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Technical and Economic Characteristics of a CO_2 Transmission Pipeline Infrastructure

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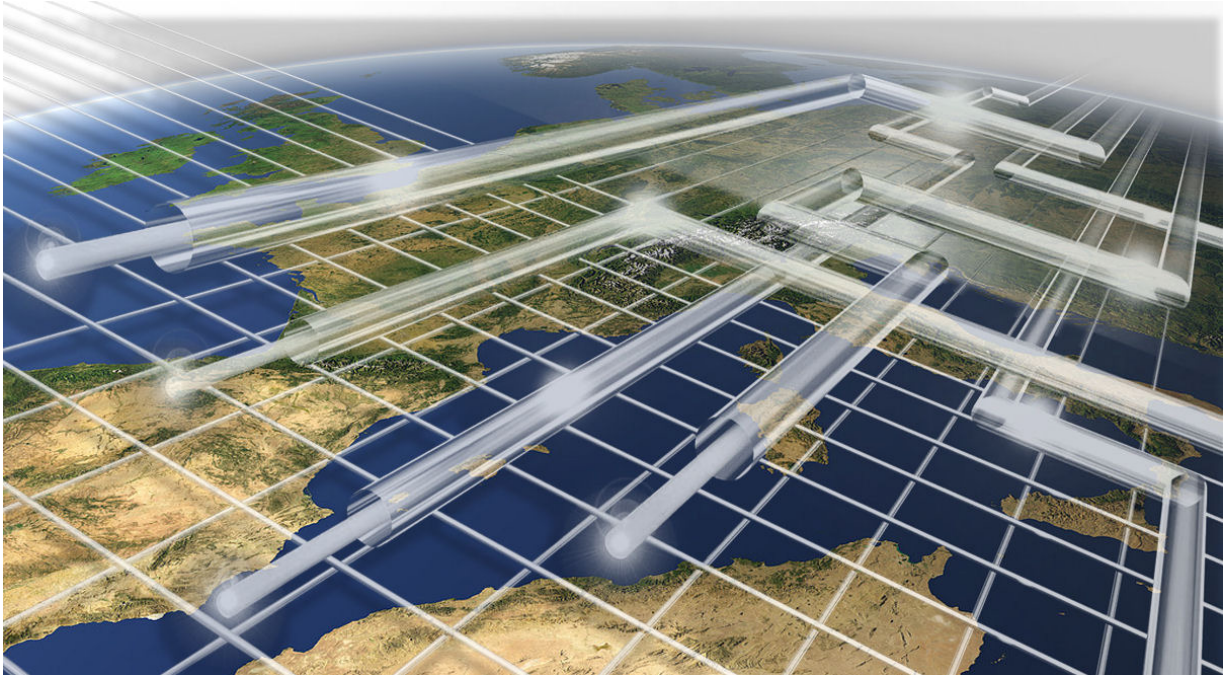

EUR 24731 EN - 2011

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JRC62502

EUR 24731 EN
ISBN 978-92-79-19425-2
ISSN 1018-5593
doi:10.2790/30861

Luxembourg: Publications Office of the European Union

Printed in The Netherlands

EUROPEAN COMMISSION
DIRECTORATE-GENERAL
JOINT RESEARCH CENTRE
INSTITUTE FOR ENERGY

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Executive summary

Carbon capture and storage is considered one of the most promising technological options for the mitigation of CO_2 emissions from the power generation sector and other carbon-intensive industries that can bridge the transition period between the current fossil fuel-based economy and the renewable and sustainable technology era. CCS involves the capture of CO_2 from the sources, the transport of CO_2 through dedicated pipelines and ships, and the storage of CO_2 in geological reservoirs, such as depleted oil and gas fields and saline aquifers, for its permanent isolation from the atmosphere.

The development of CCS technologies has increased significantly in the last decades; however, there are still major gaps in knowledge of the cost of capture, transport and storage processes. Pipelines have been identified as the primary means of transporting CO_2 from point-of-capture to sites where it will be stored permanently but there is little published work on the economics of CO_2 pipeline transport and most cost studies either exclude transport costs or assume a given cost per tonne of CO_2 in addition to capture costs.

The aim of this report is to identify the elements that comprise a CO_2 pipeline network, provide an overview of equipment selection and design specific to the processes undertaken for the CO_2 transport and to identify the costs of designing and constructing a CO_2 transmission pipeline infrastructure.

1 Introduction

1.1 Context, aim and organization of the report

Carbon capture and storage is considered one of the most promising technological options for the mitigation of CO_2 emissions from the power generation sector and other carbon-intensive sources that can bridge the transition period between the current fossil fuel-based economy and the renewable and sustainable technology era. CCS involves the capture of CO_2 from the sources, the transport of CO_2 through dedicated pipelines and ships, and the storage of CO_2 in geological reservoirs, such as depleted oil and gas fields and saline aquifers, for its permanent isolation from the atmosphere.

The development of CCS technologies has increased significantly in the last decades; however, there are still major gaps in knowledge of the cost of capture, transport and storage processes. Most of the literature concentrates on carbon capture processes and engineering-economic models linking process cost to key engineering parameters, but transport and storage models to determine the cost of an integrated CCS process have not yet been addressed by the majority of the studies. There is little published work on the economics of CO_2 pipeline transport and most cost studies either exclude transport costs or assume a given cost per tonne of CO_2 in addition to capture costs.

The aim of this report is to identify the elements that comprise a CO_2 pipeline network, to provide an overview of equipment selection and design specific to the processes undertaken for the CO_2 transport and to identify the costs of designing and constructing a CO_2 transmission pipeline infrastructure. Pipelines have been identified as the primary means of transporting CO_2 from point-of-capture to site where it will be stored permanently. Although the use of ship transport for CO_2 has been proposed as an alternative option for pipeline transport, it is considered unlikely to be realised at the early stages of CCS deployment due to its state of maturity and capacity and due to non-accessibility by sea of many possible CO_2 sources and sinks. In this way, ship transport is out of the scope of this report.

The report draws on recent literature and is organised in two main sections, one related to the technical aspects of CO_2 transport and the other to the costs of CO_2 pipelines. The report is divided in four chapters, including this introductory chapter and the conclusion. The technical section identifies the main processes undertaken in CO_2 pipeline systems and its constituting elements, the basic conditions involved in the preliminary pipeline design and the key equations that affect pipeline design. The costs section identifies cost categories, reviews cost estimation studies and methods, and presents the development of a pipeline costing formula based on a statistical analysis of available CO_2 pipeline cost estimates, combined with publicly available assessments of ongoing large natural gas pipeline projects.

1.2 General aspects of CO_2 transport

CO_2 can be transported in gaseous, liquid or, rarely, solid phase. Today, CO_2 is mainly used for industrial purposes. Examples of CO_2 applications include oil recovery, food industry and wine making. Commercial-scale transport is based on tanks, pipelines and ships for gaseous and liquid CO_2. Pipelines are the dominant mode of transporting CO_2 and previous work has identified pipeline transport of CO_2 as the most economical method of transport for large volumes of CO_2 in the context of CCS [46][54]. The advantage of pipeline transport is that it can deliver a constant and steady supply of CO_2 without the need for temporary storage along a transmission route. Ship transport may be feasible when there is a need for transport over long distances or overseas; however, the location of anthropogenic CO_2 sources and suitable sinks is typically away from navigable waterways, so such scheme would still most likely require pipeline construction between CO_2 sources and port terminals [54].

1.2.1 Existing experience with CO_2 pipelines

CO_2 has been transported and used by industries for several decades and, in recent years, for enhanced oil recovery (EOR) applications, and therefore, large-scale transport of CO_2 is not a new technology [1]. The majority of the CO_2 pipelines are located in North America, where there is over 30 years of experience in carrying CO_2 from mostly natural sources to oilfields as part of CO_2 EOR operations through an extensive CO_2 pipeline infrastructure [11]. There is also some limited transport of captured CO_2. The CO_2 pipeline infrastructure now extends over more than 2500 km in the western USA [23], and it is estimated to be about 3100 km long worldwide with a capacity of 44 million tonnes of CO_2 per year [55]. In Europe, except for Turkey, long-distance pipelines for the transport of CO_2 are non-existent but recently networks have started to operate, with the biggest infrastructures in the North Sea (e.g. 160 km pipeline for Snøhvit LNG project) and in the Netherlands (about 80 km pipeline to transport CO_2 to greenhouses from Rotterdam to Amsterdam).

Onshore and offshore CO_2 pipelines are constructed in the same way as hydrocarbon pipelines, and for both there is an established and well understood basis of engineering experience. Fluid transmission by pipelines is a mature technology and pipelines routinely carry large volumes of natural gas, oil, condensate and water over distances of thousands of kilometres, both on land and in the sea. Different environments for pipelines locations include deserts, mountain ranges, heavily populated areas, farmland and the open range, in the Arctic and sub-Arctic, and in seas and oceans up to 2200 m deep [23]. Nevertheless, there is significantly less experience for CO_2 than for hydrocarbon transport.

Table 1 presents the characteristics of the main existing long-distance pipelines from natural and anthropogenic sources of CO_2. The oldest long-distance CO_2 pipeline in the USA is the 225-km Canyon Reef Carriers pipeline, which began service in 1972 for EOR in Texas and the longest CO_2 pipeline, the 800-km Cortez pipeline, has been delivering about 20 Mt of CO_2

per year to a CO_2 hub in Texas. Table 2 presents the existing CO_2 transport projects in the North Sea.

Table 1 – Existing long-distance pipelines with natural and anthropogenic sources of CO_2 (adapted from [23][49]).

Pipeline	Location	Operator	Capacity (Mt/yr)	Length (km)	Diameter (mm)	Pressure (bar)	CO_2 source	Year
Cortez	USA	Kinder Morgan	19.3	803	762 (30'')	186	McElmo Dome	1984
Sheep Mountain	USA	BP AMOCO	n/a	296	508(20'')	n/a	Sheep Mountain	1983
Sheep Mountain North	USA	BP AMOCO	n/a	360	610 (24'')	132	Sheep Mountain	1983
Bravo	USA	Kinder Morgan	7.3	350	508 (20'')	165	Bravo Dome	1984
Central Basin	USA	Kinder Morgan	20	278	400-650 (16-26'')	170	Denver City hub	1985
Bati Raman	Turkey	Turkish Petroleum	1.1	90	n/a	170	Dodan field	1983
Canyon Reef Carriers	USA	Kinder Morgan	4.4	352	400 (16'')	140	Gasification plant	1972
Val Verde	USA	Petro Source	2.5	130	250 (10'')	n/a	Gas plant	1998
Bairoil	USA	n/a	8.3	180	n/a	n/a	Gas manufacturing plant	1986
Weyburn	USA&Canada	North Dakota Gasification Co.	5	328	305-356 (12-14'')	152	Gasification plant	2000

n/a – not available

Table 2 – Existing projects of CO_2 transport for CCS in the North Sea (adapted from [44]).

Pipeline	Operator	Capacity (Mt/yr)	Length km)	Diameter (mm)	Pressure (bar)	CO_2 source	Purpose	Year
Sleipner	Statoil	1	160	n/a	n/a	Separation from natural gas	Storage	1996
Snøhvit	Statoil	0.7	153	200 (8'')	100	Amine CO_2 separation/natural gas	Storage	2006

n/a – not available

Considering the high number of suitable offshore CO_2 storage sites identified, considerable proportions of the CO_2 transport system would be subsea, for which there is virtually no experience as yet. To date only one offshore CO_2 pipeline has been put to service, but this is due to a lack of demand rather than any technical barrier. The only existing offshore CO_2 transport pipeline is the Snøhvit pipeline, a 153 km seabed pipeline from Hammerfest to the subsea injection well at the Snøhvit field in Norway, which has been transporting CO_2 since in May 2008 [21]. All of the currently operating CO_2 pipelines in the US are onshore, and many are

routed through sparsely-populated areas, and there is little experience with multi-source transport systems through densely-populated regions. There are significant differences, however, between the USA experience with natural CO_2, and the transport requirements for anthropogenic CO_2. These differences will be explored later in section 2.2.

