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GLOBAL STORAGE RESOURCES GAP ANALYSIS FOR POLICY MAKERS

Report: 2011/10

September 2011

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ACKNOWLEDGEMENTS AND CITATIONS

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GLOBAL ANALYSIS OF STORAGE RESOURCES AND RECOMMENDATIONS TO POLICYMAKERS TO MEET CCS DEPLOYMENT OBJECTIVES

Executive Summary

The IEA Greenhouse Gas R&D Programme (IEAGHG), on behalf of the Global CCS Institute, commissioned Geogreen to undertake a study reviewing the current global portfolio of operational and announced CO_2 geological storage projects, in the context of key CCS deployment targets for 2020: 20 operational sites stipulated by the G8; and 100 operational sites as described in the 2009 IEA CCS Roadmap 'Blue' scenario (limiting atmospheric CO_2 concentrations to 450ppm).

The Geogreen study included detailed modelling of the timescales and resources required for storage sites to achieve bankable status, whereby final investment decisions can be made in advance of site construction, commissioning and operations. Building on this analysis, the study showed that the current CCS project portfolio could allow the G8 target to be reached provided that adequate resources are made available for a large proportion of the proposed projects and that storage associated with CO2-EOR can be included.

However, the analysis also showed that the IEA Roadmap target for 2020 is effectively unattainable. Project lead times are long – up to 15 years for deep saline formation storage sites, accompanied by significant risks of project failure due to both technical (e.g. geological) and non-technical (e.g. financing, public acceptance) issues. Based on current projections and assuming adequate funding, Geogreen estimated that approximately 50 sites could be operational by 2025 or, with the inclusion of CO2-EOR projects, 100 sites by 2028. The latter will require up to 6 billion Euros of total investment to achieve the requisite number of storage bankability assessments, not including site construction and operational costs.

Hence the gap between the current global portfolio of CCS projects and roadmap deployment targets to mitigate greenhouse gas emissions is wide, being especially stark in non-OECD countries where only a small fraction of required project numbers have been announced. In the absence of adequate funding to resource storage site exploration and incentivise CCS, this gap will continue to widen as CCS falls further behind climate science – driven targets.

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Background to the Study

Establishing access to an adequate bankable CO_2 geological storage resource is a pre-requisite for investment in the construction of commercial-scale CO_2 capture and storage (CCS) projects. In this context, the term bankable refers to storage sites that have been evaluated such that sufficient confidence exists in technical and cost elements, to support final investment decisions. Regional mapping, exploration and characterisation of storage resources provides a critical technical, cost and timing element in the development of initial CCS projects that will pave the way for subsequent commercial deployment.

Geogreen was commissioned by the IEA Greenhouse Gas R&D Programme (IEAGHG), on behalf of the Global CCS Institute to undertake an analysis of requirements to realise bankable storage resources, in the context of existing global projects and key CCS deployment targets.

Scope of Work

The primary objective of the study was to alert policymakers to the scale, cost and timing of the storage resource assessment tasks to enable deployment of the 20 commercial-scale CCS projects by 2020 envisaged by G8 Leaders in 2008, and the 100 projects by 2020 as targeted in the 2009 IEA CCS Roadmap. In practice the challenge is to have sufficient bankable storage sites by 2015, so that CCS projects can be operational by 2020.

The study, comprising a literature review and desk based assessment, aimed to identify and prioritise the key storage resource gaps for each of the world's main carbon-intensive regions, and to outline the work programs (including time and costs) that would be required to fill those gaps to enable sufficient bankable storage sites to be defined to support the widespread commercial-scale deployment of CCS. These issues were considered both in the context of the G8 target and the 2009 IEA CCS Roadmap. Consideration was also given to subsequent wider deployment required over longer timescales (e.g. 2050) in order to make a significant contribution to mitigation of greenhouse gas emissions.

The existing evaluation of storage resources in developed countries, and the identification of the gaps in those countries, provided a reference framework for reviewing the evaluation status and gap analysis of storage in developing countries. The report summarised the status of storage resource evaluation in major world regions, identifying the distinctive challenges and key storage resource assessment tasks of each region in the timeframe aligned with 2020 targets.

A key objective was assessment for each region of the phasing and costs of the exploration and characterisation activities required to provide the bankable storage resource platform needed to support the CCS development outlined in the 2009 IEA CCS Roadmap, thus providing policy makers with reliable estimates of the corresponding phasing of resources that will be required to develop CCS in line with 2020 targets.

Findings of the Study

Review of Regional Storage Resource Assessments

The first stage of the study comprised a review of existing levels of deep subsurface geological knowledge. Largely dependent on exploration and production activities from the oil and gas industry, this knowledge level allowed qualification of the probability, cost and timescale for development of bankable storage resources.

The starting point for the assessment was the 2005 IPCC map of global storage prospectivity. Geogreen updated and expanded this map using information from subsequent storage research publications, and internal knowledge of global oil and gas exploration activities. Figure 1 presents a summary map of this work, used in the subsequent analytical sections of the report.

Development of Bankable Storage Resources

Geogreen developed workflows to identify the main project tasks required to achieve bankable status for commercial scale storage projects (100Mt CO_2 total capacity) in deep saline formations (DSF), depleted oil and gas fields (DOGF) and CO_2 enhanced oil recovery (CO2-EOR) schemes. Each project task was assigned probabilistic values for timescale and associated costs, with regional variations where appropriate. This information allowed probabilistic modelling of project time and resource requirements to achieve bankable status and formed the core of the subsequent analysis of current progress against key CCS deployment targets. An example workflow for DSF is shown in Figure 2 below.

The analysis needed to allow for project failure rates, which could be broadly related to either technical or non-technical factors. Technical factors would be mainly geological in nature and could include unsuitable reservoir characteristics, inadequate caprocks or unacceptable leakage risks; Geogreen allowed for technical project failure rates of between 10% and 40%, based partly on industrial analogues such as natural gas storage.

Non-technical project failures could be due to such factors as financing, public acceptance or regulatory requirements and the report noted that prediction of non-technical failure rates is relatively subjective. For this reason, non-technical failure rates were not specifically modelled within the bankability assessment workflows.

