ieaghg

Zep
Zero emissions platform

The Costs of CO_2 Storage

Post-demonstration CCS in the EU

European Technology Platform for Zero Emission Fossil Fuel Power Plants

This document has been prepared on behalf of the Advisory Council of the European Technology Platform for Zero Emission Fossil Fuel Power Plants. The information and views contained in this document are the collective view of the Advisory Council and not of individual members, or of the European Commission. Neither the Advisory Council, the European Commission, nor any person acting on their behalf, is responsible for the use that might be made of the information contained in this publication.

Rue du Trône 61
1050 Brussels, Belgium
info@zero-emissionplatform.eu
www.zeroemissionsplatform.eu

Contents

Rue du Trône 61
1050 Brussels, Belgium
info@zero-emissionplatform.eu
www.zeroemissionsplatform.eu

Executive Summary

Founded in 2005 on the initiative of the European Commission, the European Technology Platform for Zero Emission Fossil Fuel Power Plants (known as the Zero Emissions Platform, or ZEP) represents a unique coalition of stakeholders united in their support for CO_2 Capture and Storage (CCS) as a critical solution for combating climate change. Indeed, it is not possible to achieve EU or global CO_2 reduction targets cost-effectively without CCS – providing 20% of the global cuts required by 2050.[1] Members include European utilities, oil and gas companies, equipment suppliers, national geological surveys, academic institutions and environmental NGOs. Its goal: to make CCS commercially available by 2020 and accelerate wide-scale deployment.

ZEP is an advisor to the EU on the research, demonstration and deployment of CCS. Members of its Taskforce Technology have therefore now undertaken a study into the costs of complete CCS value chains – i.e. the capture, transport and storage of CO_2 – estimated for new-build coal- and natural gas-fired power plants, located at a generic site in Northern Europe from the early 2020s. Utilising new, in-house data provided by ZEP member organisations, it establishes a reference point for the costs of CCS, based on a "snapshot" in time (all investment costs are referenced to the second quarter of 2009).

Three Working Groups were tasked with analysing the costs related to CO_2 capture,[2] CO_2 transport[3] and CO_2 storage respectively. The resulting integrated CCS value chains, based on these three individual reports, are presented in a summary report.[4]

This report focuses on CO_2 storage.

As the IEA Greenhouse Gas R&D Programme[5] (IEA GHG) was planning a similar project on storage cost estimation, this work has been carried out as a joint venture.

- **Realistic cost estimates based on ZEP members' extensive knowledge and experience**

As external cost data proved scarce and the development of a generic model prohibitive from a time and resources perspective, this study utilised the technical and economical knowledge of ZEP member organisations who have substantial research and experimental experience in the area of CO_2 storage and associated costs. A "bottom-up" approach, based on potentially relevant cost components, was taken and data consolidated into a robust and consistent model.

Thanks to the diverse representation within the group and the use of external parties for review, all data and assumptions were challenged, vetted and verified – guided by the principle of consensus. Assumptions have also been detailed in order to facilitate future reference and comparisons with specific projects (see Chapter 2).

The availability and capacity of suitable storage sites proved a key consideration: data were made available from the EU GeoCapacity Project[6] database, comprising 991 potential storage sites in deep saline aquifers (SA) and 1,388 depleted oil and gas fields (DOGF) in Europe. In terms of *numbers*, the majority are below the estimated capacity of 25-50 Mt, so more than five reservoirs are needed to store the 5 Mtpa[7] reference single stream of CO_2 for 40 years, which is assumed to be uneconomical. However, the majority of estimated

[1] International Energy Agency (IEA), World Energy Outlook, 2009
[2] www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html
[3] www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html
[4] www.zeroemissionsplatform.eu/library/publication/165-zep-cost-report-summary.html
[5] www.ieagreen.org.uk
[6] www.geology.cz/geocapacity
[7] For the commercial phase

capacity is found in very large DOGF and SA (>200 Mt capacity). In the commercial phase, exploration activities should therefore focus on large reservoirs which are capable of storing CO_2 from both single *and* multiple sources.

In order to cover the range of potential storage configurations and still provide reliable cost estimates, storage was divided in six main "typical" cases according to major differentiating elements – DOGF vs. SA; offshore vs. onshore (Ons/Offs); and whether or not there is the possibility of re-using existing (legacy) wells (Leg/NoLeg). N.B. The decision was made to restrict this costing exercise to reservoirs with a depth of 1,000 to 3,000 m.

For each of these cases three scenarios ("Low", "Medium" and "High") were defined to yield a final storage cost range estimate. A cost breakdown for project components/phases is also given and sensitivity analyses carried out to determine which of the 26 cost elements considered carried the most impact on the final cost. To allow a transparent comparison between cost figures for the various cases, a 1:3 source-to-sink ratio was assumed as the base setting in all cases. This may represent a slightly conservative assumption for SAs and is quantified in the sensitivity analysis.

• The results

The resulting total storage cost ranges are presented in Figure 1. A key conclusion is that there is a wide cost range within each case, the "High" cost scenario being three to up to 10 times more expensive than the "Low" cost scenario. This is mainly due to natural variability between storage reservoirs (i.e. field capacity and well injectivity) and only to a lesser degree to uncertainty in cost elements.

Despite the wide cost range, however, the following trends stand out:

- Onshore is cheaper than offshore.
- DOGF are cheaper than SA – even more so when they have re-usable legacy wells.
- The highest costs, as well as the widest cost range, occur for offshore SA.

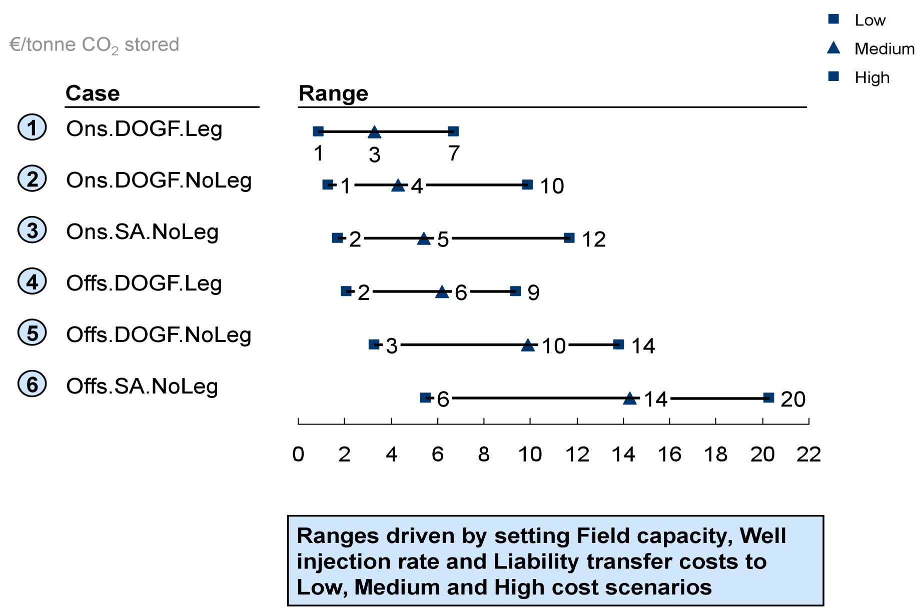


Figure 1: Storage cost per case, with uncertainty ranges – triangles correspond to base assumptions

The capacity of storage reservoirs in Europe, according to current understanding, exhibits a mirror image of these cost trends:

- There is greater storage capacity offshore than onshore, especially for DOGF.
- There is greater storage capacity in SA than in DOGF.

In other words, the cheapest storage reservoirs also contribute the least to total available capacity.

A sensitivity study was carried out to assess the effect of eight major cost drivers – field capacity, well capacity (injectivity times the lifetime of the well), cost of liability, well completion, depth, WACC, number of new observation wells and number of new exploration wells. The impact of the variations of the remaining 18 cost elements was found not to be significant enough to be taken into account.

These sensitivity studies revealed the following:

- Field capacity has either the largest or second largest effect in all cases – the selection of storage reservoirs based on their capacity is therefore a key element in reducing the cost of CO_2 storage.
- Furthermore, well capacity is often an important contributor to variations in cost. Storage reservoir selection, design and placement of wells are therefore of key importance for onshore storage. For offshore cases, well completion costs are the second contributor to variations in cost, reflecting the specificities of that environment.

Key conclusions

- Location and type of field (available knowledge and re-usable infrastructure), reservoir capacity and quality are the main determinants for costs:
  - onshore storage is cheaper than offshore
  - Depleted Oil and Gas Fields (DOGF) are cheaper than deep saline aquifers (SA)
  - larger reservoirs are cheaper than smaller ones
  - high injectivity is cheaper than poor injectivity.
- Costs vary significantly from €1-7/tonne CO_2 stored for onshore DOGF to €6-20/tonne for offshore SA.
- The cheapest storage reservoirs (large, onshore DOGF) are also the least available as they are not common.
- High pre-FID (Final Investment Decision) costs for SA reflect the higher need for exploration compared to DOGF and the risk of spending money on exploring aquifers that are ultimately not suitable. A risk-reward mechanism must therefore be put in place for companies to explore the significant aquifer potential in Europe.
- Although well costs are ~40-70% of total storage costs, the wide ranges in total costs (up to a factor of 10 for a given case) are driven more by (geo)physical variations than by the uncertainty of cost estimates.
- Because of these (geo)physical variations, there is a need to develop exploration methods that will increase the probability of success and/or lower the costs of selecting suitable storage sites.
- The EU CCS Demonstration Programme is essential, since a number of operational storage facilities will contribute significantly to verifying storage performance. However, it is highly likely that the costs per tonne of CO_2 stored associated with demonstration projects will be very significantly higher than those for projects in the early commercial phase.

1 Study on CO_2 Storage Costs

1.1 Background

In 2006, ZEP launched its Strategic Deployment Document (SDD) and Strategic Research Agenda (SRA) for CO_2 Capture and Storage (CCS). The goal: to provide a clear strategy for accelerating its deployment as a critical technology for combating climate change. The conclusion: an integrated network of demonstration projects should be implemented urgently EU-wide in order to ensure CCS is commercially available by 2020.

In 2008, ZEP then carried out an in-depth study[8] into how such a demonstration programme could work in practice, from every perspective – technological, operational, geographical, political, economic and commercial. This approach was endorsed by both the European Commission and European Council; and by 2009, two key objectives had already been met – to establish funding for an EU CCS demonstration programme and a regulatory framework for CO_2 storage. An updated SDD followed in 2010.[9]

As importantly, ZEP has published its long-term R&D plan[10] for next-generation CCS technologies to ensure rapid deployment post-2020. Now, ZEP experts have identified the key cost elements and forecast the long-term cost of commercial-scale CO_2 storage – in the context of CO_2 capture and transport solutions. Indeed, this has been undertaken in parallel with similar work on capture[11] and transport[12] costs, and should be assessed in conjunction with these results.

As the International Energy Agency Greenhouse Gas R&D Programme (IEA GHG)[13] was planning a similar project on storage cost estimation, this work has been carried out as a joint venture.

1.2 Use of ZEP members' extensive data and experience

First, cost forecasting work was organised into three Working Groups within ZEP's Taskforce Technology – for Capture, Transport and Storage, respectively.

The original intention of the Working Group on Storage was to extract comparable cost data from published reports, align with the assumptions agreed by the group and present the results as a range of costs. However, as described below, existing literature does not readily lend itself to storage cost comparisons, either because of the lack of information on CAPEX and OPEX, or because of the wide range of assumptions made.

The development of a generic model for storage cost estimation was also decided against because the limited time and resources available would not allow sufficient stringency and quality assurance. This approach would also have gone beyond the agreed task of presenting credible estimates for the costs of large-scale CO_2 storage in both the demonstration phase *and* a commercial market.

Instead, the group decided to use its own comprehensive technical and economic knowledge of the various cost elements as ZEP member organisations have substantial research and experimental experience in the area of CO_2 storage and associated costs (see page 37 for a list of members). Thanks to the diverse representation within the group and the use of competent external parties for review, all data and assumptions were challenged, vetted and verified in order to ensure quality control.

[8] www.zeroemissionsplatform.eu/library/publication/2-eu-demonstration-programme-co-2-capture-storage.html
[9] www.zeroemissionsplatform.eu/library/publication/125-sdd.html
[10] www.zeroemissionsplatform.eu/library/publication/95-zep-report-on-long-term-ccs-rad.html
[11] www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html
[12] www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html
[13] www.ieagreen.org.uk

Indeed, the work has been guided by the principle of consensus: ad hoc subgroups were formed for specific tasks and consultations made both with colleagues from the other working groups in Taskforce Technology and member organisations. Discussions were held in an atmosphere of openness and in areas with high uncertainties, numerous iterations were performed to find the most likely scenarios and best available consensus. N.B. Certain critical technology, cost data or references may be of a proprietary nature, such that it may not have been possible to disclose certain details for commercial reasons.

1.3 A consistent and transparent approach

This report describes the technical data, assumptions and literature referenced for the cost estimates presented, documented in a format which should provide value to any reader. Indeed, considerable emphasis has been placed on detailing the assumptions made in the calculations in order to facilitate future reference and comparisons with individual projects (see pages 10-23).

