

Impacts of geological store uncertainties on the design and operation of flexible CCS offshore pipeline infrastructure



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ABSTRACT

Planning for Carbon Capture and Storage (CCS) infrastructure needs to address the impact of store uncertainties and store flow variability on infrastructure costs and availability. Key geological storage properties (pressure, temperature, depth and permeability) can affect injectivity and lead to variations in CO₂ flow, which feed back into the pipeline transportation system. In previous storage models, the interface between the reservoir performance and the transportation infrastructure is unclear and the models are unable to provide details for flow and pressure management within a transportation network in response to changes in the operation of storage sites. Variation in storage demand due to daily and seasonal variations of fossil fuels uses and by extension CO₂ flow is also likely to influence transportation infrastructure availability and the capacity to deliver. This work evaluates, at the level of infrastructure planning, the impact of geological uncertainty on CCS pipeline transportation and injection infrastructure. The analysis presented shows how to consider uncertainty in store properties in combination with CO₂ flow variability to estimate the likely impact on pipeline infrastructure design. The operational envelope of the storage site infrastructure is estimated by combining the Darcy flow analysis of simple reservoir models with rigorous process simulation of the storage site wells. The proximity of wellhead conditions to the CO₂ equilibrium line and the maximum velocities inside the well constrain the operational envelope of the storage site and limit the ability of the storage site infrastructure to handle CO₂ flow variation. These factors, which are significantly influenced by variations in subsurface conditions, have also an impact on the design of the offshore pipeline infrastructure, needing to accommodate changes in pressure delivery requirements. Based on the evaluation of examples developed for different offshore transportation scenarios relevant to the United Kingdom, detailed insight on the expected impacts of store properties on pipeline transportation infrastructure design and operation is provided. For instance, it is found that enabling storage site flexibility is simpler in stores with an initial pressure above 20 MPa. Given reductions in reservoir permeability, the requirements for pressure delivery are strongly dependent on the store temperature. Although the analysis is performed for specific geological characteristics in the North Sea the evaluation methodology is transferable to other locations and can be used for site screening to identify sites which are more flexible in terms of uncertainty in store performance.

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1. Introduction

Carbon Capture and Storage (CCS) has been given considerable attention in the last few decades as a useful technology to miti-

gate the effects of climate change. The use of CCS is expected to play an important role in lowering the cost of decarbonising the energy sector (Lam, 2014). In order to achieve the required CO₂ emissions reductions, it is necessary to develop a CCS transportation network that can handle future CO₂ emissions. At the time of writing, demonstration projects, including those being evaluated in the UK, typically design the elements of the network (capture plant, transportation pipeline and storage site) considering aver-

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List of symbols

C_g	Reservoir fluids compressibility
C_2	Coefficient for the estimation of erosional velocity
D	Offshore pipeline outer diameter
D/W	Ratio outer diameter to wall thickness in pipeline
e	Offshore pipeline weld factor
f_d	Offshore pipeline design factor
h	Well bore height
k	Effective permeability
$MAOP$	Maximum allowable operating pressure
$m(P)$	Pseudo-pressure for compressible fluids ($2P/\mu z$)
μ	CO ₂ viscosity
P_i	Inlet offshore pipeline pressure
P_{WH}	Wellhead pressure
P_{BH}	Well bottom hole pressure
P_R	Average reservoir pressure
P_e	Reservoir pressure at drainage radius
Q	CO ₂ volumetric flow
Q_{STP}	CO ₂ volumetric flow in standard conditions
r	Radius
r_e	Well drainage radius
r_w	Well radius
ρ	CO ₂ density
σ_h	Hoop stress
σ_{SMYS}	Specified minimum yield stress
T_i	Inlet offshore pipeline temperature
T_R	Reservoir temperature
t	Time
v	Injection velocity
v_e	Well erosional velocity
W	Offshore pipeline wall thickness
z	CO ₂ compressibility

For instance, the performance of the site might deviate significantly from expectations or degrade with time. If the problems are fundamentally due to the characteristics of the store, the options for remediating difficulties can be expensive (e.g. drilling pressure relief wells). For instance, there are known issues that affect the injectivity index (injection rate normalised per unit pressure drop [Craft and Hawkins, 2014](#)) such as the presence of multiple phase flow, especially important when injecting impure CO₂ streams, or the compression of fluids in depleted reservoirs. Confidence in site performance can be supported by store modelling and acquisition of seismic and well log data ([Yarranton and Baker, 2015](#)) and there are examples in the literature that couple uncertainty in CO₂ injection, predicted by reservoir simulations, to large infrastructure delivery scenarios ([Keating et al., 2011](#)). [Middleton et al. \(2012\)](#) use a multi-scale modelling approach that provides the overall behaviour of a CCS system including the impacts of uncertainty. However, they fail to make the link between the changes in the operation of storage sites and pipeline design to account for unforeseen factors within the subsurface that reduce injectivity and lead to variations in CO₂ flow and conditions that feed back to a pipeline transportation network.

Other important factors that affect infrastructure planning include short to medium term fluctuations in storage demand due to variations in CO₂ flows. Increasing penetration of variable renewable energy in the electricity grid is expected to impose additional flexibility requirements on power plants, including those fitted with CO₂ capture. As a result, seasonal and daily variations in CO₂ flows, created by changes in dispatch of coal and gas CCS power stations, will need to be accommodated by the transportation pipeline and storage site ([IEAGHG, 2012](#)).

Flow variation in CCS networks increases transportation and storage costs since the utilisation rate of the transport system, designed for the highest operational flow rate, decreases ([Middleton and Eccles, 2013](#)). Besides costs, the ability of the CCS transportation network to deliver sufficient CO₂ storage capacity for produced CO₂ might change if the demand for storage varies with time. In this case, the uncertainty around store characteristics is an important issue to consider to ensure full capacity delivery and high availability of CCS transportation networks for the large scale commercialisation of CCS ([Sanchez Fernandez et al., 2015](#)). The concept of average load factors to design CCS networks is no longer sufficient at this stage to ensure network reliability.

The development of CCS networks in the North Sea has been the focus of multiple studies ([Element Energy et al., 2014, 2005](#); [Loeve et al., 2013](#); [Neele et al., 2012](#)), which estimate the overall CO₂ storage capacity in the North Sea and provide the cost of CCS infrastructure under different scenarios. The economic models specifically developed for CO₂ pipeline transportation ([Knoope et al., 2014, 2013, 2015](#)) can be used to economically evaluate alternative solutions (e.g. investing in larger diameter pipelines, increasing the operating pressure or placing compression or pumping stations along the pipeline). However, these models do not consider the changes in storage site performance or the impact of geological uncertainty on CO₂ injection rates during the life time of CCS infrastructure.

Improved infrastructure planning models need to address the impact of uncertainties in store properties within a wider framework including flow variability. The changes in CO₂ delivery conditions need to be assessed during the design of the pipeline infrastructure to ensure that it can respond to long term variations in injection flows and delivery pressure. To achieve this, understanding the sensitivity of CO₂ pipeline transportation to changes in the performance of the storage sites is essential. Despite the existing models, there is need for more clarity in the interface between a single store model and a transportation model to tailor the design of infrastructure and ensure flexibility of the whole CCS chain.

age load factors, which translate into annual CO₂ flows and specific CO₂ source conditions. The store geological characteristics are also extensively evaluated to manage risks ([DECC, 2011, 2015](#); [Frost, 2015](#); [Spence et al., 2014](#)). In this context, store refers to a geological formation that is suited to store CO₂, whereas, storage site refers to a developed field or site, i.e. a store that includes the necessary infrastructure to inject CO₂.

The storage capacity of a network could be increased incrementally from anchor stores, to be developed around initial demonstration storage sites, as demand increases ([Element Energy et al., 2005](#)) or could be planned with high integration of CO₂ sources and stores to minimise system costs ([Element Energy et al., 2005](#); [Morbee et al., 2012](#)). The common user CO₂ transport and storage concept is also gaining attention among the CCS community ([Loeve et al., 2013](#)). In this concept, commercial deployment of CCS is expected to happen by installing large scale infrastructure that is shared by multiple users, substantially reducing carbon abatement costs. CO₂ infrastructure models are used at various scales to find the optimal least cost infrastructure ([Middleton and Bielicki, 2009](#); [Neele and Koorneef, 2010](#)). Models generally consider potential stores that have not been characterised. The initial screening of stores has multiple criteria including likely performance of the store, which is normally included in planning models in the form of capacity and injectivity constraints, and proximity to existing infrastructure. However, the CO₂ storage capacity and injectivity of potential stores remains uncertain, which significantly increases the performance uncertainty of any planned transportation network.

Many factors can lead to a mismatch between the required injection rates into the storage sites and what is possible in practise.

The focus of this paper is the role of specific store properties and subsurface conditions in the design of pipeline infrastructure that can handle medium to long term variations in CO₂ flow. The effects of geological store properties on the required CO₂ delivery conditions for hypothetical CCS offshore single store scenarios in the UK are explored. For two different types of stores, hydrocarbon reservoirs and saline aquifers, fluid flow models based on Darcy's law have been developed for simple store geometry and limiting scenarios of the store's pressure response to the injection of CO₂. This flow analysis is used to study the effect of key geological store parameters (pressure, temperature, depth and permeability) on the CO₂ injection conditions and requirements. The flow analysis is then completed with rigorous flow modelling of the well, to estimate the wellhead CO₂ delivery conditions, and the pipeline, to estimate the impact of changes in wellhead delivery pressure on pipeline design. For this purpose, rigorous models in Aspen Plus[®] have been developed to estimate the properties and conditions of the CO₂ stream in the pipeline and well bore.

Using these models, various case studies are developed, which consider storing CO₂ in different regions in the North Sea. Substantial flow variations over a baseline flow rate are investigated to assess store flexibility to variations in CO₂ flow. Based on the sensitivity of the performance of the transportation and storage system to changes in single store properties, this work identifies the capability of the pipeline and well to accommodate changes in flow. The results will help to assess the feasibility of infrastructure design under flexible scenarios, to understand the implications for pressure management and flow constraints in the offshore pipeline system and also provides useful information for screening of potential stores.