Figure 1. Global Suitability for CO_2 Geological Storage

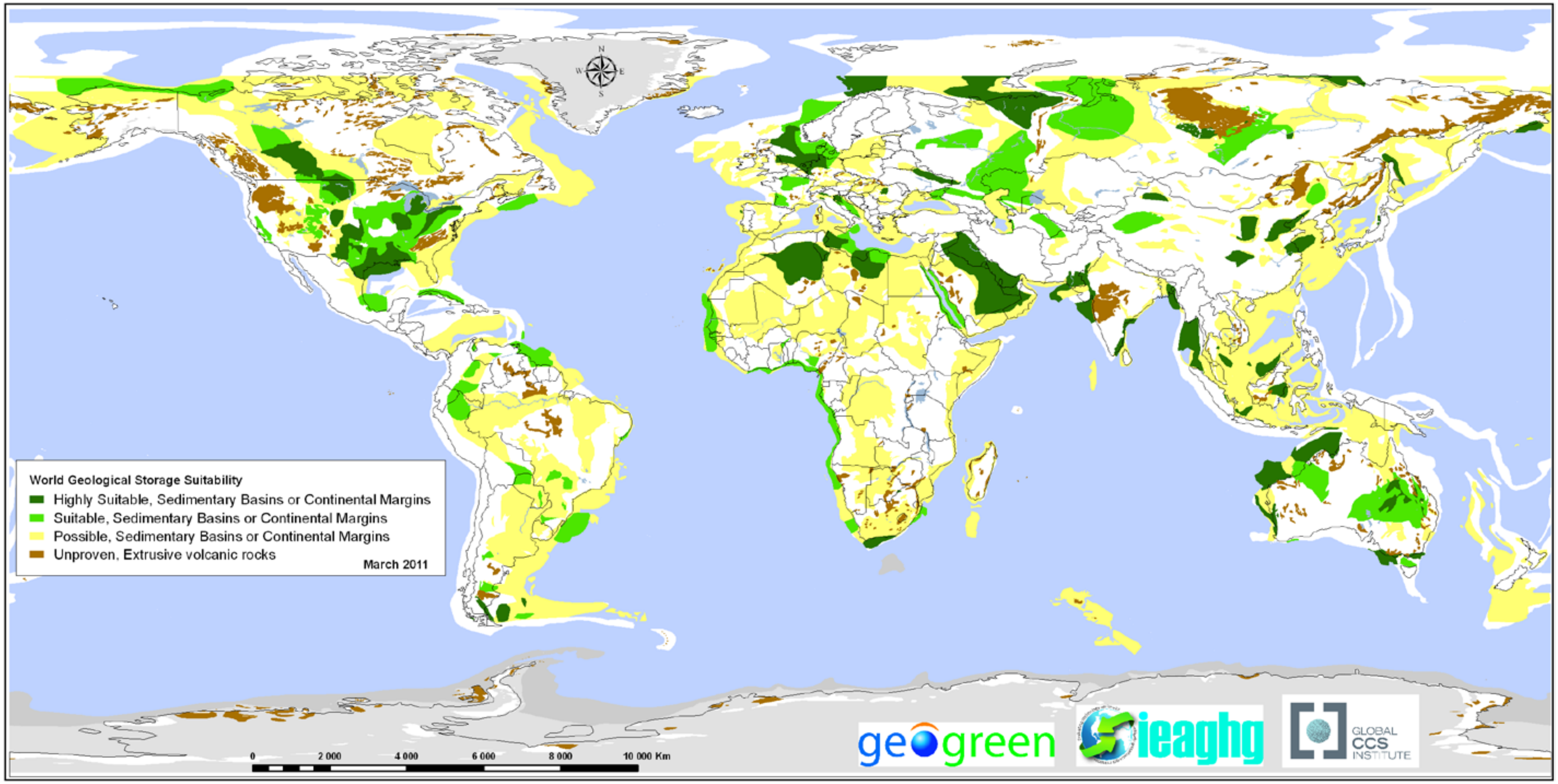


Figure 2. Project Phasing for Onshore Deep Saline Formations

Type of study	Phase	Major costs items
National based *Non exclusive surveys*	Phase 0 Screening	First desktop studies
	Phase 1 Desk Based assessment	Desktop studies, where possible seismic reprocessing and existing wells logs analysis (inluding communication on project)
	Licensing Exploration Permit	Admistrative engineering and follow-up
Project based *Exclusive surveys*	Phase 2 Site confirmation & characterization	Studies and engineering for this phase (including monitoring actions, equipments and monitoring (soil, gravimetric, Insar)) Seismic acquisitions 2D Seismic acquisitions 3D (on CO_2 future plume only) Civil Engineering Drilling CO_2 well with rotary rig (including 20% contingency including Mob/demob)
	Licensing Injection test	Injection test permitting
	Phase 2 Injection Test	Studies and monitoring Injection test duration CO_2 injection cost
Bankable		

Development of the workflows and subsequent analyses inevitably involved a wide range of other assumptions being made on technical, cost and time factors. Full details of the assumptions made in the modelling are detailed in the Geogreen report.

Key messages reported from the development of the bankability workflows can be summarised as follows:

- Considerable time periods are required for most projects to achieve bankable status – up to 15 years for DSF and DOGF, partly due to the sensitivity of licensing and environmental issues;
- The level of pre-existing geological knowledge can also have a major bearing on timescales and associated costs;
- Lead times to bankable status for CO2-EOR schemes could be shorter, typically 1 to 3 years, but the number of these opportunities could be constrained by geographical, safety and production issues.

Assessment of Key Targets for CCS Deployment by 2020

The study considered bankable storage requirements to achieve key CCS deployment targets, in the context of currently operational and announced projects. Geogreen created a database using a variety of online information sources, including IEAGHG, and identified a total of 124 relevant projects. Further screening of these projects due to scale and other criteria reduced the total relevant number to 54; in addition, projects which have already achieved operational or bankable status (e.g. Weyburn-Midale, Sleipner, In-Salah, Gorgon etc) are automatically regarded as contributing to the key deployment targets.

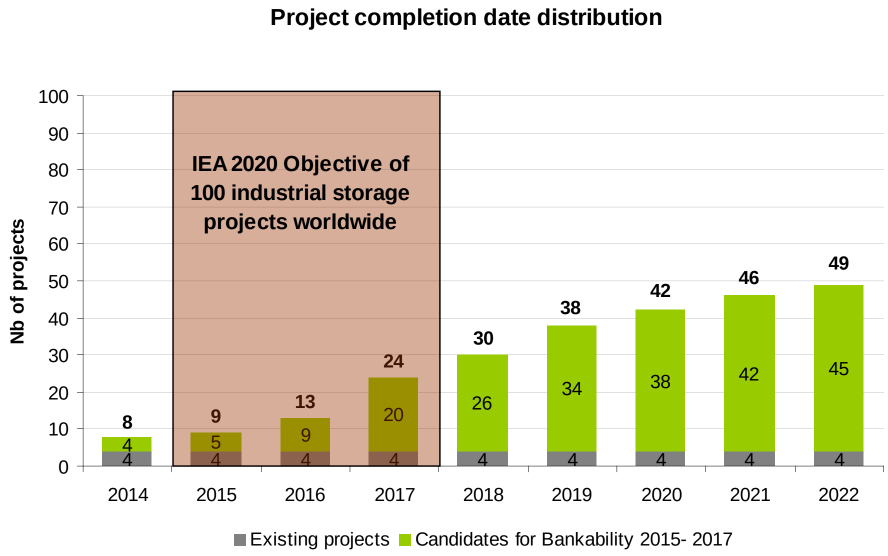
The workflow assessments for bankability described above allowed for technical failure rates for projects. Non-technical failure whilst not modelled was also discussed in the report; the study postulated that based on recent experiences of CCS proposals, between 14 and 24 of the current 54 announced projects considered by the study, could be cancelled due to non-technical factors, although inclusion of CO2-EOR projects in this context could reduce this failure rate.

2020 Deployment Targets – Excluding CO2-EOR

A key assumption made by the study was that all 54 announced projects would be able to proceed towards deployment. This assumption may of course be at odds with existing funding mechanisms, but provides a valid reference point for the analysis in the context of 2020 targets.

Figure 3 below shows the analysis of timescales required for current announced/operational DSF/DOGF projects to achieve bankable status. Note the gap between achieving bankable status and commencement of operations (for construction and commissioning) could be anticipated as typically 3 to 5 years, 2020 deployment targets require bankable status to be achieved between 2015 and 2017. Figure 3 shows that allowing only for technical failures, there ***may be*** sufficient DSF/DOGF projects announced to meet the G8 target of 20 projects – but the number of projects falls way short of the IEA Roadmap target of 100 operational projects by 2020. Rather, by 2025 only about half the target 100 sites might be operational.

Figure 3. Projected Timescales for Currently Announced DOGF/DSF Projects Achieving Bankable Status – Allowing for Technical Failure Rates



The Geogreen report included a regional analysis showing that whilst the number of announced DSF projects in OECD countries could theoretically achieve their required contribution to a 100 projects global target by 2025, non-OECD countries collectively fall far short of the same benchmark.

The study also reported the projected total cost of the bankability assessments described in Figure 3 as between 1.2 and 2.8 billion Euros, with a mean estimate of 2 billion. These costs relate to the achievement of bankable status and do not include site construction, commissioning and operational costs.

In order to achieve a total of 100 bankable projects by 2022 to 2025 (operational by 2028), Geogreen estimate an additional 60 projects would need to be announced by 2012. The total cost of achieving 100 bankable storage sites would be between 2.5 and 5.9 billion Euros.

