# Shipping $CO_2$ – UK Cost Estimation Study

Final report

for

**Business, Energy & Industrial Strategy Department**

November 2018

Element Energy Limited
Suite 1 Bishop Bateman Court
Thompson's Lane
Cambridge CB5 8AQ
Tel: 01223 852499

## Authors:

For comments or queries please contact:

elementenergy

Emrah.durusut@element-energy.co.uk
Tel: 0330 119 0990

Michael.Joos@element-energy.co.uk
Tel: 0330 119 0989

## Disclaimer

## Acknowledgements

We gratefully acknowledge the following stakeholders for the support and input they provided:

- Hans Carl Amlie (Brevik Engineering – project partner)
- Martin Hay (Brevik Engineering – project partner)
- Arne Markussen (Polarkonsult – project partner)
- Robert de Kler (TNO – project partner)
- Tom Mikunda (TNO – project partner)
- Andrew Scott (Babcock International)
- Angus Campbell (Bernard Schulte Shipmanagement)
- Baris Dolek (Shell)
- Derek McGlashan (Forth Ports Grangemouth)
- Frank Ollerhead (Equinor)
- Mark Gilks (Calor)
- Steve Murphy (Pale Blue Dot)

# Contents

# 1 Executive summary

## 1.1 Project outline

The Clean Growth Strategy (CGS) sets out Government's ambition of having the option to deploy Carbon Capture, Usage and Storage (CCUS) at scale during the 2030s, subject to the costs coming down sufficiently. The Department for Business, Energy and Industrial Strategy (BEIS) has identified a need to explore the potential role that $CO_2$ shipping could play in reducing the cost of deploying CCUS in the UK.

The key objectives of this work are:

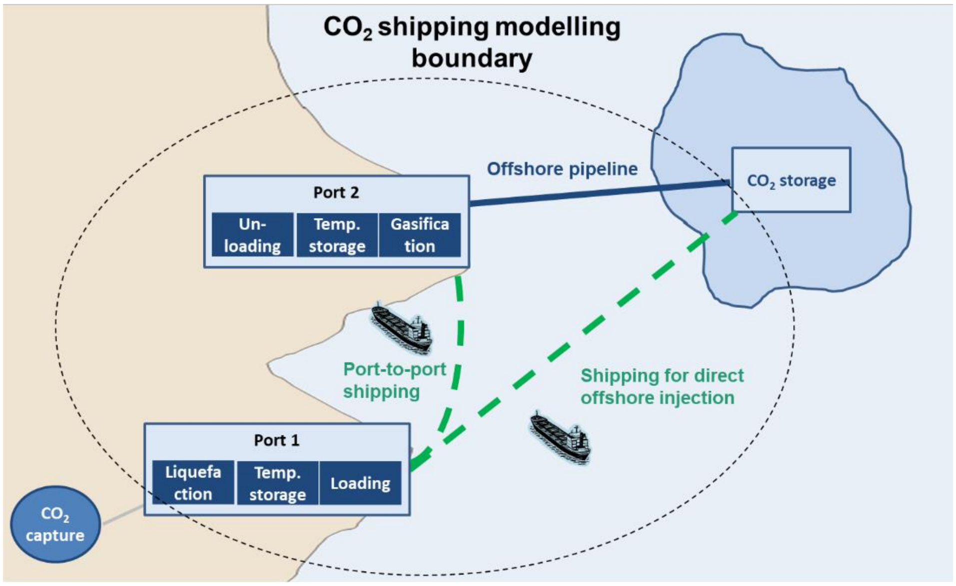
- **Estimate costs of shipping $CO_2$** from different terminals, and at a range of scales, to geological $CO_2$ storage sites in the UK, and elsewhere; and
- **Identify the opportunities** shipping brings to the UK, including circumstances in which shipping costs may represent value for money in the UK relative to fixed pipelines. Conversely, the study also aims to **identify barriers** to $CO_2$ shipping which must be navigated to develop this industry.

Element Energy has been commissioned by BEIS to undertake this study, along with project partners Brevik Engineering and SINTEF (Norway), Polarkonsult, naval architects & marine engineers (Norway) and TNO (Netherlands). The study examines whether $CO_2$ shipping could unlock additional possibilities across the CCUS chain, including development of smaller-scale and potentially cheaper CCUS projects, port-to-port shipping to aggregate $CO_2$ for transport to a single storage site, and the potential for cross-border transport of $CO_2$ to/from other countries.

## 1.2 Shipping infrastructure components and variables

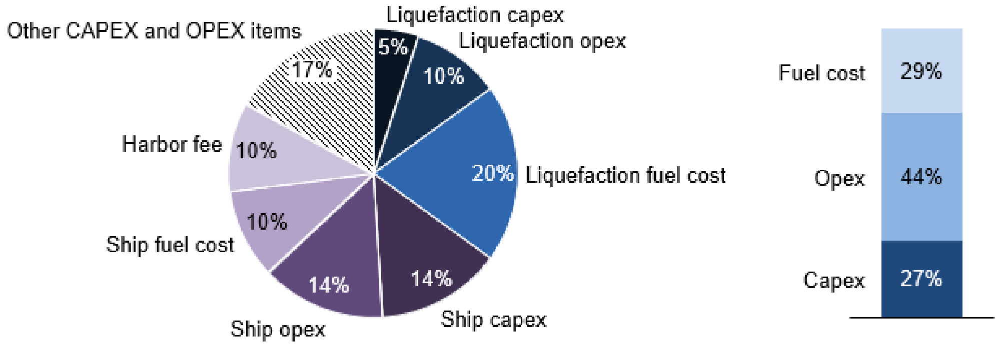
Figure 1-1 shows the components involved in the $CO_2$ shipping chain. The scope of the study includes $CO_2$ shipping, both port-to-port and port-to-storage, as well as the port infrastructure requirements; it excludes the $CO_2$ capture, onshore transport and the $CO_2$ storage facilities. **The key infrastructure elements include equipment for liquefaction, temporary storage, loading/unloading, ships and gasification.**

**Figure 1-1 Components of the $CO_2$ shipping chain**




It is important for policy makers to understand the cost-effectiveness of shipping $CO_2$ in a range of situations, relative to alternative $CO_2$ transport options, such as pipelines. The data and information gathered from partners, stakeholders and literature was used to inform development of a $CO_2$ shipping costing model. Figure 1-2 gives a summary of the breakdown of the total shipping cost, allowing an understanding of the relative importance of the different cost components. **As shown, liquefaction and ship costs including capital expenditure (capex), operational expenditure (opex) and fuel, are the biggest cost components of $CO_2$ shipping. Additionally, shipping costs are dominated by operational and fuel costs, unlike pipelines which are dominated by capex.**

**Figure 1-2 Cost components of $CO_2$ shipping under central case assumptions**



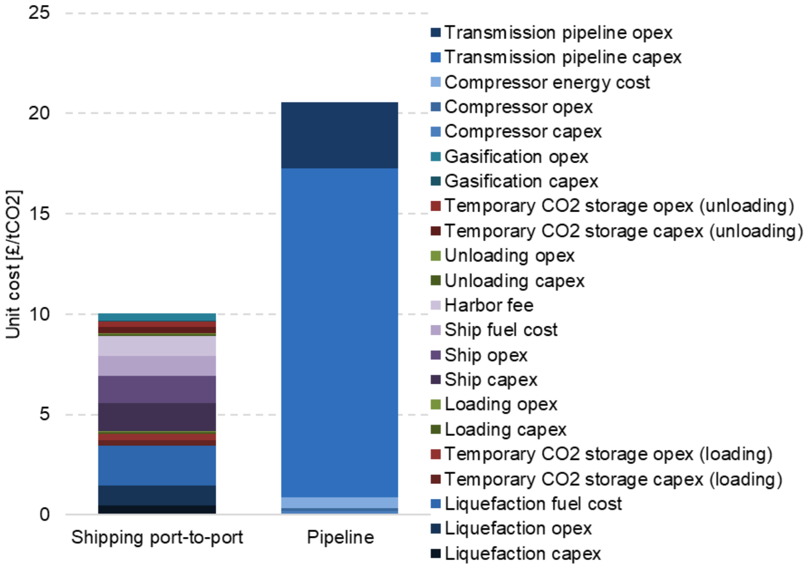

The variables which impact the economics of $CO_2$ shipping were explored.

- As the liquefaction cost is a significant proportion of the overall cost, the total cost of transporting pre-pressurised $CO_2$ can be more than a third lower. The $CO_2$ is likely to be transported via onshore pipelines from $CO_2$ sources to the liquefaction plant at the port and is expected to arrive in pre-pressurised form. **It was found that total shipping costs can be in the range of £7-12/t$CO_2$ for pre-pressurised $CO_2$ for liquefaction under certain conditions** (without the costs of transport from the source to the port and initial compression for onshore transportation)**.**
- Economies of scale can be realised in shipping across many components of the chain, including ship capex, ship fuel usage and harbour fees. **Therefore, a higher $CO_2$ flow rate decreases the unit cost of $CO_2$ shipping.** Additionally, **selecting the largest ships possible reduces the unit cost,** provided there is not significant unutilised capacity.
- A sensitivity analysis was also completed on the overall cost of shipping. **For a given $CO_2$ pressure condition, lifetime project cost shows highest sensitivity to the $CO_2$ flow rate**, due to additional ships being required; as this cost is spread over a greater quantity of $CO_2$, the unit cost (£/t$CO_2$) shows a smaller impact of flow rate. **Shipping costs were also found to be sensitive to project lifetime and ship size.** On the other hand, pipeline costs show much higher sensitivity to distance and flow rate compared to shipping costs. Therefore, the relative cost-effectiveness of shipping compared to pipelines depends on a number of important factors including distance, flow-rate and project duration.

Figure 1-3 presents the unit cost of shipping 1 Mt$CO_2$/yr over a distance of 600km with a 20-year project timeframe. As shown, under the central cost assumptions, it is estimated that port-to-port shipping is likely to be significantly cheaper than utilising a $CO_2$ pipeline for an equivalent $CO_2$ transport requirement. However, this is not always the case, and the variables which affect the cost-effectiveness of shipping relative to a pipeline are explored. The results show that shipping is more favourable for a project under the following circumstances:

- **Lower $CO_2$ flow rates (e.g. less than 5Mtpa depending on distance and project lifetime):** as shipping is less capital intensive compared to pipelines.
- **Shorter project durations (e.g. less than 20 years depending on distance and flow rate):** favour shipping due to the lower initial outlay and hence lower sunk costs.
- **Longer transport distances (e.g. more than 500km for transporting 5Mt$CO_2$/yr for 20 years):** due to the high sensitivity of pipeline costs to transport distance as they are dominated by capex.

**Figure 1-3 Comparison of the unit cost of $CO_2$ transport for transporting 1 $MtCO_2$/year over a distance of 600 km and timeframe of 20 years. All other central case assumptions were used.**




The potential for achieving **cost reduction via re-using existing infrastructure is higher for pipelines**, which are dominated by capex (it should be noted that the pipeline costs shown in this report are for new build pipelines). Although it may be technically feasible to convert an existing Liquefied Natural Gas (LNG) or Liquefied Petroleum Gas (LPG) ship into a $CO_2$ ship, **re-use of an existing ship would bring only negligible cost reductions** as ship capex corresponds to around 14% of the total shipping costs (see Figure 1-2) and some capital investment will be needed to convert the ship, which is expected to be less optimised compared to a new-built ship.

The **$CO_2$ emissions from combustion of ship fuel** and generation of the electricity consumed for liquefaction were not found to be a significant proportion of the transported $CO_2$, staying below 2% in the majority of cases. However, it should be noted that the full life-cycle analysis (LCA) emissions of the ships have not been included in the analysis. This proportion increases as ship size decreases and shipping distance increases; for the smallest ship, of 1,000 $tCO_2$, emissions may be higher than 8% of the transported $CO_2$ due to the higher number of trips.

## 1.3 Opportunities and barriers

**$CO_2$ shipping can unlock a number of opportunities for the UK, such as reducing the cost of early UK CCUS projects, extending the economic locations for CCUS and importing $CO_2$ from other European clusters**.

- Gathering $CO_2$ from multiple locations via shipping (analogous to the planned Norwegian projects) may enable the deployment of several clusters in parallel cost-effectively.
- Shipping may also extend the viability of CCUS to clusters such as that in South Wales, which does not have viable storage sites nearby.
- For short duration projects of small-scale, the potential sunk costs after 10 years are found to be significantly lower for shipping than for pipelines, thereby improving the economics.
- Finally, a market with considerable future potential is that of importing $CO_2$ from other European CCUS clusters via shipping to increase the scale of the $CO_2$ transport and storage (T&S) market in the UK, with the aim of contributing to UK economic growth. $CO_2$ shipping can connect the UK ports with potential early movers (such as Norway and Rotterdam) and other key industrial hubs with limited offshore $CO_2$ storage potential (e.g. France and Germany). Total T&S unit costs, including shipping from European ports to Humber, offshore pipeline and storage at Bunter,

could be less than £20/t$CO_2$ (e.g. for transport from Le Havre in France to Humberside in the UK).

**Key barriers to $CO_2$ shipping include regulations, port constraints and the lack of business models.**

- The key barrier for cross-border $CO_2$ shipping is the London Protocol, which prevents the cross-border movement of $CO_2$ for CCUS. Other relevant regulations include the EU-Emissions Trading System Directive, the EU CCS Directive, the United Nations Convention on the Law of the Seas (UNCLOS), the International Convention for the Safety of Life at Sea (SOLAS) and the IMO International Code of the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code).
- Early projects may be required to meet the specific constraints of existing ports (including maximum ship length, maximum ship draft, berth availability, and storage space) but dedicated infrastructure can be installed in the longer-term.
- There is currently limited experience in $CO_2$ shipping at the scale needed, so demonstration projects may be needed.
- Additionally, business models and incentives for $CO_2$ shipping will be required, as existing LPG/LNG business models and contracts are not expected to be replicable for $CO_2$ shipping.

## 1.4 Recommendations for further work

$CO_2$ shipping may have an important role to play in supporting CCUS in the UK (and elsewhere). The technical and regulatory barriers can be overcome to realise the opportunities that $CO_2$ shipping presents, both in protecting existing UK energy-intensive industry and in developing expertise in the emerging field of $CO_2$ transportation and storage. Additional studies or research should be completed to explore more detailed aspects of the supply chain and the potential market both in the UK and abroad. It is important to understand the implications of potential $CO_2$ shipping business models for industry, consumers and the government. Some suggestions for further work are given below:

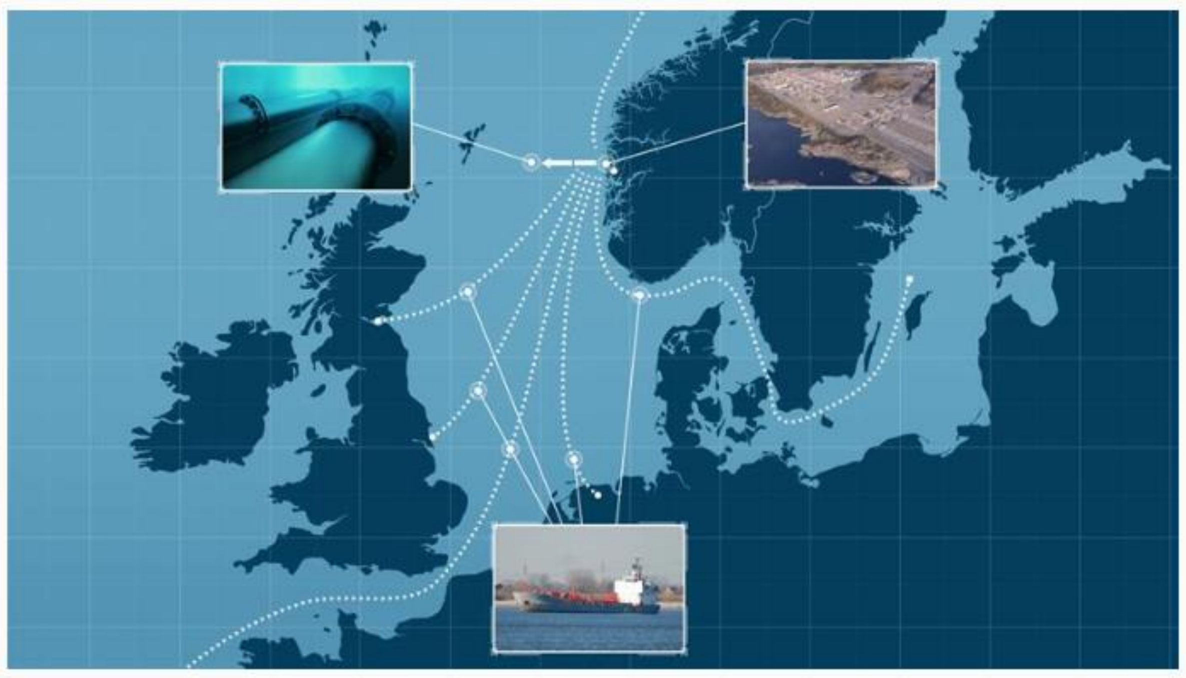
- More detailed assessment of potential **UK ports/terminals for $CO_2$ shipping**. This may include identification of suitable sites, site-specific feasibility studies, and identification of site-specific constraints.
- Inclusion of **$CO_2$ storage infrastructure** (e.g. pipelines, wells, etc.) in the $CO_2$ shipping cost model to understand financial implications of port-to-storage shipping. Detailed assessment of **port-to-storage options**, including their potential impact on $CO_2$ storage costs.
- Detailed assessment of the **market potential for importing $CO_2$** from other European countries and the associated value to the UK. This may include economic modelling on the impact on employment, gross value added (GVA) and potential additional investment.
- Activities to promote the ratification of the **proposed amendment to the London Protocol** by other Member States to enable cross-border $CO_2$ transport.
- Inclusion of $CO_2$ shipping in the BEIS Energy Innovation Programme (if possible) or provision of additional **funding to demonstrate $CO_2$ shipping** in the UK.
- Assessment of **viable business models for $CO_2$ shipping,** including incentive mechanisms, ownership structure (e.g. which entities are likely to own port vs. ship), risk management strategies and capital financing.

# 2 Introduction

The Clean Growth Strategy (CGS) sets out Government's ambition of having the option to deploy Carbon Capture, Usage and Storage (CCUS) at scale during the 2030s, subject to costs coming down sufficiently. In common with gas and electricity transmission infrastructure, $CO_2$ transportation and storage (T&S) operations could benefit from significant economy of scale cost savings. The unit cost of transporting $CO_2$ has the potential to decrease significantly at higher volumes, because the costs of constructing and installing pipelines grow at a much slower rate than volumes they can transport. Similarly, the unit costs of storing $CO_2$ can decrease significantly when higher volumes are stored in a single large storage facility compared with multiple smaller capacity facilities.

While the costs of large-scale trunk $CO_2$ pipelines (£/t$CO_2$) may be lower, they require substantial upfront capital investment, which has been a significant challenge for the previous UK CCUS projects. Recent activities in Norway have shown that $CO_2$ shipping could be a feasible option, even for the first phase CCUS projects in the UK. The Norwegian CCUS project plans to transport $CO_2$ from the capture facilities in the eastern part of Norway by ship to an onshore facility on the west coast of Norway. $CO_2$ will be temporarily stored, before being transported via an offshore pipeline to a safe geological formation in the North Sea. It is suggested that in a later phase of the project, $CO_2$ could be transported via ship from other European countries to the pipeline injection site in Norway for transport to the storage site, which can accommodate up to 4 Mt of $CO_2$ per year.[1]

**Figure 2-1: Illustration of the envisioned Norwegian CCS project: The dotted lines indicate ship transport, the solid arrow indicates the offshore pipeline; source: (Gassnova, 2018)**



$CO_2$ shipping could bring a number of opportunities, including: enabling the development of smaller-scale and potentially cheaper CCUS projects (such as industrial emitters and hydrogen production); development of CCUS projects at multiple locations (including ones not located near geological $CO_2$ storage) in the UK in parallel (similar to the Norwegian CCS project); potential $CO_2$ storage outside the UK; and storage of $CO_2$ from other European countries within the UK storage sites.

Within this context, the Department for Business, Energy and Industrial Strategy (BEIS) commissioned Element Energy and its partners to explore the potential role that shipping, as a mode of transporting

[1] https://www.gassnova.no/en/ccs-in-norway-entering-a-new-phase

carbon dioxide ($CO_2$), could play in reducing the cost of deploying CCUS in the UK. The key objectives of this work are:

- to estimate the costs of shipping $CO_2$ from different terminals, and at a range of scales, to geological $CO_2$ storage sites in the UK, and elsewhere; and
- to identify the circumstances (scales/capacity/locations/time) in which shipping costs may represent value for money in the UK relative to fixed pipelines.

The project methodology included the following steps:

- As a first step, we carried out literature review and targeted stakeholder interviews to identify key infrastructure elements for $CO_2$ shipping, which are presented in Section 3.
- We then developed an interactive $CO_2$ shipping cost model, which allows the user to run different scenarios/sensitivities and compare shipping and pipeline costs. The cost model methodology and the key data used to populate the model are presented in Section 4.
- Using the cost model, we assessed where shipping has the potential to be a cost-effective transport solution and what the impact of key cost/performance parameters on costs are. The results are presented in Section 5.
- Finally, we identified the key opportunities and barriers regarding $CO_2$ shipping (Section 6) and developed a set of recommendations for BEIS (Section 7).

# 3 Shipping infrastructure elements

**Figure 3-1: Components of the $CO_2$ shipping chain**

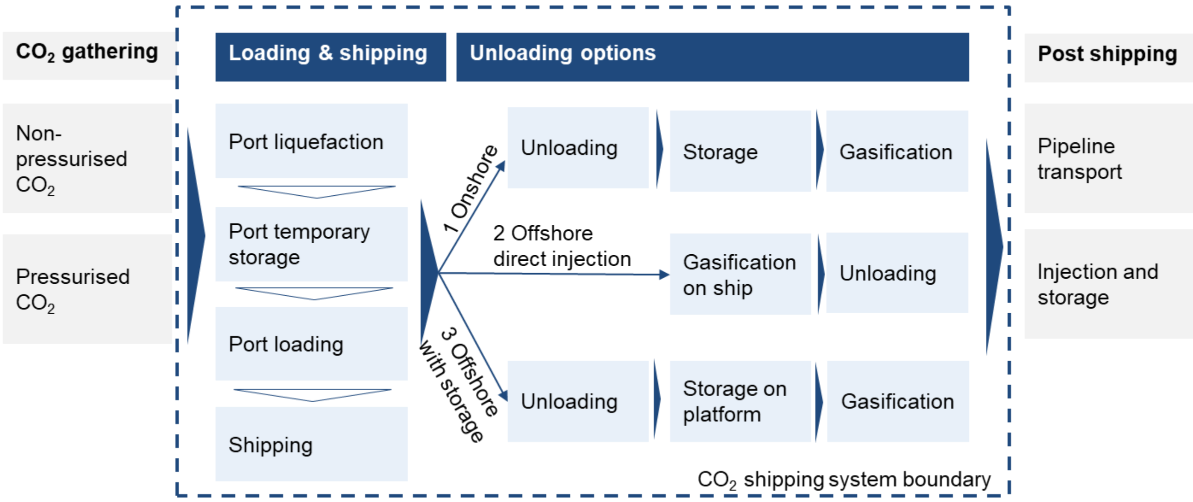



Figure 3-1 shows the components of the $CO_2$ shipping chain which are in the scope of the model. $CO_2$ is liquefied after arriving at the liquefaction plant in either pressurised or non-pressurised form. It is stored in liquified form in temporary storage tanks. From the tanks it is loaded onto the $CO_2$ carrying ship via a cargo handling system and then transported by ship to the destination.

Where the project involves port-to-port shipping, the $CO_2$ is unloaded onshore, as in the uppermost option in Figure 3-1. The $CO_2$ is unloaded from the ship in liquid form to temporary storage tanks using a cargo handling system as in the starting port. After this, the $CO_2$ is pumped and heated to conditions suitable for pipeline transport to a long-term storage site.

In addition to port-to-port shipping, port-to-storage shipping was considered. Two offshore unloading options are modelled, direct injection or onto a platform with storage, as shown in Figure 3-1. In the case of direct injection, the $CO_2$ is pumped and heated on board the ship and transferred via an offshore unloading system to the injection well of an offshore storage site. The second offshore unloading option is to transfer the $CO_2$ in liquid form to an offshore platform, where it is stored temporarily and finally pumped and heated to conditions suitable for injection into an offshore storage site.

This section describes the different infrastructure components of $CO_2$ shipping based on the literature reviewed. Each component of the shipping chain allows for particular design choices (Figure 3-2).

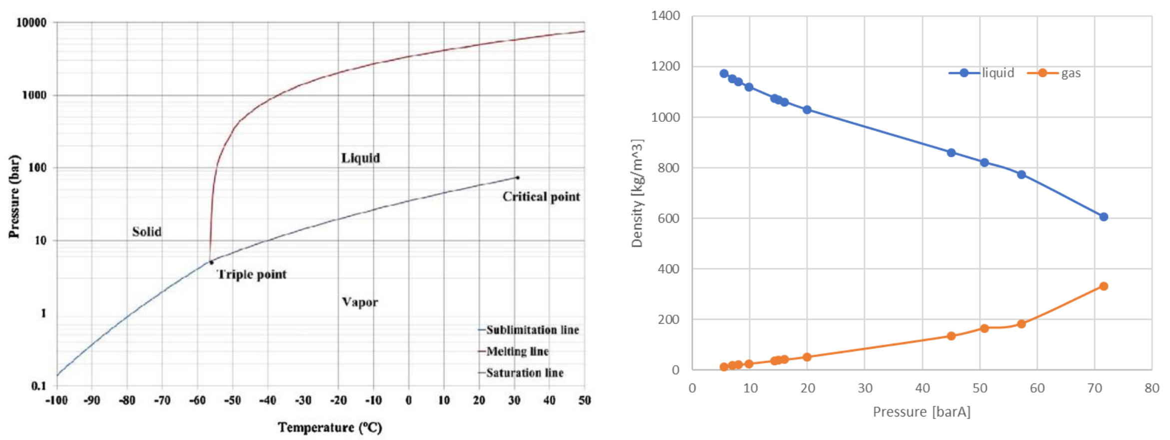
**Figure 3-2: Key design options and parameters of $CO_2$ shipping chain components**

| Process step | Key design options / *description* | Key variables |
|---|---|---|
| Port: Liquefication | • $CO_2$ transport pressure | • $CO_2$ flow rate, initial $CO_2$ pressure<br>• Energy requirement<br>• Electricity prices |
| Port: Temporary storage | • $CO_2$ transport pressure | • $CO_2$ flow rate<br>• Ship capacity, fleet size<br>• Trip time |
| Port: Loading | • *Cryogenic hoses*<br>• *Articulated loading arm* | • Loading speed/Loading time<br>• Port entry/exit time |
| Shipping | • $CO_2$ transport pressure<br>• Storage tanks/capacity | • $CO_2$ flow rate, trip time<br>• Construction/fuel/crew costs, ship speed, lifetime |
| Unloading opt. 1: port | • *Includes offloading, temporary storage, gasification*<br>• $CO_2$ transport pressure | • Same as loading and temporary storage<br>• $CO_2$ injection condition |
| Unloading opt. 2: offshore | • Gasification on ship; or temporary storage on platform (option) | • Water depth<br>• Sea environment<br>• $CO_2$ injection condition |

## 3.1 Liquefaction

For pipeline transport, as well as for shipping, $CO_2$ should be in a dense form, not gaseous, to be cost effective. While for LNG transport, natural gas is liquified by cooling it to a temperature below -160°C and then transported in tanks at atmospheric pressure, this is not an option for $CO_2$, as it only exists in gaseous or solid form at atmospheric pressure (see Figure 3-3).