1.2.2 Regulations and codes

The design of a pipeline should meet the requirements of appropriate regulations and standards in terms of: pressure (wall thickness, over-pressure protection systems), resistance to degradation (internal due to, e.g., corrosion and external due to environmental conditions), protection from damage (e.g., burying the line), appropriate monitoring facilities and safety systems, and location considerations [19][51]. CO_2 pipelines shall be designed in accordance with industry recognized standards and applicable regulatory requirements.

In the USA, CO_2 pipelines are subject to diverse local, state, and federal regulatory oversight and are regulated under the Department of Transportation 49 Code of Federal Regulations Part 195 [50]. The US Department of Transportation sets minimum safety standards for pipelines transporting hazardous liquids, including CO_2. No similar or comparable regulations for CO_2 pipelines exist in Europe.

A recent report commissioned by the International Energy Agency Greenhouse Gas Programme (IEA GHG) suggests that the safety issues surrounding CO_2 transport by pipeline can be covered by existing standards and guidance documents [21]. Table 3 identifies the main guidelines and standards applicable to the CO_2 transport.

DNV initiated a joint industry project, named CO2PIPETRANS, with ArcelorMittal, BP, Chevron, Dong Energy, Gassco, Gassnova, ILF, Petrobras, Shell, Statoilhydro and Vattenfall, to adapt the existing pipeline standards to the specifications of the transmission of CO_2 and to provide guidance and set out criteria for the development, design, construction, testing, operation and maintenance of steel pipelines, technical difference between the transmission of large volumes of CO_2 in pipelines and the transmission of hydrocarbons. The guideline developed, the Recommended Practice for Design and Operation of CO_2 Pipelines DNV-RP-J202 [6], was released in May 2010 and constitutes a supplement to current pipeline standards like ISO 13623, DNV OS-F101, ASME B31.4 and others.

The ISO 13623:2009 on pipeline transportation systems [24] specifies requirements and gives recommendations for the design, material, construction, testing, operation and abandonment of pipeline systems used for transportation in petroleum and natural gas industries, and it applies to pipeline systems on land and offshore. The relevance of these standards is that they set the scene for the development of standards for CO_2 pipelines.

The standard on Submarine Pipeline Systems DNV-OS-F101 [3] is one of the most widely-used codes for offshore design of pipelines. However, there are no stated restrictions in the use of this code for the transport of CO_2, and the gas is specifically mentioned only as an example of "non-flammable substance which is non-toxic gas at ambient temperature and atmospheric pressure conditions". With this fluid classification, pipelines for CO_2 will be designed to safety class 'low', or 'normal' in areas of human activity. Implicitly, less severe safety factors than for natural gas are applicable.

The ASME B31.4 liquid code [47] prescribes requirements for the design, material, construction, assembly, inspection and testing of piping transporting liquids such as crude oil, condensate, natural gas liquids, liquefied petroleum gas, carbon dioxide, among others. Worldwide, most operators have designed pipelines using the ASME B31.8 code for gas pipelines as these tend to be more conservative than the ASME B31.4 code for liquid transportation.

In order to assist the delivery of pipelines in compliance with international laws and regulations, the ongoing project CO2PIPETRANS Phase 2 will update the Recommended Practice for Design and Operation of CO_2 to close the significant knowledge gaps that have been identified in Phase 1 and in this way enabling CCS to move forward on an international basis using consistent knowledge-based guidance.

Table 3 – Pipeline standards.

Reference	Standard full name
DNV-RP-J202	Recommended Practice on Design and Operation of CO_2 Pipelines
ISO 13623:2009	Petroleum and Natural Gas Industries – Pipeline Transportation Systems.
DNV-OS-F101	Offshore Standard on Submarine Pipeline Systems
ASME B31.4	Code for Pressure Piping – Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids

2 Technical characteristics and design of CO_2 pipelines

The CO_2 transport chain starts with the conditioning of a CO_2-rich stream that is received from the capture process and ends with the injection into a storage site. Between these two points CO_2 transport takes place in a pipeline. The main processes taken in pipeline transport systems for CO_2 can be seen in Figure 1 and are the following: conditioning of concentrated CO_2 captured from the source, which includes the purification of the CO_2 to the desired composition and compression to the required pressure level; pipeline transport, which may include intermediate recompression via compressor booster stations, if required. Storage follows.

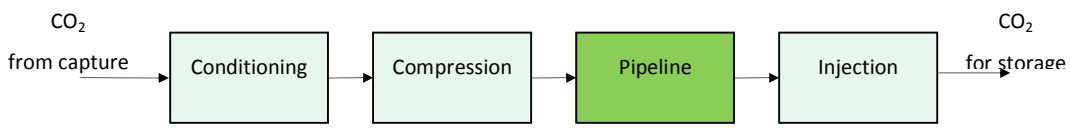


Figure 1 – The CO_2 transport chain.

The CO_2 generated by industrial and energy-related sources is first separated from the flue gas by different capture technologies. Prior to transport, captured CO_2 is conditioned to remove impurities and compressed. The conditioning and compression of the captured CO_2-rich stream is often assumed to be the final part of the CO_2 capture process. Once the CO_2 has been dried and meets the transportation criteria, the CO_2 is measured and transported to the final use site.

A CO_2 pipeline system must be able to accommodate varying flows, surges and variations in the composition of the CO_2 fluid itself. Key issues for the CO_2 transport are: chemical and physical properties of the CO_2, composition of the CO_2 stream including any impurities within it, and consideration of pressures to maintain the CO_2 in the required phase throughout the network without exceeding safe levels at other points.

The following sections provide an overview on the properties and behaviour of CO_2 that are relevant for the design and operation of a CO_2 pipeline, as well as an overview of the constituting elements, the basic conditions involved in the preliminary pipeline design and the key equations that affect pipeline design.

2.1 Properties of CO_2

Pure CO_2 is a colourless, odourless, and non-flammable substance at ambient pressure and temperature. CO_2 is naturally present in the atmosphere constituting around 0.038% of its volume. The physical state of CO_2 varies with temperature and pressure: at normal temperature and pressure, CO_2 is a gas; at low temperatures CO_2 is a solid; at intermediate temperatures (between –56.5°C, and 31.1°C), CO_2 may be turned from a vapour into a liquid by compressing it to the corresponding liquefaction pressure. The phase diagram for pure CO_2, which contains two distinct features – the triple point (5.2 bar, -56.5°C) and the critical point (73.8 bar, 31.1°C) – is presented in Figure 2. Triple point can be defined by the temperature and pressure at which the three phases - gas, liquid, and solid – of a substance coexist in thermodynamic equilibrium. The critical point is defined by the critical pressure and temperature of the fluid composition above which the substance exists as a supercritical fluid, where distinct liquid and gas phases do not exist [3]. In the vicinity of the triple point, CO_2 can exist as one of the three phases: solid, liquid, or gas, and the curve connecting the two points is the vapour-liquid line separating the gaseous and liquid phases. At pressures and temperatures above the critical point, CO_2 no longer exists in distinct gaseous and liquid phases, but as a dense-phase or supercritical phase with the density of a liquid but the viscosity of a gas. Increases in pressure no longer produce liquids at temperatures exceeding the critical temperature. At pressures above, but temperatures below critical, the CO_2 exists as a liquid whose density increases with decreasing temperature [44].

In this way, the most efficient state of CO_2 for pipeline transport is as a dense-phase liquid [20], allowing high density of fluids without risk of phase change, which corresponds to a lower pressure drop along the pipeline per unit mass of CO_2 when compared to the transportation of the CO_2 as a gas or as a two-phase combination of both liquid and gas [3]. In this 'supercritical' mode, captured CO_2 has to be compressed to a pressure above the critical pressure prior to transport, which occurs at a pressure higher than 73.8 bar and a temperature of more than 31.1°C for pure CO_2 [45][46].

It is important for operators to maintain single-phase flow in CO_2 pipelines by avoiding abrupt pressure drops, from a cost and efficiency point of view, in particular if the pipeline requires intermediate boosting stations. In a two-phase flow, two physical phases are present in the pipeline simultaneously (e.g., liquid and gas, or supercritical fluid and gas), which creates problems for compressors and other transport equipment, increasing chances of pipeline failure [23]. At pressures very close to the critical point, a small change in temperature or pressure yields a very large change in the density of CO_2, which could result in a change of phase and fluid velocity.

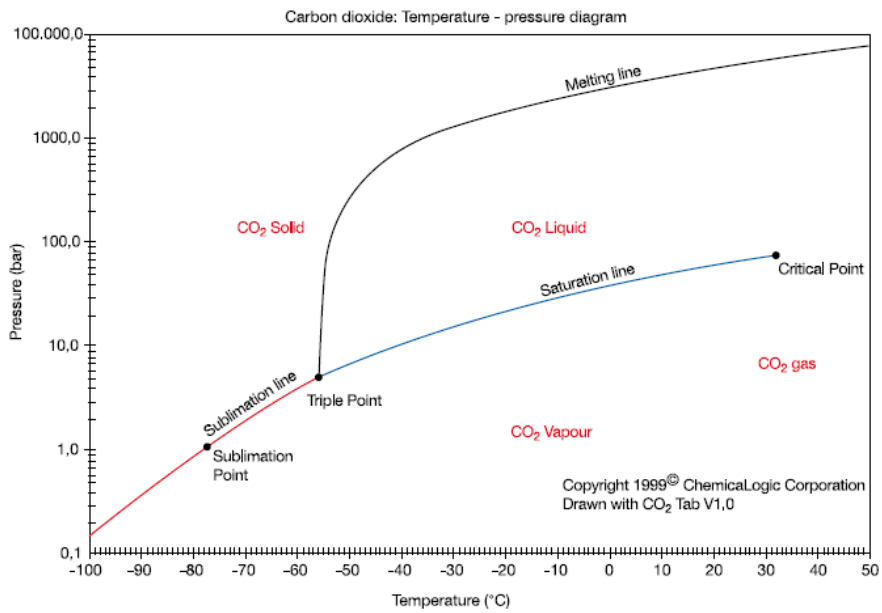


Figure 2 – Phase diagram for pure CO_2 [23].

Table 4 lists the properties of CO_2 with reference to the phase diagram presented in Figure 2.

Table 4 – Selected properties of CO_2.

Property	Unit	Value
Molecular weight	g mol^{-1}	44.01
Critical pressure	bar	73.8
Critical temperature	°C	31.1
Critical density	kg m^{-3}	467
Triple point pressure	bar	5.2
Triple point temperature	°C	-56.5
Gas density (at 0°C and 1.013 bar)	kg m^{-3}	1.976
Liquid density (at -20 °C and 19.7 bar)	kg m^{-3}	1032

2.2 Composition

The composition of the captured CO_2 stream depends on the source type, the implemented CO_2 capture technology and the type of fuel used. CO_2 that is captured from power plants and other anthropogenic sources is not pure, i.e. the stream of gases captured contains other chemical species, besides CO_2. The CO_2 may be captured either from large scale combustion of fossil fuels (gas, oil, and coal) or from industrial processes (steel manufacturing, cement manufacturers refineries, and chemical industries) and the different technologies for capturing the CO_2 include pre-combustion, post-combustion or oxy-fuel processes.