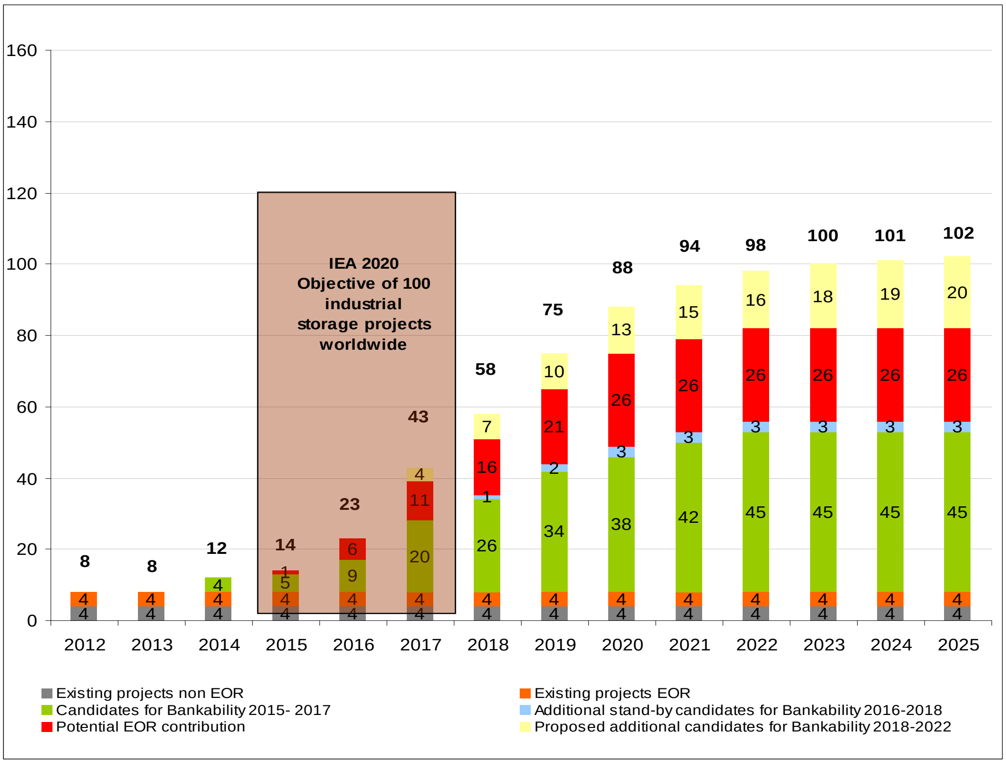
The above analysis does not allow for non-technical project failures, which could be due either to public/regulatory acceptance or financing issues. Quantitative assessment of likely failure rates due to these factors is problematic, due to the immaturity of commercial scale CCS and difficulty in finding meaningful industrial analogues. Geogreen conclude that non-technical failures may effectively more than double the failure rate from the 15% modelled for technical failures, ***giving an overall project failure rate of 30% to 40%.*** These higher failure rates serve to widen the gap between the number of current project announcements and key CCS deployment targets – achievement of the G8 target would become far more uncertain, whilst achievement of 100 bankable sites even by 2025 (operational by 2028) would require 85 new project announcements by 2012.

Potential Contribution of CO2-EOR

The report discusses some key issues relating to the inclusion of CO2-EOR projects in CCS deployment targets; CO2-EOR projects must utilise anthropogenic CO_2 sources and be accompanied by an appropriate MMV plan to satisfy storage regulations. In the context of current or near-future CCS projects, inclusion of CO2-EOR could increase by approximately 75%, the number of bankable CCS projects by 2018.

Therefore, as a result of including CO2-EOR projects in the analysis, achievement of the G8 target by 2020 becomes likely, non-technical issues notwithstanding; whilst the gap between announced projects and achieving 100 bankable sites by 2025 is narrowed or even closed. This is summarised in Figure 4 below, which provides direct comparison to Figure 3 and therefore does not include non-technical failure rates.

Figure 4. Projected Timescales for Storage Projects Including CO2-EOR Achieving Bankable Status – Allowing for Technical Failure Rates



2050 Deployment Targets

The 2009 IEA Roadmap states a target of 3,400 operational projects by 2050 in order that CCS provides the required share of emissions reduction measures to stabilise atmospheric concentrations of CO_2 at 450ppm, with approximately 150Gt of storage needing to be achieved by that date.

The study included a short, qualitative assessment of project needs for this 2050 goal. Geogreen noted that anticipated long term trends could include a decrease in project failure rates as practical experience of CCS operations is gained, and a gradual reduction in the proportion of storage in CO2-EOR projects. The study estimated that 3,750 sites might need to achieve bankable status prior to the 2050 date to reach the target, with an associated cost exceeding 100 billion Euros. The long term viability of CCS may also require the development of distribution networks linking multiple sources and sinks, and the resolution of any cross border issues.

Expert Review Comments

Expert comments were received from 6 reviewers representing industry and including corporate sponsors of IEAGHG. The overall response was positive and highlighted a significant contribution the study could make to this area of storage policy research.

Key suggestions made by reviewers and incorporated into the final report included clear statements of all significant assumptions made in the modelling and assessment, and the inclusion of CO2-EOR as an important storage option.

Conclusions

Compilation of detailed workflows for commercial scale storage sites (100Mt CO_2 storage capacity) to achieve bankable status – whereby final investment decisions can be made – has facilitated probabilistic assessment of development timescales and associated costs for projects utilising DSF, DOGF and CO2-EOR storage sites. This modelling has demonstrated long lead times for bankable status, typically 5 to 15 years for DSF and influenced by factors such as the level of pre-existing site characterisation, environmental risks and permitting requirements. Lead times for storage projects associated with CO2-EOR are typically shorter at between 1 and 3 years.

The study considered current operational and announced CCS projects in the context of key CCS deployment targets. Geogreen identified, in addition to 8 operational/imminent projects, a further 54 announced CCS projects that could progress to commercial operations. Technical failure rates of these proposed projects (e.g. due to geological factors) were assumed in the study to average 15%. Non-technical failure rates (e.g. public acceptance, financing) were not explicitly modelled, although the study suggested such factors could increase the overall project failure rate to between 30% and 40%.

The analysis showed that the current operational/announced global CCS project portfolio has the potential to achieve the G8 target of 20 operational projects by 2020, ***provided adequate funding for all projects is available*** and particularly if CO2-EOR projects are included. Conversely, the 2009 IEA CCS Roadmap target of 100 operational sites by 2020 ('Blue' scenario, charting progress required for stabilisation of atmospheric CO_2 at 450ppm) is extremely unlikely to be achieved without a large number of additional and immediate project announcements; the current portfolio of announced global projects is more likely to deliver approximately 50 operational projects by 2025, given adequate funding. A more realistic target date for 100 operational projects of 2028 could be achieved, aided by the inclusion of CO2-EOR projects and again notwithstanding financial and other non-technical issues. The gap between current efforts and deployment targets is most marked in non-OECD countries.

The 2009 IEA Roadmap also includes a target of 3,400 operational projects by 2050, with a cumulative 150Gt of CO_2 stored by that date. The study estimated an additional 3,750 sites would need to achieve bankable status between 2025 and 2050 to achieve this target, with likely long term changes including a proportional decline in the importance of CO2-EOR for storage and a decrease in proposed project failure rates as the CCS industry matures.

The study has also reported a range of modelled costs for storage sites to reach bankable status in the context of deployment targets. These costs effectively relate to site characterisation, assessment and permitting but do not include site construction, commissioning and operations. Progression of the current set of 54 announced projects towards bankable status could require between 1.2 and 2.8 billion Euros, whereas achievement of 100 bankable sites would require between 2.5 and 5.9 billion Euros. Long term achievement of 3,400 operational sites by 2050 would require investment of over 100 billion Euros just for bankability assessments.

Recommendation

Key messages derived from the study should be communicated widely to policymakers, regulators and other stakeholders in CCS deployment. These messages can be summarised as follows:

- Proposed projects will be subject to both technical (e.g. geological) and non-technical (e.g. financing) risks of failure; consequently, it is important to have a large enough portfolio of proposed projects to achieve deployment targets;
- The long lead times for storage sites to reach bankable status and subsequently, operational status require storage assessment to be commenced at an early stage in relation both to individual CCS projects and deployment targets;
- Only if funding is available to many or all currently announced projects and/or storage associated with CO2-EOR is included, can the G8 target of 20 operational commercial CCS projects by 2020 be realised;
- The gap between the 2009 IEA CCS Roadmap milestones and projected progress of the existing global portfolio of announced CCS projects, especially in the context of current resourcing/funding, highlights that CCS deployment is falling behind targets to mitigate greenhouse gas emissions. This gap is especially stark in non-OECD countries.

Consulting Engineering Operation

Global Analysis of Storage Resources and Recommendations to Policy Makers to Meet CCS Deployment Objectives

A Report For:

ieaghg

GLOBAL CCS INSTITUTE

www.geogreen.fr

This report has been prepared by Geogreen for the IEAGHG and the Global CCS Institute following call for tender IEA/CON/10/180

Geogreen is an international company dedicated to CO_2 capture and storage (CCS) development and carbon management strategy, offering consulting and engineering services for the transport and geological storage of CO_2. Geogreen in-house expertise ranges from technical (subsurface, transport, capture, life cycle assessment), to economical (cost estimates, investment optimization through real options assessment), and regulatory (analysis of present and future regulatory frameworks in Europe and North America).

This report was prepared by Jonathan Royer-Adnot, Gilles Munier, Yann Le Gallo, Anthony Lecomte, and Cameron McQuale.