**Figure 3-3: Phase diagram of $CO_2$ (left, source: (Seo, 2016)) and density of $CO_2$ liquid and gas at different pressures (right, source: (Yara, Larvik Shipping, Polarkonsult, 2016))**




Transport in gaseous form is not economic due to the low density of the gas, whereas transport in solid form is uneconomic due to the significant effort involved in loading and unloading (Geske, 2015).

Therefore, $CO_2$ is transported at or above the boundary between the liquid and gaseous phase at pressures higher than atmospheric pressure (Yara, Larvik Shipping, Polarkonsult, 2016). The density of $CO_2$ liquid and gas with varying temperature and pressure is shown in Table 3-1.

**Table 3-1: Density of $CO_2$ liquid and gas at different pressures and temperatures considered for shipping transport; source: (Yara, Larvik Shipping, Polarkonsult, 2016)**

| Pressure range | Temperature | Pressure | Density liquid (kg/m$^3$) | Density gas (kg/m$^3$) |
|---|---|---|---|---|
| **High pressure** | 30 | 72 | 607 | 333 |
| | 10 | 45 | 861 | 135 |
| **Medium pressure** | -19.5 | 20 | 1,029 | 53 |
| | -30 | 14 | 1,076 | 37 |
| **Low pressure** | -41 | 9.8 | 1,119 | 25 |
| | -55 | 5.5 | 1,173 | 15 |

A design choice which has significant implications for all parts of the shipping chain is the $CO_2$ transport pressure. In the literature reviewed, 3 distinct pressure ranges for liquid $CO_2$ transport are discussed, namely low pressure, medium pressure and high pressure (as shown above). Throughout the report we will use the terminology of low pressure, medium pressure and high pressure transport to refer to the pressure ranges as specified above.[2]

Several liquefaction processes are proposed in the literature. The general principle of liquefaction is a combination of process stages of cooling and compression of the $CO_2$. Process designs can be divided into ones that use an external refrigeration system (so called "closed" systems) and ones which cool the $CO_2$ solely by compression and expansion, without use of an external refrigerant ("open" systems or "integrated" refrigeration). Open systems have a simpler design but are less efficient (Alabdulkarem, 2012). During liquefaction, water needs to be removed from the $CO_2$ inlet stream by condensation and regenerative adsorption, to prevent hydration, freezing and corrosion. Other contaminants (volatile components such as nitrogen and argon) must be removed as well to prevent dry ice formation (Geske, 2015) (Brownsort, 2015).

The liquefaction costs are dominated by electricity costs for refrigeration and compression. The electricity requirement (kWh/t$CO_2$) depends on the initial entry condition (temperature and pressure) of the $CO_2$ and the desired final condition. Since the first step of the liquefaction processes usually consists of compression of the $CO_2$, the energy requirement is significantly reduced if the inlet $CO_2$ is pre-pressurised rather than at atmospheric pressure when it arrives at the liquefaction plant. This is the case if the $CO_2$ enters the plant through an onshore pipeline as it would be pressurised to about 100 bar for pipeline transport. Typical pressures discussed in the literature are 1-2 bar for non-pressurised $CO_2$ inlet and 70-100 bar for pre-pressurised $CO_2$.

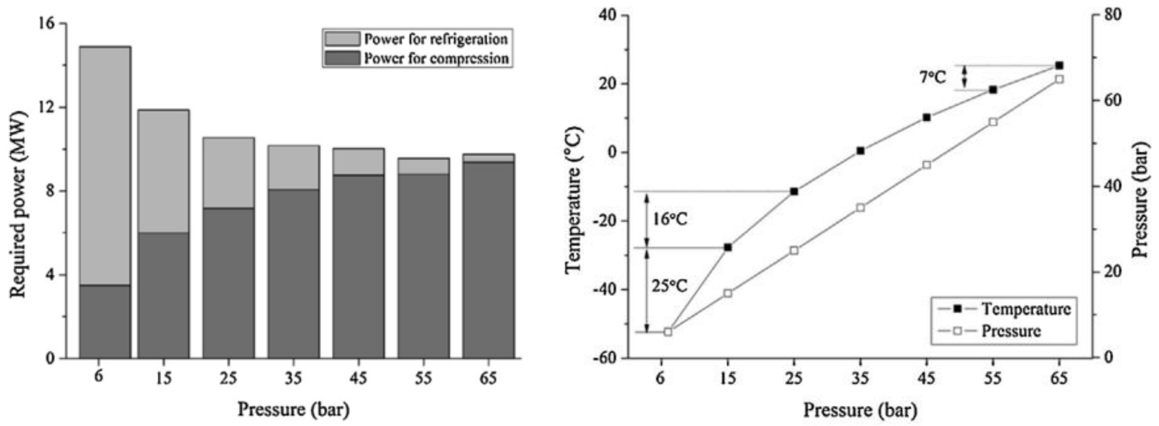
Four design variants of $CO_2$ liquefaction systems were compared (Seo Y, 2015): a Linde Hampson system, a dual-pressure Linde Hampson system, a pre-cooled Linde Hampson system and a closed system. The first three are classified as open systems, the last one is a closed system. It should be

[2] The low pressure and medium pressure conditions correspond to two standard transport modes of LPG shipping. While the low-pressure condition is very similar to the transport condition of so-called semi-refrigerated LPG (ZEP, 2011), the medium pressure condition is similar to the condition of so-called fully pressurised LPG. It is suggested that similar storage technology and materials currently used for LPG shipping could be applied to $CO_2$ storage tanks (Brownsort, 2015). The fleet of tankers carrying semi-refrigerated hydrocarbon gases is estimated to consist of more than 300 ships (ZEP, 2011).

noted that even though the pre-cooled Linde Hampson system is classified as an open system, it uses an external refrigerant in an initial process step.

The pre-cooled Linde Hampson and the closed system showed higher performance than the other process alternatives. Subsequently these two processes are considered in a follow up study, which compares the total cost of $CO_2$ shipping systems for 7 different $CO_2$ transport pressures (Seo, 2016): 6 bar, 15 bar, 25 bar, 35 bar, 45 bar, 55 bar, and 65 bar. The power requirement of the liquefaction plant for the different transport pressures is shown in Figure 3-4 (left). The power requirement for refrigeration decreases with increasing pressure as the liquefaction temperature increases. The refrigeration requirement is significantly reduced when moving from a transport pressure of 6 bar to a transport pressure of 15 bar, as the temperature of the liquefied $CO_2$ at 15 bar is almost 25°C warmer than at 6 bar Table 3-1, right. Considering the total cost of shipping, the study concluded that the 15 bar condition was the optimal balance of liquefaction cost against ship and storage costs.

**Figure 3-4 Power requirement for the liquefaction plant of a 1Mtpa project for different transport pressures (left) and temperatures (and pressures) for transport pressures; source: (Seo et al., 2016)**




Several liquefaction process designs were simulated in literature using external as well as integrated refrigeration and their costs compared (Oi, 2016). The study assumed an inlet gas pressure of 2 bar and an inlet gas temperature of 20°C. The outlet $CO_2$ condition of their liquefaction processes is 7 bar and -50°C, i.e. the low pressure transport condition. It was found that compressor costs dominate the capital as well as operational expenditure (energy for compression); a process using external refrigeration was found to be cost optimal. This differs from the finding in (Seo, 2016) that energy requirements are dominated by energy demand for refrigeration in the case of low pressure transport. This illustrates the significant differences between suggested liquefaction designs. The choice of liquefaction will not be determined by the minimum energy requirement alone, but also by the availability or desirability of an external refrigeration system (e.g. using ammonia) and the temperature of available cooling water, as well as available corporate experience (Brownsort, 2015).

$CO_2$ liquefaction is already operated today for $CO_2$ shipping. The main demand for $CO_2$ is in the food and beverage industry. However, these projects are of much smaller scale and use smaller ships, transporting less than 2,000 $tCO_2$, whereas a ship with a 10,000 $tCO_2$ capacity is needed for a project with moderate flow rate of 1 Mtpa. There is rarely any LNG liquefaction capacity of scale in Europe, therefore there is limited potential for reuse of LNG liquefaction plants for $CO_2$ liquefaction.

## 3.2 Temporary $CO_2$ storage

While the flow of $CO_2$ from a source such as a power plant or industrial emitter, and the subsequent liquefaction, is continuous, the shipping occurs in discrete runs and is a batch process. An intermediate buffer storage is therefore needed to store the $CO_2$, when there is no ship in the port. This storage also minimises the loading time of the ship by allowing a faster transfer rate than the flow rate of the $CO_2$ source; this ensures the ships are used most efficiently.

To enable fast loading of the ship, the storage should have at least the capacity of the ship in tonnes of $CO_2$. On the other hand, if the ship is unexpectedly delayed, the storage should be sufficient that it does not meet capacity, resulting in a halt to the $CO_2$ capture and subsequent liquefaction. To allow for operational flexibility, different safety margins are discussed in the literature. The capacity is quantified in multiples of the $CO_2$ ship carrying capacity. While several reports choose a storage capacity of 100% of the ship capacity ( (ZEP, 2011), (Seo, 2016)), sizes of up to 150% of the ship capacity are suggested (Berger, 2004). Yoo (2013) suggest a factor of 120% based on experience in LNG shipping and to balance the flexibility and cost efficiency. Unlike in the case of poisonous or highly flammable gases, $CO_2$ can be released into the air in case of delays and thus the storage does not have to be sized based on extraordinary incidents[3]. It is usually assumed that the design and specifications of the storage tanks on board the ship are similar or identical to those of the tanks which are used for the temporary buffer storage onshore ( (Vermeulen, 2011), (Seo, 2016)).

Depending on the availability of land close to the exporting $CO_2$ harbour, the liquefied $CO_2$ could be stored either onshore or on a floating barge, which are common in hydrocarbon transport systems. Yoo (2013) describes different conceptual designs for floating storage barges depending on the storage capacity. For smaller capacities around 28,000 $m^3$, the cylindrical storage tanks are arranged horizontally in the ship, whereas for large capacities around 110,000 $m^3$, the tanks would be arranged vertically in the ship, which allows for more flexibility in terms of arranging the tanks inside the ship and subsequently choosing the dimensions of the ship.

### *Materials, tank shape and maximum size*

A variety of classes of steel are used for the storage tanks, depending on the pressure and temperature of the contained $CO_2$. For the high pressure condition, which corresponds to ambient temperature (about 10°C), forged carbon steel is used. Carbon steel is used for the medium pressure condition in combination with either foam insulation or double skin vacuum insulation (Yara, Larvik Shipping, Polarkonsult, 2016). The low temperature condition requires the use of specialised low temperature materials, with carbon manganese steel, stainless steel and low temperature steel grades being suggested in the literature ( (Yoo B. C., 2013), (Yara, Larvik Shipping, Polarkonsult, 2016), and (Seo, 2016)). Storage tank material and equipment are required to withstand a range of $CO_2$ pressures and temperatures either side of the intended operational values. The conditions of the stored or transported $CO_2$ will vary during operation, for example due to heat leakage leading due partial vaporisation of the $CO_2$ and subsequent pressure increase (Vermeulen, 2011).

Cylindrical as well as spherical shapes of $CO_2$ storage tanks are feasible. Advantages and disadvantages of these tank shape are compared in literature (Vermeulen, 2011). Most reviewed studies propose cylindrical tank shapes. The maximum size of the cylindrical $CO_2$ storage tanks varies with the chosen transport pressure. The wall thickness increases with increasing pressure and can be calculated in accordance with guidelines of the Pressure Vessel Handbook. It should be noted that the wall thickness also varies with the ship dimensions, since larger ships usually have lower accelerations. This leads to lower additional pressure ("dynamic pressure") in the tanks due to such accelerations consequently lower required thickness[4]. The International Code of the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) recommends a maximum wall thickness of 40mm which is equivalent to a medium pressure tank of ~6m diameter[5]. The maximum size of a storage tank decreases with increasing wall thickness; this leads to less favourable economics

[3] Polarkonsult, 2018, personal communication
[4] Polarkonsult, 2018, personal communication
[5] Brevik, 2018, personal communication

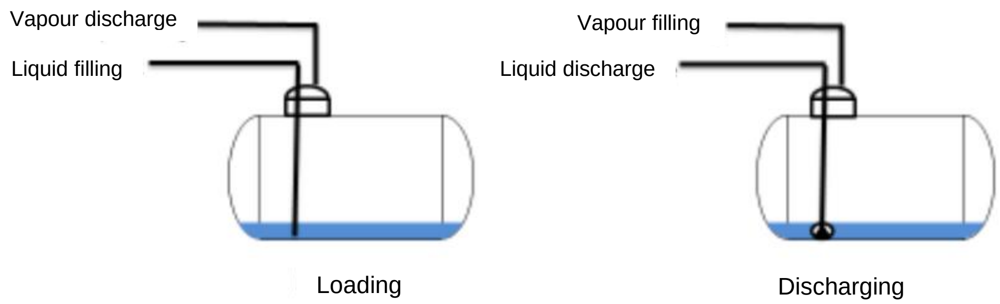
of storage for higher transport pressure, since more tanks must be constructed to transport the same volume of $CO_2$ (Seo, 2016). Brevik (2017) mention a wall thickness of 53 – 55 mm and a thickness of the insulation of 120 mm for the medium pressure condition. This is outside the area where normal design rules apply and drives cost and risk[6].

### *$CO_2$ storage operation*

The $CO_2$ will be present in the tanks in liquid as well as in gaseous form. In the bottom of the tank there is liquid $CO_2$ at the given pressure and temperature. Above the liquid is gaseous $CO_2$ at the same pressure and temperature (Knutsen OAS Shipping, 2016, p. 20). In fact, the storage tanks are not initially filled from bottom to top with liquid $CO_2$, but a certain share of the volume is intentionally left for the gaseous phase, to avoid hydraulic lock. Hydraulic lock can occur due to heat ingress and can cause rapid transient pressure spikes of the order of 10,000 bar which can result in catastrophic equipment failure; more details are given in (Yara, Larvik Shipping, Polarkonsult, 2016). The maximum allowable loading levels (in % of tank volume) range from 98% in the low pressure condition to 72% in the high pressure condition (Yara, Larvik Shipping, Polarkonsult, 2016).

As the tanks are filled with liquid $CO_2$, pressure builds up in the gaseous phase above the liquid phase. To avoid excessive pressure in the tanks, $CO_2$ vapour (also referred to as boil off gas, BOG[7]) is removed. Conversely, when the tanks are emptied, this leads to a drop in pressure within the tanks, which can result in solidification of the tank content. To prevent this, $CO_2$ vapor is added to the tanks during emptying, as shown in Figure 3-5. Therefore, in addition to the connection used to charge or discharge the liquid $CO_2$, the storage tanks have a connection used to add or subtract gaseous $CO_2$ (cp. Figure 3-5). When $CO_2$ is transferred from the onshore storage to the storage onboard the carrier, the boil off gas in the ship tanks is returned to the emptying tanks onshore (Vermeulen, 2011). Vermeulen (2011) discuss the pressure increase in the tanks over up to 90 days, given different choices of storage tank design parameters such as insulation thickness, insulation thermal conductivity and initial tank filling level.

**Figure 3-5: Charging and discharging of liquid $CO_2$ with simultaneous vapour discharging and charging respectively; source: (Knutsen OAS Shipping, 2016)**




## 3.3 Loading

Loading the $CO_2$ from the onshore temporary storage in the port to the $CO_2$ carrier can be performed using conventional articulated loading arms, developed for other cryogenic liquids such as LPG and LNG. The liquid is transferred through an insulated pipeline, specified for the chosen pressure and temperature, from the storage to the loading arm and ship, using pumps located near the storage. As mentioned in Section 3.2, a second line returns boil off gas of the ship's tanks either to the onshore storage tanks or to the liquefaction plant. Flexible hoses may be used as an alternative to loading

[6] Brevik, 2018, personal communication
[7] Boil off gas can also be a result of heat leakage from the tank environment to the inside.

arms, but these may be less reliable, which makes loading arms the preferred solution (Vermeulen, 2011).

The largest components of the overall trip time are the loading time, the ship journey and the unloading time. The total trip time determines the schedule of the ship and ultimately the number of ships needed to transport a given flow rate. While the loading costs comprise a minor cost component of the overall shipping costs, the impact of the loading time is significant and therefore the loading time should be reduced as much as possible. With increasing ship size, several loading arms should be used in parallel to avoid an increase of the loading time. Several studies therefore assume a loading time independent of the ship capacity (Geske, 2015) utilising high loading rates where necessary. For example, Vermeulen (2011) suggests a loading speed of 2,500 $m^3$ per hour, corresponding to 2,875 t/hour[8]. This would allow the loading of a 30,000$m^3$ ship in 12 hours. The high charging rate for the loading arms requires an adequate emergency shutdown (ESD) system to prevent leakage of significant amounts of $CO_2$ in case of loading arm failure or unintended disconnection from the carrier (Vermeulen, 2011).

## 3.4 $CO_2$ Ship

### 3.4.1 Experience with $CO_2$ shipping

$CO_2$ shipping has been taking place for 30 years, with the main demand for $CO_2$ coming from the food and beverage industry. The first dedicated $CO_2$ tanker was launched in 1988 in Norway (Yara, Larvik Shipping, Polarkonsult, 2016). However, the scale of the yearly $CO_2$ trade flows, and therefore the ship sizes, are much smaller than those needed for CCS projects. Currently $CO_2$ ships typically have a transport capacity of about 1,000 $m^3$ (ZEP, 2011) i.e. 1,060t of $CO_2$[9] and the total European trade flow in $CO_2$ is around 3 Mtpa (Brownsort, 2015). Industrial gas supplier Praxair owns 4 liquid $CO_2$ tankers operated by Larvik Shipping, which have been reconditioned for $CO_2$ transport from general cargo/bulk carriage. They have $CO_2$ carrying capacities of 1,200 – 1,800 $tCO_2$[10]. These ships are rated for medium pressure transport, at 16 – 21 bar and around -30°C. Shipping company IM Skaugen has six 10,000 $m^3$ ships which are registered to carry liquid $CO_2$, however their normal cargo is LPG and it is not clear if the ships have been used for $CO_2$ transport yet (Brownsort, 2015).

### 3.4.2 Ship design

#### Low pressure condition

Most publications which focus on the low pressure transport condition propose to use either existing designs of semi refrigerated LPG ships, or modifications of those. When using a conventional LPG tanker design, it is typically proposed to employ a low number of cylindrical tanks (less than ten), arranged in pairs horizontally. Vermeulen (2011) and Yoo (2013) propose a design using 6 tanks of capacity of 3,833 $m^3$ and 5,000 $m^3$ respectively (Figure 3-6), which result in a total capacity of 23,000$m^3$ and 30,000$m^3$ or 26,450t and 34,500t $CO_2$ respectively[11].

Alternative designs suggested differ in the shape of the tanks and/or the arrangement from the one described above. Vermeulen (2011) presents a ship design, called X-bow, where one smaller cylindrical tank is placed on top of 2 larger ones. This ship design is capable of transporting the same volume of gas as the variant based on a conventional LPG tanker, namely 30,000 $m^3$, but is much more compact (shorter in length) and thus requires less steel, leading to lower building costs. However, these benefits are outweighed by operational disadvantages of the X-bow design. In particular, the manoeuvrability when unloading offshore is reduced, since the bridge and accommodation are located

[8] Given a density of liquid $CO_2$ of 1150kg/$m^3$ in the low pressure condition
[9] Given a density of liquid $CO_2$ of 1060 kg/$m^3$ in the medium pressure condition
[10] Personal communication with Polarkonsult;
[11] Assuming a density of 1150kg/$m^3$ of liquid $CO_2$ at 7bar and -49°C

on the bow section, which requires the ship to approach the offloading tower with its stern (Vermeulen, 2011).

**Figure 3-6: Proposed ship designs for low pressure transport based on ship designs for semi-refrigerated LPG: left: (Vermeulen, 2011), right: (Yoo B. C., 2013)**


A further alternative design for a very large ship arranges 91 x 1000 $m^3$ tanks vertically for a total ship capacity of 91,000 $m^3$ (Figure 3-7, right). This design offers more flexibility in the arrangement of the tanks and thus can be better adjusted to a given ship size (Yoo B. C., 2013). A second layer of pairs of cylindrical tanks may be arranged on top of a lower one (Seo, 2016), for a ship of 12,310 $tCO_2$ capacity and the various transport pressures are considered (Figure 3-7, left). Alternative shapes of tanks suggested include ones with a bi-lobe cross section (Chiyoda Corporation and Global CCS Institute, 2011) as well as spherical tanks (Brownsort, 2015).

**Figure 3-7: Ship design suggested by for a 12310 $tCO_2$ ship (left) and for a 105,000 $tCO_2$ ship (right); source: left: (Seo, 2016), right: (Yoo B. C., 2013)**

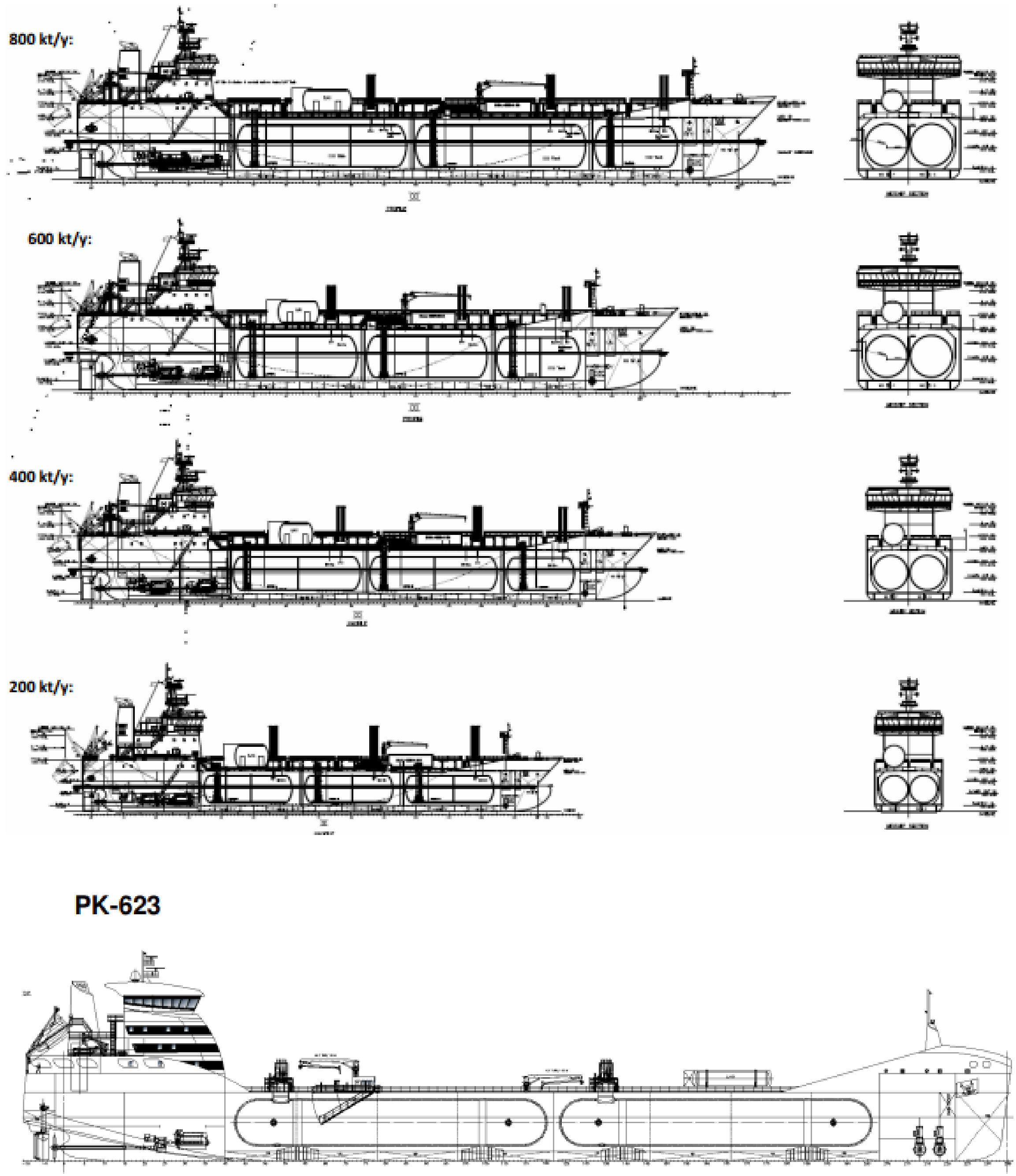

For offshore unloading the ship will require a dynamic positioning system (DPS) consisting of automatically controlled thrusters to maintain the position of the ship at the offshore storage site (Yara, Larvik Shipping, Polarkonsult, 2016), (Tel-Tek, 2014). This will be necessary regardless of the chosen transport pressure.

## Medium and high pressure condition

Most studies reviewed which focused on low pressure transport do not discuss the specific choices of materials and equipment in detail but remain on a rather high level, assuming that design choices would be very similar to those of LPG ships.

