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Existing infrastructure for the transport of CO_2

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Approved (SP-leader)	Luuk Buit	May 31, 2011

Author(s)		
Name	**Organisation**	**E-mail**
Luuk Buit	Gasunie Engineering B.V.	luuk.buit@kema.com
Albert van den Noort	Gasunie Engineering B.V.	albert.vandennoort@kema.com
Dennis Triezenberg	Gasunie Engineering B.V.	dennis.triezenberg@kema.com
Machiel Mastenbroek	Anthony Veder	mmastenbroek@anthonyveder.nl
Fred Hage	Linde Gas	fred.hage@linde.com

EXECUTIVE SUMMARY

The use of existing infrastructure and standards, regulations and modes of practice have been investigated to ascertain to what extent CO_2 transport can benefit from them. The following has been concluded.

Production platforms could potentially be used as CO_2 injection platforms. However, this needs to be assessed on a case-by-case basis and platforms vary to a large extent in size and setup. Availability, abandonment regulations and technical modifications are large hurdles to using a platform for CO_2 injection.

Existing pipelines could in principle be used to transport CO_2, but the overwhelming majority will not be available for CO_2 transport, in most cases due to the fact that they will be used for natural gas for many years to come. When they do become available, in most cases they will have a pressure rating too low to accommodate dense phase CO_2 transport. The physical state of the pipeline is also a point of consideration when assessing reuse as a CO_2 pipeline.

Only a few dozens of gas carriers are suitable to be used for CO_2 transportation, so in all probability dedicated CO_2 carriers will be used for CO_2 shipping.

The broad experience with CO_2 transportation in the United States and Canada has resulted in a fair amount of standards for CO_2 pipelines design, construction and operation. The relation between the various standards and their applicability have been elaborated on in this report. European regulation is very extensive for pipelines in general, but CO_2 transportation is lacking in existing standards, since large-scale CO_2 transport is a very limited business in Europe to date. It is an ongoing effort to address the gaps in existing standards. The Recommended Practice for design and operation of CO_2 pipelines has been published by DNV to address these gaps insofar as they have been investigated to satisfaction.

Pipeline engineering is a mature engineering subject. However, for the specific field of CO_2 transportation, there is a number of issues that need to be taken into account. An overview of technical issues that are part of the common modes of practice is given, after which an evaluation has been made of how these modes of practice could be applied to CO_2 pipeline design, engineering, construction and operation. One important aspect is that pure CO_2 is a substance with well-known characteristics, but the same cannot be said of CO_2 with impurities. It is likely that CO_2 will be transported at temperatures and pressures close to the transition between phases. Such transition is subject to change with the presence of impurities. The characteristics of CO_2 with impurities is therefore vitally important to know in order to properly engineer a CO_2 transport system. Detailed thermodynamics of CO_2 with impurities has been modeled, but the available models have not been sufficiently validated, so caution must be used in engineering CO_2 transportation pipelines.

PROJECT SUMMARY

The CO2Europipe project aims at paving the road towards large-scale, Europe-wide infrastructure for the transport and injection of CO_2 captured from industrial sources and low-emission power plants. The project, in which key stakeholders in the field of carbon capture, transport and storage (CCTS) participate, will prepare for the optimum transition from initially small-scale, local initiatives starting around 2010 towards the large-scale CO_2 transport and storage that must be prepared to commence from 2015 to 2020, if near- to medium-term CCS is to be effectively realized. This transition, as well as the development of large-scale CO_2 infrastructure, will be studied by developing the business case using a number of realistic scenarios. Business cases include the Rotterdam region, the Rhine-Ruhr region, an offshore pipeline from the Norwegian coast and the development of CCS in the Czech Republic and Poland.

The project has the following objectives:

1. describe the infrastructure required for large-scale transport of CO_2, including the injection facilities at the storage sites;
2. describe the options for re-use of existing infrastructure for the transport of natural gas, that is expected to be slowly phased out in the next few decades. This is the content of this report;
3. provide advice on how to remove any organizational, financial, legal, environmental and societal hurdles to the realization of large-scale CO_2 infrastructure;
4. develop business case for a series of realistic scenarios, to study both initial CCS projects and their coalescence into larger-scale CCS infrastructure;
5. demonstrate, through the development of the business cases listed above, the need for international cooperation on CCS;
6. summarise all findings in terms of actions to be taken by EU and national governments to facilitate and optimize the development of large-scale, European CCS infrastructure.

Project partners

Nederlandse Organisatie voor Toegepast Natuurwetenschappelijk Onderzoek- TNO	Netherlands
Stichting Energieonderzoek Centrum Nederland	Netherlands
Etudes et Productions Schlumberger	France
Vattenfall Research & Development AB	Sweden
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E.ON Engineering Ltd	United Kingdom
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1 INTRODUCTION

CO2Europipe aims at paving the road towards large-scale, Europe-wide infrastructure for the transport and injection of CO_2 captured from industrial sources and power plants. This report presents an overview of the possibilities of using existing infrastructure, regulations, standards and modes of practice. The potential use of existing production platforms, pipelines and gas carriers is investigated to enable the work in the subsequent work packages to build upon the findings. Furthermore, this report contains an overview of the standards and regulations that apply to CO_2 transport and common modes of practice that could be useful for CO_2 transport. The environmental and organizational standards for transporting CO_2 are discussed as well.

2 PRODUCTION PLATFORMS

2.1 Introduction

In North West Europe, a feasibility assessment of using existing production platforms for offshore CO_2 storage in depleted gas fields is needed to know whether CO_2 storage investments could be decreased by using existing platforms in stead of new ones.

The focus of this section is on equipment for offshore CO_2 storage. For onshore storage, existing topside production equipment is not as important as offshore because onshore only a modest facility is needed for CO_2 storage, while offshore you need either a platform or a subsea template, both expensive and time consuming to build. The main attraction of using existing platforms for CO_2 injection is not having to build a new platform, which could possibly save a large amount of money. However, as existing platforms are not custom built for CO_2 storage, it needs to be investigated whether the platforms are at all suitable for CO_2 injection and what would be the costs of adapting the platform. The latter can compared to the costs of a new platform to find the optimal storage solution.

To take a practical approach on this question, the availability of useful empty gas fields is investigated, although oil fields can be very promising for Enhanced Oil Recovery. Only the platforms on nearly empty gas fields or platforms near saline aquifers suitable for CO_2 storage are worth considering for CO_2 storage. However, the characteristics of the storage reservoir, injection well(s) and the platform will eventually allow or preclude CO_2 storage. In this work, details of reservoirs and specific platforms cannot be evaluated. A more general approach is chosen to shed some light on platform availability while admittedly being incomplete and indicative.

In the North Sea, the production of several offshore gas fields has been ceased or will be in the near future. Dutch regulations dictate that platforms have to be abandoned and decommissioned within 2 years after terminating production.[1] Postponing removal of a platform for a longer period might be necessary to bridge the time gap between abandonment of the platform and the intended start of CO_2 injection. This becomes a viable option only if regulations allow this course of action, but 'mothballing' a platform is costly. On the other hand, postponing removal of the platform is financially attractive, because the money that has been earmarked for platform abandonment can be spent later and generate interest in the meantime.

Without Enhanced Oil Recovery, oilfields offer limited capacity due to the past replacement of produced oil with water for pressure support. Depleted gas and gas condensate fields offer good storage capacity.

To adequately assess the potential use for platforms in CO_2 storage, the following issues are addressed:

- What are the boundary conditions for CO_2 storage on platforms and what platforms are suitable with regard to these conditions?
- Can we identify platforms on sufficiently large storage reservoirs?
- When will the suitable platforms be available for CO_2 storage?
- What needs to be changed on the platforms and what are the costs?

2.2 Locations

In this study the focus is on the suitability of offshore platforms for the injection of CO_2 in underground reservoirs. For the European Union together with Norway the vast majority of potentially available offshore reservoirs are located in the North Sea, which will therefore be the focus of this study. The continental waters of the UK, Norway and The Netherlands cover the majority of the gas and oil fields in the North Sea. For Denmark, Germany and Ireland, the potential CO_2 capacity in depleted fields offshore is limited in comparison with the countries mentioned above. Therefore we will focus here on the platforms in British, Norwegian and Dutch parts of the North Sea. A schematic overview of gas and oilfields in the North Sea is given in Figure 2-1.

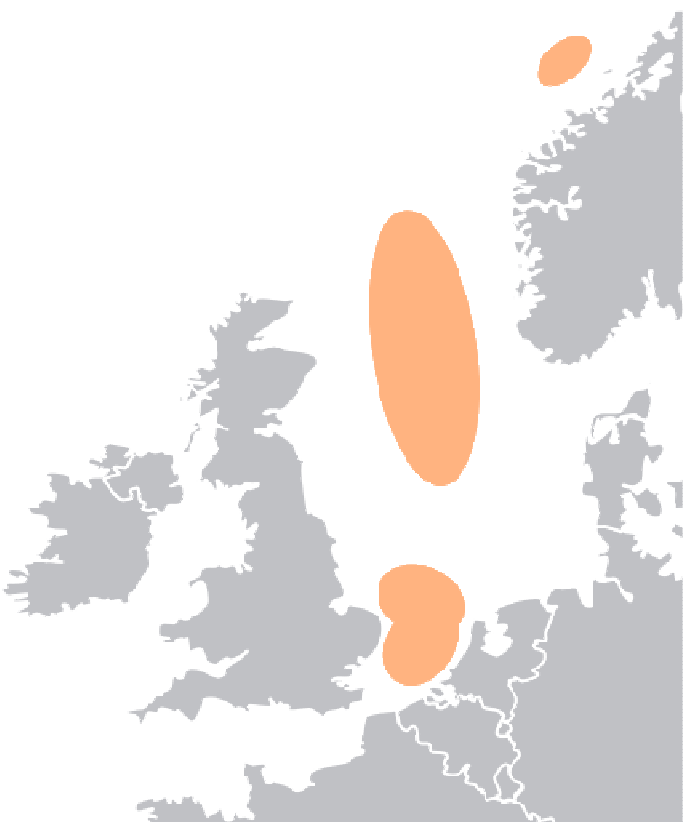

Figure 2-1 Schematic representation of oil and gas reservoirs in the North Sea

The fields on the Dutch Continental Shelf are contiguous with the fields on the UK Continental Shelf and are also referred to as the Southern North Sea Basin. The same holds for the Norwegian and UK fields in the Central and Northern North Sea Basin. Additional fields are found further north in the Norwegian Sea.

2.3 Requirements for CO_2 injection platforms

CO_2 can be stored in empty gas fields, oil fields or aquifers. The suitable storage reservoirs vary to a great extent in capacity, injectivity and field characteristics. This calls for specific injection facility requirements. Aquifer storage can be executed using a platform or a subsea template, but we will not go into that here. It is unlikely that an existing platform would be suitable for CO_2 storage without any modification because of the fact that they were custom built for natural gas production while CO_2 injection requires specific equipment. So gas fields are serviced by platforms that may be used as injection platform when the field is depleted and designated as a CO_2 storage reservoir, but dedicated injection facilities will have to be installed.