Captured CO_2 may contain impurities like water vapour, H_2S, N_2, CH_4, O_2, Hg, and hydrocarbons, which may require specific handling or treatment [54]. Indicative compositions from capture processes from coal and gas power plants are presented in Table 5. The presence of impurities has a great impact on the physical properties of the transported CO_2 that consequently affects pipeline design, compressor power, recompression distance, and pipeline capacity, and could also have implications for the prevention of fracture propagation [44]. Phase behaviour, density, and viscosity diagrams of CO_2 and CO_2-rich mixtures are necessary for the design of the pipeline.

Table 5 – Indicative compositions of CO_2 streams from coal and gas power plants, in % by volume (adapted from [3][23]).

		Coal fired power plant			Gas fired power plant		
Component	Comment	Post-combustion	Pre-combustion	Oxy-fuel	Post-combustion	Pre-combustion	Oxy-fuel
N_2/ O_2	Non-toxic	0.01	0.03-0.6	3.7	0.01	1.3	4.1
H_2S	Flammable, strong odour, extremely toxic at low concentrations	0	0.01-0.6	0	0	<0.01	0
H_2	Non-toxic	0	0.8-2.0	0	0	1	0
SO_2	Non-flammable, strong odour	<0.01	0	0.5	<0.01	0	<0.01
CO	Non-flammable, toxic	0	0.03-0.4	0	0	0.04	0
CH_4	Odourless, flammable	0	0.01	0	0	2.0	0

The presence of impurities changes physical properties such as the critical pressure, which may have a dramatic impact on the CO_2's flow behaviour. Sequentially this may change the operating regime of the pipeline and higher pressures than used for pure CO_2 might be required in order to maintain it as single-phase supercritical or dense-phase. Depending on the impurities present in the CO_2 stream, these impurities will have a significant effect on hydraulic parameters such as pressure and temperature and also on the density and viscosity of the fluid [40]. When compared to CO_2 most impurities are low-boiling. When supercritical CO_2 is mixed with small amounts of these impurities, a homogeneous mixture is formed, but

its thermodynamic behaviour is strongly influenced by these properties [37]. The change in density is one example of this. Figure 3 shows the density of pure CO_2 and a mixture stream (95% CO_2, 3% N_2, 2% O_2) over temperature. It can be seen that density is lowered due to the impurities -the density of the mixture is about 60% of the density of pure CO_2 at 40°C. Lower densities may lead to higher flow velocities, which correspond to higher pressure drops.

The properties of the CO_2 stream will determine its corrosion behaviour and therefore will have implications on the pipeline design, such as on the material and coating selection as well as the selection of materials used for seals, gaskets, internal lining, and other safety or integrity-critical components, influencing as well the transport costs.

For instance, when H_2 or N_2 are present in the CO_2 stream, they increase pressure and temperature drops for a given pipeline length, which has implications for the distance between compressor stations along the pipeline. The pipeline cost increases with the number of compressor stations which, in any event, are not viable for subsea pipelines. Sudden temperature drops can have potential material implications, such as embrittlement, and can also cause hydrates formation (solid ice-like crystals), both of which could damage the pipeline.

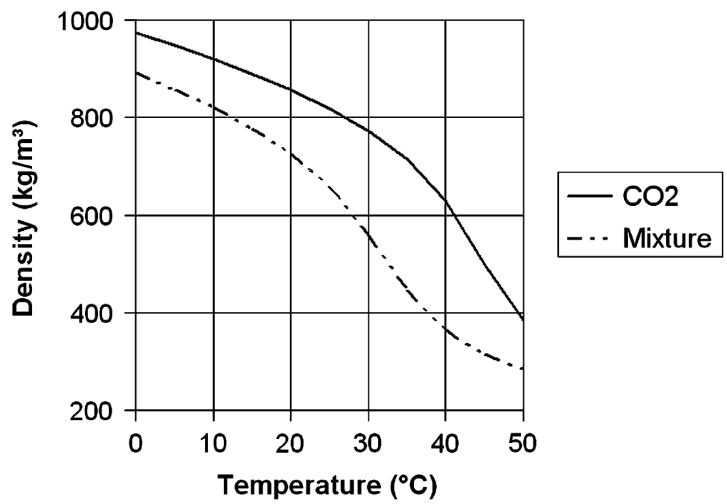


Figure 3 – Differences in densities of pure CO_2 and a CO_2 rich mixture at 100 bar (adapted from [37]).

Regarding the presence of water in the stream, CO_2 in combination with free water is well known from the oil and gas industry to form carbonic acid, which is highly corrosive to carbon steel [2]. Before transport, the CO_2 is dehydrated to levels below 50 ppm of water. Presence of water above this level is not desirable from an operational viewpoint and must be removed to avoid gas hydrates, freezing of water and corrosion [1]. The CO_2 stream ought preferably to be dry and free of H_2S, because it does not corrode the carbon-manganese steels generally used for pipelines.

Gas purification steps may be necessary to adjust to the composition requirements for the captured CO_2 stream. It is important to obtain high concentrations of CO_2 in order to maintain the CO_2 capture rates at the levels specified. Currently there are no composition requirements or established standard for permitted levels of impurities in CO_2 for CCS [31], being the pipeline-quality CO_2 compositions adhered to by the major EOR pipeline operators considered best practice [54] and dependent on the end target (EOR or storage).

For EOR, the CO_2 concentration in the gas transportable via pipeline typically ranges from 95 to 99 percent. At pressure in a reservoir, CO_2 can combine with components in the oil to create miscibility, wherein the fluid combination moves through the reservoir with a viscosity like that of a liquid rather than a gas. For this to happen in the reservoir, the CO_2 should be highly purified (>95%), compressed and cooled, to form a supercritical fluid. Should significant amounts of non condensable gases such as O_2, N_2, or CH_4 be present in the CO_2 stream, it may not be possible to practically produce a supercritical fluid. Thus, for any proposed gas composition, the pipeline designer should conduct appropriate compositional simulations to guarantee that supercritical phase behaviour can be achieved at proposed pipeline operating conditions [1] [55].

Some authors have advocated for setting a CO_2 purity standard above 90%, but many feel that there is enough uncertainty regarding the precise composition of the CO_2 stream that it is best to simply design projects with materials and procedures that account for any co-constituents in the gas stream.

According to the EU Storage Directive [7], which provides a legal framework for the management of environmental and health risks related to CO_2 storage, and which includes requirements on permitting, composition of the CO_2 stream, monitoring and reporting obligations, among others, the CO_2 stream shall consist overwhelmingly of carbon dioxide and may contain incidental associated substances from the source, capture or injection process below levels that would either adversely affect the integrity of the storage site or the relevant transport infrastructure, pose a significant risk to the environment or human health, or breach the requirements of applicable Community legislation. This Directive is a minimum requirement Directive, meaning that the detailed implementation is left to the Member States.

2.3 Operating temperature and pressure

As mentioned before, the most efficient way to transport CO_2 is in a supercritical phase. CO_2 is generally transported at temperature and pressure ranges between 12°C and 44°C and 85 bar and 150 bar, respectively [32][54]. The lower pressure limit is set by the phase behaviour of CO_2 and should be sufficient to maintain supercritical condition while the upper pressure limit is mostly due to economic concerns. Regarding the temperatures, the upper temperature

limit is determined by the compressor-station discharge temperature and the temperature limits of the external pipeline coating material, while the lower limit is determined by winter ground temperature [54]. An advantage of offshore pipelines for CO_2 transport is that higher design pressures can be used than onshore, potentially up to 300 bar. This is partly due to the reduced hazard to population compared to onshore routes, which allow higher design factors to be used; and partly due to the compensatory effects of external hydrostatic pressure, particularly in deep water [21].

2.4 Elements of a pipeline system

The main elements of a CO_2 transport system include pipeline with compressor and booster pumps, pressure control stations, flow control stations, valves, metering stations, pig launchers and receivers, supervisory control and data acquisition systems (SCADA), safety systems and corrosion protection systems. The major elements are described below.

Pipeline

Carbon-manganese steel line pipe is considered feasible for pipelines where the water content of the CO_2 stream is controlled to avoid the formation of free water in the pipeline. Application of corrosion resistant alloy steels linepipe[1] may be an option for short pipelines, as is not considered feasible from a cost perspective for long pipelines[3].

Although steels suitable for linepipe are covered today by various national and international standards - such as the US standard ASTM A984/A 984M-00, the European EN 10208-2:1996 or the International ISO 1362:2009 – most grades are still commonly referred to as from their classification in the American Petroleum Institute Specifications 5L, which identifies them with an X followed by their minimum yield strength in kilo-pounds per square inch (kpsi), e.g. X42,X46, X56 up to X80. Yield strength is the level of applied stress at which the material begins to deform permanently. The minimum yield stress is dependent on the specification and grade of linepipe selected for the pipeline. The actual pipelines for CO_2 transport are usually constructed of carbon steel material, such as American Petroleum Institute grades X60 (composition: $C \leq 0.26$, $P \leq 0.04$, $S \leq 0.05$) or X80 (composition: $C \leq 0.18$, $P \leq 0.03$, $S \leq 0.018$) with a 414–552 MPa yield strength.

Regarding the internal corrosion of pipelines, field experience and experimental work have shown that dry CO_2 and pure CO_2 with dissolved water below the saturation limit are non-corrosive to carbon steel at operating conditions. According to the U. S. Department of Transportation's Office of Pipeline Safety there are no reported damages in CO_2 pipelines caused by internal corrosion. The main strategy for corrosion control should be appropriate humidity control procedure such as dewatering of the CO_2 at the inlet of the pipeline [3]. To

[1] Cylindrical section used in a pipeline for transportation of fluids or gases.

reduce the chances of corrosion, CO_2 pipelines may be covered with a specialized coating, with the purpose of protecting the pipe from moisture [54], though, due to the risk of detachment from the base pipe material, it is not generally recommended[3]. In contrast, external coatings are often used, being fusion-bonded epoxy or polyurethane with full cathodic protection frequently applied. Cathodic protection is the typical secondary system for external corrosion protection, after the primary system provided by external coating.

Compressor stations

Compressors convert the transmissible gas from atmospheric pressure to the desirable transmissible phase, the supercritical state [54]. Compressor stations in a pipeline system can be sub-divided in two classes: the originating stations, which are positioned at the inlet to the pipeline, and the booster stations, which are located along the pipeline to compensate for the pressure decrease due to friction and elevation losses. In principle, the longer the pipeline and the elevation of the terrain crossed, the more compressor horsepower is required to achieve the required delivery pressure at destination. Under a fixed route and flow capacity, the number and size of booster stations depend on the circumstances and design. Fewer stations might be easier to operate but the disadvantage is the need of for high inlet pressures, which are likely to require the more expensive use of thicker pipes. The CO_2 pipeline industry currently uses centrifugal, single-stage, radial-split pumps for recompression to the supercritical phase, rather than compressors [32].

Metering stations

Metering stations allow the monitoring and management of the CO_2 in the pipes and are placed periodically along the pipelines. These stations measure the flow of CO_2 along the pipeline, without impeding its movement and allow tracking CO_2 as it flows along the pipeline.