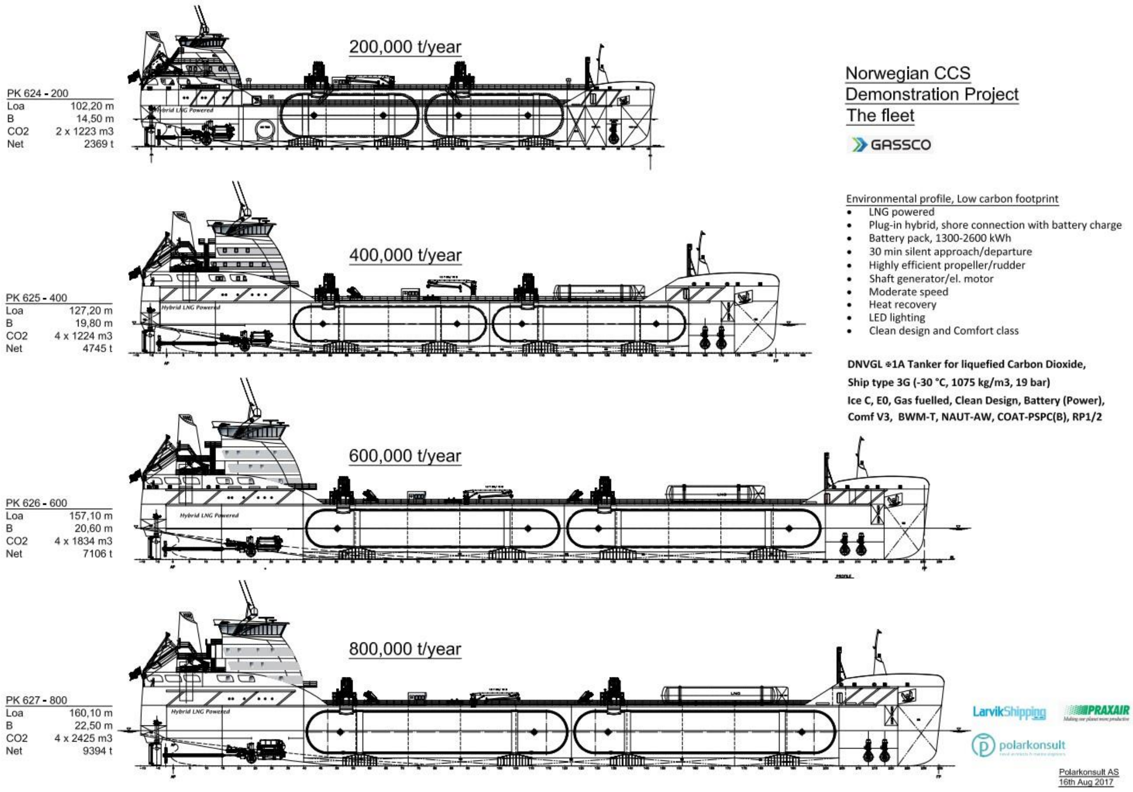
Detailed ship design studies have been commissioned in recent years by the Norwegian state owned gas company Gassco ( (Yara, Larvik Shipping, Polarkonsult, 2016), (Brevik, 2017)). These reports develop concepts for the medium pressure transport condition. For different flow rates from 0.2 up to 1.6 Mtpa, Brevik develop a ship concept, based on the design of an existing ship type. Cost estimates are provided for the proposed designs, informed by inputs from potential equipment vendors and experience of shipyard costs. Four ship types are developed, with capacities of 2,315 $tCO_2$, 4,534 $tCO_2$, 7,017 $tCO_2$ and 9,787 $tCO_2$, corresponding to flow rates of 0.2 Mtpa, 0.4 Mtpa, 0.6 Mtpa and 0.8 Mtpa respectively, with combinations of the proposed ship types used for projects of higher flow rates. The ship tanks are envisaged to operate at a temperature of -23°C and a pressure of 14 - 19 bar. All proposed ship types carry 5 cylindrical tanks, 1 positioned at the bow of the ship, in front of 4 further tanks arranged 2 by 2 horizontally. Schematic designs for these ship concepts are depicted in Figure 3-8.

**Figure 3-8 Top: ship concepts proposed by (Brevik, 2017); bottom: ship design proposed by (Yara, Larvik Shipping, Polarkonsult, 2016)**



Similarly, the joint report by fertiliser producer Yara[12], shipping company Larvik and consultancy Polarkonsult, develops a dedicated ship concept for the medium pressure condition. This provides cost estimates based on ship construction indices, main systems budget quotations and their own recent project experience of building new as well as operating existing ships. They consider projects with flowrates of 0.3 – 1.3 Mtpa and propose a small ship carrying one cylindrical tank of 1,850 $m^3$ volume and a larger ship carrying 4 tanks of 1,850$m^3$ volume, arranged 2 by 2 horizontally in the interior of the ship. These cargo tanks correspond to a $CO_2$ capacity of 1,776 t and 7,104 t respectively for the envisaged transport condition of -25°C and 16 bar. A follow up study (Polarkonsult, Praxair, Larvik Shipping, 2017) considered ship designs for the medium pressure condition, with $CO_2$ carrying capacities of 2,369 $tCO_2$, 4,745 $tCO_2$, 7,107 $tCO_2$ and 9,394 $tCO_2$. The dimensions of the tanks considered for the different ship types varied significantly with tank lengths ranging from 27m to 51m.

**Figure 3-9: Ship design concepts for the Norwegian CCS Demonstration Project; source (Polarkonsult, Praxair, Larvik Shipping, 2017)**




Seo (2016) developed ship designs for a ship with a $CO_2$ capacity of 12,310 t (for a 1 Mtpa project) and 7 different transportation pressures. They calculate the required cargo holding volume of the ship for the different pressures. As the pressure increases, the density of the liquid $CO_2$ decreases, therefore the required volume increases. Another contributing factor is that the maximum tank size decreases as pressure increases, so a greater number of tanks is required. The tanks must also be kept at a certain distance from each other to allow for inspections. Therefore, the required cargo holding volume increases for an increasing number of tanks. Thus, while the required volume of the 12,310 $tCO_2$ is 34% higher for the high pressure condition (45 bar) due to the reduced density compared to the low pressure condition (6 bar), the required holding volume is increased by 122%.

[12] Now owned by Praxair, which owns $CO_2$ ships operated by Larvik Shipping

### Transport pressure for large ships

While the medium pressure condition is the most proven form to transport liquid $CO_2$, it is not considered practical for ship sizes above 10,000 $tCO_2$. The reason for this is of commercial and technical nature: the dimensions and requirements for ships up to 10,000 $tCO_2$ are within the range typical for fully pressurised LPG ships and thus shipping designs are readily available. For higher capacities, new designs are required adding a significant premium, and the design of such larger ships is challenging. Tanks for the medium pressure condition have a maximum diameter of about 9 m, which allows a 2 by 2 arrangement at the bottom of the ship, while staying within the standard proportions of available ship designs. Depending on the ship shape, carrying more than 10,000 $tCO_2$ may require arrangement of the tanks on top of each other, which is more complex structurally[13]. Increasing the length of the tanks and the ship would lead to a long and narrow ship, which is not well suited for the envisaged environment[14].

### Repurposing LPG ships, operating multi-gas ships

Not only could new $CO_2$ ships be built with similar design elements to LPG ships, but it is also suggested that an existing LPG ship could be repurposed for $CO_2$ shipping, or ships could be built in such a way that they could be operated as multigas ships, transporting $CO_2$ as well as LPG. Conversely, $CO_2$ ships could be repurposed for LPG transport, which would offer a risk reduction for potential investors, should the ship become redundant for $CO_2$ trade ( (Yara, Larvik Shipping, Polarkonsult, 2016), (ZEP, 2011), (Equinor, 2018)). However, the economic feasibility of such a conversion or a multigas operation has not been proven yet. While the now bankrupt Norwegian shipping company IM Skaugen had six 10,000 $m^3$ LPG ships which were also approved for the carriage of $CO_2$, these ships did not seem to have been used for $CO_2$ transport yet (Brownsort, 2015). Furthermore, interviews with shipping management companies and consultancies have pointed to challenges and significant effort to repurpose LPG to $CO_2$ ships.

A further obstacle for converting an LPG ship into a $CO_2$ ship is the difference in the densities; LPG has about half the density of liquid $CO_2$ ($LCO_2$) at the considered pressure range. Therefore, a ship designed to carry a certain volume (in $m^3$) of LPG might not be able to carry the same volume of $LCO_2$ due to the greater weight of $CO_2$. Subsequently the structural design of the carrier may be suboptimal for $LCO_2$ transport[15]. Finally, retrofitting LPG ships would not bring substantial cost savings since ship CAPEX is not the most significant cost element within the overall shipping supply-chain (~14% estimated as explained in Section 5).

## 3.4.3 $CO_2$ transport pressure comparison

The density of liquid $CO_2$ decreases, and the cost of storage tanks increases, with increasing pressure (Section 3.2). Therefore, it is most cost effective to ship $CO_2$ at low pressure and temperature. Most studies assume a transport condition close to the triple point (5.2 bar, -56.6°C)[16], where $CO_2$ coexists in the gaseous, liquid and solid form, for $CO_2$ shipping. Usually the transport condition is chosen with a sufficient margin between the triple point to reduce the risk of solid formation under normal operational pressure and temperature ranges. However, the costs of liquefaction are a significant part of the total cost of $CO_2$ transport by ship and are higher for lower transport pressure, so these costs are included when assessing the cost-optimal condition of $CO_2$.

(Yara, Larvik Shipping, Polarkonsult, 2016) point to proximity to the triple point as requiring additional engineering equipment to mitigate the risk of freezing, in the case of low pressure transport, which leads to additional costs. It is also suggested that heavy engineering is required for purification of $CO_2$

[13] Source: confidential discussions with industry players
[14] Source: confidential discussions with industry players
[15] Source: confidential discussions with industry players
[16] https://www.linde-gas.com/en/images/LMB_Safety%20Advice_01_tcm17-165650.pdf

in the case of high pressure transport, leading to increased CAPEX. Storage tanks are more expensive and heavier for the high pressure condition, leading also to higher transport OPEX. Additionally, the high pressure transport may requires mitigation of the risk of so called cold BLEVE, where depressurisation from a high pressure saturation condition can cause sudden catastrophic failure. Medium pressure transport is recommended as the best understood condition.

## 3.5 Unloading

The $CO_2$ can either be unloaded onshore at a port (port-to-port shipping) from where it would be transported further by pipeline or offshore to a long term storage site. While port-to-port transport is tried and tested through experience in the food and beverage as well as ammonia sectors, offshore unloading of $CO_2$ is still unproven. However, significant experience from hydrocarbon transfer exists and it is suggested that this could be utilised for developing infrastructure for offshore unloading of $CO_2$.

When we refer to unloading infrastructure, we mean the physical connection between:

- the ship and the temporary storage in the port in the case of onshore unloading
- the ship and the wellhead of the long term storage site in the case of offshore unloading.

The infrastructure needed to bring the $CO_2$ into conditions suitable for pipeline transport or the long-term storage site is referred to as gasification infrastructure and described in Section 3.6.

In case of onshore unloading in a port, the $CO_2$ is transferred from the ship to a temporary storage in the port, using the same infrastructure as for loading: pumps, loading arms and pipelines. More detail on this infrastructure component has already been described in Section 3.3.

In case of offshore unloading, several hydrocarbon transfer systems are suggested for use connecting the ship to the injection well, with no clear consensus on what the most appropriate solution for $CO_2$ is. Offshore unloading of $CO_2$ is still immature and untested as a concept[17]. Vermeulen (2011) considers 4 different so called Single Point Mooring (SPM) systems to be used for the connection between ship and wellhead:

- A Submerged Loading System (SLS)
- A Fixed Tower Mooring System (FTSPM) also referred to as Tower Mooring System (TMS)
- A Single Anchor Leg Mooring System (SALM)
- A Conventional Buoy Mooring System (CBM)

These systems differ in terms of the water depths in which they can be deployed and their accessibility in case of high sea states. More information on these systems can be found in the literature, both in overview (Brownsort, 2015), and a detailed description (Vermeulen, 2011). This study found all considered systems to be feasible for deployment in typical North Sea conditions but recommended the FTSPM for locations with moderate depth (26.5m).

The transfer systems can be differentiated in terms of whether the $CO_2$ is discharged;

- directly to the wellhead via some subsea connection (direct injection); or
- via a platform (such as FTSPM or a Floating Storage Vessel), which allows instalment of processing equipment on it.

The $CO_2$ needs to be brought from the ship transport condition to a condition suitable for injection into the well, which depends on the storage site characteristics (more detail on this in Section 3.6). In the case of direct injection, this conditioning of the $CO_2$ must be performed entirely on the ship. In the case of unloading via a platform, it can be performed partly on the ship, partly on the platform.

[17] Brevik, 2018, personal communication

These two offshore unloading options are discussed in detail in literature (TNO, 2016), with discussion of whether the platform has temporary storage available or not. Using a platform with temporary storage allows to discharge the $CO_2$ in liquid form from the ship to the platform, which reduces the unloading time significantly. For the direct injection option, a SALM system is used; for the option of a platform without storage, an FTSPM system is used; and for the option of a platform with storage, a Floating Storage Vessel is used. TNO (2016) is the only study reviewed which provides detailed design analysis for unloading offshore as well as cost estimates for the studied designs.

To show two clearly distinct offshore unloading options, in this high level study we decided to model the direct injection option (using the SALM system) and the option of using a platform with storage. These two options differ in that the unloading time is considerably higher for the direct injection option due to a faster discharging rate of $CO_2$ in the liquid compared to in the gaseous phase.

## 3.6 Gasification

For injection into a storage site, the $CO_2$ temperature and pressure condition must be suitable for the reservoir used for long term storage. We refer to the process of reaching this required condition as gasification.

The $CO_2$ conditions suitable for injection depend on various characteristics of the storage site. Most studies on $CO_2$ shipping consider injection to be outside the scope of the study. However, the injection conditions determine not only the gasification requirements and suitable unloading technology, but also the possible flow rate, as storage sites have maximum achievable injection rates in terms of kg/s. Therefore, the flow rate of any project using a single storage site is limited by the injection rate of the storage site. In addition, careful consideration must be given to the ramping up and down of the injection of the $CO_2$ as a sudden stop in injection (e.g. when a ship has been fully discharged by direct injection) might lead to dry ice and hydrate formation (Vermeulen, 2011).

Injection of the $CO_2$ is outside the scope of this study, but it is recommended that for more detailed analysis of particular $CO_2$ shipping projects with chosen sources and storage sites, the injection conditions and their implications on the total $CO_2$ shipping chain should be considered in sufficient detail. A detailed analysis of the technical requirements of injection is given in Vermeulen (2011), an overview is given in Brownsort (2015). TNO (2016) describes the injection conditions for 2 different types of saline aquifers and 2 different types of depleted gas fields, each at four different depths (1000 m, 2000 m, 3000 m, and 4000 m). Together, these 16 different types of subsurface storage sites cover the range of typical conditions of storage locations in the North Sea region.

The storage site imposes, among others, the following constraints on the $CO_2$ conditions suitable for injection:

- The $CO_2$ pressure at the bottom-hole of the well (reservoir inlet) must overcome the reservoir pressure. This pressure depends on the filling level of the reservoir and thus changes with the maturity of the project. The pressure requirement at the bottom-hole translates into a requirement at the wellhead, and wellhead pressures of 50 – 400 bar are discussed.
- To avoid hydrate and dry ice formation, which can cause blockages, the temperature at the bottom-hole of the well (reservoir inlet) must be greater than 15°C. This translates into a required temperature of -15°C to +20°C at the wellhead depending on the pressure requirement.

To bring the $CO_2$ from the transport condition to the required wellhead condition, it is pumped to the appropriate pressure and heated to the appropriate temperature using a heat exchanger. Vermeulen (2011) suggests a small vaporiser unit should be installed on the ship to maintain the pressure in the ship tanks when the liquid $CO_2$ is discharged. Compressing liquid $CO_2$ using pumps requires much less energy than compressing gaseous $CO_2$ using compressors due to the significantly smaller specific volume of liquid $CO_2$ (Alabdulkarem, 2012).

The energy requirements for pumping and heating $CO_2$ vary depending on the injection condition as well as the transport condition. It is usually assumed that seawater is used in the heat exchanger to heat the $CO_2$. Depending on the required wellhead temperature and the seawater temperature, it may be necessary to pre-warm the seawater used in the heat exchanger. The heat required for this can be provided by waste heat from the ship engine or from available waste heat from the injection platform, if a platform is used for unloading. If there is not sufficient waste heat available, a fuelled heating system might be required which can have implications on costs and additional emissions (Brownsort, 2015).

In the case of onshore unloading, gasification happens onshore after the unloading from the ship to the temporary storage. In addition to the pressure requirement from the storage site, the $CO_2$ must be pumped to a sufficient pressure to overcome the pipeline pressure. Seo (2016) assume onshore unloading in their study and describe the equipment necessary to bring the $CO_2$ from the various ship transport conditions from 6 to 65 bar to a pipeline pressure of 100 bar. In their process design, the $CO_2$ is first brought to the appropriate pressure and afterwards heated to the appropriate temperature using the heat exchanger. They mention that for the transport pressure of 65 bar, a heat exchanger is not necessary anymore, since the temperature of the $CO_2$ at the transport pressure is already above 15°C.

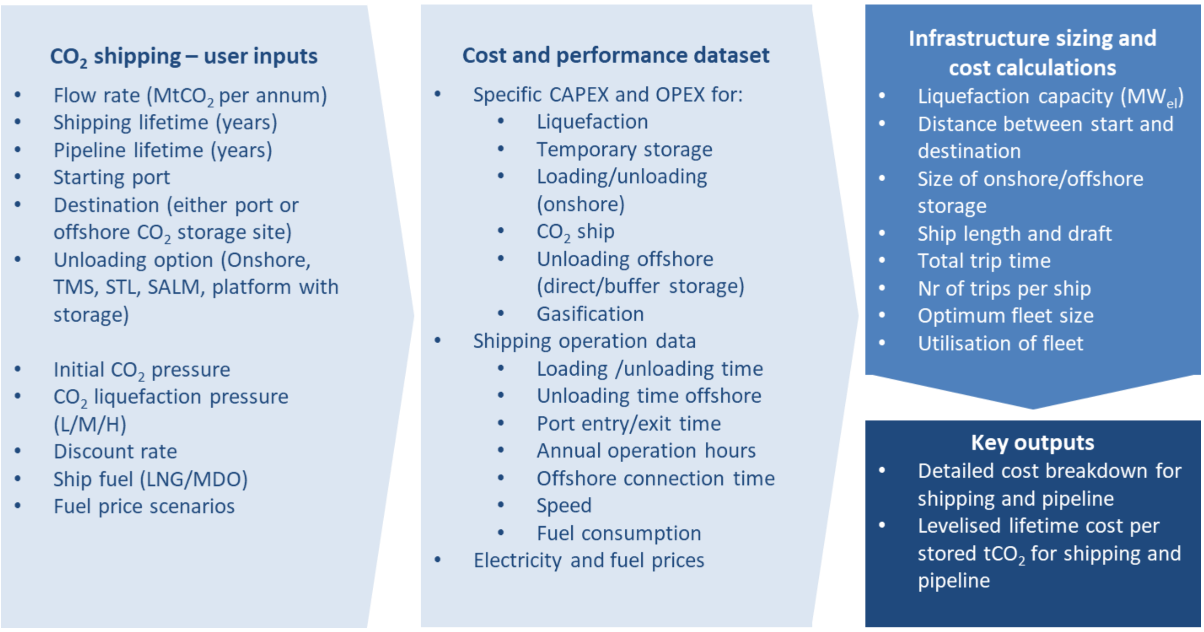
For offshore unloading, most studies suggest the $CO_2$ is pumped and heated either entirely on the ship or to some extent on the ship and to some extent on the platform. For direct injection from the ship, all pumping and heating must occur onboard the ship. Vermeulen (2011) describes a concept design for a gasification system on board the ship which pumps the $CO_2$ to the required pressure (154-400 bar) in 2 stages, with the heating applied to the $CO_2$ after the first pumping stage.

TNO (2016) considered detailed design concepts of the pumping and heating equipment needed for the unloading options they consider: direct injection or unloading via a platform (with or without storage). They also perform process simulations of the gasification and provide cost estimates for the equipment, as well as energy requirements for pumping and heating for all 16 types of North Sea reservoirs considered. In the case of direct injection, the $CO_2$ is completely pumped and heated on board the ship.

# 4 Cost model methodology

Figure 4-1 gives an overview of the cost model methodology showing user inputs, the model cost database, internal calculations and cost outputs. The following subsections describe in more detail the methodology by which the cost of each infrastructure component of the $CO_2$ shipping chain is modelled, as described in the previous section. Furthermore, the modelling assumptions, including cost estimates from literature, are presented.

**Figure 4-1: High level methodology of the $CO_2$ shipping cost model**




## 4.1 Liquefaction

Liquefaction costs consist of the CAPEX and fixed OPEX of the liquefaction plant as well as variable electricity costs. We assume the CAPEX of the liquefaction plant depends linearly on the flow rate of the project. The annual $CO_2$ flow rate determines the quantity per hour which the liquefaction plant must produce, and therefore the liquefaction plant scales with the flow rate of the project.

**Table 4-1** shows the CAPEX and OPEX values of liquefaction found in the literature as well as the values of the liquefaction energy requirement in kWh per $tCO_2$. Costs have been converted to 2017 £ using UK government exchange[18] and inflation rates[19].

[18] https://www.gov.uk/government/publications/exchange-rates-for-customs-and-vat-yearly
[19] https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/l55o/mm23

**Table 4-1: Liquefaction cost estimates from the literature**

| Reference | Transport pressure | Inlet pressure (bar) | Flow rate (Mtpa) | CAPEX (£m) | Specific CAPEX (£/(t$CO_2$/a)) | Fixed OPEX/y (% of CAPEX) | Energy (kWh/t$CO_2$) |
|---|---|---|---|---|---|---|---|
| Oi et al, 2016 - 1 | Low P | 2 | 1.1 | 18.4 | 16.8 | N/A | 80.3 |
| Oi et al, 2016 - 2 | Low P | 2 | 1.1 | 19.1 | 17.4 | N/A | 80.2 |
| Oi et al, 2016 - 3 | Low P | 2 | 1.1 | 23.1 | 21.1 | N/A | 143.2 |
| Oi et al, 2016 - 4 | Low P | 2 | 1.1 | 22.6 | 20.6 | N/A | 87.0 |
| Seo et al, 2016 - 1 | Low P | 1.8 | 1 | 21.3 | 21.3 | N/A | 130.5 |
| Seo et al, 2016 -2 | Med P | 1.8 | 1 | 16.6 | 16.6 | N/A | 104 |
| Seo et al, 2016 - 3 | High P | 1.8 | 1 | 10.6 | 10.6 | N/A | 88 |
| Yoo et al, 2013 - 1 | Low P | 1 | 10 | N/A | N/A | N/A | 106.3 |
| TelTek, 2014 - 1 | Low P | 70 | 0.8 | 6.3 | 7.9 | N/A | N/A |
| TelTek, 2014 - 2 | Low P | 70 | 0.8 | 9.9 | 12.4 | N/A | N/A |
| CO2Europipe, 2011 | Low P | 75 | 3 | 27.2 | 9.1 | 10% | 42 |
| Yoo et al, 2013 - 2 | Low P | 100 | 10 | N/A | N/A | N/A | 17.3 |
| Mitsubishi Heavy Industries, 2004 | Low P | 100 | 6.2 | 23.7 | 3.8 | 5% | 14.4 |

Based on the literature values, the input values for the cost model are summarised in Table 4-2. The reasons for choosing these input values are explained in further detail below.

**CAPEX and energy requirements:**

For low pressure transport, both the case of non-pressurised as well as pre-pressurised $CO_2$, the average of the literature values listed is used. The specific CAPEX value of Mitsubishi Heavy Industries (2004) is discarded as outlier. The pressure values of the inlet $CO_2$ vary among the reports which have been used (between 70 and 100 bar in the case of pre-pressurised $CO_2$ and 1 and 2 bar in the case of non-pressurised $CO_2$). The calculated values thus represent range of configurations both for pre-pressurised and non-pressurised $CO_2$. This is in line with the goal to use representative values for 2 principal options: liquefaction directly at the source of $CO_2$ (non-pressurised) or transport of the $CO_2$ to the liquefaction plant by pipelines (pre-pressurised).

For the medium and high pressure transport condition, less detailed data was available. Therefore, the following assumptions were made:

- Non-pressurised $CO_2$: CAPEX and energy requirement are assumed to be reduced compared to the low-pressure condition by the same factor as reported in Seo et al. (2016) (e.g. specific CAPEX for the medium pressure condition for non-pressurised inlet $CO_2$ are given by the specific CAPEX for the low pressure condition for non-pressurised inlet $CO_2$, multiplied by a factor of 16.6/21.3 = 78% cp. Table 4-1, lines 6 and 7)
- Pre-pressurised $CO_2$: CAPEX and energy requirement are assumed to be reduced compared to the non-pressurised condition by the same factor as for low pressure transport (e.g. specific CAPEX for the medium pressure condition for pre-pressurised inlet $CO_2$ is given by the specific CAPEX for medium pressure condition for non-pressurised $CO_2$ (15.1£/(t$CO_2$/a)) multiplied by a factor of 9.8/19.5=50% (cp. Table 4-2, line 2 and 3).

- **Fixed OPEX:** Fixed OPEX is assumed to be a percentage of CAPEX; the value used is 10% ($CO_2$ Europipe, 2011). Other sources did either not specify fixed OPEX (such as personnel, maintenance, and administration) or were discarded due to the low costs specified in comparison to the other literature values (Mitsubishi Heavy Industries, 2004).
- **Liquefaction fuel price:** The electricity price used is £0.08/kWh, corresponding to the price currently paid by large businesses in the UK[20]. Low and high fuel price sensitivities are defined as a 25% decrease and increase to this value respectively.