2. Store scenarios and properties that impact infrastructure planning

The impact of uncertainties in store properties and CO₂ flow variation on offshore infrastructure performance is analysed in this work by evaluating offshore storage scenarios that consider a single store coupled to a delivery pipeline from a single beach crossing. The scenarios considered, illustrated in Fig. 1, starts at the beach crossing after an optional booster station, which allows for a different entry pressure to the offshore pipeline (P_i) connecting the beach crossing to the offshore storage site location. The offshore pipeline follows a 45° inclination until reaching the seabed, follows a straight line to the location of the storage site (*i.e.* the seabed geology is simplified to a flat horizontal surface) and rises with a 90° angle to the offshore platform, just above sea level. The storage site receives the CO₂ stream at wellhead pressure (P_{WH}) and temperature (T_{WH}) and injects CO₂ at bottom hole pressure (P_{BH}) and temperature (T_{BH}) into different types of reservoirs with different reservoir pressure (P_R) and temperature (T_R). The following sections explain briefly the rationale behind the selection of the storage scenarios and conditions, their relevance to the UK CCS context and the detailed characteristics of each scenario.

2.1. Store types and scenarios for storage in the UK

The potential geological sites for CO₂ storage in the UK are located offshore. The UK Storage Appraisal Project (UKSAP) has estimated that the UK has a total Theoretical Storage Capacity of 78 Gt (ETI, 2014). The identified stores are either oil and gas reservoirs or saline aquifers.

Oil and gas reservoirs account for 10% of the total storage capacity and are often regarded as preferential stores due to their proven capacity to retain buoyant fluids and the availability of geological data acquired from production experience.

Two limiting scenarios for the pressure response of hydrocarbon fields to CO₂ injection have been considered, which are strongly related to how pressure evolved during the production of the hydrocarbon. Open Reservoirs are defined to be oil and gas fields which have a strong hydraulic connection to surrounding aquifers such that water can flow in and out as hydrocarbon is produced or CO₂ is injected; they can be considered to remain at near hydrostatic pressure. Closed Reservoirs are defined as oil and gas fields that are essentially a closed box such that no fluid can flow in or out of the surrounding geology when either hydrocarbon was produced or CO₂ is injected; the pressure in these fields will have been low at abandonment and rise during the injection of CO₂. In practice, many closed reservoirs are managed by injecting water into the reservoir to maintain pressure. This scenario has not been considered.

On the other hand, the majority of the theoretical capacity in the North Sea resides in saline aquifers, which have a higher uncertainty because of the obvious lack of exploration and production data. The store pressure can also be approximated by the hydrostatic pressure at the depth of the formation; however, saline aquifers differ to hydrocarbon open reservoirs in the level of confidence in the pressure response to CO₂ injection.

Fig. 2 shows the UK Continental Shelf geological basins map provided by the Oil and Gas Authority of the UK (OGL, 2015). Although the geology of the North Sea is very heterogeneous, generally speaking, UK oil fields are predominantly located in the Northern and Central North Sea basin whereas the UK gas fields occur mainly in the Southern North Sea Basin, and to a lesser extent in the Northern North Sea Basin (Evans et al., 2003). With respect to saline aquifers, potential storage formations have been characterised and identified in the Southern North Sea Basin (Furnival et al., 2014).

The scenarios analysed in this work consider two storage regions that represent two major alternatives previously proposed for the large scale development of CCS infrastructure in the UK sector of the North Sea: Northern development and Southern development (Element Energy et al., 2014, 2005; SCCS, 2009). These scenarios are based on the store locations of two CCS projects included in the UK CCS Commercialisation Programme competition; the Goldeneye gas field for the Peterhead project (DECC, 2011) and the Bunter saline aquifer for the White Rose project (Furnival et al., 2014), the location of the main CO₂ sources and sinks in the UK and the status of current infrastructure (onshore and offshore). The Northern development scenario considers the expansion of CCS infrastructure to the Northern part of the North Sea Basin. This scenario is driven by the utilisation of CO₂ to produce additional revenues from enhanced oil recovery (EOR). The Southern development scenario considers the development of CCS infrastructure in the Central and Southern North Sea (SNS). This scenario takes advantage of the large storage capacity in saline aquifers and its connection opportunities to the Dutch Continental Shelf.

The two scenarios considered are characterised by the predominant storage formation in the region of development, the distance from the shore and the water depth. Table 1 lists the ranges of these variables and information sources that are used to evaluate infrastructure performance. Developing infrastructure in the Northern North Sea (NNS) basin requires more pipeline infrastructure than the Southern North Sea (SNS) basin due to the remote locations of the oil fields. Moreover, water depth in the NNS is in the range of 100 m–200 m, which has higher associated costs of drilling, and platform investments than the typical water depth in the SNS basin (40 m–50 m) (OSPAR, 2000; Palson et al., 2014). The additional infrastructure costs can be offset with revenues from EOR, however, this is highly dependent on oil prices, which have to be at least in the range of £50/bbl to £60/bbl (Element Energy et al., 2014) to balance the additional infrastructure costs. Moreover, the geological uncertainties in EOR projects are substantially higher than in conventional hydrocarbon exploitation. Typically,

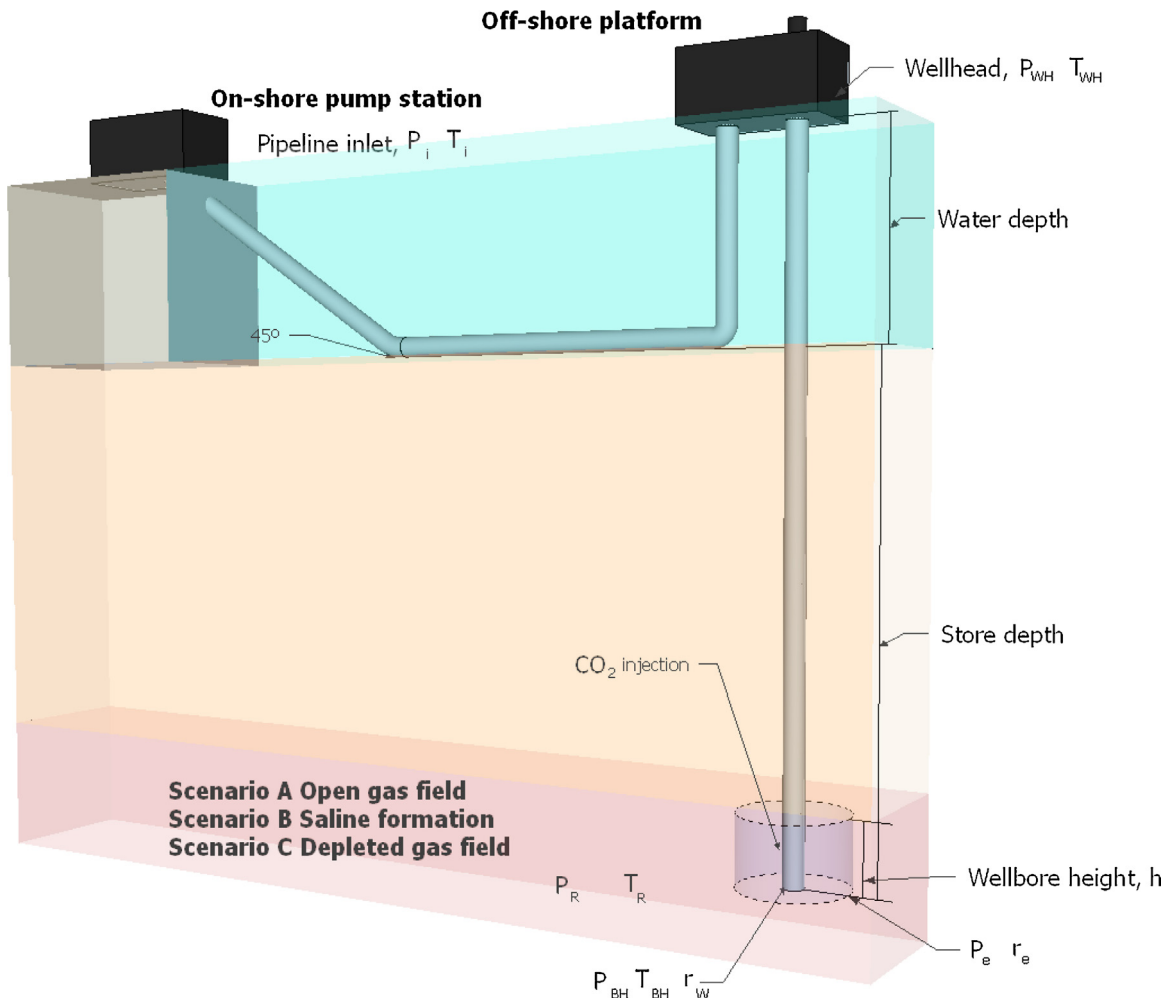


Fig. 1. Illustration of the boundary limits of the offshore transportation and storage scenarios. The figure illustrates the geometry of the pipeline and the geometry selected for flow analysis in the store model.

Table 1
North Sea regions considered for CCS infrastructure development.

Scenario	Range	Reference
SNS (Southern North Sea)		
Distance from shore (km)	85 km–180 km	OGL (2015)
Water Depth (m)	40 m–60 m	OSPAR (2000)
Main geological store	Gas field (open or closed), saline aquifer	Element Energy et al. (2005)
Storage capacity (Mt)	80 Mt (one saline aquifer), 50 Mt (one gas field) 68 Gt (cumulative in saline aquifers) ^a 5 Gt (cumulative in gas fields) ^a	Element Energy et al. (2005), ETI (2014)
NNS (Northern North Sea)		
Distance from shore (km)	100 km–200 km	OGL (2015)
Water Depth (m)	100 m–200 m	OSPAR (2000)
Main geological store	Oil field (open or closed)	Element Energy et al. (2005)
Storage capacity (Mt)	60 Mt (one store), 3 Gt (cumulative in oil fields) ^a	Element Energy et al. (2005), ETI (2014)

^a The cumulative capacity represents the total estimated capacity for the geological store type but the sources do not specify the region, therefore it is only indicative. The one store capacity is estimated as the arithmetic average of the estimated total capacity for the store type and the number of reported sites.

the reservoir scenarios are unique and based on assumptions that are case specific and difficult to generalise. In addition to the geological uncertainty challenges in EOR, there is significant uncertainty in oil prices. For example, The World Bank commodity market outlook forecasts a slow increase in oil prices up to 70\$/bbl (real 2010 US dollars) by 2025, equivalent to 46£/bbl (real 2010 British pounds) (World Bank, 2016). The EOR possibility is not considered further in this work. Instead, only depleted gas fields that are closer to

shore are included in this study as an example for the NNS region development.