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REVISION RECORD

Revision	Date	Established	Checked	Project	Approved	Issue for
0	02/20/2011	Y. Le Gallo, J. Royer-Adnot, A. Lecomte, C. Mc Quale	G. Munier	Y. Le Gallo	G. Munier	First Issue
1	03/11/2011	J. Royer-Adnot, G. Munier, Y. Le Gallo	G. Munier	Y. Le Gallo	G. Munier	Revised issue with Executive summary and section on offshore costs in Appendix
2	07/20/2011	J. Royer-Adnot, G. Munier, Y. Le Gallo	G. Munier	Y. Le Gallo	G. Munier	Revised issue with inclusions that follow comments from IEA GHG reviewers
3	24/08/2011	J. Royer-Adnot,	Y. Le Gallo	Y. Le Gallo	G. Munier	Revised issue following review by Global CCS Institute

EXECUTIVE SUMMARY

The storage of carbon dioxide (CO_2) is broadly accepted today among numerous international organizations as necessary in order to achieve present emission reduction targets in a timely manner. As a result, Carbon Capture and Storage (CCS) technologies are set to play a central role as an emission mitigation solution across the global economy and as such are included within the framework of existing pragmatic plans to reduce anthropological emissions. By 2050, the International Energy Agency (IEA) projects that 3,400 CCS projects would represent 20% of the necessary effort to stay below a global average temperature increase of 2°C (corresponding to a CO_2 atmospheric concentration of 450ppm by 2100). Following IEA, Green House Gases (GHG) reduction costs would potentially be 70% higher without CCS technologies.

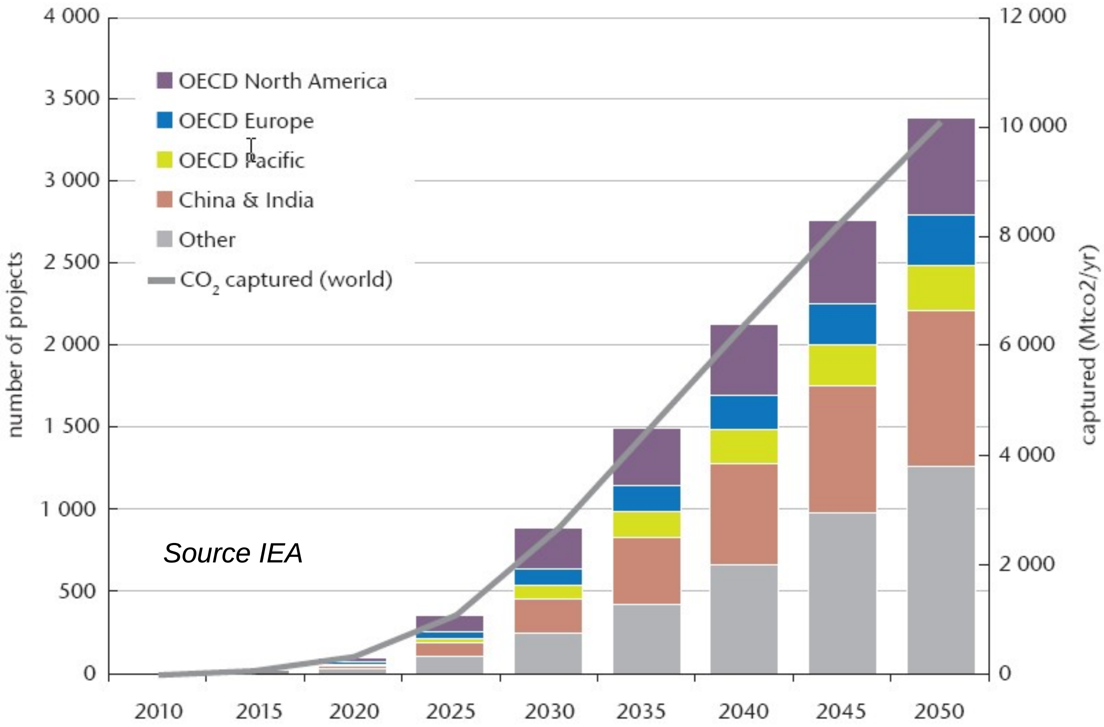

Figure 1: Global CCS project deployment - IEA Blue Map scenario[30]

The first major milestones for this achievement are the G8 objective and commitment to support "the launching of 20 large-scale CCS demonstration projects globally by 2010 taking into account various national circumstances with a view to beginning broad deployment of CCS by 2020". Although not formally endorsed by any jurisdiction, the IEA analysis [29] recommends that 100 projects should start commercial injection by 2020 in order to keep abreast with existing GHG mitigation targets (2°C increase by 2100).

The availability of CO_2 storage options in a timely manner for CCS projects shall drive this ambitious deployment. Storage exploration, as any other geological activity, is not always successful. As such, some of the storage sites might not achieve their intended industrial scale for technical reasons. Additionally, the above mentioned deployment scale and milestones must take into account the necessary and often fixed development time of such storage sites.

Such fast track development needs a quick and strong political support as well as a state-based financial funding scheme that must be consistent with typical development time required for the storage part of the CCS chain. Like all activities related to geology, storage operations are not straight forward: 4 to 12 years are necessary to confirm the bankability of a storage site[1]. After such bankability threshold, 1 to 3 years are needed to start industrial injection[2]. Therefore, investments required for storage characterization and bankability assessment must be anticipated soon enough not to jeopardize deployment targets as set out above.

Several countries have developed financing scheme and set incentives to deploy CCS technology. It is now legitimate to assess on the storage standpoint if the current effort could allow developing the number of CCS projects needed to attain the 2°C global temperature increase target by 2100. In this analysis, we took into account storage sites development success (or failure) rates and development time to properly quantify the appropriate number of sites to be launched so as to meet the 450ppm scenario of IEA in 2020 and 2050. As far as storage site developments are concerned, 2020 is tomorrow. This is the primary objective of this study that was commissioned by IEAGHG and Global CCS Institute.

The study then gives insights to meet the 2050 recommendation.

For this report, Geogreen has employed a bottom-up analysis to allow policy makers to better understand:

1. Whether a sufficient number of "bankable" storage projects exist to meet the storage needs implied by the current global commercial-scale CCS deployment goals,

2. Where the storage development gaps exist, globally and regionally, if the number of bankable sites is found to be insufficient, and

3. How to address any identified gaps through appropriate work programs (including estimated timing and costs).

To answer these questions we developed specific storage development workflows which explain the steps needed for storage characterization. These workflows follow a probabilistic approach to assess the costs and development times of the storage bankability assessment of CCS projects.

[1] A storage site is bankable if it has been evaluated such that sufficient confidence exists in technical and cost elements to support final decisions for commercial-scale investment.
[2] This phase can even take up to 5 years in certain conditions

Our analysis showed an obvious gap between the effort currently engaged in CCS and what is needed according to IEA 450ppm scenario. The key points of the answers for the two first questions are given in the next section:

The gap between existing effort and what is required by 2020:

1. CO_2 storage development deserves more attention from policy makers and emitters

Storage site bankability assessment takes time because it is an iterative process as with all industrial activities dependent on geological characteristics. The level of geological knowledge in an area has a significant impact on storage development costs and times up to bankability. Additionally, taking into account regulation requirements for Deep Saline Formation (DSF) and Depleted Oil and Gas Fields (DOGF), between 4 to more than 15 years in worst cases for DSF may be needed to develop a storage site up to bankability.

Most of existing projects might achieve storage bankability between 2017 and 2020 and be commercial by 2018-2023.