**Table 4-2: Liquefaction cost assumptions used in the model**

| Transport pressure | Inlet pressure | Specific CAPEX £/($tCO_2$/a) | Fixed OPEX/y (% of CAPEX) | Energy (kWh/t) |
|---|---|---|---|---|
| Low P | Pre-pressurised | 9.8 | 10% | 24.6 |
| Low P | Non-pressurised | 19.5 | 10% | 104.2 |
| Med P | Pre-pressurised | 7.6 | 10% | 19.6 |
| Med P | Non-pressurised | 15.1 | 10% | 83.1 |
| High P | Pre-pressurised | 4.9 | 10% | 16.6 |
| High P | Non-pressurised | 9.7 | 10% | 70.3 |

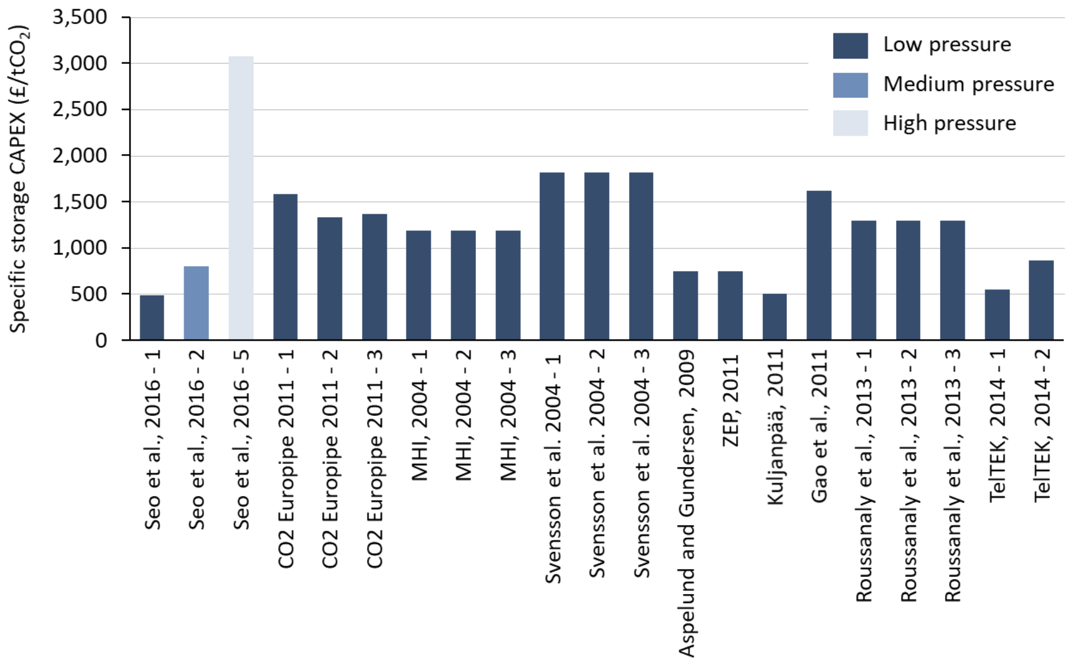
Many reports in the literature do not debate different liquefaction process options but focus instead on a particular option due to local cooling service availability or corporate experience but without clear justification (Brownsort, 2015). Given the significant share of liquefaction in the total shipping cost, a detailed feasibility study for a shipping project should consider different process options for liquefaction.

## 4.2 Storage

For the cost model, it is assumed that the cost of temporary onshore storage depends linearly on the storage capacity. The storage capacity is assumed to be 120% of the combined $CO_2$ capacity of the ship fleet, i.e. a fleet of two 10,000 $tCO_2$ ships requires storage capacity of 24,000 $tCO_2$. This multiple is based on literature (Yoo B. C., 2013), providing a good compromise between operational flexibility and cost efficiency. The values for the specific cost of the temporary storage (i.e. cost per tonne of $CO_2$ storage capacity) as found in the literature are illustrated in Figure 4-2.

[20] https://www.gov.uk/government/statistical-data-sets/prices-of-fuels-purchased-by-manufacturing-industry

**Figure 4-2 Specific storage CAPEX of temporary storage from literature**




For the medium and high pressure condition, the specific CAPEX from (Seo, 2016) is used, the only reviewed publication specifying costs for low pressure and high pressure transport. For the low pressure condition, we consider only the specific CAPEX values of the 2 newest publications (Seo, 2016) and (Tel-Tek, 2014) and furthermore only the NOAK (Nth of a kind) value of the latter one. The other literature cost values are discarded as they are not considered to be consistent with the ones of (Seo, 2016); they show higher cost values for the low pressure condition than the ones specified by (Seo, 2016) for the medium pressure condition. This is in contradiction to the finding explored by (Seo, 2016) that higher transport pressures lead to higher storage costs.

Storage OPEX values (in % of CAPEX, primarily maintenance and repair) are taken from (Seo et al., 2016). The cost values for storage from the literature and the ones used in the model are summarised in **Table 4-3** and **Table 4-4** respectively. In the case of onshore unloading, or offshore unloading to a platform, it is assumed that storage of the same size as for loading will be built in the destination terminal or platform. In the case of offshore unloading with direct injection, no storage is assumed to be built for the unloading site.

**Table 4-3: Storage cost estimates from the literature**

| Datapoint reference | Transport pressure | Capacity ($tCO_2$) | CAPEX (£m) | Specific CAPEX (£/$tCO_2$) | OPEX/y (% of CAPEX) |
|---|---|---|---|---|---|
| Seo et al., 2016 - 1 | Low P | 12,310 | 5.9 | 482 | 5% |
| Seo et al., 2016 - 2 | Med P | 12,310 | 9.8 | 795 | 5% |
| Seo et al., 2016 - 3 | High P | 12,310 | 37.8 | 3,073 | 5% |
| TelTek, 2014 - 1 | Low P | 14,285 | 12.3 | 550 | 5% |

**Table 4-4: Storage assumptions used in the model**

| Transport pressure | CAPEX per $tCO_2$ of storage capacity (£/$tCO_2$) | OPEX/y (% of CAPEX) |
|---|---|---|
| Low P | 516 | 5% |
| Med P | 795 | 5% |
| High P | 3,073 | 5% |

## 4.3 Loading

The loading infrastructure in the port consists of pumps and pipelines, through which the $CO_2$ is pumped from the temporary storage onto the ship. The loading time is assumed to be independent of the ship size due to the reasoning in Section 3.3 and a loading time of 15 hours is assumed (Cato, 2016), representing a central value compared to further values specified in the literature.

It is assumed that the CAPEX for the loading infrastructure in the port depends linearly on the flow rate of the project, as more loading infrastructure must be deployed for higher flow rates to keep the loading time constant. The cost values of CAPEX and OPEX of loading infrastructure found in the literature are displayed in **Table 4-5**.

**Table 4-5: Loading cost estimates from the literature**

| Datapoint reference | Flow rate (Mtpa) | CAPEX (£m) | Specific CAPEX (£/($tCO_2$/a)) | OPEX/a (% of CAPEX) |
|---|---|---|---|---|
| CO2 Europipe, 2011 | 3 | 8.4 | 2.80 | 2% |
| MHI, 2004 | 6.2 | 6.3 | 1.02 | 25% |
| MIT, 2003 | 8.1 | 57.0 | 7.03 | 2% |
| Aspelund and Gundersen, 2009 | 10 | 4.6 | 0.46 | 1% |
| Kuljanpää, 2011 | 3 | 2.6 | 0.88 | 1% |
| TelTEK, 2014 - 1 | 0.8 | 0.9 | 1.07 | 5% |
| TelTEK, 2014 - 2 | 0.8 | 1.3 | 1.68 | 4% |

In the model, the average of the values of specific CAPEX and OPEX specified in the literature are used, after discarding the outliers (MHI, 2004 and MIT, 2003). These averages are shown in **Table 4-6**. For unloading onshore, the same costs as for loading are assumed, since the same infrastructure as for loading (e.g. pumps, pipelines, loading arms) is used.

**Table 4-6: Loading cost assumptions used in the model**

| Specific CAPEX (£/($tCO_2$/a)) | OPEX/a (% of CAPEX) |
|---|---|
| 1.4 | 3% |

## 4.4 Ship costs

Ship costs are modelled as consisting of the ship CAPEX and OPEX, where the OPEX is broken down into fixed OPEX, harbour fees and fuel costs.

### 4.4.1 Ship CAPEX

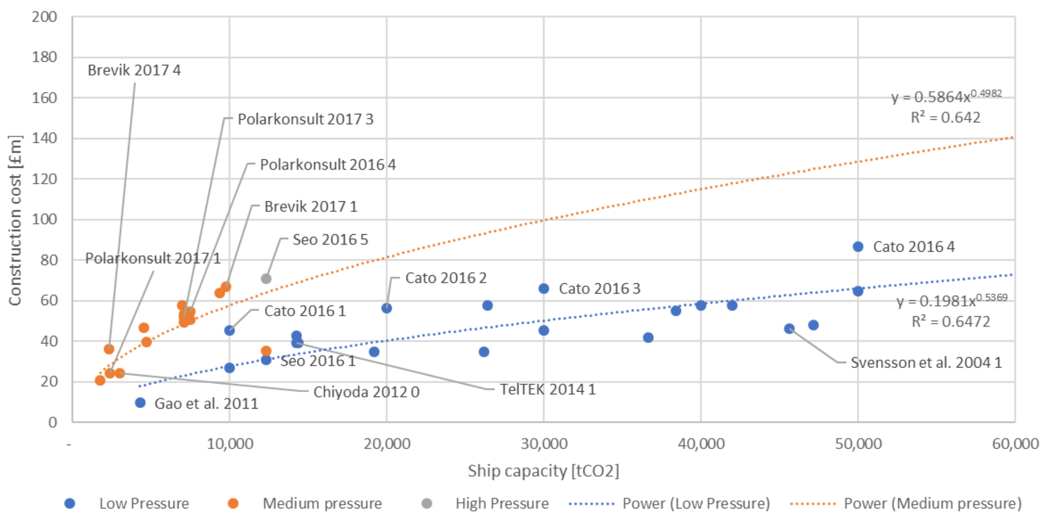
The ship CAPEX depends on several factors, primarily the ship size and the number of ships needed. For a given flow rate, distance and ship size, the model calculates the number of ships needed using the total round-trip duration; this duration consists of loading time, travelling time (to and from destination, dependent on distance and speed), port manoeuvring and unloading time. A ship speed of 15 knots is assumed, the average speed of chemical tankers (Seo, 2016), and in line with the values found in the literature review (mostly between 13 – 16 knots). Dividing the total operational hours of a ship per year by this total trip time delivers the total number of trips a ship can make per year, and thus the amount of $CO_2$ that can be transported per ship per year. Dividing the flow rate by the amount of $CO_2$ transportable per ship per year delivers the number of ships needed. The parameters assumed for the ship operation modelling are summarised in the table below.

**Table 4-7: Operational parameters of shipping**

| Parameter | Unit | Value | Source |
|---|---|---|---|
| Loading/unloading time onshore | h | 15 | Cato 2016 |
| Unloading time offshore | h | 36 | Cato 2016 |
| Port entry/exit | h | 2 | Seo et al., 2016 |
| Offshore connection | h | 4 | TelTek, 2014 |
| Annual operational hours | h | 8,322 | Roussanaly et al, 2014 |
| Ship speed (large ships) | nm/h | 15 | Seo et al., 2016 |

The figure below shows values of ship CAPEX, i.e. construction cost, found in the literature. For the low and medium pressure transport condition, power regression curves are used to estimate values.

**Figure 4-3: Ship CAPEX values found in the literature**



Based on the values found in the literature, the cost assumptions used in the model are summarised in the table below. The values for low and medium pressure transport are based on the regression curves as displayed in the chart above. The high pressure values are derived by scaling the regression curve of the medium pressure transport condition such that it crosses the data point found for high pressure transport. The resulting values for the ship capacities used in the model are also displayed below. For ship sizes above 10 kt $CO_2$ it is assumed that only the low pressure transport is viable.

**Table 4-8: Ship CAPEX values used in the model**

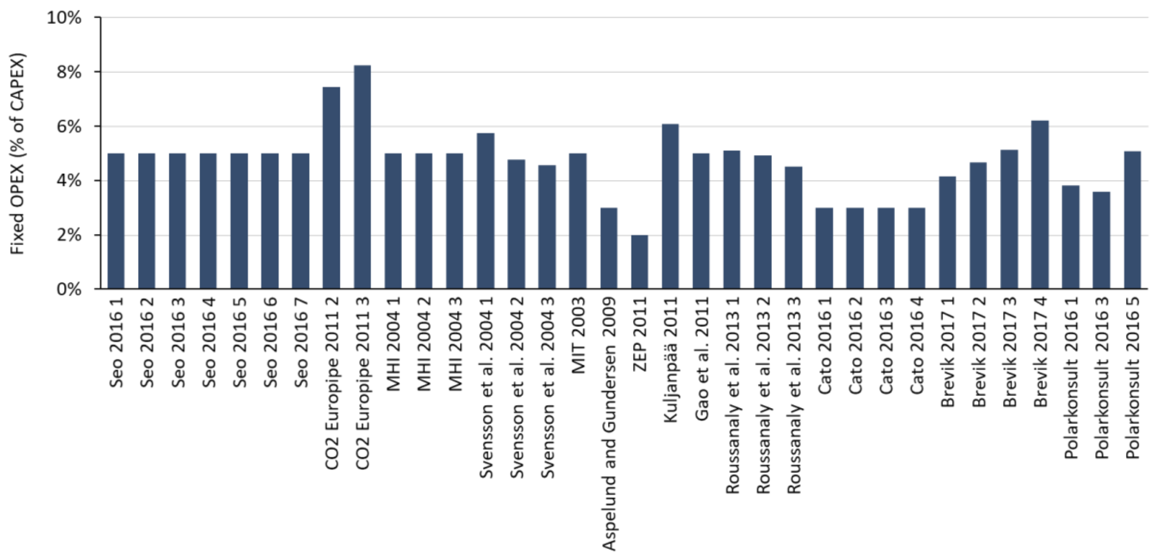
| Capacity ($tCO_2$) | CAPEX low pressure (£m) | CAPEX med. pressure (£m) | CAPEX high pressure (£m) |
|---|---|---|---|
| 2,000 | 12 | 26 | 52 |
| 4,000 | 17 | 37 | 74 |
| 6,000 | 21 | 45 | 90 |
| 8,000 | 25 | 52 | 104 |
| 10,000 | 28 | 58 | 117 |

| Capacity ($tCO_2$) | CAPEX low pressure (£m) |
|---|---|
| 20,000 | 42 |
| 30,000 | 53 |
| 40,000 | 61 |
| 50,000 | 69 |

## 4.4.2 Ship fixed OPEX

Fixed OPEX of the ship consists of the costs for crew, maintenance and repair as well as administration and insurance costs. The values for these costs in % of the ship CAPEX are displayed in Figure 4-4. Based on these, in the model we are using 5% of CAPEX as the value of fixed OPEX, the most common value specified in the literature.

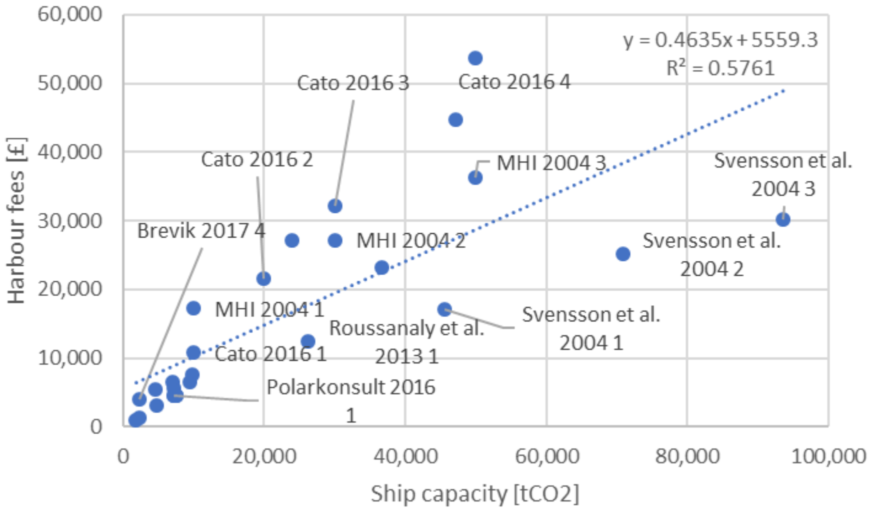
**Figure 4-4: shipping fixed OPEX values found in the literature**




## 4.4.3 Harbour fees

A further cost component of the ship OPEX are harbour fees, which increase with the size, i.e. capacity, of the ship. A regression based on the data found in the literature is presented below. We are modelling the harbour fees using the regression line shown. The resulting fees for the ship sizes used in the model are shown below. Harbour fees vary of course between harbours and detailed feasibility studies for any particular project should consider the fees of all harbours on the route of the ship.

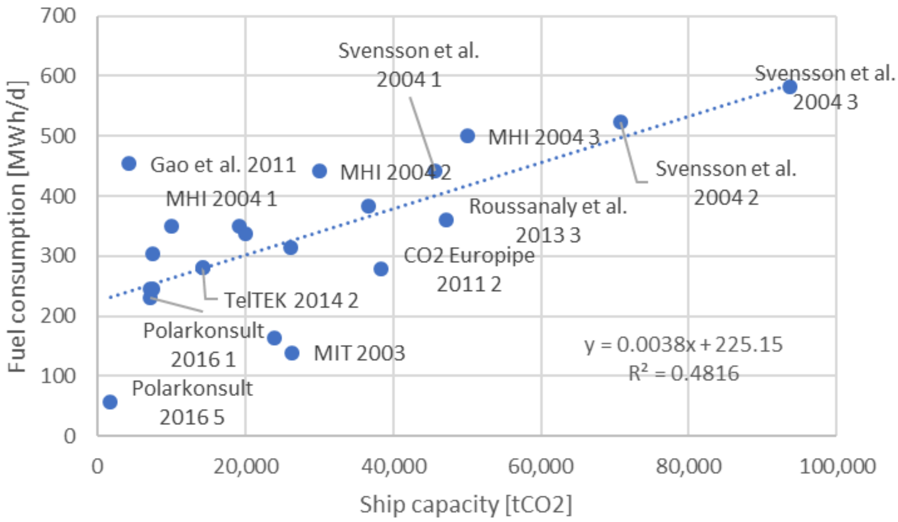
**Figure 4-5: Harbour fees found in the literature, per round trip.**




## 4.4.4 Ship fuel costs

Fuel costs depend on the fuel consumption of the ship and the ship size (in $tCO_2$). The fuel consumption values in MWh/d found in the literature for various ship sizes are displayed in Figure 4-6. We use the regression line displayed to calculate the fuel consumption for the ship sizes used in the model, with the values given in the table below.

**Figure 4-6: Fuel consumption values found in the literature**




The ship fuel can be selected by the user: either LNG or MDO (Marine Diesel Oil). The fuel consumption in MWh/d is converted to a fuel consumption of tonnes of LNG per day or tonnes of MDO per day, depending on which fuel is used. This fuel consumption in t/d is multiplied by the total travelling time of one ship per year, and the number of ships, to obtain the total fuel consumption of the fleet per year. Finally, this consumption is multiplied with the assumed fuel prices of LNG and MDO respectively, shown in Table 4-9. The fuel prices in £/t have been converted to £/MWh using a fuel content of 11.63 MWh/t for MDO and of 14.45 MWh/t in the case of LNG. As a sensitivity, the user can select a high fuel cost or a low fuel cost scenario. In these cases, the fuel prices are increased or decreased by 25% respectively.

**Table 4-9: Ship fuel prices and sources**

| Fuel | Price (£/t) | Price (£/MWh) | Source |
|---|---|---|---|
| LNG | 282 | 20 | Ship and bunker, 2018 |
| MDO | 275 | 24 | Baresic et al., 2018 |

**Table 4-10: ship OPEX used in the model, depending on ship size**

| Capacity ($tCO_2$) | Fixed OPEX (% of CAPEX) | Harbour fees (£/cycle) | Fuel consumption (MWh/d) |
|---|---|---|---|
| 2,000 | 5% | 6,486 | 233 |
| 4,000 | 5% | 7,413 | 240 |
| 6,000 | 5% | 8,340 | 248 |
| 8,000 | 5% | 9,267 | 256 |
| 10,000 | 5% | 10,194 | 263 |
| 20,000 | 5% | 14,829 | 301 |
| 30,000 | 5% | 19,464 | 339 |
| 40,000 | 5% | 24,099 | 377 |
| 50,000 | 5% | 28,734 | 415 |

## 4.5 Unloading

### 4.5.1 Onshore unloading

As mentioned before, the same costs as for loading are assumed to accrue in the case of onshore unloading, since the same infrastructure is used. Therefore, these costs are modelled in the same way as loading costs.

### 4.5.2 Offshore unloading

For offshore unloading there are 3 user options available:

- Direct injection
- Injection via a new platform with storage
- Injection via an existing platform with storage

The cost estimates are based on (TNO, 2016), which explores the offshore unloading option in most detail among the reviewed literature and provides cost estimates of the necessary infrastructure. The cost estimates of this infrastructure, as specified in this study, along with estimates from other studies are summarised in the table below.

**Table 4-11: Offshore unloading cost estimates found in the literature**

| Reference | Design | $CO_2$ condition | $CO_2$ flow rate (Mtpa) | CAPEX (£m) | OPEX/a (% of CAPEX) |
|---|---|---|---|---|---|
| Cato, 2016 | SALM[21] | Low P | 3.8 | 16.5 | 5% |
| Cato, 2016 | TMS[22] | Low P | 3.8 | 37.2 | 5% |
| Cato, 2016 | Platf. w/ stor. | Low P | 3.8 | 91.0 | 5% |
| Petrofac, 2012 | CALM[23] | Low P | 5 | 60.6 | 4% |
| TelTEK, 2014 | STL NOAK | Low P | 0.8 | 17.2 | 5% |

For the direct injection option, the cost of the SALM system specified (Cato, 2016) is assumed as a fixed CAPEX cost, with OPEX assumed to be 5% of CAPEX yearly.

The CAPEX estimate in (TNO, 2016) for the platform with storage includes the cost of a 40,000 t storage system. As the storage cost has already been accounted for in the model, we subtract our model's estimate for a 40,000 t storage system from the estimate in (TNO, 2016) to avoid double counting of the storage system on the platform. The yearly OPEX is assumed to be 5% of CAPEX.

In the case of unloading to an existing platform with storage, we assume no CAPEX for the platform but the same OPEX as in the case of unloading to a (newly built) platform.

CAPEX costs of the offshore unloading infrastructure have been assumed to be a fixed cost, independent of the flow rate, to reflect the fact that offshore infrastructure cannot simply be scaled to the project size but requires large scale equipment which comes in standardised form and the construction in challenging conditions is costly. This approach to model offshore unloading CAPEX was also taken in (TNO, 2016).

## 4.6 Gasification costs

### 4.6.1 Gasification onshore

For onshore gasification, the cost assumptions taken from (Seo, 2016) are summarised in Table 4-12. CAPEX is assumed to scale with the flow rate of the project and OPEX is modelled as a cost per t $CO_2$ including maintenance and fuel cost of the plant.

**Table 4-12: Onshore gasification cost assumptions used in the model**

| Reference | Transport pressure | CAPEX (£/(t/a)) | OPEX (£/t$CO_2$) |
|---|---|---|---|
| Seo et al., 2016 | Low P | 0.83 | 0.33 |
| Seo et al., 2016 | Med P | 0.78 | 0.31 |
| Seo et al., 2016 | High P | 0.50 | 0.23 |

[21] Single Anchor Leg Mooring
[22] Tower Mooring System
[23] Catenary Anchor Leg Mooring

### 4.6.2 Gasification offshore

For offshore gasification, the cost estimates given in (TNO, 2016) are used as this study provides the highest level of detail for the offshore unloading option among the reviewed literature, while also providing cost estimates. The assumptions used are given in **Table 4-13**.

**Table 4-13 Offshore gasification cost assumptions used in the model**

| Reference | Unloading option | Transport pressure | CAPEX (£/(t/a)) | Fixed OPEX (% of CAPEX) | Energy ($kWh/tCO_2$) |
|---|---|---|---|---|---|
| (TNO, 2016) | Direct inj. | Low P | 4.3 | 5% | 6.8 |
| (TNO, 2016) | Direct inj. | Med P | 4.3 | 5% | 6.5 |
| (TNO, 2016) | Direct inj. | High P | 4.3 | 5% | 5.4 |
| (TNO, 2016) | Platf. w/ st. | Low P | 6.7 | 5% | 10.3 |
| (TNO, 2016) | Platf. w/ st. | Med P | 6.7 | 5% | 10.0 |
| (TNO, 2016) | Platf. w/ st. | High P | 6.7 | 5% | 9.0 |

A generator efficiency of 35% was assumed for the electricity generator on board the ship or the platform to produce the electricity needed to operate the pump. It is assumed the generator uses the same fuel as the ship, i.e. either LNG or MDO.

It should be noted that for a given flow rate, the energy requirement for gasification is higher in the case of injection via a platform than for direct injection. This is because the $CO_2$ injection pressure is about 200 bar in the case of direct injection whereas it is 300 bar in the case of injection via a platform. However, the injection at 300 bar also enables a higher injection rate and thus shorter unloading time.

# 5 $CO_2$ shipping cost modelling results

## 5.1 Key cost components and parameters

For analysing the cost model results, a central case was chosen from which to explore the sensitivities of the results further. The parameters of the central case are summarised in Table 5-1. Costs in this section are specified without any discount rate.

**Table 5-1 Assumed central model parameters**

| Parameter | Central value | Parameter | Central value |
|---|---|---|---|
| Unloading option | Onshore | Ship fuel | LNG |
| Flow rate | 1 Mtpa | Ship fuel price | central |
| Distance | 600 km | Liquefaction fuel price | central |
| Initial $CO_2$ condition | Pre-pressurised | Lifetime | 20 years |
| Transport $CO_2$ condition | Low pressure | Discount rate | 0% |
| Ship size | 10 kt$CO_2$ | | |

The cost components are displayed in Figure 5-1 and the unit cost in £/t$CO_2$ in Figure 5-2. Ship and liquefaction costs, both CAPEX and OPEX, are the biggest components of $CO_2$ shipping. Together they constitute 83% of the cost. Storage, loading and gasification costs are low in comparison. Liquefaction and ship costs are dominated by OPEX: ship and liquefaction OPEX (including fuel) make up 54% of the total cost.

