International Standard

ISO 27913

Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems

Captage, transport et stockage géologique du dioxyde de carbone — Systèmes de transport par conduites

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Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular, the different approval criteria needed for the different types of ISO document should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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This document was prepared by Technical Committee ISO/TC 265, *Carbon dioxide capture, transportation, and geological storage*.

This second edition cancels and replaces the first edition (ISO 27913:2016), which has been technically revised.

The main changes are as follows:

— the entire text has been editorially revised;

— normative references have been updated;

— a subclause about CO_2 stream flowrate and impurity measurement has been added;

— the level of impurities has been limited to 5 % and a set of 17 requirements are defined to ensure CO_2 stream pipeline integrity;

— Annex A has been added to show example compositions of CO_2 streams for gaseous and dense phase CO_2 streams which fulfil the requirements of this document;

— the latest findings in fracture arrest design have been included in Annex D;

— Annex F has been added to describe the decompression effects on pressure and temperature versus time.

Any feedback or questions on this document should be directed to the user’s national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

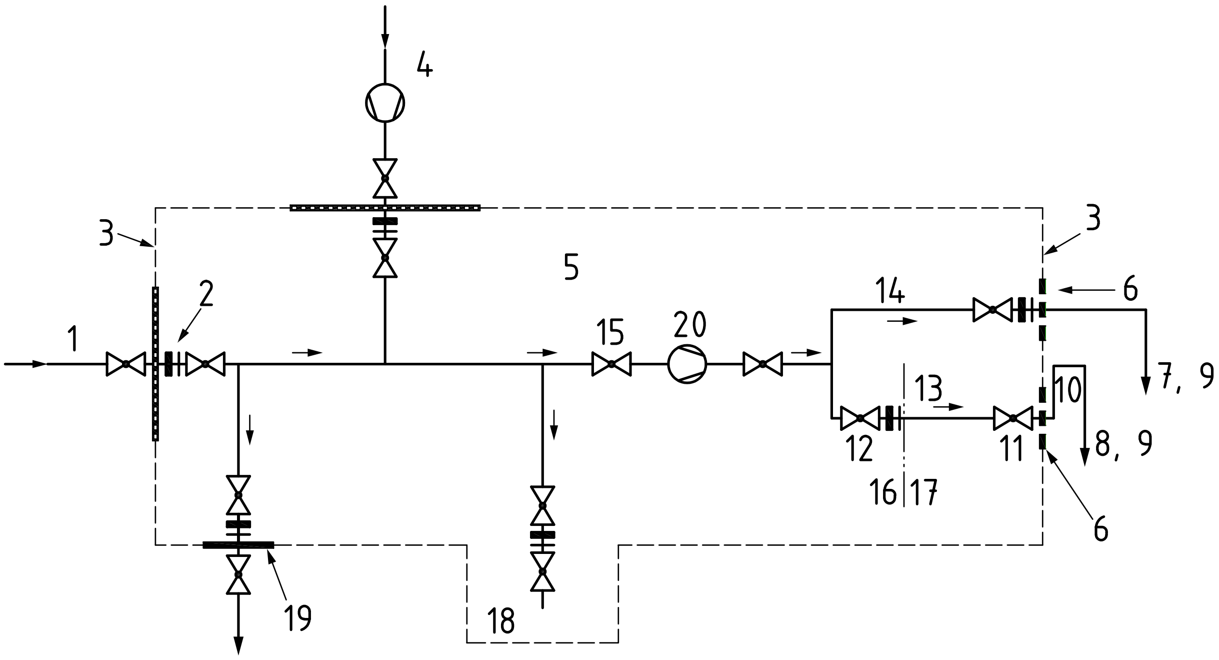
Introduction

Carbon dioxide (CO_2) capture, carbon dioxide use (CCU) and carbon dioxide storage (CCS) have been identified as key abatement technologies for achieving a significant reduction in CO_2 emissions to the atmosphere. Pipelines are likely to be the primary means of transporting CO_2 from the point-of-capture to storage sites (e.g. depleted hydrocarbon formations, deep saline aquifers), or to usage points (e.g. enhanced oil recovery or utilization) to avoid its release to the atmosphere. While there is a perception that transporting CO_2 via pipelines does not represent a significant barrier to implementing large-scale CCS, there is significantly less industry experience than there is for hydrocarbon service (e.g. natural gas). Furthermore, there are a number of issues that need to be adequately understood and associated risks that need to be effectively managed to ensure safe transport of CO_2. In a CCS or CCU context, there is a need for larger CO_2 pipeline systems in more densely populated areas and with CO_2 coming from multiple sources. Also, offshore pipelines for the transportation of CO_2 to offshore storage sites are likely to become common.

The objective of this document is to provide specific requirements and recommendations on certain aspects of safe and reliable design, construction and operation of pipelines intended for the large-scale transportation of CO_2 that are not already covered in existing pipeline standards such as ISO 13623, ASME B31.4, ASME B31.8, EN 1594, AS 2885 or other standards listed in the Bibliography. Existing pipeline standards cover many of the issues related to the design and construction of CO_2 pipelines. However, there are some CO_2-specific issues (e.g. fracture arrest, internal corrosion protection) that are not adequately covered in these standards but are addressed in this document. The purpose of this document is to cover these issues consistently. Hence, this document is not a standalone standard, but is written to be a supplement to other existing pipeline standards for natural gas or liquids for both onshore and offshore pipelines.

The system boundary (see Figure 1) between capture and transportation is the point at the inlet valve of the pipeline, where the composition, temperature and pressure of the CO_2 stream is within a certain specified range to meet the requirements for transportation as described in this document.

The boundary between transportation and storage or utilization is the point where the CO_2 stream leaves the transportation pipeline infrastructure and enters the downstream infrastructure, which can be permanent geological storage, utilization or buffer storage prior to shipping.



Key

1 source of CO_2 from capture (e.g. from power plant, industry; see ISO/TR 27912)
2 isolating joint
3 boundary limit
4 other source of CO_2
5 transportation system inside given in this document
6 boundary to storage facility or utilization
7 onshore storage facility
8 offshore storage facility
9 enhanced oil recovery
10 riser (outside transportation scope)
11 subsea valve (inside transportation scope)
12 beach valve
13 offshore pipeline
14 onshore pipeline
15 valve
16 landfall
17 open water
18 third party transport system
19 export to other uses than those of Keys 7, 8 and 9
20 intermediate compression or pumping

Figure 1 — Schematic illustration of the system boundaries of this document

Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems

1 Scope

This document specifies the requirements and recommendations for the transportation of CO_2 streams from the capture site to the storage facility where it is primarily stored in a geological formation or used for other purposes (e.g. for enhanced oil recovery or CO_2 use).

This document applies to the transportation of CO_2 streams by

— rigid metallic pipelines,

— pipeline systems,

— onshore and offshore pipelines for the transportation of CO_2 streams,

— conversion of existing pipelines for the transportation of CO_2 streams, and

— transportation of CO_2 streams in the gaseous and dense phases.

This document also includes aspects of CO_2 stream quality assurance, as well as converging CO_2 streams from different sources.

Health, safety and environment aspects specific to CO_2 transport and monitoring are also considered in this document.

Transportation of CO_2 via ship, rail or on road is not covered in this document.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 3183, *Petroleum and natural gas industries — Steel pipe for pipeline transportation systems*

ISO 20765-2, *Natural gas — Calculation of thermodynamic properties — Part 2: Single-phase properties (gas, liquid, and dense fluid) for extended ranges of application*

ISO/TR 27925, *Carbon dioxide capture, transportation and geological storage — Cross cutting issues — Flow assurance*

API SPEC 5L, *Line Pipe, 46th Edition, April 2018*

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminology databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at https://www.electropedia.org/

3.1
aqueous phase
liquid phase composed predominantly of water and other impurities that are not dissolved in the gaseous or dense CO_2 phase

3.2
block valve
full-bore valve inserted into a pipeline to reduce the total volume of the *CO_2 stream* (3.4) that would be emitted in the case of planned or unplanned depressurization of that section or in the case of a pipeline rupture

3.3
bubble point pressure
pressure of the saturated liquid at a given composition and temperature

3.4
CO_2 stream
stream consisting overwhelmingly of carbon dioxide

Note 1 to entry: A carbon dioxide stream consists of usually more than 95 mol% CO_2.

3.5
corrosion allowance
additional wall thickness beyond that required by the mechanical design to compensate for any reduction in wall thickness by corrosion (internal/external) during the design operational life

3.6
critical point
highest temperature and pressure at which a pure substance (e.g. CO_2) can exist as a gas and a liquid in equilibrium

Note 1 to entry: For a multicomponent fluid mixture of a given composition, the critical point is the merge of the bubble point curve and the dew point curve.

Note 2 to entry: The critical point can be established with the *critical pressure* (3.7) and the *critical temperature* (3.8).

3.7
critical pressure
vapour pressure at the *critical temperature* (3.8)

Note 1 to entry: The critical pressure for pure CO_2 is 7,38 MPa.

3.8
critical temperature
pure substance temperature above which liquid cannot be formed simply by increasing the pressure

Note 1 to entry: The critical temperature of pure CO_2 is 304,13 K (equivalent to 30,98 °C).

Note 2 to entry: For *CO_2 streams* (3.4), phase transitions can still occur above critical temperature.

3.9
dense phase
<engineering> CO_2 or *CO_2 streams* (3.4) in the single-phase fluid state above a density of 500 kg/m^3

Note 1 to entry: For more details on the dense phase, refer to ISO/TR 27925.

3.10
dew point pressure
pressure on the saturated vapour line

3.11
ductile fracture
shear fracture
mechanism which takes place by the propagation of a crack or stress-raising features, linked with a considerable amount of local plastic deformation

3.12
environmental cracking
brittle fracture of a normally ductile material in which the corrosive effect of the environment is causing the embrittlement

3.13
flow assurance
engineering discipline that is required to understand the behaviour of fluids inside pipelines, at flowing and static conditions

Note 1 to entry: The flow assurance provides input to design activities, such as pipeline design or risk analysis and operating philosophy development.

3.14
fracture arrestor
crack arrestor
additional pipeline component that can be installed around portions of a pipeline designed to resist propagating fractures

3.15
hydraulic capacity
maximum flow rate achievable in a system for a given pressure loss and given mechanical and operating constraints

3.16
in-line inspection
ILI
operation of sending an inspection tool inside a pipeline for the purposes of maintenance procedures such as pipeline cleaning, liquid removal, corrosion detection

3.17
internal coating
layer to reduce internal roughness and minimize friction pressure loss on the inside of the pipeline

3.18
maximum allowable operating pressure
MAOP
highest possible pressure to which the equipment or system may reasonably be exposed locally during operation

3.19
minimum design temperature
lowest possible temperature to which the equipment or system may reasonably be exposed locally during installation and operation

3.20
multi-phase flow
co-existence of more than one fluid phases (e.g. gas and *dense phases* (3.9) or two dense phases) in the same location of the pipeline

3.21
non-condensable component
component that, when pure, can be in gaseous form at possible CO_2 equilibrium conditions throughout the CO_2 value chain

EXAMPLE N_2, Ar, H_2, CO, CH_4, O_2 (excluding CO_2).

3.22
operating envelope
limited range of parameters over which operations result in safe and acceptable performance of the equipment or system

3.23
pipeline commissioning
activities associated with the initial filling and pressurization of the pipeline system with the fluid to be transported

3.24
pipeline dewatering
removal of water after hydraulic testing of the pipeline system

3.25
rapid gas decompression
phenomenon brought about by pressurized fluid migrating at a molecular level into a polymer and then being released suddenly causing failure of polymeric materials

3.26
saturation pressure
saturation vapour pressure
pressure of a vapour which is in equilibrium with its liquid at a given temperature applicable to pure CO_2

Note 1 to entry: For a *CO_2 stream* (3.4) containing impurities, the saturation pressure can either be the pressure on the saturated liquid line [*bubble point pressure* (3.3)] or the pressure on the saturated vapour line [*dew point pressure* (3.10)]. For CO_2 streams, both pressures are different for a given temperature.

3.27
short-term storage reserve
accumulation of the fluid in a pressurized section of a pipeline additional to the fluid that is extracted from the pipeline, for the purpose of temporary storage of that fluid

3.28
single phase
flow of CO_2 or a *CO_2 stream* (3.4) in a gas or a *dense phase* (3.9), but not in any combination of them

3.29
threat
activity or condition that alone or in combination with others has the potential to cause damage or to produce another negative impact if not adequately controlled

3.30
triple point
temperature and pressure at which the three phases (gas, liquid and solid) of a substance coexist in thermodynamic equilibrium

3.31
vent station
installation from which the contents of the pipeline or a section of pipeline between *block valves* (3.2) can be vented

3.32
network code
set of rules that are operational terms and conditions and agreed by either operators or governments, or both, under which a CO_2 stream system is required to operate safely and in a way that allows the objectives of each party to be realised

Note 1 to entry: Figure 1 shows where the network code becomes relevant for different system operators.