It should therefore be accessible to any reader with a reasonable understanding of the main complexities and drivers for the CCS industry. For those who are not familiar with the subsurface environment – especially within the context of CO_2 storage – the report, "A Technical Basis for Carbon Dioxide Storage"[14] provides excellent conceptual and technical background information. The ZEP website[15] also features an animation by way of introduction to CO_2 storage, as well as information on all aspects of CCS.

In order to cover the range of potential storage configurations and still provide reliable cost estimates, CO_2 storage was divided in six main "typical" cases, according to major differentiating elements (see Section 3.2, page 14). Ranges for cost items were then evaluated to give the most likely value, together with a lower and upper bound. For each case, a "Low", "Medium" and "High" scenario was constructed to calculate cost ranges for each case.

The validity of the results is of critical importance. No attempt was made to directly compare the outcome of this work with the costs of current storage demonstration projects, either operational or planned/studied. Indeed, CO_2 storage has not yet reached the commercial phase that is the study's frame of reference. All existing projects are therefore "special cases" associated with a demonstration environment. However, a framework for comparing costs associated with demonstration projects with those of a commercial project is presented in Chapter 7.

ZEP has striven both for internal consistency of the hypotheses underlying the computations and consensus on the validity of these hypotheses. By the nature of the process, individual data points will remain undisclosed, but considerable effort has been made to detail cost evaluation procedures and basic assumptions. By sharing both the model structure and the assumptions, it is hoped that the reader will gain sufficient insight to allow for some level of judgement as to the strength and quality of the work presented herein. This should also lead to discussions and the opportunity to use the current work for updates in a few years' time when more tangible data becomes available.

1.4 Literature and references

There are only a limited number of articles, studies and reports focusing specifically on the cost of CO_2 storage in a CCS context. However, some reports were particularly useful when comparing technical assumptions and, ultimately, in validating the results of ZEP's work (see page 38). In 2008, McKinsey and Company published its report "Carbon Capture and Storage: Assessing the Economics", which highlighted the need for both DOGF *and* SA as storage options, on- *and* offshore. This was confirmed in ZEP's Proposal for an EU CCS Demonstration Programme (see footnote 8). A comparison between the results of this study and that of McKinsey is presented in Chapter 9.

[14] Published by the CO_2 Capture Project, 2009: www.co2captureproject.org/pubsearch.php
[15] www.zeroemissionsplatform.eu/ccs-technology/storage

2 Assumptions

For consistency across the ZEP study on the costs of CCS, a number of common assumptions were established and applied in all three Working Groups on CO_2 capture, transport and storage. Those with the highest impact on storage cost estimates are summarised below.

N.B. In order to remain independent of the choice of capture technology, storage costs relate to tonnage of CO_2 stored, not abated. Conditions for the delivery of CO_2 to the storage site are specified in the parallel report on CO_2 transport.

2.1 Cost of energy

Parasitic emissions caused by storage activities are considered as low, due to limited energy requirement of CO_2 storage.

2.2 Project lifetime

Project operational life is assumed to be 40 years of injection for commercial projects and 25 years for demonstration projects, followed in both cases by 20 years of post-injection monitoring, before hand-over of liability to the Competent Authority. The commercial case is taken as the base case, while the demonstration phase is modelled using a sensitivity analysis (shortening the lifetime of the project). N.B. 40 years is longer than the average expected lifetime of a wellbore without intervention; this translates into associated costs for wells, which are detailed in Chapter 3.

2.3 CO_2 stream

One of the most important assumptions is an annual storage rate of 5 Mt (5 million metric tonnes), thus requiring 200 Mt of CO_2 storage capacity over a 40-year plant lifetime. This corresponds to the CO_2 emissions of a typical coal-fired power plant equipped with CO_2 capture. Variation of this rate has not been modelled explicitly, but is dealt with by varying the available storage field sizes.

The CO_2 is assumed to be delivered from the capture plant by pipeline or ship in dense phase and in a state that is “fit-for-purpose” for injection, hence no further pressurising or conditioning equipment is required at the injection site.

2.4 Availability of storage

The availability and capacity of suitable storage sites is a key consideration. Data were made available from the EU GeoCapacity Project database, comprising 991 potential storage sites in deep saline aquifers (SA) and 1,388 depleted oil and gas fields (DOGF) in Europe. In Figure 2, the number of potential storage reservoirs is reported according to estimated capacity – for SA and DOGF, both onshore and offshore.

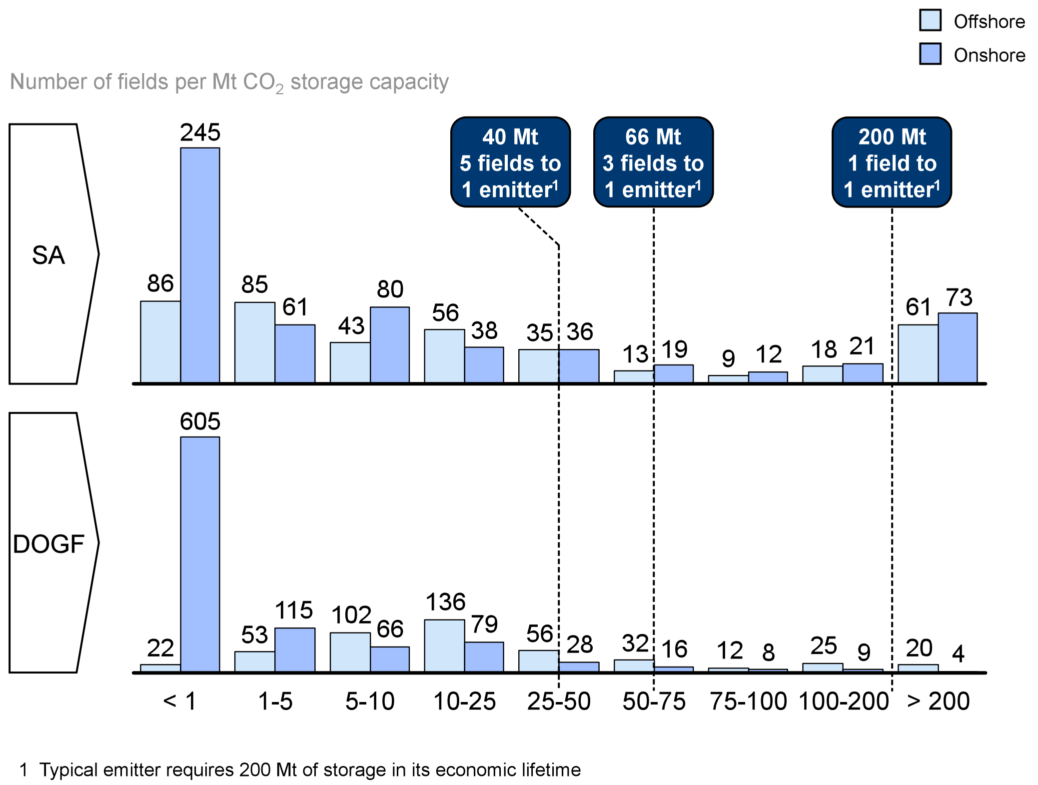


Figure 2: Distribution of storage capacity in Europe – number of fields (after GeoCapacity final report, EU project SES6-5183180)

Figure 3 presents this information in another way, where cumulative available capacity is shown instead of the number of fields, where an average capacity was computed for each size. Note that this total available storage capacity is an approximation calculated by multiplying the number of fields per category with the mid-point of the field size range of the category (assumed to be 400 Mt for the >200 Mt category).

Note that in terms of *numbers*, a majority are below the estimated capacity of 25-50 Mt, so more than five reservoirs are needed to store the 5 Mtpa[16] reference single stream of CO_2 for 40 years, which is assumed to be uneconomical. This is also supported by the sensitivity analysis on the size of fields (see Section 5, p.24). However, the majority of estimated *capacity* is found in very large DOGF and SA (>200 Mt capacity). In the commercial phase, exploration activities should therefore focus on large reservoirs which are capable of storing CO_2 from both single *and* multiple sources.

Whilst the GeoCapacity Project has provided the best available dataset for estimated storage capacity across Europe as a whole, the limitations of the data need to be understood. Capacities are reported at the "effective" level according to the classification scheme devised by the Carbon Sequestration Leadership Forum (CSLF). Here, geological and certain technical factors are taken into account but other factors, such as legal and regulatory requirements, are not considered.

Furthermore, whilst Figure 2 and Figure 3 show that SA have higher potential capacities than DOGF, there is greater uncertainty in capacity estimation due to more limited characterisation data and understanding of

[16] For the commercial phase

long-term trapping mechanisms. This highlights the need for exploration data acquisition for large SA, as these not only represent the largest portion of available storage, but could also show considerable scope for economies of scale due to their size.

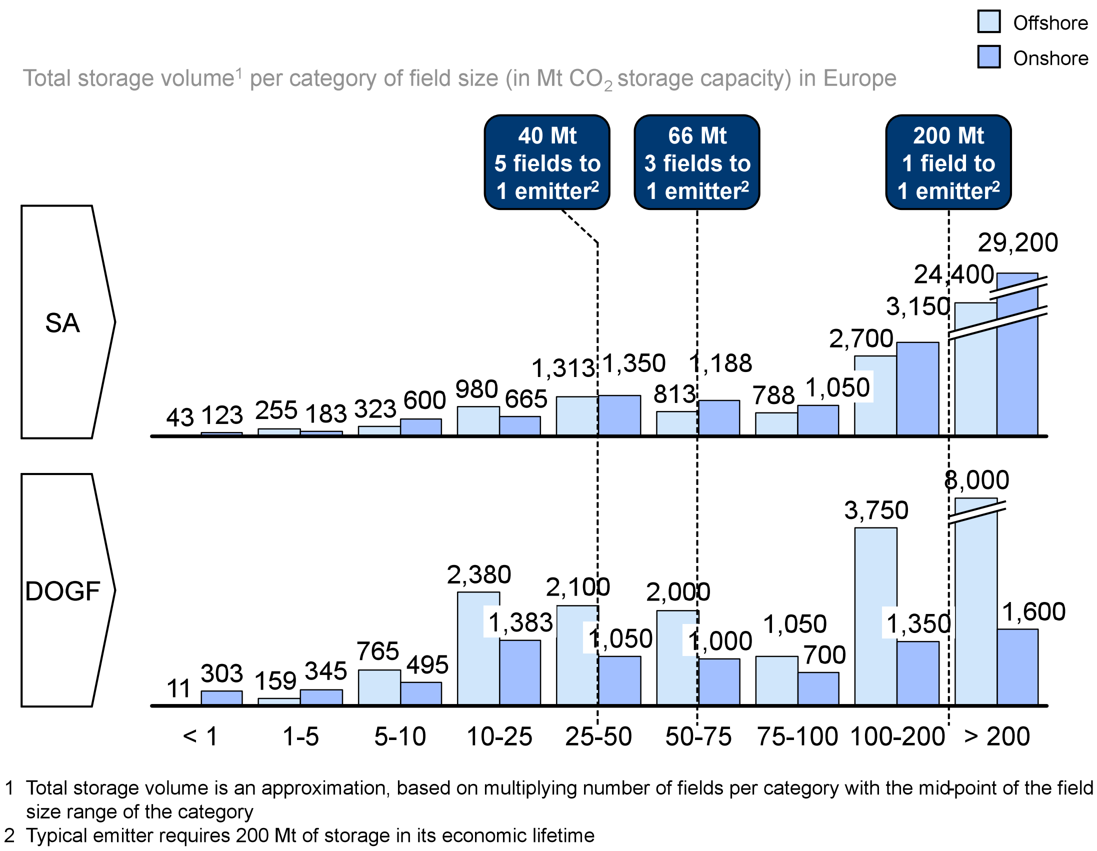


Figure 3: Distribution of storage capacity in Europe – overall capacity (after GeoCapacity final report, EU project SES6-5183180)

To allow a transparent comparison between cost figures for the various cases, a 1:3 source-to-sink ratio has been assumed as the base setting in all cases. This may represent a slightly conservative assumption for SA and is quantified in the sensitivity analysis presented in Chapter 6.

The decision was made to restrict this costing exercise to reservoirs with a depth of 1,000 to 3,000 m. Even though a depth of over 800 m is sufficient to ensure that the CO_2 is in a dense phase in the reservoir, the cost implications for depths shallower than 1,000 m have not been taken into account. However, the effect of reducing the depth is likely to be smaller than the uncertainties on the well cost. N.B. As the bulk of storage capacity in Europe lies at depths of 1,500 m and below, the majority of CO_2 storage will take place at these depths.

2.5 Currency and time value of money

The cost basis is European and all reported costs are in euros. As input is based on global experience in a mainly dollar-based industry, the currency exchange rate used here for conversion is $1.387 = €1. Costs are split between capital expenditure (CAPEX) and operational costs (OPEX). The CAPEX/OPEX split applied here is specific to storage projects and operations.

The cost of capital for investment – here designated as WACC (Weighted Average Cost of Capital) – is assumed to be 8% as a base case. WACC could be of particular importance because of the long duration of projects. Because of this, sensitivity studies were also carried out with values of WACC of 6% and 10%, in line with previously published work (McKinsey, 2008).