For empty natural gas reservoirs, the type of platform necessary to inject CO_2 into the reservoir depends on the condition of the CO_2 at the end of the pipeline and on the pressure in the CO_2 reservoir. Safe and controlled injection of CO_2 is guaranteed when the CO_2 is injected into the reservoir at or near reservoir pressure. Natural gas production is terminated when the reservoir pressure is too low to produce any more natural gas profitably. Common final pressures are 50 bars or lower, down to below 10 bars. Naturally, when the CO_2 is transported in the dense phase, the pressure may need to be decreased to match the reservoir pressure. When the pressure of the CO_2 stream equals the requested pressure at the wellhead, a sub sea installation can be used. In this situation a sub sea wellhead with valves to control the CO_2 stream is sufficient. A central platform could be used for conditioning of the CO_2 if needed, e.g. in the case of shipping, while the injection takes place at the subsea installation. When the pressure at the end of the pipeline is too high or too low for direct injection or if more wells are needed, additional equipment is necessary near the storage location.

As the reservoir is filled with CO_2, the pressure increases and the pressure at the well head needs to be high enough to overcome the reservoir pressure, so, during injection, the pressure at the well head should increase, depending on the reservoir characteristics. In this situation additional boosters are necessary to pump the CO_2 in the reservoir. On the other hand, if new pipelines are constructed and large quantities of CO_2 are transported it is likely that the CO_2 is transported in the dense phase. In this situation, especially if empty gas fields are used for storage, the pressure of the pipeline has to be reduced at the platform. Reducing the pressure requires additional heating to condition the CO_2 to the specifications needed at the wellhead, because pressure drop is accompanied by a temperature drop down to temperatures considerably lower than the temperature in the reservoir. For safety and operability the CO_2 to be injected must have about the same pressure and temperature as the reservoir. As a result heaters have to be in place at the platform. However, if a storage reservoir can be found that is less demanding, a sizeable sum of money can be saved. In the case of aquifer storage, the OPEX of the needed equipment can be fairly low, whereas aquifers in many cases will be further away from the CO_2 source, requiring higher CAPEX.

Compressors, pumps and heaters need energy. On gas producing platforms this is obviously no problem, but if the platform is no longer producing gas an alternative energy source has to be found. At the moment this issue is not resolved. It is discussed in a Bellona report on offshore CO_2 storage.[6]

All situations described before assume that the wells in the depleted gas or oil field can be reused for CO_2 injection. In this case, risers, manifold and wellheads are already available. There is also a possibility that new wells are needed, for example when the CO_2 is injected in an aquifer, or when existing wells are not suitable for CO_2 injection. The platform should be able to accommodate these newly drilled wells. If this is not the case, sub sea satellite wells could be used, that are interconnected to the central platform with short pipelines. Obviously for drilling new wells, drilling equipment is needed on the platform. Furthermore, well testing and control equipment is necessary.

For maintenance of the wells, pipeline and the equipment on the platform, accommodation facilities, a helideck and a crane should be available on the platform. These facilities are similar to facilities on 'normal' gas or oil producing platforms and do not add special requirements for CO_2 injection platforms.

2.4 Available fields and platforms

Many of the platforms in the North Sea were built in the previous century with an expected lifetime of 30 years. The oldest platform on the Dutch Continental Shelf (DCS) was built in 1974. Many of these old platforms are therefore at the end of their lifetime. In the NOGEPA study [1] the number of available platforms in the coming years on the DCS is given, see Figure 2-2. More detailed information on structures on the DCS can be found in reference [2]. Abandonment information can be deducted from Company Environment Plans, but are very sensitive to gas/oil prices. At high gas or oil prices it is economically beneficial to extend the lifetime of the platform.

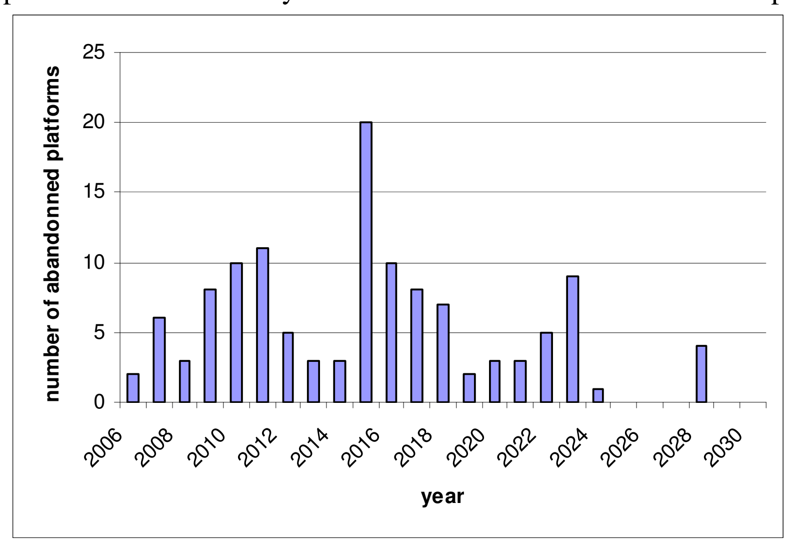

Figure 2-2 Number of abandoned platforms (from NOGEPA study [1])

Similar numbers are found for other parts of the North Sea. For example the EEEgr report [3] identifies 15 potential CO_2 storage fields in the Southern North Sea (SNS). Their expected date for end of production is given in Table 2-1, together with the CO_2 capacity.

Table 2-1 Potential CO_2 storage fields in the Southern North Sea [3]

Field	Optimum CO2 capacity (Mton)	Time to fill (years)	Expected production end (year)
Leman (Shell)	430	23	2025
Leman (Perenco)	405	25	2013
Hewett	298	19	2012
Viking Area	211	29	2013
Inde (Perenco)	184	37	2012
Inde (Shell)	113	15	2005
Inde South West	6	17	2006
Victor	66	34	2015
Ravenspurn North	64	19	2013
Ravenspurn South	38	21	2015
Amethyst West	16	23	2015
Amethyst East	32	13	2009
Audrey	46	11	2012
Thames	28	24	2017
Pickerill	26	11	2007

Fields suitable for enhanced oil recovery in the North Sea Basin are listed in the BERR report [5]. Figure 2-3 shows the expected date for the start of EOR in these fields and the corresponding CO_2 capacity. The names of the fields were omitted from the public report.

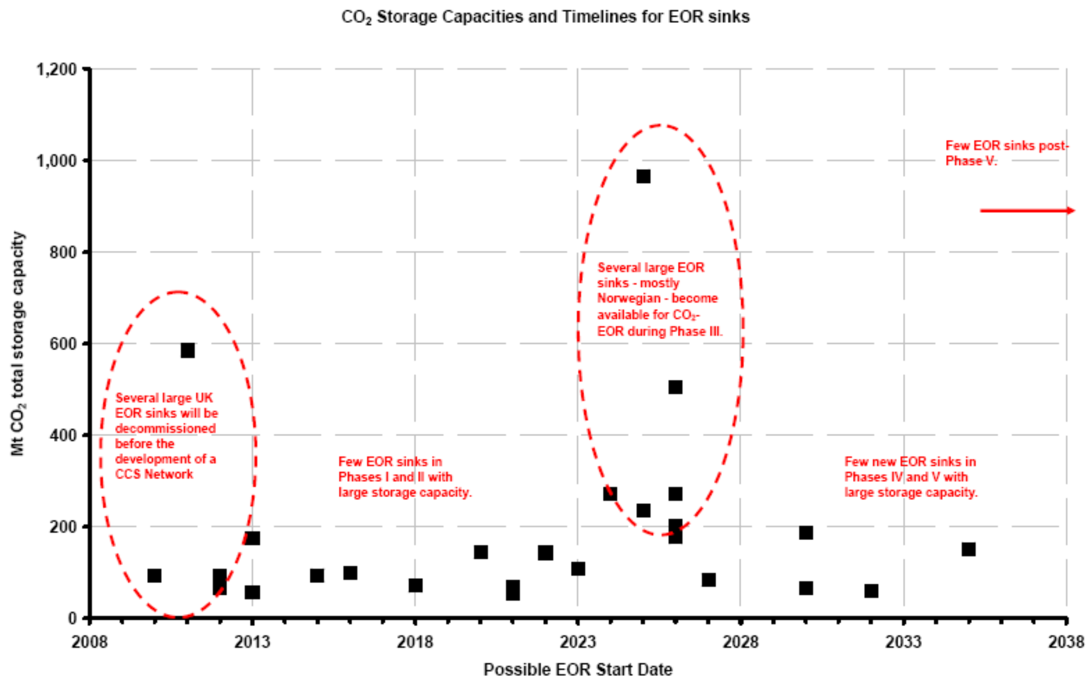

Figure 2-3 Expected start date for EOR in the North Sea Basin with corresponding CO_2 capacity [5]

The data from all three regions in the North Sea show that many fields will become available for CCS in the near future. The older platforms, now at the end of their lifetime, are in general larger and heavier due to limited data available at the time of design. This makes them more suitable for reuse for CO_2 injection as they can better support heavy new equipment.

On the other hand, legislation demands that abandoned platforms must be brought ashore for decommissioning (Petroleum Act 1998, for the Southern North Sea). According to the OSPAR Convention, abandoned platforms should be removed within 2 years, implying that either CO_2 storage should start soon after hydrocarbon production has stopped, or that legislation should be adapted to allow a longer period of inactivity before CO_2 injection starts.

2.5 Adaptations and costs

Using either new or existing platforms for the injection of CO_2 in the storage location has a number of cost consequences. In this chapter, a number of aspects are addressed and where possible cost estimates are given.

For existing platforms, a distinction can be made between two alternatives. In the first case the existing platform will simultaneously produce oil or gas and inject CO_2, the EOR/EGR option. The second case involves existing platforms that have stopped producing gas or oil.

Concerning the first situation, one should consider that additional to the existing equipment on the platform, extra equipment has to be installed, because existing compressors, pumps and piping are not necessarily suitable for CO_2. It is questionable if enough space is available on the platform for all new equipment, therefore one could consider building a new platform adjacent to the production platform. In general, modifying a platform to accommodate CO_2 storage will have a narrow window of opportunity and high costs.[1]

For existing platforms that stopped producing gas or oil it is also not obvious that existing piping, gas compressors and pumps can be reused for CO_2 injection. For these stations another issue is the maintenance in the period after the production and before the CO_2 injection. Most platforms were designed for a lifetime of about 30 years, which normally is reached at the end of the production life of the platform. The residual lifetime of the platform depends on the state of maintenance. As stated before, the oldest platforms on the North Sea were overdesigned, which allows to extend their lifetime under the condition that they are well maintained. For younger platforms one should investigate whether the structure is suitable for CO_2 injection, since it was not specifically designed for this purpose. In this situation the platform should be preserved for later use, without producing gas or oil anymore. This process is known as mothballing and is essential for reusing existing platforms. The costs of mothballing are estimated at 10% of the abandonment costs, i.e. 3-5 M€/year for central platforms and 1 M€/year for satellite stations. If possible the injection should thus start as soon as possible, after the production on the platform has stopped. The costs to reconfigurate a badly maintained platform are high.