4 Symbols and abbreviated terms

4.1 Symbols

A_C	cross-section area of the notched-bar impact specimen equal to 80 mm^2	mm^2
C_v	Charpy V-notch absorbed energy value of the pipeline steel measured in the transverse direction	J
D	outer diameter of the pipe	mm
E	Young's modulus	MPa
P	pressure	MPa
P_s	bubble point pressure at given temperature and CO_2 stream composition	MPa
R	average pipe radius	mm
t	wall thickness of the pipe	mm
t_{min}	minimum wall thickness	mm
t_{minDP}	minimum wall thickness against internal pressure	mm
t_{minHS}	minimum wall thickness against hydraulic shock	mm
t_{minDF}	minimum wall thickness against fracture propagation	mm
T	temperature	°C
σ_f	flow stress	MPa

4.2 Abbreviated terms

BTEX	collective term for the highly volatile aromatic hydrocarbons benzene, toluene, ethylbenzene and xylene
BTCM	Battelle Two Curve Method
CCS	carbon dioxide capture and storage
CCU	carbon dioxide capture and utilization
DEG	diethylene glycol
EOR	enhanced oil recovery
ILI	in-line inspection
IMP	integrity management plan
MAOP	maximum allowable operating pressure
MEG	monoethylene glycol
SSC	sulphide stress cracking
TEG	tri-ethylene glycol

NDMA N-nitrosodimethylamine, also known as dimethylnitrosamine (DMN)

NMEA N-methylethanolamine

NDEA N-nitrosodiethylamine

NDELA N-nitrosodiethanolamine

NPIP N-nitrosopiperidine

NOMor N-nitrosomorpholine

PCDD polychlorinated dibenzodioxins

PCDF polychlorinatedfurans

5 Properties of CO_2, CO_2 streams and the mixing of CO_2 streams that influence pipeline transportation

5.1 General

According to ISO 20765-2, pure CO_2 and CO_2 streams have properties that can be very different from those of hydrocarbon fluids and can influence all stages of the pipeline life cycle. The thermodynamic and chemical behaviours of pure CO_2 have been explored throughout literature (e.g. see Reference [50]). In the usual operating envelope for CCS or CCU, the temperature and pressure vary and are project-specific. CO_2 can be in the gaseous or dense phase. There can be a large change in properties when crossing a phase boundary and for this reason, normal operation close to the phase boundaries should be avoided if possible.

In case multi-phase flow cannot be avoided for any reason, it should be given special consideration during design, commissioning, operation and decommissioning (see References [25] and [52]).

Subclauses 5.2 and 5.3 provide information for the designer and pipeline operator on how to decide on the correct parameters to be used to avoid negative impacts on the pipeline integrity.

Impurities within the CO_2 stream affect the phase envelope and can result in negative impacts on the pipeline operation and integrity. As part of the design process, limits shall be specified for the maximum levels of impurities within the CO_2 stream, and robust measurement equipment shall be installed to monitor the composition against this specification prior to its entry into the pipeline. For more information, refer to Annex A.

5.2 Pure CO_2

5.2.1 Thermodynamics

The thermodynamic properties of CO_2, particularly the saturation pressure, shall be taken into account because they have a significant impact on the design and operation of the pipeline. For a dense phase pipeline, the maximum saturation pressure resulting from isentropic expansion from within the operating envelope shall be used as the principal parameter in the design against running ductile fractures as described in 8.1.6. For gaseous transport, refer to 8.1.5.

The potential for inaccuracies in saturation pressure prediction and fluid properties should be taken into account when evaluating the design and operational philosophy of a CO_2-transport system, and when applying a margin of error to the maximum saturation pressure as a design criterion is recommended.

5.2.2 Chemical reactions and corrosion

With pure CO_2, there are no chemical reactions or internal corrosion in the pipeline.

5.3 CO_2 streams

5.3.1 Thermodynamics

The phase diagram and the physical and chemical properties change depending on the CO_2 stream composition, leading, among other things, to changed values of the bubble point pressure compared to pure CO_2. For a dense phase pipeline, the maximum bubble point pressure resulting from isentropic expansion from within the operating envelope shall be used as the principal parameter in the design against running ductile fractures as described in 8.1.6. For gaseous transport, refer to 8.1.5.

This bubble point pressure for the specific stream should be determined by use of a validated equation of state or other validated methods which are appropriate for the specific CO_2 composition, such as in Reference [37].

Note that there are uncertainties in modelling the phase behaviour of CO_2 streams. Fluid properties and phase behaviour of pure CO_2 are described very accurately by the Span and Wagner equation of state, which was specifically developed for pure CO_2. However, this equation of state cannot describe CO_2 with impurities.

The potential for inaccuracies in the bubble point pressure prediction and fluid properties should be taken into account when evaluating the design and operational philosophy of a CO_2-transport system, and when applying a margin of error to the maximum bubble point pressure as a design criterion is recommended.

5.3.2 Chemical reactions

The different impurities within a CO_2 stream shall be considered because some have the potential of reacting together to form other compounds in the location of the mixing zone and elsewhere as the flow goes along the pipeline (see also 6.6.2). The presence of these other compounds has the potential to affect the thermodynamic properties of the CO_2 stream or the integrity and operability of the system. The worst cases result in an acidic aqueous phase giving corrosion and, in some cases, also solid deposition. These potential effects should be modelled or confirmed experimentally.

6 Concept development and design criteria

6.1 General

Clause 6 includes requirements and recommendations related to design issues that are specific to CO_2 streams and that are usually considered as part of the pipeline concept phase.

CO_2 stream pipelines shall be designed in accordance with industry recognized standards specific to CO_2 streams – otherwise water pipe standards can be selected.

6.2 Safety philosophy

Safety is ensured in different ways in different countries. Some countries use risk-based and probabilistic design and operation philosophies, others use deterministic concepts. These concepts can be found in existing pipeline standards such as ISO 13623, EN 1594, AS 2885 or other standards given in the Bibliography. Hence, for risk assessment, risk management and hazard identification, the designers and pipeline operators should refer to these pipeline standards.

In cases where, in the design of the pipeline, the existing pipeline standards require a classification of the fluid with respect to potential hazards to public safety, the differences in hazards shall be recognized and compared to other fluids, e.g. natural gas. Compared to hydrocarbon pipelines, there is a limited length of CO_2 pipeline and only a limited amount of incident data are available. Examples are given in References [56] and [86]. Users should be aware that, because of the different design criteria and operational conditions, other pipeline incident databases, e.g. for natural gas pipelines, will not necessarily reflect the situation appropriate to CO_2 streams accurately. Therefore, they should be used with caution.

Failure statistics for onshore and offshore pipelines shall be considered separately, particularly in relation to corrosion and the causes of third-party damage. Statistical databases relevant to the application should be used but if data assembled in a different nation or geographical region are used, appropriate factors shall be applied where there are differences in design approach. For instance, requirements for minimum ground cover of a pipeline can vary from one country to another, as a result of which the frequency or severity of damage to the pipeline by third parties can correspondingly also vary.

The failure frequency analysis should examine the available historical incident data in detail to extract and use the most relevant data for a particular CO_2 stream pipeline project. When applying failure statistics, the designer shall consider pipelines designed in accordance with equivalent codes.

Incident data from other relevant pipeline systems may also be consulted and assessed carefully as input to any frequency analysis.

For internal failure mechanisms, such as corrosion, the application of pipeline failure statistics should be made with caution and only be applied on the basis that there is adequate control to prevent the formation of aqueous phases. It is possible that some impurities (such as acid formers, amines, glycols) have a large impact on the formation of an aqueous phase. The lack of dew point control is expected to increase the potential for failure of the pipelines as the internal corrosion rate increases significantly.

6.3 Reliability and availability of CO_2 stream pipeline systems

The reliability or availability of each part of the process from CO_2 production to storage shall be considered, as well as the design and operational impact on other parts. When assessing the availability of a component within the pipeline system, attention should be paid to the operational interdependency with other components as the components of a pipeline system including pumps and valves are necessarily very interdependent. Attention should also be paid to the provision of redundancy or diversity for key components in order to maximize the operational availability of the overall pipeline system and to avoid deferred CO_2 stream injection.

As data are limited on the reliability performance of equipment in CO_2 stream operational service, assessments using reliability data from traditional oil and gas service should be considered as an initial approximation. It should be noted that it can be inadequate to address failure modes present in a CO_2 stream pipeline service. For instance, unlike natural gas, when operating a pipeline close to the phase boundary, a small change in temperature or pressure can cause changes in the phase of the CO_2 stream or solubility of some of the impurities.

6.4 Short-term storage reserve

Short-term storage within the pipeline can be used as a buffer to smooth out some variations in CO_2 deliveries and receipts. The extent to which short-term storage reserve and other buffering solutions can be used should be reviewed and optimized against other project drivers both in the design phase of a project as well as during operations.

When operating a pipeline close to the phase boundary, a small change in temperature or pressure can cause changes in the phase of the CO_2 stream or the solubility of some of the impurities.

Consideration should be given to the limited availability of short-term storage reserve in low compressibility dense-phase pipeline systems.

More short-term storage reserve capability is possible in the higher compressibility gaseous phase pipeline systems. When accessing short-term storage reserve in a gas phase pipeline operating close to the phase boundary, operators shall ensure that gas phase is maintained over the entire pipeline length, and that temperature effects over the entire pipeline length are adequately considered.

6.5 Access to the pipeline system

Access by additional parties to contribute an additional CO_2 stream to an existing pipeline system is technically permissible, as long as the CO_2 stream specification and the design of the pipeline itself is within the operational regime of the existing pipeline system and meet the requirements of 6.6.2.

6.6 System design principles

6.6.1 General

The general design principles are defined in existing standards for oil and gas pipelines. In addition to these, the following design principles shall apply to CO_2 streams.

6.6.2 CO_2 stream specification

A specification for the CO_2 stream shall be agreed between the parties, including the producer, the transportation entity and the storage or utilization entity and any other entities responsible for the safe operation of the transportation infrastructure. The specification shall:

a) recognize that CO_2 greater than 95 mol% in the stream is a widely used industry practice;

b) recognize that the combined non-condensable content of lesser than 5 mol% is the industry practice with H_2, O_2, N_2, CH_4, Ar and CO being potential contributors;

c) set the specification such that, and with sufficient margin, hydrates or an aqueous phase are never present during any operational scenario, including transient operations (e.g. depressurization, restart), which, although infrequent and temporary, dictate the most onerous pressure and temperature conditions;

d) ensure that impacts of all impurities in the CO_2 stream at all operational conditions are considered when determining the maximum value of the bubble point pressure; the minimum operation pressure shall be above the bubble point pressure for that stream within the operating envelope for dense phase transport;

e) consider the impact of lighter impurity components on a refrigerated CO_2 stream, because they remain in gaseous state when the CO_2 stream is in dense phase;

f) take into consideration the impact of lighter components on the potential for running ductile fracture of pipelines carrying a CO_2 stream in dense phase;

g) ensure that the impact of the level of H_2 on hydrogen-enhanced crack propagation behaviour is considered, including for scenarios where a phase change can occur which results in partitioning and an increased mole-fraction of H_2 in the gas phase, and that sufficient margin to crack growth exists;

h) in the event of a release of CO_2 stream, ensure that the local hazard associated by any single impurity, is always lower, and with sufficient margin, than the hazard associated with the CO_2 itself;

i) note that during depressurization from dense phase the concentration of an impurity in the released CO_2 stream can be different due to lighter components being released from that in the original fluid, which can result in a more corrosive mixture remaining in the pipeline;

j) where there is a release to the environment, the specific hazards associated the liquid or solid phases of the components of the CO_2 stream shall be considered;

k) where there is a possibility of impurities accumulating anywhere in the CCS/CCU chain, the hazard associated with this accumulation shall be considered;

l) consider the corrosion risk of induced aqueous phases in the CO_2 stream for hygroscopic components that, where there is a possibility that liquids, such as glycols, amines and methanol are present in a CO_2 stream;

m) consider the corrosion risk of polar light components that can impact the corrosivity of an aqueous phase induced by a hygroscopic impurity;

n) note that there are possible chemical reactions within the CO_2 stream, both between the impurities and the CO_2 and between the impurities themselves; the potential impact(s) of consequential products shall be considered, see Reference [71];

o) employ measures at source to eliminate the possibility of liquids accumulating in a gaseous CO_2 stream and ensure that there is no subsequent build-up of liquid in the pipeline and downstream equipment;

p) keep to a practical minimum the presence of solids in a CO_2 stream;

q) consider the impact of solid particles within the CO_2 stream on equipment, e.g. such as compressors.

Example specifications that meet the above requirements are provided in Annex A.

Designers should also consider the potential for and impact of chemical and biological reactions between the CO_2 stream and the components of the storage medium.

6.6.3 Pressure control and protection system

The pipeline pressure control scheme shall ensure that both operating and transient conditions shall remain within the pipeline design envelope during, normal, upset, start-up and shutdown conditions.

A pressure protection system shall be used unless the pressure source to the pipeline cannot deliver a pressure in excess of the design pressure including possible dynamic effects.

Unless the materials of the pipeline or pipeline system are selected to accommodate such a situation, the pressure control system should be configured to ensure that there is a sufficient margin to aqueous phase formation (see 6.7) in case of a pipeline shut-in condition.

Venting of CO_2 to atmosphere to reduce pressure levels within a pipeline is permissible, but the design shall ensure that any venting does not lead to significantly higher exposure of personnel to adverse impacts or significantly affect the environment. The phase changes of the vented CO_2 and subsequent dispersion of the resultant plume should be modelled as described in Annex B.

6.7 General principles to avoid internal pipeline corrosion

6.7.1 Particular aspects related to CO_2 streams

It should be taken into account that a high degree of dehydration of the CO_2 stream is essential for internal corrosion control (see 7.1) and to reduce the potential for hydrate formation (see 6.7.3).

NOTE As CO_2 stream dehydration is part of capture process, refer to ISO/TR 27912.