CAPEX was annualised and discounted back to present using WACC. OPEX was not adjusted, i.e. it was assumed that the effect of inflation would be cancelled out by the effect of discounting. N.B. The results vindicate this hypothesis, e.g. the learning rate applicable to OPEX costs has very little effect on the overall costs.

Post-closure MMV costs are handled in the same way as decommissioning costs, with one additional step: the costs (occurring in years 41-60) are first summed, then converted into Present Value using the discount factor for year 40, and then annualised. As a consequence, the discount factor used (1/21.7 for 8% WACC) is somewhat too large. However, because costs are incurred so late in the life of the project, their contribution to the cost of storage is already very small, so the effect of using the correct discount factor (which is even smaller) is not material.

2.6 Enhanced recovery of hydrocarbon not in scope

CO_2 for Enhanced Oil Recovery (EOR) has been around for several decades and there are more than 70 ongoing or past EOR projects, mainly in the USA and Canada. Most of these use CO_2 of volcanic origin so the abatement effect is limited. In Europe, EOR experience is sparse, from only a few oil fields in Hungary and Turkey (both now defunct) and an ongoing operation on a small field in Croatia. However, there is much to learn from the practical experience of these EOR projects when it comes to, for example, material choices, recompletion of wells, cementing, injection performance etc.

Work in this report has been focused strictly on CO_2 storage for the sake of CO_2 abatement and includes only DOGF and SA. As the business case for CO_2 abatement is quite different to that of CO_2 EOR, no economical application of CO_2 for EOR, Enhanced Gas Recovery (EGR), Enhanced Coal Bed Methane (ECBM) or other uses has been factored in. The storage potential related to such economic uses is, in any case, small relative to DOGF and SA. It should be noted, however, that locally, the use of CO_2 in commercial operations may be a pathfinder for further CO_2 and CCS activities.

Nevertheless, interest in EOR comes from the positive cash flows generated and in the postponing of the field closure. The additional oil produced has to be balanced by the CO_2 breakthrough to the well producer, which can be quick and generate a circulation of CO_2 and thus create the need for CO_2 reprocessing. The EU project ECCO[17] illustrates this topic and shows the necessity of reinvestment at the end of the field's life.

[17] ECCO – European value Chain for CO_2: www.sintef.no/Projectweb/ecco

3 Storage Cases

This chapter describes the cases which have been considered for this exercise and which provide the canvas for comparing the cost of various options for CO_2 storage in Europe.

3.1 Frame of reference

CCS deployment can be divided into three distinct phases: demonstration, early commercial deployment and full commercial deployment. The costing exercise reported here focused on early commercial deployment, with demonstration projects assessed as a special case for comparison. The effect of learning has been used to simulate the difference between early commercial deployment and full commercial deployment.

3.2 Base cases

Three factors (offshore vs. onshore, DOGF vs. SA, the possibility of re-using existing wells or not), could result in eight different base cases. However, it was assumed that, at the early commercial deployment phase, SA will typically be undeveloped without existing wells suitable for use by projects, i.e. there would be no re-usable wells for SA.

Six distinct cases have therefore been used for the cost modelling:

Case	Location	Type	Re-useable legacy wells	Abbreviation
1	Onshore	DOGF	Yes	Ons.DOGF.Leg
2	Onshore	DOGF	No	Ons.DOGF.NoLeg
3	Onshore	SA	No	Ons.SA.NoLeg
4	Offshore	DOGF	Yes	Offs.DOGF.Leg
5	Offshore	DOGF	No	Offs.DOGF.NoLeg
6	Offshore	SA	No	Offs.SA.NoLeg

Table 1: Storage cases

For each of these cases, three values were defined for all cost elements – minimum, most likely and maximum – to allow for sensitivity analyses, both on the final cost per tonne of CO_2 stored and to highlight which cost elements matter most (in terms of cost) for each case.

3.3 Data quality

Commonly, DOGF exhibit a larger amount of data compared to undeveloped SA. Significant cost differences between DOGF and SA will therefore arise in terms of acquiring the necessary data to assess, characterise, develop and monitor the storage sites. Furthermore, the cost of exploration to find a suitable site is relatively low for DOGF compared to SA, as most of these costs have already been committed a long time ago, whereas costs for exploring aquifers will still have to be incurred.

3.4 Field capacity

Based on GeoCapacity Project data (Section 2.4, page 10), the estimated capacity of individual sites varies considerably, with only a minority exceeding 200 Mt. The base case has been taken to be three storage sites for a typical CO_2 stream. Two other cases were considered for sensitivity analysis of the effect of site capacity: five fields and one field for each CO_2 stream.

3.5 Re-use of wells ("legacy wells")

In the case of SA, it was assumed that no existing well could be re-used for the purpose of CO_2 storage. However, the possibility of exploration wells being re-used for either injection or monitoring was taken into account (see also page 21).

In the case of DOGF, two separate cases were evaluated: the first considers the re-use of existing wells, subject to including possible workover costs to ensure their suitability as injection/monitoring wells. In the second case, existing wells are considered to be unsuitable for re-use. An optimisation process needs to be established in order to balance the workover of an adequate number of wells vs. drilling new wells on the one hand and, on the other hand, properly abandoning wells that may represent a risk to permanent CO_2 containment.

In that sense, the two cases considered may be taken as boundary cases for what could actually happen. For simplification purposes, it was assumed that sites with wells that can technically and/or financially not be remediated, or would only achieve an unacceptable well integrity, will be de-selected from the site selection process.

4 Storage-specific Assumptions

This chapter first describes the lifecycle associated with CO_2 storage. The lifecycle is a convenient method of describing the complete process for CO_2 storage, starting with an extremely costly exploration phase; followed by the injection period; and ending in the abandonment of the wells and reservoir. Underlying hypotheses are then described and key assumed parameter values (minimum, most likely and maximum) are explained.

4.1 Storage-specific assumptions – storage lifecycle

4.1.1 Phases of storage

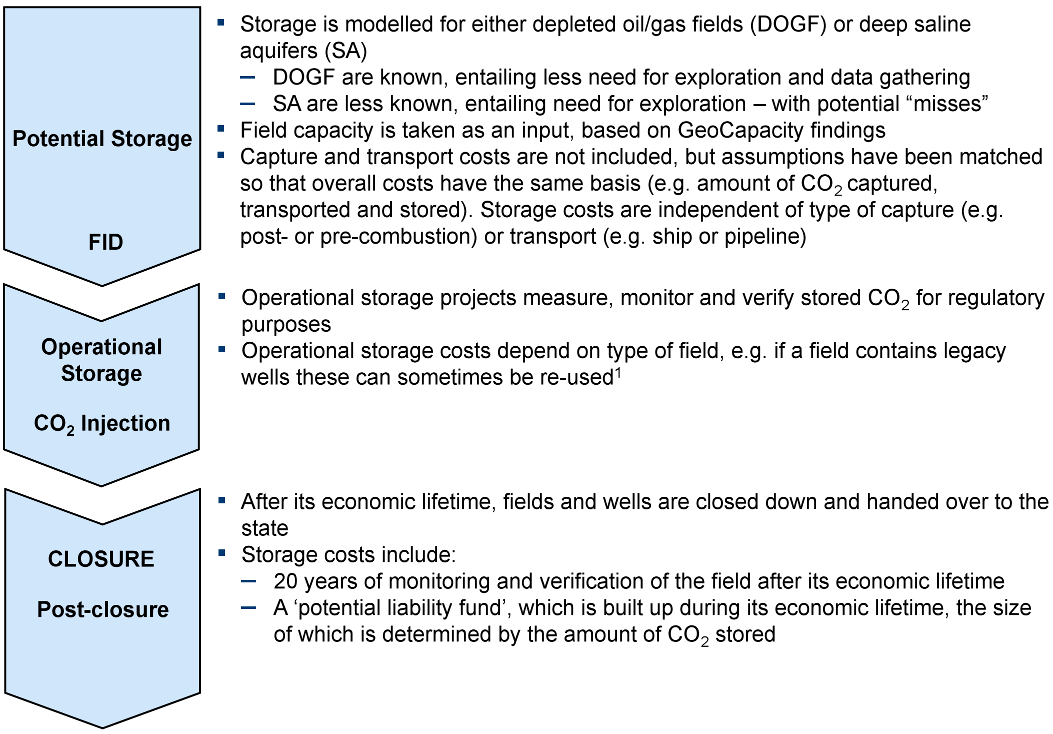


Figure 4: CO_2 storage lifecycle, phases and activities

The storage lifecycle shown in Figure 4 has been divided into three phases:

1. The potential storage phase, or pre-FID (Financial Investment Decision) phase, which includes:
    - An initial screening of multiple sites
    - The characterisation of selected site(s)
    - The permitting process.

This phase ends with the operator taking FID.

2. The operational phase, which includes:

- The Field Development Plan
- The development of the site, plus associated construction of the necessary infrastructures, including wells
- The commissioning of the site
- The injection operations.

3. The post-closure phase, starting with the closure of the site itself. This phase includes the decommissioning of the wells and site. Additional monitoring activities are also required for 20 years after the end of injection operations. The Competent Authority may then validate the transfer of liabilities that ends the operator's responsibility to monitor the site.

4.1.2 Pre-final investment decision (FID) phase

The pre-FID phase encompasses a pre-selection phase, during which a portfolio of suitable sites is created and up to three sites from this portfolio are appraised. It reflects the exploration risk that has to be taken into account in a full cost assessment exercise.

The geological and petrophysical studies required for appraisal are modelled as a lump sum per site. In the case of DOGF, the cost of such studies is estimated to be half of the costs required for the studies of SA. Some of these cost savings are related to the fact that reservoir studies of DOGF may be based on prior knowledge from oil or gas production. In the case of SA, it is assumed that a total of two to seven (on average four) exploration wells across the three sites will be needed prior to the selection of one site. Associated costs include drilling and logging of these wells.

After the pre-selection phase, it is assumed that, on average, one final selected site is fully characterised. In case it has not yet been performed, an appraisal seismic survey is performed on this final selected site (which usually only applies to SA). For DOGF, it is expected that a well-established reservoir characterisation is available and a seismic survey is generally not required. In addition, a seismic survey performed during the appraisal phase of a SA development is considered a baseline measurement for subsequent monitoring activities that will take place during the operational phase.

In all cases, injection tests estimated at €1 million per site are assumed. These are required to appraise the injectivity and capacity of the field at large scale.

The process of storage permit application is also completed within this phase prior to FID. A lump sum of €1 million is assumed for this type of activity.

4.1.3 Monitoring, measurements and verification (MMV)

Monitoring, Measurement and Verification (MMV) covers items that occur across the various phases of the storage lifecycle. This sub-section is therefore dedicated to presenting the MMV programme assumed for this costing exercise.

At this stage, EU regulatory requirements are focused on the objectives of monitoring. There is no consensus between industrial stakeholders or the certifying entities on adequate technologies, relevant frequency of measurements campaigns, spatial extent and density of monitoring techniques. They will be dependent on storage site specificities, as well as the confidence of operators, certifying entities, and public opinion.

In this section, ZEP arbitrarily proposed Low, Medium and High scenarios for MMV, based on its analysis of MMV programmes deployed on pilot projects or early demonstration projects, knowing that site specificities may significantly alter this programme in some cases. As an example, it was assumed that regulatory requirements to compare dynamic reservoir simulation models with historical CO_2 saturations and pressure perturbation may be fulfilled with 4D seismic, with the addition of equipped monitoring wells. Note that, in any case, time-lapse seismic and monitoring wells are the major cost items for such MMV programmes – there is no loss of generality in focusing on these items for the purposes of cost estimation.

Further details on the monitoring programme are given in the following paragraphs. Costs are split between the initial CAPEX, prior to operations; the OPEX; and the overall cost of post-closure monitoring.

The initial CAPEX for MMV includes the following:

- A baseline is performed prior to injection operations for all the necessary monitoring techniques and specifically for seismic, when required. In the case of SA, it is assumed the 3D seismic performed in the pre-FID phase for site characterisation will be the seismic baseline for later measurements. This specific cost is therefore not included in the MMV baseline. In the case of DOGF, however, 3D baseline seismic may be necessary prior to injection and the corresponding cost is included.
- The Low and Medium scenarios include the cost of drilling and completing one monitoring well for onshore storage and none for offshore storage. The High scenario assumes two monitoring wells for onshore storage and one for offshore storage. The costs of deploying permanent monitoring systems at the monitoring and injection wells are included in the well equipment costs.
- Note that such a choice presents a balance between seismic (which provide indirect measurements on the fate of the CO_2, but ensure full coverage of the site), and monitoring wells (which provide direct measurements but only at the location of the well). In particular, the fact that offshore wells are more complex to construct, whereas offshore seismic is of a very robust quality, was taken into account when building the offshore monitoring scenarios.

The OPEX for MMV includes the following:

- It is assumed that 3D or 2D seismic surveys are performed every five years. When recurring surveys are included, they are more restricted in coverage than the 3D survey required for characterisation. Their cost is taken as half the cost of a full 3D seismic survey. As technology evolves, the possibility of using only 2D seismic lines may also arise.
- Recurring MMV may also include logging, surface gas or seawater column monitoring, shallow aquifers monitoring or other types of measurements, such as surface deformation with InSAR, gravimetry, induced microseismicity, etc.
- The costs of interpretation and modelling studies that integrate the measurements are included in the MMV costs.