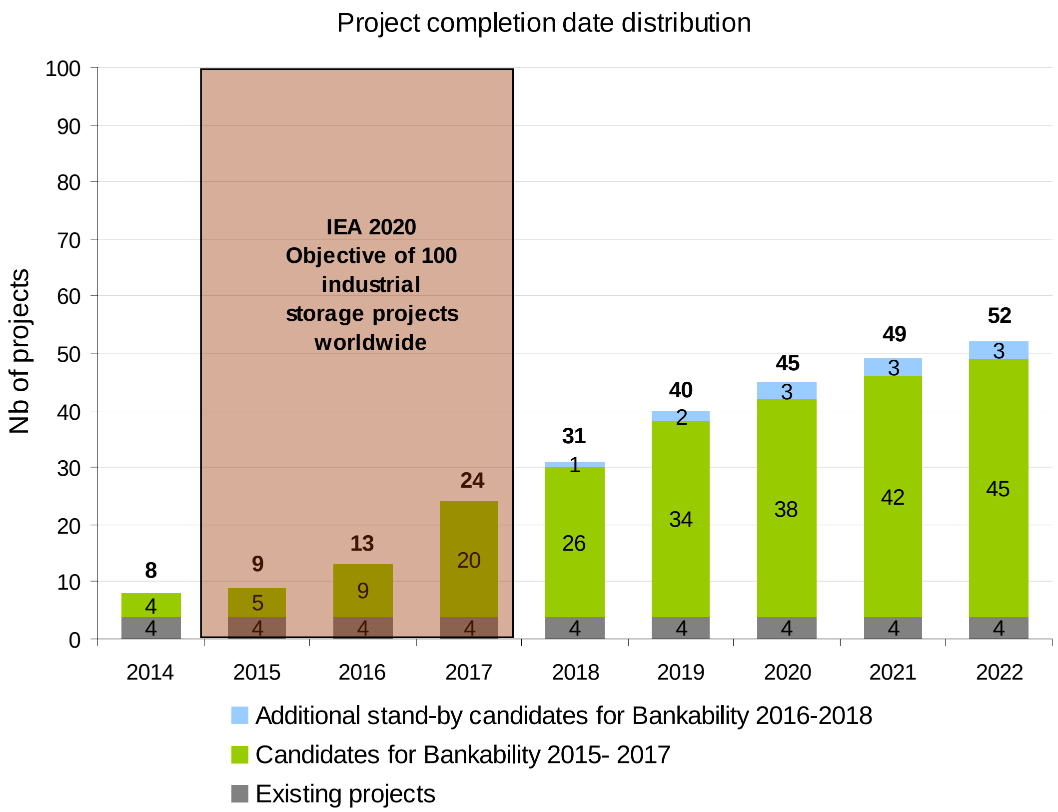

Figure 2: Yearly distribution of projects reaching bankability amongst presently declared projects

The required investments for storage bankability assessment are marginal as compared to overall CCS chain capital needs. It represents generally less than 10% of the latter. A lack of investment in the storage part of a CCS project in the first years of development may lead to important delays in commercial scale start-up and development objectives achievement. Given the required number of CCS projects to meet the IEA recommendation, public funding currently in place for storage development are not at the appropriate scale.

2. The current number of projects is not appropriate to deliver 100 commercial projects by 2022-2025

The study shows that there is a structural failure rate of storage bankability assessment of 15 to 20% at world level linked to technical (mainly geological) factors. Consequently, the gap of commercial projects by 2025 is around 60.

Non technical failures like financing, public acceptance and regulation can be very important and further widen the gap. If we take into account past observed cancellation rate of CCS DSF projects, only between 30 and 40 of the 54 announced large scale projects could become bankable, at best. In that context, the gap of commercial projects by 2025 would be more than 85 projects.

Such gap can be decreased when including CO_2-EOR projects.

The regional distribution of the gap is as follows:

- On the technical standpoint, OECD Europe and Australia have enough projects launched in order to meet IEA 2020 regional recommendation;
- Even if North America is leader in CCS development, additional projects are needed to meet IEA 2020 regional recommendation;
- More than 45 technically bankable projects (45% of the needed 100 projects) are missing in developing countries.

3. The existing incentives and funding schemes are not adapted to the climate change objectives

The 21 billion Euros earmarked thus far for large scale CCS projects concern only developed countries. Currently, there is no major public funding announcement for developing countries although their expected contribution to the overall effort of CCS deployment is close to 50%.

- Worldwide, the present level of funding would only allow between 14 (32) and 21(46) projects without (with) CO_2-EOR to be financially sound and developed.

- Even G8 objectives of 20 commercial scale CCS projects might not be achievable in the time window without CO_2-EOR.

Taking into account what CCS industry is able to technically deliver and including EOR, it is possible to obtain 100 bankable storage sites by 2025 only if between 85 and 97 storage bankability assessments are financed by 2012. Between 1 -3bn€[3] extra public funding would allow launching enough storage bankability assessments to have 100 storage sites ready by 2022 / 2025.

4. CO_2-EOR is an opportunity that might reduce necessary public funding on the short term but is not available in all regions

In the current financing framework, CO_2-EOR has the potential to increase by 70 to 80% the number of projects that can reach bankability

For storage bankability assessment, CO_2-EOR could reduce public funding to obtain 100 bankable storage projects by 2022-2025. Such reduction could be up to 50% (0.5 to 1.5bn€). One shall note that public funding should still be necessary for development of capture and transport parts of the chain if global incentives are too weak to justify private investments (low CO_2 price for instance).

The contribution of CO_2-EOR to the global effort is limited by the following factors:

- On the mid-to-long term, CO_2-EOR projects might require the development of nearby aquifer storage projects in order to cope with CO_2 emission reduction constraints (constant flow rate of captured CO_2 during the plant life time).
- They are not distributed evenly between countries (oil and gas producing provinces).
- Not all fields are suitable for conversion to CO_2 storage or CO_2-EOR.
- There is a specific time window of opportunity that can be used for conversion of the field. This window of opportunity depends on each field producing costs versus oil and gas prices and also upon technical constraints (among others, water invasion of the reservoir, surface facilities compliance with CO_2 rich streams).

Public acceptance issues over CO_2-EOR projects funding should not be neglected. In time of financial austerity, public acceptance of CO_2-EOR funding might jeopardize project developments and therefore diminish CO_2-EOR contribution to storage in some regions. Moreover, the current debate about shale gas production in some countries, particularly in Europe, might damage public's trust towards project developers.

[3] bn€ = billion (10^9) Euros

5. All types of storage must contribute to the global effort

Depleted Oil and Gas fields and CO_2-EOR although being attractive options suffer from some limiting factors such as their location limited to oil and gas producing provinces, the impossibility to convert safely all the fields and the time window issue.

Deep Saline Formations present a huge potential but are not well known and need more time and money to be developed.

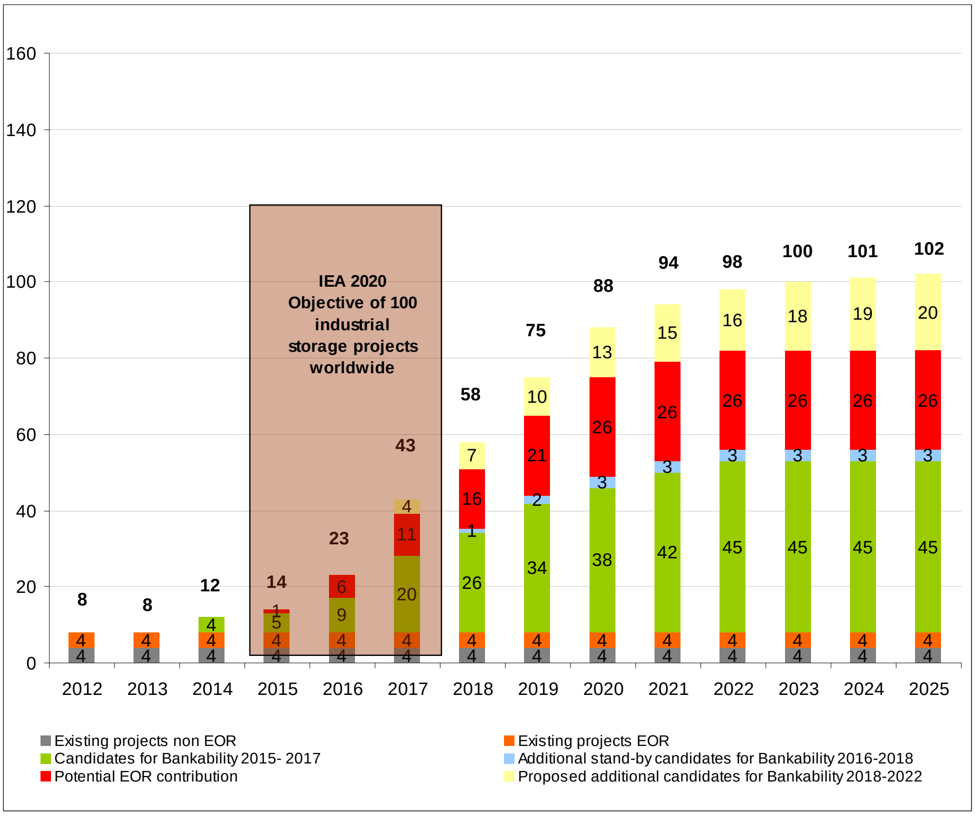

Figure 3: Cumulative distribution of the number of projects with CO_2-EOR (Low case - 23 projects)

How to fill the 2020 gap through appropriate work programs?