Costs estimates for completely new platforms depend on the water depth and the amount of CO_2 to be injected. In the BERR report [5] estimates are given for a new platform using 20 wells and capable of injecting 25 Mton CO_2 per year. For a platform without EOR the costs are approximately 44 M€ (40M£) for a water depth less then 100 meter and 83M€ (75M£) for deeper platforms. The costs for platforms with EOR are 155 M€ (140M£) and 310 M€ (280M£) for a water depth of less and more then 100m, respectively.

2.6 Conclusion

For offshore CO_2 storage in Northern Europe in oil and gas fields, the best CO_2 storage reservoirs are located in the North Sea.

While there are many offshore natural gas fields that will be empty in the coming decades and would normally be available for CO_2 storage, there are some hurdles to be overcome. At the moment, regulations state that platforms on which natural gas production has been terminated, must be decommissioned and removed within 2 years. Regulations would have to state that abandonment of a platform may be executed for a longer period than two years after production stop. In this way, the platform can be kept available for CO_2 injection.

From a technical point of view, there are many challenges to overcome when using existing platforms for CO_2 storage.

Platforms differ from each other in size, weight and configuration. Platforms that need to accommodate CO_2 storage will have to be modified accordingly. The equipment on the platform is the link between the CO_2 in the pipeline and the storage reservoir, so both dictate the requirements of the platform equipment. If the pressure of the CO_2 in the pipeline is lower than the pressure in the reservoir, compression needs to take place on the platform. However, even without compression, providing the platform with the necessary power is an issue when no gas is produced anymore. The platforms most suited to inject CO_2 are the eldest platforms, which have been overdesigned and can accommodate heavy equipment. The design of newer platforms is more cost efficient.

The age and abandonment schedule of platforms are important factors in the assessment of suitability for CCS. Production of dozens of natural gas fields in the North Sea will be terminated in the coming decade, although the exact production plans of specific fields are not publicly available, so it may be assumed that there will be fields suitable for CCS. The platform characteristics will in part determine the feasibility of the project. Modification of platforms for CCS is quite expensive.

In short, it can be concluded that existing production platforms could be used for CO_2 injection after modification. However, candidate platforms will have to be investigated on a case-by-case basis. Regulatory requirements will probably need to be adjusted to accommodate delay of abandonment and CO_2 injection.

3 PIPELINE TRANSPORT INFRASTRUCTURE IN PLACE

3.1 Introduction

In order to assess the potential of existing transport infrastructure for transporting CO_2, the design constraints for CO_2 transport are evaluated. Existing infrastructure can be useful for CCS only if certain preconditions are met regarding availability, location and routing, physical state of the pipelines and pressure ratings. This chapter consists of the assessments of the aforementioned preconditions.

3.2 Design constraints for CO_2 transport

3.2.1 Phases of CO_2

CO_2 can be transported in the gaseous form, liquid form and in the dense phase. Gaseous transport is limited to 35 bars, because at higher pressures it is likely that liquid and gaseous CO_2 coexist (multiphase flow), which is undesirable. For transport in the liquid or dense phase, the pressure has to at least exceed the saturation line, which ends at 74 bars, at the critical point. A safe minimum pressure would be around 80 bars.. For dense phase transport, the temperature has to exceed 31°C. The boundary between the liquid and dense phase is roughly at the critical temperature, 31 °C. In Figure 3-1, the phase diagram of CO_2 is given.

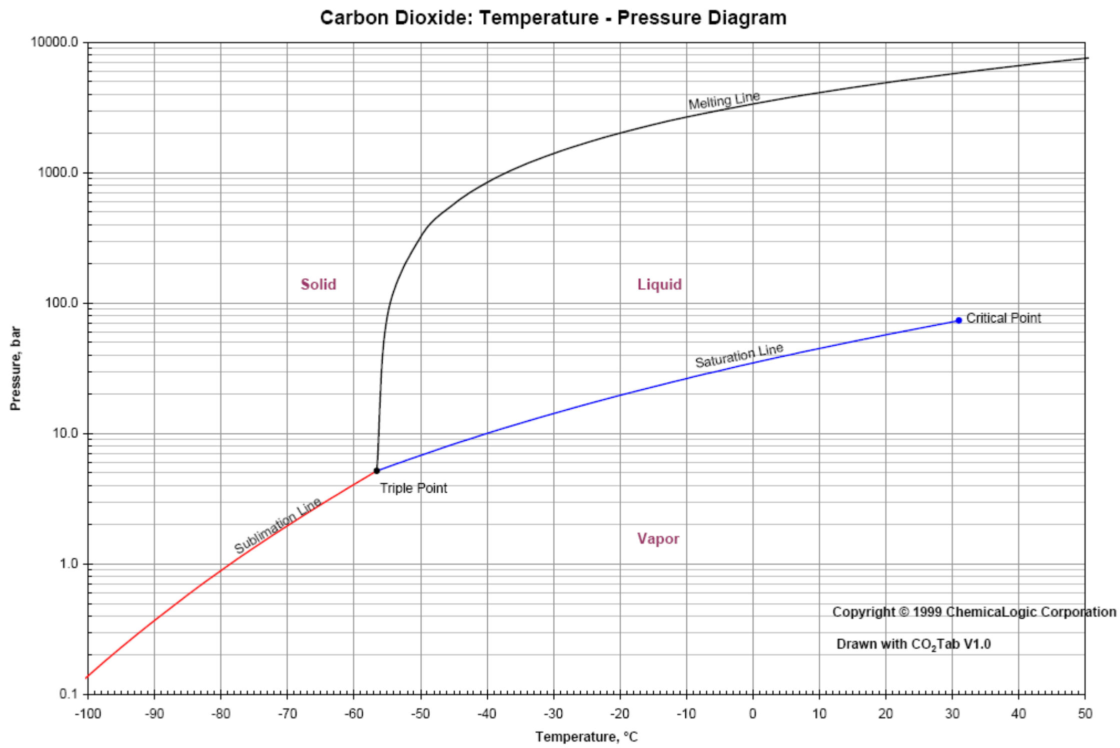

Figure 3-1 Carbon dioxide pressure diagram

3.2.2 Pipeline strength

Pipeline strength or pressure bearing capacity is the first and most important requirement for CO_2 pipeline transport. The pipe has to be able to withstand the internal pressure according to the design codes. One example is the European code for Gas supply systems over 16 bar EN 1594. Pipes are specified according to the various grades in the line pipe standard EN 10208-2 (or API 5L).

3.2.3 Fracture initiation

When however a leak develops in a CO_2 pipeline the temperature will drop due to the evaporation of the liquid CO_2 and could go as low as -78°C (Figure 3-1), the temperature of dry ice at atmospheric conditions. Even if the temperature does not drop to this value, a fracture could be initiated because of the material properties of common pipeline steel. A thermal model around leaks of various sizes is necessary to set the minimum temperature for fracture initiation. The pipeline material could then be chosen to minimize fracture initiation risk.

3.2.4 Fracture propagation

In the case of supercritical or liquid transport, when a leak develops, pressure will reduce isentropically, giving a saturation pressure when crossing the phase boundary. The pipeline has to be able to have enough resistance to withstand this pressure, e.g. initial conditions of

- 80 bar, 20°C will go isentropically to the phase boundary giving a saturation pressure of around 62 bar and around 15°C, see figure 2
- 80 bar, 5°C will go isentropically to 40 bar

These examples show that the environment, in this case the temperature, has an influence on the end pressure in the case of a leak. The higher the end pressure the more energy the gas contains which increases the probability of crack propagation since all the energy has to be dissipated in the steel.

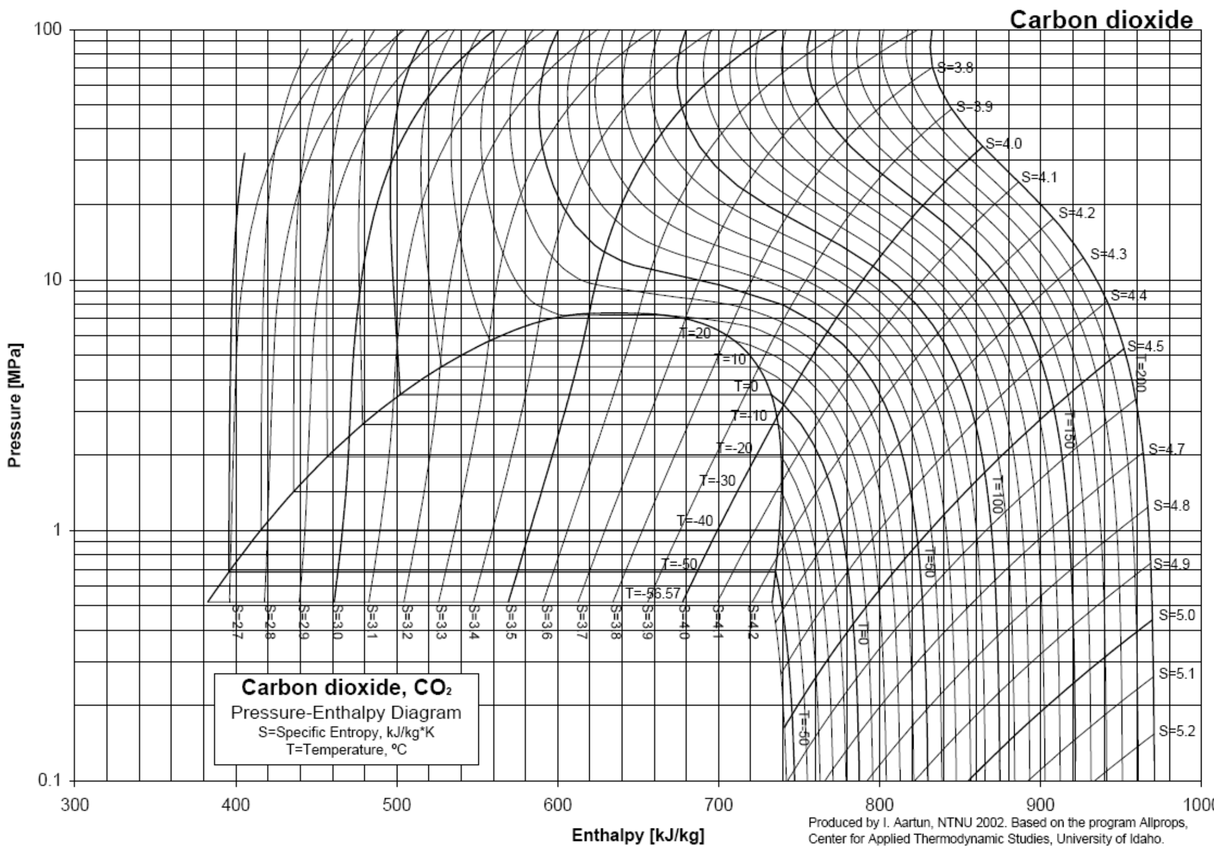

Figure 3-2 Carbon dioxide – Pressure – enthalpy diagram

In Figure 3-3 the decompression curves for natural gas and resistance curves for several surrounding media are given. Figure 3-3 below is valid for a 30”, 17 mm grade 450 pipe with 73J Charpy resistance.