Valves

Valves are used to control functions around compressor and metering stations and at the injection sites. Valves work like gateways: they are usually open and allow CO_2 to flow freely, or they can be used to stop the flow along a certain section of pipe. Pipelines may include a great number of valves along their entire length. Replacement and/or maintenance of section of pipes are some of the reasons for the need to restrict flow in certain areas. Valves can be used to isolate sections of pipe in the event of a leak or for maintenance [35]. The pipeline sectioning can be either done by block valves or check valves. While the first reduce the volume to be relieved in case of a planned or unplanned depressurzation or in case of a pipeline rupture, the second prevents reverse flow in the pipeline [3]. Valves on either end of a section of pipe can be closed to allow safe access. One important consideration in pipeline design is the distance between valves, which depends on the location of the pipe. Valves are installed more frequently near critical locations, such as road and river crossings and urban areas. Installing block valves more frequently increases both the cost of the pipeline and the

risk of leakage from the valves themselves. The further apart the valves are installed, the greater the volume contained between the valves, which increases the distance from the pipeline required for the gas to dissipate to a safe level in the event of a pipeline rupture [11].

Control Stations and SCADA Systems

Sophisticated control systems are required to monitor the CO_2 as it travels through the pipeline network. Centralized control stations collect and manage data received from monitoring and compressor stations all along the pipe. Supervisory Control and Data Acquisition (SCADA) systems provide most of the data that is received by a control station. These systems take measurements and collect data along the pipeline, usually in a metering or compressor stations and valves, and transmit them to the centralized control station. Readings on the flow rate through the pipeline, operational status, pressure, and temperature may all be used to assess the status of the pipeline at any one time. These systems work in real-time and in this way there is little lag time between the measurements taken along the pipeline and their transmission to the control station. This allows quick reactions to equipment malfunctions, leaks, or any other unusual activity along the pipeline. Some SCADA systems are able to operate certain equipment along the pipeline remotely, such as compressor stations, allowing engineers in a centralized control centre to immediately and easily adjust flow rates in the pipeline [35][54].

Pigs

Pigs are sophisticated robotic devices used for the routinely inspections to the pipelines for corrosion and defects detection to ensure the efficient and safe operation of the extensive network of pipelines. 'Pigging' a pipeline means that pigs are sent down pipelines to evaluate the interior of the pipe and test pipe thickness, roundness, check for signs of corrosion, detect minute leaks, and any other defect along the interior of the pipeline that may either impede the flow of gas, or pose a potential safety risk for the operation of the pipeline [35].

2.5 CO_2 pipelines versus natural gas pipelines

It has been commonly assumed that the transport of CO_2 may even be able to utilise the existing pipeline infrastructure. There is an extensive network of oil and gas pipelines around the world, which presents a significant opportunity for re-use as part of CO_2 transport infrastructure. Compared to natural gas pipelines, CO_2 pipelines have orders of magnitude of shorter operating history and the existing CO_2 pipelines are in remote areas. Assuming the CO_2 is dry, which is a common requirement for CCS, both pipelines will require similar materials [28]. In principle the existing pipelines, the vast majority of which are carbon steel, are metallurgically suitable to carry CO_2, provided that the moisture content is maintained at a sufficient low level, approximately 500 ppm. The main limitation of existing lines is design

pressure, which for oil and gas transmission service typically varies between 60 and 80 bar. The effect of this limitation is to reduce transport capacity compared to a purpose-built new line, which would likely to be designed for a higher pressure. The second uncertainty regarding existing lines is remaining service life. Many existing pipelines have been in operation for 20 and 40 years. Remaining service life can only be assessed on a case-by-case basis, taking into account internal corrosion, and the remaining fatigue life [21].

Figure 4 presents the comparison of the phase envelope between CO_2 and natural gas. The flow properties of dense-phase CO_2 are, in many respects, different from those of natural gas. The most notable difference is the higher critical temperature of CO_2 causing liquid or dense state at typical pipeline operating conditions when compared to natural gas. Existing CO_2 pipelines operate at pressures ranging from 85 to 150 bar, while most natural gas pipelines operate at pressures at or below 85 bar

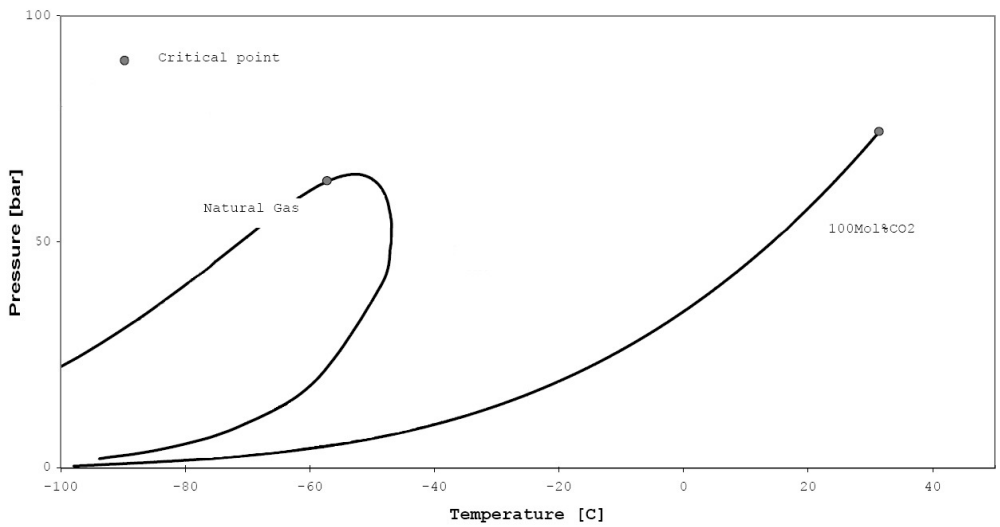


Figure 4 – Comparison between the critical point of CO_2 and natural gas (adapted from [6]).

The risks involved in operating conventional pipelines are well known due to incidents involving catastrophic accidents due to ruptures or explosions. Whereas hydrocarbons will dissipate or ignite and explode, CO_2 will accumulate in depressions, can remain undetected and may cause asphyxia if in high concentrations [2].

The existing pipeline infrastructure may be taken into use as a potentially feasible option for establishing a pipeline network for transporting CO_2, provided that the pipelines are re-qualified for CO_2 transport. Re-qualification shall comply with the same requirements as for pipelines designed for CO_2 transport. However, it may not be feasible from either a technical or cost perspective to comply with all the recommendations put forward for a new built pipeline [6].

2.6 Preliminary design of a pipeline

The aim of this section is to provide a basic understanding of the fundamentals of pipeline design, properties of pipe and fluid and conditions that affect the pipeline flow of CO_2. This section also focuses on the key pipeline design equations.

The key input for the design of CO_2 pipelines are flow rate, length, initial pressure, pressure drop and storage pressure in order to calculate the diameter. When designing pipelines, physical properties of the fluid and design parameters may be used in specific calculations. Key physical properties and key design parameters are listed below and a summary description follows in the next subsection:

- *Pipe diameter*. The larger the inside diameter of the pipeline, the more fluid can be moved through it, assuming other variables are fixed.
- *Pipe length*. The greater the length of a segment pipeline, the greater the total pressure drop.
- *Specific gravity and density*. The density of a fluid is its weight per unit volume. Specific gravity is the density of a fluid divided by the density of water or air, depending on if the fluid is a liquid or a gas.
- *Compressibility*. In gas pipeline design it is necessary to include a term in design calculations to account for the fact that gases deviate from laws describing "ideal gas" behavior when under conditions other than standard or base conditions. The compressibility is a parameter introduced in the equation of state of ideal gases that represent the deviation of real gas from the ideal gas model.
- *Temperature.* Temperature affects pipeline capacity both directly and indirectly. Operating temperature may affect the capacity and other terms in equations used to calculate the capacity in pipelines, such as viscosity.
- *Viscosity.* The property of a fluid that resists flow between adjacent parts of the fluid. It is an important term in calculating line size and pump power requirements when designing pipelines.
- *Reynolds number*. This dimensionless number is used to describe the type of flow exhibited by a flowing fluid. In turn, the type of flow exhibited by a fluid affects pressure drop in the pipeline.
- *Friction factor*. A variety of friction factors are used in pipeline design equations. They are determined empirically and are related to the roughness of the inside pipe wall.

One of the first items of information required for design is the amount of fluid that must flow through the pipeline. Estimates of pipeline input and delivery volumes must be made based on the data on production of CO_2 and expected storage capacity, among other data [25]. With

projected volumes and the origin and destination of the pipeline known, the basic steps involved in a simplified preliminary design of a single pipeline are:

1. A required delivery pressure is determined at the pipeline´s destination.

2. Pressures losses due to friction and the pressure required to overcome changes in elevation are added to the delivery pressure to determine the inlet pressure. A trial-and-error procedure may be involved because it is necessary to choose a tentative pipe size in order to calculate pressure losses. If pressure loss is too high, the resulting inlet pressure may exceed the pressure rating of the pipe or an excessive amount of pumping or compression horsepower may be required. In this case, a larger pipeline is selected and the calculations are repeated. The goal is to select a pipe size that can operate at the pressure required.

3. With the line size and operating pressure determined, the pumping or compression power needed to deliver the desired volume of the fluid at the specified delivery pressure can be accurately calculated. If more than one pump or compression station is required, the location and the size of additional stations is set by calculating pressure loss along the line and determining how much pump and compressor horsepower is needed to maintain the minimum operating pressure. A compressor can also be installed at the injection point.

Economic calculations are usually performed to compare design with other combinations of line size, operating pressure and power in order to choose the best system.

In this simplified outline for the design of a single pipeline, no branch connections are considered, neither alternative routes nor significant changes in the throughput during the lifetime of the pipeline. Few pipelines systems are this simple and because of this most pipelines are designed by sophisticated computer programs, built on basic flow equations used to design a simple pipeline manually, but the computer can perform repeated calculations on a larger number of alternative solutions quickly [25]. Different simulations are generally run for different pipe diameters, in order to calculate the most economical and efficient pipe size that can be operated at a pressure permitted by regulations. Many system variables are interdependent. For example, operating pressure depends, in part, on pressure drop in line. Pressure drop, in turn, depends on flow rate, and maximum flow rate is dictated by allowable pressure.

2.6.1 Flow capacity

The pipeline flow capacity refers to the amount of fluid through the pipeline per unit of time and it can be expressed as volume or mass flow rate. The flow capacity is a function of a number of parameters, some of which are related to the customer's requirements (e.g. the volumes to be delivered and required delivery pressure) and others depend on the technical solutions used for construction, route selection and on the physical properties of the gas (e.g. pipe diameter, changes in elevation along the pipeline path, pressure losses, viscosity and molecular weight of the gas, etc). The estimation of the volume to be handled throughout the

life of the pipeline, or flow capacity, is one key element for a successful pipeline project and will influence route planning [32].

Flow capacities are commonly calculated as steady-state, isothermal flow, in which it is assumed that the volume and composition of the gas transported remain constant with time (steady-state flow). A general equation for the steady state isothermal flow of compressible fluids in pipelines is given by the following equation [32], assuming that the effect of elevation changes along the pipeline path becomes negligible with respect to the pipeline pressure drop, which is true for a horizontal pipeline and/or for a sufficient high inlet pressure:

$$Qb = \pi \sqrt{\frac{g_c \cdot R \cdot M_A}{32}} \cdot \frac{Z_b \cdot T_b}{P_b} \cdot \sqrt{\frac{P_1^2 - P_2^2}{Z_{ave} \cdot T_{ave} \cdot G \cdot L}} \cdot \sqrt{\frac{1}{f}} \cdot D^{2.5} \qquad (1)$$

where Q_b is volume flow rate, g_c is acceleration of gravity, T_b and P_b temperature and pressure at base conditions, T_{ave} is average temperature, Z_b is compressibility factor at T_b, P_b, Z_{ave} is compressibility factor at P_{ave} and T_{ave}, M_A is molecular weight of air, G is gas specific gravity (average molecular weight of the gas/molecular weight of air, taken as=29g/mole), D is pipeline diameter, f is friction factor, L is pipeline length, p_1 is inlet pressure to the pipeline, p_2 is exit pressure to the pipeline and R is the gas constant.