2.2. Store properties and uncertainties

There are multiple empirical parameters that describe the geological characteristics of CO₂ stores. For a full assessment of CO₂ storage performance, store properties and their uncertainties need

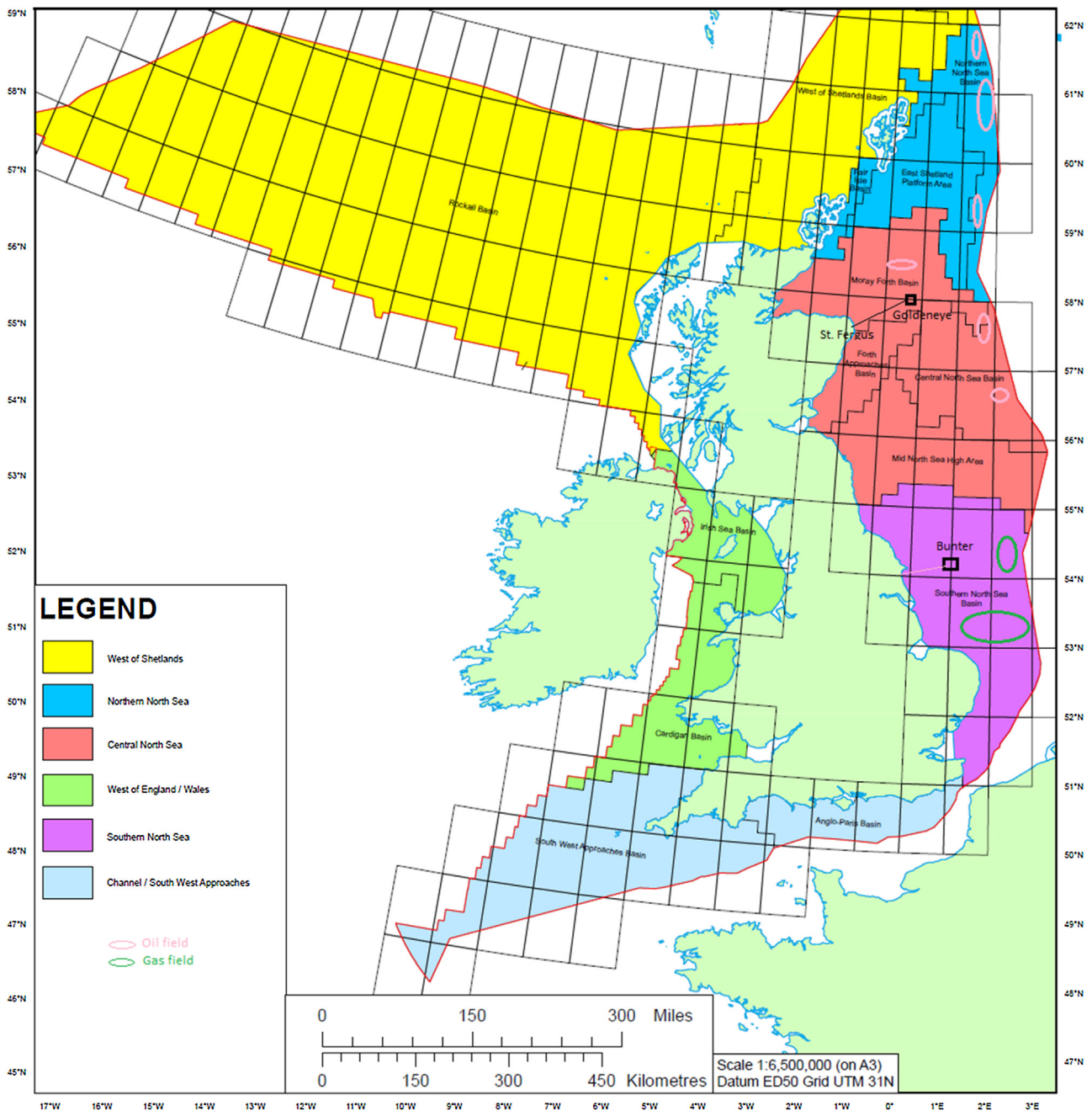


Fig. 2. North Sea Geological Basins with approximate locations for main gas and oil fields and CCS projects White Rose (Bunter sandstone, 54°N to 55°N, 1°E) and Peterhead (Goldeneye gas reservoir, 58°N, 1°W to 0°E). Modified from OGL (OGL, 2015).

to be determined by using production well data (for oil and gas reservoirs) or from a pilot hole and/or well appraisal. However, initial screening studies for infrastructure planning are more speculative and rely on property estimates from known geological formations that span broad ranges. The uncertainty around these estimates could be significant and is directly linked to data availability. The current study operates at the level of infrastructure planning and uses typical ranges of these variables from various storage screening studies (listed in the supporting information) to determine the expected impacts on infrastructure development under different scenarios and conditions, as detailed in Table 2.

2.2.1. Subsurface conditions

For all stores, the targeted depths for storage scenarios have been selected between 1000 m and 2000 m, following the recom-

mendations from several studies (Heddle et al., 2003; IEAGHG, 2013; SCCS, 2009). Estimates of subsurface conditions can be obtained by extrapolation of surface pressure and temperature using geothermal and hydrostatic gradients. Geothermal gradients can vary broadly depending on location and are typically within the range of 25 °C/km to 50 °C/km (Evans et al., 2003; IEAGHG, 2013; Middleton et al., 2012). The most frequent geothermal gradients in the North Sea are between 27.5 °C/km to 37.5 °C/km. However, there are sharp changes in geothermal gradients of more than 10 °C/km in the North Sea (Evans et al., 2003) which leads to uncertainties in CO₂ properties that dictate the design of pipeline infrastructure. To reflect this uncertainty, two temperature profiles have been chosen based on geothermal gradients of 27.2 °C/km and 40 °C/km. These cover a broad range of geothermal gradients for the North Sea. The hydrostatic gradient is then estimated based on

Table 2
Description of scenarios for open gas reservoirs (A), saline aquifers (B) and close gas reservoirs (C). Two geothermal gradients are denoted by the first number of the scenario name (1 for 27 °C/km and 2 for 40 °C/km). Two storage depths are denoted by the second number in the scenario name (1 for 1000 m and 2 for 2000 m). Only one depth and geothermal gradient are considered in Scenario C.

Scenario	Pipeline length	Water depth	Storage type	Subsurface conditions	Depth	Permeability range
Southern North Sea (SNS) basin characteristic scenarios						
A1.1	200 km	50 m	Gas reservoir	$T_R = 32.2\text{ °C}$ $P_R = 11.14\text{ MPa}$	1000 m	65 mD (1 mD–65 mD)
A1.2	200 km	50 m	Gas reservoir	$T_R = 59\text{ °C}$ $P_R = 21.56\text{ MPa}$	2000 m	65 mD (1 mD–65 mD)
A2.1	200 km	50 m	Gas reservoir	$T_R = 45\text{ °C}$ $P_R = 11.12\text{ MPa}$	1000 m	65 mD (1 mD–65 mD)
A2.2	200 km	50 m	Gas reservoir	$T_R = 85\text{ °C}$ $P_R = 21.44\text{ MPa}$	2000 m	65 mD (1 mD–100 mD)
B1.1	100 km	50 m	Saline aquifer	$T_R = 32.2\text{ °C}$ $P_R = 11.14\text{ MPa}$	1000 m	270 mD (1 mD–500 mD)
B1.2	100 km	50 m	Saline aquifer	$T_R = 59\text{ °C}$ $P_R = 21.56\text{ MPa}$	2000 m	270 mD (1 mD–500 mD)
B2.1	100 km	50 m	Saline aquifer	$T_R = 45\text{ °C}$ $P_R = 11.12\text{ MPa}$	1000 m	270 mD (1 mD–500 mD)
B2.2	100 km	50 m	Saline aquifer	$T_R = 85\text{ °C}$ $P_R = 21.44\text{ MPa}$	2000 m	270 mD (1 mD–500 mD)
Northern North Sea (NNS) basin characteristic scenarios						
C1.a ^a	100 km	100 m	Depleted Gas reservoir	$T_R = 83\text{ °C}$ $P_R = 18.9\text{ MPa}$	2500 m	790 mD
C1.b	100 km	100 m	Depleted Gas reservoir	$T_R = 83\text{ °C}$ $P_R = 24.56\text{ MPa}$	2500 m	790 mD

^a Value of permeability from (ScottishPower Consortium, 2005), only 10% of that is considered as effective permeability.

surface pressure, which is taken as seabed pressure and the saline water density (Bahadori et al., 2013).

2.2.2. Permeability

The absolute permeability is a measure of the ability of a porous medium to transmit fluids. When two or more fluids flow at the same time in a porous rock, each phase can only access a portion of the absolute permeability this is termed the effective permeability and is a function of both fluid saturation (*i.e.* the fraction of the pore volume occupied by the fluid) and the system's wetting characteristics. In such multiphase flow, the reduction in permeability for a given phase is quantified using the relative permeability (*i.e.* the ratio of effective permeability of a particular fluid, at a given saturation, to the absolute permeability of the rock). Burnside and Naylor (2014) review the implications of relative permeability and gas saturation in the injection of CO₂. Informed by this review, a relative permeability to CO₂ during drainage phase of 10% has been assumed in this work.

Permeability is also a directional property; therefore, anisotropy within the rock formation leads to a broad variation in permeability (0.01 mD–1000 mD). For instance, horizontal permeability (parallel to the flow direction) differs from vertical permeability (perpendicular to the flow direction) due to the process of compaction. For stores that are formed of layers with different properties, the values of absolute permeability are averaged using weighted, harmonic or geometric averages of the layers. Also, deterioration of the geological formation due to blockage or fracture can also result in reduced permeability and injection flows.

The factors affecting permeability are treated in the store model with one value for the effective permeability, as shown in Section 3.1, which represents an averaged vertical permeability of the store and includes all factors that might reduce it. Maintaining injection flow in a situation of reduced permeability requires the delivery pressure to the storage site to be increased or solutions such as hydro-fracturing near the well, drilling more injection wells, pressure relief wells, etc. Trade-offs between these options are investigated in Section 4.1.2 by looking at the sensitivity to large variations in effective permeability (Table 2).

2.2.3. Flow variation

CO₂ storage demand depends on several factors including operational patterns, load factors and efficiencies of CO₂ sources. In the case of power plants, CO₂ flows could vary over multiple timescales (*e.g.* hourly, daily or seasonally), depending, for example, on the penetration of renewable energy into the electricity grid or changes in coal to gas price ratios between summer and winter. They can typically operate either at base load (typically constant operation with design fuel input), part load (operation at reduced fuel input) or two-shifting (where the power plant operates during the day and shuts-down at night and weekends) resulting in variable CO₂ flow patterns. For this work, a baseline CO₂ flow of 143 kg/s (4.1 Mt/year) has been considered, which corresponds to 90% of the emissions of an 800 MW supercritical coal power plant with a net efficiency of approximately 45% pre-CO₂ capture (based on the low heat value of the fuel) and 80% annual load factor (Sanchez Fernandez et al., 2014). Sensitivity around this value is investigated using flow increments of ± 50% to the baseline.