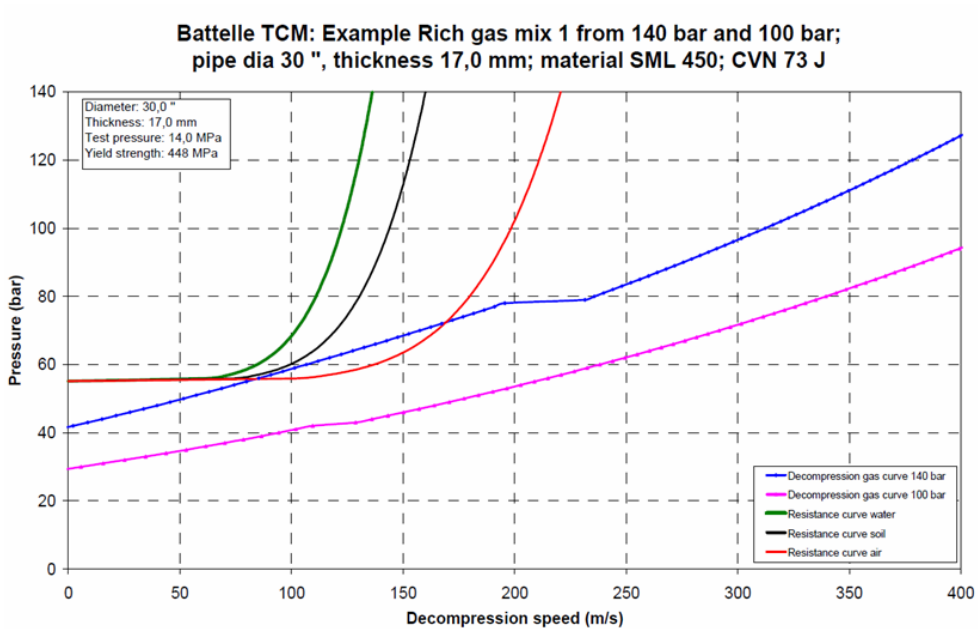

Figure 3-3 Decompression gas curves and resistance curves of water soil and air[7]

This pipe would withstand the 80 bar, 5°C case, because in this case the pressure will drop isentropically to 40 bar, at which the decompression speed is higher than the propagation speed of the crack tip. In the case of 80 bar, 20°C where the pressure will drop isentropically to around 62 bar it is not certain that this is the case making the occurrence of fracture propagation a likely possibility.

In general it can be stated that the resistance curves of steel are quite well known but that too little is known about the energy/gas-side of the figure above. So, research is required, for example, to find out how the figures change due to the presence of impurities.

3.2.5 Impurities

The presence of impurities has a great impact on the physical properties of the transported CO_2 that affects pipeline design, compressor power, recompression distance etc., and could also have implications on fracture control of the pipeline. These effects could be both negative and positive; for example, the addition of some impurities tends to reduce required compressor power, while others increase the power required. [8]

As an example of the impurity conditions that are considered acceptable, the maximum impurity levels proposed by the CCS research project Dynamis are reprinted here: [9]

Component	Concentration	Limitation
H_2O	**500 ppm**	Technical: below solubility limit of H_2O in CO_2. No significant cross effect of H_2O and H_2S, cross effect of H_2O and CH_4 is significant but within limits for water solubility.
H_2S	**200 ppm**	Health & safety considerations
CO	**2000 ppm**	Health & safety considerations

O_2	Aquifer < 4 vol%, **EOR 100 – 1000 ppm**	Technical: range for EOR, because lack of practical experiments on effects of O_2 underground.
CH_4	Aquifer < 4 vol%, EOR < 2 vol%	As proposed in ENCAP project
N_2	< 4 vol % (all non condensable gasses)	As proposed in ENCAP project
Ar	< 4 vol % (all non condensable gasses)	As proposed in ENCAP project
H_2	< 4 vol % (all non condensable gasses)	Further reduction of H_2 is recommended because of its energy content
SO_x	**100 ppm**	Health & safety considerations
NO_x	**100 ppm**	Health & safety considerations
CO_2	>95.5%	Balanced with other compounds in CO_2

The water concentration is a point of discussion, further discussed in work package 3.1. The results form part of D3.1.2 'Standards for CO_2'.

Models indicate that CO_2 with impurities tends to have a higher critical pressure than pure CO_2. This is one of the reasons why the effects of impurities are interesting: they dictate what pressures and temperatures are acceptable in the CO_2 transport network and are not in the two-phase regime.[10] Although adequate experimental data are lacking, 85 bars is considered to be a safe lower pressure limit. Figure 3-4 shows the effect of certain impurities on the thermodynamical characteristics of CO_2.

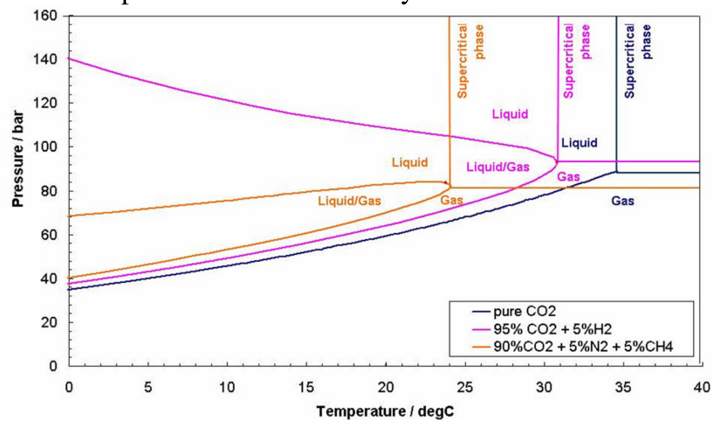

Figure 3-4 The effect of impurities on the phase diagram of carbon dioxide

3.2.6 Compressibility

The compressibility of CO_2 is non-linear in the range of pressures common for pipeline transport and is highly sensitive to impurities (e.g. H_2S). To reduce difficulties in design and operation it is generally recommended that a CO_2 pipeline operates at pressures greater than 86 bars where the sharp changes in compressibility can be avoided across a range of temperatures that may be encountered in the pipeline system[11].

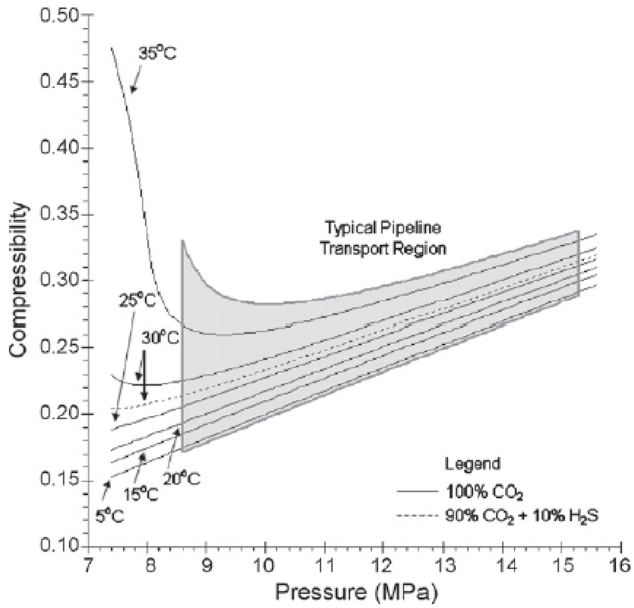

Figure 3-5 The compressibility of CO_2 based on the Peng-Robinson equation of state, showing the non-linearity in the typical pipeline transport region and the sensitivity to impurities, such as 10% H_2S (by mole fraction)

3.2.7 Components (e.g. valves)

Dense phase CO_2 is an excellent solvent for organic material. Hence, special attention must be paid to components like seals, valves, gaskets and lubricants that can come in contact with CO_2. The CO_2 resistance of certain common materials is investigated in the Energy Institute report [33].

3.3 Suitability of existing pipelines for CO_2

3.3.1 Availability

As natural gas demand in Europe is projected to increase for decades, many pipelines will not be available for other purposes than transporting natural gas. Onshore pipelines, as a rule, form part of a natural gas grid that will continue to be used for the transport of natural gas. Offshore trunk lines will be used for natural gas until the last natural gas field connected to it has stopped producing, so the offshore trunk line will not be available soon. Only offshore satellite lines become available when the connected field is depleted. Basically, the natural gas pipelines will for a very large part not be available for decades, because they will still be transporting natural gas.[1]

3.3.2 Age

Many existing pipelines have been in operation between 20 and 40 years. Remaining service life can only be assessed on a case-by-case basis. An integrity evaluation has to be performed, taking into account existing defects and potential future defects. Remaining life has to be assessed looking at corrosion and fatigue.

3.3.3 Pressure ratings of onshore pipelines

Pipelines are designed to operate within specific pressure limits. For many natural gas pipelines this limit is up to 80 bars (e.g. Dutch onshore pipelines) or 100 bars (e.g. most German natural gas pipelines).

To transport dense phase CO_2, a higher pressure is needed. When the maximum pressure of a pipeline is 100 bars, CO_2 can only be transported in vapour phase or supercritical over short distances between booster stations. An example of this is the onshore vapour phase CO_2 pipeline currently in operation called the OCAP pipeline, which supplies CO_2 to greenhouses in the west of the Netherlands. The pressure inside this pipeline is up to 22 bars.

3.3.4 Offshore pipelines

In principle, existing offshore pipelines, the vast majority of which consist of carbon steel, are metallurgically suitable to carry CO_2 provided that the moisture content is maintained at a sufficiently low level, see above. The main limitation of the existing lines, apart from availability, is design pressure, which varies between 90 and 180 bar. The effect of this limitation is to reduce transportation capacity compared to a purpose-built new line. A new pipeline could be designed with the optimal pressure rating, probably between 200 and 300 bars. [12] However, due to the stable ambient temperature, an existing offshore pipeline has a wider operational range than an onshore pipeline. Therefore, it would be worthwile to investigate offshore pipelines even if they have a design pressure below 100 bar.

3.4 Conclusion

In all probability, existing pipelines are of very limited use for large-scale CO_2 transport, because:

1. Existing pipelines are almost all unavailable for CO_2 transport for decades to come.
2. The maximum operating pressure of onshore pipelines (and of some offshore pipelines) is too low for the pipelines to be an economical solution for high-pressure CO_2 transport when compared with newly built pipelines.

4 POSSIBILITIES FOR CO_2 TRANSPORT BY SHIP

4.1 Introduction

Within the CO_2EuroPipe project framework the question is raised whether the current world wide gas carrier fleet is capable of transporting CO_2 on a large scale, or more specific: is the current world fleet capable of transporting CO_2 in liquefied, solid or gaseous form?

A gas carrier is a vessel (ship) capable of transporting liquefied gasses in bulk. Other means of shipping gasses that are not used in the shipping industry are the Compressed Gas concept (following the CNG-concept) and Solidified Gas concept. So the question can be limited to transport of liquefied CO_2 in a ship type called: gas carrier.

4.2 Gas transport principles

In a gas carrier, the product (gas) is transported as a liquid. The reason for this can be found in the density of the product, which is much higher for liquids compared to gasses, and consequently much more cargo can be transported with the same ship at the same time. A gas is liquefied by cooling it below the dew point, which is done by subsequently compression and flashing or by compressing the gas only. Based on the characteristics of a gas, special sub-types of gas carriers have been developed.