For a given pipeline configuration, the equation can be used for the comparison of the flow rate under different designs (larger or smaller diameter, higher or lower inlet pressure) or under different compositions.

2.6.2 Pressure drop

The pressure of the CO_2 drops gradually along the pipeline due to friction of CO_2 on pipe walls. The amount of pressure loss depends on a number of factors such as the pipeline diameter, CO_2 flow velocity, design of the pipeline and material used. Pressure losses increase with decreasing pipeline diameters and longer distances. The inlet pressure should be high enough to overcome pressure losses along the trajectory, maintaining the minimum operating pressure onshore and offshore. Pressure loss along a pipeline is calculated using the Darcy-Weisbach equation:

$$\Delta p = f \cdot \frac{L}{d} \cdot \frac{\rho v^2}{2} \qquad (2)$$

where Δp is the pressure drop, f is the Darcy friction factor, ρ is the mass density of the fluid (i.e. CO_2) and v is the average velocity of the fluid in the pipeline.

2.6.3 Diameter

The pipeline diameter plays an important role in the cost estimation of CO_2 transport pipeline [16][19][20][46] and the calculation of the diameter is necessary for the design of the pipeline network. As mentioned before, many technical factors, such as flow rate, pressure drop per unit length, CO_2 density, CO_2 viscosity, pipeline material roughness, topographic differences among others, play a role in the determination of the proper diameter size, Practical pipeline design equations depend on empirical coefficients that must be determined experimentally, during research and testing. Modifications in the coefficients continue to be made as more information is available and the application of various forms of basic formulas continues to be refined [25].

In the literature on CO_2 transport, the different diameter calculation methods can be divided in two main groups: 1) calculations based on hydraulic laws for turbulent flow in circular-shaped pipelines; 2) economics-related calculations based on optimal design. Most authors use the hydraulic approach but the improvement of the design formulas continues to be explored as most of the suggested equations do not take into account all the factors into account [51]. Vandeginste and Piessens (2008) [51] have critically reviewed pipeline diameter calculation equations for the transport of CO_2 and Table 6 lists the main equations evaluated.

Table 6 – Reviewed equations for the calculation of pipeline diameter (adapted from [51]).

	Source	Evaluation	Formula
1a Hydraulic equations for turbulent flow	• Block et al. (2003) • Hamelinck et al. (2001) • Heddle et al. (2003)	• No topographic height • Friction factor independent of flow rate • Fluid and pipeline characteristics into account	$D^5 = \frac{32 \cdot f_F \cdot Q_m^2}{\rho \pi^2 (\Delta p / L)}$
1b	• Vandeginste&Piessens (2008)	• Topographic height into account • Avoids use of iterative calculations	$D = \left(\frac{8 \cdot f \cdot Q_m^2 \cdot L}{\rho \pi^2 [\rho g (z_1 - z_2) + (p_1 - p_2)]} \right)^{1/5}$
1c		• Iterative calculations • Friction factor in function of diameter	$D = \left(\frac{-64 Z_{ave}^2 R^2 T_{ave}^2 f_F \cdot Q_m^2 \cdot L}{\pi^2 [M Z_{ave} R T_{ave} (p_2^2 - p_1^2) + 2 g P_{ave}^2 M^2 (h_2 - h_1)]} \right)^{1/5}$
1d	• IEA GHG (2002)	• Steady friction factor • Single phase liquid flow	$\Delta p = 2.252 \cdot \frac{f \cdot L \cdot \rho \cdot Q^2}{D^5}$
2 Hydraulic equation with velocity as parameter	• IEA GHG (2005)	• Average velocity has to be assumed • Does not take pressure drop into account	$D = \sqrt{\frac{4 Q_m}{v \pi \rho}}$
3 Optimal design	• Zhang et al. (2006)	• Pressure not taken into account • Economic pipe diameter calculation	$D_{opt} = 0.363 \left(\frac{Q_m}{\rho} \right)^{0.45} \rho^{0.13} \mu^{0.025}$

In the above equations, D is pipeline diameter, $Dopt$ is optimum pipeline diameter, f is friction factor, L is pipeline length, p_1 is inlet pressure to the pipeline, p_2 is exit pressure to the pipeline, Q is mass flow rate, T_{ave} - average temperature, Z_{ave} - compressibility factor at P_{ave}, T_{ave}, - average pressure and temperature in the pipeline, M is molecular weight, R is gas constant, ρ is fluid density, ν is viscosity, Δp is pressure drop, and h_2-h_1 is elevation change.

A comparison between the four hydraulic equations for turbulent flow to calculate pipeline diameter (equations from 1a to 1d) presented in Table 6 is shown in Figure 5.

Equations 1a and 1b are identical for the case of nonexistent height difference between pipeline inlet and outlet. Equation 1c, which introduces the compressibility factor, includes a more accurate formula for the calculation of average pressure. The overall difference between the results in equations 1a and 1c is 9%. Equation 1c is more sophisticated and accurate. The equation 1d is a form of equation 1b with a steady friction factor for a single phase liquid flow through a pipe. The equation 1d deviates from equation 1c by about 13%. The formula for the calculation of the diameter used by McCoy (2008) [29] - 1c - takes fluid characteristics, such as density and viscosity, and also pipeline characteristics, such as the roughness height, into account. Moreover, the calculation of the diameter is done in an iterative process.

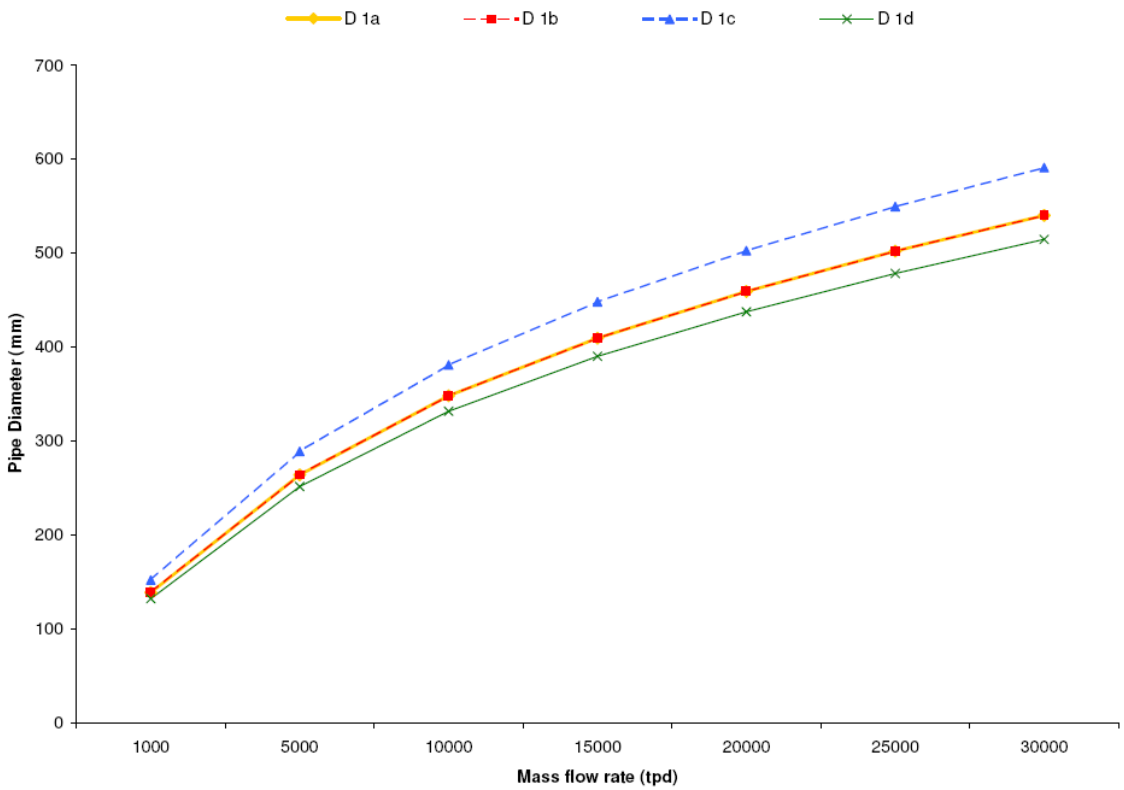


Figure 5 – Comparison of hydraulic equations for turbulent flow to calculate pipeline diameter.

2.7 Construction of pipelines

CO_2 pipelines are constructed in the same way as oil and gas pipelines, and for both there is an established and well understood base of engineering experience [23]. The difficulties and costs encountered during the construction of a pipeline depend on the characteristics of the environment that has to be crossed. Off-shore projects are those that generally pose the biggest technical difficulties, as well as on-shore construction in extreme environments.

Onshore

On-shore pipeline construction can be sub-divided in three phases: installation and cleaning; tie-in to origin and destination facilities and pumping/compressor stations; and testing for pressure leaks.

Installation starts after the pipeline has been designed and its route selected. The work is carried out on a narrow strip of land (20-50 meters), on which the rights of way have been acquired for the entire length of the pipeline. General pipelines are buried for environmental and public safety reasons, as this offers the best protection against external damages.

After digging has been carried out, the pipeline sections are put in place and joined before lowering them down to the bottom of the trench, while new pipelines are brought to the construction site.

Steel pipes are mostly connected through welding, either manual or automatic, although other methods exist. It is extremely important that the welded joints are free from defects and excessive residual stresses[2]. In this way, both the process of welding and the equipment used are subjected to strict control procedures.

After weld inspection, the joint is coated externally for corrosion protection and the pipeline section can be covered. Cover depths depend on the country or region but over the last decade the trend in Europe is cover depths higher than one meter.

Once the line has been completed and its interior been cleaned from sand, dirt and welding debris, it can be tied-in to origin and destination points and connected to the compressor station. Before the pipeline can go into operation it has to be pressure tested. Pressure tests are frequently known as hydro testing as water is used. For CO_2 transmission and distribution, the

[2] A residual stress is a tension or compression that exists in the bulk of a material without application of an external load. Residual stress in welds are due mainly to thermal and phase transformations induced by the welding process.

line has to be dried with air before use, to avoid corrosion and formation of solid hydrates, which would reduce the pipeline flow capacity.

Offshore

Many operations are common to both on-shore and off-shore pipeline construction. The key differences are that installation stresses rather than operating stresses often control the design of off-shore pipelines. Environmental forces are also more significant off-shore [25]. Several construction methods can be used for offshore pipeline construction. The most common method is the use of a conventional lay barge, which is a floating platform on which operations similar to those involved in building an onshore pipeline are conducted. A typical lay barge is fitted with three to six welding stations, an inspection station where welds are examined, and one or two field-joint coating stations. A key component is the tensioning system, which is required to hold the weight of the completed pipeline behind the barge and allow the pipe to move off the barge at the desired rate as each new joint is welded into the line. Another important part of the conventional lay barge is the stinger, which is used to support the completed pipeline as it moves off the lay barge into the water.