2.3. Description of scenarios

The main characteristics of the scenarios considered are listed in Table 2. The key difference considered between the NNS and the SNS regions is the water depth, which determines the seabed pressure. Pipeline distances are expected to be longer in the NNS, however, the same distances are used for comparison purposes. In the scenarios considered, the entry pressure to the offshore pipeline is considered to be independent of the onshore delivery pressure and the target delivery pressure to the wellhead is at least 8.5 MPa in order to avoid phase changes in the pipeline. No insulation of the pipeline is assumed, therefore, the temperature at wellhead is approximated to be the seabed temperature, which is assumed to be 5 °C.

A distinction has been made between open gas reservoirs (Scenario A), saline aquifers (Scenario B), which are assumed to be located in the SNS basin, and closed gas reservoirs (Scenario C), located in the NNS basin. The average pressure in the store has been assumed to be constant with time and approximated by the hydro-

static pressure at a given depth in Scenarios A or B, or estimated at two different times in Scenario C based on the literature.

These three idealised cases of stores have been adopted to estimate the boundary conditions of the pipeline and well for each scenario. The impact of two geothermal gradients and permeability on well design, delivery conditions and pipeline design is evaluated using process simulation of the scenarios and adjusting the well and pipeline design conditions to maintain a given CO₂ flow of 4.1 Mt per year.

3. Modelling assumptions and methods

The flow behaviour of the store is crucial in determining the delivery conditions of pipeline networks to the storage site. The primary store characteristics that must be considered for this evaluation are the types of fluids in the store, flow regimes, store geometry and the number of flowing fluids in the store.

3.1. Reservoir modelling of radial flows

For this analysis, a simplified model for viscous fluid flow through a porous media is developed assuming radial homogeneous flow. In the absence of severe store heterogeneities, the flow of CO₂ will be in the radial direction for substantial distances from the wellbore. This is referred to here as the drainage radius (r_e). For distances beyond the drainage radius, it can be assumed that reservoir properties no longer influence the wellbore flow. Under steady state conditions, the injection velocity is given by Darcy's Law [Eq. (1)].

$$v = -\frac{Q}{A} = -\frac{k}{\mu} \times \left(\frac{\partial P}{\partial r} \right)_r \quad (1)$$

where v is the fluid velocity, Q is the volumetric flow, A is the cross-sectional area at radius r , k is the store effective permeability to CO₂ (here considered as a vertical average permeability), μ is fluid viscosity and $\partial P/\partial r$ is the radial pressure gradient. The negative sign takes into account the fact that pressure decreases as the radius increases from the wellbore radius to the drainage radius.

The CO₂ flow injection rate is obtained by integration of Eq. (1) between the wellbore radius and the drainage radius for two types of fluid flow, incompressible and compressible, under steady-state flow conditions and taking into account the area of the wellbore that is permeable. For incompressible fluids the CO₂ flow injection rate is given by:

$$Q = -9.868 \times 10^{-3} \times \frac{2 \times \pi \times h \times k}{\mu \times \ln \left(\frac{r_e}{r_w} - 0.75 \right)} \times (P_{BH} - P_R) \quad (2)$$

where Q is the volumetric flow (m³/s), h is the well bore height (m), k is the store permeability (mD), μ is fluid viscosity (cP), P_{BH} is the well bottom hole pressure (MPa) at wellbore radius, P_R is the reservoir or store pressure and r_w and r_e are wellbore radius and drainage radius respectively (m). The numerical constant is to convert Darcy units into the specified units.

If the fluid is compressible, integration of Eq. (1) using standard conditions (273 K and 0.1013 MPa) yields:

$$Q_{STP} = 8.357 \times 10^{-3} \times \frac{k \times h}{T_R \times \ln \left(\frac{r_e}{r_w} - 0.75 \right)} \times [m(P_{BH}) - m(P_R)] \quad (3)$$

where Q_{STP} is the volumetric flow in (Nm³/s) and T_R is the reservoir or store temperature. The function $m(P_i)$ in Eq. (3) is the pseudo-pressure potential for compressible fluids (Ahmed, 2001)

and requires evaluation of fluid properties at different temperatures and pressures using:

$$m(P_i) = \int_0^{P_i} \left(\frac{2 \times P}{\mu \times z} \right) \times dP \quad (4)$$

where z is the CO₂ compressibility factor. Integration of Eq. (4) is conducted numerically by determining the relevant properties of CO₂ for a range of pressures (from atmospheric to 30 MPa) and temperatures (from 32 °C to 125 °C) which cover the range of geothermal and hydrostatic gradients considered in this study. Property estimation is achieved through commercial software (AspenTech-2, 2006) using the Peng-Robinson equation of state with Boston-Mathias modifications (Mathias et al., 1991). This equation of state is considered acceptable for the purpose of estimating CO₂ properties relevant to transportation and storage (Mathias et al., 1991).

For depleted or closed reservoirs, the average pressure in the store cannot be considered constant and the change in reservoir pressure with time and initial conditions needs to be known. For these cases, a pseudo-steady state condition is assumed:

$$\left(\frac{\partial P}{\partial t} \right)_{r_e} = C_1 \quad (5)$$

where C_1 (MPa/y) is a constant related to the compressibility of the remaining fluids in the reservoir. The derivation of Eqs. (2)–(5) and the estimation of constants is described in detail in the supplementary information to this paper.

Whereas Eqs. (2) and (3) describe the pressure increase due to the introduction of fluids into a store another relevant application of flow analysis is to determine the pressure increase that will break the store rocks. To determine this limit, information about the lithostatic and fracture gradients of the rock formation must be known. The maximum pressure differential applicable at any depth would be the difference between the fracture gradient and the hydrostatic gradient [Eq. (6)]:

$$\Delta P_{max} = P_{max} - P_R \quad (6)$$

where ΔP_{max} is the maximum pressure difference (MPa) at a specific depth, P_{max} is the fracture pressure at the same depth (MPa) and P_R is the store pressure (MPa) given by the hydrostatic gradient for open reservoir and saline aquifers at the specific depth.

The determination of the fracture gradient depends on many characteristics of the geological formations and is also subjected to a certain degree of uncertainty. It is beyond the scope of this paper to analyse the many empirical correlations that exist to estimate fracture gradient. For this work, it is assumed 0.2262 bar/m (1 psi/ft) and 0.2095 bar/m (0.926 psi/ft) as lithostatic and fracture gradients respectively, which are representative of the scenarios studied (Burke, 2011). These are used to check that the estimated pressure increase at the well bottom hole, ΔP_{BH} , is below the fracture limit [Eq. (7)]:

$$\Delta P_{BH} = P_{BH} - P_R < \Delta P_{max} \quad (7)$$

3.2. Well design and performance

The number of wells required is determined by estimating CO₂ wellbore flow and the CO₂ velocity profile in the well for each scenario. Well velocity profiles are obtained with the simulation package Aspen Plus®. The maximum well diameter considered is 7".

Heat transfer resistance in the well casing is estimated from literature when enough data is provided (ScottishPower Consortium, 2005) or neglected when no information is available. It is believed

the latter assumption is practical to highlight possible bottlenecks since CO₂ injection takes place at higher temperatures and lower densities in this case, (*i.e.* less pressure is available for the CO₂ to permeate into the reservoir).

Based on these assumptions, the number of wells and diameter are optimised provided that the average fluid velocity in the well is equal or lower than the erosional velocity, given by:

$$v_e = \frac{C_2}{\sqrt{\rho}} \quad (8)$$

where v_e is the maximum allowable erosional velocity (m/s), ρ is fluid density at flowing conditions of temperature and pressure (kg/m³) and C_2 is a constant in the range of 100–125 (kg/m² s) as recommended by the American Petroleum Institute standard (API, 1991) depending on the presence of sand and operational factors (*e.g.* continuous or intermittent operation). We have assumed a value of 100 in this work. However, due to the fact that CO₂ will carry no sand particles it is likely that this value could be increased and higher fluid velocities be allowed in the well. A roughness value of 0.0457 mm (Mohitpour et al., 2003) is assumed in the well.

3.3. Pipeline design and performance

Pipeline wall thickness and diameter are determined, following the practice outlined by Wetenhall and co-authors (Wetenhall et al., 2014), from a pressure requirement at the wellhead of 8.5 MPa. This is so the CO₂ remains in the liquid phase throughout the pipeline. The pipeline design procedure was conducted using commercial software (Schlumberger, 2011) and the Peng-Robinson Equation of State (Peng and Robinson, 1976), Pedersen viscosity model (Pedersen et al., 1984) and the Beggs and Brill flow model with the Moody friction factor (Moody, 2016) as the flow equation. Manufacture and construction standards and practices for the CO₂ pipelines are assumed to be similar to those for natural gas pipelines. Consequently, plain carbon steel of grade EN10208 L450 (BS EN 10208-2, 2009) and a roughness value of 0.0457 mm (Mohitpour et al., 2003) is assumed. To determine the diameter, the inlet pressure to the pipeline is calculated based on a pressure gradient of 0.02 MPa/km and inlet temperature is assumed to be 30 °C. Varying the flow rate inside the pipeline affects pressure. Pressure in the pipeline cannot exceed the Maximum Allowable Operating Pressure (MAOP) which is calculated using

$$MAOP = \frac{20Wef_d\sigma_{SMYS}}{D} \quad (9)$$

where σ_h is the hoop stress in MPa, D is the outer diameter in mm, W is the wall thickness in mm, e is the weld factor (assumed to be 1), f_d is the design factor and σ_{SMYS} is the Specified Minimum Yield Stress in MPa. A design factor of 0.72 was selected which is suitable for pipelines along the seabed according to PD8010-2 (PD 8010-2:2015).

As shown later in this work, the wellhead pressure requirements depend on the storage site characteristics and reservoir properties. For higher wellhead pressure requirements, the pressure in the pipeline is evaluated and, if necessary, the pipeline design is adjusted so that the MAOP is not exceeded. The MAOP can be increased by selecting a higher grade steel, using a larger wall thickness or a smaller pipeline diameter.

4. Results and discussion

4.1. The Southern North Sea (SNS) basin scenario: saline aquifer and gas field storage

This scenario considers storage in open gas fields (Scenario A) and saline aquifers (Scenario B) that are located in the SNS basin.

