Transportation of Carbon Dioxide by Pipeline

API RP 11CO2

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Introduction

While transportation of gases such as CO2 may be completed by truck, train or pipeline, pipelines hold advantages when it comes to achieving large-scale networked transportation of fluids [1] [2] including:

- Established safety protocols, engineering standards, and regulatory oversight,
- Reliable means of transportation of captured emissions consistently and continuously. This is crucial for industries that depend on steady operations.
- Most efficient means of safe high-volume transport of CO2,
- Seamlessly integration with various industrial processes, such as power plants, cement manufacture, and chemical facilities. This integration streamlines the carbon capture and utilization (CCUS) process and minimizes logistical complexities.

The design and operation of CO2 pipelines in the United States are subject to regulation in the United States by the Pipeline and Hazardous Materials Safety Administration (PHMSA), a federal agency under the Department of Transportation, [Title 49 of the Code of Federal Regulations (CFR), specifically in Part 195 for hazardous liquid pipelines [3]]. The regulations provide standards for the design, construction, and testing of new CO2 pipelines, many of which are the same as those applied to other pipelines, including those carrying chemicals, oil, and natural gas, although the risks in the event of release vary. Individual states also provide regulations to CO2 pipelines on state lands and private lands within the state.

NOTE This Recommended Practice does not provide guidance on compliance with regulations.

The objective of this document is to identify the distinct characteristics of CO2 pipelines not found in oil and gas pipelines, and provide guidance on these factors. This document identifies many of these unique features and provides guidance and best practices for the design, operation, and maintenance of CO2 pipelines. It covers aspects such as operating pressure ranges, ductile fracture control, pressure fluctuations, corrosion challenges, non-metallic component interactions, blowdown stack design, and emergency response plans in case of accidental releases.

1 SCOPE

This document provides guidance for the design, construction, operation, maintenance and emergency response for both dense phase and gas phase carbon dioxide (CO2)- related to pipelines, appurtenances and facilities.

The provisions are applicable to onshore gathering and transmission pipelines and related facilities used to convey carbon dioxide in gas and dense phase conditions. Offshore deep-water pipelines and sequestration facilities were not explicitly considered in the development of this document, although it provides useful guidance to support these other applications. The guidance provided herein is based on the physical, regulatory, and social environment of the United States, but could be applied in other countries with due consideration for their regulatory requirements.

The intent of this document is to provide operators, contractors, regulators, consultants and the public with guidance in the design and management of carbon dioxide pipelines. The document focuses on issues of unique concern to carbon dioxide pipelines. Where issues of concern do not differ from those for hydrocarbon pipelines, a lower level of detail is provided.

Carbon capture and sequestration involves collection, transportation and storage of CO2, however, this document does not specifically address processes and procedures associated with:

- Storage reservoirs,
- Injection,
- Capture, and
- Delivery.

NOTE Some methodologies, enhancements, and emerging technologies might not be covered in this document because they are in the early stage of their development. The document considers issues specific to CO2 pipelines and seeks to avoid presenting methodologies common to all pipeline systems. Where possible, supporting references are provided for additional details regarding useful data, practices and tools for CO2 pipeline design, construction, operation, maintenance, security and integrity management.

2 NORMATIVE REFERENCES

There are no normative references in this document.

3 TERMS, DEFINITIONS, ACRONYMS, AND ABBREVIATIONS

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

3.1 Terms and Definitions

3.1.1
anthropogenic CO2
CO2 that originates directly from human activities.

3.1.2
carbon dioxide fluid
CO2
A fluid that is primarily composed of CO2 but also contains other trace molecular constituents defined on a case-by-case basis

3.1.3
CO2 fluid constituents
Molecules other than CO2 that are present in the CO2 fluid being transported.

NOTE Often referred to as impurities.

3.1.4
dense phase CO2
A fluid being transported by pipeline including either liquid or supercritical CO2

3.1.5
dispersion
Natural spreading of released CO2 in a gaseous state.

3.1.6
equation of state
Mathematical model describing the temperature and pressure condition defining the CO2 phase.

3.1.7
fluid
A material being transported by pipeline regardless of phase.

3.1.8
fluid specification
A document defining the bounds of the fluid stream composition.

3.1.9
gaseous CO2
A fluid being transported by pipeline in a gas phase.

3.1.10
incapacitation
Exposure limit promoting recoverable harm such as unconsciousness or loss of coordination

3.1.11
operational specification
A document describing the limit operating conditions defined in the pipeline design or conversion

3.1.12
potentially affected area
Geographic region considered to be at risk of negative consequences of CO2 considering both concentration and duration of exposure

3.1.13
pure CO2
A fluid that has a composition of 100 % carbon dioxide

3.1.14
release
CO2 that has been discharged from the pipeline such that it can freely disperse

3.1.15
transient
Short term change in pressure or temperature resulting from a change in pipeline operating condition or failure

3.1.16
venting
Controlled or planned release of CO2 from the pipeline such that it can freely disperse

3.1.17
toxicity
Exposure limit promoting permanent harm

3.1.18
two-phase flow
A flow condition including both dense phase and gas phase CO2

3.2 Acronyms and Abbreviations

BTCM	Battelle Two Curve Method
CCS	carbon capture and sequestration
CCUS	carbon capture, utilization, and storage
CO2	carbon dioxide
DP	differential pressure
DTL	dangerous toxic load
EOR	enhanced oil recovery
EOS	equations of state
ERP	emergency response plan
FFS	fitness for service
HCA	high consequence area
ILI	in-line inspection
MDMT	minimum design metal temperature
M_w	fluid molecular weight
P	pressure
PAA	potentially affected area
PREP	preparedness and response exercise program
P-T	pressure – temperature
P&M	preventive and mitigative measures
R	ideal or universal fluid constant
ROW	right of way
SCADA	supervisory, control and data acquisition
SCC	stress corrosion cracking
SLOT	specified level of toxicity dangerous toxic load
SLOD	significant likelihood of death dangerous toxic load
T	temperature
Δρ	change in density
ΔP	change in pressure
ΔT	change in temperature
ΔV	change in volume

4 EQUATIONS OF STATE AND ESSENTIAL SPECIFICATIONS

4.1 Equations of State

The successful design and operation of CO2 pipelines requires accurate thermophysical properties and phase boundaries of the CO2 being transported, under both normal and upset conditions. Equations of state (EOS) are used to evaluate these parameters. EOSs support hydraulic calculations (density predictions) and line pipe parameter requirements for mitigating fracture propagation (phase boundary predictions). EOS for CO2 pipeline application shall quantify the impact of the constituents found in both natural and anthropogenic CO2. A range of EOS have been developed [9]. Improvements in the ability to consider the impact of constituents remain a subject of research for EOS developers.

EOSs can be broadly categorized into three different forms:

1. **Helmholtz Energy-Explicit EOS**: These are based on Helmholtz energy expressed as an explicit function of temperature and density [$\alpha = \alpha(T, \rho)$]. They are highly accurate in the single phase, achieving this precision by optimizing parameters to minimize deviations from accurate empirical measurements and by incorporating many different terms (up to 60), which consequently requires significant computational resources. Examples include GERG 2008 [10], PC-SAFT, and Span-Wagner (SW) for pure CO2.

NOTE The GERG 2008 EOS is currently available in the NIST REFPROP program [11].

2. **Pressure-Explicit EOS**: These express pressure as an explicit function of temperature and density [$P = P(T, \rho)$]. While generally less accurate in their basic form than Helmholtz-Explicit EOSs, they are more computationally efficient, because they use fewer terms. The accuracy of some of these EOSs can be improved to be comparable with Helmholtz-Explicit EOSs by optimizing the parameters to minimize deviations from accurate empirical measurements. Examples include Benedict-Webb-Rubin (BWR), Benedict-Webb-Rubin-Starling (BWRS), and Soave-Benedict-Webb-Rubin (Soave-BWR).

3. **Density-Explicit EOS**: These allow density to be calculated explicitly as a function of pressure and temperature [$\rho = \rho(P, T)$], making them the easiest to use among the three forms. They are fast and require minimal computational resources. They are often used in Helmholtz-Explicit and Pressure-Explicit EOSs to find starting points for calculations. Examples include the Peng-Robinson (PR), Redlich-Kwong (RK), and Soave-RK.

Helmholtz-explicit EOSs are generally more technically complex and perhaps accurate than pressure-explicit EOSs, which, in turn, are more complex and accurate than density-explicit EOSs. The choice of which equation of state to use in a particular situation should be made considering a balance of accuracy and computational speed. The most complex equations of state developed by the metrology institutes tend to be most limited to high accuracy applications with high purity CO2. The simpler EOS's offer faster computation speed and lower accuracy. In some applications, simpler models where a high degree of accuracy is less important or the lower accuracy of results can be managed through the application of an uncertainty design allowance may be viable.

Comparative studies have shown minor overlaps in accuracy among these three forms. For example, in 2017, Varzandeh et al. [12] conducted a comparative study of GERG-2008 [10] and the Soave-BWR EOS [13], which is a modification of the original BWR EOS [14]. Their findings indicated that the Soave-BWR EOS matched GERG-2008 in accuracy across the dense and gas phases, including the critical region. Moreover, it demonstrated superior performance in predicting bubble-point pressure and the vapor-phase composition of binary mixtures.

In 2017, Botros et al. [15] compared experimentally measured decompression wave speeds for seven binary mixtures of CO2 with predictions made by GERG-2008 and Peng-Robinson (PR) [16] EOSs. The results revealed that the GERG-2008 predictions of bubblepoint pressure for four of the seven binary mixtures (binaries of CO2 with O2, CO, Ar, and H2) deviated from the measured values over the range of from −600 kPa to 850 kPa. Deviations as large as these can lead to significant errors in the toughness required to arrest longitudinal ductile fractures. It is also worth noting that in tests with CO2/CO and CO2/H2, the PR EOS was more accurate than GERG-2008.

As the accuracy of EOS improve through modifications to their mathematical formulae and optimization of coefficients to better align with empirical data, should consider the relative performance of the various EOS used for pipeline integrity, hydraulics, and phase prediction to ensure their effective application. When determining the pipe toughness, steel strength, and wall thickness required to arrest longitudinal ductile fractures in project pipe, shock tube tests should be considered to fine-tune the accuracy of the

EOS selected for the project when predicting the phase boundary of the CO2. This fine tuning may be completed when the Operational and Fluid Specifications are established or altered.

Accurate values for ideal gas state enthalpy and entropy of CO2 and all its constituents are necessary for the accurate functioning of an EOS. These values can be derived from various sources, including comprehensive work completed by NASA [17].

A comparison of CO2 fluid enthalpy calculations for mixtures with water or brine [18] considers two equations of state—the Cubic Plus Association (CPA) EOS [19] and the CO2 Activity Coefficient model [20]. The CPA EOS provides good agreement with density and solubility data and accurately calculates molar enthalpies of pure CO2, pure water, and both CO2-rich and aqueous (H2O-rich) mixtures. Importantly, the CPA and CO2 activity coefficient models outperform other EOS in predicting water solubility. While the GERG-2008 EOS has demonstrated capabilities, its ability to predict water solubility requires further development (see Mckay, et al [21]).

4.2 CO2 Equation of State Selection

This section reviews some of the many EOSs that have been used successfully in the pipeline industry. No single EOS is perfect for all applications and each one has its own strengths and weaknesses. An EOS user could select more than one EOS to explore the impact of different EOSs on the design and performance of the pipeline. When selecting an EOS to support CO2 pipeline design, maintenance, or operations, four aspects of EOS performance are important:

a. **Accuracy of Density Predictions**: This is the most important parameter for hydraulic calculations including real time leak detection in both the dense phase and gas phase. The Joule-Thomson coefficient and sonic velocity are also important, but their accuracy largely hinges on the precision of density predictions. While viscosity is also important, EOSs do not explicitly model viscosity. A second correlation, which is usually a function of density, has to be used.

b. **Accuracy of Phase Boundary Predictions**: The pressure at which the decompression path crosses the phase boundary is the most important parameter for calculating the toughness required to arrest longitudinal ductile fractures (LDF). The bubblepoint line is key for Dense Phase pipelines, and the dewpoint line is key for gas phase CO2 pipelines. Accurate sonic velocity predictions are also important in LDF control, but to a lesser degree.

c. **Versatility**: Users should select an EOS capable of handling all the constituents in their project-specific CO2 with the required accuracy over the full range of operating and upset conditions.

d. **Required Computational Resources**: The more accurate EOSs have long runtimes which can make them impractical for some applications such as optimization studies and design work where large numbers of cases need to be analyzed. In those cases, the practicality of using an EOS depends on its computational efficiency and resource requirements.

Table 1 provides a brief overview of the capabilities of several identified EOS, based on information readily gleaned from publicly available data, and experience at the time this RP was developed (2024). The capabilities of some of the EOS will depend on their implementation details, as such the observations offered in the table may not be universally applicable. Other reviews of EOS for CCUS applications have been produced which consider the CO2 constituents [23] and provide data and recommendations for the viscosity and thermal conductivity methods [24] [25] [26].

Table 1—Equations of State Introduction

EOS and Form of Equation	Capability Observations	Application Notes
REFPROP [11] [27] Helmholtz Explicit [$\alpha = \alpha(T, \rho)$] and Pressure Explicit	Developed by the National Institute of Standards and Technology (NIST) to provide highly accurate thermophysical property models for a wide range of industrially important fluids.	A computational tool that employs a number of EOS Computationally intensive and requires significant computer resources Good for fracture control of gas phase and dense-phase CO2 pipelines

EOS and Form of Equation	Capability Observations	Application Notes
[*P = P(T, ρ)*]	Accurate fluid density values, and phase boundary delineation for binary CO2 mixtures in the dense phase and gas phase Good prediction of Joule-Thompson cooling and velocity of sound	Good for hydraulics of gas phase and dense phase CO2 pipelines
GERG 2008 [10] Helmholtz Explicit [*α = α(T, ρ)*]	Developed by the European Gas Research Group (GERG) to provide highly accurate thermophysical properties for mixtures of 20 typical constituents of natural gas and extended in 2008 to include 14 more components typical of anthropogenic CO2. Accurate fluid density values of CO2 mixtures in the dense phase and gas phase Unless it has been upgraded recently, delineation of the bubblepoint line may be questionable when CO2 contains significant amounts of CO, H2, O2, and Ar. Good prediction of Joule-Thompson cooling and velocity of sound.	Computationally intensive and requires significant computer resources Interaction coefficients need to be checked for some CO2 constituents such as CO, H2, O2, and Ar. Good for fracture control of gas phase CO2 pipelines Good for fracture control of dense phase CO2 pipelines unless the CO2 contains measurable levels of CO, H2, O2, or Ar. Shock tube tests can resolve phase boundary deviations. Good for hydraulics of gas phase and dense phase CO2 pipelines Water solubility prediction requires improvement
Soave BWR [13] [Pressure Explicit *P = P(T, ρ)*]	Developed in 1995 to improve the accuracy and generality of the original BWR EOS. It modifies the original terms and optimizes parameters to minimize deviation of predictions from highly accurate empirical measurements, making it suitable for dense phase and critical region calculations. Accurate fluid density, sonic velocity, and JT cooling, predictions, and phase boundary delineation.	Average computing requirements Good for fracture control of gas and dense phase CO2 pipelines Good for hydraulics of gas and dense phase CO2
BWRS [28] [Pressure Explicit *P = P(T, ρ)*]	Developed in 1966 to extend the original BWR EOS and improve accuracy. It incorporates additional terms to make it suitable for dense phase and critical region calculations. Accurate fluid density and JT cooling predictions, and phase boundary delineation.	Average computing requirements Good for fracture control for gas and dense phase CO2 pipelines Good for hydraulics of gas and dense phase CO2
Peng-Robinson [16] [Density Explicit *ρ = ρ(P, T)*]	Well established tool used widely in the gas processing industry because it is fast and stable and can handle a wide variety of process fluids including CO2 Good prediction of water solubility Good for gas phase calculations and dewpoint line delineation.	Computationally efficient and requires minimum computer resources. Good for fracture control of gas phase CO2 pipelines Good for hydraulics of gas phase CO2 pipelines

EOS and Form of Equation	Capability Observations	Application Notes
Soave-Redlich-Kwong (SRK) [29] [Density Explicit *ρ = ρ(P, T)*]	A modification of the RK EOS, introducing a temperature-dependent function to better account for non-ideal behavior, particularly near the critical point. Widely used for modeling vapor-liquid equilibria in hydrocarbon systems.	Computationally efficient and requires minimum computer resources. Good for fracture control of gas phase CO2 Good for hydraulics of gas phase CO2 pipelines Can make good water solubility estimates
Cubic Plus Association (CPA) [18] [19] [Density Explicit *ρ = ρ(P, T) + Associative Term*]	Combines either SRK or PR with association terms to account for hydrogen bonding to more accurately model polar and associating fluids, such as water. Good prediction of water and brine /solubility	Average computer requirements Limited usefulness for CO2 pipelines because Internal corrosion concerns keep the water content of pipeline quality CO2 very low Very good water solubility estimation Good for modelling CO2 behavior in downhole pore space where there is an abundance of water and brine.
CO2 Activity Coefficient [20] Gibbs Energy Explicit *g = g(T, ρ) + Deviation from ideal solution Term*]	Models the behavior of CO2 by focusing on deviations from ideality and using activity coefficients to account for molecular interactions. It is useful for predicting solubility and phase behavior in systems involving CO2 and water.	Computationally intensive and requires significant computer resources Limited usefulness for CO2 pipelines because Internal corrosion concerns keep the water content of pipeline quality CO2 very low, typically less than 100 ppmv. Useful for modelling mixtures of CO2 and components such as salts and organic compounds in wet external environments.

4.3 Essential Specifications

In the design and operation of a CO2 pipeline a CO2 fluid specification and an operational specification shall be developed. These documents define design intent and limits for the pipeline system including the information such as that listed in Table 2. These specifications represent the basis for the design and operation of the pipeline and may be developed in an interactive fashion during the pipeline planning and design phase. As industry knowledge increases and experience with the operation of a specific pipeline is gained, these documents may be updated.

Table 2—Essential CO2 Pipeline Document Design and Operational Data Specifications

CO2 Pipeline Fluid Specification Identifying the requirements for processing CO2 to meet the identified allowable concentration limits of the constituents of the stream.	**Pipeline Operational Specification** Identifying the range of normal acceptable operational conditions of the pipeline and procedures used to start up and interrupt normal operations.
• Constituents that facilitate water-rich liquid phase dropout that can cause CO2 corrosion (e.g., methanol and glycol). • Constituents that facilitate rapid degradation or cracking of carbon steel pipe.	• Expected maximum phase boundary for the fluid to be carried in the pipeline • Expected nominal operating pressure and temperature condition including the effect of seasonal temperature fluctuations

• Impurities such as H2O, O2, SOx, NOx, and H2S that can form strong acids and elemental sulfur. • Constituents that would increase the fracture resistance required to control longitudinal ductile fractures. • Other constituents for which the impact has not yet been fully determined but are thought to need control.	• Pipeline startup and shutdown procedures and expected range of pressure and temperature conditions during startup and shutdown. • Pipeline flow interruption procedures and resulting range of pressure and temperature conditions

5 PLANNING

This section provides recommended practice observations for the planning of CO2 pipelines including the application of risk management and siting or route selection. The emphasis of the presented information is CO2 pipelines and how they differ from hydrocarbon pipelines.

5.1 Risk Management Program Elements in Design and Planning

ASME B31.8S defines risk as a “measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences.” Hazard identification and supporting risk assessment and management may be used to support design alternative assessment considering:

- **Likelihood Indices:** employing a qualitative relative ranking or rating system representing the relative likelihood of failure
- **Probability:** derived from a quantitative analysis, using tools such as Monte Carlo simulation or Taylor series approximations, of the chance of occurrence expressed as a number between 0 and 1, where 0 is an impossibility and 1 is absolute certainty.
- **Frequency:** describes the observed or estimated number of events per defined unit of time. Frequency can be applied to past events or to potential future events, where it can be used as a measure of likelihood or probability.
- **Consequence:** defines an estimate of the impact that a failure could have on the public, employees, property, the environment, or organizational objectives.

ASME B31.8S identifies risk assessment as a systematic process in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. The operator should follow the process of ALARP (as low as reasonably practicable) or equivalent risk reduction protocol, as a technique of risk management in the areas of system design, construction, operation and decommissioning. Risk assessments can have varying scopes (to include risk identification, analysis, and evaluation), and can be performed at varying levels of detail depending on the operator’s objectives, and include factors unique to CO2 pipeline systems such as:

- Release dispersion to mitigate as reasonably practicable Intentional (venting) or unintentional (pipeline failure) releases including:
    - Evaluation of affected areas,
    - Asphyxiation risk for heavier than air fluid,
    - Toxicity versus incapacitation in CO2 releases (including consideration for fluid constituents),
- Ductile fracture process,
- Risk or reliability targets

The risks to people in the vicinity of the pipeline shall be assessed and effectively managed down to an acceptable level. To achieve this, CO2 hazard management processes, techniques and tools require critical examination and validation. The safety risk related to the transport of CO2 includes controlled and uncontrolled releases of CO2. Elements of the design and integrity management process can benefit from the application of a risk management treatment thatis recognized by international standards, including but not limited to:

- ISO 31000:2018 – Risk Management
- IEC 31010:2019 – Risk management – Risk assessment techniques
- CSA Z662: 2023 – Oil and Gas Pipeline Systems (Annex B)
- API RP 1160 - Managing System Integrity for Hazardous Liquid Pipelines (Section 8)

These standards are aligned with recommendations which specifically identify the use of risk assessment and management for:

- The potential release of CO2 near water bodies which are considered sensitive areas,
- The direction of integrity management activities to evaluate the likelihood of a pipeline release occurring and evaluation of the consequence. This determination should consider relevant risk factors, including:
  - Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;
  - Elevation profile;
  - Characteristics of the product transported;
  - Amount of product that could be released;
  - Possibility of a spillage in a farm field following the drain tile to a low lying area;
  - Ditches alongside a roadway the pipeline crosses;
  - Physical support of the pipeline segment such as by a cable suspension bridge;
  - Exposure of the pipeline to operating pressure exceeding established maximum operating pressure;
  - Seismicity of the area.
- Evaluation of alternatives to pressure testing.
- Identification of threats as outlined in ASME B31.8S, also called out by API 1160, *Managing System Integrity for Hazardous Liquid Pipelines*. Including time dependent, static or resident, time independent threats and human error.

5.2 Siting of CO2 Pipelines

The route of the pipeline and location of facilities can affect the scope and stakeholders involved in public consultation and awareness activities as discussed in Section 12. Similarly, the pipeline route and facility locations will affect the Potentially Affected Area (PAA) for a release evaluated using a dispersion analysis as discussed in Section 11. Route selection should consider PAA rather than traditional definitions of Potential Impact Radius (PIR) because CO2 is nonflammable, heavier than air, can act as an asphyxiant, and its release and dispersion process differ from oil or natural gas pipelines.

With one exception, CO2 pipeline route selection or evaluation should be completed using an approach like that used for hydrocarbon pipelines with special consideration given to population density, immobile congregation areas such as schools, hospitals, prisons or livestock yards and release dispersion. The exception is that a variable-width impact corridor should be established to address issues defining the PAA, particularly the topography of the terrain surrounding the pipeline that could channel a plume of high concentration CO2 to areas on higher population density or immobile congregation areas.

Details regarding dispersion modelling are provided in Section 11 and the normative standards provide details on dispersion risk modelling.

Population density for onshore pipelines should be determined according to standardized techniques such as those in ISO 13623. The distances in determining zones of influence should consider operational and accidental release scenario CO2 concentrations in conjunction with exposure limits and populations.

Pipeline and facility siting shall consider the characteristics of a potential release, as well as the local environment such as topography, seismicity, weather, population density, amongst other factors, as discussed in the sections that follow.

5.2.1 Terrain – Elevation and Wind

The topographic and wind conditions of the right of way can impact the dispersion of CO2 from a release in a variety of ways including, but not limited to:

- CO2 generally disperses in the windward direction and prevailing wind direction or wind rose for the site should be included in the dispersion analyses supporting siting, construction and operational processes.
- CO2 concentrations from a release may tend to remain at lower elevation locations if sheltered from the wind,
- A slope may promote down slope movement of a CO2 gas plume. Directional changes may occur due to channels on the slope or wind effects,
- Upwind and downwind vegetation or built environment may affect the dispersion process depending on the prevailing winds.
- Determination of the release potentially affected zone should have a variable width for a CO2 pipeline depending on the topography and prevailing wind.

5.2.2 Geology and Geohazards

The structural integrity impact of seismic events including aseismic faulting, geotechnical or hydrotechnical hazards including soil deformation to include shrinkage, swelling, subsidence, sinking and sloughing on a CO2 pipeline are the same as for hydrocarbon pipelines. However, the failure consequence due to differences in the fluid release and dispersion process for a CO2 pipeline will differ from conventional hydrocarbon pipelines. Additionally, operational temperature changes on CO2 pipelines can affect the local soil properties, including the freezing of soils and water external to the pipeline.

API RP 1187 provides guidance supporting geohazard management programs for landslide threats. If the fluid being transported contains hydrogen, the reduction in strain capacity should be included in a geohazard assessment, as discussed in Section 9.1.2.