In offshore pipeline construction, it is common to apply coating in an onshore yard before the pipe is delivered to the lay barge. In addition to coating required for corrosion protection, offshore pipelines are coated with a layer of concrete – used primarily to provide negative buoyancy for the pipeline (weight needed to keep the pipe on the seafloor) – concrete coating also must resist damage during the laying and trenching.

All of the stations on the lay barge – welding, inspection, coating – remain in the same position while the pipe moves through these stations as the lay barge proceeds along the pipeline route [25].

2.8 Planning pipeline routes

The source and storage points affect the overall pipeline system design. The locations of the sources and storage points determine the pipeline route and the locations of facilities and control points [32].

Following the identification of CO_2 sources and storage locations, and as a prelude to pipeline design, a preliminary route selection is undertaken. Determining the pipeline route will influence design and construction in that it affects requirements for line size (length and diameter), as well as compressor or pumping facilities and their location [32].

Urban areas

The pipeline construction in urban areas is very complex from a planning, legal, safety and technical perspective. It is under the appliance of strict regulation and it considerably adds to the costs because of accessibility to construction and additional safety measures required. In addition, planning procedures tend to be more time consuming. In this way, urban areas are avoided and the pipeline trajectory should go around such areas.

Existing cables and pipeline corridors

In the planning of onshore pipelines it is recommended to follow existing pipeline trajectories because this will reduce costs and limit delays in planning procedures. The pipeline trajectory should follow existing cable and pipeline corridors where possible.

Land cover

Not all land covers are equally suitable for land pipelines to be placed. For example, steep slopes and unstable peaty soils add significantly to the costs.

Connection to the mainland

For the offshore storage of CO_2, the pipeline must make a crossing from the onshore to offshore area via a CO_2 export terminal. The most consistent sites for such CO_2 export terminals would be at or close to existing landfall reception terminals for gas and oil pipelines arriving at the coast as facilities and infrastructures can be shared and connection to the existing offshore pipeline network goes relatively easy. The use of existing pipeline terminals and landfalls depends on the distance between capture location and existing landfalls whether the pipeline can be channelled through it.

Sensitive areas

The identification of areas that are of special interest when planning a pipeline route is indispensable to identify because of nature protection, biodiversity or other environmental constraints. In some cases it might be forbidden to construct pipelines through sensitive areas and the magnitude of impact of pipeline construction and operation on sensitive areas defines whether it is necessary to relocate the pipeline and circumvent sensitive areas.

Obstacles

Linear features such as roads, railway tracks, streams, and rivers are considered as major obstacles in the course of pipeline. The construction costs may increase however there are techniques to let pipelines cross such obstacles. In order to rank the routes on obstacles, the number, complexity and location of obstacles along alternative pipeline trajectories need to be identified.

Bathymetry

Water depth is a main factor for offshore pipeline trajectories. The costs increase with depth, due to higher costs for the laying of pipelines. Moreover the seabed profile (flat or not) is crucial for the type of laying method. When the seabed is relatively flat, no shipping lanes are crossed and the water is so deep that waves do not endanger stability, the pipeline can be laid on the seabed. For the offshore part of the pipeline trajectory bathymetry information will be collected. The location of sand banks and sand waves are also important to identify.

3 Costing of CO_2 pipelines

The following sections provide an overview of cost categories, review cost estimation studies and methods, and present the development of a pipeline costing formula based on a statistical analysis of available CO_2 pipeline cost estimates, combined with publicly available assessments of ongoing large natural gas pipeline projects.

3.1 Cost categories and components

The costs of pipelines can be broken down into three categories: construction, operation and maintenance, and miscellaneous costs.

The construction category includes the costs of material and equipment (pipe, pipe coating, cathodic protection, telecommunication equipment, possible booster stations) and the costs of installation (pipeline construction labour). Costs are sensitive to the design capacity of the pipeline and the pipeline length [28]. The pipeline material costs depend on the length and diameter of the pipeline, the amount of CO_2 to be transported and the quality of CO_2.

The operation and maintenance category includes surveying, engineering and supervision costs, monitoring costs, maintenance costs, possible energy cost for compressors and pumps.

The miscellaneous category includes design, project management, regulatory filing fees, insurance costs, right-of-way costs, and contingency allowances. Right-of-way covers the cost of obtaining right-of-way for the pipeline and allowance for damages to landowners' property during construction. The acquisition of these rights requires dealing with a number of public and private land owners, as well considering the environmental impact. Most countries have regulations on this matter for oil and gas pipelines, but this may need to be upgraded in view of CO_2 transport.

The total cost of a pipeline system is composed of two major components, i.e. capital and operating costs; the former are further subdivided in pipe and compressor capital costs, while the latter consists mainly of compressor operating costs.

Pipeline capital costs are generally quantified per unit length, and tend to increase linearly with the pipeline diameter; however, difference in materials, technology and labour costs in different world regions can induce strong variations in cost as well as the exact geographical location within the same (scarcely or densely populated areas, rivers or other difficult crossings) and design factors (number and size of compressor stations). Costs increase in mountains, in nature reserve areas, in areas with obstacles, such as rivers and freeways, and in

heavily urbanised areas because of accessibility to construction and additional required measures.

Investment costs can be calculated empirically using cost specifications on existing data, or by direct calculations, such as the amount of steel needed, or a mixed approach. As a general rule, offshore pipelines have a much higher cost than pipelines on land.

3.2 Review of cost estimation studies

There have been few studies that have addressed the cost of CO_2 transport and storage in detail. Skovholt (1993) presented rules of thumb for sizing of CO_2 pipelines and estimated the capital cost of pipeline transport. In 2002, the IEA GHG released a report that presented several correlations for the cost of CO_2 pipelines in Europe based on detailed case study designs [19]. More recently, an engineering-economic CO_2 pipeline model was developed at the Massachusetts Institute of Technology (MIT) [15]. Results from these and similar studies were summarized in the recent IPCC report. None of these studies considered the physical properties of CO_2 at high pressures, the realities of available pipeline diameters and costs, or regional differences in the cost of CO_2 transport.

Due to the non-availability of detailed construction cost data for actual CO_2 pipelines (i.e., as-built-cost including the length and diameter) and to the fact that not many projects have been constructed in the last decade [28], natural gas pipelines have been suggested as an analogue for estimating the cost of constructing CO_2 pipelines due to some similarities between transport of natural gas and CO_2 [29].

Table 7 summarizes the main studies found on CO_2 transport costs, in which analytical formulas have been proposed by different authors based mostly on natural gas pipeline project cost estimates. However, no comparison between the formulas' results and real data from existing CO_2 pipeline costs has been found in the public domain.

Table 7– Main CO_2 transport cost related studies.

Source	Full name	Authors	Description	Date
International Energy Agency Greenhouse Gas Programme (IEA GHG)	Pipeline transmission of CO_2 and energy	Woodhill Engineering Consultants	Model to estimate the cost and performance of CO_2 transport. Sizing module, in which diameter is calculated, and cost model that calculates capital, fixed and variable operating cost, based on in-house cost equations. Equations based on location and terrain factors, length and diameter.	2002
Carnegie Mellon University (CMU)	An engineering-economic model of pipeline transport of CO_2 with application to carbon capture and storage	McCoy, S. T., Rubin, E.S.	Model to estimate the cost per tonne of transporting CO2 for a range of CO_2 flow rates over a range of distances that takes into account regional cost differences within the continental US. Cost equation based on regression analyses of 263 natural gas pipeline project costs published between 1995 and 2005.	2008
Massachusetts Institute of Technology	The economics of CO_2 storage	Heddle, G., Herzog, H., Klett, M	Presents pipeline cost calculations based on natural gas pipelines project cost estimates. Determines cost of subsea pipeline based on literature.	2003
Massachusetts Institute of Technology	CO_2 Pipeline Transport and Cost Model	Zhang et al.	Presents methodology for the calculation of the optimal pipeline route and estimation of transport costs. Construction costs based on natural gas pipeline cost estimates between 1989 and 1998.	2007
Intergovernmental Panel on Climate Change	Special report on carbon dioxide capture and storage	Coleman et al.	Presents onshore and offshore transport costs based on cost information from various sources.	2005
Institute of Transportation Studies -University of California	Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs	Parker, N.	Provides equation for the estimation of the cost of construction of a pipeline for a given diameter and length based on construction cost projections of natural gas, oil, and petroleum product pipelines in 893 projects in the US over 13 years.	2004
Institute of Transportation Studies -University of California	Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity	McCollum, D, Ogden, J.	Analytical formulations for CO_2 capture, transport, and storage. Analyses several studies and their approaches for CO_2 transport. Provides a new equation for the calculation of capital costs based on average output from the various studies. Equation based on flow rate and length. Diameter not included.	2006

3.2.1 Overview of IEA GHG and CMU tools

This section focuses on two tools that assess the costs of CO_2 transport by pipeline: the IEA GHG and the CMU tools. These tools aim at assessing the costs of CO_2 transport. An overview on their objectives, input and output parameters is provided in Table 8**.** However, they present differences on their cost and flow equations and on their assumptions for operating conditions. The output of the models, such as pipeline diameter, capital cost, O&M costs, levelized costs, costs' reference years, are also expressed in different ways. A brief summary with the basic concepts for each of the models follows.

IEA GHG tool

In 2002, the IEA GHG released a report that presented several correlations for the cost of CO_2 pipelines in Europe based on detailed case study designs. Woodhill Engineering Consultants

performed the study and created a spreadsheet model to estimate the costs and performance of CO_2 transport, among other energy transmission systems. The model is based on Microsoft Excel and can be run on a conventional Windows-based computer. A pipeline branch asset comprises: Pipeline (offshore, onshore, onshore with onshore storage, onshore with offshore storage), Initial Pressure Boost (IPB) facilities, and Booster stations. The user can choose the size the pipeline and calculate the number of booster stations by using an automatic sizing routine or by setting them manually. Through the automatic sizing of the pipeline distance between booster stations is specified and the model selects an appropriate diameter. Through the manual sizing, the pipe diameter and number of booster stations are defined and the model calculates the pressure drop. For each pipeline, the user specifies the following information as input data: throughput (kg/s), length (km), onshore or offshore, type of terrain, country, type of fluid, pipeline inlet pressure, number of booster stations or minimum distance between stations, compressor inlet and outlet pressures (optional), and pipe diameter (optional).

The sizing module of the model produces as output: pipeline nominal diameter[3], pipeline inlet pressure, pipeline outlet pressure, number of booster stations, and distance between booster stations. For the estimation of the pipeline diameter, the model uses the Darcey formula, valid for the flow of any single phase liquid, which is provided in Table 6.

The spreadsheet model uses a look-up table of pipeline diameters to find the closest nominal pipe size for the internal diameter of the pipeline. The look up table ranges from a nominal diameter of 50 mm (2 inches) to 2000 mm (80 inches).

As the output, the model calculates for each pipeline: capital cost, fixed operating cost, variable operating cost, and booster compressor power consumption. Pipeline cost equations developed by Woodhill Engineering, are based on in-houses estimates.

CMU tool

The Centre for Energy and Environmental Studies from the Carnegie Mellon University developed a CO_2 pipeline transport model to estimate the cost per tonne of transporting CO_2 for a range of CO_2 flow rates (e.g., reflecting different power plant sizes) over a range of distances, and to also incorporate regional cost differences within the continental US. The transport model includes a performance model, which takes a series of inputs defining the design of the pipeline and calculates the required diameter, and a cost model, which estimates the capital cost and annual operating costs of the pipeline from the pipe diameter combined with user-specified pipeline length and the pipeline project region (US only). The transport performance model includes a comprehensive physical properties model for CO_2 and other fluids of interest, accounts for the compressibility of CO_2 during transport, allows booster pumping stations and segment elevation changes. The pipe segment engineering and design is

[3] Nominal diameter refers to the pipe outside diameter and is based in mm.

based on an energy balance on the flowing CO_2, where the required pipeline diameter for a pipeline segment is calculated while holding the upstream and downstream pressures constant. The equation used for the calculation of the diameter is provided in Table 6.