As for monitoring during post-closure phase:

- Monitoring activities are required after the end of injection operations prior to the transfer of liabilities. As these activities happen in the 20-year post-closure phase and 40 years after the start of injection, their cost has to be discounted over time in accordance with the expected value of money. Hence, the cost of all monitoring activities was summed up and fed into the cost model as an aggregated cost, discounted over time and added to the CAPEX.
- The EU Directive 2009/31/EC on the geological storage of CO_2 states in Article 18 that the responsibility for the storage site is transferred i) if when all available evidence indicates that the stored CO_2 will be completely and permanently contained ii) a minimum period of 20 years has elapsed.
- The risks associated with CO_2 storage occur mainly during the injection phase and hence more intense MMV is required in this phase, as opposed to the post-closure phase. Less comprehensive MMV programmes are therefore required during the post-closure phase. Associated costs are assumed to be 10% of the MMV yearly recurring costs during injection operations.

- In addition, a final seismic survey was assumed to meet regulatory requirements for mapping the CO_2 plume in the reservoir, including a subsequent history match of the reservoir model.

4.1.4 Operational phase

Operations and maintenance includes project management, on-site operations and maintenance. Associated costs are mainly related to maintaining and operating injection wells and the offshore structure, where applicable – similar to oil and gas operations. They are assumed to be in the order of 15% of the corresponding CAPEX.

The operation phase also includes MMV with associated modelling and interpretation studies. These cost items are already covered in the previous sub-section. When analysing the breakdown of cost components, (Figure 7, page 27) the MMV costs during the operational phase are not reflected in the operation and maintenance cost component, but in the MMV cost component.

4.1.5 Closure and post-closure phases

At closure, the injection wells and offshore structure (where appropriate) are decommissioned. At a later stage, usually in the post-closure phase, monitoring wells are also decommissioned. Decommissioning costs are assumed to be ~15% of the associated CAPEX. In order to decommission a site, a final seismic survey was assumed to meet the regulatory requirement for mapping the CO_2 plume in the reservoir, including a history match of the reservoir model and predictions for the fate of the CO_2 in the reservoir. This is described in the MMV sub-section on page 17.

As these activities happen in the post-closure phase, costs are discounted for time value of money and added in the CAPEX.

4.1.6 Liabilities

Liabilities are described in detail in two Articles of the EU Directive 2009/31/EC:

- Article 19 contains guidelines for financial security items: proof of adequate provision needs to be established prior to the commencement of operations and periodically adjusted to take into account the assessed risk of leakage and the estimated costs of all obligations arising under the permit. The liability is risk-based.
- Article 20 of the Directive states that a financial contribution will be made available to the Competent Authorities before the transfer of liabilities in order to cover monitoring costs for 30 years. These contributions are also meant to cover costs associated with permanent CO_2 containment and related corrective actions, such as re-plugging wells etc.

The transposition of these articles by Member States is currently under development and expected to be clarified in the near future.

In order to account for the cost of liabilities, average costs of €1 per tonne of CO_2 stored were assumed, with a minimum of €0.2/tonne and a maximum of €2/tonne. Note that this approach is purely for the purpose of covering modelling costs as of today. Proposals from industry as to how to handle these costs are not included. Furthermore, such an assumption makes the cost of liability per tonne of CO_2 stored completely transparent: that element of the storage cost can easily be subtracted from the total cost and replaced by other estimates of the cost of liability as they arise.

4.2 Storage-specific assumptions – storage cost elements

4.2.1 Source properties

The CO_2 stream taken as an input for storage is estimated at an average rate of 5 Mt per year. No variation in the average rate of the CO_2 stream is taken into account, as this is already covered by assumed variances in the storage capacity (a smaller CO_2 stream corresponds to a smaller field capacity required). A possible peak load of 116% is used, which translates into an available injectivity rate of 116%. This corresponds to a power plant utilisation rate of 86%, which is consistent with the work carried out on CO_2 transport.

It is assumed that the CO_2 stream arrives at the wellhead in a fit-for-purpose state for injection, both in terms of CO_2 composition, pressure and temperature. No extra separation, heating/cooling or compression is taken into account.

4.2.2 Reservoir properties

The following characteristics of reservoirs have been taken as input parameters: storage capacity, reservoir depth and injectivity. It is assumed that reservoir containment – another key performance indicator for storage – was established during the storage selection phase.

As mentioned earlier, three cases were assumed: one reservoir matched to a single stream of 5 Mtpa of CO_2 as the high case; three reservoirs strung together to match a single stream of 5 Mtpa of CO_2 as the base case; and five reservoirs in parallel to match a single stream of 5 Mtpa of CO_2.

4.2.3 Wells

Wells are a fundamental cost component of CO_2 storage and commonly represent one of the largest elements of the CAPEX and OPEX. For this study, costs for drilling and completing new wells are considered, as well as costs associated with workovers and contingency costs. Note that the use of special corrosion-resistant alloys for the lower well section (at least where injection takes place) and the injection tubing was also considered.

Different types of wells are considered to be of importance to a CCS project. Depending on the type of reservoir – DOGF or SA – only some are needed. The following types of wells were considered:

- *Exploration wells*: for DOGF, new exploration wells are usually not required, as enough data already exist to fully evaluate history-matched reservoir models. For SA, the number of exploration wells has been taken as four for the base case, with a minimum of two and a maximum of seven. It was considered that a third of these wells could subsequently be re-used, either as an injection well or a monitoring well. Other wells that would have been drilled for delineating the reservoir would not be placed appropriately for either use.
- *Injection wells*: the number of injection wells is computed by dividing the rate of CO_2 to be injected by the well injectivity. Based on industry experience with CO_2 injection, the injectivity of a single well, which is the average injectivity over the life of the well, was taken as 0.8 Mtpa for the base case, both for onshore and offshore.

  The low value was taken as 0.2 Mtpa for onshore storage only; it was left at 0.8 Mtpa for offshore as a lower injectivity would drive the cost to uneconomical levels. From experience in the oil and gas industry with high-rate gas producers, the high value for injectivity was taken as 2.5 Mtpa, assuming that injectivity and productivity would be similar. (Note that this is not out of sync with the performance of the Sleipner injection well, which is currently limited by the amount of available CO_2 and not by its injectivity.) Because the life of a particular well is unlikely to be 40 years of injection without any intervention, contingency wells have also been considered to ensure that the storage site can accommodate the incoming CO_2 stream, regardless of whether any of the wells have planned or unplanned downtime. As a base case, it was considered that 10% extra wells should be added, with a Low scenario of 5% and a High scenario of 20%. As no fraction of a well can be drilled, a minimum of one extra injection well was considered in all cases.

- *Monitoring wells*: the base case for onshore storage is that a single observation well is required, with a High scenario comprising two observation wells. Onshore, it was assumed that one such well would always be required. In contrast, the base case for offshore storage is zero monitoring wells. The underlying assumption is that time-lapse seismic provides sufficient means to monitor the site in offshore conditions. Seismic is more conveniently deployed offshore than onshore. The “high” scenario for offshore is that one monitoring well is required. Note that the cost of a monitoring well was taken to be similar to that of an injection well, which is verified by industry experience.

- *Well abandonment*: at the end of the project, wells must be plugged and abandoned. For a particular well, that cost was considered as a fraction of 15% of the CAPEX associated with that well.
- *Legacy wells*: it has been assumed that legacy wells are not present for SA, whereas they do exist for DOGF. Depending on their condition, such wells can either be re-used for injection or monitoring, or need to be abandoned. For this study, two cases have been considered for legacy wells in DOGF: (1) wells that can be re-used, including potential workover costs or (2) all wells have to be drilled afresh.

  From industry experience, the cost of well workover was taken as 60% of the cost of a new well. If a potential site has too many wells to be abandoned, e.g. if well integrity is an issue, it is assumed that such a site would be de-selected completely during the site selection phase; consequently, this case is not considered in the report. The possibility of having integrity issues with legacy wells was taken as 65% onshore and 50% offshore. This difference is related to the fact that DOGF offshore typically exhibit more technologically advanced and more recent wells than DOGF onshore (no legacy wells were considered for SA, as mentioned above).

- *Well workover*: the possibility that a new well is not fit-for-purpose over the lifetime of the well was also evaluated, with the likelihood of having to perform a workover on a new well taken as 15% onshore and 0% offshore. (The offshore environment makes well intervention and workover so difficult that extra precautions are taken with the construction of offshore wells.)

4.2.4 Offshore structure
Surface structures associated with wells are required to allow injection (well pad etc.) separately from any kind of surface equipment that would be required to condition the CO_2 (e.g. heaters or compressors), as it is assumed that the CO_2 always comes in a “fit-for-purpose” state for injection. For storage onshore, the cost of such an item has been included in the cost of a well as it is not significant enough to warrant separate treatment. In the case of storage offshore, however, it is necessary to consider the cost of an offshore structure separately, either as a surface or subsea structure.

In the case of offshore SA, the full cost of building a new structure is assumed. In the case of offshore DOGF, it is assumed that an existing structure can be used, with some work to be done to extend its life. The associated cost consists of a pro-rated value of the cost of building a new structure. Note that the cost assumed for such a structure is rated as the highest so as not to underestimate it. Depending on specific site circumstances, it can be (much) lower.

4.2.5 Learning rate
The oil and gas industry generally assumes a learning rate in the order of 3% for operating costs. A sensitivity analysis for such a learning rate was performed and the effect on costs was found to be below the uncertainty range resulting from the rest of the input parameters in the current model. As learning rate is not significant, it is therefore not included in the final computed cost.

4.2.6 Summary of all assumptions

Tables 2 and 3 summarise the assumptions described above – a total of 26 cost elements were considered for the computation of the cost of CO_2 storage. All cost items are presented with their base case value ("most likely"). For the top eight cost drivers – i.e. those deemed to have a major impact on the overall cost of storing CO_2 – "minimum" and "maximum" values used for computing cost ranges and carrying out sensitivity studies are also reported. A brief description of the rationale used to select the particular cost for each item is also presented – such a variation either stems from known natural variations (e.g. driven by (geo)physical conditions) or from uncertainty.

In Table 2, the eight major cost drivers are presented with the associated "most likely", "minimum" and "maximum" values that have been used for the sensitivity analysis.

Cost driver	Medium case assumption	Sensitivities	Rationale
▪ Field capacity	66 Mt per field	▪ 200 Mt per field ▪ 40 Mt per field	▪ Based on Geocapacity data
▪ Well injection rate	0.8 Mt/year per well	▪ 2.5 Mt/year ▪ 0.2 Mt/year[1]	▪ Medium value based on actual projects ▪ High and low based on oil and gas industry experience
▪ Liability transfer costs	€1.00 per tonne CO_2 stored	▪ €0.20 ▪ €2.00	▪ Rough estimate of liability transfer cost ▪ Wide ranges reflect uncertainty
▪ WACC	8%	▪ 6% ▪ 10%	▪ Same range as McKinsey study, September 2008
▪ Well depth	2000 m	▪ 1000 m ▪ 3000 m	▪ Well costs strongly dependent on depth[2]
▪ Well completion costs	Based on industry experience, offshore cost 3 times onshore cost	▪ -50% ▪ +50%	▪ Ranges based on actual project experience
▪ # Observation wells	1 for onshore; nil for offshore	▪ 2 for onshore; 1 for offshore	▪ 1 well extra to better monitor the field
▪ # Exploration wells	4 for SA; nil for DOGF	▪ 2 for SA, nil for DOGF ▪ 7 for SA, nil for DOGF	▪ DOGF are known, therefore no sensitivities needed ▪ SA reflects expected exploration success rate

1 0.2 Mt/yr not modelled for offshore cases as costs would become to high to be viable
2 Supercritical state of CO_2 occurs at depths below 700 - 800 m

Table 2: Eight main cost elements

In Table 3, the other 18 cost elements are presented together with their associated values. The reason for not considering these cost elements in a sensitivity analysis is that either the resulting sensitivity would be small as the cost effect of these cost elements is small, or the sensitivity range would be too small as that particular parameter is well understood from experience in the oil and gas exploration & production industry.