4.3 Types of gas carriers

Fully refrigerated (FR) gas carriers
We find vessels that transport the cargo (LPG) fully refrigerated (FR), meaning the cargo is liquefied by lowering the temperature below the dew point, down to -48 °C, but keeping the pressure on or slightly above ambient.

LNG carriers
Basically an LNG carrier is a kind of Fully Refrigerated gas carrier, however, the design temperature is much lower than with an LPG FR gas carrier (-163ºC against -48 ºC), and therefore it is considered a different type of gas carrier (LNG).

Semi Refrigerated (SR/FP) gas carriers
If the cargo (LPG) is cooled and compressed we use a SR/FP (semi refrigerated, fully pressurised) gas carrier.

Ethylene carriers
Transporting ethylene occurs at temperatures much lower than that of LPG (-104ºC against -48 ºC) and a gas carrier for ethylene is considered a different type of gas carrier as well (Eth.).

Custom carriers
And finally we find gas carriers custom built for certain cargos or trades. An example is the (Anthony Veder owned) dedicated CO_2 carrier Coral Carbonic.

In conclusion: we find 4 types of gas carriers: Fully Refrigerated (FR) gas carriers, LNG carriers, semi refrigerated, fully pressurized (SR/FP) gas carriers and ethylene (Eth) carriers. There are custom built carriers as well, which do not fit in the other categories.

4.4 View on world CO_2 tanker fleet

In our review of the world fleet for ships capable of carrying CO_2 in bulk, we have found the following results. In the current world fleet there are some 1300 vessels (**ref. Clarkson**) that are classified as gas carriers. Due to the characteristics of CO_2, some classes of Gas carriers can be disregarded with respect to transporting CO_2. In the figure below the T,p diagram for CO_2 is shown.

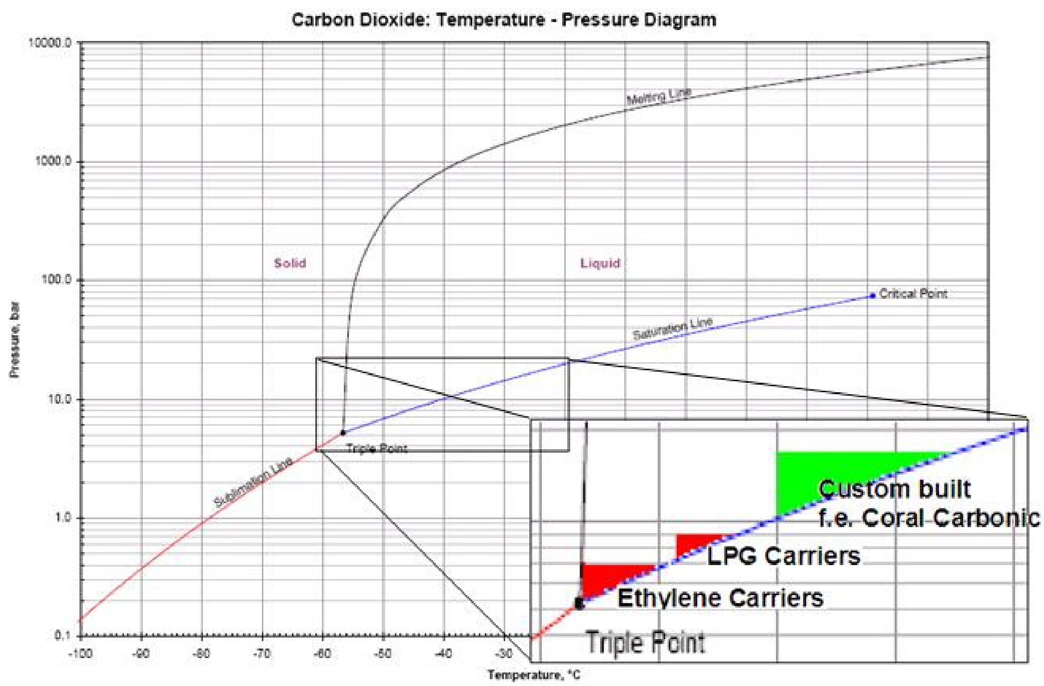

Figure 4-1 Pressure and temperature envelope of CO_2 transport by existing gas carriers.

From this figure it can be determined that the following types of gas carriers are not suitable. Since liquefied CO_2 cannot be transported at atmospheric pressure (the triple point of CO_2 is at 5.18 barg), FR (fully refrigerated) and LNG gas carriers are out of the question.

What remains are SR/FP (semi refrigerated, fully pressurised) gas carriers and ethylene carriers. In the close up of the figure both types are represented. SR/FP LPG carriers have a minimum temperature of -48 ºC, and a maximum pressure ranging from 4 to 9 bars. From the figure it is clear that LPG (SR/FP) carriers need a pressure setting >7 bar. Ethylene carriers generally have a temperature setting of -104 ºC, however as the triple point of CO_2 is at -56.6 ºC, the transport temperature will be over -56.6 ºC. The pressure setting of ethylene carriers generally ranges from 4 to 7 bars. As the pressure of CO_2 in the triple point is 5.18 bars, only ethylene carriers with a higher set point will be considered. Dedicated CO_2 carriers like the Coral Carbonic have set points and equipment that are especially designed for transport of liquefied CO_2.

From the figure and description above, we immediately find the constraints in common gas carriers. Two types are not usable at all, and from the two types (SR/FP and Eth carriers) that might be used, most of the vessels have a pressure set point that is too low, to allow transport of liquefied CO_2. From the 1300 gas carriers worldwide, only 34 might be able to transport liquefied CO_2, based on their temperature and pressure settings.

4.5 Considerations on reuse and purposely built CO_2 tankers

A gas carrier fitted with cargo tanks that are able to withstand a pressure / temperature setting suitable for transport of liquefied CO_2, not necessarily will be able to actually transport the product. Technically speaking, we have found that it takes some conversion for a gas carrier to be able to transport CO_2. The specific weight of CO_2, or simply the weight of CO_2, is higher than regular products for a gas carrier. That means that specific equipment has to be upgraded to cope with higher weight of the cargo.

Cost assessment and conversion-studies are ongoing at the moment by AV in order to derive the most cost efficient solution for the transport of large scale CO_2.

So far AV believes that CCS projects will be best served by CO_2 carriers in the range of 15.000-50.000 cubic meters. From this commercial point of view, of the 1300 gas carriers, with 34 potential candidates, no vessels are in the 15.000-50.000 cubic meters range. Therefore it may be concluded that from a CCS point of view, technically there are some vessels available for transport of liquefied CO_2, with a requirement for conversion, however commercially it is questionable if they can be readily used for CCS projects.

The requirement for dedicated CO_2 carriers, or gas carriers designed with additional CO_2 capacity will not be ground braking – revolutionary designs. Most design features, and equipment will consist of a combination of proven technologies, for which we have ample experience, combined with a 'new' ship type. One of the things that is not commonly seen in gas carriers, is an option for offshore discharge, at the moment no gas carriers are equipped for offshore discharge for regular LPG and ethylene gasses, and very limited for LNG, without exception all Ultra Large Gas Carriers. There is no infrastructure at the moment for offshore discharge of liquefied gasses.

4.6 Conclusion

Of the existing fleet of 1300 gas carriers, only 34 could be used for CO_2 transport. These vessels are technically capable of transporting CO_2, although they would have to be converted to be used for CO_2. From a commercial point of view however, CO_2 transport by newly built dedicated CO_2 carriers is probably the best option.

5 STANDARDS AND REGULATIONS

5.1 Introduction

For CO_2 transportation with relatively small volumes, experience is mainly based on truck, train and ship transportation. Pipelines are the dominant mode of transporting large volumes of CO_2 over large distances. Tanker and ship CO_2 transportation is mainly found in the food and beverage industries. On site transportation of CO_2 in these industries done through small diameter pipelines. About 100,000 tons of CO_2 are transported annually for these industries—far less than the amounts expected to be associated with a commercial-scale power plant, or even ethanol, cement, or natural gas refining output. These volumes are expected to be in the order of magnitude of millions of tonnes per year. The advantage of pipeline transportation of CO_2 is that it can transport huge amounts of CO_2 in a controlled manner, under conditions that can be predetermined, controlled and managed. Pipeline transporation is a relatively safe method of delivering large quantities over long periodes of time in a controlled way. It can provide a constant and steady transport solution for CO_2 without the need for intermediate storage along a distribution route. The distribution route can be chosen in advance and made fitting with the demands for safety and reliability. Ship transportation of large quantities of CO_2 may be feasible when transportation over long distances or overseas is needed; however, not all anthropogenic CO_2 sources are located near navigable waterways, so a shipping solution for the transportation of CO_2 to an offshore storage location will still most likely require pipeline construction between CO_2 sources and the loading dock of the ship.

As such the implementation of carbon dioxide capture and storage will require very large quantities of CO_2 to be transported from point of capture to point of injection into geological repository. Pipelines are seen as the primary transportation means of CO_2 in the context of CCS. There is experience worldwide in pipeline transportation of CO_2 in its liquid and/or supercritical phase (i.e. collectively termed "dense phase") on the scale that will be required for CCS. This experience is site specific and can only partially be translated to other projects. Much of the operation experience is seen by the operator as proprietary, because of the commercial value of the experience.

Partly the experience with CO_2 transportation heretofore can be used because CO_2 is CO_2, but the specific issues such as composition and large-volume transport in densely populated areas are specific for CCS.

5.2 Current context

Current large scale CO_2 utilisation projects are based on transporting CO_2 by pipeline to a site where the CO_2 is injected. There is a decent amount of experience with CO_2 pipelines, which in some cases have been in operation for several decades. EOR driven CO_2 systems include most of the existing CO_2 transportation infrastructure around the world. By far the largest concentration of pipelines is in North America, where 5,900 kilometres of pipeline are transporting approximately 50Mtpa CO_2 for EOR (United States Interagency Task Force on Carbon Capture and Storage 2010). A map of the main existing and proposed CO_2 pipeline infrastructure in North America is shown in Figure 5-1, which includes transporting CO_2 from both natural geologic and anthropogenic sources.