The CO_2 pipeline capital cost model is based on regression analyses of natural gas pipeline project costs published between 1995 and 2005. These project costs are based on Federal Energy Regulatory Commission (FERC) filings from interstate gas transmission companies. The entire data set contains the "as-built" costs for 263 on-shore pipeline projects in the contiguous 48-states and the states in the dataset have been grouped into six regions – Midwest, Northeast, Southeast, Central, Southwest, and West. The total construction cost for each project is broken down into four categories: materials, labour, right-of-way, and miscellaneous charges. The materials category includes the cost of line pipe, pipe coatings, and cathodic protection. Labour is the cost of pipeline construction labour. Right-of-way covers the cost of obtaining right-of-way for the pipeline and allowance for damages to landowners' property during construction. Miscellaneous includes the costs of surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, administration and overheads, and regulatory filing fees.

The key results reported by the pipeline model include the total capital cost, annual O&M cost, total levelized cost, and the levelized cost per metric tonne of CO_2 transported (all in constant 2004 US dollars). The capital cost can be subject to capital cost escalation factors applied to individual categories of the capital cost (i.e., materials, labour, miscellaneous, and ROW). These escalation factors can be used to account for anticipated changes in capital cost components (e.g., in the cost of steel) or other project-specific factors that might affect capital costs relative to the regional averages discussed earlier (e.g., river crossings). Capital costs are annualized using a levelized fixed charge factor calculated for a user-specified discount rate and project life. The cost per tonne CO_2 transported reflects the amount of CO_2 transported, which is the product of the design mass flow rate and the pipeline capacity factor [29].

Table 8 – Overview of the IEA GHG and CMU tools.

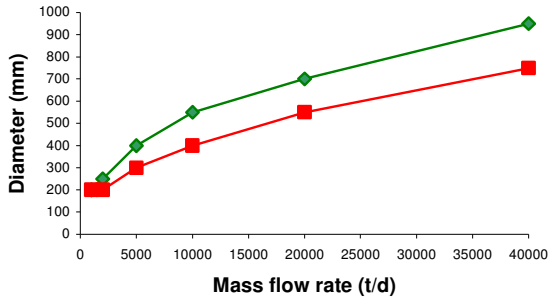
	IEA GHG	CMU	
		Performance model	Cost model
Objective	Estimation of cost and performance of CO_2 transport	Cost per tonne of transporting CO_2 for a range of CO_2 flow rates over a range of distances, and incorporating regional cost differences within the continental US	
Input	Throughput Length Onshore or offshore Type of terrain Country/region Pipeline inlet pressure Number of booster stations or minimum distance between booster station Pipe diameter (optional)	Design parameters (mass flow, length, capacity factor, inlet temperature, material roughness, nr booster stations) Segment performance parameters (inlet pressure, outlet pressure, length segment, elevation change) Compression station parameters (mechanical and isentropic efficiency) Fluid composition	Pipe diameter and length Pipeline cost parameters (annual O&M, annual compressor O&M, COE, CFR, project region) Real capital escalation factors (materials, labor, right-of-way, engineering, compression)
Output	Capital cost [$millions] Annual capital charge [$millions/yr] Fixed operating cost [$millions/yr] Variable operating cost [$millions/yr] Booster compressor power consumption and CO_2 emissions	Pipe diameter	Total capital cost [$] Annual operating costs Annualized capital cost[$/yr] Annual O&M cost [$/yr] Annual cost [$/yr] Transport cost [$/t CO_2]

3.2.2 Comparison of results from different tools

In order to compare the IEA and the CMU models, and their cost results and to identify similarities and/or differences among the models, the same set of input assumptions were applied across the models for the common input parameters. For different input parameters, the models were run with the default values. The IEA and CMU models were used to calculate the pipeline diameter [mm] and the transport cost [€/tonne CO_2] as a function of both CO_2 mass flow rate [tonnes/day] and pipeline length [km]. The CO_2 mass flow rates ranged from 1000 to 40000 tonnes/day while for the pipeline length the range was from 100 to 1000 km. As the cost values of both of IEA and CMU models were expressed in dollars and in different reference years, the Chemical Engineering Plant Cost Index (CEPCI) methodology was applied to harmonize their values to Euros 2009. Pipeline costs were firstly adjusted from their reference years to US Dollars 2009 using the CEPCI Composite index 2009/2010. Then US Dollars 2009 were converted to Euros 2009 through the Eurostat USD/EUR exchange rate 2009. No additional correction for inflation is required because this was already included in CEPCI. The flow and cost equations used by each of the models can be found with detail in IEA GHG (2002) [19] and McCoy (2008) [29], respectively.

Figure 6 and Figure 67 show the diameter and transport cost, respectively, for a 200 km pipeline at different flow rates. Figure 8 and Figure 89 show the diameter and transport cost, respectively, as a function of pipeline length for a mass flow rate of 10000 tonnes/day. The graphs show that the IEA and CMU models exhibit the same trends: the diameter increases with the mass flow rate and the transport costs decrease with the increase of mass flow rate; the diameter increases slightly as the pipeline gets longer and the transport cost is nearly constant for lengths above 200 km. The values obtained from the IEA model were slightly higher than the ones from the CMU model, both for the diameter or the transport costs.

The difference between the estimates for the pipeline diameter may be explained by the difference of equations used (see section 2.6 and discussion around Table 6) and by the fact that the while the IEA assumes a fixed friction factor for its calculations, the CMU model employs a flow equation that is a function of the friction factor. Since not exactly the same input parameters where run within the models, the comparison is uneven. Nevertheless, with the analysis taken, the CMU revealed to be a more sophisticated tool, using a more accurate diameter equation and allowing the user to define the composition of the stream.



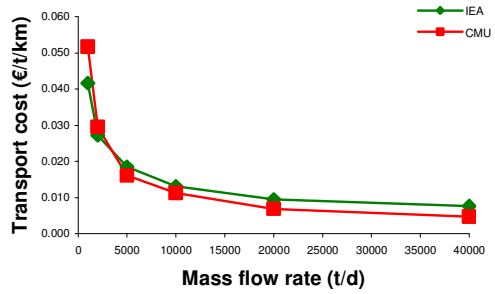
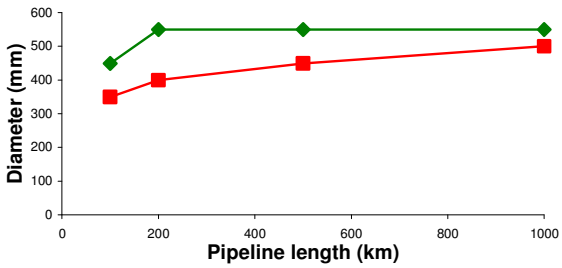


Figure 6 and Figure 7 – Diameter and transport cost as a function of flow rate for pipeline length of 200 km, respectively.



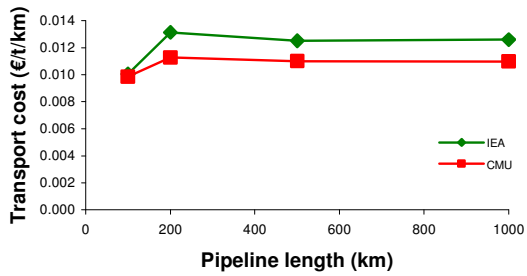


Figure 8 and Figure 9 - Diameter and transport costs as a function of pipeline length for a mass flow rate of 10000 tonnes/day, respectively.

3.3 Heuristic pipeline costing formula

The studies reviewed in the previous section present non linear cost equations, which make it difficult to integrate them in certain applications that require a simpler cost approach, such as in linear optimisation programmes for pipeline network design. An example of a complex optimization problem requiring a Mixed Integer Linear Program (MILP) approach is the analysis performed in Morbee et al. (2010) [33] to determine the optimal CO_2 transport network in Europe and its evolution over time, in order to transport predefined volumes of CO_2 to suitable storage sites at the lowest possible cost.

This section aims, in this way, to develop a mathematically convenient pipeline costing model, which is accurate enough to represent the main features of the non-linear models described above. The main feature that needs to be represented is that pipeline investments exhibit significant economies of scale, e.g. a pipeline carrying 5 Mt/y of CO_2 may not be much more expensive than a pipeline carrying 1 Mt/y and a joint CO_2 pipeline network may be significantly cheaper than individual source-sink connections.

The starting point is the pipeline investment cost formula proposed by IEA GHG (2002) [19]:

$$I = (a_0 L + b_0) + (a_1 L + b_1)d + (a_2 L + b_2)d^2 \qquad (3)$$

where I is the pipeline investment cost, L is the pipeline length, and d is the pipeline diameter. For the coefficient values cited by IEA GHG (2002), the ratio b_i / a_i (i=0,…,2) is typically on the order of 10 (expressed in km). Therefore, it is assumed that $b_i = 0$ (i=1,…,3). Furthermore, for typical pipeline diameters in the range of 20 to 40 inches, the ratio between $a_2 d^2$ and $a_1 d$ is between 5 and 10. By making the mathematically simplifying assumption that $a_1 = 0$, equation (3) reduces to:

$$\frac{I}{L} = a_0 + a_2 d^2 \qquad (4)$$

The coefficients a_0 and a_2 will be re-estimated later, in order to compensate for the fact that a_1=. Since the data points that will be used for this estimation include also the cost of compressor stations, we assume that this cost is also captured by equation (4).

In order to be able to express equation (4) as a function of the capacity of the pipeline, a simplified version of the flow capacity equation given in section 2.6.1 is derived. Firstly, the Darcy-Weisbach equation for pressure loss along a pipeline is used:

$$\Delta p = f \cdot \frac{L}{d} \cdot \frac{\rho v^2}{2} \qquad (5)$$

where Δp is the pressure drop, f is the Darcy friction factor, ρ is the mass density of the fluid (i.e. CO_2) and v is the average velocity of the fluid in the pipeline. Secondly, considering the pipeline geometry, the mass flow rate Q (i.e. the capacity of the pipeline) is given by:

$$Q = \rho \cdot \frac{\pi d^2}{4} \cdot v \qquad (6)$$

Combining equations (5) and (6), equation (7) yields:

$$Q = \frac{\pi}{4}\sqrt{\frac{2\rho}{f}\frac{\Delta p}{L}}\, d^{5/2} \qquad (7)$$

Eliminating d between equations (4) and (7), one finds:

$$\frac{I}{L} = a_0 + \beta Q^{\gamma} \qquad \text{with} \qquad \beta = a_2 \left(\frac{8 f L}{\pi^2 \rho \Delta p} \right)^{2/5} \qquad \text{and} \qquad \gamma = \frac{4}{5} \qquad (8)$$

The final simplifying assumption is that γ=1. Cost data shown below will illustrate that this is reasonable simplification. More importantly, this assumption is crucial in order to obtain a mathematically convenient costing formula. The costing formula (8) is meant for onshore flat

terrain. For mountainous areas, it is assumed that costs per km are 50% higher, based on IEA GHG (2002, Table 4.13) [19]. Offshore pipelines are assumed to be twice as expensive as onshore pipelines, based on the typical ratios between offshore and onshore pipeline costing formulas in IEA GHG (2002, Tables 4.14 and 4.15) [19]. To summarise, the pipeline costing formula becomes:

$$\frac{I}{\tau L} = a_0 + \beta Q \qquad (9)$$

with τ the terrain-related correction factor (1.5 for mountainous terrain, 2 for offshore). Values of the τ for various other types of terrain can be found in IEA GHG (2002) [19].