Cost driver	Assumption
Re-use of exploration wells	1 out of 3 exploration wells is re-usable as an injection well; others are not located correctly, do not match the injection depth etc.
Utilisation	Utilisation is 86%, implying a peak production of 116% average
Contingency wells	10% of the required number of injection wells is added as a contingency, with a minimum of 1 per field
Well re-tooling cost	Re-tooling legacy wells as exploration wells, or exploration wells as injection wells, costs 10% of building the required well from scratch
Operations & Maintenance	4% of CAPEX costs for platform and new wells
Injection testing	Fixed cost per field
Modelling/logging costs	Fixed cost per field; SA costs ~2 times as much as DOGF
Seismic survey costs + MMV Baseline	Fixed cost per field; offshore costs ~2 times as much as onshore. In addition, at the end of its economic life, final seismic survey is performed prior to handover (costs discounted for time value of money)
MMV recurring costs	Fixed cost per field; offshore costs ~2 times as much as onshore

Why no sensitivities

1. Sensitivity range is minor as cost driver is small
2. Sensitivity range would be small as cost driver is well understood from E&P experience

Cost driver	Assumption
Permitting costs	€1M per project
Well remediation costs	Provision ranging from nil to 60% of new well costs, based on the possibility of risky wells and the costs of handling them.
Platform costs	For offshore there are platform costs: SA is assumed to require a new platform; DOGF is assumed to require refurbishment of an existing platform
Decommissioning	15% of CAPEX of all operational wells and CAPEX of platform
Post-closure monitoring	20 years after closure, at 10% of yearly MMV expenses during first 40 years
Economic life	40 years; demonstration phase 25 years (in line with assumptions for CO_2 capture)
Learning rate	0% as CO_2 storage technologies are well known and build on oil and gas industry experience[1]
Exchange rate	1.387 USD/EUR (as of 6 October 2010)
Plant CO_2 yearly captured	CO_2 captured is assumed to be 5 Mt per year. Variation in the amount captured is implicitly modelled by variation in storage field capacity as a sensitivity

Why no sensitivities

1. Sensitivity range would be small as cost driver is small
2. Sensitivity range is small as cost driver is well understood from E&P experience

Table 3: 18 other cost elements considered for storage

5 Results by Cases

In this chapter, the results of the costing exercise are presented. All costs are reported in €/tonne CO_2 stored.

5.1 Cost overview totals

For each case, the cost model was first run with the input cost elements set to their base (most likely) values, according to the case. The resulting costs correspond to what has been termed the "Medium" scenario. The model was then run to determine the three major uncorrelated drivers that had the largest impact on cost – field capacity, well capacity (injectivity times the life of the well) and liability. Note that other cost items related to well capacity sometimes have a large impact on cost (e.g. well completion cost), but these are related to the well capacity driver. Liability, however, is completely decoupled from other items and has a large impact on Low cost scenarios.

The Low and High cost scenarios were then obtained as follows: for each case, the model was run with these three major drivers set to their minimum values for the Low cost scenarios and maximum values for the High cost scenarios, whilst taking care of their combined effects. This method has the advantage over mathematically more rigorous techniques (e.g. Monte Carlo techniques) in that the Low and High scenarios correspond to a transparent set of input cost elements, while still representing realistic (i.e. reasonably probable) Low and High scenarios.

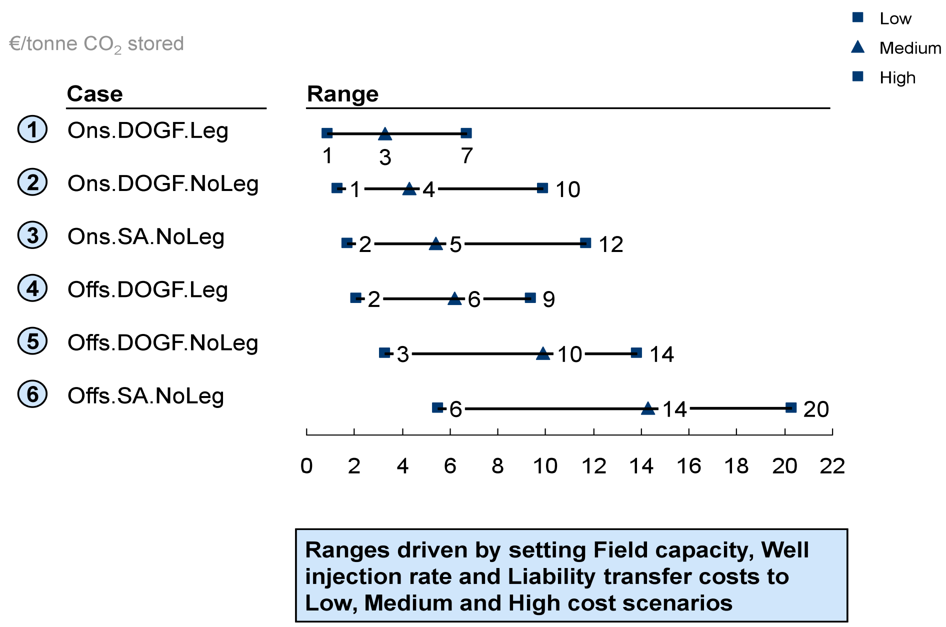


Figure 5: Storage cost per case, with uncertainty ranges – triangles correspond to base assumptions

The resulting total storage costs are presented in Figure 5, with the CAPEX/OPEX split in Table 4. A key conclusion is that within each case there is a wide cost range, the High cost scenario being three to up to 10 times more expensive than the Low cost scenario. This is mainly due to natural variability between storage reservoirs (i.e. field capacity and well injectivity) and only to a lesser degree to uncertainty in cost elements (i.e. liability transfer cost).

Despite this wide cost range the following trends stand out:

- Onshore is cheaper than offshore.
- DOGF are cheaper than SA – even more so if they have re-usable legacy wells.

The highest costs, as well as the widest cost range, occur for offshore SA.

	Case 1			Case 2			Case 3			Case 4			Case 5			Case 6		
Location	Onshore			Onshore			Onshore			Offshore			Offshore			Offshore		
Type	DOGF			DOGF			Aquifer			DOGF			DOGF			Aquifer		
Legacy Wells	Yes			No			No			Yes			No			No		
Cost Scenario	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High
CO_2 stored (MT)	200	66	40	200	66	40	200	66	40	200	66	40	200	66	40	200	66	40
Lifetime (yr)	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
CO_2 rate (MT p a)	5	2	1	5	2	1	5	2	1	5	2	1	5	2	1	5	2	1
CAPEX (M€)	27	27	29	48	48	68	70	70	89	56	48	44	127	120	96	238	199	169
Annualised CAPEX (M€ p a)	2	2	2	4	4	6	6	6	7	5	4	4	11	10	8	20	17	14
OPEX (M€ p a)	2	3	4	2	3	4	2	3	4	6	6	6	6	6	6	8	7	6
CAPEX (€ per tonne)	0	0	1	0	1	2	0	1	2	0	1	1	1	2	2	1	3	4
Annualised CAPEX (€ per tonne)	0	1	2	1	2	6	1	4	7	1	2	4	2	6	8	4	10	14
OPEX (€ per tonne)	0	2	4	0	2	4	0	2	4	1	4	6	1	4	6	2	4	6
Cost of storage (€ per tonne)	1	3	7	1	4	10	2	5	12	2	6	9	3	10	14	6	14	20

Table 4: Cost summary per case – annualised CAPEX takes the WACC into account

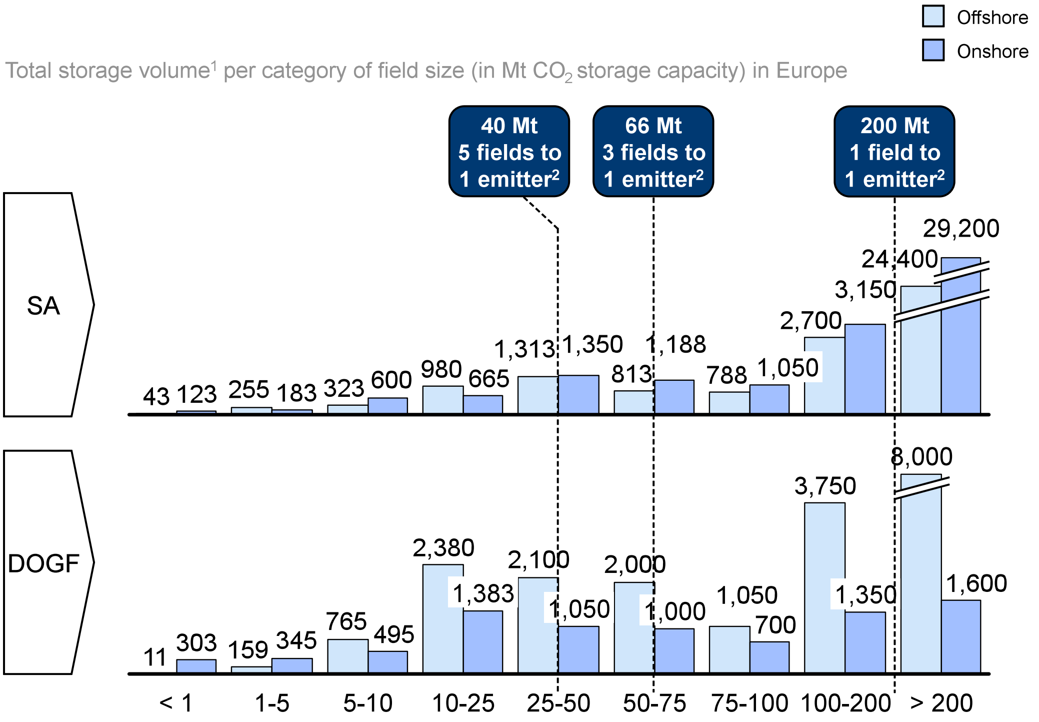
Unfortunately, according to current understanding (Figure 6), the capacity of storage reservoirs in Europe shows the mirror image of these cost trends:

- There is more storage capacity offshore than onshore, especially for DOGF.
- There is more storage capacity in SA than in DOGF.

In other words, the cheapest storage reservoirs also contribute the least to total available capacity.

Offshore SA may only be viable if their costs can be reduced to the lower end of the predicted range. As already mentioned, the main drivers for storage costs are field capacity and well costs. Large storage reservoirs drive down storage costs towards the lower end of the ranges. It is therefore pleasing to note that, according to Figure 6, most capacity in SA is available in large reservoirs. However, it should be stressed that SA will require considerable exploration effort in order to screen for suitable reservoirs. That will require considerable upfront investment, particularly in seismic acquisition and processing, and in geological characterisation. These points are quantified in Chapter 6.

From Figure 6 it is also clear that for onshore DOGF, most capacity is in medium-sized reservoirs, therefore there is only very limited scope for “cherry-picking” of the very low-cost scenario (€1/tonne CO_2 stored). To a lesser extent, this also holds for offshore DOGF.



1 Total storage volume is an approximation, based on multiplying number of fields per category with the mid -point of the field size range of the category
2 Typical emitter requires 200 Mt of storage in its economic lifetime

Figure 6: Total storage volume per category of field size (in Mt CO_2 storage capacity) in Europe, based on GeoCapacity data. N.B. Total storage volume is an approximation, calculated by multiplying the number of fields per category with the midpoint of the field size range of the category (assumed to be 400 Mt for the >200 Mt category). A typical emitter requires 200 Mt of storage in its economic lifetime.

5.2 Cost breakdown per project phases

A cost breakdown per project phase provides insight into the cost differentiators between the cases. The following project phases – and associated cost elements – were therefore defined:

Phase	Description	Typical cost elements
Pre-FID	Activities prior to decision whether to go ahead with injection	Seismic survey, exploration wells, injection testing, modelling, permitting
Structure	Construction of supporting structure for injection wells (e.g. offshore platform)	New build or refurbishment (offshore)
Injection wells	Construction of injectors	Drilling of new wells, refurbishing of legacy wells
Operating	CO_2 injection phase (40 years)	Operations and maintenance OPEX
MMV	Monitoring activities (both during the injection and the post-injection phase)	Drilling of observation wells, monitoring OPEX, final seismic survey
Close down	Close down activities	Decommissioning, liability transfer

Table 5: Description of project phase

The cost breakdown for each of the cases is presented in Figure 7. It can be seen that the main cost differentiators are:

- High pre-FID costs for SA compared to DOGF. The reason is that SA need exploration to determine their suitability for storage. This pre-FID activity requires a seismic survey, as well as drilling of exploration wells and modelling (study) activities.[18] Such costs could accrue to several tens of millions of euros.
- Offshore is more expensive than onshore for nearly all cost elements since it is a more expensive environment for construction, drilling and operations.
- DOGF with re-usable legacy wells have lower well costs. This is a key differentiator offshore because of the high drilling and completion costs in that environment.