5.2.3 Weather Related Runoff, Rivers, Water Bodies, Road and Rail Crossings

The soil and water contamination issues associated with hazardous liquid pipelines involving soil saturation or release run off into waterways is not a concern for CO2 pipelines. If the CO2 fluid contains high levels of other constituents then the effects of the other constituents may pose an environmental risk. Protection of a CO2 pipeline at a river crossing to mitigate geotechnical and hydrotechnical hazards can be accomplished using the same engineering and construction practices applied to hydrocarbon pipelines such as the guidance provided in API RP 1133, *Guidelines for Onshore Hydrocarbon Pipelines Affecting High Consequence Floodplains*.

Long term and high-pressure conditions may promote water absorption of CO2 to create carbonic acids or reduce the water oxygen content, however, most CO2 release and dispersion events are not likely to provide the required conditions to affect water quality. Experimental studies and resulting engineering models indicate a low solubility of CO2 in water at ambient temperatures and low pressure levels that would be consistent with released CO2 gas [30] [31].

Pipeline structural integrity protection at road and rail crossings to prevent pipe deformation or fatigue due to vehicle loading on CO2 pipelines should follow the same approaches used in hydrocarbon pipelines, such as that provided in API RP 1102, *Steel Pipelines Crossing Railroads and Highways*.

CO2 pipeline design and routing at road and rail crossings should consider the dispersion of the fluid in a possible release event to provide for public safety. CO2 release dispersion modelling is discussed in Section 11.

5.2.4 Population Centers and Communities

Similar to oil and gas pipelines, when CO2 pipeline designs that are or will be developed in sensitive areas the following actions should be considered:

- Stakeholder awareness and education regarding CO2 and the pipeline
- Stakeholder concerns, beliefs, and traditions
- Employment opportunities or other benefit agreements for indigenous people and disadvantaged communities during construction and for right-of-way surveillance and maintenance, and pipeline repair work
- Opportunities for community investment to create and preserve affordable homes, promote health and wellness, grow businesses, and fuel economic vitality
- Increased design capacity or safety margin of the pipeline
- Siting or design variations that could reduce risk;
- Surface slabbing or deeper burial over the pipeline to provide enhanced protection from third party damage, environmental or weather events

Public or stakeholder engagement is discussed in more detail in Section 12.

5.2.5 Other Considerations – Public Lands, Population Clusters and Growth

When evaluating the safety of population centers near CO2 pipelines, operators should consider the effects of release dispersion. The failure of natural gas pipeline may be confined to a zone approximately 300 yards from the pipeline centerline, whereas a release from a CO2 pipeline has the potential to have effects much further from the pipeline. Release dispersion is detailed in Section 5.1 and 11.

NOTE The Pipelines and Informed Planning Alliance (PIPA) prepared a recommended practice [32] for stakeholders considering pipelines in general and may be of use in the consideration of CO2 pipelines.

NOTE PHMSA has developed a guidance note on the risks involved with pipelines and their relation to land use planning and development decisions by local governments, landowners, and property developers [33].

If population centers grow and encroach upon a CO2 pipeline ROW, the risk of profile of the pipeline operation changes. This change in risk should be considered in the public engagement and awareness programs discussed in Section 11 along with updates to the threats and hazards to the pipeline identified through risk assessment updates. Operational risk mitigation measures, that may consider the local site conditions and their implications on exposure risk associated with CO2 release and dispersion, should be considered in design.

6 DESIGN AND CONSTRUCTION

Methods developed for traditional oil-and-gas assets may not always be useful for CO2 facilities or pipeline systems because of the differences in CO2 behavior. The design should employ fundamental engineering and consider full chain, through-life operation and maintenance of service for the entire system, to determine the size and configuration of components. This approach allows the selection of optimum pipeline operating parameters, such as pressure and temperature, pipeline diameter, and booster station spacing.

6.1 Material Selection

6.1.1 Steel Line Pipe and Associated Fittings

CO2 pipeline systems, line pipe, pipe fittings, valves, and other pipe components are generally constructed from carbon steel, similar to conventional hydrocarbon pipelines. There are several additional materials selection considerations unique to CO2 pipelines which are discussed below.

Materials selection should consider upset conditions that may be experienced by a CO2 pipeline. The pipeline shall be constructed from materials that resist brittle fracture at the lowest metal temperatures anticipated in operations. Materials selection and pipeline design should also consider resistance to longitudinal ductile or brittle fractures over the anticipated operational life of the pipeline, including the impacts of chemical components that may be present in the CO2 stream. Special attention should be paid to hydrogen, which if present under certain conditions will cause a significant reduction in fracture toughness of carbon steel. As the composition of the CO2 stream(s) shipped in the pipeline may not be fully understood at the time of pipeline design, a conservative approach to materials selection and design should be adopted.

Blowdown or sudden decompression of a CO2 pipeline can result in fluid temperatures falling below -100 ˚F, generating low pipe wall temperatures potentially below the minimum design material temperature (MDMT) in the vicinity of the release. As a result of low material temperatures, thermal contraction can exert tensile and bending stresses on the pipeline, potentially impacting features in girth welds causing or extending circumferential cracks. Girth weld designs and associated weld procedures should minimize weld area discontinuities and resist circumferential crack growth from stresses generated during blowdown and rapid decompression.

AMPP provides guidance for material selection to support long term integrity via effective corrosion control for CO2 transport and injection, including recommendations for setting a safe CO2 compositional specification [34]. While corrosion control may be achieved through the specification of corrosion resistant alloys, including stainless steels or steels with elevated chromium or nickel chemistries, most pipelines are constructed using corrosion-susceptible ferritic carbon steels. As such, control of CO2 stream composition, as well as the potential use of cleaning and inhibition methods, are the primary corrosion control mechanisms employed.

Specific corrosion stream constituents, including combinations of constituents which existing independently may be benign, may promote time-dependent cracking mechanisms including HIC and SCC. Consideration should be given to potential cracking mechanisms when selecting pipe and components for use in CO2 pipelines.

6.1.2 Non-metallic Materials

Valve seats, valve stem seals, and rotating equipment seals should be made from materials with chemical resistance to CO2 mixtures and resistance to explosive decompression. Fluoroelastomers (FKM) are commonly used in oil and gas service and have excellent chemical resistance to CO2, but newer materials such as perfluoroelastomer (FFKM) and hydrogenated nitrile butadiene rubber (HNBR) along with metal seals can also be selected because they offer better resistance to explosive decompression in CO2 service.

API SC6 develops and maintains standards related to wellhead and christmas tree equipment, as well as pipeline valves and connectors. These standards represent a valuable source for non-metallic component information.

AMPP provides guidance to select non-metallic materials to ensure longer term time integrity [34] and provides testing procedures to demonstrate suitability for CO2 decompression environments [35] [36]. ISO 23936-1 [37] and 23936-2 [38] provide general principles, requirements, and recommendations for the selection and qualification of non-metallic materials for service in equipment used in oil and gas production environments for thermoplastics and elastomers, respectively. Norsok M-710 [39] is a globally recognized standard developed by the Norwegian Petroleum Industry used to qualify nonmetallic materials for the petroleum industry. Elastomers and polymers for permanent use subsea, including well completion, christmas tree, control systems and valves have been accepted.

AMPP suggests that avoidance of polymers and rubbers for seals in favor of carbon, graphite or metals where possible [28]. AMPP indicates that the desired non-metallic materials are manmade materials that can be modified and novel materials with desirable properties may be developed in this area of ongoing research and development. The following failure modes or issues should be considered when selecting non-metallic components:

- CO2 absorption and swelling
- Rapid gas decompression damage
- Low temperature flexibility reduction
- Chemical interaction resistance
- Extrusion and nibbling
- Loss or sufficiency of adhesion

The AMPP guide [34] provides some general guidance on the solubility and chemical interaction of generic material types, however, the selection or qualification of non-metallic materials involves a large volume of privately held proprietary information and remains in the testing and research domain.

6.2 Fracture

This section is related to the mitigation of fracture initiation and propagation in CO2 pipelines through material selection and the use of crack arrestors. An important aspect of the design to mitigate the effects of fracture propagation is to prevent them from initiating in the first place. This is achieved by designing the wall to be thick enough and tough enough to make the critical defect length long enough to be easily detected by standard integrity maintenance programs, and long enough that the pipeline will leak without bursting.

6.2.1 Fracture Initiation

The CO2 pipelines shall be designed to have material strength and toughness levels that prevents pipe axial and circumferential fracture initiation considering the applied loading, pipe size and feature geometry, in the same manner as a hydrocarbon pipeline. Material strength and toughness selections are significant for a CO2 pipeline, because:

- Fracture initiation can result in a fracture propagation event,
- Dense phase pipelines get colder than gas phase pipelines when they decompress during blowdown or other changes in operational condition and in the unlikely event of a pipe failure. The CO2 pipeline design material selection shall include the effects of strength and toughness in the presence of low pipe wall temperature conditions and can induce significant thermal contraction tensile axial pipe stresses.

Strength and toughness material requirements shall be used to define unacceptable circumferential and axial weld (long seam and girth) feature sizes, pipe body axial and circumferential feature sizes such as environmentally assisted cracking and weldment or heat affected zone strength over matching to the base material.

API RP 1176 and ASME B31.4 [40] discuss tools and procedures for evaluating fracture initiation resistance.

6.2.2 Fracture Propagation

Preventive measures for longitudinal ductile or brittle fractures during operation shall be included in the design process for material selection considering fluid and operational specifications. Since CO2 containing components such as hydrogen, nitrogen, methane, and argon, require higher resistance to longitudinal ductile fractures. The CO2 composition used for fracture control assessment and in defining required longitudinal fracture resistance shall use the CO2 composition outlined in the pipeline fluid specification along with other compositions of interest to the design. During the life of a CO2 pipeline, new sources, not known at the time of design, may be introduced. The fluid specification should include a range of possible fluid compositions to support the design process.

CO2 pipelines should be designed and operated to avoid brittle fracture propagation. Approaches to evaluate the potential for brittle fracture propagation are presented in ASME B31.8.

A range of tools or methodologies for the assessment of fracture propagation events have been developed and continue to be enhanced. Fracture propagation or arrest can be evaluated using:

- empirical engineering tools such as the modified Battelle Two Curve model (BTCM) as outlined in ISO 27913 or DNV RP F104,
- numerical modelling assessments employing coupled fluid-structure finite element calculations such as described in DNV RP F104 and others [41] [42] [43]
- experimental trials [44]

Currently, the available tools and experimental trial data supporting fracture propagation control are focused on dense phase operations. Engineering judgement relating the behavior of gas phase CO2 fracture events to those in natural gas pipelines, may be required.

Figure 5-3 of DNV RP 104-2021 presents an approach for evaluating longitudinal ductile fracture arrest in dense phase CO2 pipelines but the approach has four limitations that restrict its application in most cases:

1. CVN absorbed energy > 250 J
2. Pipeline size between NPS 16 and NPs 36
3. Pipe grades of only L415 (X60) and L450 (X65)
4. C-Mn SAW TMCP pipe

Because of these limitations, it may be easier to use a modified Batelle Two Curve Method (BTCM) that has been tuned to agree with the published results of nine burst tests that have been undertaken to date in open literature. This tuning is done by adjusting several of the empirical constants in the original BTCM, and by adding parameters to adjust for depth of cover.

In addition to engineering tool evaluating longitudinal ductile fracture, burst tests using project pipe and project CO2 compositions may be used. Due to the complexity and effort associated with trial programs they tend to be reserved to explore unique conditions and then used to calibrate and validate empirical and numerical assessment tools. All of the modelling tools are calibrated based on small- and large-scale pipe burst tests and their development is a matter of continued research [45] [46]. The factors affecting the potential for fracture propagation that should be considered in the assessment include:

- Fluid thermodynamic properties including temperature, pressure
- Pipe properties including diameter, thickness
- Line pipe material properties including strength, ductility, elongation and toughness
- Backfill material properties including density, cohesion, internal friction angle and stiffness

6.2.3 Fracture Control/Crack Arrestors and Placement Guidance

Longitudinal ductile fracture control attempts to:

1. Prevent fractures from initiating during construction and operation by:
    a. Limiting the allowable defect size during pipe manufacture and pipeline construction.
    b. Specifying precautions during operation to prevent damage due to excavator strikes, corrosion, geohazards, and operator error.
2. Prevent longitudinal ductile fractures from propagating in the pipeline (if one initiates) by:

a. Providing sufficient steel strength, wall thickness and toughness in the body of the pipe to make the pipe resistant to longitudinal ductile fractures, or by installing crack arrestors.

b. Controlling and monitoring the contaminants in the fluid carried by the pipeline to prevent fluids that do not comply with the pipeline fluid or operational specifications from entering the pipeline.

Consideration should be given during design to pipelines that are inherently fracture resistant by virtue of having higher wall thickness or material toughness.

Crack arrestors are designed to stop the progression of a pipeline longitudinal fracture and may be an element of a pipeline conversion to CO2 service (see Section 7). In a CO2 pipeline longitudinal fracture event, the volume of released fluid will be concentrated at the end of the fracture and then disperse from that location. If the fracture arrests in a populated area or other critical location, the exposure of the area to higher concentrations and for longer durations may be maximized. For this reason, crack arrestors should be located, as practicable, away from populated areas or other critical locations to both allow propagation out of these areas and prevent propagation into these areas.

Crack arrestors can be designed produce "hard" and "soft" arrestor conditions: For a hard arrest, the crack is stopped at the edge of the arrestor. For a soft arrest, the crack advances inside the arrestor but should not exit. Crack arrestors can be designed and fabricated from steel [47] or composite materials [48]. All arrester types have merits which should be considered for the specific installation location and condition.

6.3 Corrosion Control

The AMPP guide to CCS material selection [34] and published data [49] provide overviews of potential CO2 gas stream constituent components, their known or unknown limits, and the impact they could have in relation to integrity, as shown in Table 3. Generally acid/water solubility levels will decrease as temperature decreases resulting in a higher risk of acid/water dropout in colder temperature systems.

Corrosion and cracking resistance in CO2 service conditions through a range of fluid composition components remains an area of active research and as such the limits for some fluid constituents and interacting constituents remain unknown. The information provided in in the AMP guide and other published experimental data may be used in the definition of CO2 stream composition limits for corrosion and cracking control and the consideration of the management of the combined composition of CO2 fluids received from multiple sources. While initial starting points and conservative CO2 stream composition component limits are provided in various references, this is an area of active research and currently engineering judgement shall be used to establish composition limits for CO2 pipeline fluid specifications. The factors to be included in fluid specification development shall include:

- Inlet fluid temperature,
- Ambient temperature and its variation,
- Length of line,
- Winter buried ground temperature,
- Velocity/transit time,
- Fluid moisture level,
- Operational conditions of the line including flow rate seasonality, and
- Pipeline response related to corrosion and crack arrest.

Table 3—Overview of the Expected Impact of Composition Components on Corrosion [34] [49]

Component	Comments

H2	Depending on material microstructure and grade hydrogen may reduce ductility, reduce toughness, and increase fatigue crack growth rate. Lower solubility for hydrogen is typically observed in gas phase. *
H2O	Presence of H2O influences formation of strong acids and elemental sulfur. In balance with O2, NOx, H2S, and SOx, the limit can be optimized.
O2	Presence of O2 influences formation of strong acids and elemental sulfur. In balance with O2, NOx, H2S, and SOx, the limit can be optimized, and increases sensitivity to pitting crevice corrosion and SCC.
NOx (NO2 + NO)	Presence of O2 influences formation of strong acids and elemental sulfur. Highly reactive oxidizing components that can form HNO3 and contributes to the potential formation of H2SO4. In balance with H2O, SOx, O2 and H2S, the limit can be optimized lower concentrations for lower operating temperatures (i.e. sub-sea pipeline).
SOx (SO2 + SO3)	Presence of SOx influences formation of strong acids and elemental sulfur. In balance with H2O. O2, NOx, and H2S, the limit can be optimized.
H2S	Highly reactive reducing components that can form H2SO4.or elemental sulfur (S8). Presence of H2S influences formation of strong acids and elemental sulfur. In balance with H2O, O2, NOx, and SOx, the limit can be optimized. H2S may also trigger cracking at specific conditions.
H2S + SOx	Presence of H2S and SOx influences formation of strong acids and elemental sulfur. In balance with H2O. O2, and NOx, the limit can be optimized,
CO	Under specific conditions, such as when a free water liquid phase is present, CO-CO2 SCC may be triggered.
Glycol (MEG TEG DEG)	Water will trigger CO2 corrosion; however, corrosion rate is lower depending on the fraction of water/glycol Presence of glycol influences water phase drop out below dewpoint
Alcohol (Methanol Ethanol)	Water will trigger CO2 corrosion; however, corrosion rate is lower depending on the fraction of water/alcohol. * Presence of alcohol influences water phase drop out below dewpoint.
NH3 (Ammonia)	Likely ammonium carbamate being formed. *
Amines (e.g., MDEA)	Undefined impact; may stimulate a water phase dropping out but also acts as a corrosion inhibitor when co-condensing with water. Its presence may trigger a water phase where it also acts as a corrosion inhibitor - details not fully understood. *
HCN	Promotes hydrogen absorption into the metal in wet conditions and influences passivity breakdown, depending on pH. *
Organic Acids (e.g., HAc)	Influence on CO2 corrosion well known. *
Carbonyl Sulfide (COS)	Unknown impact, may influence some chemical reactions, sometimes added to the H2S+SO2+COS balance (but seems less critical). *
N2	Inert. No negative impact expected.

Ar	Not expected to be a significant issue. *
Aldehydes	May trigger corrosion rate reduction, may influence water solubility, acid formation. *
Dimethyl Sulfide (CH3)2S	May have impact on formation of sulfuric acids. *
Phosphorus components	May be reactive. No data available. *
Other strong acids e.g., HCl	Very likely plays no role in acid formation and drop out as well as acidification of a potential water phase *
Ketones	Not expected to be a significant issue *
Aromatics	Not expected to be a significant issue *
Ethylene	Not expected to be a significant issue *
Alkanes	Not expected to be a significant issue *
Hg	These metals can cause potential liquid metal embrittlement with copper and aluminum. These metals should not be used when the presence of this fluid constituent component is expected. *
* Research required to resolve advisable limits.	

Corrosion evaluation software can provide modeling and process simulation for chemical stream analysis, scale prediction, and corrosion management. None of the commercially available software packages at the time of publication include results from the latest research into corrosion of carbon steel pipelines carrying rich CO2-compositions. AMPP [34] and recent corrosion publications of fundamental researchers [49] [50] [51] [52] provide recommendations.

6.4 Pipeline Valves

The pipeline layout, including valves and facilities for depressurization, should consider local requirements, fracture control, and release dispersion risk.

Rapid closing automated or check valves, have been considered useful in managing the release volume following a pipeline failure when considered in dispersion modelling sensitivity studies [53]. In a release event these valves are not likely to affect the size or CO2 concentration distribution in the PAA. The duration of CO2 exposure can be reduced through the placement of additional valves.

Consideration should be given to appropriate instrumentation, including valve status and upstream/downstream pressure transmitters such that the hydraulic state of all pipeline segments can be monitored in single phase operating conditions. Rapid valve closure concerns associated with pipeline surge pressures in liquid pipelines are mitigated by the compressible nature of dense phase CO2 as discussed in Section 4. Low temperature CO2 fluid operation may increase rapid valve closure associated surge pressures.

6.5 Multi-emitter Networks

Some CO2 pipelines may operate with multiple fluid sources. Each fluid source's properties included in the following list shall be controlled relative to the design limits of specification:

- Pressure / flow rate
- Temperature
- Composition in terms of constituent volume fraction
- Moisture content
- Solid particulate content

The flow of fluid from each source should be continuously monitored and controlled independently to ensure only fluids which are compliant with the pipeline operating specification and fluid specifications are accepted into the pipeline. There may be different fluid specifications applied to each lateral. The integrity of each lateral shall be managed based on the composition of the fluid they transport. The integrity of the transmission pipeline shall be maintained considering the combined fluid properties. Special attention should be given to managing water content as discussed in Sections 6.3 and 9.1.1.

The operator shall have a decision making and documentation process to manage the mixing of fluids that addresses the integrity threat posed by shipping fluids with differing specifications.

6.6 Design of Venting Systems

The venting requirements for CO2 pipelines may be the same as those for natural gas pipelines, however, procedures and mechanical components may need to be different due to the potential for dry ice buildup when venting dense phase CO2.

The vent stack may be equipped with a flow control valve connected to a temperature sensor, to enable reductions in emission rate when the temperature inside the pipe falls below the minimum design metal temperature (MDMT). This concept may lead to problems with:

- CO2 ice buildup inside the vent stack unless the control valve is mounted at the top of the vent stack,
- Localized cooling at locations other than the vent stack,
- Potential for hydrate formation.

The recommendation for a temperature flow control valve as part of the venting design and procedure is related to the preservation of metallic and non-metallic materials, and the formation of solid CO2. The control valve should be remotely operated for safety and have a set point to control dispersion and thermal damage to the system.

When designing the stack and flow control valves, consideration may be given to the observations that there may not be enough pressure inside the pipe, and thus not enough hoop stress, to initiate a longitudinal fracture when the temperature falls below the MDMT. The through wall temperature during venting of dense phase and gas phase CO2 pipelines generally does not fall low enough to create an integrity concern.

The height of a vent stack should be assessed for CO2 dispersion, as discussed in more detail in Sections 5 and 11, including:

- operational conditions,
- environmental conditions,
- health and safety issues (CO2 concentration and temperature exposure),
- environmental impacts (including noise), and
- geographical location.

Vent tip design should maximize air mixing..

An alternative to vent tip design modifications, in developing a blow down procedures, a blowdown stack which blows the CO2 directly upwards at sonic velocity with no throttling from control valves at the bottom of the stack to slow the emission rate can be employed. If this is achieved, the CO2 jet may go more than a hundred meters into the air and mix so thoroughly with atmospheric air, due to the turbulence created by the jet, that in the event the CO2 returns to ground level it is not harmful to people and wildlife, as shown in the simulation characterized in Figure 6.

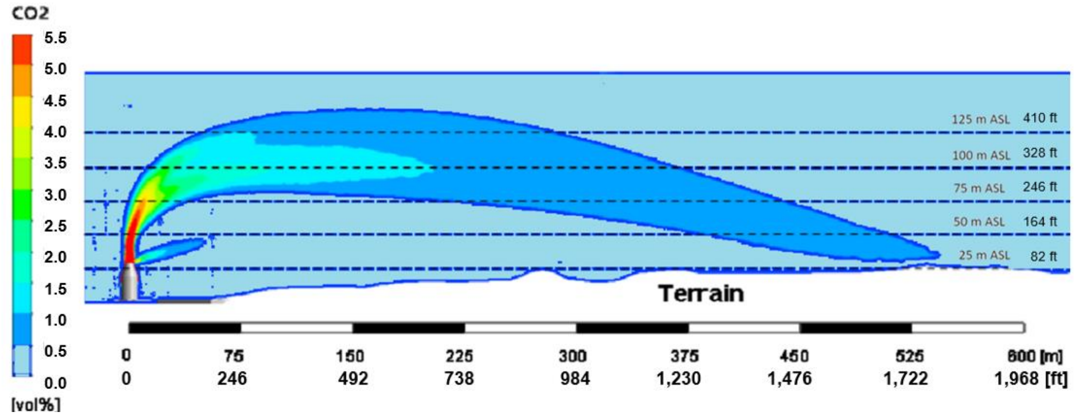

Figure 6—Simulated CO2 Concentration in Venting Process

When CO2 pipelines decompress quickly, the temperature of the CO2 inside the pipe may fall -100 ˚F and may draw down the pipe metal temperature below -5 ˚F. In thinner walled pipes equipped with crack arrestors, the temperature may be drawn down below -58 ˚F. Because buried pipelines are restrained in the axial direction, the resulting thermal contraction may put them into tension.

During operation at normal operating pressures and temperatures, all the girth welds, except some at bends, are in compression and have not experienced high axial tensile stress. Girth welds should be designed so that circumferential defects in the weld area do not grow under the expected axial tensile stress associated with rapid pressure reduction. This can take the form of limiting circumferential defect size, using low hydrogen, low temperature weld consumables with sufficient toughness at the lowest expected temperature. Consideration should be given to tensile and toughness testing on weld specimens, made under field conditions in accordance with the weld procedure, at the lowest expected temperature to demonstrate that the weld and heat affected zone can withstand the tensile forces that are possible during blowdown and pipe failure.

Using nitrogen to displace the CO2 may be used to mitigate localized cooling.

6.7 Over Pressure Protection

A pressure protection system shall be included in the CO2 pipeline system [54] such that the pipeline cannot operate in excess of the rated maximum operating pressure, including possible transient effects at any point along the pipeline. Pressure controls shall be in place to prevent thermal overpressures in isolated piping segments. Since the density of dense phase CO2 is highly sensitive to temperature change, more sensitive than an ideal gas, temperature control and monitoring is an important consideration, and the sizing of relief equipment should be larger than commonly used for natural gas. Annex B provides CO2 behavior examples to illustrate the relationship between CO2 density change and temperature change.

Pressure relief device performance requirements and operational procedures developed for hydrocarbon pipelines may act as a useful starting point for CO2 pipeline devices; however, these operating procedures and mechanical component designs may need to be altered to consider the unique properties of dense phase CO2 including the potential for solids formation during pipeline depressurization.