To account for the assumptions made above, an independent re-estimation of the coefficients a_0 and β follows based on pipeline investment cost data reported in the literature. The analysis includes all public data points from a recent survey by Schoots et al. [42] – i.e. Denbury (2008) [4], Hamelinck et al. (2002) [14], Hendriks et al. (2004) [17], IEA (2009) [21], IPCC (2005) [23], Lako (2006) [26], and NEBC (1998) [36] – complemented with data points from the recent GHGT-10 conference (ICO_2N, 2010 [18]; Wells, 2009 [52]). In order to represent and incorporate CO_2 trunk lines that may have far larger capacities than the above-mentioned data points available for CO_2 pipelines, cost information from recent or ongoing European large natural gas pipeline projects is also included, such as GALSI [12], GASSCO [13], Medgaz [30], Nabucco [34], and Nordstream [38]. Where the CO_2 mass flow rate of a pipeline is not available or not stated in the source (e.g. for the natural gas pipelines), it is estimated based on the diameter, using equation (7), assuming typical parameters f = 0.015, ρ = 850 kg/m^3 and $\Delta p / L$ = 0.3 bar/km. All cost data are converted to Euros 2010 using the CEPCI Composite index [53] and average annual exchange rates from Eurostat [9]. Table 9 presents the pipeline data points' information as explicitly stated by from the source (i.e. before the conversion).The final results are shown in Figure 10.

With $I / \tau L$ expressed in millions of Euros per km, and the capacity Q in million tonnes (Mt) of CO_2 per year, results are a_0 = 0.533 and β = 0.019. The R^2 of the regression is 0.80, which implies a reasonably good fit. One should take into account that pipeline cost data always shows relatively large scatter, as also pointed out by Schoots et al. [42].

Table 9 – Pipeline cost data points: source and information available.

Source	Pipeline characteristics				Investment	
	Diameter	Flow rate	Length onshore	Length offshore	Cost (M)	Year
Denbury Resources Inc. [4]	24 in	-	320 mi	-	725 USD	2007
Hamelink et al. – I [14]	15 cm	-	1 km	-	0.22 EUR	1999
Hamelink et al. – II [14]	70 cm	-	1 km	-	0.86 EUR	1999
Hendriks et al. [17]	100 cm	-	-	-	1.1 EUR	2004
IEA Greenhouse Gas R&D Programme [22]	13 in	13000 t/d	205 mi	-	100 USD	2000
IPCC –Chandler [23]	42 cm	-	1 km	-	0.38 USD	2005
IPCC – Chandler II [23]	52 cm	-	1 km	-	0.62 USD	2005
IPCC – McDermot [23]	76 cm	-	1 km	-	1.08 USD	2005
IPCC – O&GJ [23]	41 cm	-	1 km		0.53 USD	2005
IPCC – O&GJ II [23]	51 cm	-	1 km	-	0.78 USD	2005
IPCC – O&GJ III [23]	61 cm	-	1 km	-	0.8 USD	2005
IPCC – Omerod [23]	41 cm	-	1 km	-	0.6 USD	2005
IPCC – Omerod II [23]	42 cm	-	1 km	-	0.4 USD	2005
Lako, P. [26]	35 cm	2 Mt/y	100 km	-	40 EUR	2006
Wells, P. [52]	-	14.6 Mt/y	240 km	-	600 CAD	2009
ICO_2N Canada – I [18]	-	7.5 Mt/y	400 km	-	400 CAD	2010
ICO_2N Canada – II [18]	-	15 Mt/y	400 km	-	500 CAD	2010
Medgaz [30]	24 in	-	-	240 km	630 EUR	2010
GALSI [12]	22 in	-	940 km	565 km	2000 EUR	2010
Nordstream [38]	45 in	-	-	1220 km	8800 EUR	2010
Nabucco [34]	56 in	-	3300 km	-	8000 EUR	2010
Langeled [13]	43 in	-	-	1166 km	1700 EUR	2010

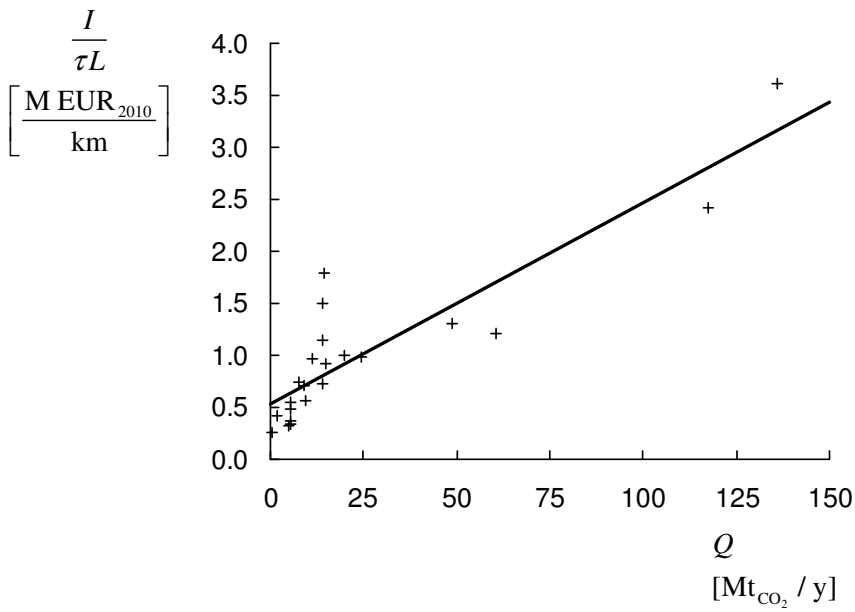


Figure 10 - Estimation of equation (9) using cost data from the literature: Pipeline investment costs are expressed in Euros 2010 and are based on a statistical analysis of available CO_2 pipeline cost estimates, combined with publicly available assessments of ongoing large natural gas pipeline projects.

The statistical analysis is performed with *Stata 11*. Table 10 presents the investment costs for CO_2 pipelines onshore, in mountainous terrains and offshore, with different pipeline diameters, calculated through the proposed pipeline costing formula given by equation (9).

Table 10 – Estimated investment costs for CO_2 pipelines for various pipeline diameters using the proposed pipeline costing formula (9).

		Investment (M EUR/km)		
Diameter (in)	Mass flow rate (Mt/y)	Onshore	Mountainous terrains	Offshore
12	2.5	0.59	0.89	1.18
16	5	0.64	0.96	1.28
24	15	0.83	1.25	1.78
32	30	1.11	1.67	2.22
40	50	1.49	2.24	2.98

4 Highlights and conclusions

Large-scale deployment of CCS will require the development of infrastructure to transport the captured CO_2 from its sources to the appropriate CO_2 storage sites. There are different views on how such CO_2 transport infrastructure might evolve: on the one hand, there is often a perception that CCS plants will be built very close to potential storage sites in order to minimise transport costs; on the other hand, proposals for CCS projects that have become public tend to show that their location is dictated by other factors, such as safety and public acceptance concerns that may require that CO_2 is initially stored offshore; or the presence of old power plants that are suitable for retrofitting or refurbishing with CO_2 capture technologies.

Major challenges associated with the transport of CO_2 are the composition requirements of the stream, to understand the technical difference between transport of CO_2 and hydrocarbons, and to estimate the costs developing a CO_2 infrastructure.

The presence of impurities has a great impact on the physical properties of the transported CO_2 that consequently affects pipeline design, compressor power, recompression distance, and pipeline capacity. These effects have direct implications for both the technical and economic feasibility of developing a CO_2 infrastructure. Storage site specifications and purpose will determine the CO_2 stream composition requirements, which will in turn affect the pipeline design and characteristics.

In future CCS projects there may be the attempt to use the existing hydrocarbon pipeline grid for CO_2 transport and existing pipelines previously used for transport of other media, such as natural gas, may be re-qualified for transport of CO_2 given that the appropriate standards and regulations are followed. The flow properties of dense-phase CO_2 are, in many respects, different from those of natural gas. Existing CO_2 pipelines operate at pressures ranging from 85 to 150 bar, while most natural gas pipelines operate at pressures at or below 85 bar, CO_2 pipelines are constructed specifically for transporting CO_2. Compared to natural pipelines, CO_2 pipelines have a much shorter operating history and the existing CO_2 pipelines are in remote areas. Assuming the CO_2 is dry, which is a common requirement for CCS, both pipelines will require similar materials. Guidelines for requalification of pipelines changing use from transport of hydrocarbons to CO_2 that would address inspection for integrity assessment, dimensional limit-state checks, and material evaluations are currently in development.

Detailed construction cost data for actual CO_2 pipelines are not readily available; nor have many such projects been constructed in the last decade for CCS purposes and also offshore. For these reasons, natural gas pipelines have been suggested as an analogue for estimating the cost of constructing CO_2 pipelines due to some similarities between transport of natural gas and CO_2. Several authors propose analytical formulas to estimate costs for CO_2 transport,

presenting non linear cost equations, which make it difficult to integrate them in certain applications that require a simpler cost approach, such as in linear optimisation programmes for pipeline network design. In this report a mathematically convenient pipeline costing formula is developed, based on a statistical analysis of available CO_2 pipeline cost estimates, combined with publicly available assessments of ongoing large natural gas pipeline projects and accurate enough to represent the main features of the non-linear equations found in the literature.

Further research work is required on the collection and analysis of costs for CO_2 pipelines and on comparing the formula proposed with real data from existing CO_2 pipeline costs that can be found in the public domain in order to evaluate the costs of deployment of large-scale infrastructure for CO_2 transport.

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European Commission

EUR 24731 EN – Joint Research Centre – Institute for Energy

Title: Technical and Economic Characteristics of CO_2 Transmission Pipeline Infrastructure

Author(s): J. Serpa, J. Morbee, E. Tzimas

Luxembourg: Publications Office of the European Union

2011 – 43 pp. – 21.0 x 29.7 cm

EUR – Scientific and Technical Research series – ISSN 1018-5593

ISBN 978-92-79-19425-2

doi:10.2790/30861

Abstract

Carbon capture and storage is considered one of the most promising technological options for the mitigation of CO_2 emissions from the power generation sector and other carbon-intensive industries that can bridge the transition period between the current fossil fuel-based economy and the renewable and sustainable technology era. CCS involves the capture of CO_2 from the sources, the transport CO_2 through dedicated pipelines and ships, and the storage of CO_2 in geological reservoirs, such as depleted oil and gas fields and saline aquifers, for its permanent isolation from the atmosphere.

The development of CCS technologies has increased significantly in the last decades; however, there are still major gaps in knowledge of the cost of capture, transport and storage processes. Pipelines have been identified as the primary means of transporting CO_2 from point-of-capture to site where it will be stored permanently but there is little published work on the economics of CO_2 pipeline transport and most cost studies either exclude transport costs or assume a given cost per tonne of CO_2 in addition to capture costs.

The aim of this report is to identify the elements that comprise a CO_2 pipeline network, provide an overview of equipment selection and design specific to the processes undertaken for the CO_2 transport and to identify the costs of designing and constructing a CO_2 transmission pipeline infrastructure.

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LD-NA-24731-EN-C

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ISBN 978-92-79-19425-2

9 789279 194252

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