brought to a specific temperature before being collected for shipping	Constrains phase boundary; interacts with seabed cooling and depressurisation behaviour

[220] Values in Table A-1 are subject to ratification during project design phases and may change from that stated. HyNet parameters conform to the CCS Network Code data except for the pressure and temperature of gas and dense phase streams which was sourced from project circa March 2026.
[221] CCS Network Code. Network Code – Current Version, Annexure B Part 2. 2026. Available: Network Code – Carbon Capture and Storage Network Code [Accessed 09 March 2026].
[222] HyNet North West. HyNet CCUS Pre-Feed, WP5: Flow Assurance Report, Table D-3 and Table D-4. **2020**. Available: HYN01-02 Rev 01 Flow Assurance Operational Scenarios [Accessed 12 March 2026].
[223] Arcadis Consulting. Preliminary Environmental Information Report, Volume 2, Chapters, Table 2-18. **2025**. Available: HCCP+PEIR+Vol+2+-+Chapters+v11.pdf [Accessed 09 March 2026].
[224] Northern Endurance Partnership. CO_2 Pipelines Entry Specification. **2025**. Available: Microsoft Word - NEP00-EN-SPE-000-00001 - Public B03 [Accessed 12 March 2026].
[225] Northern Lights JV. How to store CO_2 with Northern Lights – Liquid Specification. Available: How to store CO2 with Northern Lights - Northern Lights [Accessed 03 March 2026].

Appendix B: International Benchmarks

International CCS and CO_2 transport experience is growing but remains limited at the scale required by multi-cluster, multi-emitter networks. Benchmarking is therefore usually a combination of operational experience from enhanced oil recovery (EOR) CO_2 pipeline networks, historically driven by the United States[226], and newer CCS 'full chain' projects (capture-to-storage), especially offshore injection schemes. Recent synthesis work identifies dense-phase (supercritical or near-supercritical) CO_2 as the most efficient pipeline transport state for large volumes, while also highlighting design challenges: higher operating pressures, the need for higher fracture toughness, and complex behaviour during large accidental releases[227]. DNV's CO_2 pipeline joint-industry efforts emphasise that arresting running ductile fractures in CO_2 pipelines can be more challenging than for natural gas, and that many pipelines fall outside historical applicability ranges, driving ongoing updates to recommended practice[228]. Northern Lights provides a current reference case for an offshore storage chain using an onshore receiving terminal, a 100 km subsea pipeline, and subsea injection facilities into a deep reservoir (~2,600 m below seabed)[229]. The Northern Lights joint venture reported successful transport through the 100-kilometre pipeline and injection into the Aurora reservoir in 2025, demonstrating end-to-end operability of a subsea (no platform at storage location) injection concept[230]. HSE notes that the USA operates many high-pressure onshore CO_2 pipelines employing EOR, see Figure B-1, and that the main codes used are the US Federal pipeline regulations (49 CFR Part 195 for hazardous liquids) with ASME B31.4/B31.8. It also notes that US regulations primarily apply to supercritical CO_2 transport[231].

[226] IEA. Whatever happened to enhanced oil recovery?. 2018. Available: Whatever happened to enhanced oil recovery? – Analysis - IEA [Accessed 09 March 2026].
[227] Alberta Innovates. State-of-the-Art in Transporting CO_2 in Pipelines. 2024. Available: CCUS-Whitepaper-Supplement-5-Carbon-Transportation.pdf [Accessed 09 March 2026].
[228] DNV. Design and Operation of CO2 pipelines – CO2SafePipe. Available: Design and Operation of CO2 pipelines – CO2SafePipe [Accessed 09 March 2026].
[229] TotalEnergies. Northern Lights: A CO2 Transport and Storage Project to Reduce Industrial Emissions in Europe. Available: Northern Lights: a CO2 transport and storage project to reduce industrial emissions in Europe | TotalEnergies.com [Accessed 09 March 2026].
[230] Northern Lights JV. Northern Lights JV has successfully stored first CO_2. 2025. Available: Northern Lights JV has successfully stored first CO_2 - Northern Lights [Accessed 09 March 2026].
[231] HSE. Pipeline design codes and standards for use in UK CO2 Storage and Sequestration projects. Available: Pipeline design codes and standards for use in UK CO2 Storage and Sequestration projects - HSE [Accessed 09 March].

Figure B-1 – US Dense Phase Pipeline Heritage [232]

Pipeline Name	Green Pipeline	Greencore Pipeline	Seminole Pipeline	Coffeyville Pipeline	Webster Pipeline	Emma Pipeline	TCV Pipeline, LLC
Company	Denbury Gulf Coast Pipelines, LLC (LA) & Denbury Green Pipeline – Texas, LLC (TX)	Greencore Pipeline Company, LLC	Tabula Rasa Energy, LLC	Perdure Petroleum, LLC	Denbury Green Pipeline – Texas, LLC	Tabula Rasa Energy, LLC	Texas Coastal Ventures, LLC
State	LA/TX	WY/MT	TX	KS/OK	TX	TX	TX
Pipeline Constructed (year)	2009/2010	2011/2012	2012	2013	2013	2015	2016
Pipeline Length (miles)	320	232	12.5	67.85	9.1	2	81
Pipeline Diameter (inches)	24	20	6	8	16	6	12
Maximum Operating Pressure (psig)	2,220	2,220	1,825	1,671	2,220	2,319	2,220
Total Pipeline Cost ($/mile)	$3,044,000	$1,372,700	$480,000	$928,500	$3,190,000	$750,000	Not Available
Pipeline Cost ($/diameter inch mile)	$126,823	$68,635	$80,000	$116,062	$199,176	$125,000	Not Available
Notes	Extensive wetlands and marshlands crossed along with Galveston Bay	Right of way on 65% private ranchland with 35% public and state lands		Construction issues with rock on lower section of pipeline; major boring requirements	Entire right of way within suburban high consequence area; more than 60% of pipeline was installed using horizontal directional drilling, which added significant cost to construction		Hilcorp Energy I, L.P. (50%) & Petra Nova LLC (50%); pipeline cost consistent with industry standards for diameter inch mile; primarily rural farm and grazing land; significant portion of line is colocated with other pipelines and utility transmission lines

[232] National Petroleum Council. Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage. Chapter Six – CO_2 Transport. 2021. Available: dualchallenge.npc.org/files/CCUS-Chap_6-030521.pdf [Accessed 02 March 2026].

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