The pressure control system shall be designed so the dense-phase condition is retained both within the pipeline operating envelope, at relevant reduced flow rates and in pipeline shut-in situations. Unless the materials of the pipeline or pipeline system are selected to accommodate such a situation or other control measures are employed, the pressure control system should be configured to that there is a sufficient margin to prevent free water formation in case of a pipeline shut-in or other relevant pipeline upset condition.

The pressure control system is not a limiting criterion to prevent pipeline internal corrosion, when the anthropogenic CO2 has been thoroughly dried, if H2S, SOx and NOx are constituents of the fluid and waterless corrosion is possible.

These requirements should be applied in the short-term isolation of pipe segments, in particular above ground pipes where heating or cooling from the environment may be more pronounced.

6.8 Hydraulics and Potential Changes in P-T Parameters

The pressure-temperature (P-T) behavior of CO2 depends on its composition as illustrated in the description of the behavior of CO2 in Appendix B. As the composition of the fluid stream changes, increasing volume fraction of components other than CO2, the P-T or phase behavior may change. Similarly, changes in pressure or temperature conditions due to operational changes, environmental heating or cooling, or losses along the length of the pipeline can affect the phase and behavior of the CO2 fluid.

The design operating envelope for a CO2 pipeline should be based on a range of fluid compositions defined in the pipeline operating pressure and fluid composition specification.

The design of the pipeline should consider:

- Operational variations beyond ideal values in the development of an operational specification
- Composition control measures that limit uncertainty in the P-T behavior for various fluid compositions,
- Operational procedures to reduce risks associated with operational upset conditions,
- Development of hydraulic models of the pipeline system that can consider the impact of transient events.

CO2 operators should consider employing both real time steady-state and transient flow assurance models for CO2 pipeline systems, including, CO2 pumping, measurement, pipeline, and CO2 sequestration wells or other CO2 delivery points. Those real time models should monitor potential flow assurance challenges, surge, and optimizing the injection and storage process. Below are key objectives from conducting these modeling efforts:

1. The Steady-State Flow assurance model should, be capable of, but not limited to:
    - Simulation and analysis of the steady-state operation of the CO2 pipeline at both minimum and maximum design flow rates.
    - Identify potential flow assurance challenges such as hydrate formation, corrosion, and Two Phase flow behavior under steady-state conditions.
2. Transient Flow Assurance Model should be capable of, but not limited to:
    - Simulation of transient events, such as start-up, shutdown, and flow rate fluctuations, including startup of individual sequestration wells during flow rate increases.
    - Prediction and management of potential issues like pressure surges, temperature drops, and transient-induced flow instabilities.
    - Identification of any required flow control to maintain the pipeline in dense phase operation.

While transient conditions may promote muti-phase CO2 fluid flow conditions, two phase flow should be avoided, and simulation tools may be useful in identifying the conditions that promote or prevent this behaviour [55], however, these tools for a range of CO2 fluid compositions remain a subject of research.

6.9 Pipeline Construction and Commissioning

The construction and commissioning process for a CO2 pipeline should draw upon hydrocarbon pipeline practices, such as that identified in API Std 1104 and B31.4, Chapter 10. The commissioning process should be documented in a commissioning plan which includes:

- Line pipe and fitting material verification to ensure compliance with the CO2 pipeline design requirements related to fracture control;

- Girth weld production and inspection procedure development with project pipe and electrodes such that weldments provide sufficient strength and ductility to support potentially axial loading developed due to cooling events.
- Prepacking the line with 50 to 100 psi nitrogen prior to CO_2 filling to minimize J-T thermal effects. Alternatively, slowly filling the line with CO_2 from gas phase may be considered along with the potential for vapor lock.
- Adequate pressure testing and drying, as discussed in Section 9.2. Consideration may be given to inserting valves or valve trim after pipeline hydrotesting testing with water to facilitate drying. If leak tests are completed with CO_2 gas the test procedure should be designed to minimize damage to non-metallic materials and consideration of the risks associated with the test procedure.
- Exposure of employees to CO_2 in locations such as ditches, low points, depressions or at leak sites.

6.10 Facility Design

Pipeline-related facilities, including booster stations, crossovers, and terminals, should be designed with the specific characteristics of the CO_2 stream in mind. This includes factors such as material compatibility, pressure and temperature ranges, and potential degradation, as well as operational challenges outlined in this document and relevant engineering standards.

Key differences between hydrocarbon and CO_2 facility design include:

- Thermodynamic Behavior: Understanding the fundamental thermodynamic properties of CO_2.
- Pipeline Fluid Quality Specifications: Ensuring the quality of the pipeline fluid to prevent:
  - Corrosion (as detailed in Section 6.3).
  - The cricondenbar of the source gas from exceeding the cricondenbar used for specifying pipe steel strength, wall thickness, and the Charpy V-Notch (CVN) absorbed energy necessary to arrest longitudinal ductile fractures.
- Monitoring and control of CO_2 quality: Installing analyzers to monitor the composition of source CO_2 and implementing measures to prevent or limit off-specification CO_2 from entering the pipeline system.
- Temporary onsite storage: Consider the benefits of storage versus release to the atmosphere. If storage is required for CO_2 displaced from lines during maintenance or repair outages, as well as for handling of off-specification CO_2, consider banks of interconnected large diameter pipes instead of pressure vessels.
- Worker safety: Considering that CO_2 is heavier than air and a potential asphyxiant. Certain precautions which should be taken include:
  - Elevating work locations relative to valves, compressors/pumps, and piping.
  - Using ventilation or air supply systems, in enclosed locations, that run continuously or can be activated immediately when a leak is detected.
  - Placing ventilation louvers at floor level rather than ceiling level, in enclosed facilities, unlike traditional natural gas facilities.
  - Considering unmanned facilities.
  - Deploying CO_2 detection devices rather than O_2 level detection devices,
  - Eliminating pits and low-lying maintenance areas.
  - Following safe work practices relating to confined spaces

- Cooling effects: Addressing the cooling effects of CO2-rich fluid due to pressure drops or flow path obstructions, focusing on worker safety and the design of pipe run direction and size changes.
- Solid CO2 formation: Considering the potential for solid CO2 formation, especially when blowing down pipe segments.
- Initial compression: Initial compression of CO2 to raise its pressure from atmospheric to pipeline operating pressure, requires considerable horsepower and fuel consumption. For dense phase pipelines on strategy is to consider the efficiencies of cooling the CO2 to the “liquid” side of the two-phase region and then pumping the “liquid’ to dense phase pressure to reduce fuel consumption. While this approach is attractive the additional energy expended in cooling the fluid should be considered,
- Retaining operating pressure levels: The number of booster stations required to maintain operating pressure and temperature over the length of pipeline segments shall preclude two-phase flow operational conditions. This also requires pipeline operating condition monitoring and control to consider environmental loading and operating condition changes.
- Emission capture: Capturing exhaust and flue gas emissions from equipment used in CCUS processes.

6.11 Offshore or Underwater Pipelines

The material selection and design for offshore or underwater CO2 pipeline system can follow procedures developed for hydrocarbon pipelines [56] [57]. The design process [58] [54] shall take into account unique conditions associated with underwater CO2 pipelines including, but not limited to:

- Fluid phase and properties for the temperature, pressure and composition of interest,
- Service and environmental effect resulting pipe wall temperature,
- Differences in construction, commissioning and operation,
- Release event dispersion process, and
- External loading on the pipeline.

7 CHANGE OR CONVERSION OF SERVICE

7.1 Conversion Viability Evaluation

Repurposing a pipeline for CO2 service can enable [59] :

- utilization of pre-existing rights-of-way minimizing disturbance to stakeholders, the public, landowners and the environment,
- utilizing existing commercial infrastructure, particularly in congested areas, and
- reduced risk.

If multiple pipeline segment options are available for a route, the viability of existing assets for conversion to CO2 service may evaluated using a feasibility evaluation or screening approach. These techniques may be developed based on semi-quantitative ranking derived from risk assessment, engineering judgment or experience. If a pipeline segment passes a screening process of this nature, a detailed assessment as outlined in Section 7.2 shall be performed.

The content and form of these screening or ranking processes should be developed to suit the project requirements and the experience base of the user [60]. These approaches may be used to rapidly identify those assets which are not suitable for CO2 service or those which would require a greater level of modification to be made suitable. The factors that can include:

- Pipeline capacity – Depending on the opportunity, the volumes may be transported in either gas or dense phase CO2. Both gas and dense phase operation should be evaluated.
- Maximum Operating Pressure. Review the pipeline attributes and material properties to assess suitability for service in the desired CO2 phase, as well as the regulatory environment. Calculate the maximum operating pressure (MOP) based on the pipe grade, wall thickness and diameter based on location specific design requirements. It is important at this stage to consider potentially affected areas to ensure the appropriate design requirements are applied to the analysis.
- Sufficient Pipe Toughness. For service in dense phase carbon dioxide the ability to arrest ductile running fracture is imperative. The installation of crack arrestors may be required when the pipe toughness requirement is higher than a threshold value. The threshold value may be calculated based on nominal pipe size, properties and fluid composition or may be set based on engineering judgement. Additional consideration should be given to toughness transition temperatures of newer pipeline vintages to ensure a ductile fracture rather than a brittle fracture occurs.
- Review pipeline route for safety - Safety associated with the pipeline route such as impact to landholders and stakeholders as well as emergency officials such as those discussed in Section 12.

This form of a screening tool may be used to rapidly identify line segments that are not suitable or less desirable for CO2 service conversion. Regardless of the outcome of the screening process, a detailed conversions assessment shall be competed as outlined in Section 7.2.

7.2 Conversion Assessment Requirements

In general, conversion requires that the requirements of a new pipeline design be met by the converted pipeline system unless demonstrated through engineering or risk assessment that adequate safety is achieved.

NOTE Conversion requirements for pipelines to transport CO2 are identified in regulations, codes and standards such as those provided by PHMSA in their Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service [61].

Pressure testing of components is commonly completed with test pressures of 110 % or 125 % or more of the maximum operating pressure. The test pressures is commonly held for a duration of 4 hours depending on the application of visual inspection during the test.

Alternatives to traditional pressure testing may be considered if consideration is given to the risk associated with the release caused by a pressure test failure event. The conversion process of an existing pipeline to CO2 service should include a dispersion analysis and a risk assessment. The risks associated with CO2 pipeline releases and dispersion are discussed in Sections 5 and 11.

Existing integrity verification practice for existing hydrocarbon pipelines converted to CO2 service, such as that provided in ASME B31.8S [62], DNV-RP-F104 [58] and ISO 27913 [54], can be used, which includes a review of:

- The potential for hydrogen embrittlement or reduced ductility resulting from the presence of hydrogen in the fluid,
- Operational upset conditions that promote load effects which may induce significant thermal and pressure loading,
- Appropriateness of existing fittings, valves, vent, pressure relief and drain component designs and materials. It is noted that CO2 will jet from an open drain in a CO2 pipeline and the released CO2 can disperse differently than oil or natural gas. Some sump pits to capture released fluids will not be appropriate and worker safety related to CO2 exposure should be considered.
- Adequacy of the pipeline fracture control plan, and
- Drying of the pipeline, if following hydrostatic testing.

8 PIPELINE OPERATIONS

8.1 Operational Change Management

8.1.1 Operational Transients

In any pipeline, changes in operational condition including activation of valve or activation of flow from a branch line produces transient pressure fluctuations. The commissioning, start-up, or depressurization of a CO2 pipeline can introduce significant pressure fluctuations involving phase transformation and pipe cooling [63] [64]. The comingling of fluids from branch lines may be used to maintain desirable fluid composition but may also result in changes in operational conditions that are unique to CO2 systems as discussed in Annex B.

Mitigation of the potential for large pressure fluctuations may be accomplished through:

- the inclusion of control systems in the design to reduce the magnitude of transients,
- management of CO2 fluid composition and temperature which may promote changes in transport behavior and including the generation of two-phase flow [65], and
- start-up procedures that involve establishing some pipeline internal pressure with an inert gas such as nitrogen, insertion of a pig and backfilling behind the pig with CO2. This permits the CO2 in the pipeline to be loaded into the pipeline at a pressure promoting a dense phase condition and avoiding two-phase operations.

At branch connections where multiple flows are mixed, the branch line delivering CO2 should be monitored to ensure that the fluid pressure is compliant with the pipeline operating specification. A low branch line pressure, relative to the main line, can both block the introduction of CO2 and affect the pipeline mixed fluid operating pressure. To monitor the incoming line pressure a slug catcher bypass segment may be used to allow sensors to sample the branch connection operating pressure and monitor operating pressure conditions. Branch connection flows that do not meet the maximum or minimum operating pressures defined in the pipeline operating specification should not be accepted in the pipeline.

8.1.2 Two-Phase Flow

Two-Phase flow, as discussed in Annex B, occurs when there are pressure and temperature conditions for CO2 where both dense and gas phases coexist and during which the operating conditions of the pipeline are difficult to control. The EOS and behavior of CO2 in the two-phase operating region remain a subject of research. As with natural gas pipelines, Two-Phase flow should be avoided during operations for several reasons:

- In the case of two-phase flow, slugs of liquid CO2 can cause severe damage to booster pumps and compressors unless slug catchers and gas scrubbers are installed at the suction side of pump and compressor stations. Managing these slug catchers, gas scrubbers, and the additional pumps required to route liquids around the compressors and then recombining the gas and liquid streams on the discharge side, introduces operational complexities. These complications reduce flow efficiency and increase system risk.
- Even with slug-catchers installed, the drop in temperature due to Joule Thomson cooling when CO2 enters the suction nozzles of pumps or compressors, can cause the CO2 to enter the two-phase region, and instantaneously reduce sonic velocity limiting flow through the machine and causing a severe pressure surge that can seriously damage the pumps or compressors.
- Pressure surges due to slug flow will promote pipe wall stress fluctuations with the potential to promote fatigue damage accumulation and crack growth.

Because of the potential for severe damage to pump/compressor installations, a sophisticated fast-acting monitoring and control system should be considered to reduce the speed of booster pumps or compressors and maintain suction pressure at a safe margin above the bubblepoint pressure (saturation pressure).

While two-phase flow should be avoided in normal pipeline operations, it is noted that two-phase flow may occur:

1. During pipeline pressurization and blowdown (startup or shutdown),
2. In vent stacks when CO2 is being released,
3. Pump or compressor station upsets.
4. In downhole injection tubing,

The first three scenarios can be managed by not running booster pumps and compressors until pressure in the system has been restored to levels above the bubblepoint saturation pressure.

The fourth scenario involves complex interactions between flow regimes, mass flow rate, target bottomhole pressure, and evolution of the CO2 plume throughout the reservoir. Even though the complexity can be reduced because target bottomhole pressure is affected more by mass flow than the specifics of phase behavior, and downhole temperatures are well above the critical temperature of CO2 so that two-phase flow only occurs near the top of the injection tubing and becomes single phase before reaching bottomhole, the fourth scenario is complex enough to require specialist attention.

8.1.3 Temperature Effects and Potential for Hydrate (Clathrate) Formation and Remediation

The characteristics of the CO2 fluid being transmitted shall be monitored and controlled in terms of moisture content and temperature. For a given CO2 fluid composition, there is a strong relationship between fluid pressure and temperature. Monitoring fluid temperature provides the opportunity to manage:

- Fluid pressure variation because the density of CO2 density is very responsive to temperature
- In conjunction with moisture monitoring and control it may be used to control the threat of corrosion and hydrate production.

Because of the ability of dense phase CO2 fluids to absorb water, the production of hydrates is not expected to be an issue for these pipelines. Drying CO2 gas prior to transmission by pipelines can mitigate the threat of hydrate formation.

8.1.4 Joule Thomson Cooling Effects for both Dense Phase and Gas Phase Fluids

The design, operation, and maintenance of a CO2 pipeline shall include the Joule Thomson effect which describes the fluid cooling due to a pressure drop which may occur in number of scenarios such as within a pipeline at a restriction, at a leak or during venting. Some equations of state, see Section 4.2.1, can provide adequate accuracy for most aspects of CO2 pipeline design, including Joule Thomson cooling effects. In both dense phase and gas phase CO2 pipelines the design and operating procedures shall include this effect. An illustrative example describing the sensitivity of CO2 to the Joule-Thomson effect is provided in Annex B.

As a mitigative measure, the operator should consider the installation of instrumentation in the system for monitoring temperatures and pressures at locations of interest.

8.2 Pressure Management

8.2.1 Pressure Cycling on Growth Potential of Anomalies and Associated Interactive Threats

The fatigue life analysis tools and procedures applied to hydrocarbon pipelines may be applied to CO2 pipelines, including operational pressure cycle counting as laid out in API RP 1176 and API RP 1183. The response of anomalies or stress risers in a CO2 pipeline should consider the operational pressure cycling promoted by:

- short-term storage reserve strategy for smoothing out upstream or downstream transients
- transients derived from changes in CO2 stream source fluctuations and Two Phase flow conditions
- thermal load effects due to operational changes

- the relatively high compressibility of dense phase CO_2 compared with liquids like oil and condensates.

8.2.2 Purging, Loading, and Blowdowns

Operational changes including start-up (loading) may promote undesirable changes in the pressure and temperature conditions. Transient effects are discussed in Section 0.

The blowdown process of a dense-phase CO_2 pipeline shall be developed to mitigate the risks associated with the following issues [67]:

- As the pressure in the pipeline drops such that the fluid saturation (bubble) point is crossed, very low temperatures occur and may promote pipe wall cooling resulting in a reduction of ductility increasing the risk of fracture
- With rapid depressurization, there is the potential for dry ice and hydrate formation which can result in pipeline and fitting blockages
- Operator and public safety shall be managed to preclude harm from high noise levels and dispersion of the CO_2 gas

The duration to execute a blowdown cannot be defined by a rule of thumb for all pipelines or operating conditions. The duration of the blowdown process shall be defined including the following:

- fluid operating conditions and properties including P-T behavior
- air temperature and wind speed affecting heat transfer and CO_2 dispersion. Other factors affecting the dispersion process are discussed in Sections 5 and 11.
- pipeline depth of cover, soil type, ground temperature affecting heat transfer to and from the pipe
- pipeline size and elevation changes which can produce localized cold spots and affect hydrate formation and two-phase flow

Blowdowns should be avoided where possible using in-service maintenance or purging to maintain pressure.

8.3 CO2 Fluid Composition and Measurement

8.3.1 CO2 Fluid Composition

Since the pressure temperature behavior and corrosion potential of a CO_2 fluid stream is related to its composition, the specification, measurement and control of constituent components shall be integrated in the design process and operations of pipeline and related facilities. The composition limits of the CO_2 fluid gas stream is controlled by the fluid specification, while the actual fluid stream composition reflects the composition of the fluid delivered to the pipeline by its source(s). Appendix A provides several examples of typical flue gas compositions for specific industrial applications. There are many sources of CO_2 fluid composition data. This composition information will both change over time and is approximate as the exact flue gas composition will depend on the industrial process details and feedstock material compositions, amongst other factors. The most common constituent components in a CO_2 stream include O_2, N_2, Ar, H_2O, SO_2, H_2, and CH_4. This type of data is, however, considered useful for pipeline operators in considering issues such as:

- target CO_2 composition specifications to control fluid behavior,
- required flue gas cleaning processes and effectiveness;
- supporting pipeline internal corrosion rate estimation or cracking potential,
- CO_2 detection and measurement equipment effectiveness,
- expected mixtures from independent sources and how they will affect the pipeline fluid stream composition.

- waterless corrosion in the presence of H_2S, SO_x, and NO_x. This effect has been observed for bulk fluid chemical reactions generating acids that accumulate until solubility levels are exceeded.

The connection of new sources to an operating pipeline system could result in the CO_2 stream no longer meeting the previous design specification and shall be subject to a design review to ensure that the changed composition is still appropriate for the pipeline design and operation.

8.3.2 Specifications for CO2 Composition Limits

The allowable limits on CO_2 fluid constituent components are defined by their effect on factors such as gas behavior, corrosion rate, and environmental cracking risk. The effects of each constituent component and their interactions remain the subject of research in the enhancement of fluid equations of state and corrosion and environmental cracking rate.

Some standards provide illustrative composition limits [54] and CCS demonstration projects and operational agreements have been developed and may be considered as reference limits [68] [69]. These composition limits can change over time as additional research is completed on the impact of composition on fluid behavior and corrosion rate. The primary fluid components that should be specified or controlled at this time include:

- water (H_2O);
- oxygen (O_2);
- nitrogen (N_2);
- hydrogen (H_2);
- carbon monoxide (CO)
- sulfur oxides (SO_x);
- nitrogen oxides (NO_x);
- hydrogen sulfide (H_2S);
- hydrogen cyanide (HCN);
- carbonyl sulfide (COS);
- methane (CH_4)
- ammonia (NH_3);
- amines;
- aldehydes;
- alcohol / glycols;
- particulate matter (PM)

The maximum allowable water content, specified in parts per million on a volume basis (ppmv), should be determined to preclude hydrate formation and such that corrosion and solids formation will not compromise pipeline integrity. The maximum water content will depend on the operational conditions and should be specified based on relevant field experience, reliable experimental data or experimentally verified models.

While experimentation on some CO_2 blends with other components has been completed and demonstrate the potential for accelerated corrosion [70] [71], other blends are practically inert. Some CO_2 induced chemical reactions occur between the components, however, these reactions may not cause corrosion or formation of aqueous or solid phases. It has been stated that based on the large number of experiments completed to date that it is premature to conclude on a “universal” CO_2 fluid composition specification that controls the interaction of all possible CO_2 stream components to mitigate corrosion susceptibility.

Research continues to be completed to develop CCUS industry guidelines for CO2 specifications for effective CCUS chains [72]. These efforts indicate that unknowns remain, however, provides a framework for the development of composition limit guidance and advises on the impact on the various permutations of CCS chains. The guidance is not intended to be a replacement for regulation or legal requirements.

Further discussion of testing and the definition of CO2 fluid composition limits, as it affects corrosion, and cracking resistance is presented in the AMPP guide for CO2 material selection [34]. Operational controls need to be determined to minimize potential for dropout and related negative impacts during startup, shutdown, upset conditions or maintenance and inspection as discussed in Section 6.3.

8.3.3 Measurement and Quality Control

Flow measurement and characterization of constituent components of CO2 pipeline fluids are essential to integrity management and financial management of CCS applications. Flow measurement devices remain in the developmental stage with several studies [73] [74] [75] [76] [77] [78] [79] [80] [81] [82] [83] considering their performance. The performance of measurement devices to define the composition and phase of the CO2 fluid are also the subject of research and development. The sections that follow identify the types of requirements that are needed to develop a specification for the performance of this equipment.

Fluid composition and moisture quality control is more important for CO2 pipelines than natural gas systems because of the sensitivity of the CO2 pressure temperature behavior as discussed in Section 4. The composition and moisture level of the fluid shall be monitored and controlled as an element of the pipeline operational procedures.

Dense phase CO2 can absorb a lot of water, however, pressure reductions that bring the fluid to a two-phase or gaseous state can drop out the water and initiate a corrosion process or initiate cracking, depending on the constituent components of the CO2 fluid. The frequency of interruptions in normal operating conditions shall be minimized as outlined in the pipeline integrity management program.

Moisture level and composition of the CO2 fluid are always important for gas phase CO2, which does not absorb as much water as dense phase CO2 and can promote corrosion and cracking.

The moisture level, pressure, temperature and composition of the sampled CO2 fluid delivered to the pipeline, shall be in accordance with the operational and gas specifications for the project. Non-compliant fluids should not be accepted into the pipeline and returned to the supplier for handling, if possible. Key CO2 constituents, moisture, pressure and temperature should be monitored continuously with notifications to the supplier for off-specification situations.

To ensure compliance with the fluid quality specification and prevent or limit the entry of off-specification CO2 to the pipeline, online analyzers and sampling systems should be installed. Sampling may be completed using full flow inline measurement technologies, extracting fluid samples for lab testing or by including a large volume lower flow pipeline segment for low flow measurement technologies. The frequency of sampling and technology specified for fluid quality measurement as part of the design should consider the measurement technology capabilities, fluid composition, phase and flow rate.

8.3.3.1 Selection of measurement systems and devices

Measurement systems and device technology capabilities continue to advance and are the subject of research and development. For the selection of pipeline measurement systems and devices the ability to provide data on the parameters listed in Table 4 should be considered.