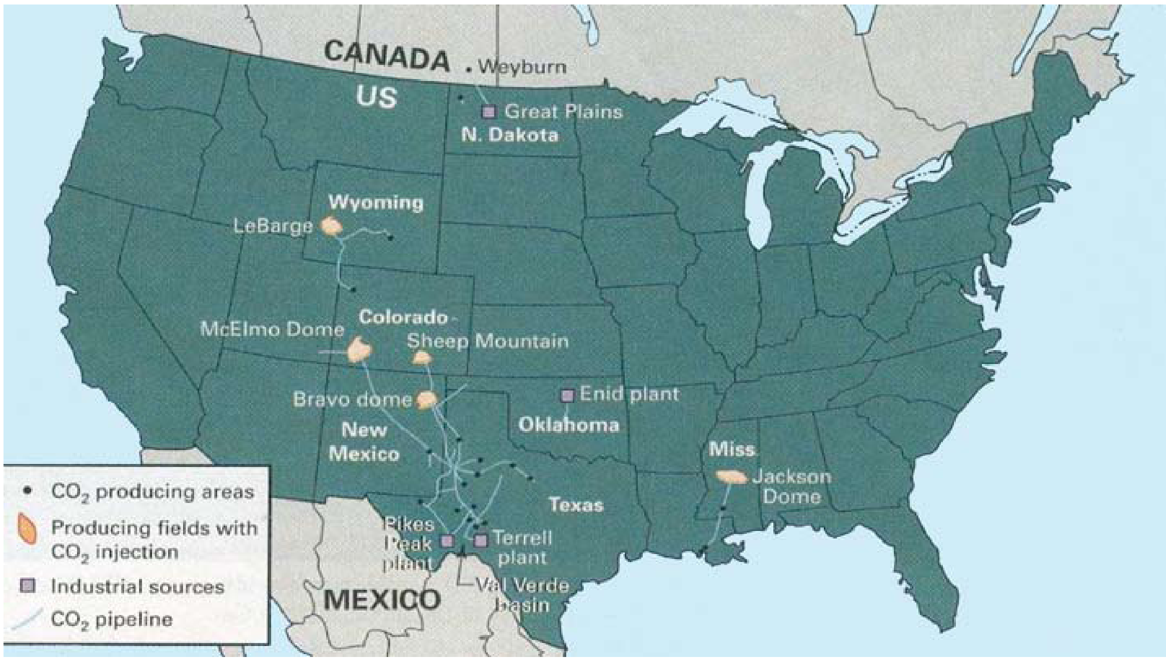

Figure 5-1 CO_2 pipelines in North America. (Courtesy of Oil and Gas Journal).

Only a few CO_2 pipelines exist outside of North America. For example: the only existing offshore pipeline for transporting CO_2 is the Snøhvit pipeline, which has been transporting CO_2 (obtained from natural gas liquefaction) through a 153 km sea-bed pipeline from Hammerfest in northern Norway to a storage location under the Barents Sea, since May 2008. Further CO_2 transportation by pipeline occurs in the Netherlands with approximately 85 km pipeline for supplying 300 Kton gaseous CO_2 to greenhouses as well as in Hungary, Croatia and Turkey for EOR.

5.3 Current Experience

In the US, naturally occurring CO_2 is routinely transported for considerable distances overland, although mostly through sparsely-populated regions (see table 5-1), for the purpose of enhanced oil recovery (EOR). There is also some limited transport of captured, or 'anthropogenic', CO_2.

Table 5.1: List of existing long-distance CO_2 pipelines. Most of the projects listed below are described in greater detail in a report by the UK Department of Trade and Industry (2002). While there are CO_2 pipelines outside the USA, the Permian Basin contains over 90% of the active CO_2 floods in the world (O&GJ, April 15, 2002, EOR Survey). Since then, well over 1600 km of new CO_2 pipelines has been built to service enhanced oil recovery (EOR) in west Texas and nearby states [14].

Pipeline	Location	Capacity (Mt CO_2/y)	Length (km)	Year Complete	Origin of CO_2
Cortez	USA	19.3	808	1984	McElmo Dome
Sheep Mountain	USA	9.5	660		Sheep Mountian
Bravo	USA	7.3	350	1984	Bravo Dome
Canyon reef Carriers (SACROC)	USA	5.2	225	1972	Gasification
Val Verde	USA	2.5	130	1998	Val Verde Gas Plants
Bati Raman	Turkey	1.1	90	1983	Dodan field
Weyburn	USA & Canada	5	328	2000	Gasification

Typically entry into a pipeline system is controlled in terms of conditions, temperature and pressure as well as composition. For example the Canyon Reef project advises the following specification for carbon dioxide: [14]

- 95% mol carbon dioxide minimum
- 0.489 mg/m^3 (50ppm wt) water in the vapour phase, no free water
- <1500 ppm (w/w) hydrogen sulphide
- <1450 ppm (w/w) total sulphur
- <4% mole nitrogen
- <5% mole, <-28.9°C dew point for hydrocarbons
- <10 ppm (w/w) oxygen
- <$4x10^{-5}$ l/m^3 glycol, no free liquid at pipeline conditions
- <48.9 °C temperature

In Europe, a number of suitable offshore CO_2 reservoirs (or 'sinks') have been identified in the North Sea for EOR, or simply for storage. It has been commonly assumed that the transport of CO_2 to offshore sinks is straightforward. Using existing pipeline infrastructure has been considered, but does not appear to be very promising. This question is dealt with in chapter 3 of this report.

However, there are significant differences between the US experience with natural CO_2, and the know-how needed to design transport systems for anthropogenic CO_2. Europe, for instance, will be dealing with the latter, mostly from power plants. The composition of the CO_2 from these plants will influence the hydraulics calculations that are needed to design these pipelines. These effects have not yet been fully explored. Considerable proportions of the transport system will be subsea, for which there is limited specific experience. In Norway, a dedicated offshore CO_2 pipeline is in operation. In offshore natural gas transport, however, there is considerable experience.

There are questions as to the suitability of much of the existing infrastructure and the desirability of using it; and, there is little experience with multi-source transport systems through densely-populated regions. Again, the know-how that companies have gathered with subsea installations is not available or limited because of commerciel reasons. Companies are reluctant to make detailed data available, leading to time consuming and expensive research projects by universities and research institutions.

5.4 Current Guidance and Standards

Regulations and pipeline certification requires that the design of a pipeline, or any modification to it, takes account of the operating regime of the pipeline and the conditions under which the fluid is to be transported as well as the environment to which the pipeline will be exposed. In particular with regard to the re-use of existing pipelines, any proposal to change the fluid transported will require a re-assessment of the original pipeline design to ensure that the pipeline is capable of conveying the fluid safely.

5.4.1 Transport of CO_2 in Pipelines

In the EU experience on operating CO_2 pipelines is limited, and only some pipeline design codes include it as a relevant fluid within their scope of application. Moreover, current pipeline codes were not established to cover bulk transportation of CO_2 in the quantities likely to be seen in CCS projects.

Since there are currently no suitable CO_2 specific guidelines or standards for safety it has been suggested that industry uses similar safety criteria for CO_2 pipelines as they use for natural gas pipeline systems. However the hazards are very different, and in doing so, the designers and developers of CCS and sequestration projects need to keep in mind that whereas natural gas is a flammable and explosive substance, CO_2 is toxic, so the CO_2 release hazard is qualitatively and quantitatively different from that of natural gas release. Only specific research on CO_2 release can lead to good safety standards for CO_2 transport. Research on specific issues concerning release of large quantities of CO_2 is underway and being performed by the transportation industry involved in CO_2 transportation.

To bridge the gap from existing standards to CO_2 transportation, in 2010 a Recommended Practice has been published by DNV[16]. This document states which standards apply to CO_2 transportation by pipeline and gives recommendations for designing, constructing and operating CO_2 pipelines as a supplement to the existing standards.

5.4.2 Risk Mitigation

Application of good practice at the design stage is essential to demonstrate reduction of Reducing risk As Low As Reasonably Practicable (ALARP). Depending on the level of risk and complexity involved, it is possible that the adoption of good practice alone may not be sufficient to comply with applicable law. For example, in high hazard situations where the circumstances are not fully within the scope of the good practice, additional measures may be required to reduce risks ALARP. Furthermore, where the potential consequences are high, HSE will take a precautionary approach by giving more weight to the use of sound engineering and operational practice than to arguments about the probability of failure.

5.4.3 European Standards

European Standards are providing a sound basis for the design of pipelines in general. Other codes are likely to be acceptable be applicable if they provides equivalent levels of safety. Such codes may be the national or international codes e.g. a relevant standard or code of practice of a national standards body or equivalent body of any member state of the European Union.

In Europe pipeline safety regulation is well established, as are the design codes. These regulations do not consider carbon dioxide as a specific named substance in the prescriptive manner of the US federal regulations.

Standards relevant to the transport of fluids in pipelines include:

- ISO 13623 - Petroleum and Natural Gas Industries – Pipeline Transportation Systems, 2nd ed. 2009
- PD 8010: 2004 Parts 1 - Steel pipelines on land and 2 - Subsea pipelines
- BS EN 14161: 2003 - Petroleum and Natural Gas Industries. Pipeline Transportation Systems
- DNV OS-F101 - Submarine Pipeline Systems (2007)
- NEN 3650 / 3651 for transport pipeline in the Netherlands (Eisen voor buisleidingsystemen)

ISO 13623, BS EN 14161, BS PD 8010 and DNV OS-F101 are all applicable to pipelines transporting CO_2; the last three categorising it as a non- flammable, non-toxic fluid which is gaseous at ambient temperature and pressure. However none of these standards address CO_2 transported in its dense or supercritical phases. This is no neglect of the standards organisations but rather a reflection of the fact that to date, CO_2 has not been transported in these phases and volumes and hence there has been no driver to address the issues associated with such activities.
BS 8010 has been withdrawn and has been replaced by BS PD 8010: 2004 Parts 1 and 2. European Standard BS EN 14161: 2003 – Petroleum and Natural Gas Industries, Pipeline Transportation Systems has also been introduced. DNV OS-F101 is specifically an offshore standard, limited to submarine pipeline systems.

Both standards, like the US regulations highlight a number of other standards (Figure 5-3 and Figure 5-4) that should be used in conjunction with the core code.

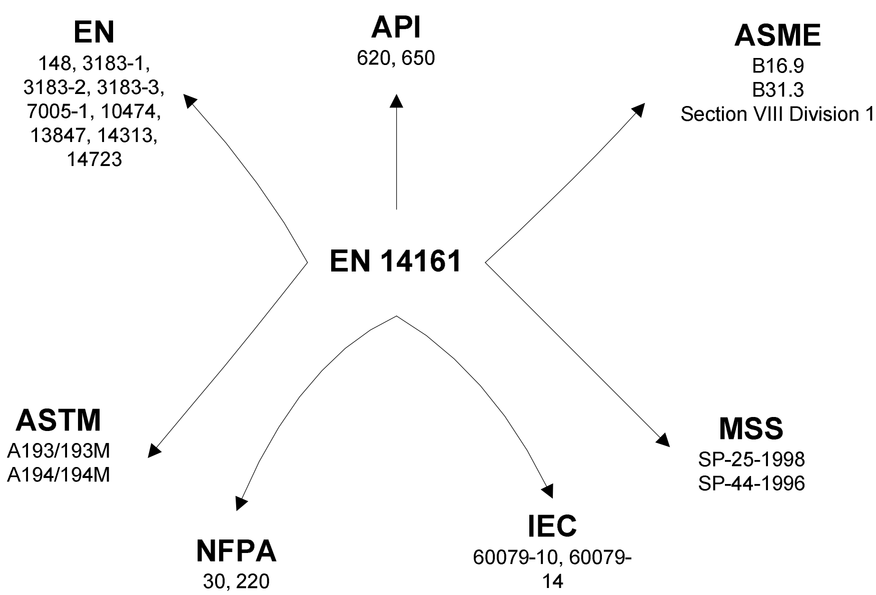

Figure 5-2 Standards associated with EN 14161 [33]

5.4.4 US Pipeline Codes

The US Federal Code of Regulations, Title 49, Volume 3, Part 195 – Transportation of Hazardous Liquids by Pipeline and the associated ASME standards B31.4 and B31.8 are the main American codes which address the transportation of liquids and gases by pipeline respectively.