6.7.2 Maximum water content

The primary control to prevent corrosion is dehydration and moisture control within the CO_2 stream, since the corrosion rate is difficult to predict with confidence.[85] The maximum concentration of water should be determined such that aqueous phase formation, hydrate formation and corrosion do not take place or be comfortably within design margins. The impact of polar impurities, such as methanol, glycols, on the aqueous phase shall be considered when specifying the maximum water content.

6.7.3 Avoidance of hydrate formation

The potential for hydrate formation both in gaseous and dense-phase CO_2 shall be considered with reference to the water content in the CO_2 stream and the temperatures at which the pipeline is expected to operate, see References [79] to [81].

In addition to the potential for forming CO_2 hydrate, the potential for forming hydrates from other non-condensable components shall be considered.

The potential for forming hydrates during pipeline commissioning or re-start shall be considered with reference to the pipeline desiccation procedure and potential for residual water in the pipeline after pressure testing (see 9.2.2).

The primary strategy for hydrate prevention should be sufficient dehydration of the CO_2 stream prior to it entering the pipeline system. The hydrate formation curve should be plotted. The maximum water content shall be selected so that the operating envelopes lie outside of the hydrate formation curve for the selected water content by a margin. It should be noted that hydrate formation requirements from systems downstream of the pipeline can set a more stringent specification than that required for the pipeline.

6.7.4 Measurement of water content in the CO_2 stream

Subclause 10.5.3 requires that the impurities within the CO_2 stream shall be monitored to ensure that compliance with the agreed specification is maintained. The pressure, temperature and water content should be measured continuously. Valid calibration certificates should exist for the water monitoring system. Calibration should be performed, taking the project-specific CO_2 stream into account, as other impurities within the stream can influence the readings. The reliability can be improved by using two separate water monitoring systems.

The speed of response to the detection of “out-of-specification” water content should be defined based on an appropriate assessment of the consequences.

6.8 Flow assurance

6.8.1 General

The key technical requirements and challenges to address flow assurance issues are described in this subclause but for more comprehensive information, ISO/TR 27925 shall be taken into account.

The main issues that should be considered in a flow assurance study for CO_2 stream pipeline transport include:

— system configuration to comply with the operational parameters including hydraulic capacity and downstream requirements;

— defining the permissible operating envelope of the pipeline transport in terms of flow rate, operating conditions and phase assurance, including operating conditions for mitigating against aqueous phase drop out;

— management of transient operations, such as those caused by varying injection rates, changes in CO_2 stream supply, liquid accumulation, surge, start-up, ramp-up, ramp-down and shutdown (and packing after shutdown of a downstream facility and de-packing after shutdown of upstream facility);

— thermal management under various operational scenarios to ensure that the variations of fluid temperature are within the operating constraints, including thermal expansion cooling, heat transfer to surroundings and ambient temperature variations;

— hydrate avoidance;

— planned and unscheduled depressurization of the systems, such as that resulting from a pipeline rupture, well blow-out or controlled venting of pipeline and equipment during maintenance activities need a specific consideration; safe operation, should be ensured, taking into consideration integrity failure mechanisms such as corrosion, erosion, vibration, material fatigue and embrittlement (especially low temperature embrittlement);

— changes in the levels of some impurities.

6.8.2 Operation under single-phase flow conditions during normal operation

The vast majority of CO_2 stream pipeline transport systems are operated under single phase conditions. The operation of a CO_2 stream pipeline transport system under single-phase flow conditions means that the CO_2 stream is in a single-phase state (gaseous or dense phase) in the entire system.

Although some CO_2 stream transport systems are operated in gaseous phase, the vast majority are operated in dense phase above the bubble point pressure of the CO_2 stream. CO_2 stream gathering systems and repurposed pipelines may be operated in the gaseous phase, however, typically longer distance transport pipelines are often operated in dense phase above the bubble point pressure of the CO_2 stream.

The main benefit of single-phase operation is that phase transitions do not occur, and density variations are limited. Risks associated with two-phase flow of CO_2 streams are not fully understood at the moment (see 6.8.4).

Normal operation includes stable operation as well as up and down ramps of mass flow rates.

The main tasks of flow assurance of CO_2 stream single phase flow in pipelines are to provide information on:

— hydraulic capacity for a given pipeline and boundary conditions;

— temperature, pressure and composition distribution along the pipelines;

— transient behaviour of the flow during the operation for shut-in and restart in pipelines and fluid hammering.

6.8.3 Pipeline operation under multi-phase flow conditions during transient operations

Multi-phase flow conditions can occur in situations, for example, after a pipeline shut-in and cooldown (especially in transport systems in which a CO_2 stream enters the pipeline at temperatures above ambient levels). It also occurs during depressurization of a dense phase transport system and during depressurization. After such events, multiphase flow conditions are unavoidable and the operator shall plan such that the duration under which such conditions are present is minimised as far as practicable. The potential for multi-phase flow to occur should be considered. The major issues that shall be taken into account as part of operating a pipeline in multi-phase flow conditions are:

— maintaining stable conditions is the priority; this can involve adjusting the injection capacity of the given system (pipe and well geometry, reservoir condition, ambient temperature, compression and pumping equipment etc.);

— identifying flow conditions that can reduce the hydraulic capacity (hydrate formation) and compromising system integrity (erosion, corrosion potential, etc.);

— maintaining temperature within acceptable range; reductions in pressure resulting from normal operations can cause very large temperature reductions due to evaporation of liquid CO_2, influence heat transfer and pipeline minimum temperature and depressurization duration; for example, a buried pipeline in dry soil (low heat transfer from ambient) can be harder to manage within operational limits than an offshore pipeline surrounded by seawater (high heat transfer from ambient);

— mass flow and composition measurements become uncertain when two-phase flow is present;

— use of an equation of state that has been validated in the multi-phase region being considered.

6.8.4 Planned and unscheduled pipeline pressure release

Temperature effects experienced during depressurization of CO_2 lines operating in the gas phase only are sufficiently dealt with by existing guidance for natural gas pipelines.

During the depressurization of a CO_2 stream from typical pipeline operating conditions in a dense phase, the CO_2 stream becomes cold due to the evaporation from dense phase to gas and the strong expansion cooling (Joule-Thomson effect). A reduction in pressure below the bubble point pressure of the CO_2 stream leads to the formation of gas phase. A further reduction in pressure causes strong cooling as long as the CO_2 stream is present in two-phase conditions (described in detail in Annex F). The potential for multi-phase flow to occur during depressurization events and the associated cooling should be evaluated to ensure planned depressurization operations can be safely conducted.

The main issue in pipeline pressure releases is that the pressure level must be controlled to avoid excessively low temperatures associated with two-phase operation. This can result in fluid temperatures well below the minimum design temperature of a pipeline system. This phenomenon is described further in Annex F. Very low temperatures can occur at moderate pressures if the CO_2 stream is boiling off. As the CO_2 stream expands below the triple point pressure (0,517 MPa for pure CO_2), some solid CO_2 forms. This can potentially lead to blockages in the system.

The major challenge is understanding the circumstances that can lead to such depressurization events and in turn their potential effects on pipeline material integrity to allow for appropriate controls to be put in place to mitigate such events and potential effects.

During the assessment of depressurization events, consider the following issues in a pipeline design:

— mass-release rate and its variation with time; this can be different for controlled and uncontrolled depressurization events;

— CO_2 stream phase state and its variation with time; phase distribution, pressure and temperature distribution;

— noise levels (for planned pressure release only);

— solids formation;

— minimum design temperatures;

— soft seals can be affected by rapid explosive gas decompression.

In the case of planned depressurization events, robust operating procedures shall be developed to ensure the operation can be performed safely, as described in 10.4.

6.8.5 Reduced flow capacity

In addition to the designed flow capacity, it shall be documented through thermo-hydraulic analysis that the pipeline is able to operate at a reduced flow without significant operational constraints or upset conditions being experienced.

6.8.6 Available transport capacity

Seasonal, daily and weekly variations in ambient temperature shall be considered in the thermo-hydraulic design process due to its effect on the density of the CO_2 stream.

The effect of temperature (seasonal variations) is likely to be more pronounced for onshore pipelines compared to offshore pipelines, however, depending on geographical location and pipeline installation (e.g. insulated versus non-insulated, buried versus un-buried); see 6.8.8.

6.8.7 Flow coating

The application of an internal coating to reduce pressure drop or for other purposes is generally not recommended for gaseous phase, but should not be used in dense phase due to the following:

— detachment of the internal coating in a pressure reduction situation, due to diffusion of CO_2 into the space between the coating and steel pipe during normal operation or due to low temperature during depressurization; it should be noted that the decompression effects can be gradual;

— diffusion of CO_2 into the polymer materials can lead to blistering during decompression and ultimately lead to rapid gas decompression failure of the coating;

— damaged coating can be transported to the receiving facilities, causing process upsets or plugging of injection wells;

— the difficulties associated with providing consistent internal coating over site welded joints: inferior coating can lead to areas of localized corrosion.

If an internal coating is applied, (or an existing pipeline with a flow coating is being re-purposed), the material shall be qualified for compatibility with CO_2 streams and the ability to withstand relevant pipeline decompression scenarios.

6.8.8 External thermal insulation

It should be taken into account that, for a pipeline, the heat ingress from and egress to the surroundings is determined by the difference between the ambient temperature and the temperature of the CO_2 stream inside the pipeline, combined with the insulation properties and burial depth of the pipeline. In case the temperature difference is too large, thermal insulation can be considered necessary to minimize the environmental impacts on the CO_2 stream.

The implications of thermal insulation, burial and soil condition (conductivity, moisture level) on minimum pipeline temperature in a depressurization situation should be considered.

6.8.9 Leak detection

It is important to ensure that loss of containment or leak incidents are detected and that measures to respond to these are available. Risk assessments should be utilized to quantify potential leak scenarios and leakage rates. Leakage rate should be quantified by numerical simulations assuming a location and opening size and operating conditions.

If a leak occurs in the pipeline, the duration, release rates and total release volumes can be limited by prompt detection, etc., possibly resulting in the shutdown of the source. The time for detection depends on the size of the leak.

Unless otherwise justified by a safety evaluation, an automated pipeline leak detection system is recommended. It is recommended that the system is diverse by utilizing more than one proven technology to reduce false alarms and increase its availability.

6.8.10 Fugitive emissions

An assessment of possible sources of fugitive emissions should be made and options to minimize them should be considered. The number of bolted joints should be minimized (e.g. on ILI launchers and traps), and the number of operational blowdowns should be controlled such that the minimum volume of the pipeline content is emitted.

6.8.11 Impurities

The effects of impurities on the physical and thermodynamic properties of CO_2 are described in Clause 5. In terms of flow assurance, increasing the concentration of impurities in the CO_2 stream generally reduces the flow capacity of the pipeline, depending on the type, quantity and combination of the impurities. This can have implications on the required pipeline sizing (e.g. pipeline wall thickness) or inlet pressure or distance between intermediate compressor or pumping stations.

Recognized thermo-hydraulic tools and suitable physical property models for the composition of the CO_2 stream shall be applied and documented for determining the pipeline flow capacity.

6.9 Pipeline layout

6.9.1 Vent stations

Vent stations are needed to allow the filling or release of the pipeline contents to be charged or discharged in a safe and controlled fashion. The pipeline layout and facilities for pressurization, depressurization shall be considered in the design phase of the vent stations. Also, the possibility to pump or compress the CO_2 stream from one to another section with the necessary connections should be considered.

Vent stations shall be designed such that the release of the CO_2 stream does not lead to a significant increase in hazards. A risk-based assessment is the preferred method to determine the best possible location.

A typical design for an in-line vent station is a full-bore ball valve in the main line, a bypass arrangement and a place(s) for mobile connections to be added if needed. The vent should include a control valve or orifice to control the rate of depressurization and the noise level.

6.9.2 Block valve stations

Block valve stations divide the pipeline into multiple sections to facilitate maintenance or to control the inventory of an escape of the CO_2 stream.

A block valve station is similar in design to a vent station without having a permanent venting system.

For onshore pipelines, the location and performance requirements of intermediate block valves should be based on qualitative risk assessments.

6.9.3 Pumping and compressor stations

Depending on local conditions along the pipeline route, there is a possibility that intermediate compressor or pumping stations are needed as a part of the pipeline system (see Figure 1). Power and signal/control availability can influence the optimal location of pump and compressor stations.

The design of pumps and compressors should consider all phases that can occur at the location during transient operation of the pipeline.

6.9.4 In-line inspection

CO_2 stream pipelines shall be designed such that ILI is possible and pipeline standards available elsewhere should be used in the design to ensure that this is the case (e.g. ensuring minimum bend radii). ILI launch and receive traps may be either temporary or permanent. A particular aspect related to CO_2 streams is materials selection on the ILI tool due to the possibility of low temperatures during pressurization or depressurization of the system (see Clause 7). Atmospheric vents from the traps shall be designed in such a way that ground level concentrations of CO_2 and any associated impurities do not reach harmful levels during depressurizing operations (see 6.9.5).

In-line inspection in CO_2 stream pipeline system are subject to the following effects.

— Very dry conditions mean that the dry surface of the pipeline causes high wear on the sliding part of the tool, especially cups and discs. This wear on the carrying and sealing elements is crucial. Performance of these elements in dry CO_2 stream conditions can define the maximum ILI length.

— The dense phase CO_2 is a very strong solvent; the size and shape of the molecules allow it to diffuse into rubber or plastic materials which can have a critical effect on numerous tool components such as cables, sensors and seals.