Table 4—Desirable Measurement Parameters

Parameter	Comments
Phase state of the CO2 fluid	Even in small concentrations, change in fluid constituents can significantly affect the phase behavior and deteriorate measurement accuracy if a second phase arises. It is relevant to identify the presence of a second phase.
Flow rate	Flow rate monitoring and is essential to pipeline operational control

Process temperature	Strongly linked to fluid pressure. Control of temperature is essential to maintain fluid phase and behavior.
Ambient temperature	Can affect the behavior of the CO2 fluid
Internal pressure	Strongly linked to fluid temperature. Control of pressure is essential to maintain fluid phase and behavior.
Constituent component composition	Required for fluid characterization related to operational quality checks and process control Considering components such as O2, N2, Ar, NOx, So2, H2O, H2S, Co, H2S/COS, H2, Amines, NH3, SOX,
Leak detection	Encompasses both measurement-based leak identification and technologies that enable flow-based leak detection and mass balance tracking

The in-line fluid measurement technologies available have been classified [84], considering technology readiness level for bulk measurement (average properties over the pipe cross section) phase identification, composition and leak detection. The technologies were classified into eight significant groups:

- Dielectric measurement – relying on the sensitivity of the sensors to changes in the dielectric properties of the fluids.
- Gamma radiation – considering the electromagnetic radiation derived from the radioactive decay of atomic nuclei.
- Ultrasonic flow meters – measuring the velocity of the fluid to calculate volume flow.
- Coriolis flow metering – employs vibrating measuring tubes to estimate the inertia of flowing fluid or its mass flow rate.
- Differential Pressure (DP) flow measurement – considers the pressure differential across an orifice plate to estimate material flow rate.
- Absorption spectroscopy – measures the concentration of the constituent components in the CO2 gas stream and, in some cases, the phase of the material by passing a light through the fluid to consider the received light intensity or spectrum.
- Optical particle counters – count the number of particles of given size ranges using a light source aimed at the gas/liquid stream, which is then detected using a photosensor.
- Distributed fibre optic sensors – measure strain and temperature with relatively high spatial resolution to detect changes in temperature and strain state along a pipeline.

Table 5 summarizes the potential applicability of the technologies studied for the measurement parameters considered using a qualitative scale of poor, intermediate, and good. The shaded cells highlight the technologies with higher potential per criterion. In this evaluation, the potential, sensor installation location for sensors, identified in in Table 5, include:

3. Outlet of capture facility
4. Regular points along the transport network (pipeline)
5. Inlet and outlet of onshore transport networks (pipelines)
6. Temporary storage sites
7. Entrance and exit to an onshore storage facility
8. Loading and offloading locations
9. Injection sites

Table 5—Potential Applicability of In-Line Measurement System [84]

Criteria	Dielectric	Gamma	Ultrasonic	Coriolis	DP	Absorption spectroscopy	Optical Particle counter	Distributed Fiber Optics
Bulk measurements	Good for all conditions [5,6]	Good for all conditions [5,6]	Good for gas Intermediate for liquid [2] Poor [6]	Good [5] Poor [6]	Good [5] Poor [6]	Poor [1]	Poor	Poor
Phase Identification	Good – Setup dependent [3]	Good – Setup dependent [3]	Poor	Poor	Poor	Intermediate [2] – Setup dependent [3]	Good	Poor
Composition	Intermediate [7]	Intermediate – Setup dependent [3]	Poor	Poor	Poor	Good [4]	Poor	Poor
Leak detection	Poor	Poor	Good [8]	Good [8]	Good [9]	Poor	Poor	Good
Potential location	3 4 5 7 8 9	3 4 5 7 8 9	3 4 5 7 8 9	3 4 5 7 8 9	3 4 5 7 8 9	3 6 8	3 6 8	4 9
Comments	Needs a nonelectrical conducting liner. Can also be installed like probes	Uses radioactive source Sensitive to scale or layer buildup on the probe	Requires partly developed flow profile (5D - 10D straight upstream)	Some pressure drop. Size, weight and cost can become prohibitive above 16”	Need density input. Accuracy deteriorates with larger fractions of impurities.	Needs low pressure Needs window	Needs window	

1 Some applicability for bulk measurements might be feasible depending on the species.
2 Requires experimental validation.
3 Performance is dependent on the arrangement/setup.
4 For high accuracies (ppm) sampling is required. For higher concentration thresholds (%) useful information might be obtained at higher operating pressure.
5 Pipeline service (gas and liquid phase), shipping offloading (supercooled liquid).
6 Operating conditions where multiphase flow can arise.
7 Small changes in impurities (within the same phase), likely difficult to identify.
8 For flow-based leak, tracking mass balance.

8.3.3.2 Calibration

Valid calibration certificates shall be available for the CO2 stream constituent component monitoring system. Calibration of the CO2 stream constituent component monitoring system shall be performed, taking the project-specific CO2 fluid specification into account, as constituent components and fluid phase within the stream may influence measurement readings. The reliability of the monitoring system can be improved by using multiple, independent monitoring devices or technologies.

9 CO2 INTEGRITY MANAGEMENT

9.1 Data Integration and Threat Assessment

Various industry accepted practices and recommendations exist for managing the integrity of pipeline systems including API Std 1160, API RP 1188, and ASME B31.8S. While these practices can be applied to CO2 pipeline systems in the same manner as they are applied to hazardous liquid or gas systems, the following sections will highlight specific considerations for CO2 dense phase systems.

The development of a comprehensive integrity management program involves consideration of the threats to integrity, health and safety and the environment. Integrity management of CO2 pipelines should consider similar pipeline integrity threats posed to hydrocarbon pipelines, as outlined in ASME B31.8S:

Time Dependent:	Stable (Resident):	Time Independent:
• External corrosion	• Manufacturing-related defects	• Third party/mechanical damage
• Internal corrosion	• Construction-related defects	• Incorrect operational procedure
• SCC	• Equipment	• Weather related and outside forces

The threats to pipeline integrity that are unique or have higher potential to promote failure in a CO2 pipeline are listed below, acknowledging that there is some repetition:

Time Dependent:
- Internal corrosion
- Environmental. cracking

Stable (Resident):
- Non-metallic material suitability

Time Independent:
- Incorrect Operational Procedure
    - Operating start up and shutdown
    - Fluid release procedures
    - Fluid composition management
    - Fluid moisture control

9.1.1 Internal Corrosion Prevention and Control

The internal corrosion rate for CO_2 pipelines is related to the constituent component concentrations, temperature, pressure, flow rate and pipeline material. While research continues on corrosion prevention or control general trends have been observed identifying the factors which promote corrosion:

- Higher H_2O concentrations
- Higher concentrations of NO_x, SO_x, and H_2S
- Higher oxygen
- Higher operational temperatures
- Lower pH of the CO_2 fluid
- Increased temperature at low pH and lower temperature at high pH

CO_2 fluid stream constituents such as NO_x, SO_x, and H_2S can potentially lead to acid formation in the fluid stream, likewise, the presence of O_2 and H_2O can serve to create conditions that allow CO_2 corrosion or provide the conditions for reactants to form.

Dense phase is relatively more tolerant to moisture concentration than gaseous CO_2. Corrosion rate testing to date has provided general guidance on corrosion prevention and control [85] [86].

Water content of the CO_2 streams shall be controlled to mitigate corrosion and the formation of hydrates within a pipeline. The CO_2 capture process used, as well as the composition of the flue gas, can have a significant effect on the level of water in the CO_2 stream. There are a variety of dehydration methods that may be used on the CO_2 delivered to a pipeline from differing sources, and the combined effect of the water content of all emitter CO_2 streams shall be managed. The composition of the fluid stream shall be controlled to ensure that components that may promote corrosion in the presence of moisture, identified in Section 6.3, are limited.

The presence of moisture in instrumentation or gauges should be controlled as indicated in API RP 1110.

Research is ongoing to address the validity and efficiency of using corrosion inhibitors to mitigate internal corrosion, particularly during H_2O or corrosion promoting constituent off-specification events in CO_2 pipelines.

9.1.2 Hydrogen Embrittlement

Atomic hydrogen in the pipeline can diffuse into the pipeline material resulting in a reduction in ductility. This topic has been extensively studied for hydrocarbon conveying pipelines [87] [88] [89] [90]. Hydrogen embrittlement can be mitigated in a similar fashion as hydrocarbon pipelines, by:

- Appropriate line pipe material selection such as low sulfur content or low carbon / carbon equivalent steels that exhibit lower hardenability,
- Appropriate weldments developed to have lower hardness in the weld and heat affected zones, and
- Reducing pipe axial and circumferential maximum and cyclic loading.

Hydrogen embrittlement is a broad term often used generically to describe the way hydrogen affects the properties of steels. The primary effects include a loss in fracture toughness, a reduction in fracture ductility, increased subcritical crack growth rate under cyclic load, and time-dependent crack extension under a static load when a minimum stress intensity is exceeded [91] [92].

If hydrogen is present as a component in the CO2 fluid from a source where hydrogen is integral to the source process, then the effects of hydrogen on long term material properties should be considered in design and integrity management programs. The impact of hydrogen on a CO2 pipeline can be managed in the same way as hydrocarbon pipelines (API RP 1176).

The lower bound of hydrogen concentration at which embrittlement occurs is an area of active research..

9.1.3 Environmentally Assisted Cracking

External environmentally assisted cracking of CO2 pipelines generally follows similar mechanisms as hydrocarbon pipelines, though pipe wall temperature differences may differentiate CO2 pipelines from hydrocarbon pipelines.

Current research is ongoing on how constituents can impact the likelihood to develop inside diameter environmentally assisted cracking in CO2 service. When constituents such as O2, H2S, CO, and NOx combine with H2O inside a gas phase or dense phase CO2 stream in a carbon steel pipeline system, they can form strong acids that may increase the sensitivity to environmentally assisted cracking. In a dense phase operation, reduced operational pressure can result in water drop out and promote cracking. To control the risk of cracking, moisture shall be controlled.

As a part of the data integration and threat assessment, the chemical makeup and exposure limits of the CO2 product stream should be taken into consideration when determining the likelihood of failure for cracking threats. A summary of the fluid stream components that may promote cracking [34] are listed in Section 6.3. Cracking risk evaluations shall include the potential for:

- H2S cracking – Drivers of this mechanism are the H2S fugacity or concentration in water, pH, and temperature (the lowest temperature is the most critical). This mode of cracking only occurs in the presence of a free liquid water phase.
- Stress corrosion cracking [93] – Drivers for SCC are the presence of O2, chlorides, H2S, tensile stresses, and higher temperatures such as may be encountered in a well environment. SO2 and NO2 may also influence susceptibility to SCC of carbon and low alloy steel.
- CO/CO2 cracking – Drivers for this form of cracking are oxidizers such as O2 and NO2 and minor levels of impurities like CO, and H2 associated with pre-combustion CO2 sources can cause environmentally assisted cracking of line pipe steels in gas phase or dense phase CO2 environments. This mode of cracking only occurs in the presence of a free liquid water phase.

These cracking risks remain the subject of ongoing research.

9.2 Integrity Management Considerations

CO2 pipelines have some unique features which require consideration when developing and implementing an integrity management program (IMP).

9.2.1 Pressure Testing

As listed above in Sections 6.3 and 6.9, when pressure testing a CO2 pipeline with water as a medium, care should be taken to ensure proper drying of the pipeline prior to reintroduction of CO2.

If drying of the pipeline can not be documented or confirmed, additional inspection or higher corrosion rates may need to be included in integrity management programs.

9.2.2 Corrosion Direct Assessment

External corrosion direct assessment (ECDA) methods such as those described in ANSI/NACE SP0502-2010 [94] may be used for CO2 pipelines.

When considering internal corrosion direct assessment, the applicable approach shall consider the phase and moisture content of the CO2 fluid stream. Internal corrosion in a CO2 pipeline may be effectively controlled by drying the gas stream and controlling fluid constituents such as H2O, SOx, and NOx, and others as listed in Section 6.3. The development of internal corrosion direct assessment processes for

CO2 pipelines remains an area of research which may draw from existing ICDA for hydrocarbon pipelines including those with wet products.

9.2.3 Pipeline Pigging

CO2 pipelines should be designed such that pigging and in-line inspection are possible, and hydrocarbon pipeline standards should be followed.

9.2.3.1 Pigging Infrastructure

Material selection and design for traps, valves and ILI systems should be suitable for the CO2 pipeline design with consideration given to CO2 pipeline specific factors such as:

- Attention should be given to positioning of drains to direct and control CO2 venting in a controlled manner for worker safety;
- Design of atmospheric vents and local topography to manage ground level CO2 concentration potential harm; and
- Develop loading and launching procedures specific for CO2 pipelines that consider the CO2 fluid pressure temperature and phase conditions.

To minimize the concerns above, nitrogen may be used to purge a receiver of CO2 prior to depressurization.

9.2.3.2 In-Line Inspection

In-line inspection of CO2 pipelines is broadly like inspection of hydrocarbon pipelines with ILI systems being calibrated according to API Std 1163. Operators should coordinate inspection procedures with ILI vendors. Regulations require that new pipelines are designed to permit the passage of instrumented internal inspection devices in accordance with NACE SP0102.

The following are some of the unique considerations for CO2 ILI inspection:

- CO2 is non-lubricating (dry) and may increase wear on cups and runners. This limits the length of ILI runs in CO2 pipelines.
- Because CO2 is heavier than air, additional precautions should be taken prior to blowing down pig traps during the launching or recovery operations.
- Operators should consider displacing the CO2 in pig traps prior to launch or recovery.
- Upon retrieval of the ILI tools, depressurization may promote damage to non-metallic components of the ILI tool, unless protected from the CO2.
- Technologies that require liquid couplant, such as ultrasonics, may not be appropriate for CO2 service.
- When higher wall thickness is utilized, certain ILI technologies may not be acceptable due to lower sensitivity or detectability.
- Rapid decompression of CO2 trapped in the ILI tool during or after recovery can cause harm to personnel, equipment, and facilities

9.2.3.3 Temperature Control for ILI / Tools

In a CO2 pipeline, it is possible to have local cold zones created by flow restrictions and ILI systems shall be aware of this possibility. Sensitivity of ILI system mechanical systems, instrumentation or electronics shall be corrected at a high enough frequency to respond to this local cold zones. Further discussion of the development of cold zones is presented in Sections 6.8 and 0.

9.2.3.4 Frequency of ILI Assessment

The frequency of ILI inspection determination and integrity analysis for non-through wall defects may be completed in accordance with acceptance limits and tools developed for hydrocarbon pipelines such as those in API 579 [95] with due consideration given for:

- Corrosion rate observed in the pipeline, which can be increased by the presence of fluid constituents in the CO2 stream (see Section 0)
- Operational pressure cycling severity defining fatigue crack growth and embrittlement in the presence of hydrogen
- Abnormal operating conditions, including the effects of operational upsets related to water dropout

9.2.4 Operational Risk Management Program

The pipeline operator should develop, implement, maintain, and document a risk management program that includes comprehensive data collection, identification and update of potential threats and hazards, thorough risk assessment, development of preventive and mitigative measures, conduct of periodic reviews and record keeping. The pipeline operator shall conduct an annual review of its risk management program.

Risk assessments should be complete to identify, analyze, and evaluate hazards or threats that ultimately lead operators to prudently manage risk. A variety of tools and techniques are available and used that evaluate and prioritize risks to promote operational and functional integrity. Risk assessment may also result in not only recognizing the operator's own operational impacts but also other nearby non-associated third-party activities.

A risk assessment process should include the following steps:

- Identification, collection and incorporation of all information (data) relevant to the pipeline and its operation (data collection);
- Identification of all potential threats and hazards (risk identification);
- Evaluation of the likelihood of events and consequences related to the events (risk analysis);
- Determination of risk ranking to develop preventive and mitigative measures (P&M) (risk evaluation);
- Documentation of risk evaluation and decision basis for P&M measures (record keeping);
- Periodic (regular) evaluation of risk assessment and determination of the need to escalate the implementation or modification of P&M measures;
- Evaluation of the risk management program and results using comprehensive performance measures.

9.2.5 Pipeline System Safety Principles

The pipeline operator should develop and maintain comprehensive programs that incorporate safeguards to site security, safety, public health and the environment, as described in API RP 1173. These programs apply to planning, design, ongoing operations, maintenance, and potential decommissioning and should be based upon regulatory requirements and industry best practices and recommendations adjusted appropriately for specific nuances of their facilities, locations and operations. These programs should include, but are not limited to, important elements such as:

- Operational controls – safe work practices, system integrity, management of change, contractors, incident investigation and emergency response (see Sections 11.2 and 11.2.2);
- Safety assurance – audit functions, goals and objectives, evaluation of safety culture;
- Management review and continuous improvement;

- Competence, awareness, and training;
- Documentation and record keeping; and
- Any other elements deemed necessary by the operator.

The operator should verify that the programs, processes and procedures fully address the conduct of all work in a manner that minimizes safety, health and environmental risks.

9.3 Defects/Imperfections (Acceptance Criteria)

Integrity assessment for non-through wall defects should be completed in accordance with acceptance limits and tools developed for hydrocarbon pipelines such as standards available from API or ASME, with due consideration given for:

- Internal corrosion rates which may be higher than observed in hydrocarbon pipelines due to the fluid constituents and the presence of moisture, and
- The potential for hydrogen embrittlement or reduced ductility resulting from the presence of hydrogen in the fluid.
- The pipeline pressure and temperature conditions that may differ from those of hydrocarbon pipelines

9.4 Repairs

Repairs for CO2 pipelines should follow procedures developed for hydrocarbon pipelines [96] with due consideration for:

- Similar to liquid hydrocarbon lines, the heat sink capacity of the CO2 fluid is defined by its properties when applying in-service welding. The heat sink capacity may be measured in-situ using a spot heating test procedure as outlined in the PRCI pipeline repair manual [96].
- Avoiding two-phase flow if pressure reduction is required for a repair or other activity,
- Safety for workers to preclude exposure risk associated with in ditch CO2 accumulation at a leak site,
- Safety for workers to preclude frostbite in or around a leak repair location, and
- Material selection consistent with that used in Section 5.

9.5 Preventative and Mitigative Measures

Preventative and mitigative measures can follow industry best practices such as API Std 1160, API RP 1183, API RP 1176, and API RP 1188 to identify appropriate and beneficial measures that can reduce the likelihood of failure or mitigate the consequence if one were to occur. Mitigative measures may be identified as part of safety management or operational risk assessment, as discussed in Section 9.2.4. In addition to approaches considered for hydrocarbon pipelines, operators shall address unique issues for CO2 pipelines such as:

- drying and moisture control,
- Installation of crack arrestors,
- Installation of EFRD devices,
- fluid sampling and constituent control,
- enhanced public awareness, and
- CO2 pipeline specific operations, maintenance and emergency response procedures.

9.6 Facility Integrity Management

Best practices for facility integrity management are found in both API Std 1160 and API RP 1188. But unlike traditional hazardous liquid facilities, carbon dioxide facilities are at the same or similar operating pressures and temperatures as the line pipe to maintain a consistent phase flow. This may make the threat profile of the facility piping more in line with the line pipe than traditional hazardous liquid facilities.

In a similar manner to highly volatile liquid assets, the carbon dioxide facilities will have different designs related to drains and blow off systems that are not found on other hazardous liquid assets. And due to the higher operating pressures, higher wall thickness may be required to maintain the maximum operating pressure. When a facility integrity program utilizes visual inspections or non-destructive examination (NDE) inspections, these higher wall thicknesses as well as different designs should be taken into consideration. In some cases, standard NDE methods may not be applicable due to the piping design or configuration.

10 CO2 LEAK DETECTION AND ODORANTS

10.1 Leak Detection

Operators should develop a comprehensive leak detection program which may include a continuous leak detection system. Leak detection may form an important part of the overall risk management strategy. Due to the differing behaviors of hydrocarbons and CO2, not all techniques used for hydrocarbon pipelines are suitable for CO2 pipelines. Leak detection methodologies, as described in API RP 1175, can incorporate both internal and external leak detection technologies, as detailed in Table 6.

Often more than one leak detection technique is applied to a pipeline system. Operators should consider multiple factors in addition to the CO2 phase and composition when selecting leak detection methodologies (see API RP 1175, Section 8). The selection of a leak detection technologies should consider:

- the effects of the pipeline operating conditions defining fluid properties and phase
- technology deployment difficulties, as some hardware is more suitably deployed during construction and maybe more difficult to deploy on a converted pipeline segment.
- Leak rate detection threshold, continuity of monitoring, and reporting interval
- Ability to identify the location of the leaks along the pipeline
- Opportunities to tune the technology to the specific pipeline operating conditions
- Potential for false positive reporting

Internally based techniques considered as a Computational Pipeline Monitoring (CPM) system should be designed, installed, and maintained according to API RP 1130. API 1149 provides guidance around the evaluation of the reliability and sensitivity of these systems with the reader considering the properties of CO2.

Table 6—Leak Detection Technologies

	Technology	**Notes**	**System Capability for CO2 Pipelines**
Internal	Mass Balance	Measurement of imbalance between incoming and outgoing mass may be considered to determine an alarm threshold signaling a leak.	Mass balance using Coriolis metering can be applied to incompressible fluids and as such may be suitable for CO2 pipelines.
	Volume Balance	Measurement of imbalance between incoming and outgoing volume may be considered to determine an alarm threshold signaling a leak. Determined by considering changes in fluid pressure and temperature conditions and estimating fluid density.	Volume balance is best applied to incompressible fluids and as such may not be suitable for CO2 pipelines. For best performance this should be combined with a line pack adjustment.
	Rate of pressure / Flow change	The rate of change in fluid pressure or flow may be considered as an indicator of a release when compared to normal operational conditions.	This approach may be suitable for identifying large CO2 pipeline release events. It's challenging to differentiate changes in pressure and flow during a leak from normal fluctuations during transient operating conditions. This technology can be effective when paired with transient models. Realtime knowledge of fluid composition is important for this approach.
	Real time transient models	A pipeline hydraulic model may be compared to measured conditions along the pipeline to identify differences in characteristics such as flow rate, pressure, temperature, density that indicated a release has occurred.	Precision dependent on inclusion of: • Well developed EOS for fluids • CO2 properties being calculated in real time including consideration of phase transitions including boundary discontinuities • Testing the system under various leak conditions Modelling relies on understanding of compressible and transient nature of gaseous or dense-phase CO2 in pipelines.
	Statistical analysis	Statistical analysis of measured data such as flow, pressure or temperature relative to normal operational conditions may be used to identify significant variations suggesting a release.	This approach may be suitable for identifying large CO2 pipeline release events. Requires sufficient leak data for a variety of conditions to ensure sensitivity, and can be enhanced when paired with real time transient models
	Negative pressure wave (Acoustic)	The pressure wave generated by a leak. travels upstream and downstream of the leak location and may be identified through pressure data analysis.	Ultrasound wave attenuation through gaseous CO2 may reduce the applicability of this technique. Distinction between leaks and other

			transient events with similar signatures may be challenging.
	Pigging	A leak detection acoustic or ultrasonic pig may travel along the pipeline with the fluid to record sounds that through analysis may be used to identify a release.	This approach may be suitable for a CO2 pipeline, however, technology modifications from hydrocarbon pipelines will be required.
External	Biological	Visual observation by the pipeline operator or the public along the right of way to consider damage to vegetation. This approach is not likely to be sensitive to modest CO2 leak rates.	This approach will not be effective for small CO2 pipeline leak events.
	Fiber optic	Fiber optic cables along the pipeline may detect small leaks than other methods by considering changes in temperature, acoustic (or vibration) and local chemical conditions. Fiber optic technology can detect pipe axial strains due to geotechnical and other hazards prior to initiating leaks and breaks. Fiber optic sensors are unique in that they can also reliably locate leaks and breaks so that they can be responded to and repaired quickly.	Fiber optic cables should remain effective for CO2 pipelines because their functionality does not rely on the fluid properties inside the pipe, except for the Joule-Thomson coefficient, which helps in detecting and locating smaller leaks than other methods. These cables can also measure soil movements, pipe strains, and vibrations caused by third-party activities near the pipeline, thereby preventing potential leaks and breaks.
	Vapor sensing tube	Vapor sensing in gas samples drawn from a perforated tube laid along the pipeline may be used to detect elevated levels of CO2.	Vapor sensing may be effective for CO2 pipelines assuming that they can be positioned to intercept the released fluid.
	Liquid sensing tube	Cables buried beneath the pipeline are used to detect changes in local electrical properties by contact with a fluid.	Liquid sensing tubes may not be effective for CO2 pipelines.
	Acoustic sensor	The sound generated by a leak may be detected, however, this approach is generally reserved for use in conjunction with other internal leak detection technologies.	May not detect small leaks for CO2 pipelines.
	Vapor sensor	Gas sensors may be used as an “electronic nose” at specific locations along a pipeline or in handheld units to detect gases from a leak.	Requires positioning of sensors at locations of interest, such as low lying areas near population centers.
	Infrared signature	Infrared cameras (handheld, fixed position, or vehicle mounted) may be used to detect local changes in temperature associated with a leak site.	Requires positioning of sensors at locations of interest, or land-based mobile units or small plane/drone mounted sensors.

10.2 Odorization

Pure CO2 is colorless and virtually odorless. However, anthropogenic CO2 streams contain components which can colorize and odorize a CO2 release. The artificial addition of components that enable olfactory detection (‘odorizing’) can provide an additional attribute of safety in the event of unplanned CO2 leakage, reducing the level of risk involved. If an odorant is used, operators should consider it having some or all of the following characterizations:

- a unique odor, distinct from that used for hydrocarbons,
- able to maintain its characteristics despite phase changes,
- resistance to change (stability) by other stream components or time,
- no contribution to pipe or other system corrosion or damage,
- no downstream impact on CO2 use or environmental impact, and
- non-soluble in water.

Research on this subject continues with a historical perspective available [97]. The appropriateness of odorants in dense phase CO2 transmission pipelines is not yet established. Some end-uses of transported CO2 preclude the usage of CO2, such as food and beverage production.

11 CO2 DISPERSION, EXPOSURE AND EMERGENCY RESPONSE

This section describes CO2 exposure limits and techniques used to evaluate the dispersion of released CO2. With an understanding of the time history of the spatial distribution of released CO2 concentrations and exposure limits Potentially Affected Areas (PAA) and the total released volume of CO2 may be defined and emergency response plans can be developed, as outlined in this section.