**Figure 5-1: Cost components of $CO_2$ shipping for the central case**

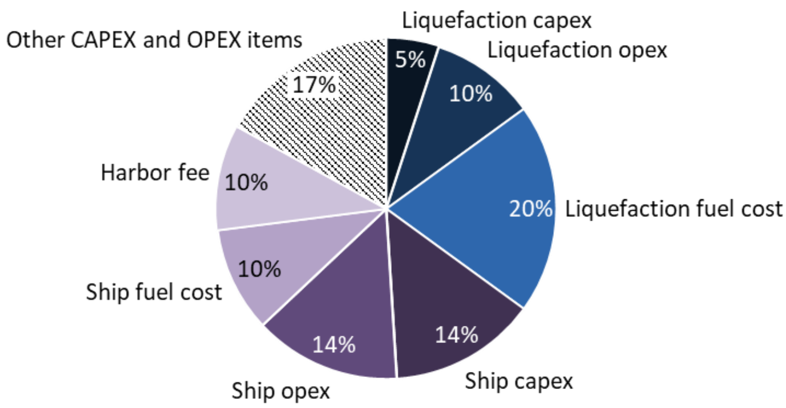
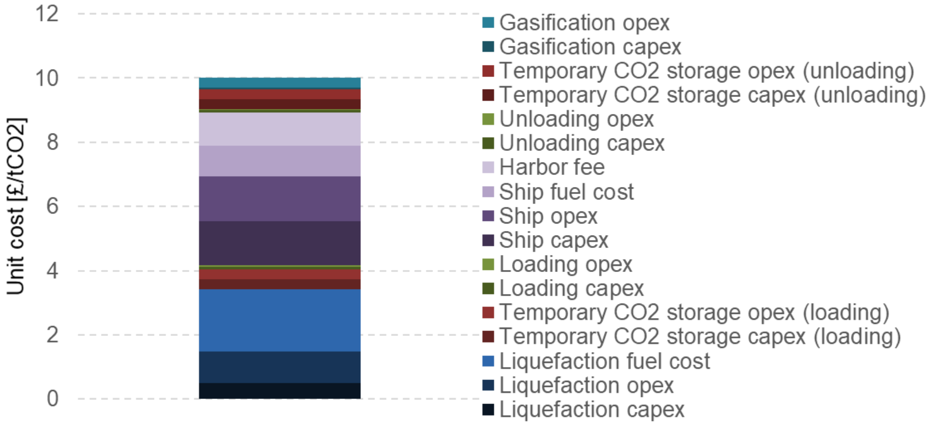


**Figure 5-2 Costs components of $CO_2$ shipping for the central case (£/t$CO_2$)**



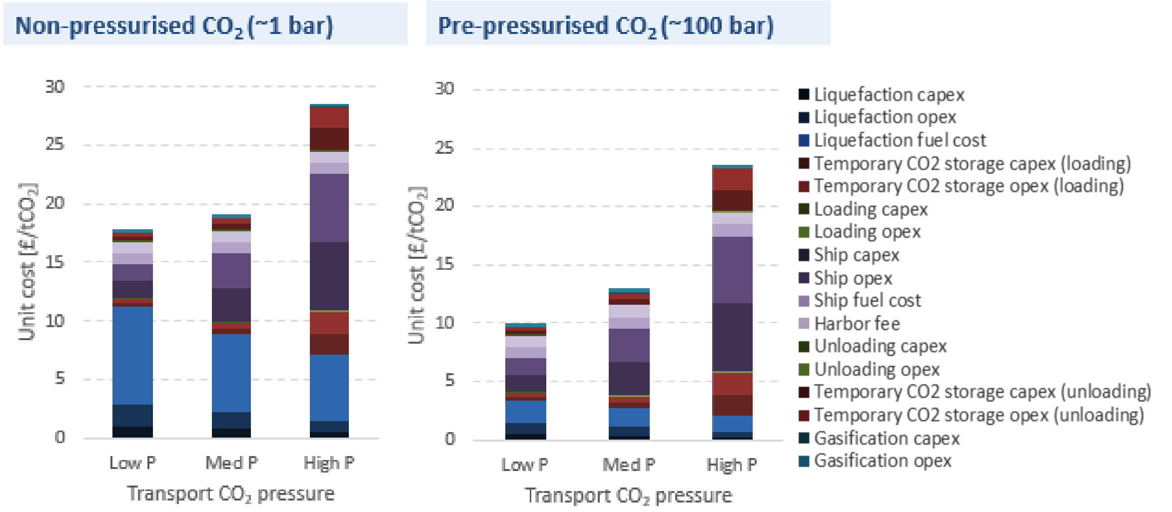

The potential for achieving cost reduction via re-using existing infrastructure is higher for pipelines, which are dominated by CAPEX. Note that the pipeline costs shown in this report are for new build pipelines. Although it may be technically feasible to convert an existing Liquefied Natural Gas (LNG) or Liquefied Petroleum Gas (LPG) ship into a $CO_2$ ship, re-use of an existing ship would bring only negligible cost reductions as ship capex corresponds to around 14% of the total shipping costs and some capital investment will be needed to convert the ship, which is expected to be less optimised compared to a new-built ship.

### 5.1.1 Impact of pressure

Both the chosen transport pressure and the initial $CO_2$ pressure before entering the liquefaction plant have a significant impact on the shipping costs. Figure 5-3 below shows the unit cost of shipping for the three different transport pressures, for non-pressurised $CO_2$ in the case of the left figure and pre-pressurised $CO_2$ in the case of the right figure. All other parameters are at central case values. Costs of liquefaction decrease with increasing transport pressure due to the lower energy requirement for refrigeration. However, the ship and storage costs increase, leading to a total increase of shipping costs. If the $CO_2$ is pre-pressurised (which is the case if onshore pipelines are used to transport $CO_2$ from capture plan to port), costs are significantly lower in all three cases, mainly due to the lower liquefaction fuel cost.

Costs of the low pressure and medium pressure transport condition are similar in the case of non-pressurised $CO_2$, as the reduction in liquefaction costs balance the increase in ship and storage costs. In the case of pre-pressurised $CO_2$, the liquefaction cost is a smaller component of the overall cost and thus cannot balance the increase in ship and storage costs in the same way. All remaining charts in this report assume a pre-pressurised $CO_2$ for liquefaction and low $CO_2$ pressure condition for transport.

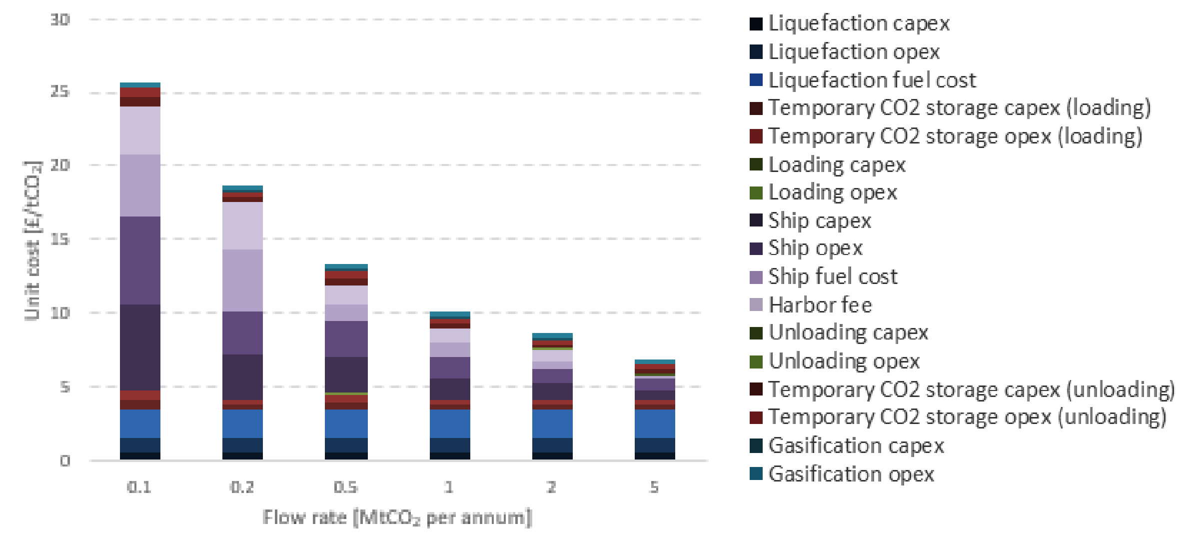
**Figure 5-3: Impact of transport pressure and initial pressure on unit cost of $CO_2$ shipping**




## 5.1.2 Impact of flow rate

Figure 5-4 below shows the unit cost of $CO_2$ shipping for different flow rates, while all other parameters are kept at the same values as in the central case. Increasing the flow rate above 1 Mtpa can bring the levelised cost of shipping to less than £10/t$CO_2$. Ship related cost components are reduced with higher flow rates due to economies of scale; shipping CAPEX per t$CO_2$ decreases, as do shipping fuel costs and harbour fees since bigger ships are used (50 kt in the case of 5 Mtpa). On the contrary liquefaction unit costs do not decrease as liquefaction infrastructure scales with the flow rate and is furthermore dominated by OPEX.

**Figure 5-4: Impact of flow rate on unit cost of $CO_2$ shipping (£/t$CO_2$), undiscounted**




## 5.1.3 Impact of ship size

Figure 5-5 below illustrates the impact of choosing different ship sizes. While all other parameters are kept at the central case value, the ship size is varied from 1,000 t$CO_2$ to 30,000 t$CO_2$.

Increasing ship size reduces the number of ships needed as well as the total number of trips, thus harbour fees and fuel costs are reduced. Ship CAPEX is reduced as well, due to economies of scale of ship building.

For ships bigger than 10,000 $tCO_2$, the number of ships does not reduce anymore by increasing the ship size, therefore shipping costs increase as the ship becomes bigger than necessary, as well as increasing costs of storage, sized in relation to the ship capacity.

**Figure 5-5: Impact of ship size on unit cost of $CO_2$ shipping 1 Mtpa, undiscounted.**

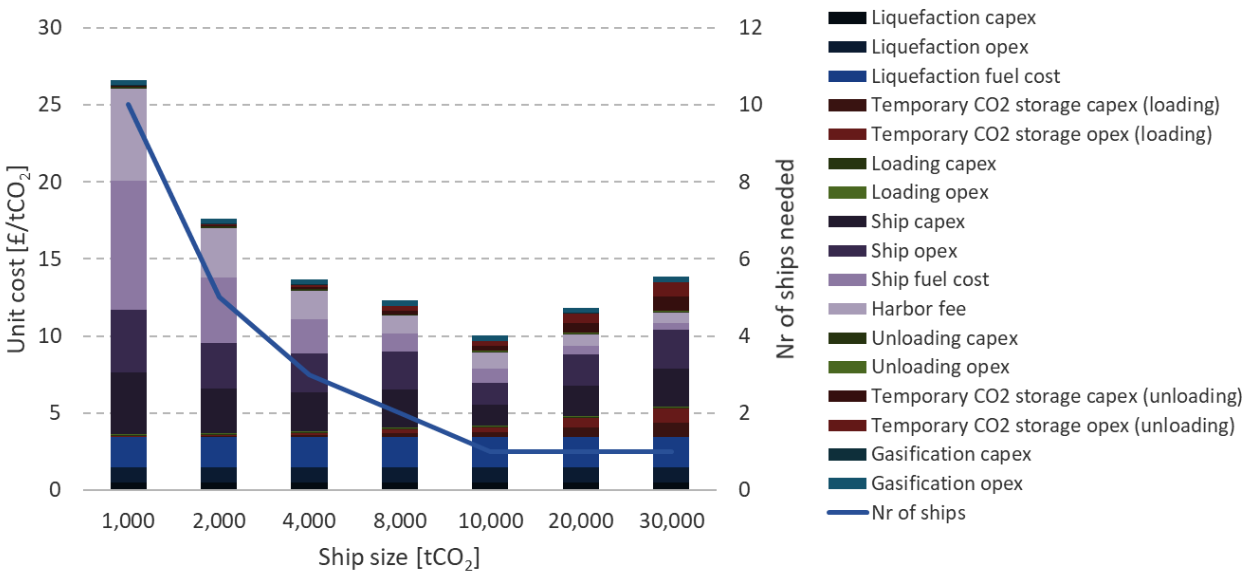



Table 5-2 shows the optimal ship size and the number of ships needed for a variety of shipping distances and flow rates, as calculated by the model. Selecting a larger ship is always advantageous to using several ships of lower size. The model only chooses to use several ships, if the capacity of one ship cannot be increased further as the maximum ship size of 50 kt $CO_2$ is reached.

**Table 5-2: Ship sizes and number of ships needed for different flow rates and transportation distances**

| | Flow rate (Mtpa) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Transportation distance (km)** | **0.1** | **0.2** | **0.5** | **1** | **2** | **5** | **10** |
| **200** | 1x1,000 | 1x2,000 | 1x4,000 | 1x8,000 | 1x20,000 | 1x30,000 | 2x30,000 |
| **400** | 1x2,000 | 1x2,000 | 1x4,000 | 1x8,000 | 1x20,000 | 1x40,000 | 2x40,000 |
| **600** | 1x2,000 | 1x2,000 | 1x8,000 | 1x10,000 | 1x20,000 | 1x50,000 | 2x50,000 |
| **800** | 1x2,000 | 1x4,000 | 1x8,000 | 1x20,000 | 1x30,000 | 2x30,000 | 3x40,000 |
| **1,000** | 1x2,000 | 1x4,000 | 1x8,000 | 1x20,000 | 1x30,000 | 2x40,000 | 3x50,000 |

## 5.1.4 Sensitivities

The sensitivities of the unit and lifetime cost of $CO_2$ shipping have been tested to understand which parameters the costs are most sensitive to. Starting from the central case, single parameters were changed by ±25% (±50% in the case of unloading time) and the resulting percentage changes of the unit and lifetime cost were recorded. The results are illustrated in Figure 5-6 and Table 5-3 below.

The table shows the relative change of unit and lifetime cost for an increase ("High") or decrease ("Low") of the parameter in question by 25%. The unit cost in the central case is £10.02/$tCO_2$, the lifetime cost in the central case is £200m.

Lifetime costs show the highest sensitivity to flow rate, lifetime and ship size. Increasing the distance, unloading time and flow rate leads to a bigger ship being required. As the ship size can only be increased in discrete increments (e.g. from 10 kt$CO_2$ to 20 kt$CO_2$ in this case), this leads to a significant increase in capital costs. The increment size for the larger ship sizes (>10,000 t$CO_2$) is taken from (Cato, 2016) and used to reflect the fact that ships are built in standardised sizes. The impact of particular parameter changes are described in more detail below.

### Distance

Reducing the distance by 25% (to 450 km) leads to a decrease of the unit cost by 5% as a smaller ship size can be used (8,000 t$CO_2$ instead of 10,000 t$CO_2$). Increasing the distance by 25% (to 750 km) leads to an increase of the unit cost of 19%. However, the reason for this high increase is that the ship size must be increased in this case from 10 kt$CO_2$ to 20 kt$CO_2$ (given the increments of ship size assumed); the sensitivity in unit cost to distance would be lower where the ship size does not need to change to accommodate the additional duration of travel. A longer distance leads to a longer trip time of the ship and thus a lower number of trips per ship. Consequently, the amount of $CO_2$ transported by the ship annually is reduced. Therefore, a bigger ship is needed to transport the same amount of $CO_2$ annually as in the central case.

**Figure 5-6: Sensitivities of unit cost (left) and lifetime cost (right) of $CO_2$ shipping**

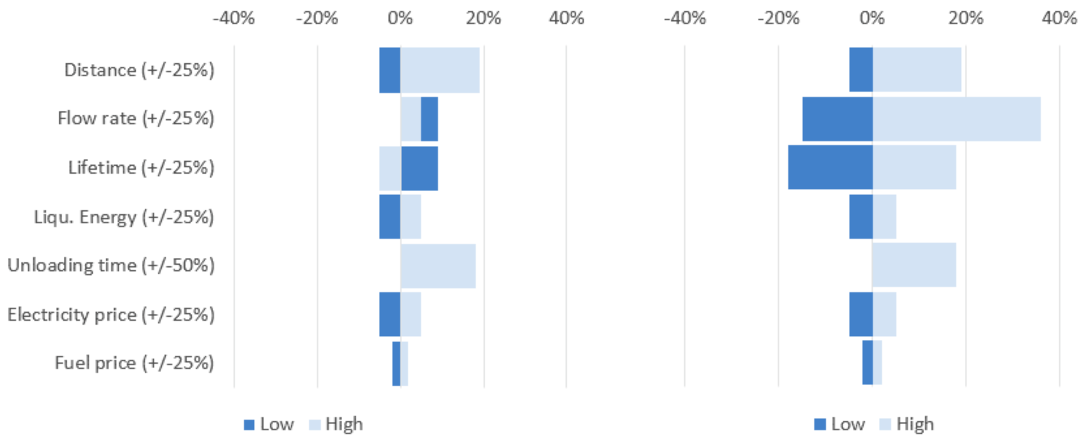



**Table 5-3: Sensitivities of unit and lifetime cost of shipping, numerical values**

| | Change in unit cost (£/t$CO_2$) | | Change in lifetime cost (£) | |
|---|---|---|---|---|
| | Low | High | Low | High |
| Distance (+/-25%) | -5% | 19% | -5% | 19% |
| Flow rate (+/-25%) | 9% | 5% | -15% | 36% |
| Lifetime (+/-25%) | 9% | -5% | -18% | 18% |
| Liqu. Energy (+/-25%) | -5% | 5% | -5% | 5% |
| Unloading time (+/-50%) | 0% | 18% | 0% | 18% |
| Electricity price (+/-25%) | -5% | 5% | -5% | 5% |
| Fuel price (+/-25%) | -2% | 2% | -2% | 2% |

### Flow rate

A 25% lower flow rate increases the unit costs by 9% as economies of scale are reduced. A ship of smaller size can be used for the lower flow rate (8,000 t$CO_2$ instead of 10,000 t$CO_2$) but the reduction of CAPEX is more than compensated by the fact that the CAPEX is now spread over a lower number of $tCO_2$. Increasing the flow rate. on the other hand. leads to a bigger ship being required (20,000 $tCO_2$ instead of 10,000 $tCO_2$). However, this increase in CAPEX is spread over more $tCO_2$, therefore the increase of the unit cost is only 5%. If increasing the flow rate doesn't require a larger ship, a higher flow rate leads to lower unit costs.

### Lifetime

A higher lifetime leads to a 5% lower unit cost, as the CAPEX can be spread over more $tCO_2$. The opposite is the case for a lower lifetime, leading to an increase in unit costs of 9%. Lifetime costs show a high sensitivity to changes in the lifetime: they are increased and reduced by 18% given a 25% increase or decrease of lifetime. This is because the shipping costs are dominated by OPEX and therefore lifetime costs and lifetime change by a similar rate (unlike in the case of pipeline costs, which are dominated by CAPEX and thus don't scale with lifetime in the same way).

### Unloading time

As with the increase in distance or flow rate, increasing the unloading time by 50% (from 15h to 22.5h) requires a larger ship, and consequently storage. This is because the longer loading time increases the total trip time of the ship and consequently reduces the number of trips per ship and thus the amount of $CO_2$ transported per year per ship. Reducing the unloading time by 50% does not have a similar impact, the ship size cannot be reduced and thus this parameter change does not have any impact at all.

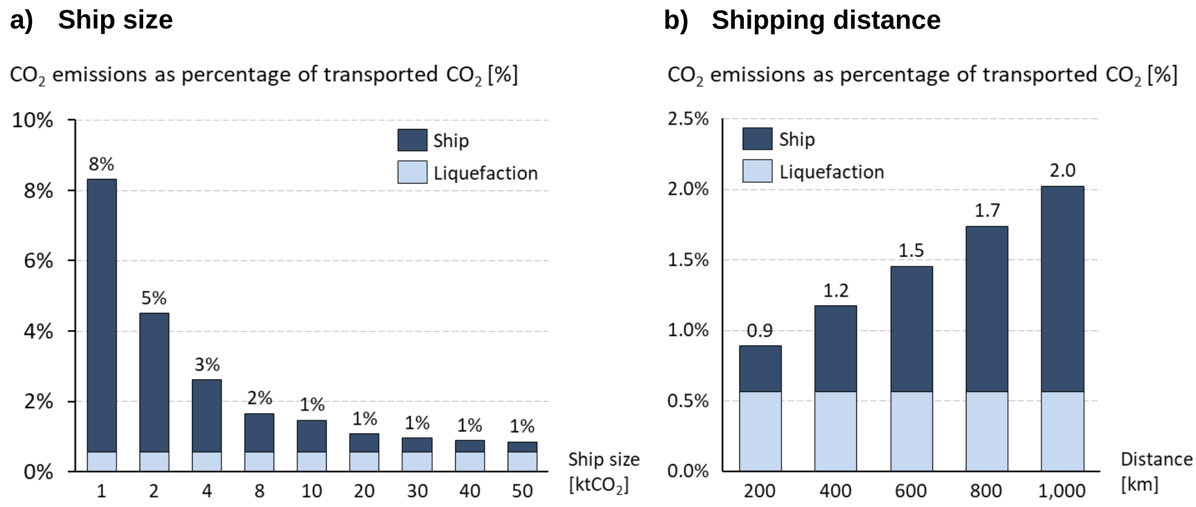
### Liquefaction energy, liquefaction fuel price, ship fuel price

Unit costs and lifetime costs increase by 5% given an increase of liquefaction fuel prices or the liquefaction energy requirement by 25%, while decreasing by 5% given a decrease of one of these parameters by 25%. The sensitivity to ship fuel prices is significantly lower (±2%). Increasing both fuel prices by 25% would thus lead to an increase of unit and lifetime costs by 7%, with a corresponding decrease of 7% given a decrease of both fuel prices by 25%.

### 5.1.5 Emissions from shipping

The emissions from combustion of ship fuel and generation of the consumed electricity for liquefaction have been calculated for the central case as well as cases deviating from the central case in terms of ship size and distance. Figure 5-7 a) displays the $CO_2$ emissions for a distance of 600 km and various ship sizes. Figure 5-7 b) shows the emissions for a 10kt $CO_2$ ship and various distances. Emissions are expressed in % of the transported quantity of $CO_2$ (1 Mtpa in all cases) and LNG is assumed to be used as ship fuel.

**Figure 5-7: Variation in emissions from $CO_2$ shipping with a) ship size and b) shipping distance**




In most cases emissions stay below 2% of the transported $CO_2$ quantity. However, using a very small ship (1,000 $tCO_2$) leads to emissions higher than 8% of the transported $CO_2$ due to the higher number of trips. It should be noted that these emissions have not been considered for the calculation of the unit costs of shipping, i.e. the cost of shipping are calculated per $tCO_2$ transported, not per $tCO_2$ abated. When a sufficiently large ship is used, the unit cost per abated $tCO_2$ would not significantly differ from the unit cost per transported $tCO_2$. However, if a very small ship is selected (<2000 $ktCO_2$), the unit cost per abated $tCO_2$ will be significantly higher than the unit cost per transported $tCO_2$, so the shipping emissions should be considered. While ships of this size are currently used for shipping $CO_2$ for the food and beverage sector, they would not be suitable for a CCUS project. For a more detailed assessment of emissions, potential methane leakage through the main engine should be considered as well in the case of using LNG as ship fuel.[24] Also, it should be noted that the full life-cycle analysis (LCA) emissions of the ships have not been included in the analysis.

[24] Personal communication with Brevik

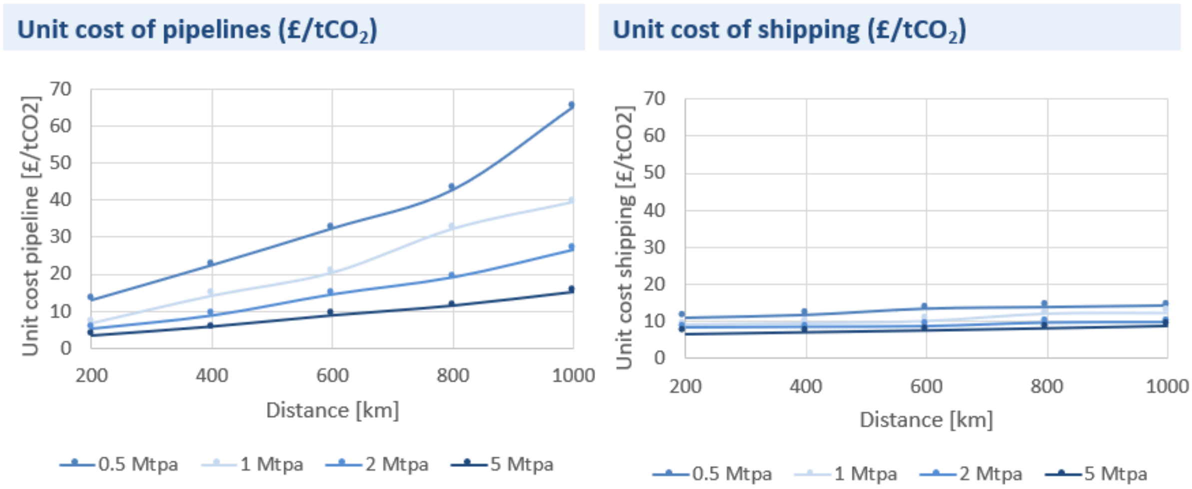
## 5.2 Comparison of pipeline transport and shipping (port to port)

### 5.2.1 Sensitivities to flow rate and distance

Comparing the unit cost of pipeline and port to port shipping transport shows their fundamentally different cost structure, as seen in Figure 5-8. Pipeline costs are dominated by CAPEX and thus show high sensitivity to flow rates, as higher flow rates allow the CAPEX to be spread over more $tCO_2$. As a result, unit costs of pipes are significantly lower for high flow rates (left chart). Shipping costs are dominated by OPEX and thus are less sensitive to flow rates (right chart).