The following sections investigate the influence of subsurface conditions and CO₂ permeability on the design of a delivery system (well and pipeline design and delivery conditions) for a baseline CO₂ flow of 4.1 million tonnes per year. Key issues for flow management are analysed by studying the scenario responses to increments in the baseline flow of $\pm 50\%$.

4.1.1. Impact of subsurface conditions on delivery conditions

Table 3 shows the final design of the offshore pipeline and storage system to deliver baseline flow for Scenarios A and B under various conditions. The design is obtained by process simulation following the assumptions in Section 3. Due to the lack of real life analogues, the conditions at the well bottom hole are assumed to be equal to the reservoir conditions (*i.e.* the well simulations are conducted assuming no thermal resistance, therefore, the temperature of the CO₂ injected is equal to its surroundings and determined by the geothermal gradient).

The simulation results for Scenarios A and B are shown in Fig. 3 in the form of pressure and temperature operating envelopes around the wellhead and well bottom hole and the velocity profiles along the well. The P - T diagram shows the pipeline inlet and wellhead conditions and final well bottom hole conditions together with the change in CO₂ pressure and temperature inside the well from wellhead to bottom hole. The CO₂ phase equilibrium and critical point are also shown in the figure to indicate any possible phase change within the well. The velocity profile for each scenario is also shown as a ratio between the fluid velocity and the erosional velocity.

The results show that subsurface conditions have a significant effect on CO₂ injection. This is reflected in the variations of the required pressure difference between the well bottom hole and reservoir conditions to deliver baseline flow. Nevertheless, for every scenario it is possible to deliver the exact baseline CO₂ flow starting from a wellhead pressure of 8.5 MPa by choking the flow. The pressure difference between the well bottom hole and reservoir is substantially lower for the saline aquifers (Scenario B) than for the gas reservoirs (Scenario A) at every subsurface condition due to the higher permeability of saline aquifers. As a result, the saline aquifer scenarios require fewer wells to deliver the same CO₂ flow (Table 3).

Given that drilling costs are one of the major cost drivers for wells (Element Energy et al., 2005), the diameter has been maximised in this study to minimise the number of wells. However, with large diameters the flow needs to be choked substantially to control the delivery conditions in the well bottom hole, which might result in a phase change within the well or very low temperatures around the choke valve because of Joule-Thompson expansion. This is especially true for the cases with subsurface conditions at 1000 m depth (Fig. 3). Therefore, the diameter is limited on the lower end by the velocity, which should not exceed the erosional velocity, and on the higher end by the operating conditions at wellhead to avoid a phase change. The latter depends on the subsurface conditions and, under the framework of this work, is an issue for reservoirs at lower depths (1000 m). A possible solution would be decreasing delivery pressure at the wellhead with successive steps of heating as suggested in (ScottishPower Consortium, 2005) but this will transfer the risk of two-phase flow to the pipeline.

With respect to velocity, Fig. 3 shows that the cases at 1000 m depth have velocities that are closer to the erosional velocity than the cases at 2000 m depth. This is due to the fact that the diameter has been decreased to create additional back pressure and avoid phase changes in the well. Therefore, these cases will also have a limited flexibility to accommodate higher flows due to potential erosion and lower flow rates due to phase change.

Table 3
Design details of Scenarios A (open gas reservoirs) and B (saline aquifers).

	Scenarios A and B							
	A1.1	A1.2	A2.1	A2.2	B1.1	B1.2	B2.1	B2.2
	Reservoir				Saline aquifer			
Water depth [m]			50				50	
Reservoir depth [m]	1000	2000	1000	2000	1000	2000	1000	2000
Temperature (T_R) [°C]	32	59	45	85	32	59	45	85
Pressure (P_R) [MPa]	11.14	21.56	11.12	21.44	11.14	21.56	11.12	21.44
Water salinity [%wt]			10				10	
Permeability (k) [mD]			65				270	
	Well design							
Design flow [Mt/year]			4.1				4.1	
No. Wells [–]	4	4	5	4	3	3	3	3
Well radius (r_w) [cm]	6.35	8.89	7.62	8.89	7.11	8.89	7.62	8.89
Well bore height (h) [m]			30				30	
Wellhead pressure (P_{WH}) [MPa]			8.5				8.5	
Bottom hole pressure (P_{BH}) [MPa]	12.35	23.94	13.37	23.73	11.31	21.72	11.30	21.56
	Pipeline design							
Pipeline length [km]	200				100			
Inlet temperature (T_i) [°C]	30				30			
Inlet pressure (P_i) [MPa]	10.196				9.968			
Inner diameter [mm]	488.0				439.4			
Wall thickness (W) [mm]	10				8.8			
D/W [–]	50.8				51.9			
MAOP [MPa]	12.76				12.48			

4.1.2. Impact of store permeability on delivery conditions

Permeability has a direct impact on CO₂ injection rates that can be directly quantified from Darcy's Law of fluid flow. Upon a change in permeability, there are different options that can be applied to maintain a constant injection flow equal to the baseline. One option is to modify the pipeline delivery conditions and, if necessary, the pipeline design to accommodate changes in pressure requirement for injection. Another option is to modify the well design (i.e. drilling more wells) to maintain injection flow given the variations in permeability. Both options have been considered to evaluate the pressure response sensitivity of the scenarios in Section 4.1.1 to different permeability values and are illustrated in Fig. 4 for the open gas field scenarios (Scenarios A). The effects of phenomena that can lead to reduced permeability, as discussed in Section 2, are assumed to be lumped into the value of permeability in Eq. (3) (k), which can be considered as the overall average effective permeability.

The first option assumes that the well design is fixed and illustrates the scenario where existing platforms and wells are being used and, therefore, no changes to the storage site are possible. Fig. 4a)–c) shows the variations in pressures along the system as a result of changing permeability for Scenarios A. As shown in Fig. 4, small reductions in permeability can be handled by the system without changing the delivery pressure from the pipeline. Reductions in permeability down to 50 mD are possible for Scenarios A without substantial changes. However, larger permeability reductions require higher bottom-hole pressure drops and, in turn, higher wellhead pressures than the baseline to maintain injection flow rate. The inlet pressure to the offshore pipeline has to increase accordingly to ensure sufficient pressure for injection. The rise in pressure required for injection depends on the subsurface conditions, which influence CO₂ properties, and well design, which influences the back pressure created in the well from friction. Assuming the well design is kept constant, the wellhead pressure and pipeline inlet pressure increase significantly for values around 10 mD. To deliver CO₂ at higher pressures to the wellhead the design of the pipeline would have to be modified to increase the MAOP. Changes to the pipeline design (Fig. 4d) are reflected in the

outer diameter to wall thickness ratio (D/W) relative to the reference case presented in Table 3. The D/W parameter decreases with respect to the reference case to allow higher pressures within the pipeline without changing the grade of steel when higher delivery pressures are required to maintain the injection rate.

At the same time, the maximum pressure drop at bottom-hole cannot be exceeded to avoid fracturing the geological formation surrounding the wellbore. Fig. 4c) shows that most Scenarios can be realised safely for a fracture pressure gradient of 0.9 psi/ft. However, Scenario A2.1, with a reservoir temperature of 45 °C is an exception. In this case, values of the permeability below 18 mD will result in bottom-hole pressure drops higher than the fracture limit.

The alternative option to maintain injection flow rate consists of increasing the number of wells to reduce the wellhead pressure whilst maintaining the pipeline design fixed. The pressures along the system and number of wells are represented for this option in Fig. 4e) to h), which shows that wellhead pressure can be maintained between 8.5 MPa and 10 MPa by increasing the number of wells to 10 for values of permeability in the region of 10 mD for all the scenarios. However, further reductions in permeability will require a higher number of wells which may not be economically feasible.

Although not illustrated in Fig. 4, similar pressure responses and design analysis are obtained for Scenarios B (saline aquifers). The data to support this argumentation is provided in the supporting information to this paper. The key differences with Scenario A are related to the differences in well design for the reference cases (Table 3). Assuming the well design is kept constant, the pipeline inlet pressure increases significantly for permeability values that are higher for Scenarios B than Scenarios A. If the pipeline design is kept constant, Scenarios B require an increase in the number of wells over the reference design at higher values of permeability than Scenarios A. This is related to the fact that the reference design for Scenarios B is based on a significantly higher value of permeability, which results in fewer wells and smaller diameters in the reference design than in Scenarios A. This, obviously, affects the back pressure created in the well when reducing permeability resulting in higher pressure requirements.