11.1 CO2 Toxicity Versus Incapacitation

CO2 is minimally toxic by inhalation [98]. A health effect caused by CO2 is the result of its behavior as a simple asphyxiant. A simple asphyxiant is a gas which reduces or displaces the normal oxygen in breathing air. CO2 levels in outdoor air typically range from 300 to 400 ppm (0.03 % to 0.04 %) but can be as high as 600-900 ppm in metropolitan areas. [98].

Symptoms of mild CO2 exposure may include headache and drowsiness. At higher levels, rapid breathing, confusion, increased cardiac output, elevated blood pressure and increased arrhythmias may occur. Breathing oxygen depleted air caused by extreme CO2 concentrations can lead to death by suffocation.

Table 7 provides examples of exposure levels and related symptoms developed for pure CO2 exposure. These limits may be considered relative to CO2 gas dispersion assessment in evaluating the risk of a release (Section 5).

Table 7—Exposure Level Symptoms [98]

Exposure	Symptoms
5000 ppm (0.5 %)	OSHA Permissible Exposure Limit (PEL) and ACGIH Threshold Limit Value (TLV) for 8-hour exposure
10,000 ppm (1.0 %)	Typically no effects, possible drowsiness
15,000 ppm (1.5 %)	Mild respiratory stimulation for some people
30,000 ppm (3.0 %)	Moderate respiratory stimulation, increased heart rate and blood pressure, ACGIH TLV-Short Term (15-minute exposure limit four times per day separated by an hour)
40,000 ppm (4.0 %)	Immediately Dangerous to Life or Health (IDLH)
50,000 ppm (5.0 %)	Strong respiratory stimulation, dizziness, confusion, headache, shortness of breath
80,000 ppm (8.0 %)	Dimmed sight, sweating, tremor, unconsciousness, and possible death

The response to CO2 inhalation varies greatly even in healthy individuals. The seriousness of the symptoms is dependent on the concentration of CO2 and the length of time a person is exposed. Since CO2 is odorless and does not cause irritation, it is considered to have poor warning properties unless an odorant is added to the gas. Fortunately, conditions from low to moderate exposures are generally reversible when a person is removed from a high CO2 environment.

NOTE More information is available here:

- OSHA website https://www.osha.gov/dts/chemicalsampling/data/CH_225400.html
- Centre for Disease Control Website, National Institute for Occupational Safety and Health (NIOSH), Carbon dioxide - IDLH | NIOSH | CDC

Similar CO_2 exposure limits to those provided in Table 7 are provided by the UK Health and Safety Executive (HSE) [99]. In assessing the significance of exposure to CO_2 the UK HSE applies an assessment of the Dangerous Toxic Load (DTL) which describes the exposure conditions, in terms of constant airborne concentration and duration of exposure, which would produce a particular level of toxicity in the general population [100], as illustrated in Figure 7. Two exposure limits are defined in terms of the concentration of CO_2 in the air (c) and the duration of exposure (t):

• Exposure to the SLOT level would result in many people with serious injury requiring prolonged treatment, and	SLOT DTL: $1.5 \times 10^{40} = c^8.t$
• Exposure to the SLOD level would result in many people dying.	SLOD DTL: $1.5 \times 10^{41} = c^8.t$

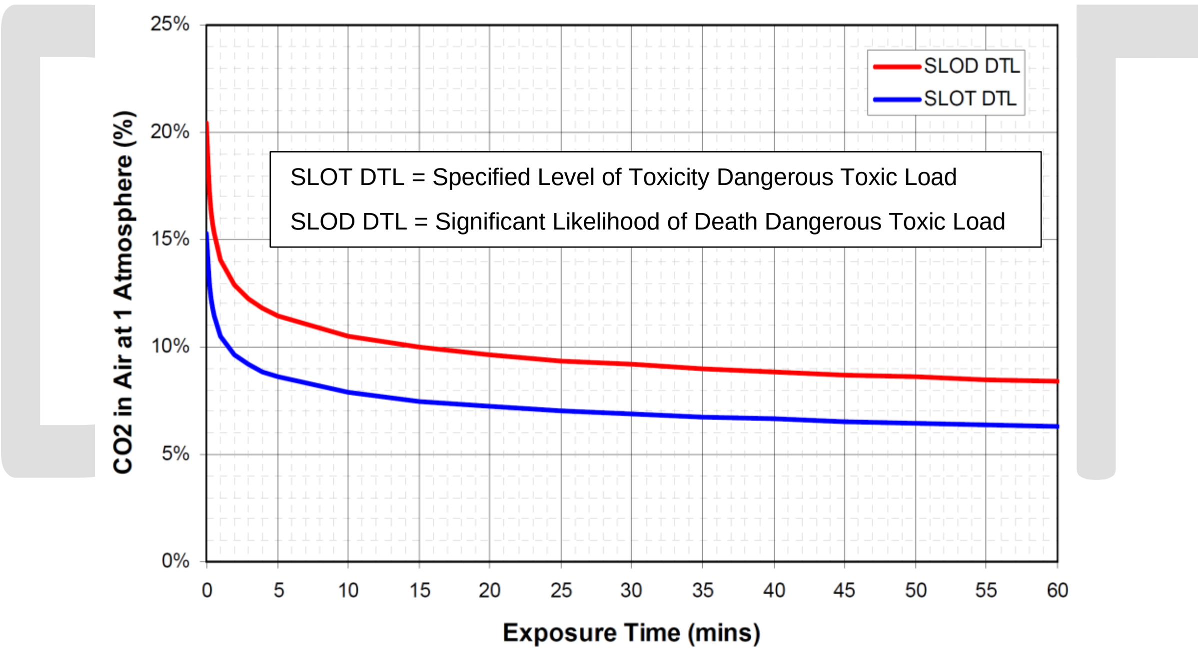

Figure 7—UK HSE Exposure Limits for CO_2 [101]

The SLOD and SLOT criteria have been identified as broad in scope [102], but reflect the fact that:

- there is likely to be considerable variability in the responses of different individuals affected by a release event;
- there may be pockets of high and low concentrations of a released substance in the dispersing cloud, so that not everyone will get the same degree of exposure; and
- the available toxicity data are not usually adequate for predicting precise dose-response effects.

Importantly, the criteria are also relatively easy for non-scientists to understand in terms of the overall health impact. More complex toxic load estimation techniques that can consider fluctuations in exposure concentration have been developed [103].

11.2 Dispersion Modelling Methods and Techniques

Dispersion modelling is of specific concern for releases because CO2 tends to be more mobile than liquids and being heavier than air and non-flammable, unlike natural gas, can remain at ground level for a time and concentration that may be defined in a dispersion modelling process. Other highly volatile liquids (HVL's) transmitted by pipelines will also vaporize into a heavier than air gas when released and thus may provide a starting point for CO2 pipeline release dispersion assessments. While the physical and chemical properties are different, the diffusion modelling tools used for gases other than CO2 may include similar dispersion modes, scenario description details, and model boundary considerations.

The dispersion process due to intentional (e.g. venting) or unintentional (e.g. failure) CO2 releases involve developing an understanding of the properties of the gas of interest and the role played by the following modes of dispersion:

- Convective transport – gas movement driven by thermal differentials
- Diffusive spreading – gas movement promoted by differentials in gas partial pressures or concentrations
- Advective movement – gas movement driven by wind
- Gravitational effects – the effect of gravity on gas movement driven by the density of the gas
- Turbulence based flow resistance and mixing – disturbance or impedance of gas flow by boundaries as affected by gas density, velocity and viscosity promoting mixing. Models can consider built environment, surface roughness, texture or dimensions of the built (buildings, roads) or natural (vegetation, water, topology) environment.

The significance of each of these factors will depend on the scenario being considered and the level of precision required in the modelling process. The CO2 dispersion process may be approximated to identify areas of interest using a multi-level approach that could include methods of the types outlined in Table 8. The numbering of the available model types is not intended to reflect the order in which they are used but rather identify the complexity of the modelling process. The capabilities or limitations of models are changing because dispersion modelling is an area of active research [104] [105].

Table 8—Levels and Types of Tools for Gas Dispersion Modelling*

Model Level	Evaluation Tools	Capability and Application	Application
1	Qualitative Risk Ranking	Qualitative treatment applying engineering judgement, observed trends and risk factors, such as: • Terrain analysis • Surface texture (roughness) • Prevailing wind direction	May be used to screen locations along the pipeline route to identify locations and scenarios for more detailed evaluation. Rapidly applied to subjectively rank location risk. May not be appropriate for final identification of PAA, however, these models may be used to augment empirical model scenario rankings such that consideration is given to factors not considered in the empirical models.
2	Empirical Models	Dispersion modelling based on • Gaussian models considering presupposed gas concentration distributions, including those with calibrated corrections for	May be used to define local CO2 concentration distributions at the release point or fine tune selection of detailed dispersion assessment scenario applications. Empirical models with a range of capabilities exist and can provide numeric ranking of many sites but

		scenario factors, such as wind speed, or • Steady state models considering characteristic profiles for gas concentration, velocity and temperature.	may not consider all significant factors required for a specific dispersion scenario. May be used to consider local concentration time history and potential release risk.
3	Computational Fluid Dynamics	Capable of applying a quantitative treatment to explicitly consider: Convective Transport, Diffusive Spreading, Advective Movement, Gravitation Effects, and Turbulence based resistance and mixing. Computational time may limit the ability to consider multiple scenarios	May be used to support a detailed assessment of local concentration and potential release risk. Can be used if fluid equations of state are valid for CO2 (Section 4.2.1)
* All models being considered should be validated			

Scenario characteristics that should be used to define the release scenario dispersion assessment, include:

- local topography, built and natural environment which may direct the dispersion process,
- release location such as, below ground leak, release in crater, or at a vent stack,
- 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
- CO2 fluid components and impact on boundaries between the fluid gaseous and dense phases.

Dispersion modelling tools need not consider all the modes of dispersion or scenario characteristics. For example, a release scenario on a flat plain need not employ a model that includes local topology changes. Studies using a range of modelling levels have been completed to estimate the sensitivity of dispersion results to scenario characteristics and their interaction [106] [107] [108]. Dispersion models continue to be developed and a range of models are available, [109] [110] each having their strengths and weaknesses [111].

Prior to dispersion modelling, the application of the various model types and scenario parameters to be explored should be considered.

11.2.1 Potential Affected Area Determination

In defining potential affected areas (PAA), the safety of individuals and the environment are considered based upon the impact of the release event. Since CO2 is a nonflammable fluid, the primary impact relates to either the displacement of air or its toxicity. The surface or temperature effects of CO2 releases are highly localized and should not be used to determine the extent of the PAA. The PAA shall be defined by:

- the dispersion of CO2 from its release location,
- the population affected by the dispersed CO2,
- the ecological and environmental impact of a potential release,
- the consequences of the exposure of the population to the CO2 concentration.

The exposure limit consequence assessment should consider the time dependent exposure of the population rather than just the maximum exposure concentration. CO2 will mix with ambient air over time and reduce its local concentration. Operators should determine boundaries of PAA based on the hazard of CO2 concentrations considering exposure and toxicity limits, such as that presented in Section 11.2.5.

An operator may also need to consider the exposure concentration and time for other constituents in the CO2 fluid stream.

11.2.2 Release Volume Estimation

Accidental release rates from a CO2 pipeline primarily differ from a hydrocarbon pipeline because of the potential for phase changes within the flow expansion region.

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

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 CO2 stream over time,
- pipeline diameter, segment length, and topography,
- initiation time and estimated duration of release,
- temperature, pressure and chemical composition of the CO2 stream,
- heat transfer between the pipeline and the surrounding environment, and
- closing time of any inventory segregation valves (e.g. EFRD, block or check valves).

11.3 Emergency Preparedness and Response

The safety of life, property and the environment should be the primary goal of Emergency Response Plans (ERP) which will support preparedness and response especially accounting for the unique properties and risks associated with CO2. The plans shall include processes and procedures that address accidental releases, equipment failures, natural disasters and third-party encroachments. Guidance related to ERP development and maintenance is provided by:

- Carbon Dioxide (CO2) Emergency Response Tactical Guidance Document [112]
- API RP 1171, Section 10.4 Emergency Preparedness/Emergency Response
- API RP 1174, Recommended Practice for Onshore Hazardous Liquid Pipeline Emergency Preparedness and Response

The Carbon Dioxide Emergency Response Tactical Guidance Document [112], prepared by API and LEPA with input from the National Association of State Fire Marshals, provides best practice guidelines for preparedness and initial response to a release from a super critical CO2 pipeline. Existing training programs related to this document and emergency response planning is available and may prove useful in the development of plans. The guidance contains operational tools and references to assist in response to CO2 releases where guidance is given on the expressed hierarchy of priorities:

- People: safety of response personnel and the public;
- Environment: prevention of environmental, human health, and welfare effects;

- Assets: minimizing damage to structures and equipment; and
- Relations: keep customers, community, and federal, state, and local government agencies informed

API RP 1174 provides an outline of the minimum requirements for an ERP and is applicable to CO2 pipelines. Related information on public awareness and engagement is provided in Section 12.

11.3.1 Emergency Response Communication Plans

Operators shall conduct outreach and awareness along the pipeline's route. The release from a CO2 pipeline and desired response should be different than those for oil and gas pipelines. It is important to educate the stakeholders so that they will be more likely to identify a CO2 release and assist in enacting the proper response procedures.

Emergency response plans should be developed and maintained by operators with input from and communicated to emergency responders along the pipeline rights-of-way (ROWs). When developing a course of action with local emergency response officials, the following should be considered:

- The location of public gathering centers such as schools and hospitals and the ability to safely evacuate people from them
- visibility limitations caused by the dense vapor cloud and risk of driving or walking into the vapor cloud;
- Potential of internal combustion engine vehicles stalling or rendered inoperable in the presence of high concentration CO2 hampering egress from the site;
- effectiveness of sheltering in place, making sure people stay off the ground or move to an upper floor of a building and not into a basement or low area where CO2 may enter a building and collect;
- communicating with and educating emergency response personnel that may be stationed outside of the public awareness area but could ultimately respond to a release from the pipeline.
- consider local resources available providing electrically driven vehicles in low lying areas for evacuation if the CO2 cloud with dangerous concentrations of CO2 lingers for longer than an hour or a period of time defined to be significant through risk assessment.

Emergency response plans should be communicated and practiced through drills to prepare both pipeline operators and responders. The API / LEPA Carbon Dioxide Emergency Response Tactical Guidance Document suggests that although only applicable for oil pipelines, the National Preparedness and Response Exercise Program (PREP) Guidelines outline a drill and exercise program that can prove effective if adopted by CO2 pipeline operators, especially if it is used beyond the HCAs of the pipeline system. For CO2 pipelines the limits for communication, education and training should consider the PAA.

API RP 1174 provides a framework to enable continual improvement of pipeline emergency response. Similar or related training is available from industry associations. Additional resources are available from CDC/NIOSH in their Pocket Guide to Chemical Hazards.

Training and response plan communication should be renewed at least annually.

11.4 Venting Procedures

To support maintenance, it may be necessary or desirable to vent CO2 from the pipeline at a safe location. Venting CO2 to atmosphere to restore pressure levels within a pipeline is permissible, but the design (see Section 6.6) shall ensure that any venting does not lead to significantly higher exposure of individuals to adverse impacts, or significantly affect the environment. The venting scenario should be considered to evaluate CO2 phase changes and the CO2 plume dispersion process and its risks. A venting plan should be prepared to document and communicate procedures to be followed.

During controlled venting operations, the following procedure should be followed to safely vent the CO2 from the pipeline system [112]:

1) Select a location that will not affect the public (homes, roads, schools, etc.).
2) Avoid venting from locations near low areas such as creek crossings or heavily wooded areas, which prohibit the dispersion of CO2 into the atmosphere.
3) Select a location where an evacuation is practicable and can be accomplished. Combustion engines may not function when CO2 concentrations exceed a certain threshold.
4) Operators should notify appropriate local and state emergency officials to make them aware of the venting operation and to discuss any questions they may have regarding the event.
5) During venting operations, minimize personnel on-site to only essential personnel.
6) Station air monitors capable of detecting oxygen and carbon dioxide levels in the atmosphere at the venting site If short-term oxygen levels or CO2 concentrations become hazardous (Section 11.2.5), the venting shall cease and personnel at the venting site shall evacuate to fresh air immediately.
7) When CO2 is released from the pressurized pipeline into the atmosphere, the large associated pressure drop causes it to cool down dramatically (sub-freezing temperatures). Temperature should be monitored during venting operations and the venting procedure and equipment design shall minimize the formation of solid CO2 blockages in the valves, vent stack or pipeline.
8) Venting equipment, including valves, should be designed to operate in extreme cold conditions. Venting procedures should be designed to minimize the formation of solids in the pipeline, stack, or valves, and to remediate the effect of extreme cold temperatures on personnel or equipment.
9) Certain meteorological conditions (cool, humid, no wind) may limit the dispersion of CO2 during venting. Every effort should be made to avoid controlled venting operations during these periods. In addition, understanding wind direction and how it may cause the plume to migrate is important so that it is not blown into a public area by the wind.

As an alternative to venting, displacing CO2 with an inert medium such as nitrogen may be considered.

Recommended actions for unplanned releases should be considered in an emergency response plan discussed in Section 11.2 [112].

12 PUBLIC ENGAGEMENT AND AWARENESS

Carbon dioxide pipelines are widely perceived as a new asset class with unknown or unique hazards by many in the public. A lack of information or understanding may lead to unwarranted concern or inappropriate response to operational or upset conditions. For this reason, stakeholder engagement and awareness are essential to inform and educate stakeholders to the threats posed, safeguards employed, and desirable responses are essential to support CO2 pipeline systems. Recommended public engagement programs and processes are like those for hydrocarbon pipelines with the information presented being focused on CO2 pipeline systems.

NOTE US Department of Energy Best Practices for outreach and engagement for CCUS are available [113].

12.1 Public Awareness

Pipeline regulations generally provide requirements for public awareness, education and calls out API RP 1162. Similarly, the requirement for a damage prevention program is required in pipeline regulations and supporting resources are provided in the API Excavation Damage Prevention Toolbox [114]. These requirements include enhanced public awareness programs which may be considered applicable to CO2 pipeline systems because they are novel to stakeholders.

Public awareness programs provide safety information to stakeholders to promote community safety.

Establishing a public awareness program involves:

- Definition of program objectives

- Gathering management commitment and support
- Establishing program administration
- Identification of pipeline assets
- Identification of stakeholder audiences

An operating public awareness program will involve a continuous cycle of message development, delivery, program evaluation and update, as required to increase the awareness of pipeline safety with targeted stakeholders.

The awareness should consider stakeholders:

- Affected public – Residents, schools, farms, businesses and places of congregation near or adjacent to the pipeline system
- Emergency officials – local, city, county, state or regional officials and organizations with jurisdiction in the area on the pipeline
- Public officials - local, city, county, state, regional officials, federal and agencies with jurisdictions in the area on the pipeline
- Excavators – persons or companies normally engaged in excavation activities in areas in which pipelines are located.

12.2 Public Engagement

Resources to support public awareness are developed by individual pipeline operators and pipeline trade associations. API RP 1185 provides recommended practices for pipeline companies to build upon existing related programs or establish and implement new stakeholder engagement processes to make sure all stakeholders can engage in meaningful dialogue throughout a pipeline life cycle. Likewise, API RP 100-3 provides upstream oil and gas sector operators guidance on community engagement. Existing practices for hydrocarbon program engagement may be followed with specific attention paid to the unique characteristics of CO_2 pipelines which are perceived by the public to be novel. A public engagement program life cycle should include:

- Commitment and Alignment: Describes how operators, through their management, demonstrate the organization's commitment to stakeholder engagement.
- Identification, Understanding, and Confirmation: Describes stakeholders who should be the subject of engagement.
- Planning and Preparation: Describes how operators get ready for stakeholder engagement activities.
- Sharing Information: Describes what operators should share as part of baseline information.
- Asking, Listening, and Responding: Describes how operators should engage with stakeholders.
- Monitoring, Evaluation, and Adjustment: describes how operators should assess, document, verify, and improve stakeholder engagement performance.

Engagement program support information and tools are identified in API RP 1185.

The engagement process should involve the education of the public and can draw upon lessons learned from previous incidents to both describe the root cause of the incident and identify lessons learned. Failure investigations [116] are useful resources in the development of public engagement information and provide an opportunity to learn from past events. In this CO_2 pipeline failure event report identifies contributing factors providing industry opportunities for improvement related to:

- Improved understanding of the potential for pipeline damage due to changing climate, geohazards, and soil instability. This lesson suggests both education and practice enhancement related to geohazards.

- Specific integrity management program practices to address pipeline integrity threat identification and assessment for geohazards or preventative or mitigative measures. This lesson suggests integrity management program enhancement opportunities.
- Enhanced ROW surveillance to identify geohazards prior to failure. This lesson suggests enhancement opportunities for ROW surveillance.
- The CO2 dispersion model underestimated the potential affected area that could be impacted by a release. This lesson suggests enhancements in dispersion modelling and identification of potentially affected areas.
- Notification of local responders advising them of a potential failure. This lesson suggests enhancements in emergency response planning, education, and communication with third parties.

13 FACILITY INTEGRITY AND DELIVERY

13.1 Process Safety Considerations

The procedures employed to evaluate and manage hazardous liquid and gas facilities, identifying high-consequence area impact determinations; data integration; threat identification; risk assessment; inspection and reinspection; preventive and mitigative measures (P&MM); performance measures (API RP 1188) are applicable to CO2 facilities. Due consideration should be given to unique features of CO2 operations such as:

- Ground level focused gas dispersion support processes. This means that for safety one should have workers at the highest elevation with piping below them and facility venting below the piping,
- Solid CO2 formation, potentially causing blockages,
- Potential for accelerated corrosion in the presence of water and off-specification CO2 stream composition,
- Significance of pressure or flow interruptions and thermal loading. This may involve care in isolating or shutting in a line segment,
- Operational procedures for controlled pipeline CO2 filling, and
- Potential for erosion promoted wall thinning due to CO2 stream particulate content.
- Seasonal ground or ambient temperature fluctuation that may have a pronounced effect on CO2 volume, density or pressure shall be considered in the design or operation of rotating equipment (compressors/pumps), pressure monitors, relief system and pipes.

13.2 Control Philosophy

API produces a series of recommended practices in support of process control and control room management:

- API RP 1168: Pipeline Control Room Management – focused on pipeline system control best practices including: personnel roles, authorities and responsibilities; guidelines for shift turnover; pipeline control room fatigue management; and, pipeline control room management of change (MOC).
- API RP 554, Part 1: Process Control Systems, Part 1: Process Control Systems Functions and Functional Specification Development – focused on the basic functions that a PCS may need to perform, and recommended methodologies for determining the functional and integration requirements for a particular application.
- API RP 554, Part 2: Process Control Systems-Process Control System Design — focused on practices to select and design the installation for hardware and software required to meet the functional and integration requirements.

- API RP 554, Part 3: Process Control Systems-Project Execution and Process Control System Ownership — focused on project organization, skills, and management required to execute a process control project and then to own and operate a process control system.

At present process control system guidance documents provide frameworks and processes to support pipeline and facility control but are not developed specifically for CO2 systems, but rather for oil and gas applications. These guidance documents may be used to support CO2 system control with due consideration for issues such those listed in the preceding section.

13.3 Pipeline Security System

Facility and pipeline system security planning or risk assessment develop measures and procedures designed to mitigate risk and protect people, assets, operations, and company reputation from vandalism [117] [118]. Security plans for CO2 facility and pipeline security plan development may follow the same threat identification and risk mitigation processes as hydrocarbon pipelines with due consideration given to:

- Building ground level venting or open layout to allow CO2 dispersion,
- Multiple distributed fluid compression and composition detection facilities,
- Multiple laterals connecting to CO2 sources
- Identification of CO2 release potentially affected areas

APPENDIX A – SAMPLE CO2 SOURCE AND COMPOSITION DATA

(Informative)

A.1 CO2 Source Compositions

Since the pressure, temperature behavior, and corrosion potential of CO2 is related to its composition, the specification, measurement and control of constituent components is important in the design and operations of pipeline and related facilities. This section provides several examples of typical flue gas compositions for specific industrial applications. This information is approximate as the exact flue gas composition will depend on the industrial process details and feedstock material compositions, amongst other factors. The most common constituent components in a CO2 stream include O2, N2, Ar, H2O, SO2, H2, and CH4. This type of data is useful in considering issues such as:

- target CO2 composition specifications to control gas behavior,
- required flue gas cleaning processes and effectiveness;
- supporting pipeline internal corrosion rate estimation or cracking potential,
- CO2 detection and measurement equipment effectiveness,
- expected mixtures from independent sources and how they will affect the pipeline fluid stream composition.
- waterless corrosion in the presence of H2S, SOx, and NOx.

Pipeline standards such as ISO 27913 recognize that “the connection of new sources to an operating pipeline system could result in the CO2 stream no longer meeting the previous design specification and shall be subject to a design review to ensure that the changed composition is still appropriate for the pipeline design and operation.” This annex provides the constituent components of flue gases from example CO2 sources to consider the potential pipeline fluid constituent components.