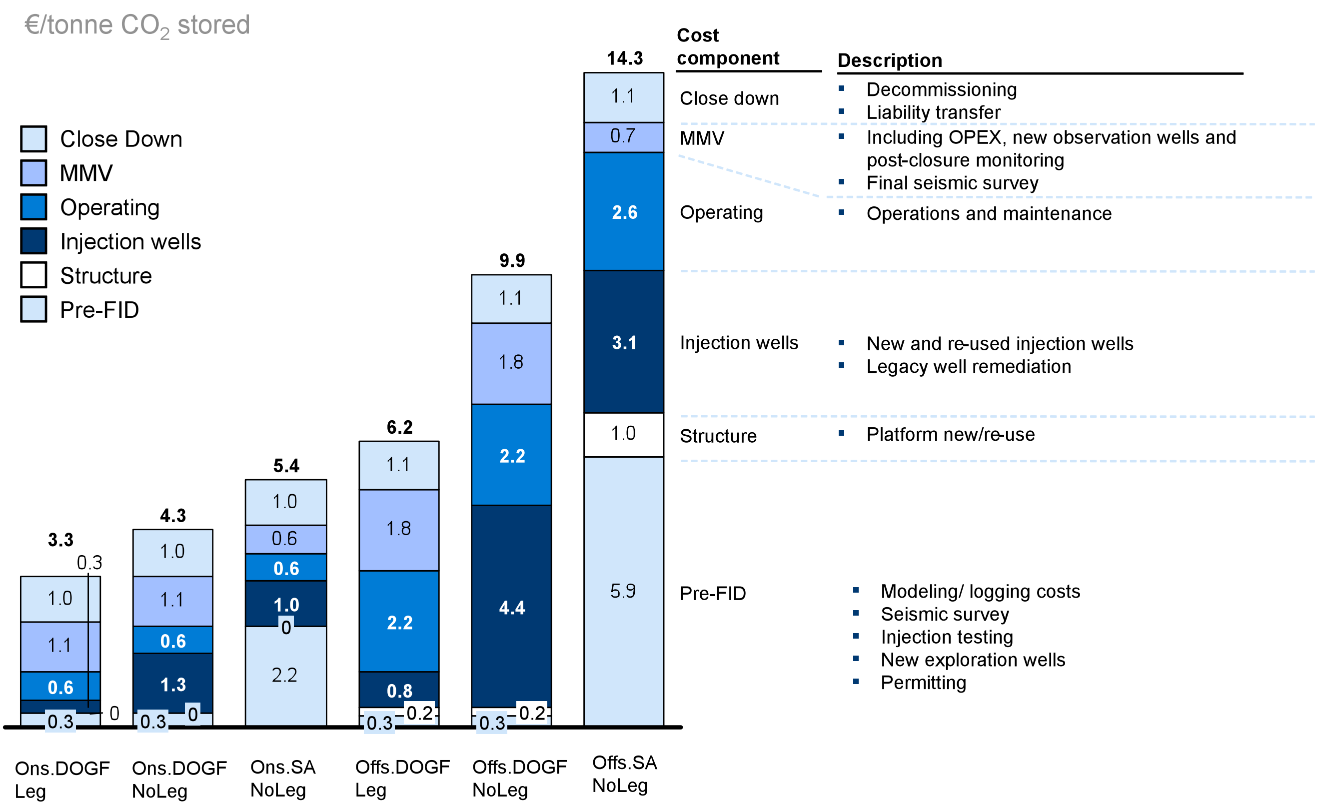


Figure 7: Breakdown of cost components – medium scenarios for all six cases

---

[18] Exploration wells may be re-usable as injectors or observation wells (thus lowering costs for injectors and MMV), but this cost benefit only materialises for projects that pass FID and occur later in the project life, thus diminishing the benefit (due to WACC). Similarly, the pre-FID seismic survey leads to a cost saving for MMV (no new baseline survey required), but again the cost benefit only occurs at a later stage and only for projects that pass FID. N.B. It is assumed that on average only one in three sites that have been explored will pass FID.

6 Variations and Uncertainties

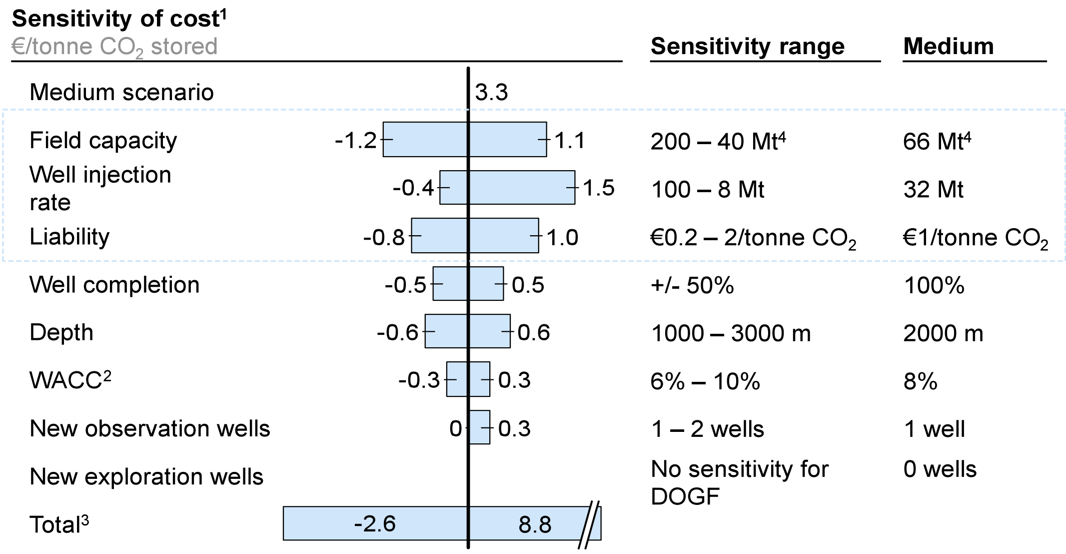
An extensive sensitivity study was carried out for all the cases – not only for the three cost elements that were used to compute the ranges of cost (i.e. field capacity, well capacity and liability), but also the other top five cost elements that have a strong effect on cost, i.e. well completion, reservoir depth, WACC and the number of new observation and exploration wells (Table 2). As mentioned in Section 4.2.6 (page 22), the cost impact of the other 18 cost elements was not found to be significant enough to be taken into account in this sensitivity study.

6.1 Accumulation of sensitivities

For each case, the cost obtained for the Medium scenario is taken as the reference from which the cost effects of the variation of each parameter are displayed. The methodology is that of a tornado chart, where one displays the effect on the final cost of a single parameter changing value whilst keeping all others at the base case (i.e. Medium scenario) value. This methodology has the advantage of simplicity and clarity to broadly evaluate the effect of the cost elements. Apart from showing the effect of each individual parameter, the total effect of setting all of these eight most significant cost elements to the low (respectively high) values is also shown. Note that the individual effects do not add up to the total effect, as there are interdependencies between variables that are taken into account when computing the total effect.

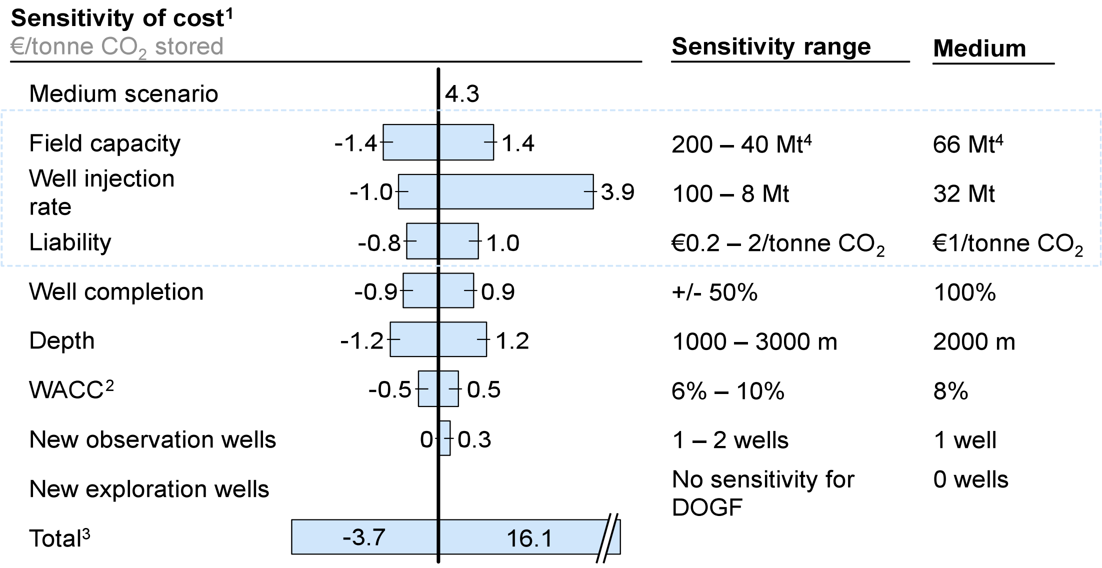
6.2 Results

The results are presented in the following figures for the six cases (all for the Medium scenario). Note that the total cost variation resulting from all cost elements being set to their low values (or high values) is much larger than the variation reported in the cost ranges of Chapter 5. This is a reflection that such situations are highly unlikely.



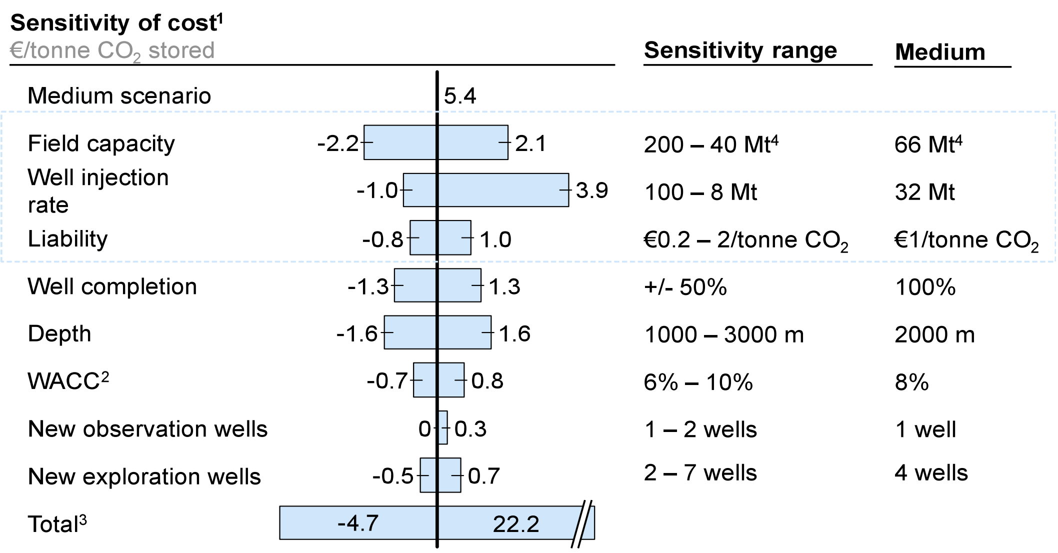
1 The sensitivity denotes the individual effect of ranging a parameter on the total cost in medium scenario
2 Weighted Average Cost of Capital
3 Parts do not add up to total. Combined effect of variables is larger due to interdependencies
4 High scenario is 1 emitter to 1 field; medium scenario is 1 emitter to 3 fields; low scenario is 1 emitter to 5 fields

Figure 8: Sensitivity study for Case 1 (onshore DOGF with re-usable wells)



1 The sensitivity denotes the individual effect of ranging a parameter on the total cost in medium scenario
2 Weighted Average Cost of Capital
3 Parts do not add up to total. Combined effect of variables is larger due to interdependencies
4 High scenario is 1 emitter to 1 field; medium scenario is 1 emitter to 3 fields; low scenario is 1 emitter to 5 fields

Figure 9: Sensitivity study for Case 2 (onshore DOGF without re-usable wells)



1 The sensitivity denotes the individual effect of ranging a parameter on the total cost in medium scenario
2 Weighted Average Cost of Capital
3 Parts do not add up to total. Combined effect of variables is larger due to interdependencies
4 High scenario is 1 emitter to 1 field; medium scenario is 1 emitter to 3 fields; low scenario is 1 emitter to 5 fields

Figure 10: Sensitivity study for Case 3 (onshore SA, no re-usable wells)

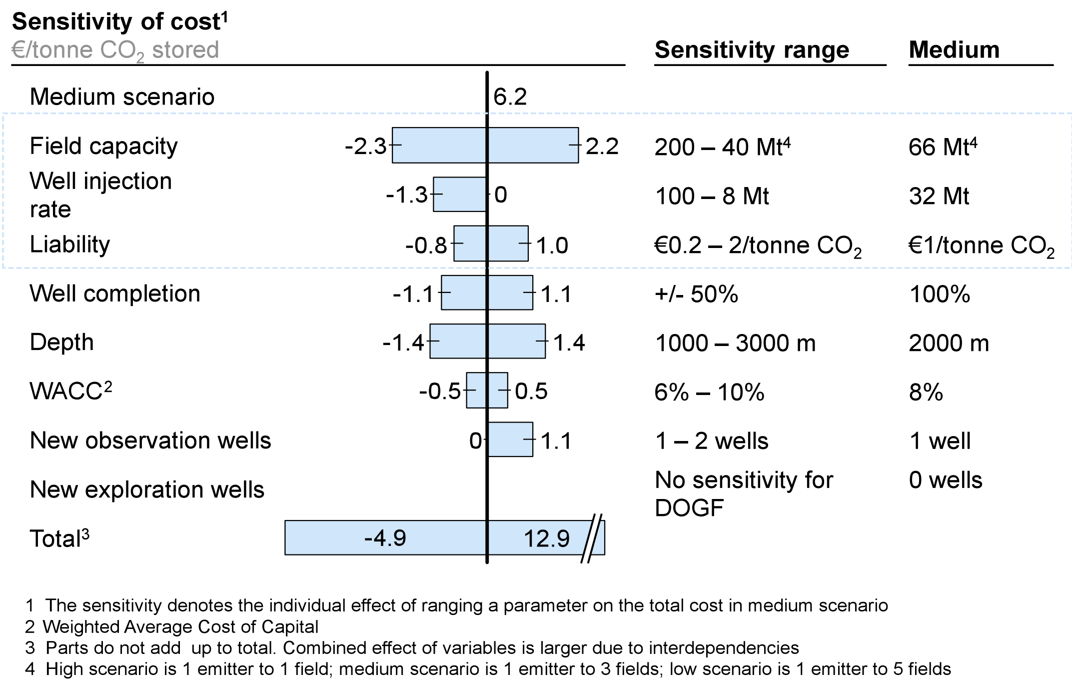


Figure 11: Sensitivity study for Case 4 (offshore DOGF with re-usable wells)