Furthermore, pipeline costs are highly sensitive to distance as CAPEX costs are proportional to distance (left chart). Shipping costs are far less sensitive to distance: fuel cost is a small component of costs and CAPEX are only increased due to larger distances if these lead to a larger ship being required.[25]

**Figure 5-8: Unit cost of pipeline transport and shipping for different flow rates and distances**

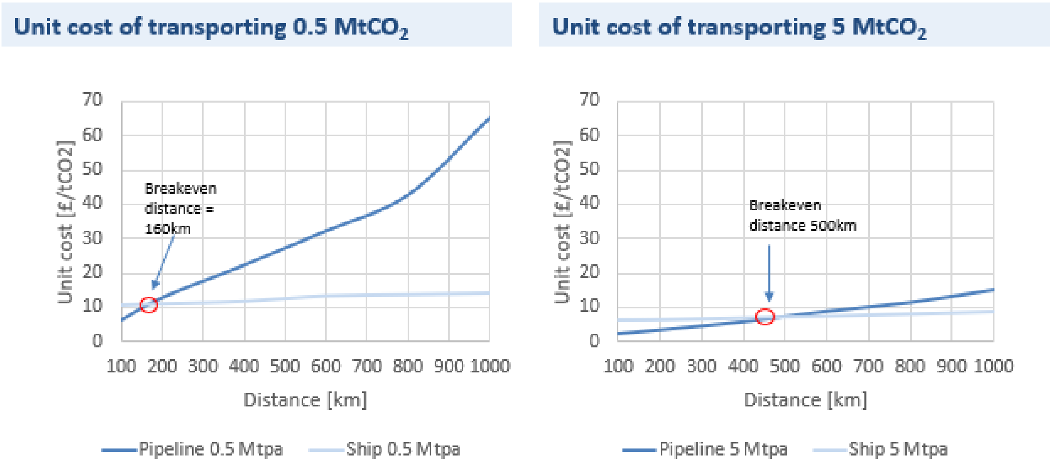



### 5.2.2 Breakeven distances of shipping – impact of flow rate

The charts above display that for high distances and low flow rates, shipping $CO_2$ is cheaper than pipeline transport. The distance at which shipping breaks even with pipeline transport depends on the flow rate. For a low flow rate pipeline transport is not economic and the breakeven distance of shipping is low. For a higher flow rate, pipeline transport unit costs decrease and the breakeven distance of shipping increases, as depicted in Figure 5-9 below.

[25] Pipeline transport is based on a 15MPa pressure drop allowed between start and end point, 20 year lifetime, 0% discount rate. Shipping costs are based on onshore unloading, low pressure transport, pre-pressurised $CO_2$, optimal ship size (picked by model), LNG fuel, central fuel prices, 20 year lifetime, 0% discount rate.

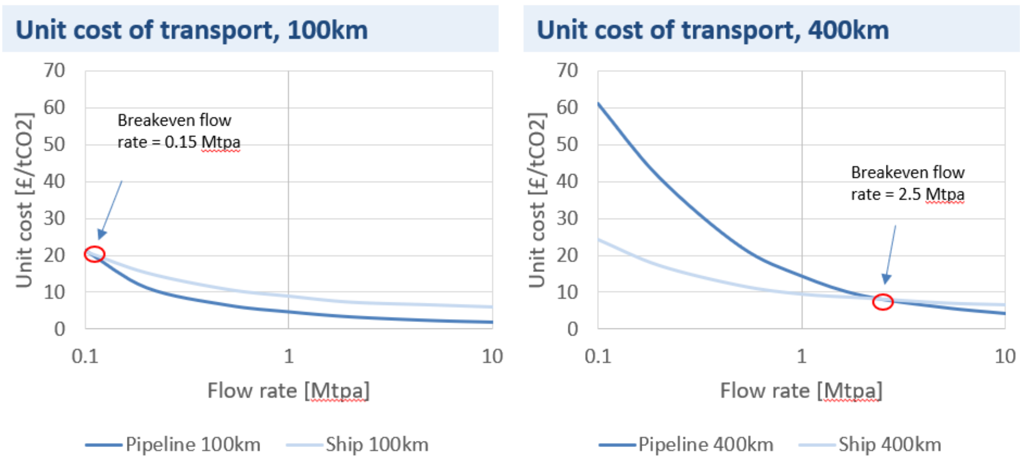
**Figure 5-9: Breakeven distance of shipping for different flow rates**




For a low flow rate of 0.5 Mtpa, shipping $CO_2$ is cheaper than pipeline transport for all distances above 200km (left chart). For a high flow rate of 5 Mtpa, shipping is only cheaper than pipeline transport for distances above 500km. The remaining assumptions for shipping and pipeline transport are the same as in section 5.2.1.

To show the impact of the flow rate on the comparison of pipeline and shipping costs, Figure 5-10 shows the unit costs of both transport options for flow rates from 0.1Mtpa to 10 Mtpa, in the case of a transport distance of 100 km (left) and 400 km (right). The remaining assumptions are the same as in Section 5.2.1. For the short distance, pipeline transport is cheaper for flow rates above approximately 0.15 Mtpa, whereas for the longer distance, pipeline transport is cheaper for flow rates above approximately 2.5 Mtpa (note that the scale of the chart is logarithimic).

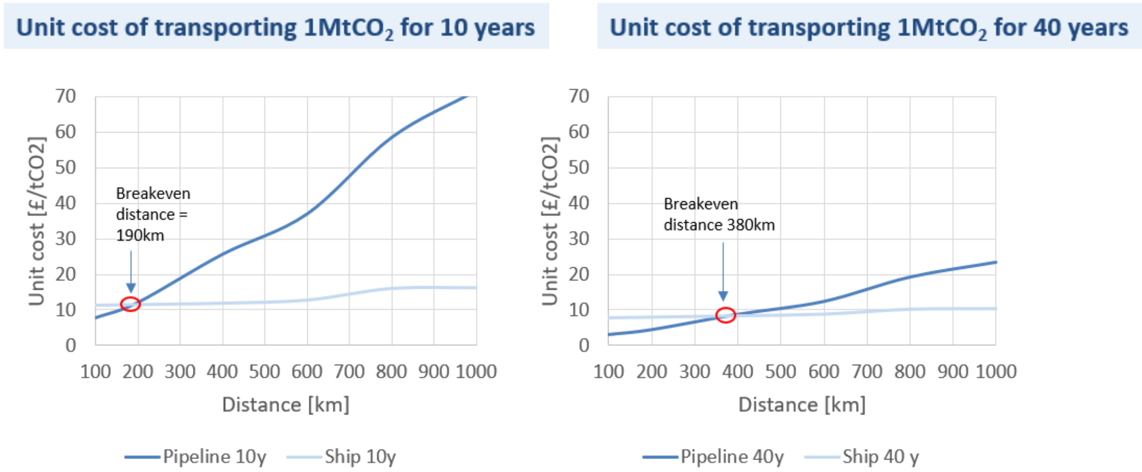
**Figure 5-10: Breakeven flow rates of pipeline transport for two different transport distances**




### 5.2.3 Breakeven distances of shipping – impact of lifetime

The breakeven distance of $CO_2$ shipping furthermore depends on the lifetime of the project. This is illustrated in Figure 5-11 below, showing unit costs of shipping and pipeline transport for a 1 Mtpa project and various distances. The project lifetime is 10 years in the chart on the left, and 40 years in that on the right. The remaining assumptions are as in Section 5.2.1. For a short lifetime of 10 years, pipeline transport is expensive, as the CAPEX cannot be distributed over many tonnes of $CO_2$. Therefore, shipping is cheaper already at small distances (left chart). Increasing the lifetime to 40 years reduces pipeline unit costs to a much higher extent than shipping costs and thus shipping is only more economic for distances above about 380 km (right).

**Figure 5-11: Breakeven distance of shipping for different lifetimes**




## 5.3 Comparison of pipeline transport and shipping (port to storage)

### 5.3.1 Impact of flow rate on lifetime costs

Lifetime costs for offshore unloading options have been compared to those for onshore unloading options, as well as those of pipeline transport, as shown in Figure 5-12. Figure a) shows the lifetime costs for the different transport and unloading options for a flow rate of 0.5 Mtpa, and Figure b) shows the lifetime costs of the different options for a flow rate of 5 Mtpa.[26]

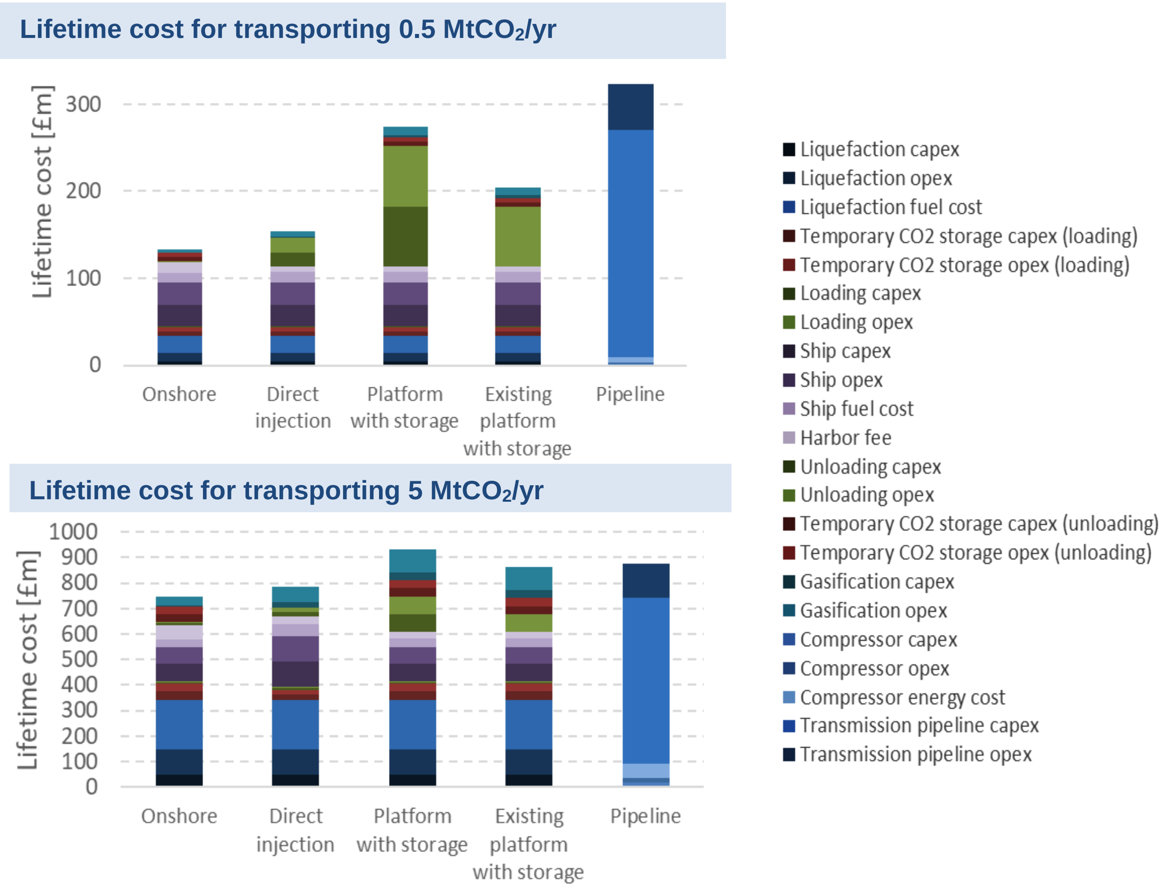
The following observations can be made:

- For the low flow rate, all shipping options are cheaper than pipeline transport. For the 5 Mtpa flow rate, pipeline economics improve; unloading to a new platform with storage is more expensive than pipeline transport, the other shipping options remain slightly cheaper than pipeline transport.
- Liquefaction fuel cost (i.e. electricity cost) becomes the dominant cost component of shipping for high flow rates.
- For higher flow rates, onshore unloading and direct injection have similar costs.
- Gasification and unloading costs are significant cost components for all offshore unloading options.

It should be noted that very few detailed design studies of the offshore unloading options have been undertaken and therefore the cost estimates are more indicative, with greater uncertainty than the onshore unloading estimates. While the onshore unloading option has been tried and tested for $CO_2$, if only on a smaller scale than expected for CCUS projects, the offshore unloading option remains untested.

[26] Pipeline cost is based on 600km distance, 15MPa pressure drop allowed between start and end point, 20 year lifetime, 0% discount rate. Shipping cost is based on 600km distance, low pressure transport, pre-pressurised $CO_2$, optimal ship size (picked by model), LNG fuel, central fuel prices, 20 year lifetime, 0% discount rate.

**Figure 5-12: Lifetime cost of shipping for different unloading options with a flow rate of a) 0.5 Mtpa and b) 5 Mtpa.**



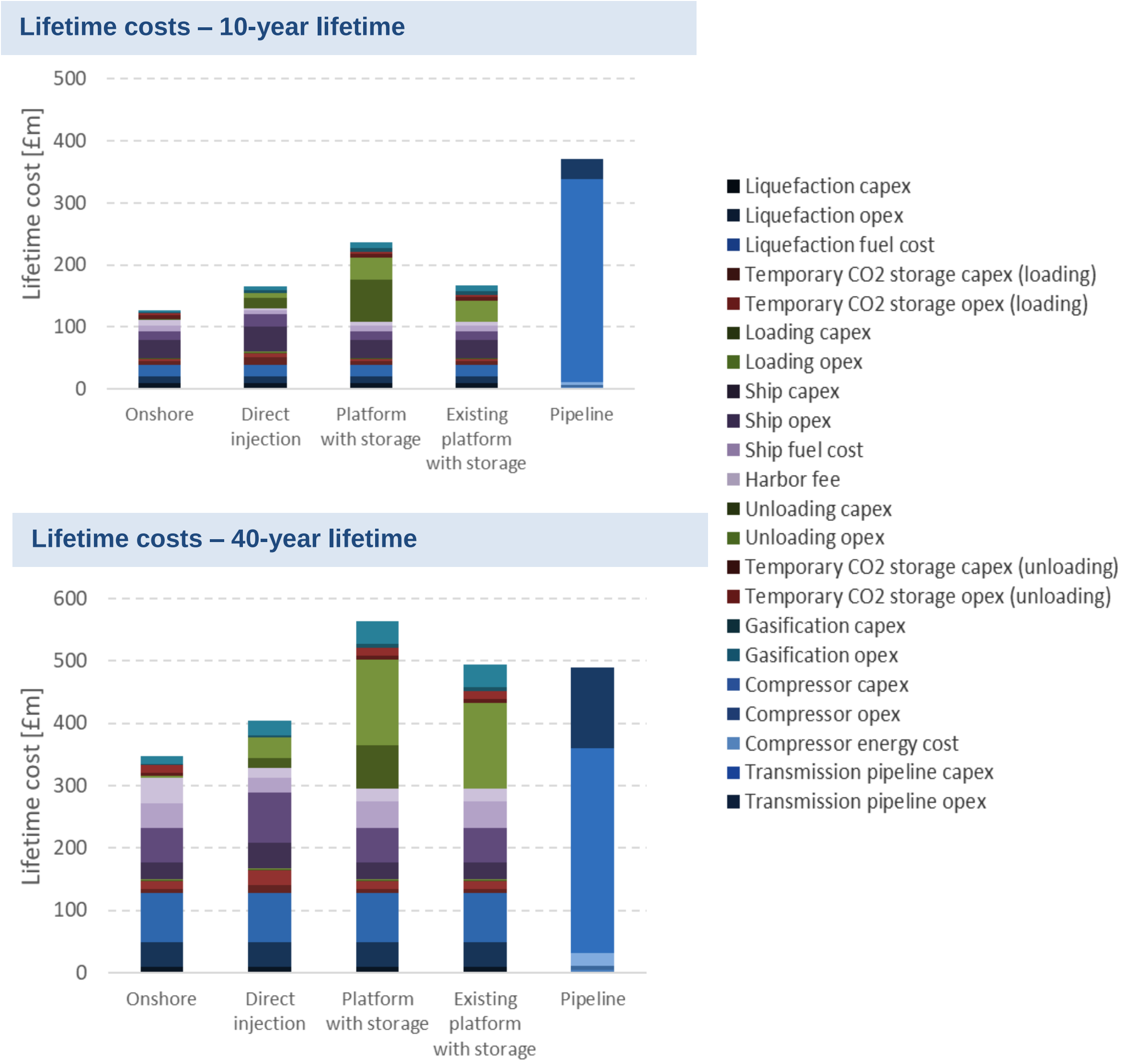

## 5.3.2 Impact of lifetime on lifetime costs

Figure 5-13 shows the estimates of the lifetime cost of a 1 Mtpa project for the different shipping transport and unloading options relative to a pipeline, for a 10-year project lifetime (a) and a 40-year project lifetime (b). The remaining assumptions are as in Section 5.3.1.

Due to the high CAPEX proportion, pipelines become more cost-effective with a greater lifetime. For the chosen distance and flow rate, all shipping options are cheaper than pipeline transport for the short lifetime of 10 years, however for the longer lifetime, only shipping with either onshore unloading or direct injection is cheaper than pipeline transport.

Offshore unloading to a new platform is the most expensive shipping option; however, assessment should include detailed storage cost calculations to be able to compare the options properly (e.g. if platforms are needed anyway for certain flow-rates and storage sites and thus need to be added to pipeline transport and shipping with onshore unloading as well). Overall ship costs (i.e. CAPEX and OPEX of the $CO_2$ ship) are highest for direct injection as a bigger ship is needed due to the longer unloading time. However, platform CAPEX and OPEX offset the ship cost savings in case of unloading offshore to a platform for high flow rates. For the low flow rate costs of direct injection and unloading to an existing platform are almost identical (£165m and £167m respectively).

**Figure 5-13: Lifetime costs of shipping for different unloading options with lifetimes of a) 10 years and b) 40 years**



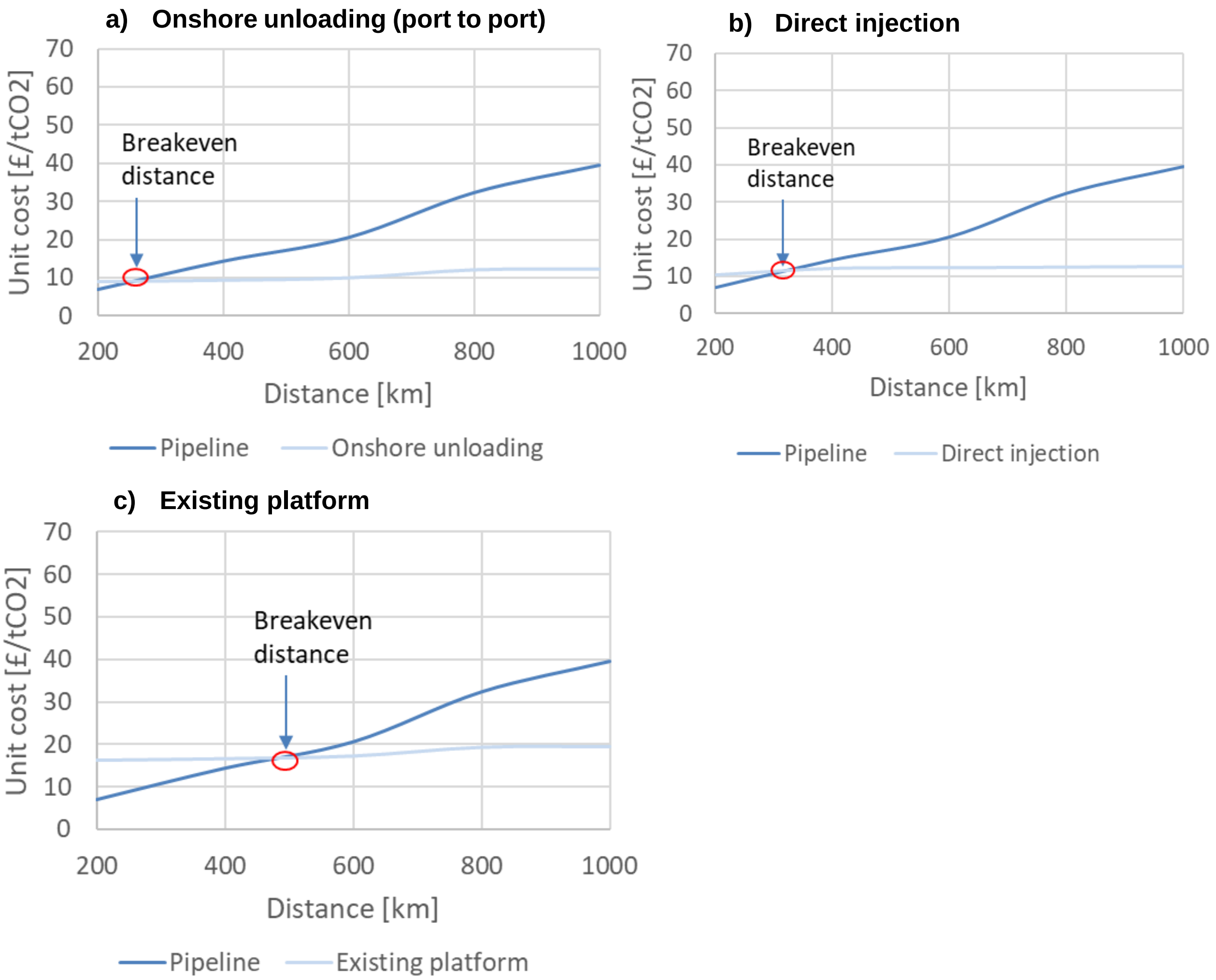

### 5.3.3 Breakeven distance for offshore unloading options

The unit costs of shipping are compared with that of pipeline transport in Figure 5-14, for onshore unloading, direct injection and unloading to an existing platform with storage.[27]

Offshore unloading is more expensive than onshore unloading. Therefore, the breakeven distance of shipping costs with pipeline costs is higher for the offshore unloading options than for the onshore unloading case. However, shipping with any of the selected unloading options is cheaper than pipeline transport for distances above about 500 km.

[27] Pipeline transport is based on 1 Mtpa flow rate, 15 MPa pressure drop allowed between start and end point, 20-year lifetime, 0% discount rate. Shipping is based on 1 Mtpa flow rate, low pressure transport, pre-pressurised $CO_2$, optimal ship size (picked by model), LNG fuel, central fuel prices, 20-year lifetime, 0% discount rate.

**Figure 5-14: Breakeven distances for pipeline transport and $CO_2$ shipping with a) onshore unloading b) direct injection and c) existing platform**



# 6 Opportunities and barriers

Previous chapter clearly showed that $CO_2$ shipping can be more cost-effective compared to $CO_2$ pipelines under certain conditions. $CO_2$ shipping therefore presents opportunities for the decarbonisation of the UK and for clean growth of the UK economy. However, the current barriers to $CO_2$ shipping must be considered and overcome to develop this emerging industry effectively. This section presents the key opportunities in the UK and internationally, and the key barriers that must be overcome

## 6.1 Opportunities in the UK

This section presents the key roles that $CO_2$ shipping can play in the UK CCUS market, including:

- Collecting $CO_2$ from multiple clusters via shipping to enable the development of multiple CCUS clusters in parallel;
- Enabling the deployment of CCUS clusters in locations that do not have nearby offshore storage sites such as South Wales; and
- Enabling the deployment of small-scale and short-duration projects if needed.

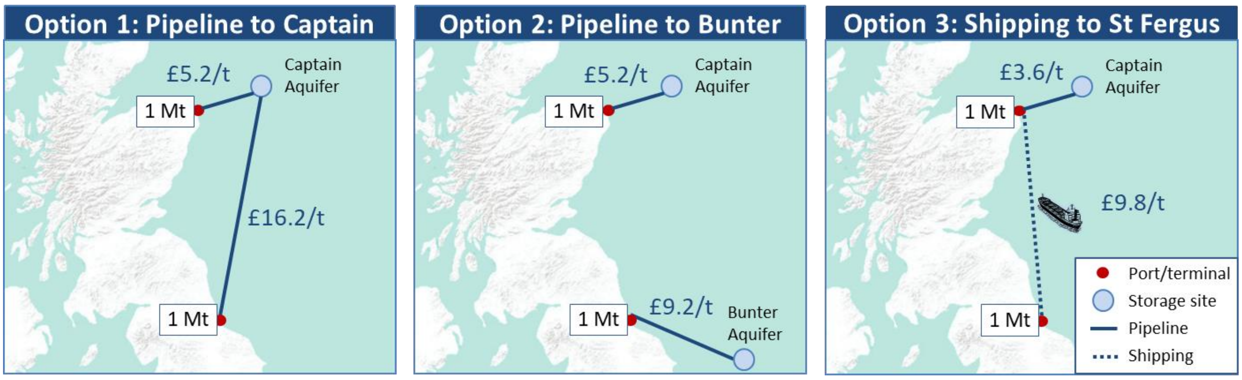
These key opportunities are illustrated via three case studies below.

### *Case study 1: Gathering $CO_2$ from multiple UK CCUS clusters via shipping*

The first case study aims to illustrate that several CCUS clusters can be developed in parallel using $CO_2$ shipping to gather $CO_2$ from various locations. this case study, it is assumed that 1 $MtCO_2$ per annum is being capture and transported from St Fergus and Teesside each. Figure 6-1 shows three illustrative options for the development of St Fergus and Teesside clusters in parallel:

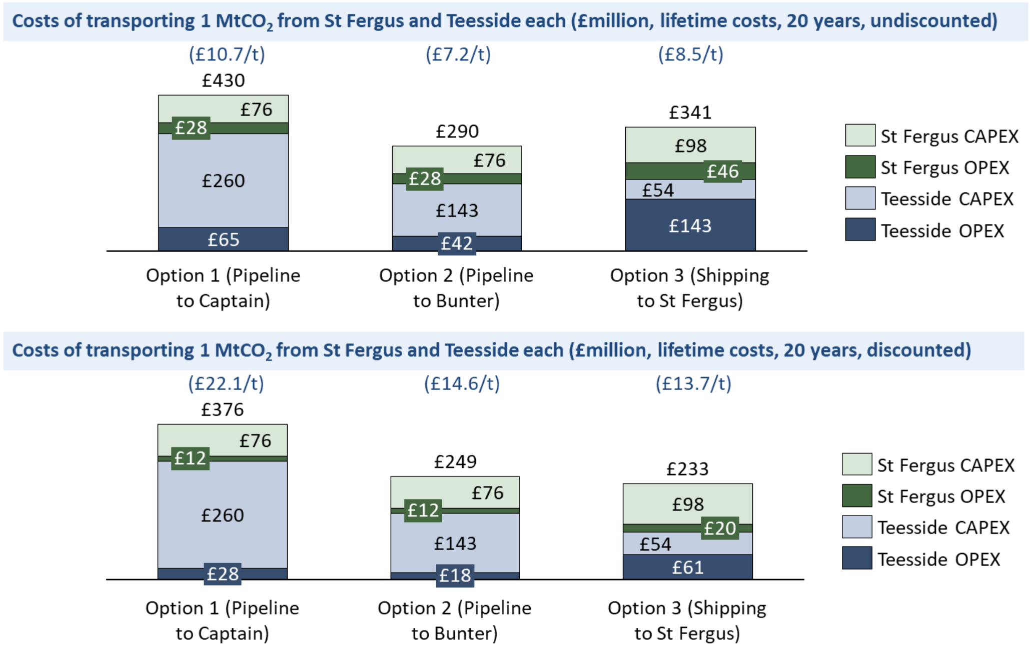
1) Two offshore pipelines from St Fergus and Teesside to the Captain Aquifer to transport 1 $MtCO_2$ per annum each;
2) An offshore pipeline from St Fergus to the Captain Aquifer and another offshore pipeline from Teesside to the Bunter Aquifer to transport 1$MtCO_2$ per annum each;
3) $CO_2$ shipping from Teesside to the St Fergus and an offshore pipeline from St Fergus to the Captain Aquifer to transport 2$MtCO_2$ per annum.