In assembling the example flue gas constituent components listed in the sections that follow from EPA data [120], other industrial sources of CO2 were observed, including:

- Scrap tire processing,
- Carbon black primarily for natural and synthetic rubber manufacturing,
- Lime production,
- Chemical production, and
- Agricultural applications.

The data presented below represent industry averaged data reported to the US EPA and can be expected to change with time, as can be observed in some of the data that is presented as a time series. Other references related to typical CO2 stream compositions are available [121] [122].

A.2 Geologic CO2

Geologic (naturally occurring) CO2 fluids have traditionally contained non-condensable constituent components such as N2 and H2 and are free of corrosion producing components such as H2S, NOx, SOx, and O2. Relatively large amounts of water have therefore been carried in geologic CO2 pipelines. The main limitation is to limit the water content to prevent free water from forming when the pipeline is depressurized.

A.3 Cement Manufacturing

Portland cement accounts for 95 % of the hydraulic cement production in the United States as reported by the EPA. Portland cement consists of a mixture of raw materials that are mechanically and thermally processed. While the flue gas constituent components from the manufacturing process may vary, the primary flue gases include NOx, SO2, CO, and CO2. Table A.1 provides an estimate of the relative proportions of flue gases from a cement production process.

Table A.1—Summary of Flue Gas Factors and Relative Proportions for Portland Cement Kilns [123]

Component	Max. Flue Gas Content, kg/Mg	Relative Proportion of Composition
CO2	1100	99.04792 %
Total organic carbon	0.09	0.00810 %
CO	1.8	0.16208 %
NOx	3.7	0.33316 %
SOx	4.9	0.44121 %
HCl	0.073	0.00657 %
Acetone	0.0019	0.00002 %
Benzene	0.008	0.00072 %
Toluene	0.0001	0.00001 %
Chloromethane	0.00019	0.00002 %
Benzoic acid	1.80E-03	0.00016 %
Bis(2-ethylhexyl)phthalate	4.80E-05	0.00000 %
Phenol	5.50E-05	0.00000 %
Hg	1.10E-04	0.00001 %

A.4 Aluminum, Steel Manufacturing, and Other Metal Production and Thermal Mechanical Processes

Steel production can produce a range of flue gases throughout the production process and the composition depends on the composition of the materials involved. The steelmaking process was estimated by the EPA to produce flue gas constituent components from the blast furnace with compositions similar to that outlined in Table A.2. Carbon capture technology applied to the flue gas constituent components could be expected to produce flue gases similar to that of a power plant.

Table A.2—Steelmaking Flue Gas Composition [124]

Component	Relative Proportion of Composition
Nitrogen	60 %
CO	28 %
CO2	12 %

An EPA estimate of the flue gas composition (post carbon capture) from the production of metallurgical coke used in iron and steel industry processes, often co-located with iron and steel production facilities, is presented in Table A.3.

Table A.3— Flue Gas Factors and Relative Proportions of Combustion Stack Flue Gas from Coke Production [125]

Component	Flue Gas, kg/Mg	Relative Proportion of Composition
Extractable organic matter	0.012	0.00247 %
CO	0.34	0.07010 %

CO_2 (BFG)	482	99.37313 %
NO_x	0.82	0.16906 %
SO_x (DCOG)	1.47	0.30307 %
HCl (DCOG)	0.013	0.00268 %
Total organic compounds	0.19	0.03917 %
Methane (CH_4)	0.1	0.02062 %
Ethane	0.005	0.00103 %
Acetone	0.0295	0.00608 %
VOC	0.047	0.00969 %
Benzene	0.0075	0.00155 %
Toluene	0.0033	0.00068 %
Chloromethane	0.0032	0.00066 %
Benzoic acid	4.14E-05	0.00001 %
Bis(2-ethylhexyl)phthalate	3.40E-06	0.00000 %
Diethyl phtalate	9.90E-06	0.00000 %
2,4-Dimethylphenol	4.17E-06	0.00000 %
Phenol	2.56E-06	0.00000 %
BFG = Blast furnace gas. DCOG = Desulfurized coke oven gas. VOC = Volatile organic compound.		

A.5 Ethanol Production

Flue gas constituent components from corn ethanol production facilities reported under the EPA Greenhouse Gas Reporting Program are presented in Table A.4 for the years 2010 to 2014. Refinery flue gas constituent components are primarily from on-site fuel combustion from both fossil and biogenic fuel sources.

Table A.4—Flue Gas Constituent Components from Corn Ethanol Production Facilities [126]

Component	**Flue Gas (metric tons CO_2e) [Relative Proportion of Composition]**				
	2010	**2011**	**2012**	**2013**	**2014**
CO_2	17,600,254 [99.4 %]	18,151,600 [99.8 %]	17,182,627 [99.0 %]	17,063,166 [99.8 %]	18,265,090 [99.7 %]
CH_4	17,450 [0.1 %]	14,689 [0.1 %]	17,771 [0.1 %]	11,866 [0.1 %]	20,801 [0.1 %]
N_2O	80,960 [0.5 %]	20,182 [0.1 %]	159,205 [0.9 %]	17,166 [0.1 %]	27,561 [0.2 %]
Total	17,698,648	18,186,453	17,359,574	17,092,175	18,313,426

A.6 Hydrogen Production

Hydrogen production flue gas constituent components are generated from fuel combustion, sorbent use, carbonate use, and other industrial processes. Table A.5 provides EPA reported estimates of flue gas constituent components from hydrogen production. The tabulated data does not include the potential hydrogen constituent in the reported data.

Table A.5—Hydrogen Production Reported Flue Gas Components [127]

Component	Flue Gas (Million Metric Tons CO_2e) [Relative Proportion of Composition]										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CO_2	37.5 [99.7 %]	40.1 [99.8 %]	42.0 [99.8 %]	44.3 [99.8 %]	43.7 [99.8 %]	44.5 [99.8 %]	45.6 [99.8 %]	45.4 [99.8 %]	44.1 [99.8 %]	41.3 [99.8 %]	41.4 [99.8 %]
CH_4	<0.05 [<0.2 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]
N_2O	<0.05 [<0.2 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]	<0.05 [<0.1 %]

A.7 Power Production

Flue gas derived from combustion of carbon-rich fuel such as coal, may contain SO_x, NO_x, several different low molecular weight hydrocarbons, carbon monoxide (CO), and mercury, and concentrations of these fluid components may vary greatly. Table A.6 provides an estimate of the relative proportions of flue gas constituent components from a coal power plant.

Table A.6—Relative Concentrations of Coal Power Plant Flue Gas Components in a Separated CO_2 Stream [modified from [128] [129]

Component	Relative Proportions in Flue Gas (by volume)	Relative Proportions in Separated CO_2 Stream Without Wet Flue Gas Desulfurization Scrubber (by weight) (a)	Relative Proportions in Separated CO_2 Stream with Wet Flue Gas Desulfurization Scrubber (by weight) (a)	Relative Proportions in Separated CO_2 Stream with Low NO_x Burners, Selective Catalytic Reduction, and Wet Flue Gas Desulfurization Scrubber (%[w]) (a)	Estimated Concentrations in Separated CO_2 Stream, Assuming Amine Adsorption (b) (by volume
CO_2	13.5 %	97.45 %	99.8 %	99.8 %	93.2 %
SO_2	0.016 %	2.3 %	0.12575 %	0.12575 %	Trace
SO_3	0.00325 %	0.0295 %	0.01535 %	0.01535 %	Trace
N_2	74.7 %	-	-	-	0.17 %
NO_2	0.0025 %	0.00585 %	0.0046 %	0.00185 %	-
NO_x	0.06 %	-	-	-	Trace
HCl	0.00525 %	0.0422 %	0.000575 %	0.000575 %	
O_2	4 %	-	-	-	0.01 %
H_2O	7.7 %	-	-	-	6.5 %
Hydrocarbons	Trace(b)	-	-	-	Trace(b)
Metals	Trace(b)	-	-	-	Trace(b)
Hg^{2+}	Trace	0.0000142 %	0.00000145 %	0.00000145 %	-

Flue gas derived from combustion of natural gas in power production, or ither industrial heat/steam production application can vary due to the composition of the natural gas. The flue gas constituent components from natural gas-fired boilers and furnaces were observed by EPA to include NO_x, CO, CO_2, CH_4, N_2O, VOCs, trace amounts of SO_2, and particulate matter. Control techniques (both during and after combustion) are used to reduce these flue gases (particularly NOx). An EPA estimate of the flue gas factors, in lb/million standard cubic feet (scf) of natural gas fired, are summarized in Table A.7.

Table A.7— Flue Gas Factors and Relative Proportions from Natural Gas Combustion [130]

Component	Maximum Flue Gas, lbs/10^6 scf	Relative Proportion of Composition
CO2	120,000	99.7 %
CO	98	0.0814 %
N2O	2.2	0.00183 %
SO2	0.6	0.0005 %
NOx	280	0.233 %
CH4	2.3	0.00191 %
VOC	5.5	0.00457 %
TOC	11	0.00914 %
Lead	0.0005	0.00000 %

A.8 Petroleum Refining and Petrochemical Manufacturing

Flue gas constituent components reported by refineries to the EPA are shown in Table A.8.

Table A.8—Petroleum Refineries Sector: Annual Flue Gas by Reported Component [130]

Component	Flue Gas (Million Metric Tons CO2e) [Relative Proportion of Composition]										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Carbon Dioxide	176.8 [99.2 %]	171.3 [99.2 %]	173.0 [99.3 %]	174.0 [99.3 %]	175.6 [99.3 %]	179.6 [99.3 %]	177.6 [99.3 %]	180.8 [99.2 %]	176.3 [99.2 %]	159.6 [99.3 %]	163.6 [99.2 %]
Methane	0.9 [0.5 %]	0.8 [0.5 %]	0.8 [0.5%]	0.8 [0.5 %]	0.8 [0.5 %]	0.8 [0.4 %]	0.8 [0.4 %]	0.9 [0.5 %]	0.9 [0.5 %]	0.8 [0.5 %]	0.8 [0.5 %]
Nitrous Oxide	0.5 [0.3 %]	0.5 [0.3 %]	0.5 [0.3 %]	0.5 [0.3 %]	0.5 [0.3 %]	0.5 [0.3 %]	0.5 [0.3 %]	0.5 [0.3 %]	0.5 [0.3 %]	0.4 [0.2 %]	0.5 [0.3 %]

Additional data is available from alternate sources [131].

A.9 Waste Incineration

Combustion is used to manage 7 % to 19 % of solid waste generated in the United States and as expected the range of materials included in the waste stream is variable. This EPA data includes all municipal solid waste including scrap tires, but not hazardous waste materials. The combustion of MSW tends to occur at waste-to-energy facilities or industrial facilities and is estimated by the EPA to produce flue gas constituent components similar to those presented in Table A.9.

Table A.9--CO2, CH4, and N2O Flue Gases from the Combustion of Waste [132]

Component	Flue Gas (Million Metric Tons CO2e) [Relative Proportion of Composition]						
	1990	2005	2017	2018	2019	2020	2021
CO2	12.9 [97.0 %]	13.3 [97.8 %]	13.2 [97.8 %]	13.3 [97.1 %]	12.9 [97.0 %]	12.9 [97.0 %]	12.5 [97.7 %]
CH4	+	+	+	+	+	+	+
N2O	0.4 [3.0 %]	0.3 [2.2 %]	0.4 [3.0 %]	0.4 [2.9 %]	0.4 [3.0 %]	0.3 [2.3 %]	0.4 [3.1 %]
Total	13.3	13.6	13.5	13.7	13.3	13.3	12.8

+ Does not exceed 0.05 MMT CO_2 Eq.

NOTE Totals may not sum due to independent rounding

A.10 Natural Gas Processing and Treating

Field separators at the wellhead are typically used to remove hydrocarbon condensate and water, however, other fluid constituent components remain in the gas including principally CO_2 and H_2S, that are removed before gas separated gas use in a “sweetening” process.

Most gas processing plants employ elevated smokeless flares or tail gas incinerators for complete combustion of waste gas constituents, including virtually 100 % conversion of the H_2S to SO_2. The EPA estimated flue gas constituent components from various stages of gas processing and transportation are presented in Table A.10.

Table A.10—Gas Processing Flue Gas Composition [132]

Activity	Flue Gas (Million Metric Tons CO_2e) [Relative Proportion of Composition]		
	CH_4	**CO_2**	**N_2O**
Exploration	0.2 [3.2 %]	-	6 [96.8 %]
Production	94.1 [3.3 %]	9.1 [0.3 %]	2,779 [96.4 %]
Processing	14.3 [0.3 %]	26.1 [0.6 %]	4,300 [99.1%]
Transmission and Storage	44.5 [9.5 %]	0.9 [0.2 %]	422 [90.3 %]
Distribution	15.3 [100 %]	-	-
Post Meter	13.0 [100 %]	-	-
Total	181.4 [2.3 %]	36.2 [0.5 %]	7,649 [97.2 %]

A.11 Petroleum Systems

During oil exploration, production, transportation, and refining operations, CH_4 is released to the atmosphere from leaks, venting (including from operational upsets), and flaring. The gas constituent components estimated for this category by EPA are presented in Table A.11.

Table A.11—Gas Constituent Components from Petroleum Systems – Reported for 2021 [132]

Activity	Flue Gas (Million Metric Tons CO_2e) [Relative Proportion of Composition]		
	CH_4	**CO_2**	**NO_2**
Exploration	0.2 [0.1 %]	0.5 [0.2 %]	219 [99.7 %]
Production	48.9 [0.5 %]	20.0 [0.2 %]	10,539 [99.4 %]
Crude Oil Transportation	0.2 [100 %]	<0.0 [-]	--
Crude Refining	0.8 [1.7 %]	4.2 [9 %]	41.8 [89.3 %]

APPENDIX B

CO2 PROPERTIES AND BEHAVIOR

(Informative)

B.1 General

This annex is presented to provide an understanding of the properties of CO2 fluids and terminology. This background information is essential because of the unique behavior of CO2 when compared to hydrocarbon fluids commonly considered in pipeline applications. These behaviors change as the composition of the fluid that is predominantly CO2 includes other components, such as NOx, SOx, O2, H2O, which may be byproducts of a combustion process. Throughout the document, a fluid that is predominantly CO2 mixed with other components is referred to as CO2. When the document deals with a fluid that is 100 % CO2 it is referred to as pure CO2.

B.2 Terminology

CO2 has unusual properties, and clearly defined terminology is needed to successfully describe its behavior at pipeline operating conditions. Figure B.1 shows a typical phase diagram for pure CO2 on a pressure-temperature graph.

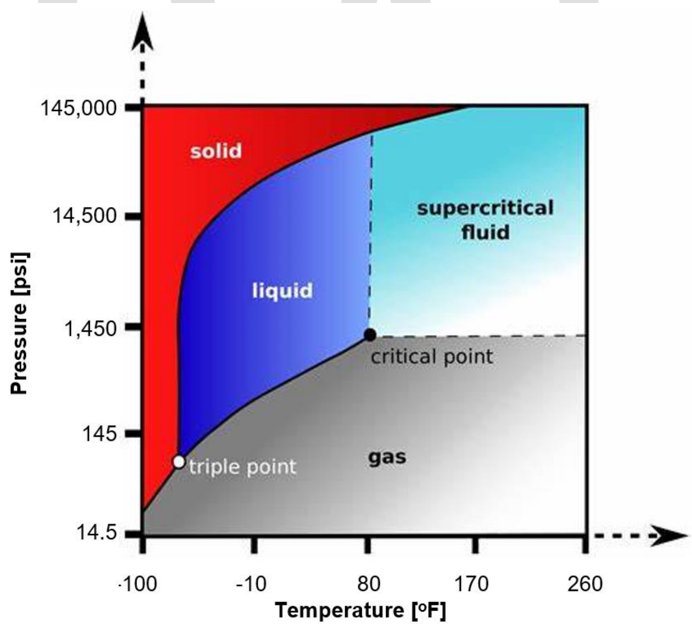

Figure B.1—Standard Phase Diagram for pure CO2

A key aspect of this phase diagram is that CO2 in the "gas" region can be compressed into the "supercritical" region and then cooled into the "liquid" region without undergoing a phase change or displaying any discontinuity in its properties. In other words, the regions labelled "gas", "supercritical" and "liquid" are all part of a continuously changing material behavior. Another notable feature is that CO2 in the "liquid" region is not a true liquid. It is dense like a liquid, but behaves like a gas in that it generally:

- has no free surface,
- is compressible,
- expands to completely fill its container, and
- does not remain as a liquid if it is released into the atmosphere.

Figure B.2 is a pressure-temperature diagram for a fluid consisting of 95 % CO2 and 5 % other constituents by volume. Unlike Figure B.1, where the two-phase region is depicted as a one-dimensional line, Figure B.2 shows the two-phase region expanding into a visible two-dimensional area.

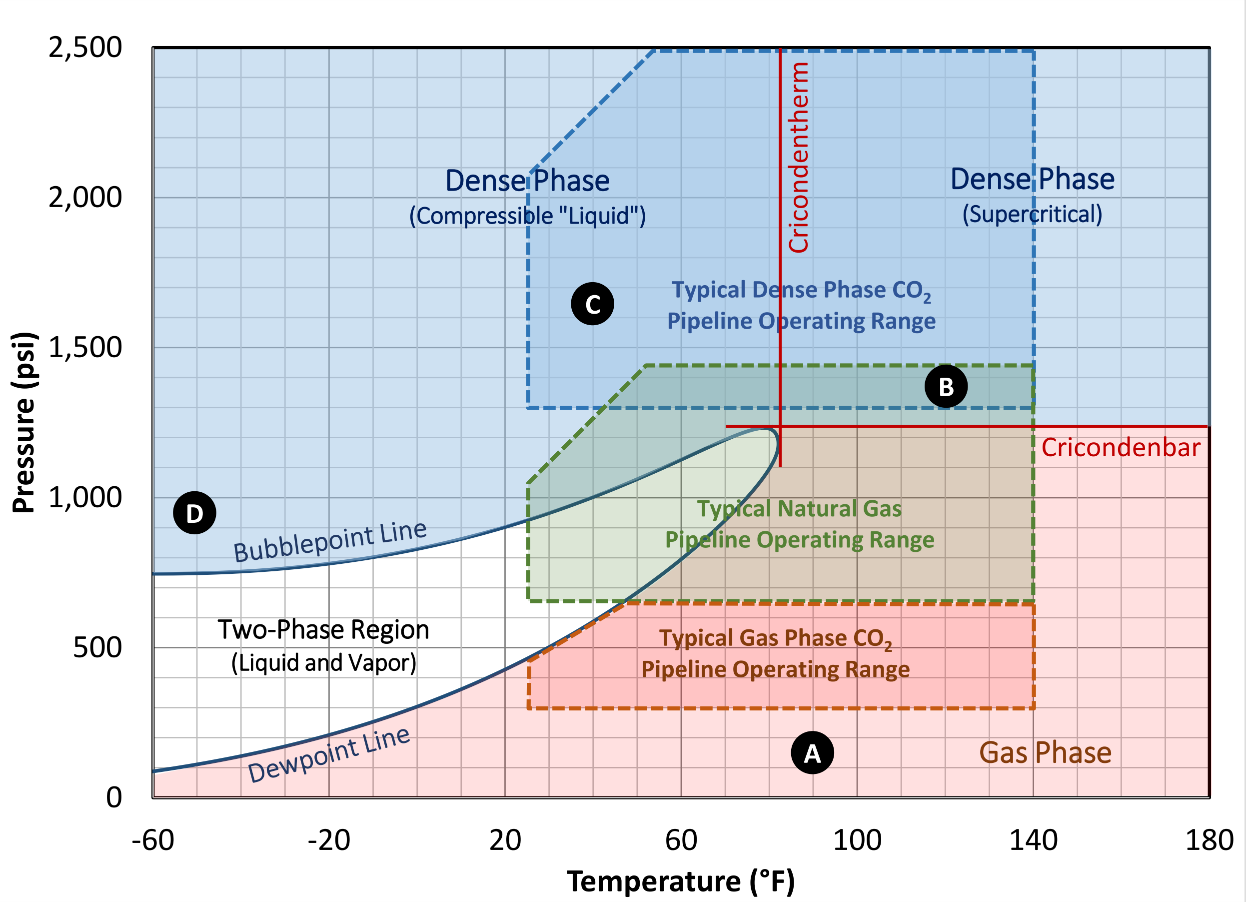

Figure B.2—Phase Behavior of CO2 with 5 % other Constituents[1]

Figure B.2 demonstrates how the two-phase region of CO2 cuts across the typical operating range of natural gas pipelines, effectively splitting it into two distinct operating zones. This intersection forces CO2 pipelines to operate either at higher pressures above the Two-Phase region or at lower pressures below it.

Figure B.2 identifies the path that can be taken from Point A in the gas phase to Point B in the dense phase supercritical region. Transition from Point B to Point C in the dense phase, and finally to Point D in the 'Liquid' Phase, all without entering the two-phase region and without changing phase. As a result, the entire region outside the two-phase envelope represents a fluid that retains its gas-like property of completely filling its container with no free surface, while its density steadily increases along the path from Point A to Point D.

Because fluids in the region above the phase boundary have properties that sometimes resemble a gas, a liquid, or neither, it causes confusion to describe them as either a liquid or a supercritical fluid. It is more informative to refer to them as "dense phase" fluids [8] to reduce misunderstandings about the properties of fluids above the two-phase region.

1

When designing, maintaining, or operating CO2 pipelines, it can be misleading to use imprecise terms like 'liquid' and 'supercritical'. Instead, use one of three distinct terms relevant to the specific part of the CCUS system being designed or operated:

- Gas phase pipeline operating range — Carbon capture, initial compression, gas phase pipeline transportation, dispersion.
- Dense phase pipeline operating range — Includes liquid phase and supercritical phase above the two-phase region, suitable for long-distance CO2 transmission by pipeline.

The behavior of CO2 is explored and compared with those of an ideal gas and natural gas in this section to illustrate some differences that should be considered in design, maintenance and operations of pipeline systems. The sensitivity of the CO2 phase diagram to fluid constituent components is also explored. The Benedict–Webb–Rubin–Starling (BWRS) equation of state [28] with Han's generalized correlation [133] has been used to support the comparisons presented in the two sections that follow. Other EOS formulations may be used and would provide similar results.

B.3 Compressibility of CO2 at a Constant Temperature

The density of CO2 is far more sensitive to changes in pressure and temperature compared with natural gas, which the oil and gas pipeline industry has worked with for many years and has acquired much experience. This sensitivity can cause dense phase CO2 pipelines to exhibit unusual flow characteristics that are not observed in hydrocarbon pipelines when there are variations in operating conditions due to factors such as seasonal temperature fluctuations, changes in flow rates, and operational upsets. Therefore, the sensitivity of CO2 should be considered in the configuration and operation of assets such as compressors/pumps, pressure relief systems, and line pipe.

The compressibility of a fluid, at any given pressure and temperature, is defined here as the change in density ($\Delta\rho$) divided by the change in pressure (ΔP) at constant temperature (T). Since the compressibility of an ideal gas at constant temperature is M_W/RT, the compressibility of a real gas compared to that of an ideal gas can be found by dividing its compressibility by M_W/RT. The Compressibility Ratio, defined as the ratio of the compressibility of a real gas compared to an ideal gas with the same molecular weight, is therefore equal to $(\Delta\rho/\Delta P)_T/(M_W/RT)$.

Figures B.3 and B.4 are two graphs that allow the compressibility ratio of lean natural gas to be compared with the compressibility ratio of CO2:

- Figure B.3 shows the maximum value of the compressibility ratio of lean natural gas is equal to 1.9 at approximately 1300 psi and 0 ˚F, meaning it is only 1.9 times more compressible than an ideal gas at that pressure and temperature.
- Figure B.4 shows that the maximum value of the compressibility ratio of CO2 is equal to 12 at approximately 1100 psi and 80 ˚F, meaning it is more than 12 times more compressible than an ideal gas at that pressure and temperature.

Note that some of the curves in the graph of Figure B.4 are discontinuous where they pass through the two-phase region because compressibility has not been evaluated in that region.