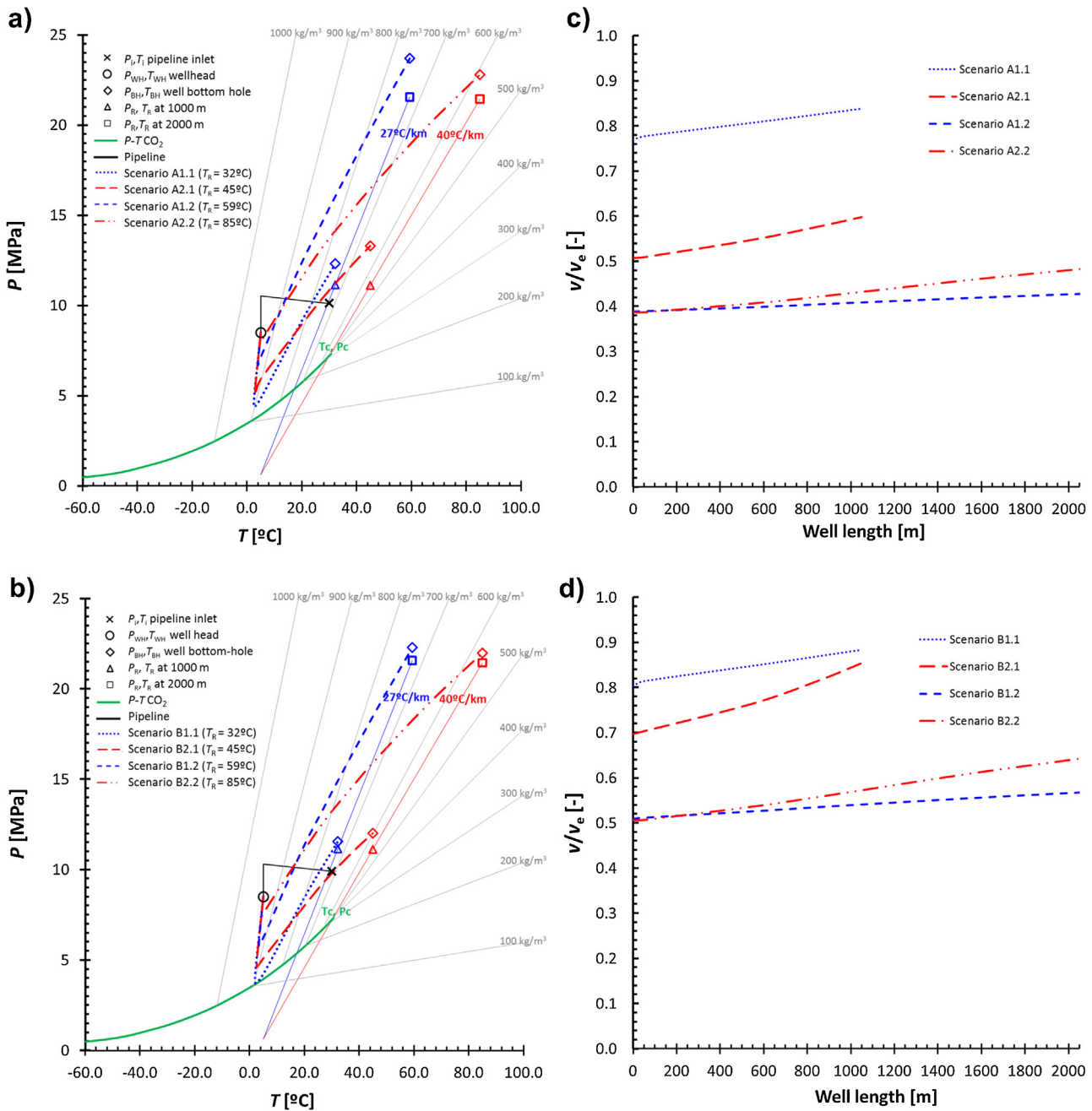


Fig. 3. Operating conditions for the injection of 143 kg/s (4.1 Mt CO₂/year) assuming constant permeability. Pressure-temperature diagrams for pipeline and well operation in (a) open gas fields (Scenario A) and (b) saline aquifers (Scenario B). The solid lines indicate the CO₂ phase equilibrium, reservoir conditions for two hypothetical geothermal gradients 27 °C/km and 40 °C/km and pipeline conditions. The dash lines indicate well conditions. x Indicates pipeline inlet conditions, o indicates the wellhead conditions, ◇ indicates the well bottom-hole conditions. △, □ represent reservoir conditions at 1000 m and 2000 m depth respectively. (c), (d) Corresponding fluid velocities to erosional velocity ratios in the well as a function of well length for scenarios A and B respectively.

These interactions between pressure response and design procedures and margins (related to the properties of the geological formations in question) imply that there are possibilities at the storage site to accommodate permeability uncertainty, which could act as a guide for the screening of storage sites, allowing them to be classified according to the ability to deal with permeability uncertainty.

In order to quantify further the contributions of the subsurface conditions to the delivery pressure requirements, an additional evaluation has been conducted for Scenarios A, which determines the required pressure difference between the well bottom hole and reservoir while keeping the same well bore design for all subsur-

face conditions. This could mean that, in this particular case, some of the scenarios will result in two phase flow within the well or pressure drops above the fracture limit of the geological formation. Fig. 5a) represents the necessary pseudo-pressure, defined in Eq. (3), normalised by the reservoir temperature that is necessary to maintain the baseline injection flow as the permeability is reduced, assuming that all parameters describing the well bore geometry are kept constant (the number of injection wells, well diameter, well bore height and reservoir drainage radius). Since the well bore geometry is kept constant, the normalised pseudo-pressure potential required to deliver the baseline flow is only a function of permeability, as shown in Eq. (3). However, establishing the

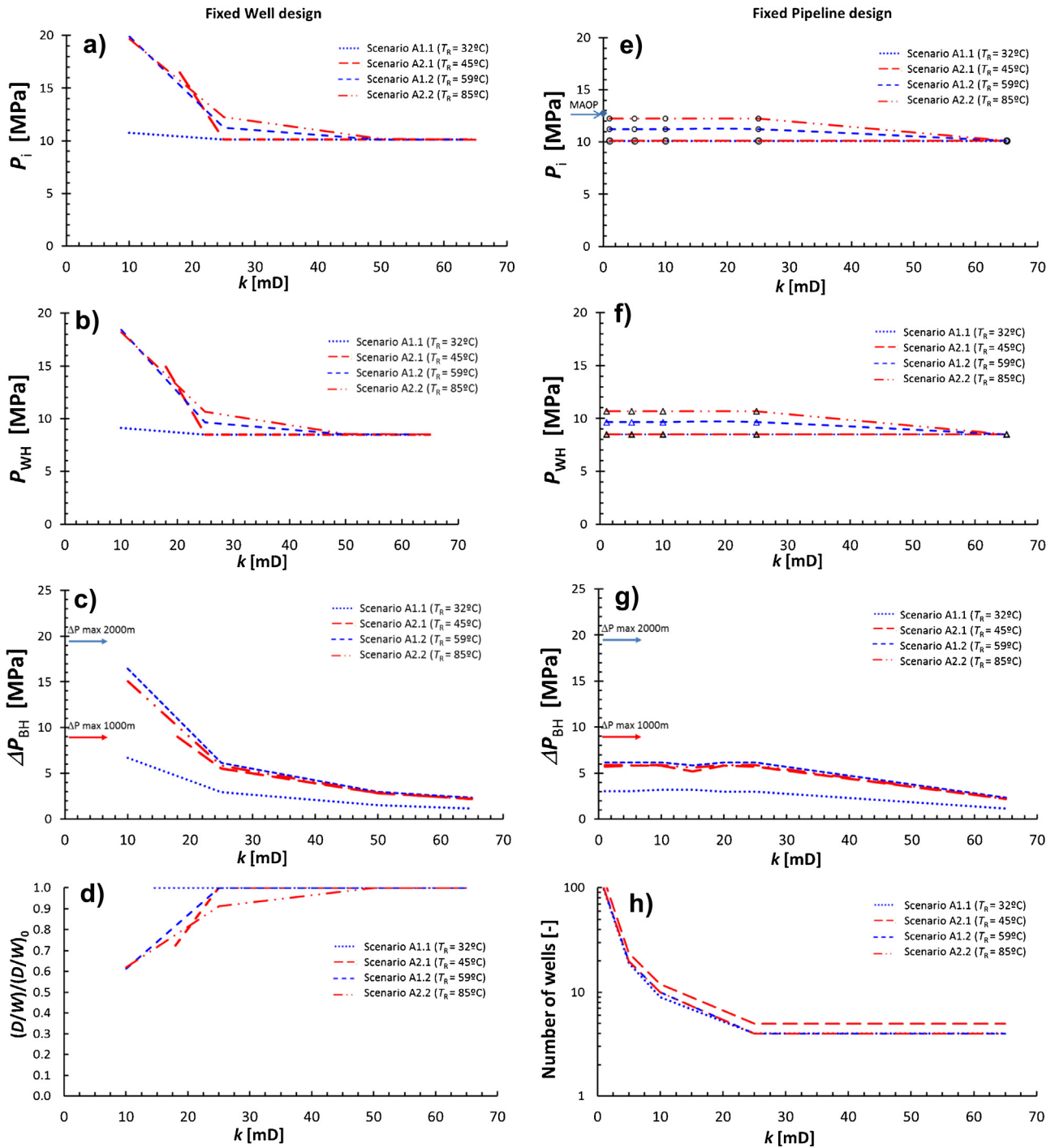


Fig. 4. Scenarios A, open gas reservoirs. Influence of effective permeability (k) on a) pipeline inlet pressure (P_i), b) wellhead pressure (P_{WH}), c) bottom hole pressure drop (ΔP_{BH}), d) ratio of pipeline outer diameter to wall thickness (D/W) normalised for reference (D/W)₀ (Table 3) for the option of keeping well design fixed and e) pipeline inlet pressure (P_i), f) wellhead pressure (P_{WH}), g) Bottom hole pressure drop (ΔP_{BH}), h) number of wells and for the option of keeping pipeline design constant.

required pseudo-pressure to maintain injection flow depends on the reservoir temperature and pressure, as shown in Fig. 5b), which represents the temperature-normalised pseudo-pressure potential for pure CO₂ estimated at various reservoir temperatures. Fig. 5 shows an example for a given permeability of 30 mD. From Fig. 5a) it can be seen that a pseudo-pressure requirement per unit temperature of 22 MPa²/cP K is necessary to maintain injection flow. Fig. 5b) shows that the pressure differences between the reservoir and well bore that are necessary to establish this gradient vary with temperature and pressure (determined by depth). The pressure dif-

ference decreases in the order 45 °C > 59 °C > 85 °C > 32 °C, which is determined by the differences in CO₂ viscosity and compressibility at the given temperatures.

However, the final required wellhead pressure, as shown in Fig. 4, is also a function of well design. In the case of Scenario A2.1 with a reservoir temperature of 45 °C it had to be altered to comply with the design basis (Section 4.4.1) by increasing the number of wells and decreasing the well bore diameter. Moreover, the required delivery pressure at the wellhead for Scenario A1.2 (with a reservoir temperature of 59 °C) is lower than that of scenario A2.2