The following 5 actions should be taken to develop CCS to the scale needed to mitigate global warming.

1. **Improve the knowledge of subsurface in areas where large volumes of CO_2 might be captured in order to save development time for future commercial CCS projects.**

   To avoid further delay in meeting IEA recommendation, the first phase of CO_2 storage development, generally a national or regional level capacity assessment, should be launched rapidly by policy makers. However, one shall note that as of today, no jurisdiction has endorsed this target as policy.

   This phase, 1 to 2 years long, provides a framework for discussion and development of local storage projects. The following Figure 4 shows the areas where such an effort should be focussed on. In these areas, extensive oil and gas production data if made available, could lead to initial capacity characterization with the use of desk based assessment only (no need for new data acquisition in this first step).

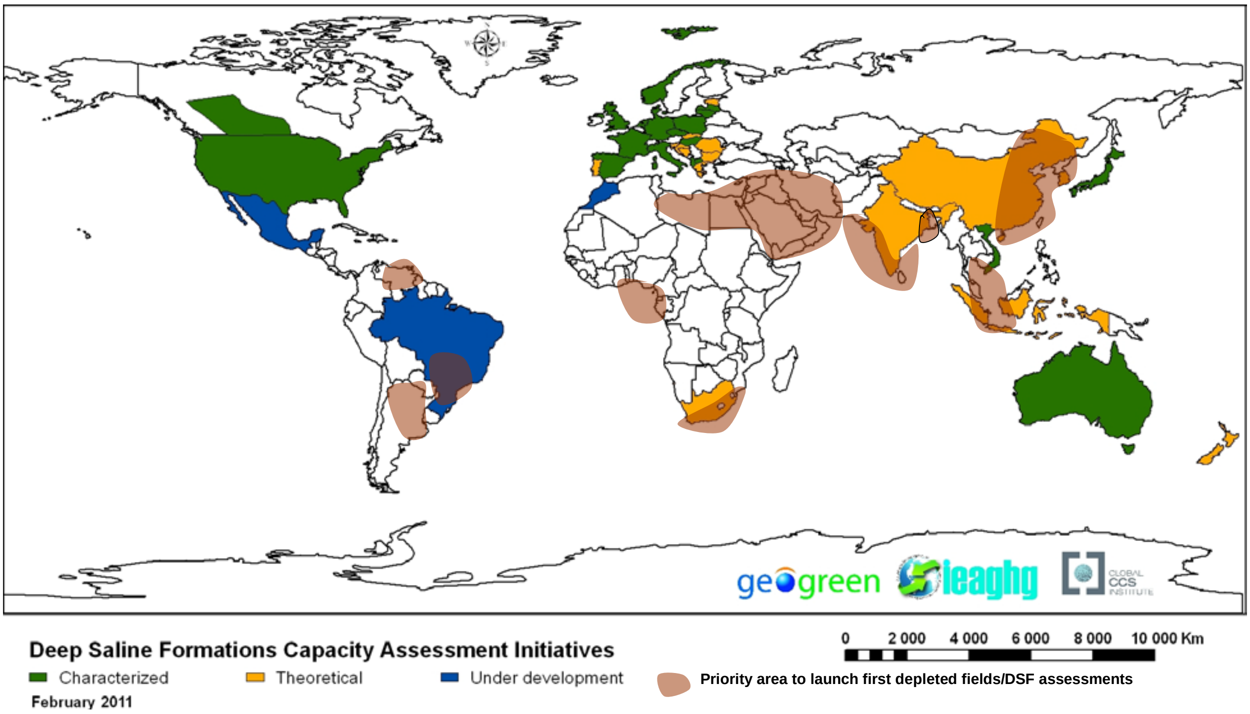

Figure 4: Required regional storage resource assessment studies to avoid further delay

2. **Ensure regulatory framework is suitable for CO_2 storage and support project developers towards public acceptance to reduce non technical failure causes**

   In addition to project financing issues, there are two other causes of non technical failure for storage project development: not adapted regulatory framework and public acceptance issues.

   Having a regulatory framework for CO_2 storage is very important for the project developers to evaluate the cost and time effort needed in the characterization phase. Indeed, regulatory framework for industrial CO_2 storage will have an impact on CO_2 storage characterization process.

   As an example of key regulatory aspects, the issue of medium to long term liabilities is very important to settle for project developers, since it impacts the costs and risks of the project.

   Public acceptance is another key issue to be addressed. It is particularly true for onshore storage projects. Active government support and proper local communities up-front involvement are mandatory to make public understand the key reasons and outcomes of CCS deployment. There is a long way to go in order to promote CCS benefits for climate change mitigation, territorial development, societal and local stakeholders.

3. **Increase or create incentives for private stakeholders to launch bankability assessment as soon as possible to avoid further time delays**

   There is not enough public funding to attain100 bankable projects by 2020 or even 2025. There are also very limited incentives for private investors to invest in storage bankability assessment although this phase is time consuming (4 to 10 years or more), and represents a marginal cost as compared to the overall CCS investment.

   It would therefore be wise to finance storage characterization programs in order to have storage sites ready when emission mitigation incentives will be sufficient to sustain private investment in CCS (expected between 2020 and 2030).

   This storage characterization programs should be preferably located next to important CO_2 emission hubs.

   If we consider CO_2-EOR contribution, our analysis shows that at least 42 large scale new storage bankability assessments (30 DSF/DOGF and 12 EOR) should be launched by 2012 in order to obtain 100 storage sites by 2025. The 30 DSF/DOGF projects represent an extra public funding requirement ranging between 0.5bn€ and 1.5bn€ worldwide (this assumes an overall subsidies rate of 50% to 75% per project for the storage part). Actually, we assume that the necessary assessment costs for bankability of the 12 CO_2-EOR projects are made by the oil field operators themselves for the sub-surface part, with no contribution from public funding.

However, there are huge regional discrepancies in terms of financing. While some countries like the US or China, can widely use CO_2-EOR, others regions in Europe, OECD Asia and Africa do not have the same extent of mature oil fields to exploit for CO_2-EOR. In order to launch necessary storage development in emerging economies, an international mechanism should be developed to allow fund transfer from the North to the South. It is not clear whether or not the Kyoto Clean Development Mechanism is adapted to this mission. CDM stream of revenue is available only when the projects as started and storage bankability has already been assessed. Nevertheless, as mentioned earlier, the CO_2 price perspectives are not sufficient to convince private investors of developing storage projects at the needed scale.

4. Increase or create incentives to provide a business case to CCS

The inclusion of CCS under CDM mechanism in Cancun is a first positive step to provide a revenue stream to projects in developing countries. However, the perspectives over CCS-CDM methodology acceptance timeline are still uncertain. As shown in this study, storage development in developing countries can be less costly than in developed countries.

Lack of revenue stream to these projects could jeopardize the achievements of storage development ambition.

5. Capitalize on low cost industrial early opportunities and BECCS

CCS is often associated with coal or fossil fuel power generation because the power sector is a huge contributor to CO_2 emissions. However, as mentioned in IEA World Energy Outlook and Energy Technology Prospective, almost half of global CCS deployment should concern emissions from other industrial sectors.

Opportunities of low cost capture exist for industrial sources with high CO_2 purity. These “easy to capture” sources are located in industrial basin worldwide and storage bankability assessment efforts should be focussed in consistency with their locations.

Such interesting opportunities can be identified in developing countries. Among them we can mention bio ethanol production associated with CCS (leading to a net reduction of atmospheric CO_2), natural gas processing, ammonia and fertilizer production, and refining activities under development in Africa, Middle East, South East Asia, China and India.

As they might potentially be carbon sinks for CO_2 from the atmosphere, the Biomass Energy with CCS projects [24] might be an efficient early opportunity as long as the biomass is grown in an environmentally responsible way. Such projects may catch up part of the delay in implementation of the GHG mitigation objectives, since biomass being carbon neutral, more carbon is stored than emitted. Policy makers should provide these projects with an adequate framework to monetize non anthropogenic CO_2. Such early opportunities have been recently studied by UNIDO [54].

Finally, we would like to stress the importance of early planning of storage development and assessment. In a decarbonised world a CO_2 storage site can be an incentive for development of territories and industrial areas.