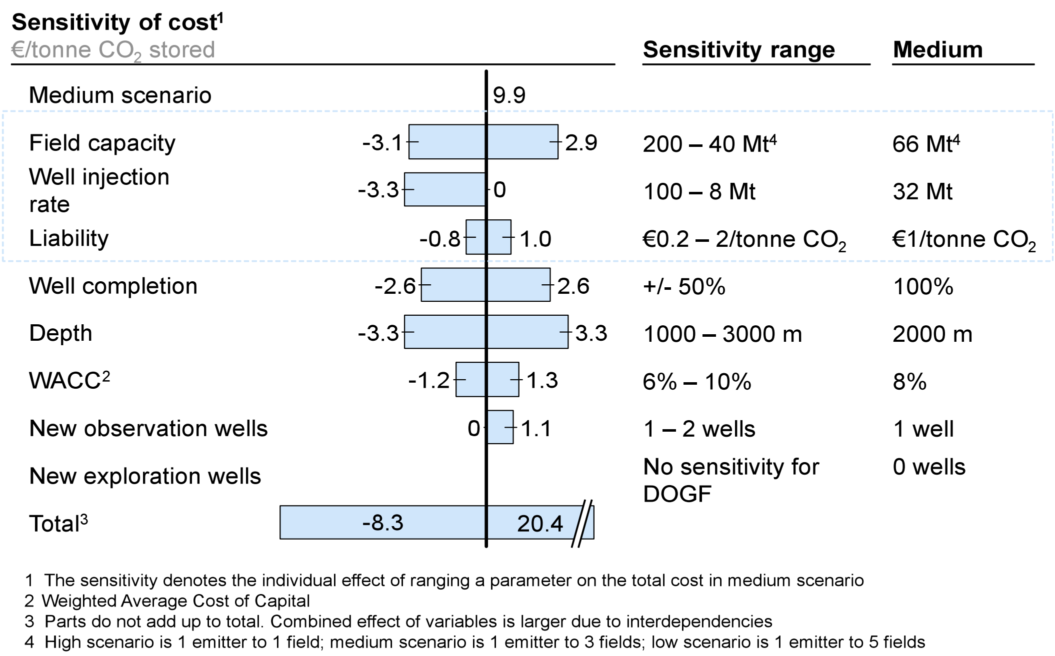
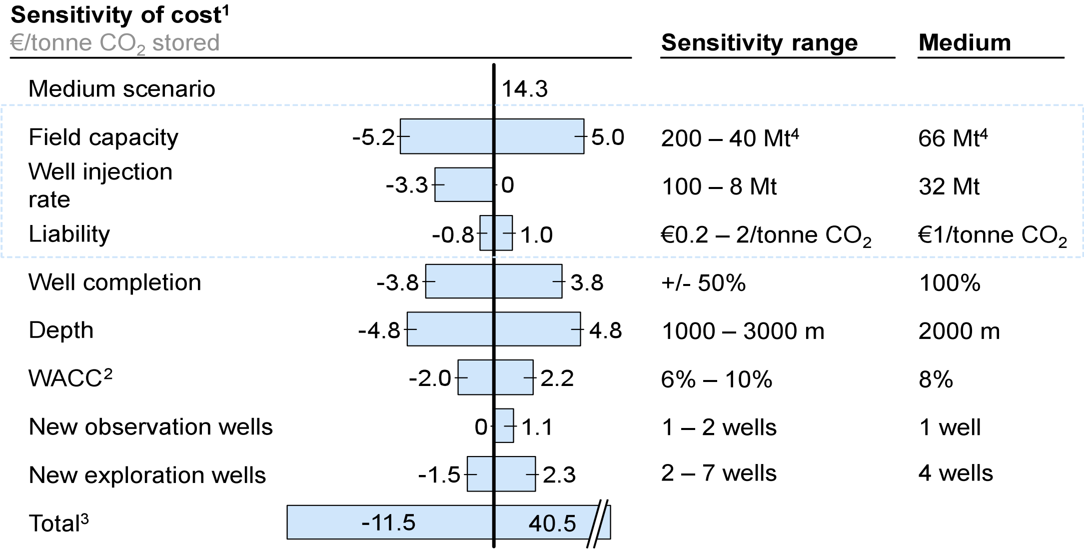


Figure 12: Sensitivity study for Case 5 (offshore DOGF without re-usable wells)



1 The sensitivity denotes the individual effect of ranging a parameter on the total cost in medium scenario
2 Weighted Average Cost of Capital
3 Parts do not add up to total. Combined effect of variables is larger due to interdependencies
4 High scenario is 1 emitter to 1 fields; medium scenario is 1 emitter to 3 fields; low scenario is 1 emitter to 5 fields

Figure 13: Sensitivity study for Case 6 (offshore SA, no legacy wells)

The following comments can be made from these results.

- Field capacity has the largest effect on cost in four cases and the second largest effect in the remaining two cases. Furthermore, field capacity has the largest effect (more than €10/tonne of CO_2 stored) for Case 6 (Offshore SA). It is therefore concluded that selection of appropriate storage reservoirs with respect to their capacity is a key element to decrease the cost of CO_2 storage. Exploration and reservoir characterisation are thus key activities for CO_2 storage as they allow selection of a storage reservoir of adequate size. This is of utmost importance for the case of offshore SA, where the use of larger reservoirs results in much lower costs than for smaller reservoirs.
- For onshore cases, the well capacity is the top second contributor to variations of cost. The design and placement of wells is therefore a key activity for such cases.
- For offshore cases, well completion costs are the next most important factor, highlighting the specificities of that offshore environment.
- The top two items for all cases relate to storage capacity and injectivity, which are two of the top leading themes for CO_2 storage, capacity, injectivity and containment. Containment is not a source of cost variation in this study as it is assumed to be dealt with during site selection. MMV costs can be considered as folded into containment but do not cause significant cost variations and thus do not appear here.
- The assumed cost of liability is the same for all cases when reported per tonne of CO_2 stored. Its relative weight is therefore the largest for cases where the overall cost of storage per CO_2 tonne stored is the smallest, namely onshore.

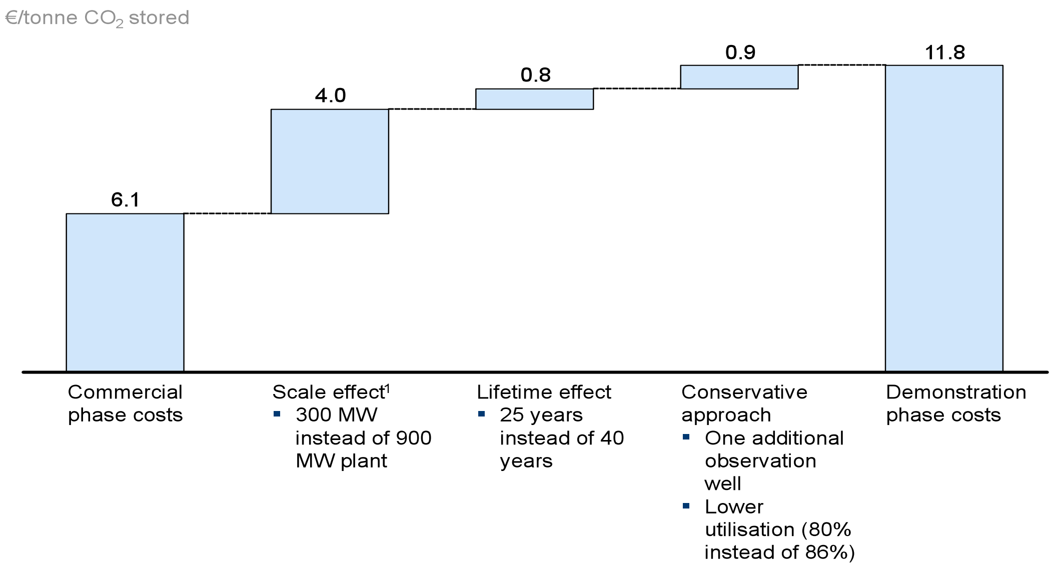
7 Demonstration Projects

As mentioned in the previous chapter, the reference for this cost study is the early commercial phase of CCS. In order to determine whether the costs would be significantly different for demonstration projects, the following approach was taken:

- It was assumed that demonstration projects would be hooked to a smaller power plant, i.e. a 300 MW plant instead of a 900 MW plant. This scale effect will entail similar cost increases to those highlighted in the previous chapter as a result of the change in field capacity. However, this scale effect has been mitigated by a factor of two-thirds as it was assumed that demonstration projects will focus on the easiest sites, thereby granting this cost reduction.
- It was assumed that the lifetime of a demonstration project would be 25 years instead of 40 years, thereby affecting the discounting effect of the present value of money.
- It was also assumed that a more conservative approach would be taken when operating these sites, compared to operating fully commercial projects. An additional observation well was therefore added as a cost and a lower utilisation rate considered (80% instead of 86%).

The addition of these three effects lead to a significant increase in cost, as illustrated in Figure 14, where the exercise was carried out for the "Medium" scenario for Case 3 (onshore SA).

N.B. No explicit reference to any current demonstration project was used. This exercise was carried out for comparison purposes – between the results of this cost exercise and what could be expected for demonstration projects. The outcome is therefore not directly representative, but a good indicator of the trend to expect. Elements have also been checked against existing demonstration projects.



1 Scale effect has been taken as factor 2, rather than 3, since absolute scale effect is mitigated somewhat by expected "cherry-picking" of storage fields

Figure 14: Cost increase (per tonne of CO_2 stored) associated with a demonstration project, compared to the costs of a commercial project

In conclusion, even if the actual cost increase varies from case to case, it is highly likely that the costs per tonne of CO_2 stored associated with demonstration projects will be very significantly higher than those for projects in the early commercial phase. Such a cost increase should be taken into account, both when financing demonstration projects and when comparing the actual costs of demonstration projects with those of early commercial projects.

8 Comparison of ZEP Storage Cost Estimates with Other Studies

It is worthwhile comparing the cost estimates from this study, which benefits from the knowledge and experience of the wide range of companies and agencies participating in ZEP, with those published by McKinsey in 2008 (Figure 15).

It can be seen that despite the substantial additional information that has been brought to the table to build the current cost estimates, the actual differences amount to relatively small changes in the estimated total cost of storage. The main relative difference occurs in onshore as well as offshore SA. This is due to a refinement of the exploration cost estimate, which results in a higher current cost estimate as successful storage reservoirs (i.e. those that pass FID) will need to cover for the exploration costs for storage candidates that were de-selected.

Note that the high exploration/characterisation pre-FID costs are in line with the findings of the Strategic Analysis of the Global Status of CCS Foundation Report Two: Economic Assessment of Carbon Capture and Storage Technologies (2009, Global CCS Institute), which stated that the impact of initial storage site assessment and characterisation costs on the CO_2 storage cost could vary from US$15 million to US$150 million.

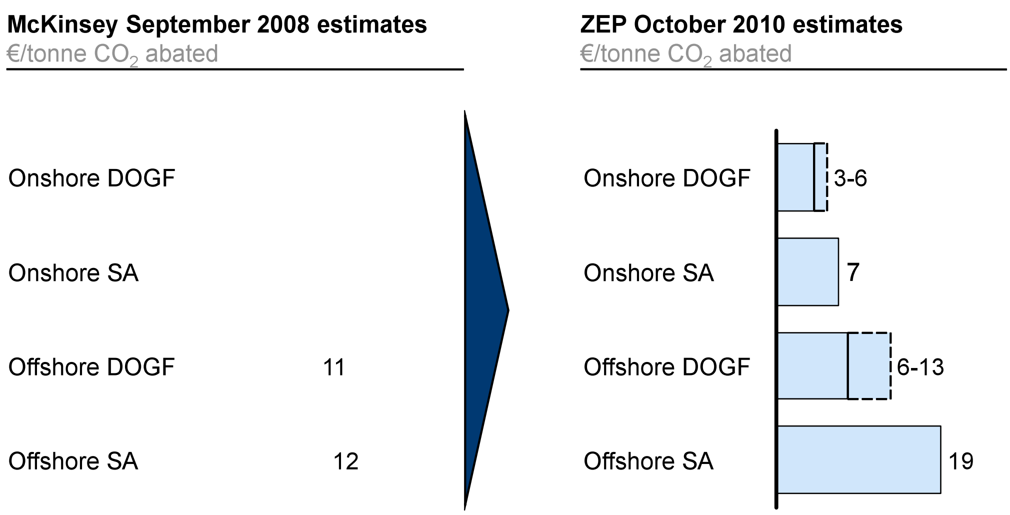


Figure 15: Comparison of the cost estimates in this report with those in the 2008 McKinsey study
Note 1: The 2008 McKinsey report calculated cost per tonne of tonne CO_2 abated, while this study calculates the cost per tonne of CO_2 stored. For the comparison it is assumed that 75% of CO_2 stored is abated (conservative assumption; value depends on capture technology employed). Furthermore, in this study, cost ranges have been generated within each case. The cost estimates in this figure are for the Medium cost scenario only. Note 2: Bottom end of the range represents the case with legacy wells; upper end represents the same case without legacy wells.