The US Federal Code (US "49 CFR 195) only applies to pipelines transporting CO_2 in the supercritical phase and is therefore only relevant to proposals to use pipelines to convey supercritical CO_2. There does not appear to be any equivalent code which addresses the transport of gaseous or liquid CO_2. For gaseous carbon dioxide then 49 CFR 192 applies rather than 49 CFR 195 [15].

ASME Standard B31.4 does not specifically exclude pipelines transporting CO_2, but does not include CO_2 within the list of fluids to which it is intended to apply. ASME Standard B31.8 specifically excludes pipelines carrying CO_2 (in any phase). This gas specific code is used to evaluate the safety issues around a gas pipeline, applying these rules to carbon dioxide liquid lines as the fluid transitions to gas on release.

The core standard is ASME B31.4 the code for liquid pipelines (see Figure 5-3). However, evidence suggests that ASME B31.8 is also applied.

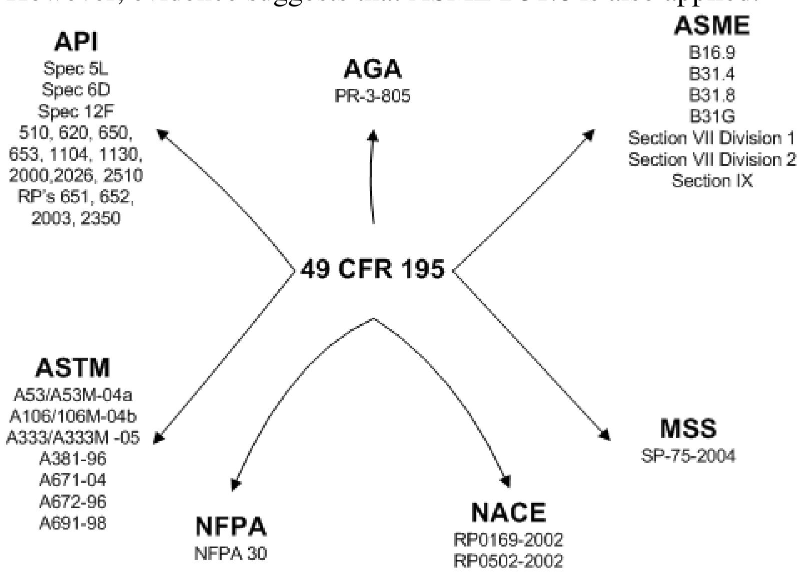

Figure 5-3 Prescribed standards and codes under 49 CFR 195 [33]

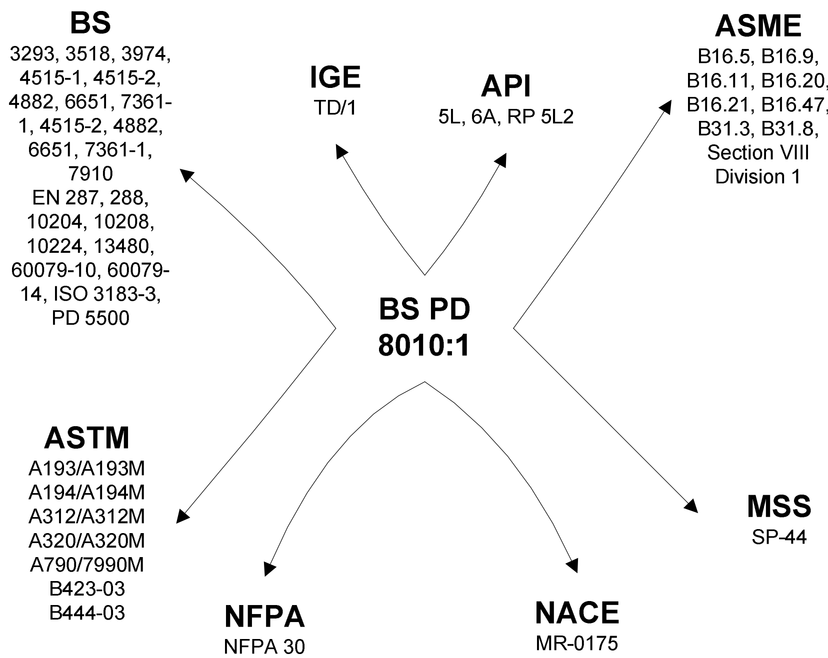

Figure 5-4 Standards associated with BS PD 8010 Part 1 [33]

5.5 Recommended practice

The existing standards do not cover CO_2 transportation sufficiently, but in 2010 a Recommended Practice has been published by Den Norske Veritas, DNV-RP-J202: Design and Operation of CO_2 pipelines (2010) [16]. This recommended practice was developed as an international joint industry project and is followed by a second phase that is ongoing (2011). This document states which standards apply to CO_2 transportation by pipeline and gives recommendations for designing, constructing and operating CO_2 pipelines as a supplement to the existing standards.

The DNV RP J202 document (guideline approved as Recommended Practice) identifies potential technology or knowledge gaps between pipeline transportation of CO_2 and hydrocarbons. International recognised standards for pipeline systems will be the basis also for pipelines for CO_2 transport, but this document will serve as an important and necessary support for specific issues related to transport of CO_2.

The standards as referred throughout the DNV guideline/RP document are:

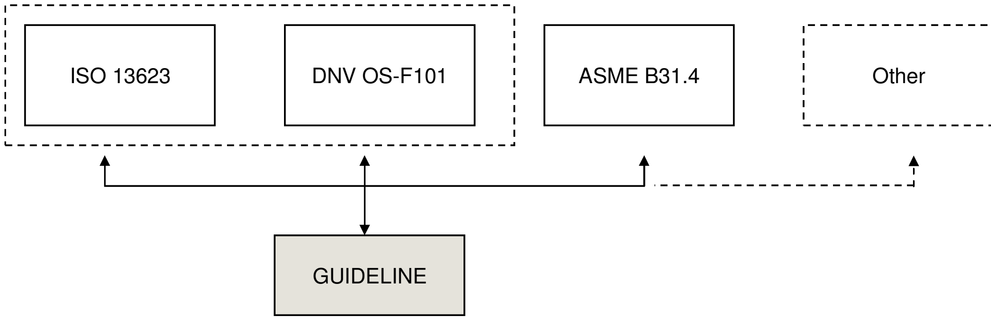

Figure 5-5 The relationship between the DNV recommended practice ("GUIDELINE" in the figure) and the major general pipeline standards referred to.[1]

The technical system boundaries for the Recommended Practice are:

- *Start of regarded system is pipeline inlet after compression and CO2 preparation.*

- *End of regarded system is pipeline outlet at a delivery point at a storage site. (Injection part is not included).*

Of the large range of standards existing on pipeline systems[2], two major standards identified by DNV (see figure above) as applicable to build further on for pipelines for CO_2 in CCS development in Europe are the international standard ISO13623[3] (for Petroleum and natural gas industries - Pipeline transportation systems), and the American standard ASME B31.4 for hydrocarbon pipeline systems. The ASME B31.4

[1] Remark: The DNV OS-F101 is an offshore standard.

[2] IEA Greenhouse Gas R&D Programme wrote a report in 2003, "Barriers to overcome in implementation of CO_2 capture and storage (2): Rules and standards for the transmission and storage of CO_2; (Report Number PH4/23). That report includes as Appendix D a 39-pages table listing various pipeline standards that in one way or another could be referred to.

[3] ISO 13623:2009 / EN 14161:2003:
ISO 13623:2009 'Petroleum and natural gas industries - Pipeline transportation systems' is an international standard which was prepared by Technical Committee ISO/TC 67, Materials, equipment and offshore structures for the petroleum, petrochemical and natural gas industries, Subcommittee SC 2, Pipeline transportation systems.
ISO 13623 specifies requirements and gives recommendations for the design, materials, construction, testing, operation, maintenance and abandonment of pipeline systems used for transportation in the petroleum and natural gas industries. It applies to pipeline systems on land and offshore, connecting wells, production plants, process plants, refineries and storage facilities, including any section of a pipeline constructed within the boundaries of such facilities for the purpose of its connection.
It applies to rigid, metallic pipelines. It is not applicable for flexible pipelines or those constructed from other materials, such as glass-reinforced plastics.
ISO 13623:2009 is applicable to all new pipeline systems and can be applied to modifications made to existing ones. It is not intended that it apply retroactively to existing pipeline systems.
It describes the functional requirements of pipeline systems and provides a basis for their safe design, construction, testing, operation, maintenance and abandonment.
Even though the standard does not give specific requirements for CO2 pipelines, the majority of requirements and guidelines also apply to CO2 pipelines.

includes some parts specific for CO_2 pipelines (mainly for the purpose of enhanced oil recovery). The European pipeline standard EN 14161 is ISO 13623 modified, and is implemented also as national European versions, e.g. in Denmark and UK respectively and are used for natural gas pipelines there.

5.6 Re-use of existing pipelines for CO_2 transport

As a potentially feasible option for establishing a pipeline network for transporting CO_2, existing pipeline infrastructure may be used on the condition that the pipelines are requalified for CO_2 transportation. Applicability of the recommendations included in this section relates to but are not limited to pipelines where the following parameters are significantly altered:

— Safety issues related to change of product
— Physical properties of the product
— Operating conditions
— Life time.

Re-qualification shall comply with the same requirements as for a pipeline designed specifically for transportation of CO_2. Any deviation identified shall be thoroughly evaluated and concluded whether it is acceptable or not. For a pipeline re-qualified for CO_2 transportation it may, however, not be feasible from either a technical or cost perspective to comply with all recommendations for a purpose built pipeline.
Under US regulations this option of re-uses is covered. Within these regulations carbon dioxide as a supercritical fluid or liquid is covered under 49 CFR 195 and any pipe changing service is required to meet the regulations for the new service.

5.7 Conclusions

The experience with CO_2 transportation in the United States and Canada has resulted in a fair amount of standards for CO_2 pipelines design, construction and operation. European regulation is very extensive for pipelines in general, but CO_2 transportation is not covered specifically. The Recommended Practice for design and operation of CO_2 pipelines that has been published addresses the gaps in existing standards. As a basis, this Recommended Practice could be useful to draft a specific CO_2 transportation standard.

6 ENVIRONMENTAL AND ORGANISATIONAL STANDARDS AND CO_2 SOURCE DESIGN CONSIDERATIONS

6.1 Environmental & Organisational Management Guidelines

Large-scale CO_2 transport requires sound environmental and organisational standards. This chapter discusses the potential impact of CO_2 transport on the environment, as well as ways to handle this impact. A guidance for proper implementation of environmental management system according to EN ISO 14001 into the existing quality system according to EN ISO 9001 is described below.

The objective is the process of enhancing the environmental management system to achieve improvements in overall environmental performance. These are elements of an organization's activities, products or services that can interact with the environment. For example transportation of carbon dioxide resulting in any change to the environment, whether adverse or beneficial, wholly or partially resulting from an organization's environmental aspects. [34].