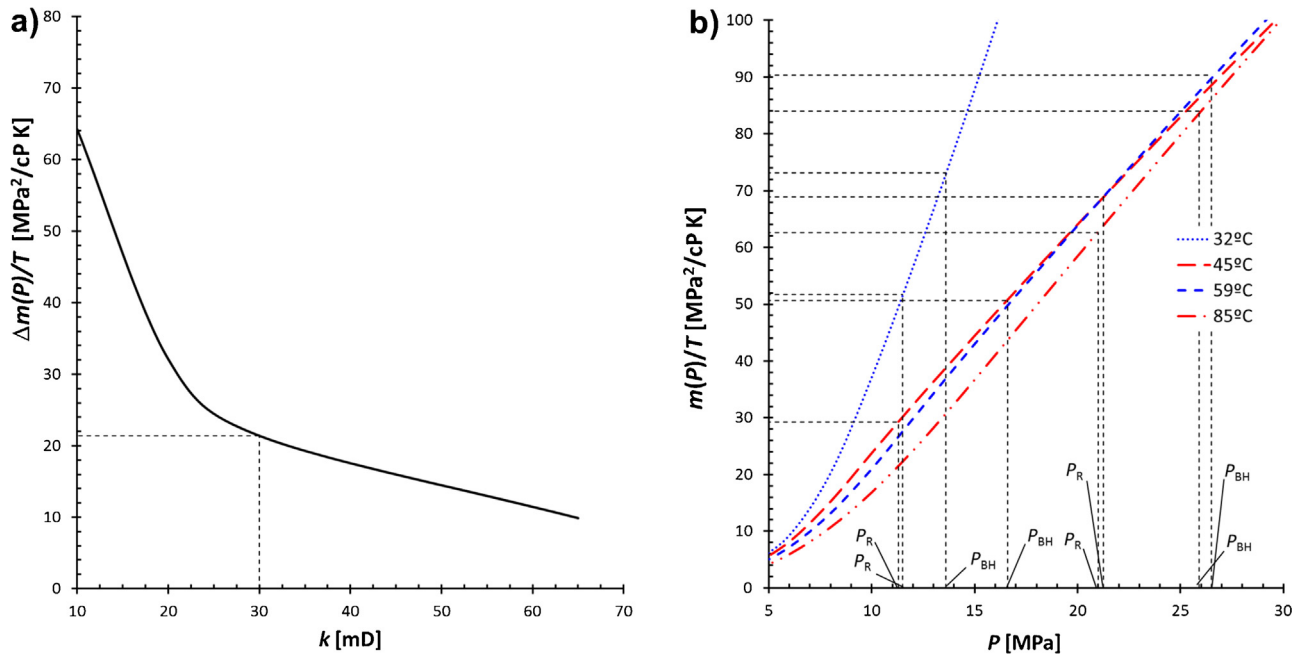


Fig. 5. a) Well bore pressure requirements calculated with Eq. (6) to inject 4.1 Mt CO₂ per year for fixed design conditions (4 wells of 7" diameter) at the same injection temperatures and pressures as in Scenarios A. b) Calculated CO₂ pseudo-pressure Eq. (5) at different reservoir temperatures.

(with a reservoir temperature of 85 °C) until a permeability of 15 mD is reached. Although the required pressure difference at bottom hole is lower for the 85 °C case, the lower density of CO₂ in this case results in a higher wellhead pressure requirement.

Based on model results for these scenarios, where injection is always conducted in the supercritical phase, it seems that the impact of permeability on the pipeline and well design is a strong function of reservoir temperature. Permeability impact is at its lowest for temperatures around the critical point (normally expected in shallow reservoirs). Depths of around 2000 m with reservoir temperatures between 59 and 85 °C will have a higher permeability impact. However, lower depths of 1000 m with temperatures around 45 °C require the highest pressure drops at the well bottom hole to maintain flow and, unless pressure is decreased by drilling more wells, will require the highest delivery pressure.

4.1.3. Impact of store demand variation (CO₂ flow variability) on delivery conditions

The majority of properties discussed so far have an impact on store flexibility. It has been considered that the store site is flexible to CO₂ flow when it can accommodate $\pm 50\%$ changes in the injection flow without operational issues (two phase flow, high erosion, etc.) (Sanchez Fernandez et al., 2015). In order to evaluate storage site flexibility and analyse the impact of store properties on CO₂ flow flexibility, simulations with flow variations of $\pm 50\%$ over baseline flow were performed for selected scenarios and store properties.

Subsurface conditions have an impact on store flexibility. Fig. 6 shows the responses of the gas reservoir scenarios (Scenario A) to variations in CO₂ flow. Flow variation is possible by choking the flow except for Scenario A1.1 (1000 m deep and with the lower geothermal gradient). In this case, it is impossible to decrease the flow without creating a phase change in the well. Moreover, increasing the flow is possible for Scenario A1.1 but the resulting velocity in the well exceeds the erosional velocity. On the other hand, Scenario A2.2 (2000 m depth with the higher geothermal gradient) requires a higher wellhead pressure (8.9 MPa) than the baseline case to deliver an additional 50% to the baseline flow.

The scenario analysis indicates that flow variation might be limited depending on the subsurface conditions. In the scenarios with lower pressure requirements (lower geothermal gradients) decreasing CO₂ flow might lead to a phase change in the well and increasing CO₂ flow can lead to velocities above the erosional velocity. On the other hand, in the scenarios with higher pressure requirements (higher geothermal gradients) increasing CO₂ flow might require higher wellhead pressure. The latter is less likely to be a technical obstacle since the available pressure can be increased by increasing the inlet pressure in the pipeline. To avoid erosion issues, flexibility should be built into the baseline design to provide a well diameter that leads to smooth operation for the whole flow operating window. However, this is more difficult for the scenarios at 1000 m depth (Fig. 3), where the erosional velocity needs to be higher to provide back pressure and avoid phase changes in the well. A possible solution could be the use of advanced materials or coating for these cases so that the erosional velocity can be increased.

Reservoir permeability will also impact store flexibility. Lower permeability will result in a higher pressure differential at the well bottom hole (Fig. 5). Increasing CO₂ flow in this situation will require higher pressures at wellhead as permeability decreases (Fig. 4). The options to deal with permeability changes are identical to the options discussed in Section 4.1.2.

4.2. The Northern North Sea Scenario: gas field storage

This section analyses the impact of subsurface conditions on Scenario C. Changes in permeability and flow variation are similar to those described in Sections 4.1.2 and 4.1.3.

4.2.1. Impact of subsurface conditions in delivery conditions for depleted gas reservoirs

Temperature and pressure for open reservoirs can be estimated based on geothermal and hydrostatic gradients at various depths. In the case of depleted gas reservoirs, reservoir pressure may be estimated from well production data. For this analysis available published data from several studies has been used to

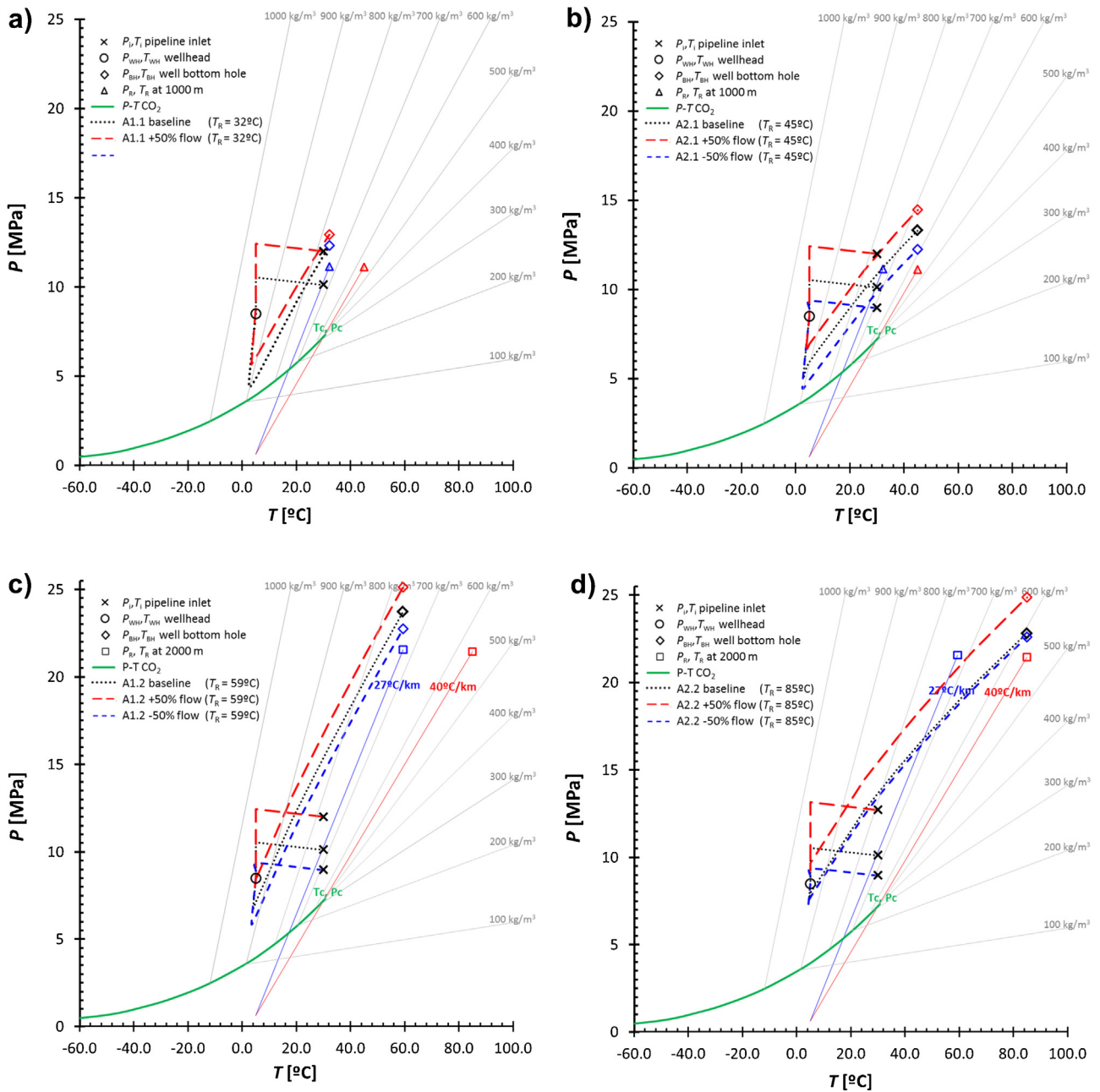


Fig. 6. Operational conditions and responses to variations in CO₂ storage flows for a) Scenario A1.1, b) Scenario A2.1, c) Scenario A1.2 and d) Scenario A2.2 (open gas reservoirs). The solid lines indicate the CO₂ phase equilibrium, and subsurface conditions for two geothermal gradients (for 27 °C/km and 40 °C/km). The dash lines indicate pipeline and well conditions for different CO₂ flow rates. × indicates the pipeline inlet conditions, ○ indicates the wellhead conditions, ◇ indicates the well bore conditions. △, □ represent reservoir conditions at 1000 m and 2000 m depth respectively.

determine temperature and pressure gradients for these NNS cases (ScottishPower Consortium, 2005).

Scenarios C1.a and C1.b have been modelled by considering two estimates of the pressure gradients presented in (ScottishPower Consortium, 2005) (7.69 MPa/km and 10.14 MPa/km), which represent the initial pressure gradient for first injection and the pressure gradient after 20 Mt CO₂ have been injected. The geothermal gradient for both cases is the same (33.8 °C/km) and yields a temperature of 83 °C at a reservoir depth of 2500 m (ScottishPower Consortium, 2005). Nevertheless, the reported temperature around the well bottom hole is substantially lower than the reservoir temperature due to the injection of cold CO₂. This means that heat transfer between the well and its surroundings is limited (the well will likely be insulated). Therefore, well simulations include energy balances, where

the heat transfer coefficient is adjusted to yield the same injection temperature (17 °C–35 °C) as in the referred studies (Table 4).