Good examples of this concept are the CCS hubs presently being studied like the Tee Valley in UK, the Rotterdam Climate Initiative in the Netherlands. Alberta is also looking to on territorial development by subsidising a CO_2 transport network where sources and sinks could be connected.

How to achieve the required deployment by 2050?

The four main drivers relative to storage project development beyond 2020 and 2030 are:

1. **Storage development time will reduce and success rate will increase** due to better knowledge of subsurface, of CO_2 storage mechanism, and experienced regulatory frameworks.
2. **Storage site developed in 2020 might reach end of life by 2050** and will have to be replaced by new injection sites.
3. **Important** regional differences exist in terms of capacity and source sink matching. This leads to the development of massive CO_2 transport facilities.
4. **More than 100bn€ would be needed to develop 3750 storage bankability assessments as** .proposed by the IEA "Blue Map" This should be supported by private stakeholders if the necessary incentives are in place.

Some key challenges will have to be faced in the decades to come to meet the ambitious development targets:

1. **Behaviour of CO_2 in the subsurface must be carefully assessed** and adequate tools developed, building in part on the experience gained through EOR. . This is a critical point to define the numbers of projects that can be developed in a given area and assess their long term interferences.
2. **CCS network development is an important near term step for sound storage project deployment.** Many R&D projects are currently underway. The importance of storage networks in terms of territory development and jobs creation as well as their feasibility should be broadly assessed. All storage options must be considered in a timely manner to ensure long term storage availability.
3. **Long distance and cross-border issues for CO_2 transport will have to be addressed for countries with limited national storage capacities.** This is a major challenge in terms of cost, regulation, and public acceptance. Joints efforts between industrial and public stakeholders seem necessary to develop such infrastructures.

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1. OBJECTIVE AND RATIONALE

1.1. Major objective of the study

CCS is a technology recognised by many international organizations as a key technology to mitigate CO_2 emissions. For instance, in 2008, the G8 resolved to launch 20 commercial scale CCS projects worldwide by 2010 in order to demonstrate the technology. In its 2009 blue map scenario analysis and CCS roadmap, IEA estimated that 100 CCS projects are needed worldwide by 2020 and 3100 by 2050 if we want to maintain global warming below the 2°C increase target by 2100 (assuming 450 ppm). It also calculated that not using CCS as a CO_2 mitigation option would mean a 70% increase of total investment to meet the above mentioned reduction target.

The availability of CO_2 storage options in a timely manner for CCS projects shall drive this deployment objective. Storage exploration, as with any other geological activity, is not always successful. As such, some of the storage sites might not achieve their intended industrial scale for technical reasons. Additionally, the above mentioned deployment objectives and milestones must take into account the necessary and often uncompressible development time of such storage sites.

It is then legitimate to include such storage sites success (or failure) rates and development time to quantify the appropriate number of sites to be launched so as to meet the IEA 450ppm recommendation in 2020 and 2050. At storage site development scale, 2020 is “tomorrow”. This is the primary objective of this study that was commissioned by IEAGHG[4] and Global CCS Institute.

The study then gives insights for meeting the 2050 recommendation.

Our objective is to allow policy makers to better understand:

1. Whether a sufficient number of “bankable” storage projects exist to meet the storage needs implied by the current global commercial-scale storage deployment goals,

2. Where the gaps exist, globally and regionally speaking, if the number of bankable sites is found to be insufficient, and

3. How to fill such gaps through appropriate work programs (including estimated timing and costs).

[4] Environmental Projects Ltd serves as the operating agent that manages the common research funds for the IEA Greenhouse Gas R&D Programme (henceforth the IEAGHG)

1.2. Overview of the proposed Methodology

Firstly, publicly available data regarding world distribution of storage resources have been cross-checked with global large scale geology, and history of hydrocarbon exploration in sedimentary basins. Such cross-checking defines the concept of storage suitability that we propose to map according to four classes: highly suitable, suitable, possible, and unsuitable areas.
The technical bankability concept is a cornerstone of this study. Storage site are considered bankable when sufficient confidence exists to support final investment decisions for launching commercial-scale (or industrial scale) projects. Bankability is therefore dependent upon various parameters. Whereas it is possible to evaluate the technical parameters influencing bankability (cost, development time and success ratios), it is quite difficult to assess subjective considerations such as public acceptance, economic situation, and national policy. Consequently, we have made our evaluation of bankable projects in two steps:

1. Technical bankability which relies upon technical parameters as stated above.
2. From the results obtained in step one above, considerations and discussions are suggested to take into account the potential reduction of projects due to influence of non technical parameters.

We have followed an original bottom-up approach to quantify where, when, and for how much necessary storage sites have to be developed to meet 2020 and 2050 recommendations. Storage development workflows have then be conceived for onshore and offshore deep saline aquifers, and depleted oil and gas fields. Pending the suitability of the area where a given project is located, probabilities of success, cost, and time required to achieve bankability were assessed.

The study considers storage in porous media only (deep saline formations, depleted hydrocarbon fields). The number of existing EOR/EGR[5] projects was however assessed and their potential contribution to meeting the targets of GHG[6] reduction was discussed. Projects of CO_2 injection in coal seams and basalts were not considered, given their immaturity to support the 2020 deployment recommendation.

The study considers regions as follows:

- OECD countries
  - North America: Canada, USA, Mexico
  - Europe : European Union and former Eastern bloc countries
  - Pacific: Australia, New Zealand
- Non OECD countries
  - China, India
- Other non OECD regions
  - Africa
  - Middle East
  - South America

[5] Enhanced Oil Recovery / Enhanced Gas Recovery
[6] GreenHouse Gas

- South East Asia: Malaysia, Vietnam, Indonesia, Japan

Two major specific tools have been developed during the study:

1. World map of CO_2 storage suitability as of today: Taking into account IEA GHG reports and other relevant sources, the study makes a comprehensive review of the storage projects and initiatives worldwide in order to build a reference baseline according to which the development of storage projects should be assessed in carbon intensive regions.

2. CO_2 storage development workflows for various cases (onshore / offshore / deep saline formations / depleted oil and gas fields). They include the clearly iterative nature of storage exploration, and the different steps of the storage characterization process.

2. DEFINITIONS

This section aims at defining some of the key terms and concepts used in the study.

- **Abandoned: relatively to Storage projects, stands for a project declared as being dropped**
- **Bankability:** following the wording of the Invitation to Tender IEA/CON/10/180, a bankable site is a storage site that has been evaluated such that sufficient confidence exists in technical and cost elements, to support final investment decisions for commercial-scale projects.
- **Commercial Scale project:** stands for a project that is beyond bankability, and for which final investment for injection above 1 million tonnes of CO_2 per year has been made, and that is ready to inject
- **Currency:** All costs are expressed in Euros. M€ stands for Million Euros (10^6 Euros) and bn€ stands for billion Euros (10^9 Euros). A conversion rate of 1.3 US dollar/Euro was used.
- **Deep saline formation:** water bearing formation whose salinity is exceeding sea water salinity
- **Deep water:** stands for sea water thickness of more than 300m
- **Depleted hydrocarbon field**: an hydrocarbon (either oil or gas) field that has reached the end of its lifetime
- **EOR – EGR:** enhanced hydrocarbon (either oil or gas) recovery
- **Exploration:** stands for phase of Storage project development which includes proper site characterization and validation through well drilling, 2D and/or 3D seismic, injection test, and corresponding engineering studies
- **Failure cost:** stands for the cost distribution of the storage part of a Storage project that has failed reaching bankability for technical (not financial nor administrative) reasons
- **Failure ratio:** stands for the probability of the storage part of a Storage project to fail reaching bankability for technical (not financial nor administrative) reasons
- **Geological Province**: stands for a spatial entity with common geologic attributes. A province may include a single dominant structural element such as a sedimentary basin, or a number of contiguous related elements. Adjoining provinces may be similar in structure but be considered separate due to differing histories.
- **GIS**: stands for Geographical information System
- **IEA 2020/2050 Recommendation**: Stands for the analysis and recommendation of International Energy Agency over the number of CCS project to be deployed

by 2020 and 2050 respectively to achieve climate change mitigation objectives (450ppm blue map)