— Explosive decompression (rapid gas decompression) has the potential to take place when the ILI receiver is vented. The CO_2 stream partly diffuses out of the ILI inspection tool material; however, some CO_2 remains trapped. Unless decompression is carefully controlled, with reduced external pressure the CO_2 stream expands in the material creating bubbles on the surface. These bubbles can collapse again or burst if the amount of trapped CO_2 is large. Also, as surrounding pressure is reduced by venting the ILI receiver, Joule Thomson effect from CO_2 expansion can lead to low temperatures. These effects can be very detrimental to components, however are only a concern after the ILI run is complete.

6.9.5 Onshore vent facility design

Unnecessary venting should be avoided. When venting is necessary, the following considerations shall be in place.

At every onshore vent station, provided that safe dispersion of the vented CO_2 stream can be reasonably demonstrated, consideration should be given to installing permanent vent facilities where appropriate for operational flexibility.

As a minimum requirement, one permanent vent facility shall be included to depressurize the pipeline system. As a general recommendation, each vent facility shall have the capacity to depressurize the volume between block valves, also considering the integrity of the pipeline and any other safety considerations related to the release of CO_2.

Vents should be designed and located in a way that their operation does not result in unacceptable impacts to personnel or the environment.

The vent stack can be equipped with a flow control valve connected to a temperature gauge. The set point for the control valve should be selected with a sufficient margin to the minimum pipeline design temperature so as to prevent the pipeline being exposed to the sub-design temperature during venting.

An alternative to temperature control is pressure control since the temperature relationship with pressure can be determined. Where the pipeline section being vented has large differences in altitude, the pressure differences along the pipeline should be considered.

Dominant wind directions and topography effects should be considered when selecting the location and orientation of vent stacks.

The height of a vent stack should be assessed based on

— operational requirements,

— health and safety issues,

— environmental impacts (including noise), and

— geographical location (e.g. higher vents closer to populous areas to assist dispersion).

Consideration should be given to the vent tip design so that air mixing at the vent tip is maximised.

It is recommended that pipeline vent valves should be remotely operated and opened slowly such that adverse effects, such as ice formation as a result of Joule-Thomson cooling are avoided. Pipeline metal temperatures should not be allowed to fall below the minimum temperature recommended by material standards.

Consideration should be given to the potential effects of noise attenuation equipment on the exit velocity and dispersion of the CO_2 stream. For onshore pipeline vents, the potentially long duration of a pipeline (section) depressurization and associated noise levels can have safety, health and environmental implications.

Additional onshore vent facilities may either be permanent or temporary. Temporary vent facilities can be portable for the purpose of depressurizing sections of the pipeline for inspection, maintenance or repair.

6.9.6 Offshore vent facilities

Offshore venting is usually preferred to onshore venting because this offers the possibility of more rapid dispersion and population densities can be lower. However, in a supporting risk assessment, attention should be paid to the potential for shipping to be within the dispersion cloud and for pockets of CO_2 to become concentrated in locations on offshore structures where ventilation is minimal.

7 Materials and pipeline design

7.1 General

The recently published Guideline by AMPP Guide 21532[85] provides guidance for material selection and corrosion control for CO_2 stream transport and injection.

7.2 Internal corrosion

CO_2 stream pipelines shall be designed for corrosion to be within design margins under normal operational conditions. Failures can occur upstream of or within the pipeline system. For additional information, see Annex C and ISO/TR 27921[73].

Corrosion can be strongly influenced by the presence of some impurities in CO_2 streams. Hygroscopic agents can further reduce the degree of sub-saturation at which corrosion starts. Cracking can be triggered by the presence of impurities such as environmental cracking agents (e.g. H_2S, H_2, CO). For both normal operation and for upset conditions, a corrosion management plan shall be developed as part of the design: this to include the definition of relevant limits for recovery actions (e.g. replacement of a section of pipeline within a fixed timescale).

7.3 Pipeline system materials

7.3.1 Steel selection

The selection of steel shall be in accordance with ISO 3183 or other comparable standards and be compatible with all phases of the CO_2 stream.

Candidate materials need to be qualified for the potential low temperature conditions that can occur during pipeline system commissioning, operation, decommissioning or recommissioning.

7.3.2 External coating

The external coating of CO_2 stream pipelines shall be designed to accommodate the possibility of low temperatures during depressurization.

After any incidental or uncontrolled depressurization, the external coating of the pipeline can be affected. Additional measures for integrity management should be considered to face possible consequences.

The insulation properties of the external coating, including burial depth, should be considered as part of the overall pipeline heat transfer coefficient. Effect of coating on the temperature for the CO_2 stream should also be considered for planned or unplanned depressurization of the pipeline (see 6.8.4).

7.3.3 Non-metallic materials

Special care should be taken to qualify the non-metallic material in case of CO_2 stream transportation in dense phase, as, for example, swelling can occur in polymers, depending on the nature of the polymer and temperature.

For the selection of non-metallic materials, it shall be considered that high partial pressure CO_2 streams cause different types of deterioration mechanism, in particular, rapid gas decompression of some non-metallic materials in contact with the CO_2 stream (e.g. O-rings, seals, valve seats, ILI and maintenance tools) when the pressure is reduced from the dense phase to the gaseous phase of the CO_2 stream. Non-metallic materials shall be qualified to ensure:

— the ability to resist rapid gas decompression,

— the chemical compatibility with the CO_2 stream (see Clause 5) without causing decomposition, hardening or significant negative impact on key material properties, and

— resistance to the design temperature range.

With respect to elastomers, both swelling and rapid gas decompression damage shall be considered.

7.3.4 Lubricants

For the selection of lubricants, it shall be considered that lubricants can dissolve in dense-phase CO_2. Petroleum-based greases and many synthetic types of grease used in pipeline components, such as valves and pumps, can deteriorate in the CO_2 stream. The compatibility of the lubricant shall be documented for the specified CO_2 stream composition and operating envelope in terms of pressure and temperature.

8 Wall thickness calculations

8.1 Calculation principles

8.1.1 Design loads

The highest and lowest internal pressures, as well as the pressure gradient for the worst-case operational mode, shall be calculated for the whole pipeline. This calculation takes into account the flow rate, the physical properties of the CO_2 stream, as well as the topographical profile for the pipeline route. To do so, the phase-boundary of the CO_2 stream is of utmost importance because a situation resulting in multi-phase flow should not be part of normal operation.

To calculate the design load, the highest internal pressures and potential vacuum pressures transient operational modes (e.g. switching and controlling operations at compressor and pumping stations, valves, branch lines or starting and shutting down of the pipeline) shall be taken into account. This is also relevant for operational interruptions which can cause pressure increases or negative pressures (e.g. due to unintended valve closure or stoppage of compressor or pumping stations). The possibility of pressure pulses shall also be considered.

The highest and lowest internal pressures and temperatures for pipelines transporting CO_2 streams in the gaseous or dense phase shall be assessed and taken into consideration in the design as well in the operational stages for the whole pipeline.

The minimum and maximum values of system for hydraulic testing shall be defined on the basis of the topography.

8.1.2 Minimum wall thickness

To determine the minimum wall thickness, t_{min}, required for CO_2 stream pipelines, different evaluations shall be applied. In particular, these evaluations contain the determination of wall thickness;

— t_{minDP} against internal pressure, for all phases of CO_2 stream transportation, see 8.1.3, and

— t_{minHS} against dynamic pressure transients, e.g. hydraulic shock, for dense phase CO_2 stream transportation, see 8.1.4, and

— t_{minDF} against fracture propagation for all phases of CO_2 stream transportation, see 8.1.5 and 8.1.6.

8.1.3 Minimum wall thickness against internal pressure

To determine the minimum wall thickness, t_{minDP}, depending on internal pressure alone, calculations should be based on existing pipeline standards.

8.1.4 Minimum wall thickness against dynamic pressure alterations

To determine the minimum wall thickness, t_{minHS}, that accounts for hydraulic shock, the CO_2 stream hydraulic shocks (comparable with water hammer in liquid pipelines) shall be considered in dense phase CO_2 stream transportation. Dynamic pressure alterations can be caused by, for example:

— operational procedures (closing or opening of valves during operation);

— unintentional failure of compressor or pumping stations;

— branch lines;

— pipeline shutdown procedures.

If the potential exists for pressure surges to occur, the maximum value shall be determined using pressure surge calculations.

The resulting pressure increase of the design pressure shall be taken into account for the calculation of the minimum wall thickness.

Additionally, measures for pressure containment should be considered if necessary, e.g. alignment of the operating envelope of the valves, the variation of the release and locking mechanisms or times, and the application of flywheel masses of the pumps.

8.1.5 Minimum wall thickness, t_{minDF}, against running ductile fracture for gas phase pipelines

For gas phase CO_2 stream transportation, the Battelle Two Curve Method can be used (see Reference [48]).

NOTE There is currently no experimental data available to validate the use of the BTCM for gas phase CO_2.

8.1.6 Minimum wall thickness, t_{minDF}, against running ductile fracture for dense phase pipelines

Design considerations shall include pipe diameter, wall thickness, fracture toughness, yield strength, local operating pressure, local operating temperature, the operating regime of the sources and the decompression characteristics of the CO_2 stream.

Caution is advised when considering the minimum design temperature to be applied and the parts of the line to which it is applied. The depressurization rate should be controlled such that the resulting wall temperature is always above the drop weight tear testing temperature. If that is not possible, fracture arrestors should be fitted to limit the potential for running ductile fractures. During the depressurization process, the pressure goes down to a value that is no longer critical.

Pipelines for the transportation of dense phase CO_2 streams should be designed with adequate resistance to running ductile fracture. The principal means of fracture control are wall thickness, the selection of suitable materials or the installation of suitable fracture arrestors. Principal methods for preventing running ductile fractures in gas pipelines are described in API SPEC 5L:2018, Annex G which includes the assessment based on the “Battelle Two-curve method”, which was modified for CO_2 streams in the dense phase to reflect early testing results. However, following additional large-scale testing of running ductile fractures using dense phase CO_2 streams, it was concluded that the modified Battelle Two-curve method of assessing the propensity for a fracture to run or arrest did not lead to a conservative design in all cases. Therefore, the present state of knowledge is based on empirical acceptance criteria derived from the recommended practice in DNV-RP-F104[12],[83], which in turn is based on the analysis of all dense phase CO_2 large-scale pipe tests available in the public domain.

Based on knowledge at the time of publication of this document, a suggested approach is given in Annex D.

8.1.7 Fracture toughness

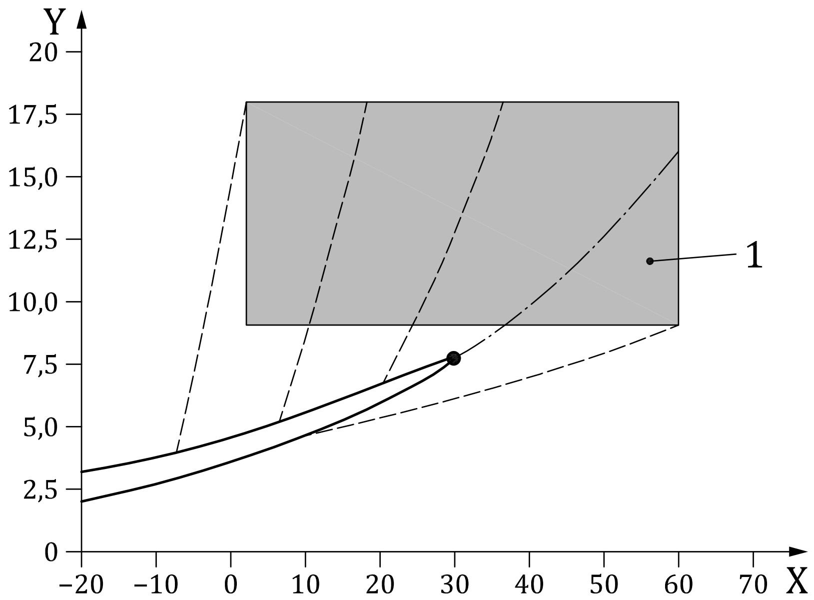
Line pipe shall meet the drop weight tear test and Charpy V-notch requirements specified in API SPEC 5L:2018, Annex G.

Caution is advised when considering what minimum design temperature to apply and to what parts of the line it should be applied, as typical DWTT performance in a pipe is limited to around −10 °C in most cases. In some cases, using fracture arrestors or limiting the lower t_{min} value to within a safe distance of a valve during blowdown should be considered.

8.1.8 Overview of the different aspects of wall thickness determination

For CO_2 streams, the required wall thickness depends on the isentropic expansion from the operating condition to the phase boundary and shall be calculated separately for each case, taking into account the specific properties of the CO_2 stream.

The pressure relevant in the design process to avoid running ductile fracture is the highest two-phase pressure that can occur after an isentropic expansion from within the operational window (pressure and temperature along the pipeline) for the CO_2 stream in question. This is illustrated in Figure 2. The dashed-dotted isentropic line intersects the phase envelope at the critical point.



Key

X temperature, T (°C)

Y pressure, P (MPa)

1 operational window

_ _ _ _ isentropes

——— phase envelope

—.— isentropic expansion line with highest pressure value on phase envelope

This figure provides an example of an operational window. The dashed-dotted isentropic line intersects the phase envelope at the critical point.