This is a key difference compared with the discussion in Section 4.1, where all scenarios considered injection at a temperature above the critical point. In this case CO₂ is injected as a liquid phase with a pressure above critical pressure but temperature below the critical temperature. Eq. (6) no longer applies and Eq. (3) has been used to estimate the well bottom hole pressure necessary for injection.

The operating envelope for the wellhead and well bottom hole is represented in Fig. 7, together with the reservoir conditions and the ratio of the fluid velocity in the well to the erosional velocity.

The operating envelope around the bottom hole is in dense conditions where the density of CO₂ is between 900 and 1000 kg/m³. This results in higher pressures at the bottom hole than required to

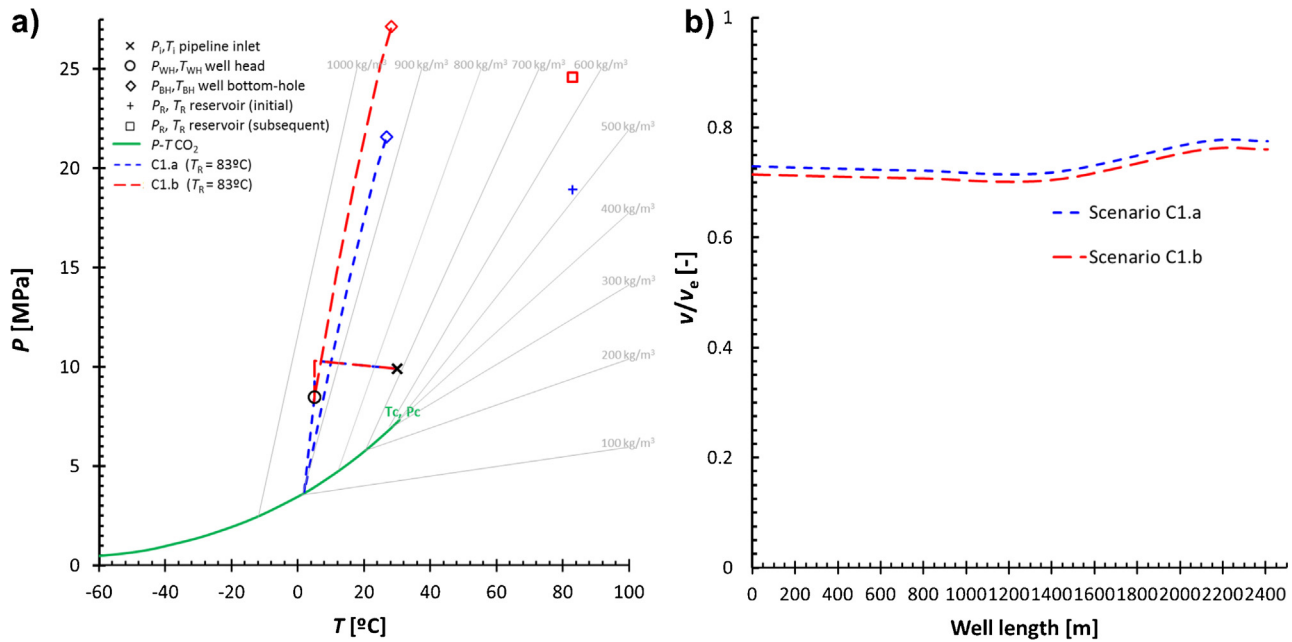


Fig. 7. (a) Pressure-temperature diagram for the injection of 143 kg/s (4.1 Mt CO₂/year) in Scenarios C. (b) Corresponding ratios of fluid velocities to erosional velocities in the well. The solid line indicates the CO₂ phase equilibrium, the dash lines indicate pipeline and well conditions. × indicates pipeline inlet conditions, ○ indicates the wellhead conditions. ◇ indicates the well bore conditions, + indicates the reservoir conditions for first CO₂ injection, □ indicates reservoir conditions after 20 Mt CO₂ injection. Scenarios developed with constant permeability of 79 mD (Gas reservoir).

Table 4
Design details of Scenarios C (depleted gas reservoirs).

	Scenarios C	
	C1.a	C1.b
Reservoir		
Water depth [m]	100	100
Reservoir depth [m]	2500	2500
Temperature (T_R) [°C]	83	83
Pressure (P_R) [MPa]	18.9	24.56
Water salinity [%wt]	10	10
Permeability (k) [mD]	79	79
Well design		
Design flow [Mt/year]	4.1	4.1
No. Wells [-]	4	4
Well inner diameter [in.]	4.2	4.2
Well bore height [m]	30	30
Wellhead pressure (P_{WH}) [MPa]	8.5	8.5
Bottom hole pressure (P_{BH}) [MPa]	21.60	27.13
Pipeline		
Pipeline length [km]	100	
Inlet temperature (T_i) [°C]	30	
Inlet pressure (P_i) [MPa]	10.196	
Inner diameter [mm]	488.0	
Wall thickness (W) [mm]	10	
D/W [-]	51.9	
MAOP [MPa]	12.76	

inject the baseline flow. As shown in Fig. 7, the operating conditions at the wellhead cannot be further manipulated without having two phase flow in the well. Instead, the diameter of the last section of the well was decreased to create additional pressure drop. At the same time the erosion coefficient was increased to 175. This value falls outside the guidelines from the American Petroleum Institute standards (World Bank, 2016), therefore, the material of this segment needs to be selected from the ones that have high erosion resistance. The changes in diameter and erosional velocity are shown in Fig. 7b).

4.3. Analysis of storage flexibility

Flow variation in storage sites is possible by choking the inlet flow to the well. The choke valve is designed to effectively dissipate the fluid energy limiting fluid velocity and it can be designed to be totally linear in their flow rate to decrease or increase CO₂ flow. The analysis in Section 4.1.3 shows that open reservoirs at shallower depths are less accommodating to a reduction in CO₂ flow rates. The limitation arises from the proximity of the required wellhead pressure to the CO₂ vapour-liquid equilibrium curve. Possible solutions to these issues are the use of smaller well diameters, or to decrease the diameter of the well segments close to the well bottom hole in order to create back pressure. However, these solutions result in higher fluid velocities and may limit the ability of the well to accommodate higher flow rates. The impact of having high fluid velocities inside the well on the life span of the infrastructure should also be considered and, when appropriate, materials should be selected to extend the use of the infrastructure.

With respect to the pressure response of the reservoirs, storage sites where the reservoir pressure is hydrostatic (open reservoirs) can provide a simpler solution for increased flexibility than depleted hydrocarbon reservoirs (closed reservoirs). In the latter case, the creation of back pressure is only required initially to control injection and, as the reservoirs become saturated with CO₂, the pressure requirements for injection increase and the additional back pressure is no longer required. When the initial back pressure is created by decreasing well diameter there is no flexibility to release pressure at a later stage. Depending on the capacity and pressure response of the reservoirs, the delivery pressure requirements can increase significantly in order to maintain or even increase CO₂ injection rates through the operational lifetime of the reservoir. An obvious solution to release pressure at this stage is to drill more wells. For an optimal solution, an economic evaluation is suggested to analyse the trade-offs of operating costs of delivering at higher pressures or investing in additional wells.

Additionally, the impact of a change in permeability on injection depends strongly on the temperature of the store. The analysis in

Section 4.1.2 shows that the impact on delivery pressures is dependent on CO₂ viscosity, compressibility and density. In the cases studied, reservoir temperatures around 45 °C resulted in the highest impact on the delivery pressures, which significantly influences how the storage site will accommodate changes in CO₂ flow.

Finally, there are scenarios that have not been considered in this work which would merit investigation. One case typically encountered in power plant operation is two-shifting operation. The framework of this has not been considered here. This operation results in intermittent flows that may lead to a complete cycle of the well (*i.e.* complete shut-down and subsequent start-up).

5. Conclusions

The development of CO₂ transportation pipeline networks that can accommodate CO₂ flow variation is an important aspect of the development of CCS infrastructure. Previous work has shown that CO₂ flow variation due to the flexible operation of CO₂ sources, such as power plants, results in higher transportation costs. This work investigates aspects related to storage site performance that also have an impact on the overall behaviour of CCS transportation infrastructure. In the context of the examples examined in this paper, which consider storing CO₂ in various locations in the North Sea, it has been found that it is very important to consider uncertainty in store properties and the expected CO₂ flow variation during pipeline and injection system design for transportation infrastructure planning. If variations in key geological store properties and the required level of injection flow flexibility are not considered, the transportation system can fail to deliver the required CO₂ flow at the required conditions depending on the actual store properties.

A selection of delivery and storage scenarios have been evaluated considering variations in important store properties, including subsurface conditions (store pressure and temperature), permeability and pressure response to CO₂ injection flow, showing a strong dependence between store property variability and the resulting operation of the storage site.

The analysis indicates that wellhead conditions are substantially influenced by subsurface conditions. The operational conditions of the storage site are limited by the proximity of the wellhead conditions to the CO₂ vapour-liquid equilibrium line and the maximum fluid velocities inside the well. For the scenarios studied, it is found that the shallower stores in locations with lower geothermal gradients present a higher risk of two-phase flow due to the consequence of a reduction in wellhead pressure necessary to maintain CO₂ injection flow. It is also found that reductions in CO₂ injection flow, due to a period of lower load operation of the CO₂ source, could not be accommodated in these cases. By analysing the operational issues related to CO₂ flow variations of ±50% over the baseline flow for all scenarios, it can be concluded that enabling storage site flexibility is simpler in the deeper open reservoirs or stores at 2000 m depth, or in other words, stores with an initial average pressure above 20 MPa.

For all the scenarios, a reduction in store permeability increases the requirements for pressure delivery and decreases storage site flexibility to variations in CO₂ flow. Possible solutions presented in this paper include an increase in delivery pressure (with associated modifications to the pipeline design) or an increase in the number of wells. Both solutions depend on the store conditions (mainly temperature) and the design of the storage system and design margins (related to the back pressure created inside the well). The examples analysed show that there are possibilities at the storage site to accommodate permeability uncertainty. Discrimination between options can be made by using an economic evaluation, which is suggested as future work.

Finally, although the flow analysis presented here is based on assumptions specific to the North Sea, the evaluation methodology is transferable to other locations and could act as a guide for the screening of storage sites, allowing them to be classified according to the ability to deal with uncertainty in store performance.

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Appendix A. Supplementary data

Supplementary data associated with this article can be found, in the online version, at <http://dx.doi.org/10.1016/j.ijggc.2016.06.005>.

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