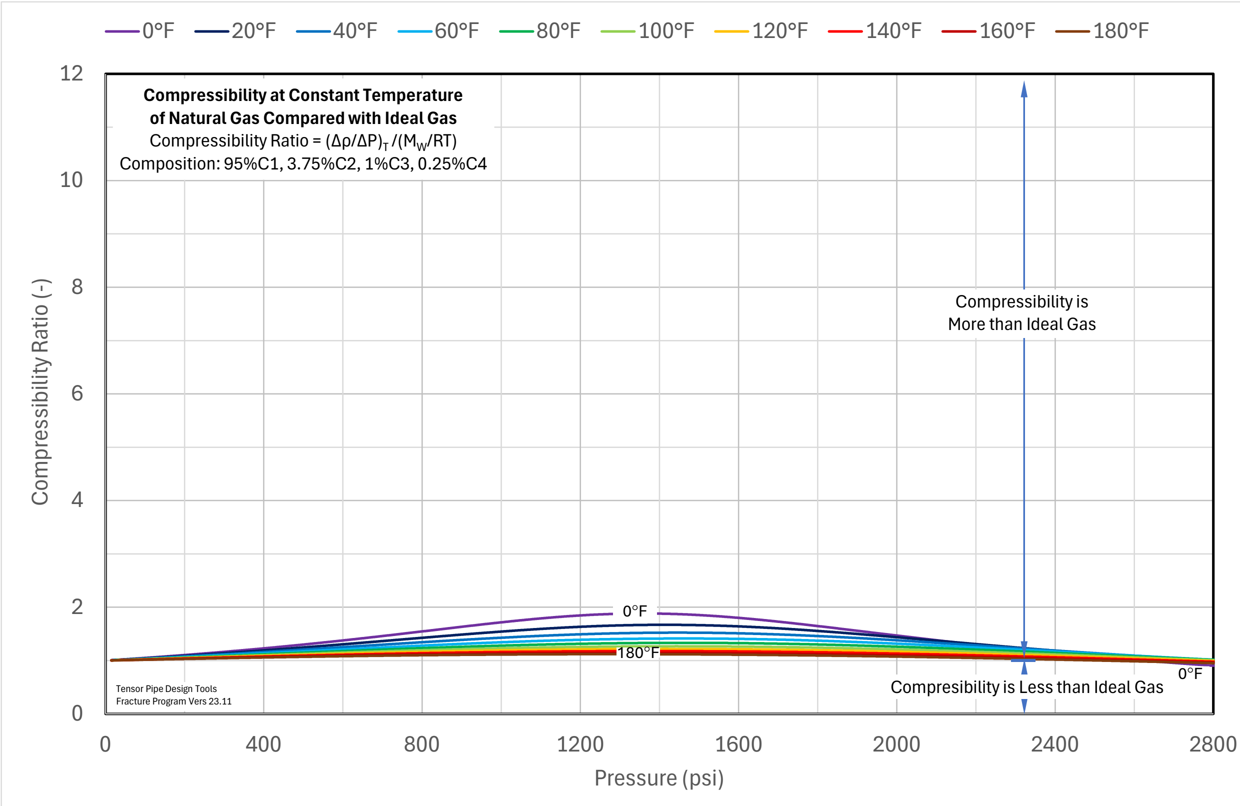

Figure B.3—Illustration of Lean Natural Gas Compressibility at Constant Temperature relative to that of an Ideal Gas

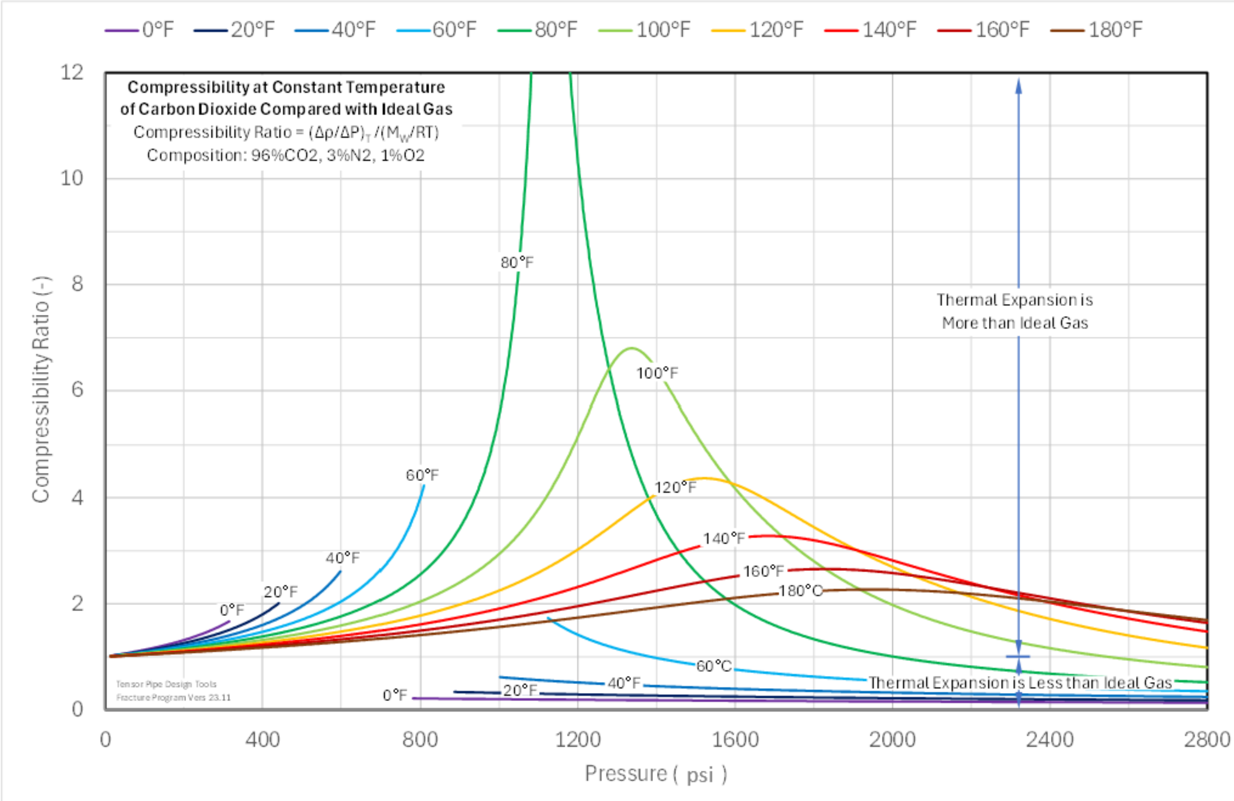

Figure B.4—Illustration of CO_2 Compressibility at Constant Temperature compared celative to that of an Ideal Gas

Figure B.3 illustrates how the density of natural gas is only marginally more responsive to pressure changes than an ideal gas, whereas the density of dense phase CO_2 can be over ten times more responsive to pressure variations. This contradicts the notion that dense phase CO_2 is a liquid and is therefore incompressible. This “gaseous” property of the dense phase is considered when designing and operating CO_2 pipelines (see section 4.XXX).

Figures B.5 and B.6 show the same information as Figures B.3 and B.4 but display it as contour lines of constant compressibility ratio on a pressure-temperature diagram, making it easier to visualize the operating conditions where the density of the natural gas and CO_2 are most sensitive to changes in pressure.

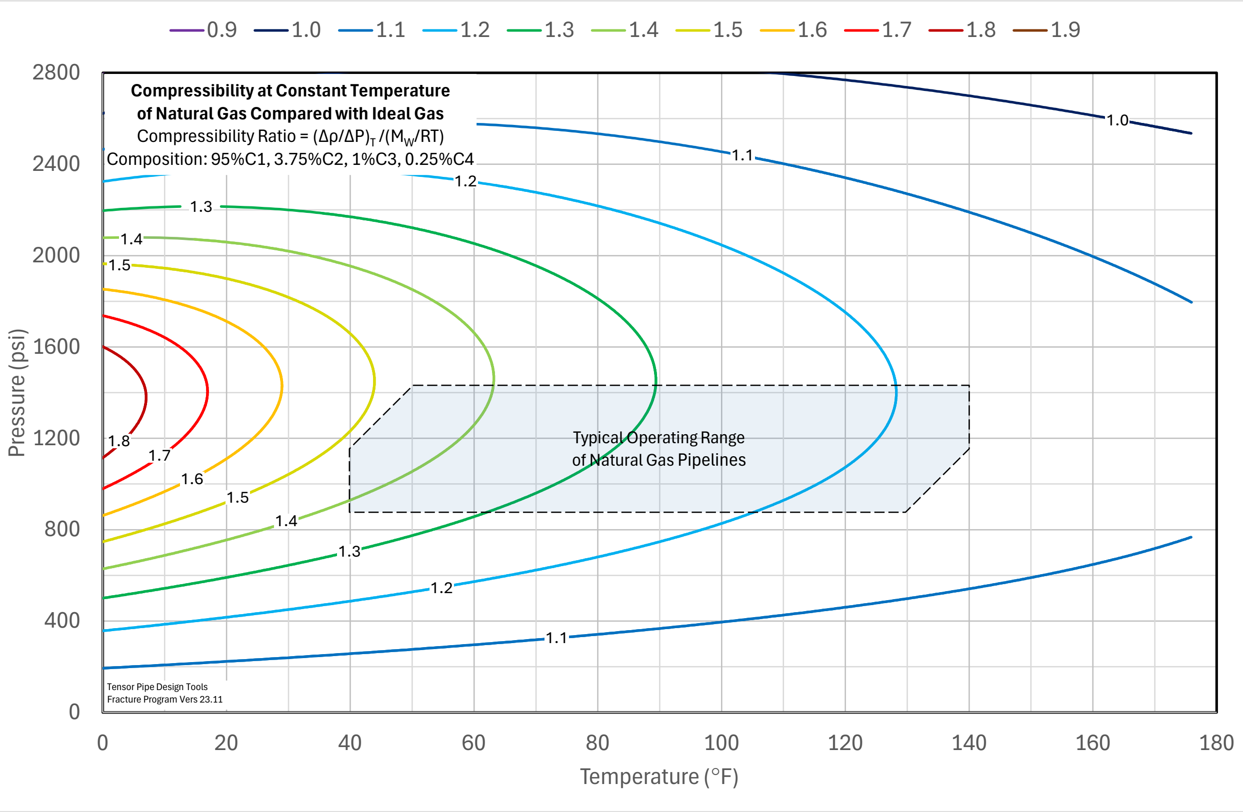

Figure B.5—Illustration of Lean Natural Gas Compressibility at Constant Temperature relative to that of an Ideal Gas

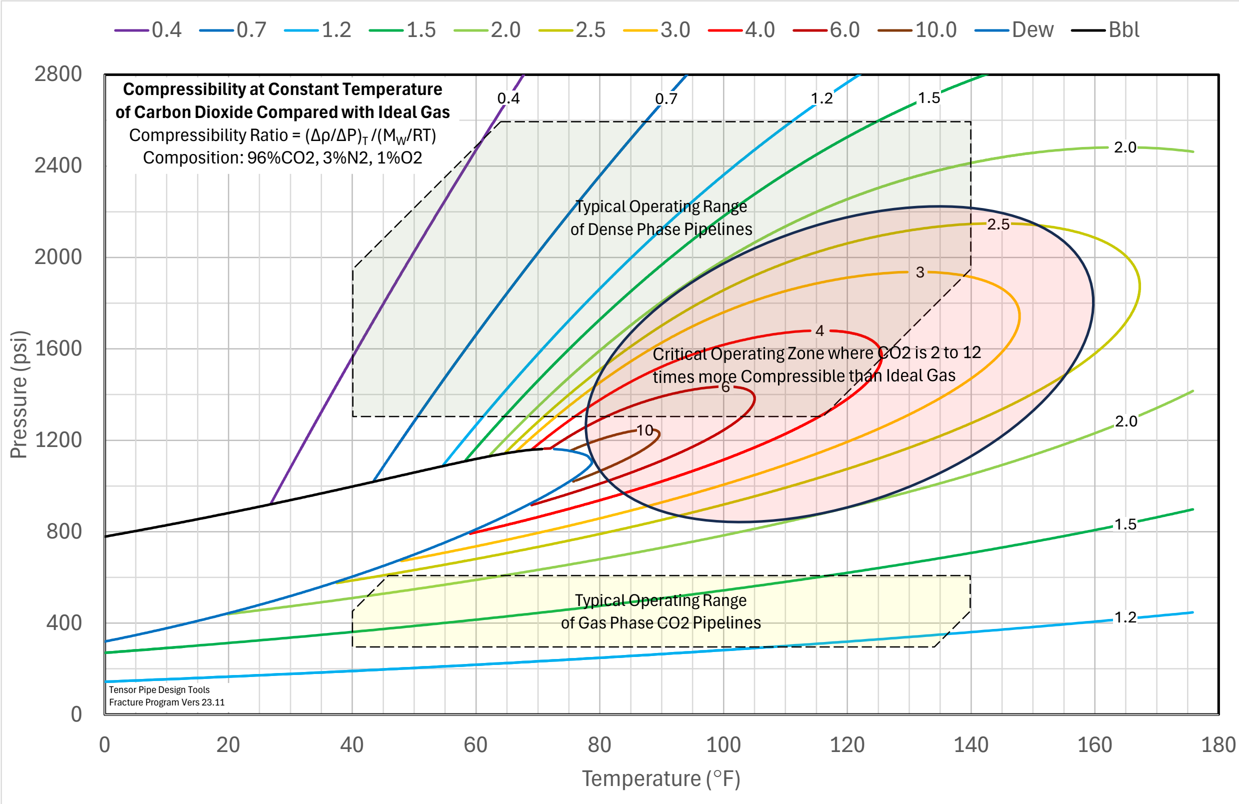

Figure B.6—Illustration of CO2 at Constant Temperature relative to that of an Ideal Gas

In Figure B.5, for lean natural gas, the light blue area indicates the typical operating range of natural gas pipelines. In Figure B.6 for CO2, the green and yellow areas indicate typical operating ranges for dense phase and gas phase CO2 pipelines, respectively. The red area in Figure B.6 highlights the range of operating conditions where CO2 is more than 2 times as compressible as an ideal gas.

The two graphs in Figures B.5 and B.6 depict distinctly different patterns of response of density to pressure changes at a constant temperature. Figure B.5, representing lean natural gas, shows that within the typical operating range of natural gas pipelines, the compressibility ratio of lean natural gas:

- Ranges from approximately 1.2 to 1.5.
- Falls within the range that the pipeline industry has wide experience with.

The Figure B.6 graph for CO2 shows that, over the typical operating range of gas phase CO2 pipelines, the compressibility ratio:

- Varies from 1.2 to 2 over the typical operating range of gas phase CO2 pipelines
- Is slightly higher than that for natural gas pipelines but is not high enough to cause operating problems that cannot be handled with existing gas hydrocarbon technology and experience.

Figure B.6 shows that within the typical operating range of dense phase CO2 pipelines, the compressibility ratio of CO2:

- Ranges from approximately 0.4 to 10.
- Falls outside the range of fluid behaviors the natural pipeline industry has wide experience with, particularly in the critical operating zone highlighted in red.

B.4 Thermal Expansion of CO2 at a Constant Pressure

The thermal expansion of a fluid, at any given pressure and temperature, is defined here as the change in specific volume (ΔV) divided by the change in temperature (ΔT) at constant pressure (P). Since thermal expansion of an ideal gas at constant temperature is M_W/RT, the compressibility of a real gas compared to that of an ideal gas can be found by dividing its compressibility by R/M_WP. The ratio of the thermal expansion of a real gas compared to an ideal gas with the same molecular weight, the thermal expansion ratio, is therefore equal to $(\Delta V/\Delta T)_P/(R/M_WP)$.

Figures B.7 and B.8 allow the thermal expansion ratio of lean natural gas to be compared with the compressibility ratio of CO2:

- Figure B.7 for lean natural gas, shows the maximum value of the thermal expansion ratio of lean natural gas over the full range displayed on the graph equal to 1.9 at approximately 1300 psi and −4 °F, meaning it is only 1.9 times more compressible than an ideal gas at that pressure and temperature.
- Figure B.8 shows that the maximum value of the thermal expansion ratio of CO2 is equal to 12 at approximately 1160 psi and 86 ˚F, meaning it is 12 times more compressible than an ideal gas at that pressure and temperature.

Some of the curves in the Figure B.6 graph are discontinuous where they pass through the two-phase region because thermal expansion has not been evaluated in that region.

Figure B.7 shows that the specific volume of natural gas is not much more sensitive to temperature changes at constant pressure than an ideal gas. In contrast, the specific volume of dense phase CO2 is highly sensitive to temperature variations compared with an ideal gas. This distinctive behavior of dense phase CO2, which differs from both liquids and gases, highlights the importance of considering its unique properties in the design, operation, and maintenance of CO2 pipelines.

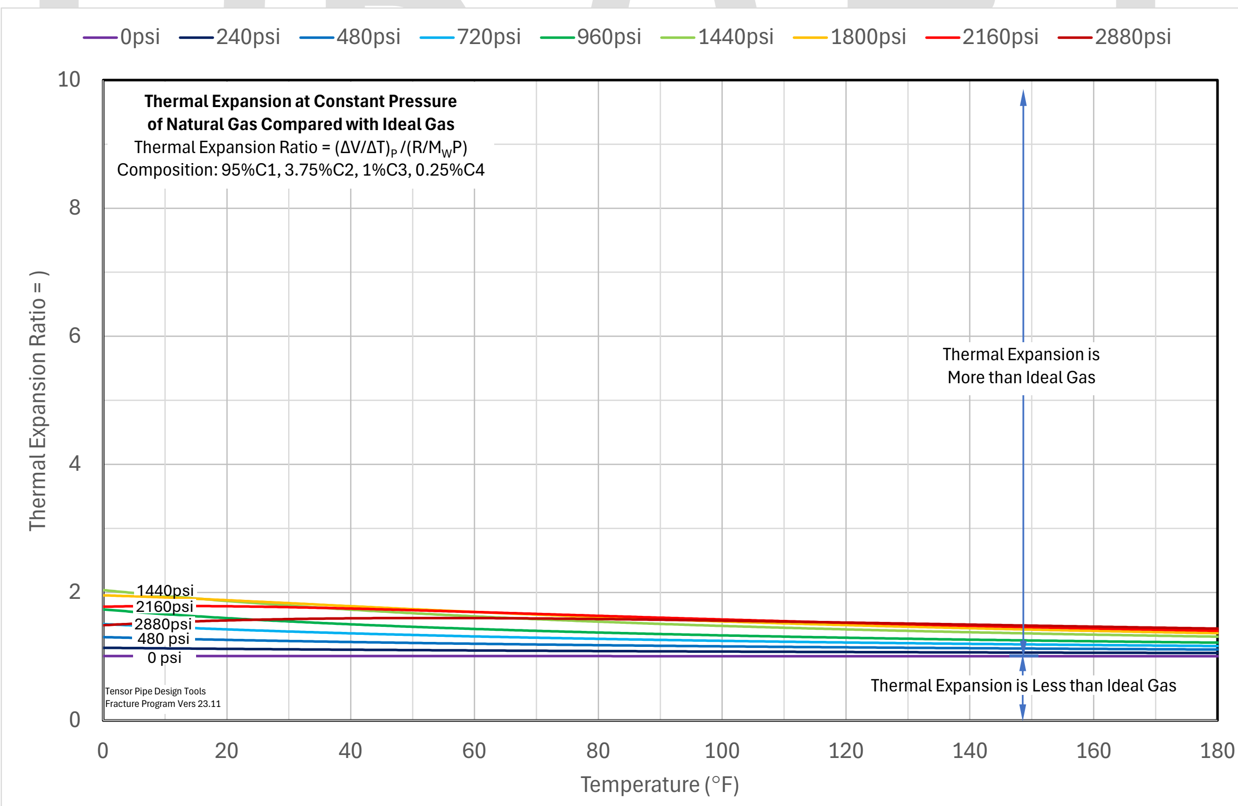

Figure B.7—Illustration of Lean Natural Gas Thermal Expansion at Constant Pressure relative to that of an Ideal Gas

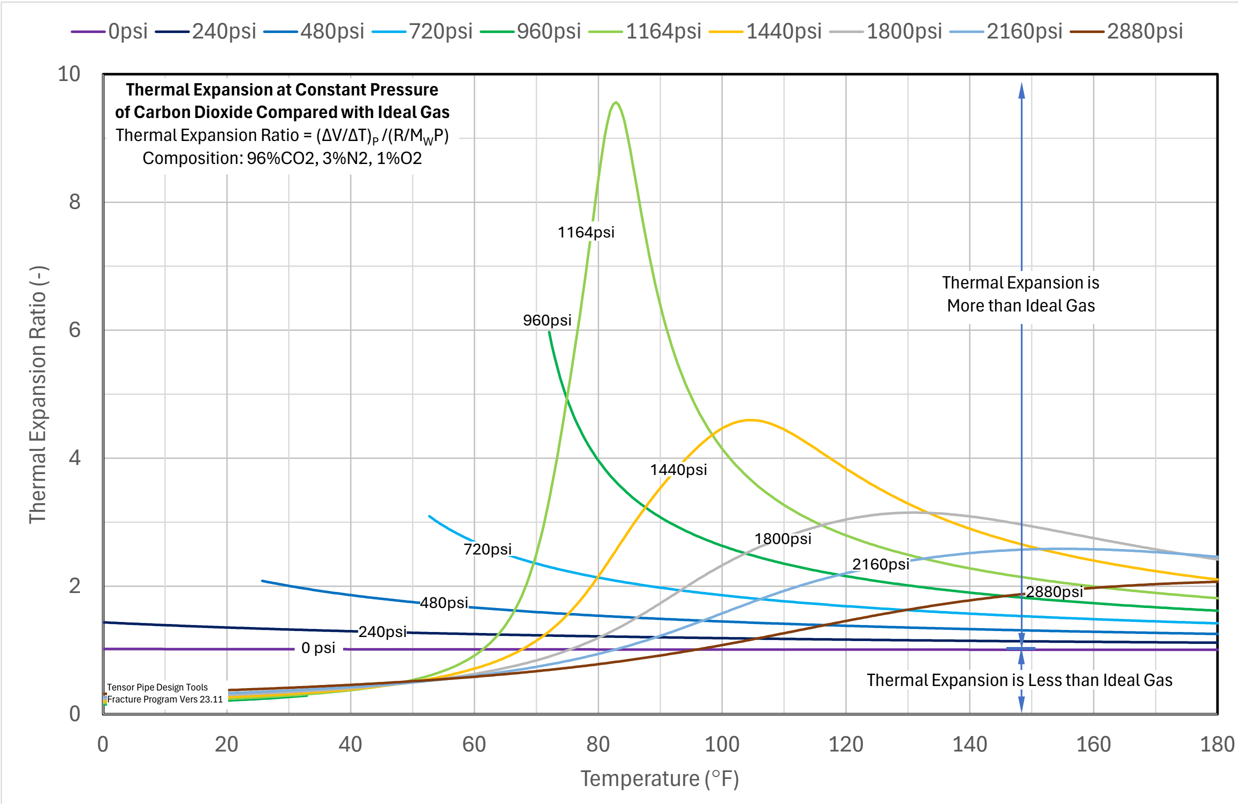

Figure B.8—Illustration of CO2 Thermal Expansion at Constant Pressure relative to that of an Ideal Gas

Figures B.9 and B.10 show the same information as Figures B.7 and B.8 but display it as contour lines of constant thermal expansion ratio on pressure-temperature axes, making it easier to visualize the operating conditions where the specific volume of natural gas and CO_2 is most sensitive to changes in temperature.