9 Results and Discussion

9.1 Results

CO_2 storage projects are differentiated according to three factors: onshore and offshore; depleted oil and gas fields (DOGF) and deep saline aquifers (SA); and the possibility or not of re-using existing wells. Because it was estimated that SA would typically be undeveloped, re-using existing wells was not considered, thus limiting the discussion to six base cases.

The cost estimates documented in this report vary from €1-7/tonne CO_2 stored for the cheapest option (onshore DOGF with re-usable wells) to €6-20/tonne CO_2 stored for the most expensive option (offshore SA). The uncertainty ranges within each case derive mainly from the natural variability of storage candidates (i.e. reservoir capacity and injectivity). The effect of the learning rate was found to be insignificant. Note that the costs quoted apply to commercial-phase CCS: demonstration projects will be more expensive due to their smaller scale, the need for more extensive study work and higher monitoring costs.

This work emphasises large differences in cost of storage, the main differentiators being:

- Field location (higher cost offshore than onshore)
- Field knowledge level (high for DOGF, leading to lower costs; low for SA, leading to higher costs)
- Existence of re-usable infrastructure (wells, offshore structure)
- Reservoir capacity (higher cost for smaller reservoirs)
- Reservoir quality (injectivity; higher cost for poorer quality reservoirs)

The cheapest storage reservoirs, onshore DOGF – especially if the existing wells are re-usable – have limited total storage capacity. If CCS is to play a significant role in the reduction of CO_2 emissions, it will therefore be necessary to develop additional storage capacity. Offshore DOGF have higher total capacity than onshore DOGF, but the largest capacity is in onshore and offshore SA.

To realise this potential, it will be necessary to identify and screen individual storage candidates for capacity and injectivity and their suitability for permanent containment of injected CO_2. Although such screening is needed both for SA and DOGF, the differentiator is that SA, unlike DOGF, are typically poorly characterised. In the case of SA, the screening therefore needs to be preceded by a costly information-gathering exercise (exploration) in the form of seismic surveys and the drilling of exploration wells. This is the main factor driving the cost of storage in SA higher than in DOGF.

The largest cost element, after subtraction of the exploration costs in the case of SA, is the drilling of injectors (plus platform/structure construction in the offshore case) plus operations and maintenance. The number of injectors required is inversely proportional to their injectivity. This is why, within each case, the injectivity is a major cost driver for the cost ranges. The injectivity is primarily driven by the reservoir quality. It should be stressed that reservoir quality is a natural, site-specific attribute.

Finally, the cost sensitivities clearly show an economy of scale benefit: large storage reservoirs lead to a much lower cost per tonne of CO_2 stored (up to 40%).

9.1 Discussion

Apart from a few exceptions, current CO_2 projects are demonstration projects. Because this study focuses on commercial projects, it meant estimating future regulatory requirements and commercial practices in a market that is under development. This resulted in intense discussions around several items: the exploration risk (the number of sites to evaluate prior to identifying an appropriate reservoir); the density of monitoring; measurement and verification (MMV); the number of exploration, monitoring and injection wells; the appropriate well completions; the use or not of an offshore platform; and the costs of liabilities. Although choices had to be made, these items remain areas of uncertainty.

The following observations were also made:

- If we add up the MMV costs during operations with the requirement of a financial provision to cover liabilities after transfer, such a cost item represents from 15% of the total cost of storage for the offshore SA case to more than 50% for onshore DOGF. This is directly related to the management of the leakage risk. The level of the costs associated with these two items will depend on the perception of acceptable risk levels and therefore ultimately on the regulatory framework.
- As with traditional oil and gas exploration, exploration activities for a suitable CO_2 storage reservoir will be risk-based. In some cases, these will not deliver potential reservoirs; in others, further exploration of potential reservoirs will eventually end in their elimination. There is thus a need to develop exploration methods that increase the probability of success/lower the cost of selecting suitable storage reservoirs. Indeed, the estimated cost of the exploration pre-investment is approximately 40% of the total cost of storage for an SA scenario. As these costs are incurred prior to FID, they must be acknowledged as part of the storage costs. Appropriate regulations and business models which recognise these risks will be essential to incentivise companies into embarking on exploration activities for CO_2 storage reservoirs.
- Finally, commercial companies embarking on CO_2 storage will wish to make a profit, balanced against their risk. Such a profit has not been included as a cost element in this report since economical screening criteria will differ per company and also depend on the company perception of risk, as well as the fiscal framework.

10 Acknowledgments

The work described this report has been possible solely due to the cooperation of participating ZEP members, resulting in a truly cross-border, cross-organisation product. Without their commitment, the challenging and constructive debate could not have been created, nor yielded such substantial results.

10.1 Working group participants and organisations

Name	Country	Organisation
Desroches, Jean	France	Schlumberger
Schreurs, Harry	Netherlands	Agentschap NL
Maas, Wilfried	Netherlands	Shell
Snippe, Jeroen	Netherlands	Shell
Picard, Guillemette	France	Schlumberger
Christensen, Niels Peter	Denmark	Vattenfall
Tarvis, Tiina	Sweden	Vattenfall R&D
Jagger, Martin	Netherlands	Shell
Neades, Samantha	U.K.	IEA GHG
Ekström, Clas	Sweden	Vattenfall R&D
Wildgust, Neil	U.K.	IEA GHG

10.2 Review partners

Surname	Country	Organisation
Buttinelli,Mauro	Italy	INGV
Dupont, Maike	Germany	E.ON Gas Storage
Czernichowski, Isabelle	France	BRGM
Ehinger, Andreas	France	IFP Energies nouvelles
Jensen, Hans	Finland	RWE Npower
Lewis, Deirdre	Ireland	SLR Consulting Ireland
Persoglia, Sergio	Italy	OGS
Piessens, Kris	Belgium	European Federation of Geologists
Quattrocchi, Fedora	Italy	INGV
Røkke, Nils A.	France	SINTEF
Serbutoviez, Sylvain	France	IFP Energies nouvelles
St. James, Cindy	U.K.	E.ON Gas Storage UK
Stangeland, Aage	Norway	The Research Council of Norway
Tjetland, Gøril	Norway	Bellona
Torp, Tore A.	Norway	Statoil
van der Kuip, Muriel	Netherlands	TNO
Wildenborg, Ton	Netherlands	TNO

References

Technical basis for CO_2 storage
"*A Technical Basis for Carbon Dioxide Storage*", by the CO_2 Capture Project: www.co2captureproject.org/pubsearch.php. Additional background information on CO_2 storage is available on the website of the IEA GHG R&D Programme: www.ieagreen.org.uk.

Economical analysis
The Climate Group, Ecofin, and Global CCS Institute. (2010). *Carbon Capture and Storage: Mobilising Private Sector Finance.*

Global CCS Institute. (2009). *Strategic Analysis of the Global Status of Carbon Capture and Storage, Report 2: Economic assessment of carbon capture and storage technologies*.

US Environmental Protection Agency. (2008). *Geologic CO_2 Sequestration Technology and Cost Analysis, (analysis prepared by ICF for EPA Office of Water as part of proposed rulemaking for sequestration).*

McKinsey & Company. (2008). *Carbon Capture and Storage: Assessing the Economics.*

Pöyry. (2007). *Analysis of Carbon Capture and Storage cost-supply curves for the UK.*

IEA GHG. (February, 2005). *Building the cost curves for CO_2 storage: European sector.* 2005/2.

Gemma Heddle, H. H. (August, 2003). *The economics of CO_2 storage.* Massachusetts Institute of Technology, Laboratory for Energy and the Environment, 2003-003 R.

Eickhoff, C., Muller, I., Hanstock, D., Krolick A., (2009). *Detailed specific case models and financial recommendations*. EU Dynamis project D 6.2.6.

Dynamis Final Report, EU project no. 019672. (2009). *Near-Zero Emissions from Electricity and Hydrogen Production with CO_2 Capture and Storage.*

Regulatory framework
Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/I/EC and Regulation (EC) No. 1013/2006.

Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide, Guidance Document 4 (Draft document for consultation June 18, 2010), Article 19 Financial Security and Article 20 Financial Contribution.

Storage scenarios in Europe
Wildenborg AFB, v. d. (2008). *CO_2 capture and storage scenarios in the European Union (CCS-SCEN).* TNO report 2008-U-R0215/B.

Geocapacity Final Report, EU project no. SES6-518318, www.geocapacity.eu.

Storage specifications
IEA GHG (June, 2010). *Injection strategies for CO_2 Storage Sites.* 2010/04.

IEA GHG (November, 2009). *What have we learned from CCS demonstrations?* 2009-TR6.

Glossary

2D	Two-dimensional
3D	Three-dimensional
CAPEX	Capital Expenditure
CCS	CO_2 Capture and Storage
CO_2	Carbon Dioxide
DOGF	Depleted Oil and Gas Fields
ECBM	Enhanced Coal Bed Methane
ECCO	Estimating the Circulation & Climate of the Ocean: www.ecco-group.org
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
EU	European Union
FID	Financial Investment Division
IEA	International Energy Agency: www.iea.org
IEA GHG	IEA Implementing Agreement on Greenhouse Gas R&D Programme: www.ieagreen.org.uk
Leg	Re-usable Legacy Wells
m	Metre (metric)
MMV	Monitoring, Measuring and Verification
Mt	Million (Metric) tonnes
Mtpa	Million Tonnes Per Annum
MW	Megawatt
NoLeg	Non Re-usable Legacy Wells
Offs	Offshore
Ons	Onshore
OPEX	Operational Expenditure
R&D	Research and Development
SA	Deep Saline Aquifer
WACC	Weighted Average Cost of Capital
ZEP	European Technology Platform for Zero Emission Fossil Fuel Power Plants, known as the Zero Emissions Platform: www.zeroemissionsplatform.eu

Annex 1: Summary of Study Model

The scope of this report is CO_2 storage – it excludes CO_2 capture[19] and transport[20], whose costs have been estimated in other ZEP cost studies undertaken in parallel. Indeed, to ensure that all studies were developed on the same basis – with no gaps or double counting – basic assumptions were aligned (e.g. volume of CO_2 captured, transported and stored) – see Chapter 2. However, storage costs were modelled so that they were independent of the different types of capture technologies (i.e. post-combustion, pre-combustion, oxy-fuel) or transport (i.e. ship or pipelines). Costs are also given in €/tonne CO_2 stored (annualised), not abated.

Two main CO_2 storage options are modelled: depleted oil and gas fields (DOGF) and deep saline aquifers (SA). DOGF are, by definition, known and therefore require less exploration and data gathering. SA, on the other hand, are typically less known and there is a greater need for exploration, as well as risk of potential "misses", i.e. investing in the exploration of an SA that turns out to be unfit for CO_2 storage. Exploration costs are therefore higher for SA. Field capacity is an input to the model, with several "typical" field sizes modelled, based on the findings of the EU GeoCapacity Project.[21]

The costs to store CO_2 are dependent on the type of field, e.g. they are lower if a field contains legacy wells that can be re-used. In general, re-use is cheaper than building new wells, even with costs associated with closing down unusable wells and mitigating the risk of CO_2 leaking from old wells. There are also more elements such as the geophysical characteristics of the field (e.g. determining the average CO_2 injection rate per well), the field depth, its location (on- or offshore) which are included. Finally, during the operational time of the field, costs are taken to measure, monitor and verify stored CO_2 for regulatory purposes.

After the economic lifetime of the project (taken as 40 years), fields and wells are closed down and handed over to the regulators. The storage costs include the costs of monitoring and verification of the field for a period of 20 years after its economic lifetime has passed. Storage costs also include a "potential liability fund", built up during its economic lifetime, the size of which is determined by the amount of CO_2 stored.

Figure 16 below summarises the methodology used in the storage cost computation model.

[19] www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html
[20] www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html
[21] www.geology.cz/geocapacity

1 Early commercial phase as basis

- Starting point for the model is the **early commercial phase**
  - Demonstration phase is modelled as a special situation
  - Mature commercial phase is assumed to be similar to the early commercial phase, i.e. only a low learning rate is assumed because of the re-utilisation of existing technologies from the mature E&P industry

2 Six discrete, realistic cases

- The model computes CO_2 storage costs for **six discrete cases**, based on **industry experience**, and varying on **three dimensions**:
  - Onshore vs. offshore
  - Depleted oil/gas fields (DOGF) vs. deep saline aquifers (SA)
  - Legacy wells present vs. no legacy wells present[1]

3 High number of parameters and sensitivity ranges

- **26 parameters** are modelled to determine the cost of CO_2 storage
- For **8 of these parameters**, sensitivity ranges have been run since these have a **material effect** on the outcome

4 All costs annualised

- All costs are **annualised** with the weighted average cost of capital, taking into account the time value of costs

5 Costs in €/tonne CO_2 stored

- The model computes CO_2 storage costs in euro per tonne of CO_2 **stored**, not abated. This ensures neutrality for different capture technologies
- The scope is Europe; for other regions, global variations in costs should be taken into account (e.g. rig costs). However, the trends between the 6 cases are expected to be the same.

1 SA fields have no legacy wells, so the three dimensions result in 6 discrete cases

Figure 16: The methodology used in the storage cost computation model

Annex 2: List of Tables and Figures