Several publications are providing more details on general environmental issues, legislation for the gas industry and operational good environmental practices. A list of these linked documents and their links to the ISO 14001 environmental management systems standard is provided in Table 6-1.

The ISO 14001 Standard shares common management system principles with the ISO 9000 series of quality system Standards (Table 6-2). Therefore the existing management system consistent with the ISO 9000 series should be used as a basis for the environmental management system. The EN ISO 14001 environmental management system model is shown in Table 6-3.

The environmental impact of the plants, pipelines and other installations related to the current operation of an organization are assessed in an initial environmental review. Such a review acts as a starting point for determining environmental protection measures and additional requirements of an installation or pipeline. An extensive initial environmental review requires the examination and disposal of records and documents, such as:

- Maps and plans of the pipeline routes and surroundings (geological, hydrogeological) (circa 5 km radius)
- Pipeline surroundings history and past operations
- Process flow diagrams and mass and energy balances
- Listings of raw materials, auxiliary material, fuels, products, hazardous substances, quantity of waste, energy and water use.
- Material Safety data sheets
- Applicable laws, regulations, licences, permissions
- Incident records

- Inspection, maintenance and calibration records
- Organization plans
- Information about emergency and crisis preparedness and response
- Training plans and records for employees and contractors
- Contractor and supplier information including waste management contractors

Table 6-1: EIGA Document links to ISO 14001

Doc No	Title of EIGA IGC document	ISO 14001 (2004) SECTIONS	Clause
107	Guidelines on Environmental Management Systems	General Requirements	4.1
		Environmental Policy	4.2
		Planning	4.3
		Objectives, targets and programme(s)	4.3.3
		Implementation and operation	4.4
		Resources, roles, responsibility	4.4.1
		Competence, Training and awareness	4.4.2
		Communication	4.4.3
		Documentation	4.4.4
		Control of documents	4.4.5
		Emergency Preparedness and response	4.4.7
		Checking	4.5
		Monitoring and measurement	4.5.1
		Evaluation and compliance	4.5.2
		Non-conformity, corrective preventive action	4.5.3
		Control of records	4.5.4
		Management review	4.6
106	Environmental Issues Guide	Environmental aspects	4.3.1
108	Environmental Legislation guide	Legal and other requirements	4.3.2
30	Disposal of Gases	Operational control	4.4.6
85	Noise Management for the industrial gas industry	Operational control	4.4.6
88	Good Environmental Management Practices for the industrial gas industry	Operational control	4.4.6
109	Environmental Impacts of Acetylene plants	Operational control	4.4.6
84	Calculation of Air Emissions from Acetylene Plants	Operational control	4.4.6
05	Guidelines for the management of waste acetylene cylinders	Operational control	4.4.6
94	Environmental Impacts of Air Separation Units	Operational control	4.4.6
110	Environmental Impacts of Cylinder Filling Plants	Operational control	4.4.6
117	Environmental Impacts of Customer Installations	Operational control	4.4.6
111	Environmental Impacts of Carbon Dioxide and Dry Ice Production	Operational control	4.4.6
122	Environ. Impacts of Hydrogen Plants	Operational control	4.4.6
112	Environ. Impacts of Nitrous Oxide Plants	Operational control	4.4.6
113	Environmental Impacts of Transportation of Gases	Operational control	4.4.6
137	Decommissioning	Operational control	4.4.6
135	Environmental auditing guide	Internal Audit	4.5.3

Table 6-2: Comparison of different management systems standards

Requirements	Quality ISO 9001 – 2008	Environment ISO 14001: 2004	Safety OHSAS 180012007
General requirements	4.1	4.1	4.1
Documentation requirements - General	4.2.1	4.4.4	4.4.4
Control of documents	4.2.3	4.4.5	4.4.5
Control of records	4.2.4	4.5.4	4.5.4
Policy	5.3	4.2	4.2
Planning	5.4	4.3	4.3
Objectives	5.4.1	4.3.3	4.3.3
Responsibility and authority	5.5.1	4.4.1	4.4.1
Communication	5.5.3	4.4.3	4.4.3
Management Review	5.6	4.6	4.6
Resources and competence	6.1 6.2 6.3 6.4	4.4.1 4.4.2	4.4.1 4.4.2
Operational Control	7.1 7.5	4.4.6	4.4.6
Requirements related to the product / Aspects	7.2.1 7.2.2	4.3.1 4.3.2	4.3.1 4.3.2
Internal Audit	8.2.2	4.5.5	4.5.5
Evaluation of compliance	8.2.3 8.2.4	4.5.2	4.5.2
Nonconformity, corrective action and preventive action	8.3	4.5.3	4.5.3.2
Emergency preparedness and response	8.3	4.4.7	4.4.7
Monitoring and measurement	8.4	4.5.1	4.5.1

6.2 CO_2 sourcing management for pipeline transport

The effect of contaminants on carbon dioxide is significant. Experience in the USA so far has been on carbon dioxide from mainly geological and to a lesser extent anthropogenic sources. For CCS, there will be different sets of compositions. The composition of a CO_2 stream will depend on the CO_2 source and the capture process. Thus, a CO_2 transport network will have to deal with the compositions of all CO_2 sources that are connected to it. A CO_2 transport network interconnects multiple sources and/or sinks. Especially when there is more than one CO_2 source, the compositions of the CO_2 streams become of interest. For simple single source to single storage solutions the composition range will be defined by what the emitter can economically produce and what the storage site can accept. However the acceptable composition for carbon dioxide streams is not just set by the emitter or capture technology but by the other elements, particularly storage and transportation. Therefore a proper guidance on standards for source qualification and specification for CO_2 pipeline transport is needed for developing a multi-source based pipeline network.

Given the economic optimisation that the capture plant owner will perform in relation to the content of the CO_2 there will be a natural tendency to impure CO_2 as removing elements is expensive in energy and cost. The discussion on point to point solutions must include possible mixing with future CO_2 streams if CCS is to develop further. The boundary conditions of the storage site will prove to be leading in setting absolute limits, whereas water would probably be the main impurity from a transportation point of view.

The rate of other components in the CO_2 stream is a matter of techno-economic optimisation of a capture process including purification processes. In a point to point pipeline scenario the CO_2 specifications limits will be set mainly by technical evaluation and risk analysis of the pipeline and geological storage. The discussion on point to point solutions must include possible mixing with future CO_2 streams if CCS is to develop further. The limitations of the storage site will prove to be leading in setting absolute limits, where the transportation limits most probably will be focussing on water and corrosion. In a larger infrastructure, with a network of sources, pipelines and receivers (aquifers, oil fields etc.) of the CO_2 stream, the specification of the CO_2 streams has to be harmonised between different operators.

6.3 Source evaluation

Carbon dioxide is a by-product of many different natural, and chemical processing mechanisms and power production. This capability of multiple source types makes it unique in the industry. The variation of sources results in a variety of specific impurities that may be anticipated to be present in carbon dioxide. The emitter, transporter and storage operator may assign acceptable levels for the potential compounds. Additionally established regulations may be required to define reasonable and prudent levels.

The emitters should perform an analysis of the source raw gas stream before design of the purification plant. During design the process controls required to ensure that carbon dioxide is produced according to the specification must be determined. The initial assessment of the raw gas source will give an indication of the normal variations in the composition of the raw gas. This may be used to select the components to be analyzed and the frequency of regular analysis. Such an assessment should include a broad screening by chemical analysis, of components that could possibly be present as impurities for the type of source or introduced as contaminants in the process.

6.4 Production qualification tests and design validation

All carbon dioxide production facilities supplying carbon dioxide must be proven by analysis of all the key characteristics in Table 6-4. This analysis may be a single analysis of a new facility or a series of analyses at a frequency determined by the emitter or by agreement with the customer.

A risk assessment (as described in EIGA doc 125) should be used to identify key process controls required to ensure compliance with the specification. The effectiveness of these process controls may be assessed directly by chemical analysis, by the use of process tracers or by the use of process control instrumentation e.g. flow switches to verify operation of water scrubbers, temperature controls on catalytic oxidation systems, pressure and flow controls on stripping columns. The operation of the plant should be reviewed on a regular basis and be subject to periodic maintenance to ensure that the plant is in good condition.

6.5 Quality control / Quality assurance

Each facility producing carbon dioxide should have a documented system for quality management following the model in the ISO 9000 series of standards. The quality control and quality assurance procedures described by this document only apply to the carbon dioxide production sources. The EIGA documents listed in references below should be consulted.

6.6 Quality control in CO_2 production

The CO_2 raw gas composition will determine the design of the plant, especially the purification steps and procedures and also the analytical controls during the process.
The purification process will need analytical controls for the process, if no other relevant parameters can be used, to assure that the purification step is working as intended.
Analytical controls during the process may be continuous using on-line instruments or based on spot checks. This choice and the selection of the frequency for checks will depend on:

- the component to be measured
- the likely concentration of the component
- the importance of the component to the perceived quality of the CO_2

- the ease of measurement
- risk assessment of the purification process designed to remove the component to acceptable levels.
- regulatory mandates and/or individual guide.

The frequency of checks will vary depending on consideration of these factors and may typically be from one per hour to two per year for components not analyzed by continuous monitoring instruments.

7 CONCLUSIONS

Production platforms could be used as CO_2 injection platforms under specific circumstances, but this would not be straightforward. When production has ceased, the platform is dismantled and removed within 2 years. It is expected that in many cases, no CO_2 injection will take place at a platform for years after the end of production, so permission is needed to postpone abandonment and the platform will have to be kept in good condition. This means there are legal and financial hurdles to take. Furthermore, platforms differ from each other in size, weight and configuration. The modifications needed to start using platforms for CO_2 injection will be expensive but the older the platform is, the better the possibilities for CO_2 injection. Power supply to the platform could also be an issue if there is no more production at the platform.

Probably existing pipelines are of very limited use for large-scale CO_2 transport, because they are unavailable when CO_2 transport is needed and because their pressure rating is not high enough for large CO_2 flows, at least for onshore pipelines. It is expected that dedicated CO_2 pipelines will be built.

For CO_2 transport by ship, only a few dozens of existing gas carriers are suitable, so new, dedicated CO_2 ships are the best option. There are no foreseeable technical hurdles to implementing CO_2 transport by ship.

The broad experience with CO_2 transportation in the United States and Canada has resulted in a fair amount of standards for CO_2 pipelines design, construction and operation. European regulation is very extensive for pipelines in general, but CO_2 transportation is not covered in detail. The DNV Recommended Practice for design and operation of CO_2 pipelines that has been published addresses the gaps in existing standards.

Pipeline engineering is a mature engineering subject. However, for the specific field of CO_2 transportation, there is a number of issues that need to be taken into account. CO_2 is a substance with well-known characteristics, but the same cannot be said of CO_2 with impurities. Especially because the pressure and temperature range of CO_2 is close to the phase boundary, which is subject to changes in the presence of impurities, the characteristics of CO_2 with impurities are vitally important to know in order to engineer a CO_2 transport system. Detailed thermodynamics of CO_2 with impurities has been modelled, but the available models have not been sufficiently validated, so caution must be used in engineering CO_2 transportation pipelines.

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