**Figure 6-1 Illustrative options for the development of St Fergus and Teesside clusters in parallel[28]**




[28] Figure shows undiscounted unit costs (assuming a 20-year project lifetime for all new assets) assuming new infrastructure. Re-using existing infrastructure and over-sizing/future-proofing are not included in this case study.

**Figure 6-2: Lifetime and unit cost of $CO_2$ transport (undiscounted and discounted at 10%)**

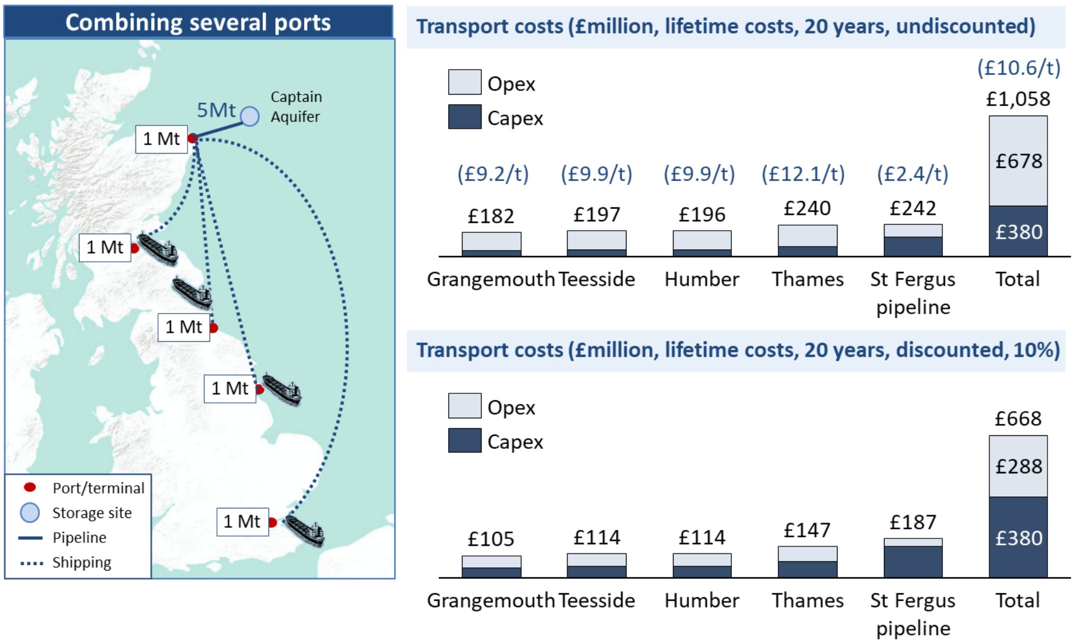



The modelling results show that shipping $CO_2$ from Teesside to St Fergus could the most cost-effective solution for this case study (considering the discounted costs). However, the business model and charging mechanism that will be selected for $CO_2$ transport may have an impact on the feasibility of this solution. Although shipping $CO_2$ from Teesside to St Fergus leads to economies of scale for the offshore transportation at St Fergus, Teesside may need to pay two separate transport fees (i.e. shipping from Teesside to St Fergus and offshore pipeline from St Fergus to Captain), whereas emitters near St Fergus may benefit from reduced transport fees due to the economies of scale. It may therefore be more cost-effective for Teesside to transport its $CO_2$ to Bunter via an offshore pipeline (although it may be more expensive for the whole T&S system). Appropriate contracting arrangements should therefore be explored further in potential subsequent studies. It should also be noted that Option 2 will require the development of two storage sites, which are not included in this analysis. Unit costs of storage can decrease significantly when higher volumes are stored in a single large storage facility compared with multiple smaller capacity facilities. Gathering $CO_2$ from multiple clusters may also bring potential benefits of achieving economies of scale for $CO_2$ storage

It may be possible to ship $CO_2$ from more than one cluster to St Fergus.

Figure 6-3 illustrates how St Fergus can be used to gather $CO_2$ from Grangemouth, Teesside, Humber and Thames via shipping (1MtCO$_2$ per annum from each cluster, 5MtCO$_2$ per annum in total). Total costs over 20 years are calculated to be around £1billion to transport 100MtCO$_2$, which corresponds to £10/tCO$_2$ (undiscounted).

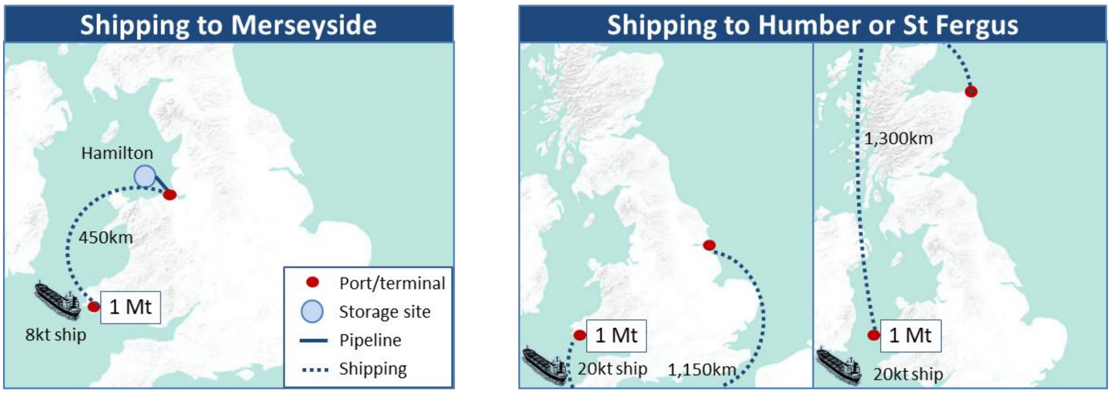
### Figure 6-3: Costs of shipping $CO_2$ from several CCUS clusters to St Fergus




### Case study 2: Enabling the deployment of the South Wales CCUS cluster via shipping

$CO_2$ shipping can enable the deployment of CCUS clusters, which lack potential $CO_2$ storage sites nearby. For instance, in its report "Building a low carbon economy in Wales", the CCC identified that "The lack of potential $CO_2$ storage sites close to South Wales presents a greater challenge in deploying carbon capture and storage (CCS)." (Committee on Climate Change, 2017) This case study aims to illustrate how $CO_2$ shipping can enable the deployment of the South Wales CCUS cluster. Three illustrative options for South Wales are shown in the maps below, namely Merseyside (450km away), Humber (1,150 km away) and St Fergus (1,300 km away).

### Figure 6-4: Three illustrative options for South Wales to ship its $CO_2$ to other ports



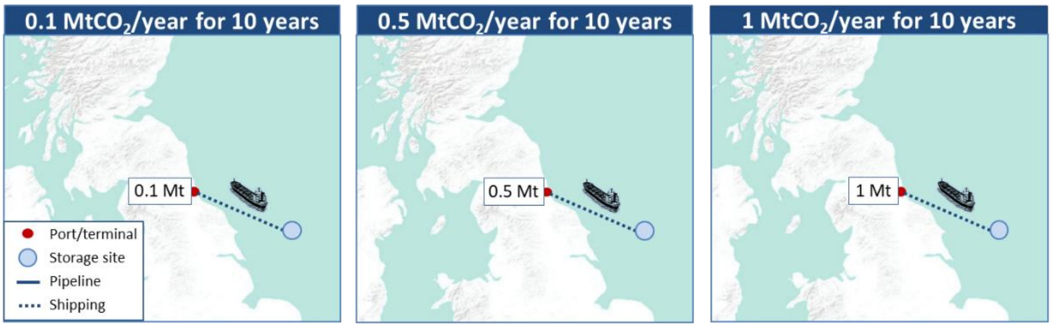

The shipping costs for these three options are estimated to be between £9.5/$tCO_2$ and £12.4/$tCO_2$ (undiscounted unit costs). The model estimates that a single ship would be sufficient to transport 1Mt$CO_2$ per annum from South Wales to these three ports; however, the required ship capacity is a lot bigger for Humber and St Fergus (20kt) compared to Merseyside (8kt). Similarly, temporary storage capacity requirement increases to accommodate longer transportation duration for each trip. The case study shows that it would be feasible for South Wales to transport its $CO_2$ to other potential CCUS hubs for permanent storage.

**Figure 6-5: Unit costs of shipping $CO_2$ from South Wales (undiscounted)**


## Case study 3: Small-scale and short-duration early projects

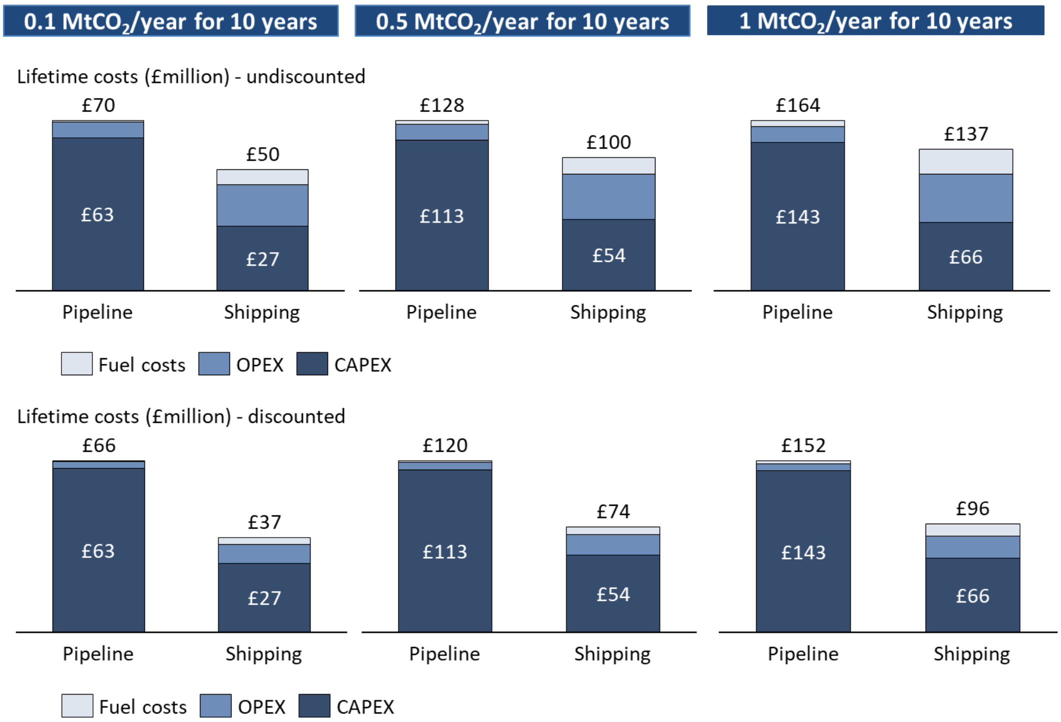
One of the key challenges of potential early small-scale projects is the scale of investment needed for capital-intensive offshore pipelines. It was therefore suggested by many CCUS experts that first CCUS projects in the UK should include over-sized (or future-proofed) offshore infrastructure to achieve economies of scale. Although this leads to a significant cost reduction in the longer-term, it is still a challenge for the first CCUS projects. In this illustrative case study, potential shipping costs for direct injection to a storage site are presented for three different flow rates of 0.1, 0.5 and 1MtCO₂ per annum for 10 years.

**Figure 6-6: Three illustrative direct injection scenarios for $CO_2$ shipping**




The shipping costs are estimated to be significantly lower than the pipeline costs, especially for the 0.1Mt$CO_2$ per annum case. Also, potential sunk costs after 10 years are found to be significantly lower for shipping compared to pipelines. For instance, the capital cost of an offshore pipeline with a capacity of 1Mt$CO_2$ per annum is estimated to be more than double the capital costs of shipping 1Mt$CO_2$ per annum. It may also be possible to convert the $CO_2$ ship to an LPG ship with some additional capital investment (if there was demand for LPG ships in the market). However, it should be noted that shipping costs are based on "direct injection" rather than "port-to-port" and direct injection cost estimates are currently highly uncertain. Further demonstration may be needed to demonstrate "direct injection" applications of $CO_2$ shipping in the UK.

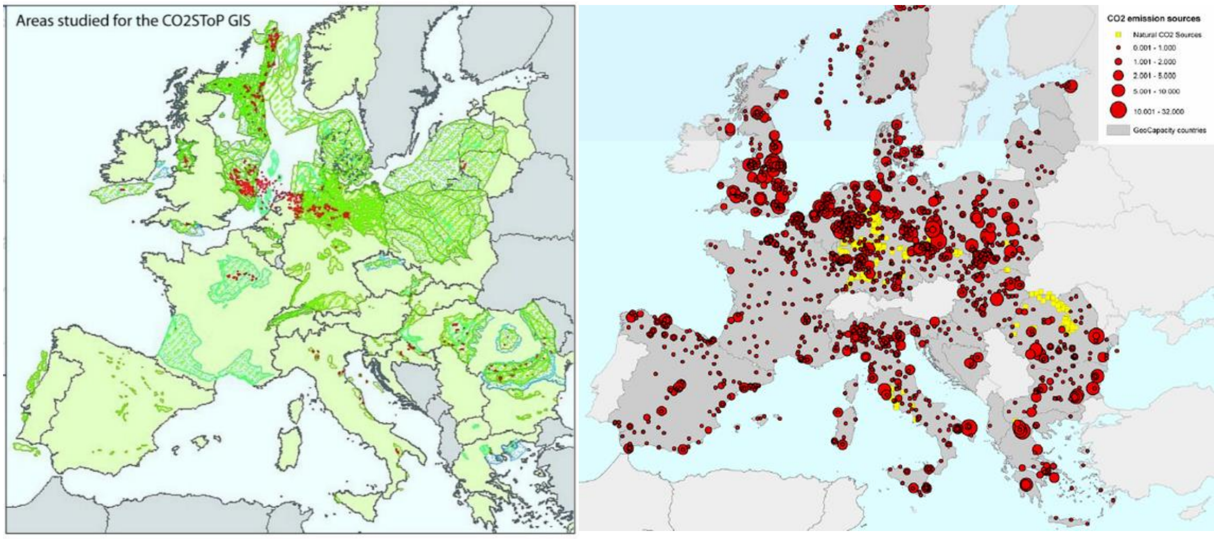
**Figure 6-7: Comparison of pipelines and $CO_2$ shipping for smaller-scale projects**



## 6.2 International opportunities

Beyond the key roles that $CO_2$ shipping can play within the UK, $CO_2$ shipping may enable development of a UK $CO_2$ T&S industry which can be utilised by other countries through **long distance cross-border transport**. $CO_2$ shipping can connect the UK ports with potential early movers, such as Norway and Rotterdam, and other key industrial hubs with limited offshore $CO_2$ storage potential, such as France and Germany. $CO_2$ from other European $CO_2$ capture clusters (including the nearby industrial clusters) can be shipped to the UK, either to Ports, or directly to storage sites. Figure 6-8 shows potential $CO_2$ storage locations (Poulsen, 2014) and key emission sources (EU Commission, 2012). The proximity of many storage sites to the UK, and the lower storage potential of some other European counties, positions the UK well to utilise our natural resources.

**Figure 6-8 Potential $CO_2$ storage formations and $CO_2$ emission sources in Europe**




The distribution of this storage capacity across Europe will be an important influence on future policy choices, with some member states such as Italy, Spain and France particularly dependent on onshore storage locations. Integrated transport networks and cross-border CCUS agreements similarly offer benefits in most countries but will be particularly relevant where storage capacity is restricted e.g. reduced onshore capacity or limited site availability. The emissions from the key industrial clusters around the North Sea are shown below.

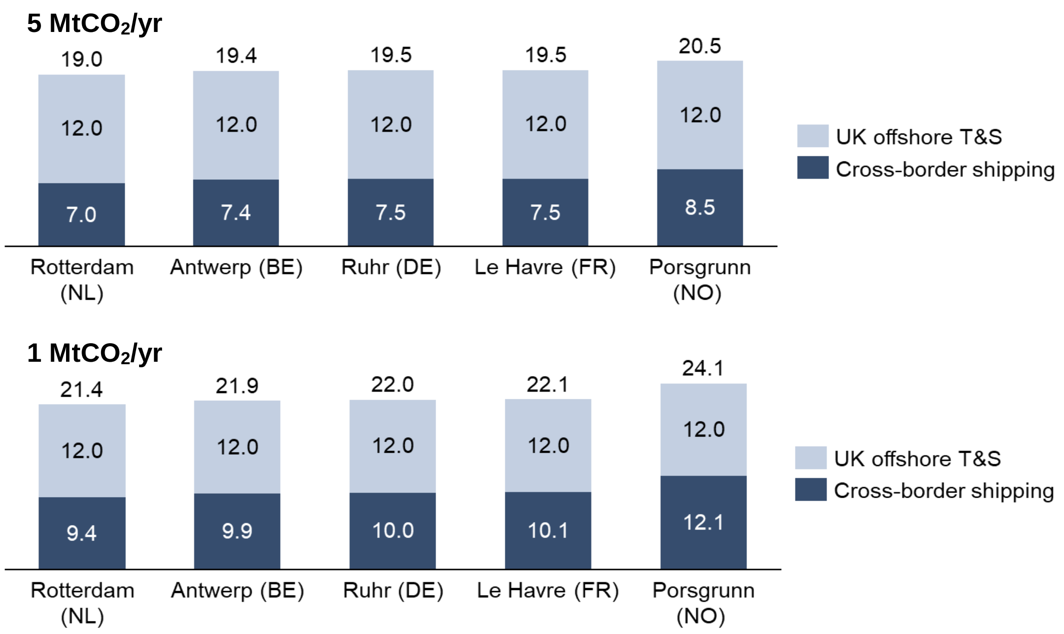
**Table 6-1 Estimated industrial emissions from key industrial hubs near the UK**

| Key industrial hubs near the UK | Emissions $MtCO_2/yr$ |
|---|---|
| Rotterdam (Netherlands) | ~20 |
| Antwerp (Belgium) | ~20 |
| Ruhr (Germany) | ~35 |
| Le Havre (France) | ~15 |

The total cost of T&S for these industrial hubs was estimated, with the results shown in Figure 6-9. The figures include both the cross-border shipping to Humber, and the offshore pipeline transport and storage at Bunter. T&S costs shown for Bunter are based on the Strategic UK $CO_2$ Storage Appraisal (Energy Technologies Institute, 2016) and assumed to be the same for both 1 $MtCO_2/yr$

and 5 $MtCO_2$/yr in this illustrative case study. The analysis indicates that total **T&S unit costs could be less than £20/$tCO_2$.** This is comparable to the levelised unit cost of Forties 5 Site 1, which was estimated to be £18/$tCO_2$ by the Strategic UK $CO_2$ Storage Appraisal project.

**Figure 6-9 Total T&S costs from nearby European ports to Bunter via Humber**




These costs could potentially by lowered even further if direct $CO_2$ storage via shipping is proven feasible and offshore $CO_2$ storage hubs are developed in the UK. Considering the UK's relevant expertise and existing supply-chain (i.e. offshore oil and gas operations), UK companies can potentially benefit from this significant international opportunity. In addition to the opportunities in $CO_2$ shipping itself, cross-border $CO_2$ transport could lead to a significant increase in the development of offshore transport and storage assets in the UK. However, the key barriers explained in the following sub-section should be addressed to unlock this significant potential.

**Figure 6-10: Shipping distances (in km, one way) between some of the UK and European ports considered for international $CO_2$ transport; sources: Marinetraffic[29], Sea-distances[30], Searoutes[31]**

| To\From | Teesside | Humberside | Thames Estuary | Rotterdam | Porsgrunn | Duisburg | Le Havre | Antwerp |
|---|---|---|---|---|---|---|---|---|
| **Teesside** | | 248 | 522 | 467 | 874 | 707 | 706 | 454 |
| **Humberside** | 248 | | 409 | 363 | 922 | 593 | 620 | 494 |
| **Thames Estuary** | 522 | 409 | | 276 | 1522 | 1002 | 370 | 304 |
| **Rotterdam** | 467 | 363 | 276 | | 913 | 220 | 500 | 131 |
| **Porsgrunn** | 874 | 922 | 1522 | 913 | | 1067 | 1326 | 1100 |
| **Duisburg** | 707 | 593 | 1002 | 220 | 1067 | | 789 | 306 |
| **Le Havre** | 706 | 620 | 370 | 500 | 1326 | 789 | | 483 |
| **Antwerp** | 454 | 494 | 304 | 131 | 1100 | 306 | 483 | |

[29]https://www.marinetraffic.com/en/voyage-planner/
[30]https://sea-distances.org/
[31]https://www.searoutes.com/routing/

## 6.3 Key barriers

### 6.3.1 Regulatory Barriers

$CO_2$ has been transported by ship as a commodity between various European countries for a number of years. However, transporting $CO_2$ for the purposes of offshore storage is exposed to different international regulatory frameworks which will have an influence on the development and requirements for $CO_2$ shipping. These include environmental legislation, monitoring and reporting guidelines, safety procedures and $CO_2$ storage regulations. A summary of these regulatory frameworks and their relevance for national and international $CO_2$ transport by ship is provided in this section.

#### THE LONDON PROTOCOL – ARTICLE 6 ON TRANSBOUNDARY $CO_2$ TRANSPORTATION

The "Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter 1972", the "London Convention" for short, is one of the first global conventions to protect the marine environment from human activities and has been in force since 1975 (International Energy Agency, 2011). Its objective is to promote the effective control of all sources of marine pollution and to take all practicable steps to prevent pollution of the sea by dumping of wastes and other matter (International Maritime Organisation, 2018).

In 1996, the "London Protocol" (LP) was agreed to further modernise the Convention and, eventually, replace it (International Maritime Organisation, 2006). Under the Protocol all dumping of wastes is prohibited, except for the named possible acceptable wastes on the so-called "reverse list", listed in Annex I of the Protocol. The Protocol entered into force on 24 March 2006, and there are currently 50 Parties to the Protocol (International Maritime Organisation, 2018).

#### *$CO_2$ sequestration in the London Protocol*

In 2007, in recognition of the potential damage of human induced climate change could have on the marine environment, and the emergence of CCUS as a promising mitigation option, the LP was amended to add $CO_2$ onto the list of possible acceptable wastes which could be “dumped”. In fact, it was agreed that “Carbon dioxide streams from carbon dioxide capture processes for sequestration” could be considered for dumping (Annex 1, Para 1.8), only if:

1. disposal is into a sub-seabed geological formation; and
2. they consist overwhelmingly of carbon dioxide. They may contain incidental associated substances derived from the source material and the capture and sequestration processes used; and
3. no wastes or other matter are added for the purpose of disposing of those wastes or other matter.

The amendment entered into force on 10 February 2007 for all Contracting Parties to the Protocol.

Despite $CO_2$ being placed on the list of acceptable wastes under the London Protocol, the regulation still prevents the transboundary movement of $CO_2$ for the purposes of disposal at sea. Article 6 states *“Contracting Parties shall not allow the export of wastes or other matter to other countries for dumping or incineration at sea*.” Therefore, the transportation of $CO_2$ from EU member states, by ship or pipeline, for geological storage to the UK offshore sector, would currently be in violation of an international treaty. Conversely, the transboundary transportation of $CO_2$ for the purposes of storage onshore, or for utilisation, is not blocked by the London Protocol.

In recognition of this potential regulatory barrier, in 2009 Norway submitted a proposed amendment to the London Protocol, which added an additional paragraph (2) to Article 6 as follows:

*"Notwithstanding paragraph 1, the export of carbon dioxide streams for disposal in accordance with Annex 1 may occur, provided that an agreement or arrangement has been entered into by the countries concerned."*

The amendment was adopted as a Resolution (Resolution LP.3(4)) by vote. However, in order for the Resolution to come into force (for parties that accept it), it must be ratified by two-thirds of the (46) Contracting Parties. At present, only Norway, the UK, the Netherlands, Finland and Iran have ratified the Resolution (T. Dixon, personal communication 24th September 2018). It is unclear why in almost 10 years, only 5 parties have ratified the Resolution, although it is assumed that the majority of parties see limited value in the transboundary movement of $CO_2$. Based on the progress to date, there is a low probability that an additional 24 parties will ratify the Resolution within the next 5 years. This could delay the development of transboundary $CO_2$ projects, such as those presented as part of European Projects of Common Interest (compare (EU Commission, 2018)for further information).

In recent years, this potential barrier has been analysed and possible legal solutions have been offered. In its working paper, the IEA (2011) explored possible ways to resolve this and distinguished five possible approaches to enable transboundary CCUS:

- To issue an interpretative resolution based on the general rules of interpretation
- Resolve to provisionally apply the 2009 amendment, until it is ratified
- To enter into bilateral or multilateral agreements
- Agree to modify the operation of the relevant aspects of the London Protocol between specific contracting parties
- Agree to suspend the operation of the relevant aspects of the London Protocol between specific contracting parties

(Henriksen, 2017) have since further developed the options presented by the IEA and found that the first option could offer room for a legal solution. Based on the general principles for interpretation from the Vienna Convention on the Law of Treaties (VCLT) from 1969, in summary, the authors applied the rule of '*overall logic'* to conclude that although the transboundary movement of $CO_2$ for dumping would be in conflict with the wording of Article 6, the activity would not hinder the objective and purpose of the London Protocol. The objective of the London Protocol, according to Article 2 is, *'Contracting parties shall individually and collectively protect and preserve the marine environment [...]"*. As part of this objective, they shall, where appropriate *"harmonize their policies in this regard"*. Therefore, transporting $CO_2$ between parties of the Protocol should not jeopardise the objective, as all parties are bound by the same obligations. Transportation of $CO_2$ between parties to the protocol and third-parties would still be prohibited.