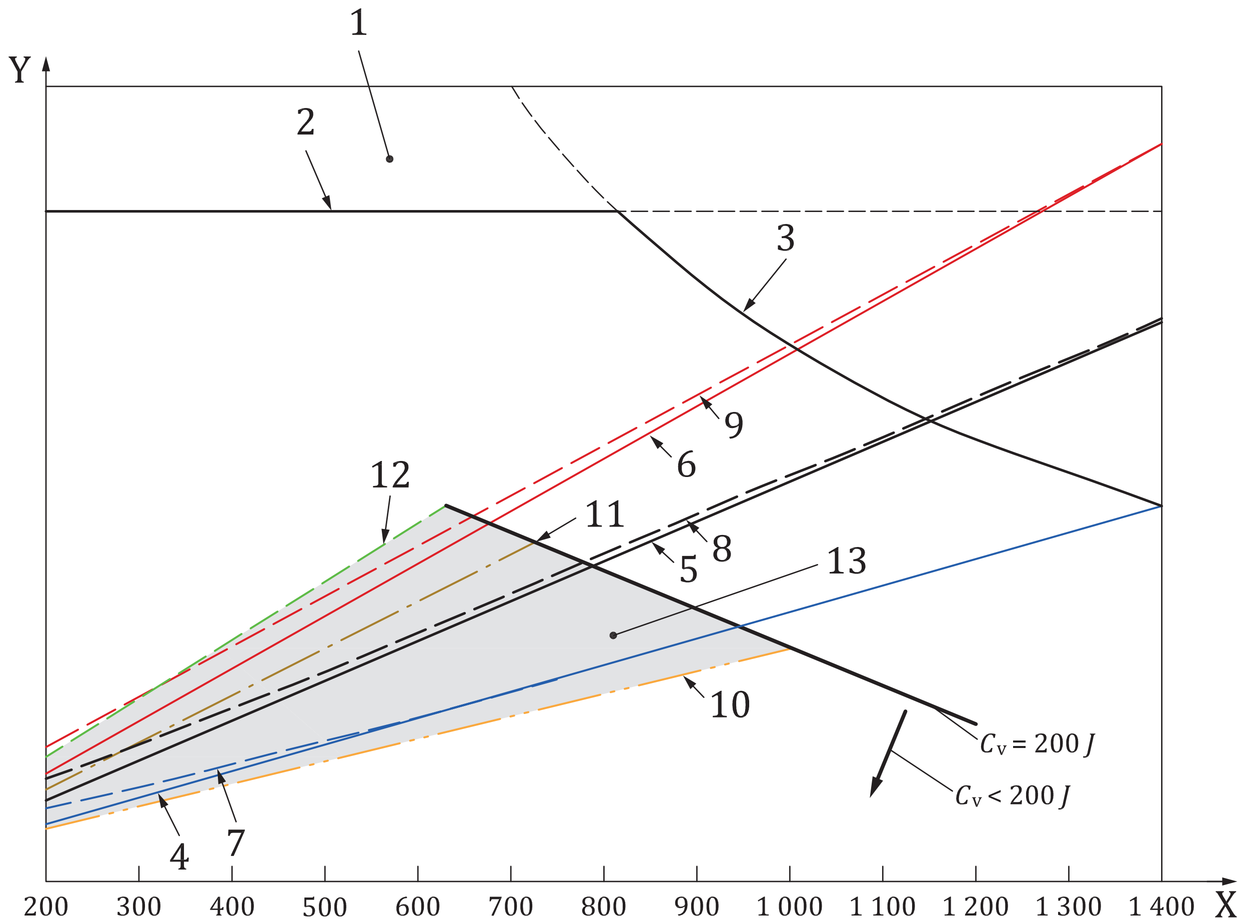
SOURCE Adapted from Reference [89]. Reproduced with the permission of the authors.

Figure 2 — Phase envelope for CO_2 with 2 mol% of N_2

In Figure 2, isentropic lines to the left (lower entropy) intersect the phase envelope at the liquid side (leading to evaporation) whereas those to the right (higher entropy) intersect the phase envelope at the vapour (gaseous) side (leading to condensation).

For a mixture, the critical point does not coincide with the maximum pressure of the phase envelope, although for the example shown, the difference is small. The maximum pressure on the phase envelope shall be taken as the basis to avoid running ductile fracture unless the operator can show that for the given pipeline and operating conditions, all isentropic lines intersect the phase envelope at lower pressures. In this assessment, the composition allowed by the CO_2 stream specification leading to the highest two-phase pressure shall be used.

Figure 3 illustrates the relationship of the wall thickness as a function of the pipe diameter against different internal pressures and demonstrates their correlation.



Key

X		diameter (mm)
Y		wall thickness, values depending on material specification, e.g. Charpy-V values
1		infeasible area (white area)
2		limited weldability
3		limited weight
4		internal pressure (10 MPa)
5		internal pressure (15 MPa)
6		internal pressure (20 MPa)
7		internal pressure (10 MPa) + hydraulic shock
8		internal pressure (15 MPa) + hydraulic shock
9		internal pressure (20 MPa) + hydraulic shock
10		fracture arrest P_s = 3,6 MPa (see Annex D)
11		fracture arrest P_s = 7,4 MPa (see Annex D)
12		fracture arrest P_s = 9,3 MPa (see Annex D)
13		fracture arrest area limited by Charpy-V ≤200 J

NOTE 1 The purpose of Figure 3 is to illustrate the design process for wall thickness dimension.

NOTE 2 The numbers for the wall thickness have been deliberately omitted to prevent users from inferring design information from the graph.

Figure 3 — Illustration of wall thickness as a function of pipe diameter, different internal pressures and different bubble point pressures

Figure 3 illustrates the linear correlation of pipe diameter and the resulting wall thickness depending on different internal pressures (solid lines). Additionally, Figure 3 illustrates the required wall thicknesses (long dashed lines) for designing a pipeline against hydraulic shocks. Moreover, Figure 3 illustrates the correlation of pipe diameter and required wall thickness against ductile fracture (short dashed lines) calculated by using the suggested approach in Annex D. That shows that this correlation is independent from the internal pressure of the steel pipeline.

One example (P_s = 3,6 MPa) is based on the assumption that after an isentropic expansion, the phase boundary of the dense phase CO_2 is encountered at 3,5 MPa. Further examples are shown for P_s = 7,4 MPa and P_s = 9,3 MPa as the phase boundary condition after isentropic expansion. The area marked with Key 13 in Figure 3 is limited due to minimum required Charpy-V values less than 200 J.

An additional aspect which should be considered within the design and construction of a steel pipeline is a practical or technical limitation. In the example illustrated in Figure 3, the white area represent where it is difficult to construct the pipeline due to:

— difficulty in welding because of the large wall thicknesses (see Figure 3 Key 2);

— too heavy a line pipe for transportation and handling during construction (see Figure 3 Key 3);

— inability to carry out field bending (see Figure 3 Keys 2 and 3).

These aspects shall also be considered separately for every case.

8.2 Additional measures

8.2.1 Dynamic loads due to operation (alternating operation pressure)

Pipes which are stressed due to dynamic pressure loads should be designed according to existing standards for pipelines transporting liquids.

8.2.2 Topographical profile

A dense-phase CO_2 stream pipeline design should consider the topographical profile due to the hydrostatic effects which can lead to higher pressures being realized downstream of a compressor or pump. The minimum and maximum values of the test pressures should take into account the local altitude along the pipeline hydrostatic test section.

8.2.3 Fracture arrestors

In case neither fracture initiation control nor fracture propagation control is ensured by other means, fracture arrestors should be considered (see References [22], [45] and [60]).

The spacing and siting of fracture arrestors should be based on a safety evaluation and should also take into account construction and operational considerations. The prevention of external corrosion should be considered during the design and installation of fracture arrestors.

8.2.4 Offshore pipelines

For offshore pipelines, the difference in dispersion following a release between that from a CO_2 stream pipeline and a hydrocarbon pipeline should be taken into consideration in the design safety assessment.

9 Construction

9.1 General

Due to CO_2 stream pipelines possibly having higher wall thickness than natural gas pipelines, as part of the construction process, consideration shall be given to the specific challenges relating to thicker wall pipelines, such as welding, field bending, radius of curvature, hydraulic testing and larger handling equipment being utilized.

The standards referred in this document should give the necessary guidance in combination with the specific design considerations as provided by the previous clauses.

9.2 Pipeline pre-commissioning

9.2.1 Overview

Pipeline pre-commissioning shall be carried out in accordance with the procedure described in standards for natural gas or oil pipelines.

The standards referred to in this document, such as ISO 13623, ISO/TR 27912, EN 1594, AS 2885, ASME B31.4 and ASME B31.8, contain guidance on the issue of pipeline pre-commissioning activities and the relevant considerations. In the following subclauses, some specific requirements and recommendations for the pipeline pre-commissioning activities are given.

9.2.2 Pipeline dewatering and drying

Due to the particular corrosion issues associated with CO_2 and water, the pipeline shall be dried to a sufficient dew point before filling with the CO_2 stream (see References [50] and [64]). Nitrogen or dry air can be used to dry the pipeline after dewatering. Glycols are not recommended because of the possibility of an aqueous phase being present during start-up and normal operation.

9.2.3 Preservation before pipeline commissioning

The need for preserving the pipeline between pipeline pre-commissioning and pipeline commissioning phases shall be assessed. Gases such as nitrogen or dry air can be used for preservation of the pipeline, but the requirement of the gas quality shall be assessed.

The means of preservation (e.g. filling with dry nitrogen above ambient pressure) shall be selected while considering the pipeline commissioning requirements, which can include requirements for internal pressure.

10 Operation

10.1 General

Clause 10 provides minimum requirements for the safe and reliable operation of pipeline systems for the whole service life.

Integrity management for CO_2 stream pipelines shall consider the specific operating challenges, threats and consequences associated with such pipelines, which are different from those associated with hydrocarbon pipelines. Subclauses 10.2 to 10.5 cover the aspects of commissioning and integrity management that require additional considerations for CO_2 stream pipelines relative to other pipelines.

10.2 Pipeline commissioning

10.2.1 Initial filling and pressurization with product

After completion of the construction activities, hydraulic testing, draining and drying, the pipeline is considered to be in a condition ready for pipeline commissioning.

Pressurization of a CO_2 stream pipeline requires special design consideration. The CO_2 stream should be injected into the pipeline in such a manner to avoid the formation of solids or allow temperatures to fall below design values. Various techniques may be employed to achieve this, including:

— controlled filling with gaseous, then dense phase (if required) CO_2 stream;

— pre-heating the CO_2 stream prior to pipeline entry as a technique for avoiding cold temperatures;

— pressurization with an intermediate gas, such as nitrogen or dry air or a combination of these appropriate to the project. The different media can be separated by one or more in-line cleaning tools;

— hydrate inhibitors (the hygroscopic behaviour of hydrate inhibitors and the potential for them to form an aqueous phase shall be considered).

10.2.2 Initial or baseline inspection

It is recommended to perform a baseline ILI run before the pipeline is put into operation. This inspection can determine the condition of the pipeline and can be used as a reference for later in-line inspections. In addition, the results of this inspection can be used as input to the subsequent inspection plans (see Annex E).

10.3 Pipeline shutdown

A pipeline shutdown procedure should be established. The potential risk of fluid hammer with quick closure of a valve in dense phase pipeline needs to be evaluated to ensure the pressure surge (fluid hammer) does not exceed the safe operating pressure, see 8.1.4.

Pipeline shutdown should be performed carefully and in a controlled manner. The shutdown procedure can depend strongly on the pipeline layout and utility system, hence, should be established for each specific pipeline.

During a planned shutdown, the pressure in the pipeline should be kept sufficiently high to prevent

— multi-phase conditions being present in gas phase pipelines, and

— risk of forming an aqueous phase.

In case there is a risk of the temperature decreasing during shutdown, i.e. due to lower ambient temperature (e.g. in offshore conditions), the potential decrease in pressure and temperature shall be considered with reference to the avoidance of multi-phase flow phenomena to protect the system.

In case there is a risk of the temperature increasing during shutdown, i.e. due to higher ambient temperature, the potential increase in pressure shall be considered with reference to the overpressure protection system and the design parameters of the pipeline system.

Where a pipeline route includes topographic features that can lead to high hydrostatic pressure differentials, measures shall be included to ensure that during shutdown conditions these pressures do not exceed the MAOP.

10.4 Pipeline system depressurization

10.4.1 General

A procedure for planned depressurization shall be established. The procedure shall take into account the pipeline layout in terms of segmentation, as well as location, capacity and function of vent facilities.

10.4.2 Pipeline depressurization

In the event of depressurization the pipeline can cool and contract longitudinally, potentially imposing a tensile force across the girth welds joining the line pipe sections. Designers should consider this potential event and ensure that pipeline stresses remain within acceptable limits.

The main risk associated with pipeline depressurization is the risk of cooling the pipeline material well below the minimum design temperature. Depressurization of a dense phase pipeline carries the potential for cooling of the pipeline steel to the point at which brittle failure is possible. The mechanism for this is described in Annex F, and in References [87] and [88], and the operator should be aware of it and plan the rate of depressurization such that the wall temperature is always above the temperature-dependent toughness level of the steel.

In uninsulated and non-buried pipelines exposed to seawater the CO_2 boil-off process occurs much more rapidly due to higher heat influx. A rapid depressurization rate can still lead to low temperatures if liquid CO_2 is still present. This should be evaluated in simulations and a reasonable orifice size should be selected to avoid this possibility.

In such systems it can be possible to control the depressurization process by monitoring the temperature at the orifice and stopping the depressurization process if the measured temperature approaches the minimum pipeline design. However, this relies on detailed transient modelling to assess the risk and behaviour of pockets of liquid CO_2 at locations remote from the depressurization location.