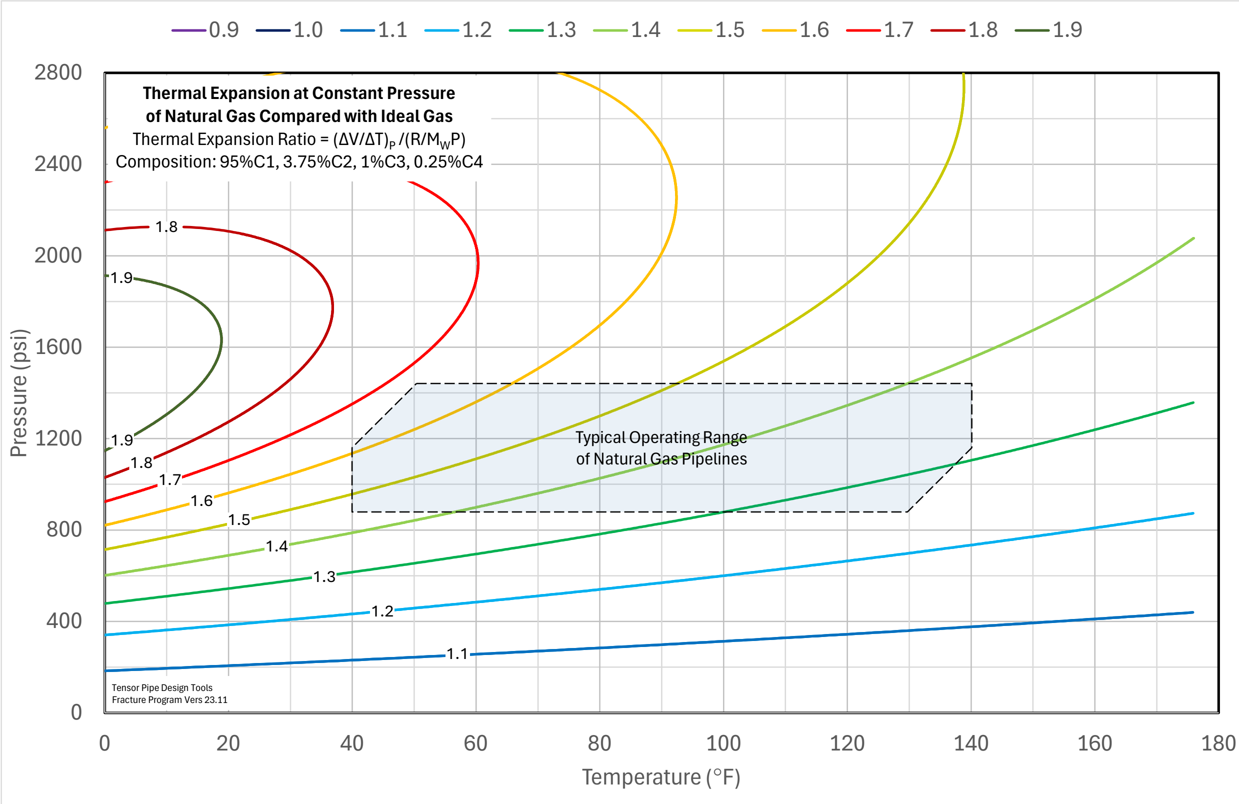

Figure B.9—Comparison of Lean Natural Gas Thermal Expansion at Constant Pressure compared to an Ideal Gas

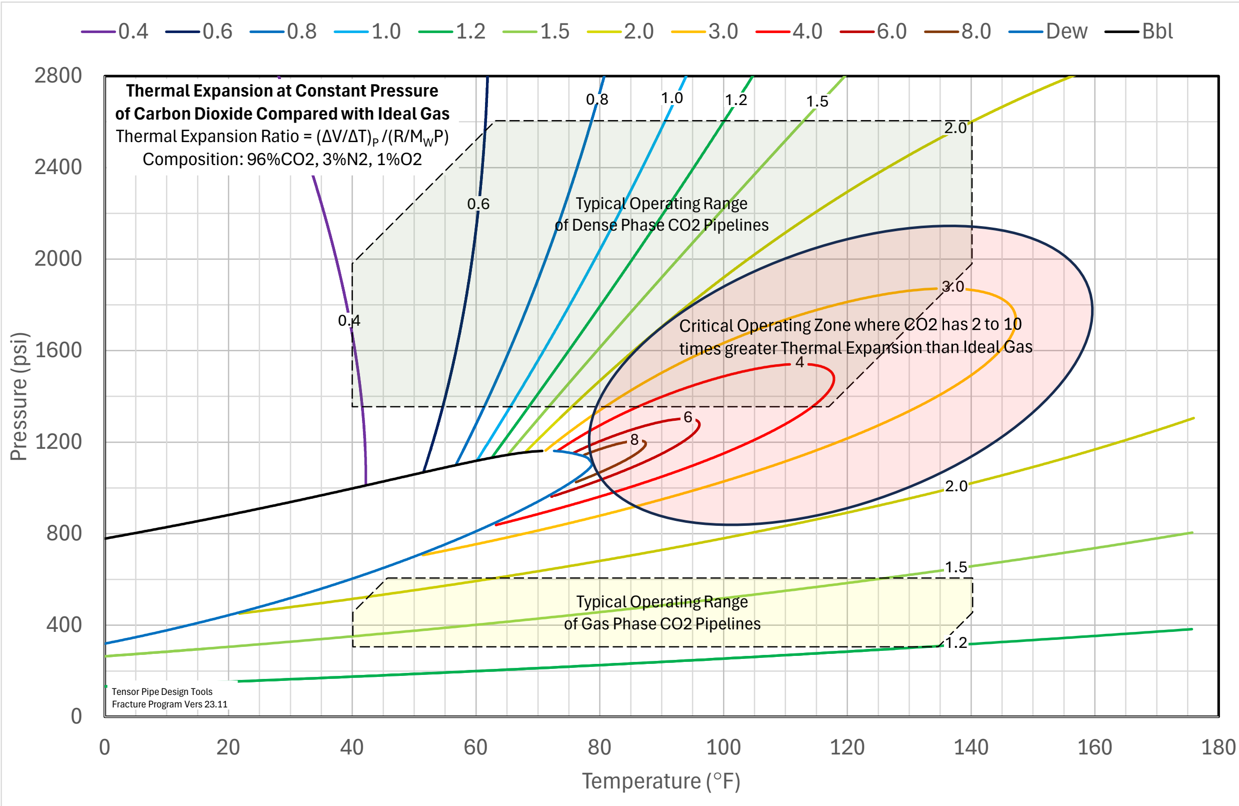

Figure B.10—Comparison of CO2 Thermal Expansion at constant pressure compared to an Ideal Gas

In Figure B.9 for lean natural gas, the light blue area indicates the typical operating range of natural gas pipelines. In Figure B.10 for CO2, the green and yellow areas indicate typical operating ranges for dense phase and gas phase CO2 pipelines respectively. The red area in Figure B.10 highlights the range of operating conditions where CO2 expands more than 2 times as much as an ideal gas when its temperature changes.

The two graphs in Figures B.9 and B.10 depict distinctly different patterns of the sensitivity of specific volume to changes in temperature at constant pressure. Figure B.9 for lean natural gas, shows that the thermal expansion ratio of lean natural gas:

- Varies from about 1.3 to 1.7 over the typical operating range of natural gas pipelines.
- Is in the range that the natural gas pipeline industry has wide experience handling

Figure B.10 for CO2, shows that, over the typical operating range of gas phase CO2 pipelines, the thermal expansion ratio:

- Varies from 1.2 to 2 over the typical operating range of gas phase CO2 pipelines,
- Is slightly higher than for natural gas pipelines but might not be high enough to cause unusual operating problems.

Figure B.10 shows that, over the typical operating range of dense phase CO2 pipelines, the thermal expansion ratio of CO2:

- Varies from 0.4 to 6.
- Falls outside the range of fluid behaviors the pipeline industry has experience with, at pressures below 2160 psi and temperatures above 80 ˚F in the Critical Operating Zone highlighted in red.

B.5 Relationship Between CO2 Density, Pressure and Temperature

Figure B.11 depicts how the density of 95 % pure CO2 varies with temperature. It indicates a 60 % density change in the dense phase (1200 psi pressure) when the temperature changes from 68 °F to 86 °F, in contrast to an 8 % increase in the gaseous phase (600 psi pressure). The density of an ideal gas would exhibit a mere 4 % change under identical conditions. Consequently, the expansion rate of dense phase CO2 at these pressure and temperature conditions may be eightfold greater than that of its gaseous counterpart and sixteen-fold greater than that of an ideal gas under the same conditions.

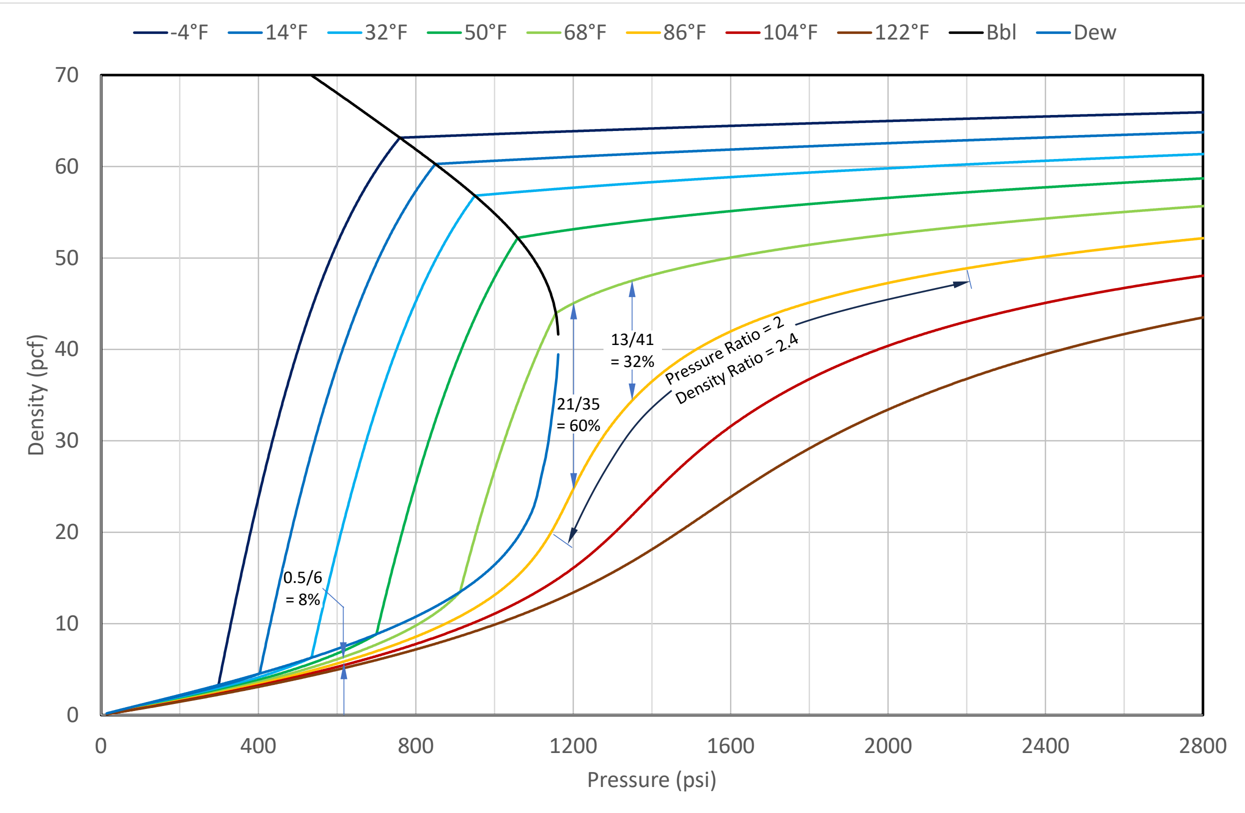

Figure B.11—Illustration Of the Sensitivity of CO2 Density to Pressure and Temperature

B.6 Joule-Thomson Coefficient for CO2

Figure B.12 illustrates that the Joule Thomson coefficient for gas-phase CO2 is approximately twice as high as that for dense-phase CO2, on average. Whether dealing with dense-phase or gas-phase CO2 pipelines, designers and operators should consider these effects, although they do not significantly differ from what is observed in natural gas pipelines. Figure 8 was derived using the BWRS equation of state [14], but other equations of state such as Soave-BWR [29] and GERG 2008 [12] have been shown to be equally suitable for most aspects of CO2 pipeline design, including Joule-Thomson cooling effects [66]. The gaps in the curves in Figure 8 are related to two-phase flow conditions.

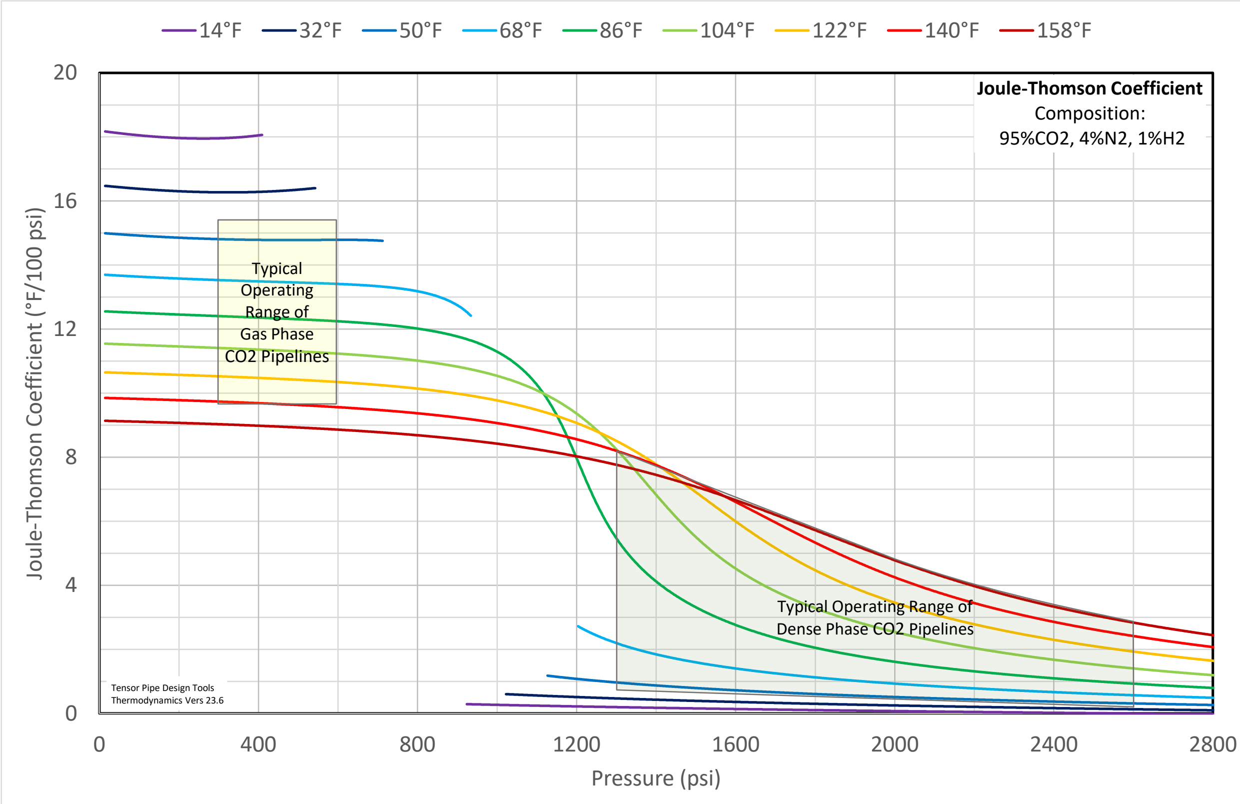

Figure B.12—Joule Thomson Coefficient for Gas Phase and Dense Phase CO2

B.7 Effect of Constituents CO2 Phase Diagram

This section is presented to describe the effects of CO2 constituents on the CO2 phase diagram describing the pressure and temperature response of the fluid which may influence release decompression, hydraulics and fracture control in the design, operation and maintenance of the pipeline. To explore the sensitivity of the CO2 phase diagram to constituent components, characteristic pressures and temperatures were calculated for fluids containing 95 % pure CO2 and 5 % of the constituent of interest. The interaction of multiple constituent components with the 95 % pure CO2 fluid is not considered. The characteristic pressure and temperature values considered are illustrated in Figure B.11, including:

- Cricondenbar, pressure,
- Cricondentherm, temperature, and
- Dewpoint temperature at 480 psi.

Table B.12 provides the estimated sensitivity of the characteristic pressure and temperature values to the introduction of each constituent at a 5 % concentration. As the CO2 phase diagram chricondentherm or chricondenbar increases higher temperature and pressure combinations are required to develop supercritical phase CO2.

While constituents may not be realistically present in a CO2 stream at 5 % concentrations, these sample calculations demonstrate the relative sensitivity of the CO2 phase diagram to each constituent. From these results, the CO2 phase diagram is most sensitive to the addition of SO2.

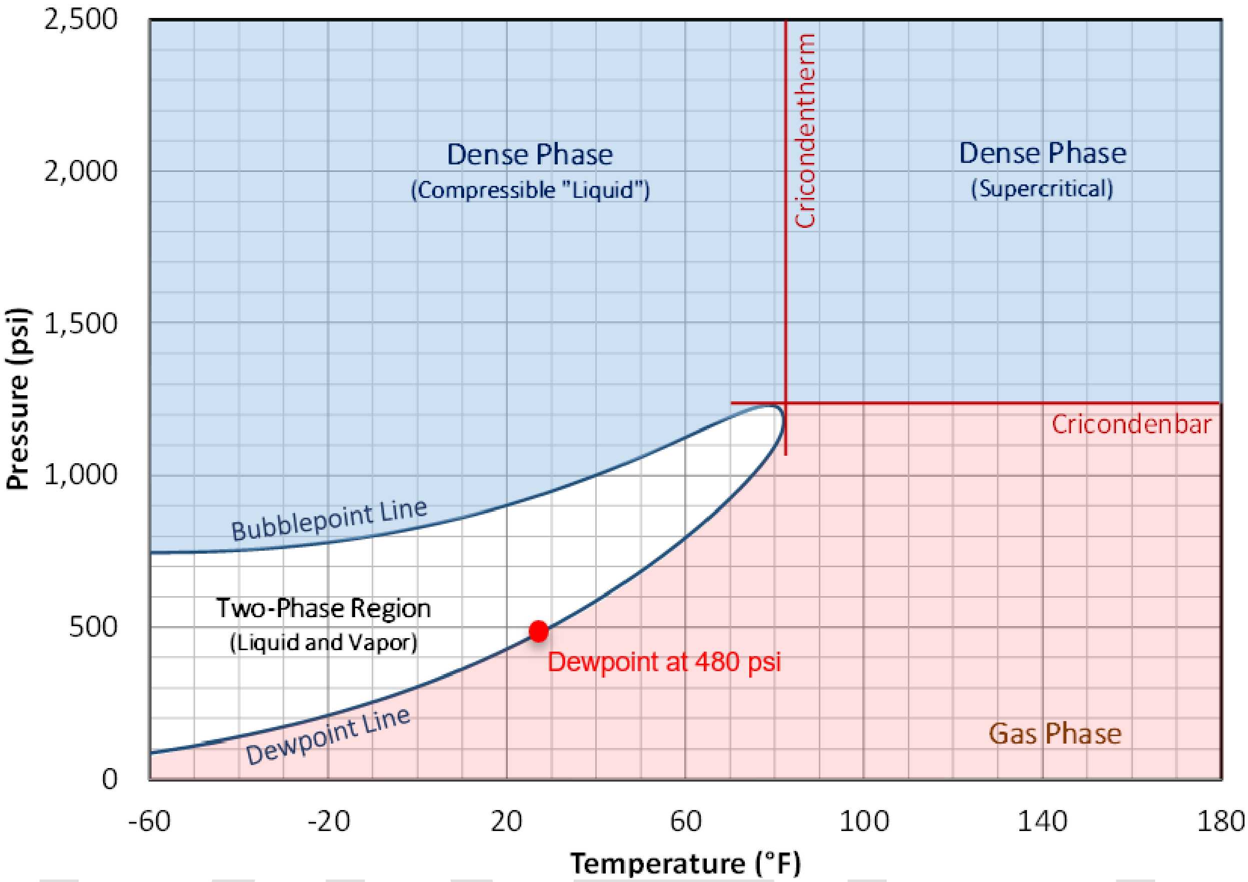

Figure B.11—Identification of CO2 Phase Diagram Characteristic Pressure and Temperature Values

Table B.12—Sensitivity CO2 Phase Diagram Characteristic Pressure and Temperature Values to the addition of other Constituents

Constituent[1]	Cricondenbar (psi)	Cricondentherm (°F)	Dewpoint at 480 psi (°F)
O2	1093	77.2	18.1
N2	1137	76.7	17.9
H2	1671	80.2	17.7
Ar	1098	77.2	18.1
CO	1119	76.6	17.9
CH4	1045	76.6	18.5
C3H8	985	88.8	36.5
NO	1082	76.5	18.1
SO2	1100	103.8	55.9
H2S	1043	89.6	28.4
[1] 95 % pure CO2 + 5 % Constituent			

B.8 Conclusions and Recommendations

Gas phase CO2 pipelines behave much like natural gas pipelines and may therefore be designed and operated with relatively minor changes to existing practices for natural gas. Since the pipeline industry has wide experience with the design and operation of natural gas pipelines, traditional natural gas tools and practices can be useful in the design and operation of gas phase CO2 pipelines. In the typical operating range of dense phase CO2 pipelines, CO2 is much more sensitive to changes in pressure and temperature than natural gas, making dense phase CO2 pipelines operate differently from natural gas pipelines in ways that must be accounted for differently in design, operation and maintenance of the pipeline.

Events that change the operating pressure and temperature along the pipeline include:

- Seasonal temperature fluctuations between early fall when ground temperature at pipeline depth is warmest and early spring when it is coolest can cause large swings in flow capacity making it difficult to maintain the steady mass flow of CO2 that is preferred to enhance the predictability and manageability of plume evolution during sequestration. Strategies to maintain a steady mass flow throughout the year include:

  a. Design efficiencies may involve series/parallel compressor/pump configurations and variable speed drives at booster stations combined.

  b. Pipeline temperature control using open- or closed-cycle refrigeration at the outlet of booster stations to maintain a constant average flowing temperature throughout the year and operate to the left of the critical Operating Zone at lower temperatures.

  c. Operating with minimum pressures above the Critical Operating Zone where dense phase CO2 has unusual properties.

  With the three options above, pipe diameter and booster station spacing can be optimized.

- Changes in flow rates and operational upsets require a fast-acting intelligent pipeline control system linked to a reliable transient model to adjust compressor or pump speeds and input flow rates.
- When isolated segments increase in temperature and the specific volume increases several times more quickly than an ideal gas, normal rules-of-thumb for sizing pressure relief valves should be replaced with fundamental principles to avoid them being undersized for the required duty.

Annex C

(informative)

Historical Overview of CO2 Pipelines

The United States is a global leader in carbon management and the deployment of CCUS. The U.S. has an extensive CO2 pipeline network representing more than 50 years of operational experience including 5,385 miles [4] (Figure 1), with a capacity to transport 80 million tons of CO2 annually. The first CO2 pipeline was brought online in 1972 by the energy industry to support an enhanced oil recovery (EOR) project. Some newer CO2 pipelines, are being constructed for carbon management from emissions sources or direct air capture facilities to permanent geologic storage sites.

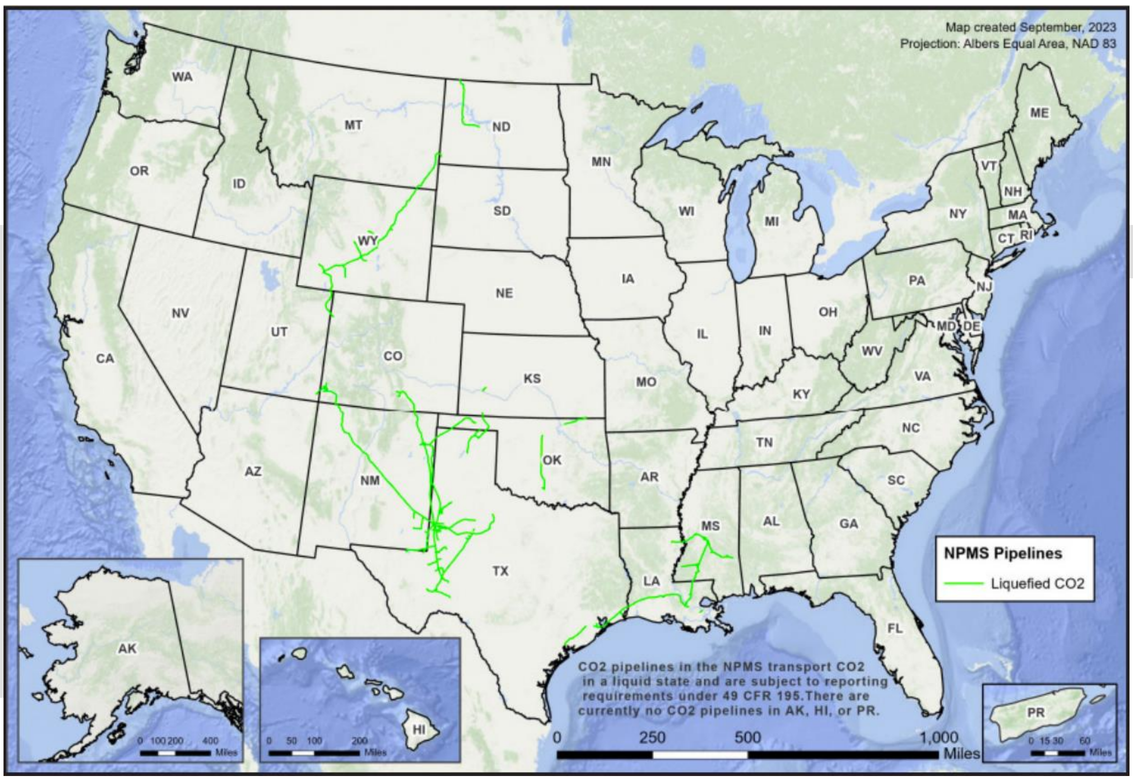

Figure 1—Current CO2 Pipeline Network in the United States [5]

New CO2 pipeline infrastructure is not unique the United States. Figure 2 provides a snapshot of the CCUS projects in development by region or country around the world in 2021.

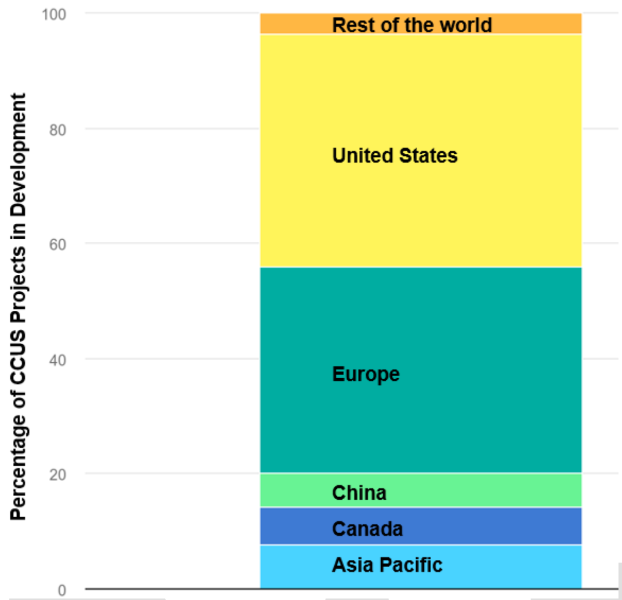

Figure 2—CCUS Projects in Development by Country or Region [7]

The design of new or conversion of existing pipelines for CO2 transmission service draws upon existing engineering expertise applied to hydrocarbon pipelines, as well as newer engineering tools developed specifically for CO2. The new tools and expertise developed for CO2 pipelines are required because of the unique properties of high-pressure CO2 which when compressed resembles a liquid but has behaviors similar to a gas. Some of these types of liquid versus gas differences in behavior have been observed in other liquified hydrocarbon products and provide guidance from other design and operational experience.

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