Despite these possible solutions, Henriksen & Ombudstvedt (2017) conclude that there is no one size fits all solution to the Article 6 issue, and each option entails complex legal arguments and interpretations. Notwithstanding these challenges, CCUS projects involving transboundary $CO_2$ movements between parties to the London Protocol continue to be discussed. It is likely that as industrial CCUS projects move closer to implementation, the relevant parties to the London Protocol affected by this barrier will undertake concrete legal steps to avert Article 6 derailing large scale investments in transboundary CCUS projects. Nevertheless, the London Protocol remains an uncertainty and efforts may be required to hasten the amendment.

### EU-ETS Monitoring and reporting guidelines

As of 2013, CCS was fully included in Phase III of the European Union Emissions Trading Scheme (EU ETS). The last set of finalized Monitoring and Report Guidelines (MRGs) were released in 2012 to be used during Phase III of the EU ETS (2013-2020) (EU Commission, 2018). In Annex IV of these guidelines, activity specific guidelines are provided for determining the monitoring requirements for $CO_2$ capture, transport by pipeline and storage in geological formations. Monitoring guidelines for $CO_2$ shipping vessels, liquefaction processes and associated loading and offloading equipment were not included. The exclusion of shipping in the current EU ETS MRGs generates questions on how CCS projects with shipping can be effectively and adequately monitored and verified. One possible solution could be that a Member State 'opt-in' shipping $CO_2$ as a regulated activity under the EU-ETS under Article 24 of the Directive. This would also require the proposal and acceptance by the European Parliament and Council of a bespoke MRG approach to $CO_2$ shipping vessels.

As of January 2018, the EU Regulation on monitoring, reporting and verification of carbon dioxide emissions from maritime transport (Regulation (EU) No. 757/2015 as amended), requires all ships with a gross tonnage of over 5000t to be subject to the monitoring and reporting of $CO_2$ emissions. However, maritime vessels are not currently included in the EU-ETS. Therefore, including $CO_2$ shipping vessels as part of the EU-ETS could raise conflicts of interest with the broader maritime industry, as such an inclusion could represent a precedent for greater inclusion of maritime vessels in the EU-ETS, and the financial consequences that would bring.

### THE EU DIRECTIVE FOR THE GEOLOGICAL STORAGE OF $CO_2$ (2009/31/EC)

The EU Directive for the geological storage of $CO_2$, 'the CCS Directive' is the key piece of regulation for the storage of $CO_2$ in Europe. The Directive provides the rules and definitions for Member State competent authorities to issue $CO_2$ storage permits, and covers the requirements for monitoring plans, risk assessments and corrective measures. However, the Directive is primarily focused on the storage component of CCS projects, and only briefly mentions the transport of $CO_2$. Furthermore, only transport by pipeline is mentioned in the document. There is no reference to marine transportation of $CO_2$.

### UNITED NATIONS CONVENTION ON THE LAW OF THE SEA 1982

When transport and storage (T&S) occurs in the territory of a state, the applicable legislation is easily determined: it is the law of the sovereign state that applies to all aspects of the transport and storage facility. In the case of offshore T&S, the situation is far more complex. International law determines which State has the competence to regulate the transport and storage. Offshore, several maritime zones are identified for which international law recognises different rights and obligations. The UNCLOS (United Nations Convention on the Law of the Seas of 1982) has defined the different maritime zones (United Nations, 2018):

- *Baseline*, coast at low water, sovereign rights of the coastal state (Art. 5 UNCLOS).
- *Territorial waters*, 12 nautical miles (nm) out of the coast, law of the coastal State applies (Art. 2 UNCLOS) 6 - Continental shelf, a natural prolongation of the land territory where coastal states have functional jurisdiction regarding the exploration and production of oil and gas, including the right to establish the necessary installations and the right to construct and regulate pipelines transporting the hydrocarbons to shore (Art. 79 UNCLOS, limited rights to lay pipelines) .
- *The Exclusive Economic Zone* (EEZ), extends 200 nm from the coast, and gives coastal states the rights to explore and exploit minerals and other types of energy and to establish all necessary installations/cables (Art. 56 UNCLOS).
- *High seas*, Art.112 UNCLOS which provides for the freedom to lay pipelines.

Practically speaking, for shipping scenarios that involve transporting $CO_2$ from the UK mainland to UK storage sites on the territorial waters or the EEZ, the UK has full jurisdiction (in territorial waters) and reserves the right to conduct economic activities in the EEZ. However, if $CO_2$ from the UK would be transported across the border to a neighboring parties EEZ, this country would assume jurisdiction over any T&S infrastructure, as it would with any other economic activity.

UNCLOS also applies to shipping vessels, whereby the concept of 'innocent passage' is important here. Innocent passage is defined in UNCLOS as *"navigation through the territorial sea for the purpose of traversing it while being nonprejudicial to the peace, good order or security of the coastal state."* UNCLOS does allow coastal states to apply laws and regulations relevant to safety of navigation and maritime traffic in its territorial waters. Importantly, innocent passage may not be denied by the coastal State merely based on the cargo of the ship. In the EEZ, UNCLOS states that all foreign ships enjoy the freedom of navigation, so long as they comply with the general provisions of UNCLOS and international maritime law.

Simply speaking, should a Danish ship carrying $CO_2$ have to pass through the Dutch and or German EEZ on route to a storage site in the UK North Sea, the Dutch or German authorities would have no jurisdictional power to prevent the ship traversing their territorial waters or EEZ, so long as there was no threat to its maritime environment. Therefore, although relevant, UNCLOS presents no regulatory barrier to national or international maritime transport of $CO_2$.

### The SOLAS Convention and IMO IGC Code

The primary instrument of international law dealing with safety in shipping is the International Convention for the Safety of Life at Sea of 1974 (SOLAS Convention, (International Maritime Organization, 2018)). The SOLAS Convention has a wide remit, with provisions for the design and construction of ships, rules with regards to the on-board equipment for safe navigation and emergency situations, and rules regarding the operation of the ship. Chapter VII of the convention is dedicated to the carriage of dangerous goods, including liquid chemicals and irradiated nuclear fuel. Part C of the chapter is focused on ships carrying liquified gases in bulk, which is relevant for the transportation of $CO_2$. These laws will have a bearing on the design and operation of $CO_2$ ships, and therefore the final cost and viability of $CO_2$ shipping.

Within Chapter VII, there are a number of sub-themes, so-called IMO codes, which include specific requirements for certain types of ships carrying various loads. Regarding $CO_2$, the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code), in place since 1986, is applicable. In fact, this code covers the carriage by ships of liquefied gases having a vapour pressure exceeding 2.8 bar absolute at a temperature of 37.8°C, in addition to a list of other products contained in Chapter 19 of the SOLAS Convention. Despite already exceeding the criteria for pressure mentioned above, in 2006 the IMO adopted a resolution to add $CO_2$ onto the list of substances in Chapter 19. The IGC code stipulates that ships carrying applicable substances, such as $CO_2$, must meet the requirements of the "International Certificate of Fitness for the Carriage of Liquefied Gases in Bulk". To receive and maintain such as certificate, a ship must undergo a series of surveys to be carried out by officers of the flag state. Further requirements to the design of liquified bulk carriers are distinguished by the foreseen hazardousness of the cargo. The least hazardous category, 3G, includes refrigerant gases, nitrogen and carbon dioxide.

Chapter 17 of the code provides "Special Requirements" for ships carrying substances covered in Chapter 19. Sections 17.21 and 17.22 lists the special requirements for ships carrying $CO_2$. The section makes a distinction between high purity $CO_2$, and reclaimed quality $CO_2$. Reclaimed quality $CO_2$ is understood to be that which has been captured from industrial processes. These provisions are primarily focused on the management of pressure of the $CO_2$ during transportation, to ensure it stays in liquid form. Information on the "triple point" temperature of the $CO_2$ must be supplied to the carrier to ensure the minimum temperature and pressure needed to keep the liquid phase of the cargo is maintained. The $CO_2$ must be kept at 0.05 MPa above the triple point. Another important requirement is the installation of carbon dioxide monitoring equipment in areas of the ship where

$CO_2$ accumulation could occur. Ships carrying reclaimed $CO_2$ must comply with all the requirements for pure $CO_2$, with the addition that the cargo system must also take account of the possibility of corrosion, in case the reclaimed quality carbon dioxide cargo contains impurities such as water or Sulphur dioxide.

### 6.3.2 Port Constraints

Using existing ports for $CO_2$ shipping projects is cost effective due to the availability of services and infrastructure e.g. for docking as well as storing and loading $CO_2$. Existing ports can impose constraints on $CO_2$ shipping projects, including **ship length, ship draft, berth availability,** and **storage space requirements**. For instance, very large $CO_2$ ships (e.g. >30 kt$CO_2$) may not be able to meet the specific maximum length and draft requirements of some ports. Many UK ports are in strategic locations for industrial clusters and $CO_2$ storage sites. A summary of the key UK port parameters is shown in Table 6-2. Other port requirements may include **proximity to $CO_2$ sources**, and electricity **grid reinforcements** that may be needed for the liquefaction plants.

**Table 6-2 Summary of UK port parameters, including ship size, tonnage and storage availability**

| Port | Maximum length (m) | Maximum draft (m) | No. of berths | Approx annual tonnage (Mt) | Storage – open ($m^2$) | Storage – covered ($m^2$) |
|---|---|---|---|---|---|---|
| Teesside | 304 | 17 | 21 | 27 | Large areas available | 30,000 |
| St Fergus/Peterhead | 280 | 11 | - | 10.3 | - | - |
| Grangemouth | 183 | 11 | 20 | 8.5 | Large areas available | 29,000 |
| Merseyside (Liverpool) | 292 | 12.8 | 50 | 33.4 | Unlimited | >1,000,000 |
| Humberside (Hull) | 214 | 10.4 | - | 9.3 | 650,000 | 125,000 |
| South Wales (Port Talbot) | 300 | 16.5 | 3 | 9.0 | - | - |
| Thames Estuary (Thamesport) | 350 | 13 | 2 | 4.0 | 320,000 | 17,500 |
| Thames Estuary (Tilbury) | 310 | 13 | 4 | 8.3 | 6,800,000 | 3,200,000 |

Table 6-3 shows the estimated size of $CO_2$ ships in the literature.

**Table 6-3 $CO_2$ ship parameters**

| Report | $CO_2$ transport pressure | Ship Size (t$CO_2$) | Ship length (m) | Ship draft (m) |
|---|---|---|---|---|
| Yara, Larvik Shipping, Polarkonsult 2016 | Med P | 1,700-7,500 | 94-160 | 5-7 |
| Polarkonsult, Praxair, Larvik Shipping, 2016 | Med P | 2,400-9,400 | 102-160 | 5-7 |
| Brevik 2017 | Med P | 2,300-10,000 | 103-150 | 5-8 |
| Petrofac 2012 | Low P | 30,000 | 210 | 11 |

Whilst the port parameters may impose constraints on the ship design in early projects, in the longer term, dedicated infrastructure can be installed.

### 6.3.3 Limited experience in large-scale $CO_2$ shipping

The shipping industry is conservative and risk averse with regards to new business areas. Large scale $CO_2$ shipping is considered technically feasible, but a demonstration project of substantial size may be needed to create confidence in the investment environment. The risk premium of a new technology is likely to decrease quickly. For example, the cost of LNG powered ships has reduced significantly after the first 3 - 5 ships. The Norwegian CCUS project plans to start with a small-scale shipping project but for the second phase an aim of a 1.5 $MtCO_2$/yr flow rate has been set with the intention to scale this up to 4 $MtCO_2$/yr relatively quickly. In the longer term, a stable supply chain and market for $CO_2$ shipping must develop, to ensure ongoing momentum, investment and innovation.

### 6.3.4 Lack of viable business models

#### *Existing LNG/LPG model may not be replicable for $CO_2$*

Shipping companies expect the business model of $CO_2$ shipping to differ substantially from LNG/LPG shipping. Whereas the LNG/LPG value chain is highly distributed and fragmented, the $CO_2$ shipping chain is expected to be owned/operated by one entity, to allow for easier administration. Joint ventures are likely to be common practice and are already being considered by shipping and infrastructure companies. The main difference between the cargos is that LNG/LPG offers value, whereas $CO_2$ is a waste product. Therefore, except for Enhanced Oil Recovery, $CO_2$ shipping requires the availability of an incentive or government backing, to create a revenue model. Business models will depend on future market conditions. Creating momentum and confidence by realising an initial demonstration project should be prioritised in the early phase while business models can be developed and refined at a later stage.

#### *Ship ownership and chartering*

The most common forms of shipping contracts between a ship owner and a ship charterer are the following:

- *Voyage charter:* contract for the carriage of a stated quantity and type of cargo, by a named vessel between named ports against an agreed price, called freight. It is the most widespread form of chartering.
- *Time charter:* contract for the hire of a named vessel for a specified period of time, during which time the charterer may use the vessel as he wishes. With a traditional time charter the time charterer will hire the ship equipped and manned. The fixed costs of the ship are for the account of the owner and the variable costs are for the account of the time charterer.
- *Bareboat charter:* Under a bareboat charter, or demise charter, the charterer must equip and man the ship himself. The charterer must pay for all operating costs and recruit the captain and the crew.

Large oil and gas companies also own substantial fleets of ships themselves.

#### *Ownership of port infrastructure*

Oil and gas companies own and operate several port facilities in the UK. Examples include:

- INEOS operates 4 berths in Grangemouth, Scotland and Hound Point, Scotland
- Calorgas owns and operates an LPG terminal on Canvey Island, England
- Shell and Exxon own Braefoot Bay, an LPG terminal in Scotland

The shipping management companies that were interviewed do not own any port facilities themselves. However, the $CO_2$ shipping chain including port infrastructure is expected to be owned/operated by one entity (which could be a joint venture of private companies, the government or a public private partnership) as all shipping infrastructure is likely to be dedicated to a single CCUS project for several years or decades.

# 7 Conclusions and recommendations

$CO_2$ shipping may have an important role to play in supporting CCUS in the UK (and elsewhere). The technical and regulatory barriers can be overcome to realise the opportunities $CO_2$ shipping presents, both in protecting existing UK energy intensive industry and in developing expertise in the emerging field of $CO_2$ transport and storage.

**In many situations, it is found that the $CO_2$ shipping costs may be lower than the equivalent $CO_2$ pipeline costs**. However, this is dependent on factors such as distance, project duration, pressure requirements and $CO_2$ flow-rate. **Liquefaction and ship costs** (CAPEX and OPEX) are found to be the biggest cost components of $CO_2$ shipping (i.e. more than 70%). Shipping costs are dominated by operational and fuel costs, unlike pipelines, which are dominated by CAPEX. The cost-effectiveness of shipping costs depends on the initial and transport pressure conditions; shipping costs can be **£7-10/t$CO_2$** for pre-pressurised $CO_2$ for liquefaction and low pressure $CO_2$ transport. Sensitivity analysis showed that, for a given $CO_2$ pressure condition, lifetime shipping project cost shows highest sensitivity to the $CO_2$ flow rate, due to additional ships being required; however, as this cost is spread over a greater quantity of $CO_2$, the unit cost (£/t$CO_2$) shows a smaller impact of flow rate. Shipping costs were also found to be sensitive to project lifetime and ship size selected. Pipeline costs show much higher sensitivity to distance and flow rate than shipping costs, due to the high capex costs. In general, **shipping costs are found to be more cost-effective relative to pipelines for lower $CO_2$ flow rates, longer distances and shorter project lifetimes**.

**Key barriers to $CO_2$ shipping include regulations, port constraints and the lack of business models.** The key barrier for cross-border $CO_2$ shipping is the London Protocol, which still prevents the cross-border movement of $CO_2$ for CCUS. Other relevant regulations include EU-ETS Derective, EU CCS Directive, UNCLOS, and SOLAS and IMO IGC Code. Early projects may be required to meet the specific port constraints (including ship length, ship draft, berth availability, and storage space) but dedicated infrastructure can be installed in the longer-term. There is currently limited experience in $CO_2$ shipping at the scale needed, so demonstration projects may be needed. Additionally, business models and incentives for $CO_2$ shipping will be required as existing LPG/LNG business models and contracts are not expected to be replicable for $CO_2$ shipping.

**$CO_2$ shipping can unlock a number of opportunities for the UK, such as reducing the cost of early UK CCUS projects, extending the economic locations for CCUS and importing $CO_2$ from other European clusters**. Gathering $CO_2$ from multiple locations via shipping (analogous to the planned Norwegian projects) may enable the deployment of several clusters in parallel cost-effectively. Shipping may also extend the viability of CCUS to clusters such as that in South Wales, which does not have viable storage sites nearby. For short duration projects of small-scale, the potential sunk costs after 10 years are found to be significantly lower for shipping than for pipelines, thereby improving the economics. Finally, a market with considerable future potential is that of importing $CO_2$ from other European CCUS clusters via shipping, to increase the scale of the $CO_2$ T&S market in the UK, with the aim of contributing to UK economic growth.

#### 7.1.1.1 Recommendations for further work

This study has presented an analysis of the costs of $CO_2$ shipping, relative to pipeline transport, as well as an overview of the opportunities and barriers associated with the development of $CO_2$ shipping in the UK. Additional studies or research should be completed to explore more detailed aspects of the supply chain and the potential market both in the UK and abroad. It is important to understand the implications of potential $CO_2$ shipping business models for industry, consumers and the government. Some suggestions for further work are given below:

- More detailed assessment of potential **UK ports/terminals for $CO_2$ shipping**. This may include identification of suitable sites, site-specific feasibility studies, and identification of site-specific constraints. Discussion with potential UK carbon capture clusters may be beneficial.

- Inclusion of **$CO_2$ storage infrastructure** (e.g. pipelines, wells, etc.) in the $CO_2$ shipping cost model to understand financial implications of port-to-storage shipping. Detailed assessment of different **port-to-storage options**, including their potential impact on $CO_2$ storage costs e.g. due to their potential effect on injectivity.

- Detailed assessment of the **market potential for importing $CO_2$** from other European countries and the associated value to the UK. This may include economic modelling on the impact on employment, GVA and potential additional investment.

- Activities to promote the ratification of the **proposed amendment to the London Protocol** by other Member States to enable cross-border $CO_2$ transport. Research should be undertaken to understand the current barriers to ratification by remaining countries and tackle these challenges where necessary.

- Inclusion of $CO_2$ shipping in the BEIS Energy Innovation Programme (if possible) or provision of additional **funding to demonstrate $CO_2$ shipping** in the UK. The UK may also learn from any demonstration programmes abroad, such as that currently being developed in Norway, but direct injection applications are likely to require further demonstration.

- Assessment of **viable business models for $CO_2$ shipping,** including incentive mechanisms, ownership structure (e.g. which entities are likely to own port vs. ship), risk management strategies and capital financing. Consideration should be given to the cost-effectiveness of these mechanisms, as well as the long-term sustainability of any policies implemented in terms of market development.

# 8 References

Alabdulkarem, A. H. (2012). Development of CO2 liquefaction cycles for CO2 sequestration. *Appl. Thermal Eng. 33*, 144-156.

American Society of Mechanical Engineers . (2010). *ASME Boiler and Pressure Vessel Code, Section VIII, Division 1: Rules for Construction of Pressure Vessels.*

Aspelund, A., & Gundersen, T. (2009). A liquefied energy chain for transport and utilization of natural gas for power production with CO2 capture and storage – Part 3: The combined carrier and onshore storage. *Appl. Energy 86*, 805–814.

Baresic, D. (2018). *LNG as a marine fuel in the EU.* Transport & Environment.

Berger, B. K. (2004). Creating a large-scale CO2 infrastructure for enhanced oil recovery. *Greenhouse Gas Control Technologies 7 Volume I, 2005*, (pp. 321-328). Vancouver, Canada.

Brevik. (2017). *CO2 ship transport study - Concept study report.* Gassco.

Brownsort, P. (2015). *Ship transport of CO2 for Enhanced Oil Recovery – Literature Survey.* Edinburgh: Scottish Carbon Capture and Storage.

Chiyoda Corporation. (2011). *Preliminary Feasibility Study on CO2 Carrier for Ship-based CCS.* Global CCS Institute.

Chiyoda Corporation. (2012). *Preliminary Feasibility Study on CO2 Carrier for Ship-based CCS (Phase-2 – unmanned offshore facility).* Global CCS Institute.

Chiyoda Corporation and Global CCS Institute. (2011). *Preliminary Feasibility Study.* Chiyoda Corporation and Global CCS.

CO2EuroPipe. (2011). *Towards a transport infrastructure for large-scale CCS in Europe; D4.3.2 Kårstø CO2 Pipeline Project: Extension to a European Case.*

Committee on Climate Change. (2017). *Building a low-carbon economy in Wales - Setting Welsh carbon targets.* Committee on Climate Change.

Decarre, S. (2010). CO2 maritime transportation. *International Journal of Greenhouse Gas Control 4*, 857–864.

DNV. (2011). *Rules for Classification of Ships/High Speed, Light Craft and Naval Surface Craft, Part 2, Chapter 2, Metallic Materials.*

Energy Technologies Institute. (2016). *Strategic UK CCS Storage Appraisal.* Energy Technologies Institute.

Equinor. (2018). Personal Communication.

EU Commission. (2012, October 03). *EU GEOCAPACITY project*. Retrieved from https://cordis.europa.eu/result/rcn/49623_en.html

EU Commission. (2018). *Monitoring, reporting and verification of EU ETS emissions*. Retrieved from https://ec.europa.eu/clima/policies/ets/monitoring_en

EU Commission. (2018). *Projects of Common Interest*. Retrieved from https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest

Gao, L. (2011). Cost analysis of CO2 transportation: case study in China. *Energy Proc. 4*, 5974–5981.

Gassnova. (2018, June 29). *CCS in Norway entering a new phase*. Retrieved from https://www.gassnova.no/en/ccs-in-norway-entering-a-new-phase

Geske, J. B. (2015). Cost-effective balance between CO2 vessel and pipeline transport. *International Journal of Greenhouse Gas Control*, 175-188.

Haugen, H. A. (2009). Options for transporting CO2 from coal fired power plants Case Denmark. *Energy Procedia 1*, 1665-1672.

Henriksen, D. E. (2017). Cross-Border Transportation – A Key to Unlock Full-Scale CCS. *Energy Procedia 114*, 7443-7458.

International Energy Agency. (2011). *Carbon Capture and Storage and the London Protocol - Options for Enabling Transboundary CO2.* International Energy Agency.

International Maritime Organisation. (2006). *1996 Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and other Matter, 1972 (as amended in 2006).* International Maritime Organisation.

International Maritime Organisation. (2018). *Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter*. Retrieved from http://www.imo.org/en/OurWork/Environment/LCLP/Pages/default.aspx

International Maritime Organization. (2008). *International Code of the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code).*

International Maritime Organization. (2018). *International Convention for the Safety of Life at Sea (SOLAS), 1974*. Retrieved from http://www.imo.org/en/About/conventions/listofconventions/pages/international-convention-for-the-safety-of-life-at-sea-(solas),-1974.aspx

Knutsen OAS Shipping. (2016). *Feasibility Study CO2 Transportation.*

Kujanpää, L. (2011). Cross-border CO2 infrastructure options for a CCS demonstration in Finland. *Energy Procedia 4*, 2425–3243.

Megyesy, E. F. (2008). *Pressure Vessel Handbook, 14th ed.* Oklahoma: PV Publishing Inc.

Mitsubishi Heavy Industries. (2004). *Ship Transport of CO2.* Cheltenham: IEA Greenhouse Gas R&D Programme.

Nam, H., Lee, T., Lee, J., & Chung, H. (2013). Design of carrier-based offshore CCS system: Plant location and fleet assignment. *International Journal of Greenhouse Gas 12*, 220-230.

Neele, F. (2017). CO2 transport by ship: the way forward in Europe. *Energy Procedia 114*, 6824 – 6834.

Oi, L. E. (2016). Simulation and cost comparison of CO2 liquefaction. *Energy Procedia 86*, 500-510.

Petrofac Engineering Services. (2012). *Peterhead CO2 Importation Feasibility Study.* CO2 DeepStore.

Plomaritou, E. (2014). A Review of Shipowner's & Charterer's Obligations in Various Types of Charter. *Journal of Shipping and Ocean Engineering 4* , 307-321.

Polarkonsult, Praxair, Larvik Shipping. (2017). *Concept study of CO2 transport by ship, as part of the Norwegian CCS Demonstration Project.*

Poulsen, N. (2014). *Assessment of CO2 storage potential in Europe - CO2StoP Final Report.* Danish Ministry of Climate, Energy and Building.

Roussanaly, S. (2014). Benchmarking of CO2 transport technologies: Part II – Offshore pipeline and shipping to an offshore site. *Int. J. Greenhouse Gas Control 28*, 283–299.

Seo Y, Y. H. (2015). Evaluation of CO2 liquefaction processes for ship-based carbon capture and storage (CCS) in terms of life cycle cost (LCC) considering availability. *International Journal of Greenhouse Gas Control 35*, 1-12.

Seo, Y. H. (2016). Comparison of CO2 liquefaction pressures for ship-based carbon capture and storage (CCS) chain. *International Journal of Greenhouse Gas Control 52 (2016)*, 1-12.

Ship & Bunker. (2018). *World Bunker Prices*. Retrieved from https://shipandbunker.com/prices/av/region/av-eme-emea-average#IFO380

Svenson, R. (2004). Transportation systems for CO2 – application to carbon sequestration. *Energy Convers. Manage. 45*, 2343–2353.

Tel-Tek. (2014). *Ship transport of CO2 - Status and Technology Gaps.* Tel-Tek.

TNO. (2016). *Transportation and unloading of CO2 by ship - a comparative assessment WP9 Final Report.* Cato.

United Nations. (2018). *United Nations Convention on the Law of the Sea of 10 December 1982*. Retrieved from http://www.un.org/depts/los/convention_agreements/convention_overview_convention.htm

Vermeulen, T. (2011). *Knowledge Sharing Report-CO2 Liquid Logistics Shipping Concept (LLSC): Overall Supply Chain Optimiszation.* The Hague: Tebodin Netherlands BV.

Yara, Larvik Shipping, Polarkonsult. (2016). CO2 Ship Transport Study In support of Full Scale CCS Chain Evaluation in Norway.

Yoo, B. C. (2013). Development of CO2 terminal and CO2 carrier for future commercialized CCS market. *Int. J. Greenh. Gas Control 12*, 323-332.

Yoo, B.-Y. (2011). New CCS system integration with CO2 carrier and liquefaction process. *Energy Procedia 4* , 2308-2314.

ZEP. (2011). *The Costs of CO2 Transport.* Brussels: European Technology Platform for Zero Emission Fossil Fuel Power Plants.