10.4.3 Vent facilities

The temperature inside the pipeline should be maintained above the minimum design temperature dependent on steel and liner quality to protect external coatings and other non-metallic materials and to prevent the potential for solid CO_2 formation within the pipeline during venting. Low pressure and low temperatures are expected at the end of the venting process when the pressure in the system is close to atmospheric.

However, the routine venting of CO_2 stream pipelines should be avoided if possible because:

— it would discharge the large inventory of CO_2 into the atmosphere (with associated costs, environmental and other impacts); and

— it would increase the potential for solid formation within the pipeline.

10.5 Inspection, monitoring and testing

10.5.1 General

It is recommended that an integrity management plan for CO_2 specific threats and consequences include the types of data shown in Annex E.

The integrity of the pipeline systems is strongly dependent on the condition of the CO_2 stream(s) entering the system. Hence, it is important to control the composition, temperature and pressure of each CO_2 stream entering the system to ensure that it is within the design specification. To ensure this, the CO_2 stream composition shall be monitored and assessed to avoid upset conditions in the pipeline. Monitoring of critical components in the CO_2 stream should be with a frequency appropriate to their potential impact on downstream components. Measures to ensure that the system is maintained in a safe operational mode shall be available, e.g. by rejecting out-of-specification CO_2 stream, or, in the extreme by shutting down the system.

If the CO_2 stream transport system includes multiple producers, it is recommended to measure critical components – and critical properties such as the formation of condensates of impurities (dew point specification) at every point of entry to the system. This allows identification of the producer delivering out of specification CO_2 stream. It is not always required immediately to shut off this producer. Short-term excursions outside normal limits may be allowed. The allowed period of off-specification operation depends on the amount by which limits are exceeded and the nature of the component under consideration.

The system should be designed in such a way to allow shutting off individual producers if allowable limits are exceeded by too large a margin or for too long a period.

10.5.2 In-line inspection procedure

The in-line inspection tool selected should be compatible e.g. with the desired CO_2 stream, operating pressure, friction conditions in the pipeline. Rapid decompression of non-metallic material is a danger for the operating personnel, mainly in dense phase systems.

For long distance pipelines, it is possible that the drive cups of the inspection tool experience excessive wear and material shall be selected accordingly.

Detailed procedures for launching and receiving an in-line inspection tool in a CO_2 stream pipeline shall be developed in order to ensure that the compression and venting processes do not result in situations damaging the infrastructure or the inspection equipment, or harming nearby personnel.

The operating personnel should consider the use of a pressurized air breathing system.

For the depressurization guidance, refer to 6.9.5.

10.5.3 Monitoring of water content and dew point

Water content and the dew point (for a CO_2 stream in gaseous phase) shall be measured using a moisture analyser. The redundancy requirements and the precision of the instrumentation shall be considered with respect to the specified margins on water content.

10.5.4 Network code or equivalent set of operational terms and conditions

A network code or equivalent set of operational terms and conditions shall be produced which requires all users connected to a transportation network to comply with consistent requirements and timelines.

The operator shall make safety-relevant data (e.g. pressure, temperature, impurity content) available in real time to the supplier of the CO_2 stream, the transportation operator(s) and the downstream custody operator(s). The network code or equivalent set of operational terms and conditions should specify minimum requirements for the communication of data between the parties.

10.5.5 Measurement of CO_2 stream at each custody transfer point

The measurement equipment for each custody transfer point shall include both sampling and compositional analysis, and flow rate measurement to enable the determination of:

— the level of defined impurities in the stream;

— the total CO_2 stream mass flow rate;

— the mass flow rate of CO_2 within the stream.

Measurement shall be provided in compliance with the network code or equivalent requirements but in all circumstances, it shall enable:

— safe operation and management of the system;

— compliance with the CO_2 stream composition specifications;

— reporting of transferred CO_2 quantity and commercial management (e.g. fiscal and custody transfer measurement).

10.5.6 Measurement of impurities

The impurities within the CO_2 stream shall be monitored to ensure that compliance with the stream composition specifications (see 6.6.2) is maintained and to provide input to the determination of the mass flow rate of CO_2.

The water content shall be measured continuously. Where there is a potential for an exceedance to result in an imminent downstream impact, the other impurities should be measured at an appropriate frequency. This should include O_2, CO, NO_x, SO_x, H_2S, NH_3 and, for dense phase applications impurities that potentially have a significant impact on the phase envelope, H_2 and N_2, unless the emission source has no potential to include a particular impurity. Other impurities should be measured at regular frequency (e.g. four times every hour) as agreed between the parties.

The accuracy, calibration range, calibration method, calibration interval and quality assurance of all the relevant measuring equipment should be appropriate to the permissible levels of impurity and to comply with any fiscal requirements, and with sufficient capacity to provide information to enable subsequent investigation in the event of an impurity level exceedance and for auditing purposes.

Impurities measurements and validation of all the relevant equipment to make such measurement should be traceable to national or international standards.

10.5.7 Action to be taken in the event of an exceedance of impurities

In order to protect the pipeline and network downstream assets, dependent on the potential impact and the nature and degree of exceedance the network operator should have the option to reject the CO_2 stream until conformity with the specification is restored. Details of how this would operate should be included within the network code and any further agreement between the parties involved.

10.5.8 Measurement of CO_2 mass flow rate

The CO_2 mass flowrate should be measured continuously (i.e. with granularity of a second or less). Measurement of the impurities and/or of the CO_2 concentration is required to determine the mass flowrate of CO_2.

Overall uncertainty of the CO_2 mass flowrate shall comply with any fiscal requirements. The calibration method, calibration range, calibration interval and quality assurance of all the relevant measuring equipment, including the equipment used to measure either the impurities or the CO_2 concentration, or both, shall be appropriate to meet with the overall uncertainty requirement.

CO_2 mass flow rate measurement uncertainty should be obtained by combining all the relevant uncertainty sources in an uncertainty assessment and ascertained according to with internationally recognized and accepted standards. The uncertainty assessment should be carried out as a minimum before and after the commissioning, servicing or changing of measurement equipment.

The mass flow and composition of the CO_2 stream shall be measured in single phase conditions: depending on the technology being used, two-phase flow is likely to result in significant uncertainties for both quantities.

Flow rate measurements and validation of all the relevant equipment to make such measurement should be traceable to national or international standards.

Where the flow meter is calibrated with a fluid different from the operational fluid, transferability of the calibration shall be assessed for the employed metering technology and if acceptable the additional uncertainty from calibration with an alternative fluid shall be accounted for in the overall uncertainty assessment.

Where the flow meter is calibrated at line pressure and temperature different from the operational ones, the impact of this difference on the performance of the meter shall be assessed for the employed metering technology and corrected for where needed and if feasible. Any additional uncertainty from calibration of the meter at line pressure and temperature different from the operational ones shall be accounted for in the overall uncertainty assessment.

Where an equation of state is used to determine the fluid properties, full account shall be taken of the impact of impurities. The fluid density uncertainty shall be determined where relevant and include the equation of state uncertainty, the impurities measurement uncertainty, the pressure and temperature measurement uncertainty.

Monitoring data should be available simultaneously to both the producer and pipeline operator, and records retained for sufficient length of time to enable trends to be identified and for auditing purposes.

11 Re-qualification of existing pipelines for CO_2 service

Existing pipelines may only be converted to CO_2 service, provided that they are re-qualified for such service according to the requirements described in this document or in other recognized standards or guidelines.

Such re-qualification should cover as a minimum:

- any changes in the safety assessment as a result of a new fluid (e.g. permitting, right of way);
- employing a ‘management of change’ process;
- the appropriateness of existing components for CO_2 duty e.g. positive material identification, elastomers, lubricants;
- wall thickness or pressure containments in general to accommodate hydraulic shock and fracture arrest and subsequent re-qualification of MAOP if necessary;
- venting arrangements and locations (see 6.9.1);
- block valve arrangements (see 6.9.2);
- the need for pumps or compressor stations to operate with the new fluid, in particular, to maintain it as a single phase;
- the need of pressure safeguarding equipment to stay within the operational envelope;
- the adoption of metering stations regarding the fluid properties (e.g. changes in fluid density);
- a pipeline integrity assessment, including the operating history of the pipeline e.g. remnant fatigue life, internal corrosion assessment;
- the potential for reactions of the CO_2 stream with the previous fluid;
- change of flow direction and its implications;
- any requirement for a lowered minimum design metal temperature, such as that required for depressurizing (see 6.8.4).

A formal life extension process should be carried out to align with the repurposed pipelines expected design life; this should be supported by a formal defects assessment and design assessment comprising hoop stress, hydraulic shock and running ductile fracture arrest.

Annex A
(informative)

Examples of CO_2 stream compositions

A.1 Introduction and examples of composition

This Annex is based on 6.6.2 and ISO/TR 27925, which reports on the thermodynamics and physics of the behaviour of carbon dioxide streams subject to the impurities contained within them.

Table A.1 provides numbers to complement ISO/TR 27925 and reflects the current state of knowledge and understanding of the science. It is intended as a guide to provide the designer with an example of a composition that reflects the principles listed in 6.6.2.

Recognizing that there is more than one way to comply with the requirements of 6.6.2, this Annex is not a specification to which CO_2 transportation systems need to comply.

The examples given in Tables A.1 and A.2 are based upon the best advice currently available. Where there are areas of uncertainty, a degree of conservatism has been applied, for example, there is a theoretical possibility that the presence of TEG in gas phase CO_2 leads to an induced aqueous phase, so the figure of zero TEG has been used. At the same time, the intention is to allow as much flexibility, recognizing that introducing additional process stages to meet a composition specification implies cost and complexity, which designers prefer to avoid.

Some designers or operators can choose to allow impurities at higher levels than listed in the examples in this Annex, and that is their choice, but safety should nevertheless be demonstrated to be according to 6.6.2. In any case, designers or operators may apply additional conservatism.

The hazards stated in Table A.1 are not intended to be an exhaustive list, but to provide the principal factor that has influenced the derivation of the numbers provided.

NOTE 1 If the impurity specification satisfies the requirements of 6.6.2 for gaseous phase, they possibly also satisfies the requirements of 6.6.2 for dense phase CO_2 streams.

NOTE 2 If the impurities specification satisfies the requirements of 6.6.2 for dense phase, they are not necessarily suitable for gaseous phase CO_2.

Table A.1 — Example of a gaseous phase CO_2 stream specification according to 6.6.2

Component	Concern(s) in a CCU context	Unit	Limit
CO_2	Asphyxiation and can act as a toxicant at high concentrations	mol%	>95,0
N_2 [a]	Enhances the potential for ductile fracture Occupies store pore space inefficiently	mol%	≤4,0
H_2 [a, b, c]	Enhances the potential for ductile fracture and hydrogen induced crack propagation Affects the size of the multi-phase zone	mol%	≤1,0
Ar [a]	Occupies store pore space inefficiently, enhanced potential for running ductile fractures	mol%	≤4,0
CO [a]	Health and safety: toxic gas	mol%	≤0,2
Methane [a]	Occupies store pore space inefficiently	mol%	≤4,0
Ethane [a]	Occupies store pore space inefficiently	mol%	≤4,0
Propane and other aliphatic hydrocarbons[d]	Liquid drop-out is possible	mol%	≤0,15 in total
H_2O	Enables corrosion of carbon steel	ppm mol	≤50
O_2 [b, e]	Enables oxidation of carbon steel Enhances bacterial growth in storage strata Other chemical reactions (e.g. with NO_x, SO_x, H_2S)	ppm mol	≤10
NO_x (NO, NO_2) [f]	Degradation of store caprock Takes place in the production of nitric and sulfuric acid	ppm mol	≤10
SO_x (SO, SO_2, SO_3) [g]	Degradation of store caprock Reactions with NO_2 can produce sulfuric acid	ppm mol	≤10
H_2S [h]	Health and safety: toxic gas with foul odour	ppm mol	≤5
COS	Health and safety: toxic gas with foul odour	ppm mol	≤100
CS_2	Health and safety: toxic gas with foul odour	ppm mol	≤20
NH_3	Can react to form solid ammonium carbamate and other ammonium salts	ppm mol	≤10
BTEX [i]	Health and safety: toxic	ppm mol	≤15 in total
Methanol	Can introduce a liquid corrosive phase	ppm mol	≤350
Solid particulates [j, k]	Can reduce store permeability Damage to compressor components	mg/Nm³	≤1 in total
Toxic metal [j]	Health and safety: toxic	mg/Nm³	≤0,15
VOCs [l]	Health and safety: toxic	mg/Nm³	≤48 in total
Acid forming compounds[m]	Enables corrosion of carbon steel	mg/Nm³	≤150 in total
Amines [n, o]	Can introduce a liquid corrosive phase	ppb mol	≤100 in total
Glycols [p]	Enables aqueous corrosion of carbon steel	—	—

[a] The combined total is ≤5,0 mol%.

[b] The risk of acid drop-out with hydrogen is >100 ppm mol if levels of SO_2, H_2S, O_2 and NO_2 are much higher.

[c] Avoidance of SCC.

[d] Heavy hydrocarbons (C_3+) shall not shift the dew point below that of pure CO_2.

[e] The presence of O_2 influences the formation of strong acids and elemental sulfur, and increases the sensitivity to sulfur-induced stress corrosion cracking.

[f] Separating out the different components of NO_x can allow higher levels of some species.

[g] Separating out the different components of SO_x can allow higher levels of some species.

[h] H_2S tends to form SO_2 and can form elemental sulfur, reacting with O_2 if present in sufficient levels.

[i] Separating out the different components of BTEX can allow higher levels of some species.

[j] The maximum size of the particulate is 1 µm.

[k] To include: ash, dust, Na, K, Mg, Cr, Ni, Cd, Hg, Tl, Pb, As and Se.

[l] To include: formaldehyde, acetaldehyde, dimethyl sulphide and ethanol.

[m] To include: Cl_2, HF, HCl and HCN.

[n] The maximum size of the liquid droplet is 2 µm.

[o] To include: MEA, MDEA, DEA, AMP, piperazine and any proprietary mixture containing any amine.

[p] To include: TEG, MEG, DEG, propylene glycol, dimethyl ethers of polyethylene glycol.

[q] To include: NDMA, NMEA, NDEA, NDELA, NPIP and NMor.

[r] To include: PCDD and PCDF.

Table A.1 *(continued)*

Component	Concern(s) in a CCU context	Unit	Limit
Nitrosamines and nitramines[q]	Health and safety: bio-toxic	µg/Nm^3	≤3 in total
Naphthalene	Health and safety: toxic	ppb mol	≤100
Dioxins and furans[r]	Health and safety: toxic	ng/Nm^3	≤0,02 in total

[a] The combined total is ≤5,0 mol%.

[b] The risk of acid drop-out with hydrogen is >100 ppm mol if levels of SO_2, H_2S, O_2 and NO_2 are much higher.

[c] Avoidance of SCC.

[d] Heavy hydrocarbons (C_3+) shall not shift the dew point below that of pure CO_2.

[e] The presence of O_2 influences the formation of strong acids and elemental sulfur, and increases the sensitivity to sulfur-induced stress corrosion cracking.

[f] Separating out the different components of NO_x can allow higher levels of some species.

[g] Separating out the different components of SO_x can allow higher levels of some species.

[h] H_2S tends to form SO_2 and can form elemental sulfur, reacting with O_2 if present in sufficient levels.

[i] Separating out the different components of BTEX can allow higher levels of some species.

[j] The maximum size of the particulate is 1 µm.

[k] To include: ash, dust, Na, K, Mg, Cr, Ni, Cd, Hg, Tl, Pb, As and Se.

[l] To include: formaldehyde, acetaldehyde, dimethyl sulphide and ethanol.

[m] To include: Cl_2, HF, HCl and HCN.

[n] The maximum size of the liquid droplet is 2 µm.

[o] To include: MEA, MDEA, DEA, AMP, piperazine and any proprietary mixture containing any amine.

[p] To include: TEG, MEG, DEG, propylene glycol, dimethyl ethers of polyethylene glycol.

[q] To include: NDMA, NMEA, NDEA, NDELA, NPIP and NMor.

[r] To include: PCDD and PCDF.

Table A.2 — Example of a dense phase CO_2 stream specification according to 6.6.2

Component	Notes	Unit	Limit
CO_2	Dry basis	mol%	>95,0
N_2	Total non-condensables to be <5 mol%	mol%	[a,b]
H_2		mol%	≤1
Ar		mol%	[a,b]
CO		mol%	≤0,7
Methane		mol%	—
Ethane		mol%	—
Propane and other aliphatic hydrocarbons	Total hydrocarbons have to be <5 mol% and a dew point of product with respect to hydrocarbons has to be <−20 °C.	mol%	≤1
H_2O	The limit for water may be higher (e.g. 630 ppm mol) if the CO_2 stream contains very low levels of O_2, NO_x and SO_x (e.g. geological CO_2).[b]	ppm mol	≤100
O_2		ppm mol	≤10
NO_x (NO, NO_2)		ppm mol	≤1,5
SO_x (SO, SO_2, SO_3)		ppm mol	≤1
H_2S		ppm mol	≤55
Total sulfur		ppm mol	≤50
Solid particulates		ppm wt	≤1
Mercury		ng/l	≤5
Amines		ppm wt	≤1

[a] Impurities causing harm or damage to pipelines, equipment, downstream systems or reservoirs.

[b] It is possible, with a water content of 100 ppm mol, for water drop-out to take place during depressurization (e.g. for maintenance). If this operation is planned, then a gas phase specification should be considered to avoid aqueous phase formation.

Table A.2 *(continued)*

Component	Notes	Unit	Limit
Glycols	Glycols must not be present in a liquid state at the temperature and pressure conditions of the pipeline.	ppm mol	≤50
Compressor lube oil carryover		ppm wt	≤50 ppmw
Liquids	The CO_2 stream shall be free of liquids at delivery conditions and shall not produce condensed liquids in the pipeline at pipeline temperature and pressure.		

[a] Impurities causing harm or damage to pipelines, equipment, downstream systems or reservoirs.

[b] It is possible, with a water content of 100 ppm mol, for water drop-out to take place during depressurization (e.g. for maintenance). If this operation is planned, then a gas phase specification should be considered to avoid aqueous phase formation.

In addition to the composition limits listed in Table A.2, the CO_2 stream shall not contain impurities that can cause harm or damage to pipeline, equipment, downstream systems or reservoirs. Impurities not listed should be brought to the attention of the pipeline operator for further evaluation. CO_2 streams, delivered by an anthropogenic source, that do not meet the specifications will be rejected at the pipeline operator’s sole discretion.

A.2 Need for sour assessment

The onset of SSC is related to the presence of water, H_2S, oxidisers and the pH of the fluid being transported. If the water content of the CO_2 stream is such that corrosion is not anticipated or no aqueous phase is formed (and thus, no pH is measurable), taking into account possible upset conditions, it would then not be necessary to assess the pipeline for SSC.

Annex B
(informative)

CO_2 characteristics

B.1 Accidental release of CO_2

Accidental release of a CO_2 stream (controlled pipeline depressurization is described in 10.4.2) from an initial phase to ambient conditions involves decompression and expansion of the released medium with a corresponding drop in temperature of the released medium and remaining inventory.

CO_2 streams differ from the decompression of hydrocarbons because the release can appear as a combination of different phases, including solid state phase of CO_2[35].

Any solid components in the CO_2 stream inventory can potentially impart erosive properties to the release stream. Direct impingement of this stream has the potential to affect critical equipment. Safety assessments should consider this possibility as a part of the design process.

The Joule-Thomson temperature reduction through the fracture or opening at the leak point is not necessarily more significant than that for volatile hydrocarbons. Measures to predict and, if necessary, mitigate against running ductile fracture should be considered in the design. Mitigation measures can include fitting fracture arrestors or increasing the wall thickness of the pipeline (see 8.1.5 for gaseous release or 8.1.6 for dense phase release).

Even though CO_2 is a colourless gas, a release from a CO_2 stream inventory most likely causes condensation of the water saturated in the ambient air, resulting in a fog type cloud visible to the human eye (until the release cloud warms to above the air's dew point temperature). This can be an indicator of the extent of a plume of a CO_2 stream, but instruments should be installed at facilities or carried by operational personnel to detect the presence and concentration of a CO_2 stream in a release situation and visual indicators should not be relied upon. A release of a CO_2 stream above the ambient air dew point temperature is invisible to the naked eye since there is no condensing water or solid CO_2 particles. In this situation, harmful levels of CO_2 can arise without any visible indication and this factor should be considered. Releases of a CO_2 stream from offshore pipelines are unlikely to be detected by the appearance of bubbles reaching the surface unless the leak is significant, in which case, it is possible during calm weather for fly-overs or boat patrols along the length of the pipeline to detect them. These visual methods of inspection for leaks can be triggered by leak detection methods (see 6.8.9), or third-party observations, such as fishing vessels.

B.2 Release rates

Accidental release rates from a CO_2 stream pipeline have the potential for phase changes within the flow expansion region.

To enable modelling of accidental release rates, the transient thermo-hydraulic behaviour of the pipeline should be considered.

The calculation of the transient release profile should include, but not be limited to:

— hole size and geometry;

— variations in the mass flow rate of the CO_2 stream over time;

— pipeline diameter, length and topography;

— initiation time and capacity of pipeline depressurization system;

— temperature, pressure and chemical composition of the CO_2 stream;

— heat transfer between pipeline and the surrounding environment; and

— closing time of any inventory segregation valves (e.g. block or check valves).

B.3 Dispersion modelling

Empirical models for estimating the dispersion of released gases in air and liquids are readily available; however, further validation can be necessary for CO_2 streams in CCUS-scale applications. Accidental release of CO_2 streams differs from other typical fluids in terms of formation of a solid state (see 6.8.4), and that gaseous CO_2 streams are heavier than air.

Effects that should be considered within the modelling, include

— release quantity, rate and pressure,

— ambient temperature and weather conditions,

— leak profile,

— jet direction (consider both impinging and free jets),

— release gas density,

— wind speed and direction,

— atmospheric stability class,

— air humidity,

— surface roughness, and

— impurities and their partitioning between gaseous and dense phases.

It is expected that the effect is larger for large leaks and full bore ruptures than for small releases. When the cold CO_2 stream hits the ground, a small release is heated by the surface; however, if the leak is large and/or long lasting, less of the CO_2 stream is heated by the surface and the effect of sublimed CO_2 is expected to be larger.

In addition to being influenced by the wind, the heavier than air CO_2 stream is spread out sideways, with off-axis ground level concentrations being higher than for a neutrally buoyant or buoyant gas release. Ground topography (e.g. slopes, hollows, valleys, cliffs, streams, ditches, road or rail cuttings and embankments) and physical objects (e.g. buildings), as well as wind direction, can have a significant influence on the spread and movement of a CO_2 cloud. Particular care should be taken in identifying topographical features and assessing how this can impact the consequences of a CO_2 stream release.

Modelling releases [e.g. by computational fluid dynamic (CFD) models] from pipelines should receive careful consideration since the crater formation and subsequent release flow can significantly reduce the momentum and therefore air mixing of the release, thereby decreasing the dispersion.

Dispersion models are available, but the designer should ensure that they have been validated for CO_2 stream in CCS- and CCU-scale applications or make suitable adjustments.

Annex C
(informative)

Internal corrosion and erosion

C.1 Measures to minimize internal corrosion

Field experience and experimental work show that CO_2 with water content well below the saturation limit is non-corrosive to carbon steel at transportation pipeline operation conditions even when other non-reactive impurities are present. In case of acid formation by reactions between impurities corrosion occurs at water levels well below saturation limits expected for the water-CO_2 binary system (see Clause C.2).

For a carbon steel pipeline, internal corrosion is a significant risk to the pipeline integrity in case of insufficient removal of water from the CO_2 stream. Aqueous phase combined with the high CO_2 partial pressure and formed acids like H_2SO_4 and HNO_3 can give rise to high corrosion rates.

There are currently no reliable models available for the prediction of corrosion rates with sufficient precision for the high partial pressure of CO_2 and aqueous phase, although there is ongoing research in this area.

C.2 Impact of impurities on internal corrosion

The presence of aqueous phase with H_2S can induce severe H_2S-induced corrosion phenomena.

The presence of other chemical components such as NO_x or SO_x can lead to an aqueous phase containing strong acids, significantly increasing the corrosion rate.

Based on the present understanding of CO_2 corrosion mechanisms at high partial pressure, there exists significant uncertainty, particularly considering the effects of other components in the CO_2 stream. The most up to date research should be consulted during pipeline design.

The water content should be such that, under all operational conditions, hydrate formation in the low temperature regions of the pipeline is avoided and internal corrosion of the pipeline is within an acceptable design range.

The CO_2 stream composition shall be such, that when different CO_2 streams mix the formation of any subsequent reaction products are at levels such that corrosion does not take place. See Reference [67] for more details.

C.3 Internal corrosion control

The primary strategy for internal corrosion protection should be sufficient removal of water and reactive impurities from the CO_2 stream.

Generally, it is recommended to operate the system such that internal corrosion is avoided through operational control. Off-specification operations can occur and the likelihood of such events should be evaluated as part of the system design.

A corrosion allowance can be applied to the wall thickness for the complete pipeline or for shorter stretches. Tolerance to off-specification water content over shorter time periods should also be considered.

It is important to note that traditional corrosion inhibitors are not as effective in CO_2 stream pipelines as they are likely to be in natural gas or oil pipelines. For example, in the case of hydrocarbon-based inhibitors the hydrocarbon can be stripped by the CO_2 and water-based inhibitors can be overwhelmed by the high concentration of CO_2.

C.4 Measures to minimize erosion

The particulate content within the CO_2 stream should be such that it is within the limits that allow it to be compressed without causing damage to the impellors of the compressor or pump. This is specific to the composition of the particulate. A guideline of <1 mg/Nm^3 with a maximum particle size of <10 µm can be used.

Another phenomenon that can lead to erosion risk that should be noted results from particulate formation at locations subject to large temperature drop and cooling due to Joule Thomson effect and high velocities such as those that can be experienced at venting stacks resulting in erosion at the venting tip.

C.5 Measures to minimize cavitation

Operation close to the two-phase region can cause mechanical wear issues to the CO_2 stream transport system (e.g. cavitation at downstream of pressure let down valves). Thereby identification of phase boundaries for the assumed CO_2 stream impurities is important to understand potential erosion issues due to phase transition. In dense phase operation, the bubble point of the CO_2 stream should be determined for the lowest pressure and highest temperature in the pipeline. A design margin should be introduced to compensate the uncertainty of phase boundaries.

C.6 Measures to minimize environmental cracking induced by impurities contained in the CO_2 stream

Some impurities within a CO_2 stream can lead to the onset of environmental cracking of the pipeline material. The impurities which have been associated with this are hydrogen, carbon monoxide and hydrogen sulphide. The detailed cracking mechanisms and the impurity concentrations required for crack initiation are currently debated and addressed in ongoing research projects. Based on the present understanding[85] and the significant uncertainties, the most up to date research should be consulted during pipeline design.

Environmental cracking associated with CO and H_2S only takes place if an aqueous phase is present. Controlling the level of water and reactive impurities in the CO_2 stream to make this, a remote possibility is the preferred mitigation strategy.

Annex D
(informative)

Avoidance of running ductile fracture: Approach for the evaluation of fracture arrest

The present approach is based on that in DNV-RP-F104.[12] The area where a special assessment is required has been modified under the assumption that a conservative result can be achieved. In any case, safety shall be demonstrated in this area.

The model formulated in DNV-RP-F104 is directly calibrated from existing large-scale test with dense phase CO_2. The currently applicable limitations for the model are defined in Table 5-5 of DNV-RP-F104. Until a more generally valid model for prediction of fracture arrest in dense phase CO_2 stream pipelines is available, the application of the model outside the limits given in DNV-RP-F104 shall require specific justification.

The criteria for estimating the fracture arrest limit are formulated based on observations from large-scale tests and are illustrated in Figure D.1.

The vertical axis (Y) of Figure D.1 describes the specific circumferential stress of a pipeline, which results from the maximum bubble point pressure of CO_2. For CO_2 streams with impurities, higher values for the maximum bubble point pressure can exist and these shall be used for design purposes.

The horizontal axis (X) describes a parameter range in which a fracture arrest can be expected based on large-scale tests carried out, taking into account the minimum C_v of the pipe material, and a parameter range for which such knowledge is not yet available.

Fracture arrest is expected for values of X and Y in the light dotted area (see Figure D.1 Key 5), which is limited by Figure D.1 Keys 1, 2 and 3.

NOTE The approach presented in this annex has been slightly modified when compared to DNV-RP-F104, in which a vertical separation of the areas at X = 25 is given. However, this does not lead to physically meaningful results. The introduction of Key 1 in Figure D.1 eliminates this deficiency, as increasing wall thickness with decreasing circumferential stress ensures fracture arrest.

To avoid a long-running ductile fracture, specific assessment is required for parameters left of Key 1 in Figure D.1. This can be, for example, the use of fracture arrestors, the performance of specific large-scale tests or the use of other validated methods.

The area to the left of Figure D.1 Key 1 where fracture arrest can occur is currently unknown, as no corresponding large-scale tests with successful fracture arrest have been carried out in this area to date.

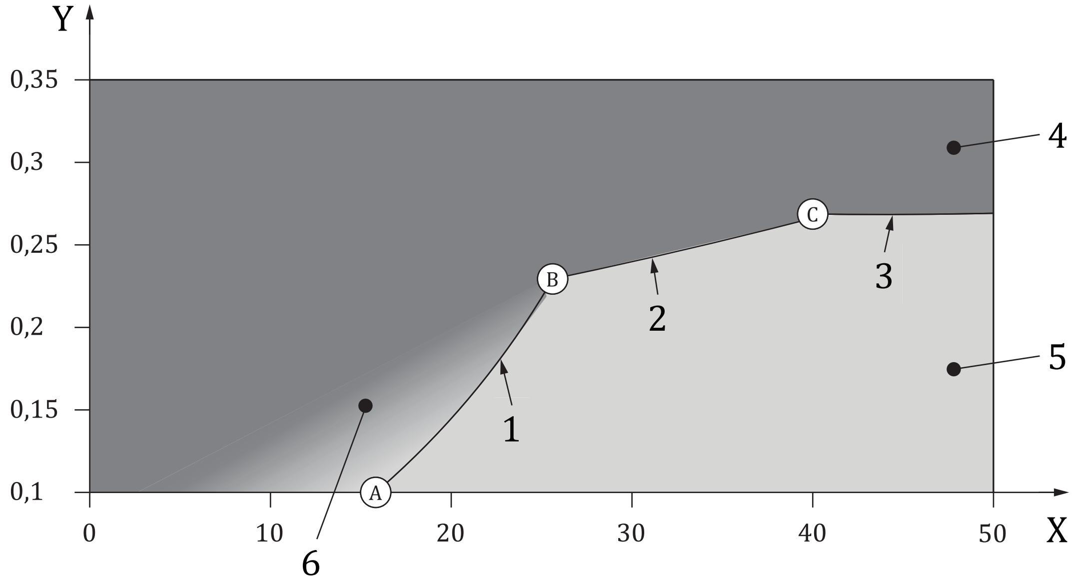
Point B in Figure D.1 describes the smallest possible minimum required notched C_v of a given pipe in combination with the wall thickness required for this. The point marked “C”, on the other hand, describes the smallest possible minimum required wall thickness in combination with the required C_v. Thus, a design according to Figure D.1 point B provides the lowest possible required impact strength and a design according to Figure D.1 point C provides the lowest possible wall thickness.

The following process is recommended to determine the dimensions to avoid fracture propagation.

a) Select a specific circumferential load for which propagation is not expected, e.g. Y = 0,23. From this determination, the required minimum wall thickness t_{min} of the pipe is obtained for the given pipe diameter D and the maximum bubble point pressure for the CO_2 stream.

b) The determination of X on the horizontal axis of Figure D.1 where fracture propagation not expected, taking Y into account, e.g. X = 25. Inserting the wall thickness t_{min} determined in the previous step into the formula for X and rearranging the formula for the only unknown variable C_v. This now results in the minimum required C_v. The minimum C_v should be in a range which is able to be delivered by the line pipe material manufacturer.

The above example corresponds to the definition of the parameters according to point B in Figure D.1.



Key

X	$1\,000\times\frac{C_v}{A_c}\times\frac{E}{\left(\sigma_f^2\times\sqrt{R\times t}\right)}$	A_c	cross-section area of the notched-bar impact specimen (80 mm^2 for a full-sized specimen)
Y	$P\times\frac{D}{2\times t\times\sigma_f}$	C_v	Charpy V-notch absorbed energy value of the pipeline steel (J) measured in the transverse direction
A	X = 16,48; Y = 0,10	D	outer diameter of the pipe (mm)
B	X = 25; Y = 0,23	E	elastic modulus (MPa); E = 2,06 × 10^5 MPa for carbon steel
C	X = 40; Y = 0,27	P	maximum bubble point pressure (MPa) resulting from isentropic expansion (see 8.1.8) from within the operating envelope
1	$Y = 3{,}68*10^{-4}*X^2$	R	average pipe radius (mm); it is $(D - t)/2$
2	$Y = 2{,}667*10^{-3}*X+0{,}163\,3$	t	wall thickness of the pipe (mm)
3	Y = 0,27	σ_f	flow stress in (MPa) to be calculated as specified minimum yield strength (SMYS) for that material +69 MPa
4	propagation expected		
5	arrest expected		
6	area where assessment is needed		

NOTE 1 According to the original BTCM, R is the average and not the outer radius.

NOTE 2 The gauge pressure for onshore pipelines is 0,1 MPa but, for offshore pipelines, the gauge pressure depends on the water depth (reduces by 0,1 MPa/10 m water depth).

NOTE 3 P depends strongly on the CO_2 stream composition, the phase diagram and the local operating conditions in terms of pressure and temperature.

Figure D.1 — Evaluation of fracture arrest in dense CO_2 stream pipelines

Annex E
(informative)

Data requirements for an integrity management plan

An integrity management plan for CO_2 specific threats and consequences should include the types of data shown in Table E.1.

Table E.1 — Data collection of CO_2 stream-specific threats and consequences

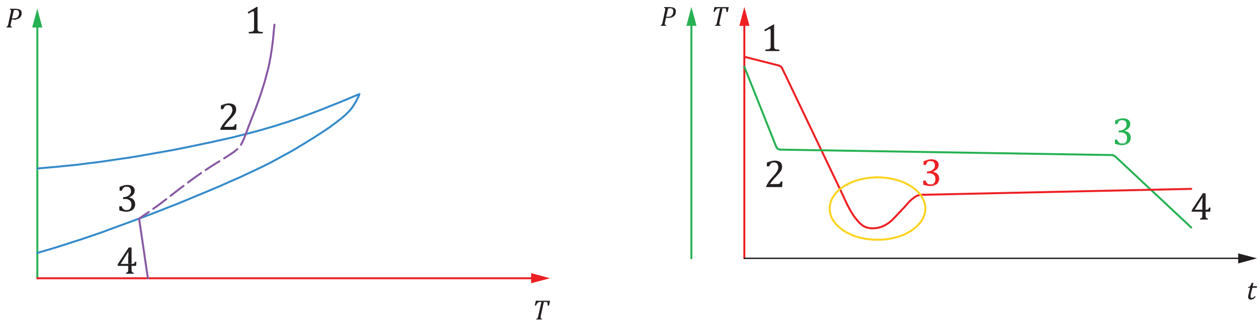
Data required for IMP	CO_2-specific threats and consequences
Design data	The pipeline system has been designed against a set of design criteria which shall include the operational envelope. These design criteria should be part of the IMP risk factors. Threats to the system are based on these data; hence, the integrity of the system shall operate within the design envelope. Regular re-assessment activities need to be undertaken and verified against these design criteria. Documentation associated with these activities is to be considered as a part of the IMP.
Attribute data	— pipe seam weld type (affects the potential for surface breaking seam-weld anomalies that would be exposed to CO_2 or H_2) — pipe manufacturer, manufacturing date and manufacturing method (which similarly affects surface breaking pipe-body anomalies that would be exposed to CO_2) — corrosion allowance on pipe wall thickness
Construction data	— construction report (identifies areas where ground conditions are poor or landslip is possible) — pressure test or line drying procedure (can identify residual water being present when the line is filled) — inspection reports (identifies types and potential impact of anomalies introduced during construction)
Operational data	— normal, upset and maximum allowable water content (along with other impurities, affects the potential for internal corrosion and other unwanted effects; water content in a CO_2 stream pipeline is typically to be specified such that aqueous reactions, under all anticipated operating conditions, do not occur) — hydraulic profile during operations, filling, shut-in, shutdown and pipeline decommissioning (result in pressure changes and should be monitored; also affects the ability of dense-phase CO_2 stream to contain water) — temperature profile during normal operations and under upset and shut-in conditions (affects mass density or transportation capacity; affects whether the CO_2 stream remains in dense phase) — normal, upset and maximum allowable levels of other components [affects phase changes that can occur with pressure or temperature changes; also impacts safety (exposure to H_2S, SO_2, etc.), operational reliability (potential for solids to be present) and material compatibility (H_2S, O_2, etc.)] — monitoring of the CO_2 stream composition on a regular basis (as described in 10.5.6) because the presence of impurities can affect the formation of an aqueous phase or unwanted chemical compounds — hydrate formation shall always be considered — flow control data (affects pressure drops and hydraulic profile along the pipeline) — depressurization history
Internal corrosion control data	— corrosion monitoring should be included, but is not limited to the use of coupons — water content and any other relevant impurities
Maintenance inspection	— in-line inspection data (quantifies the types, locations and sizes of some anomalies) — monitoring and inspection data related to non-metallic components — monitoring results to ensure no leaks

Annex F
(informative)

Depressurization of a dense phase CO_2 stream avoiding low pipeline temperature issues

F.1 General

The depressurization of a dense phase CO_2 stream pipeline is illustrated in Figure F.1.



a) Phase diagram for decompression of a CO_2 stream

b) Pressure and temperature curve during an expansion over time

Key

	1 to 2 depressurization trajectory in dense phase	1	starting conditions
	2 to 3 expansion in the two-phase regime	2	dense-phase/two-phase boundary
	3 to 4 expansion in the gaseous phase	3	two-phase/gas-phase boundary
	phase envelope line	4	finish conditions
	temperature	*P*	pressure
	pressure	*t*	time
	critical area	*T*	temperature

Figure F.1 a) shows, in purple, temperature against pressure for a depressurization of a CO_2 stream at dense phase conditions to atmospheric pressure. A typical phase diagram of a CO_2 stream is shown in blue.

Figure F.1 b) shows both temperature (in red) and pressure (in green) against time for the same depressurization.

Figure F.1 — Depressurization of dense phase pipeline

At point 1 in Figure F.1, the CO_2 stream is in the dense phase. As the pressure falls, it follows the expansion line until the phase boundary is reached at point 2 in Figure F.1. The temperature falls. There is a large gas release at this point and as the depressurization continues through the two-phase region, the temperature falls as a result of the latent heat of evaporation and the Joule Thomson effect.

Once the other phase boundary is reached at point 3 in Figure F.1, the CO_2 stream is wholly gaseous and depressurization continues and the temperature continues to fall until atmospheric pressure is reached at point 4 in Figure F.1. Theoretically, a fall in temperature is expected as a result of the Joule Thomson effect, but, in practice, the absorption of heat transfer from the surroundings can result in a slight increase in temperature.

F.2 Critical area

The critical area is circled in yellow in Figure F.1 b). The minimum temperature within this area is mainly determined by the release rate, and represents the area where excessive cooling is most likely to take place. The operator must ensure that the cooling does not cause the pipeline wall temperature to fall below the lowest temperature at which there is sufficient toughness of the steel, considering the pressure of the CO_2 stream remaining within the pipeline.

It should be noted that temperature development varies along the pipe as a function of terrain and flow conditions. Therefore, the operator should take this into account when carrying out the analysis.

F.3 Practical application

To maintain pipeline temperatures as high as possible, depressurization is usually carried out in several stages [see Keys 1, 2, 3 and 4 in Figure F.1 a)], allowing heat from the environment to be absorbed into the CO_2 stream at the end of each stage. Hence, depressurizing a pipeline will usually take days or even weeks.

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