- **Injection test:** stands for a CO_2 injection in a very limited quantity (up to 50,000 tonnes). Such injection test leads to bankability of a Storage project
- **Jack-up rig:** stands for a mobile bottom-supported offshore drilling structure with columnar or open-truss legs which can only be used in relatively shallow water depth (up to about 120m)
- **Licensing:** stands for the filing of an application to given national authorities for granting of an exploration license, or an injection test authorization
- **MAGT:** Migration Assisted Gravity Trapping, which stands for the counter effects of upward migration of gaseous carbon dioxide inside a dipping sedimentary formation, while the heavier density of carbon saturated brine balances this effect by downward migration of the same.
- **Mobilization / Demobilization:** stands for all operations related to bringing to site the required equipments (seismic equipments, drilling rig, logging tools…)
- **OGIP:** stands for originally gas in place. For a given gas field, it gives the amount of hydrocarbon contained inside a given trap.
- **OOIP:** stands for original oil in place. For a given oil field, it gives the amount of hydrocarbon contained inside a given trap.
- **Probabilistic distribution:** stands for a function of a discrete random variable (cost or time) yielding the probability that the variable will have a given value.
- **Sedimentary Basin**: stands for an area in which sediments have accumulated during a particular time period at a significantly greater rate and to a significantly greater thickness than surrounding areas.
- **Semi-submersible (semi-sub) rig:** stands for a floating offshore drilling unit that has pontoons and columns that when flooded cause the unit to submerge in the water to a predetermined depth
- **Shallow water**: stands for sea water column of less than 300m
- **Stand-by:** relatively to storage projects, stands for a project declared as being on hold
- **Success cost:** stands for the cost distribution of the storage part of a storage project that has reached bankability
- **Suitability**: qualitative ranking (highly suitable, suitable, possible, unproven, unsuitable) of geological formations that is based upon the prospectivity for CO_2 sequestration as defined by IPCC [46], crosschecked with geological world map, and history of exploration (mining or oil and gas). The higher the ranking of

suitability, the higher the success ratio of a given storage project is, to reach bankability

- **Highly suitable** stand for areas where geological knowledge is very good and where, at regional level, major geological characteristics seem well appropriate for CO_2 storage
- **Suitable** stand for areas where geological knowledge is good and where, at regional level, major geological characteristics seem appropriate for CO_2 storage
- **Possible** stand for areas where geological knowledge is poor and where, at regional level, major geological characteristics could be appropriate for CO_2 storage provided new data or information confirm it.
- **Unproven** stand for areas where geological storage of CO_2 storage could occur according to present laboratory tests, but where no field test has yet confirmed it (case of ultrabasic and volcanic rocks).

- **Storage complex:** stands for the sedimentary column which includes the reservoir in which CO_2 is injected, its caprock, and related upper geological formations, among others upper aquifers used for control.
- **Storage resource:** characterized storage resource as defined in by IEA GHG report (Figure 5). Coping with timelines for storage site injection start-up, requires that such resource identification process is compared with capacity estimates. Recent work by IEA GHG [34] has established a classification system in order to provide a set of definition for the CCS industry. This classification is shown on the following Figure 5.

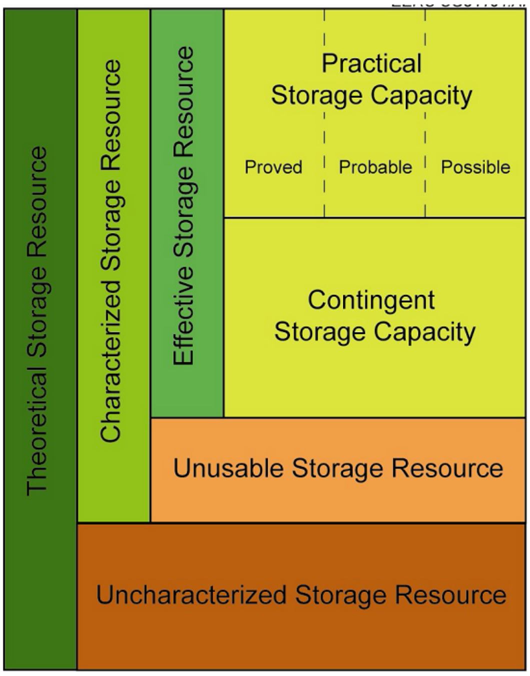

Figure 5: Static capacity assessments [34]

- **Storage capacity:** practical storage capacity as defined in by IEA GHG [34] (Figure 5). Storage capacity are expressed in Million tonnes (1Mt = 10^6 metric tons) or Giga tonnes (1Gt = 10^9 metric tons)
- **2D and 3D seismic surveys:** stands for surface reflection seismic operations either onshore or offshore. They are divided in acquisition, processing, and interpretation.
- **Well drilling:** stands for all operations from rig-up to rig-down, including all appropriate data and samples collection.
- **Workover:** stands for any kind of operation on an existing well aimed at verifying its compliance for CO_2 injection.

3. OVERALL STUDY METHODOLOGY

3.1. Overall Methodology Rationale

The first question we have to answer in this study is:

Is there a gap between the existing effort in storage development and the IEA 2020 recommendations and where?

To assess the technical potential of storage projects excluding CO_2-EOR, we firstly examined this issue only looking at the technical causes of success and failure of storage development. This first step led us to quantify a number of additional projects to achieve IEA 2020 (and 2050) recommendation. In a second step, we then integrated the non technical causes (political, economics, public acceptance) as well as CO_2-EOR potential contribution to weight the results obtained in the first step.

3.1.1. First step

The first step (technical causes' assessment) is made of several tasks.

Firstly, a mapping of the existing storage context ("storage project database") has been made. We have then identified all storage initiatives and projects worldwide as well as their status of development and location. We then designed a methodology to answer the following questions:

- How many of these projects will reach the status of bankability?
- When will they reach such a status?

The key driving idea is to base this assessment upon quantified measurements of project development, in terms of probability of success, timing, and cost. These parameters depend upon various factors:

- Type and location of storage: either onshore or offshore saline aquifer, depleted hydrocarbon field.
- Phasing steps of a project development,
- Regulatory requirements (licensing steps),
- Knowledge of a given geological area,
- Regional ranges of costs for works and tasks included in the different phasing steps of a project development.

Quantifying these factors made it compulsory to create analytical tools specific to each of them, and to properly understand and describe their relationships. These tools are described hereunder.

1. **Storage suitability map**

   This map is aimed at knowing the level of prospectivity for CO_2 sequestration, crosschecked with geological world map, and history of exploration (mining or oil and gas). Indeed, the success ratios, costs and development time of a given project will strongly depend on this factor as it will be shown later. This is detailed in part 3.2.2.

2. **Storage development workflows**

   Storage exploration is an uncertain and iterative process that depends on many parameters (location and type of target). In our bottom-up approach, we have developed these workflows from first desk assessment of a potential storage to final bankability status, taking into account the possible failures (reservoir not found or not suitable in the area, cap rock not found or not suitable in the area). Such failures during storage development make it necessary to re-perform some works (seismic survey and well drilling essentially), up to a certain extent. These tools are described in part 3.2.3 and 4.

3. **Costs and development time up to bankability status**

   Each step of the storage development workflow described in point 2 above has attached to it a success probability (which depends on suitability described in point 1 above, and on type and location of each project), a probabilistic distribution of cost (which depends on the location and type of target), and a probabilistic distribution of completion time (which depends on the location and type of target). The words “probabilistic distribution” stand for a function of a discrete random variable (cost or time) yielding the probability that the variable will have a given value. These models are described in parts 3.2.4 and 4.

Then, according to each project location, we have used the “storage suitability map” to fill the project database with the suitability status of the geological province envisaged for storage. When no storage location was already identified for a given project, we analysed the storage suitability in a 300km radius of the capture sites[7]. We then compute the storage development workflow and the costs and development time.

The first result was achieved through a simple comparison between this “technical bankability assessment” and the regional IEA 2020 recommendations.

After this first task of the first step, we developed a methodology to answer the consecutive question of this study:

[7] For first commercial CCS project and taking into account the high cost of the technology and the low price of CO_2 as of today, we assumed that CCS project will be developed only if a storage potential exists within close vicinity. Indeed, this limits project investment costs which are crucial for first CCS projects.

Considering only the technical aspects of bankability, how many more projects should be launched and where in order to achieve IEA 2020 recommendation?

The comparison gave the number of projects needed to fill the gap as well as their location. We then used a CO_2 sources GIS (the "CO_2 sources map" tool) database based upon the IEA GHG CO_2 emission sources[8] in order to identify carbon intensive areas close to areas with CO_2 storage potential and where no storage project is currently being developed.

For such quick-look source-sink matching, the CO_2 emission sources below 1Mt per annum (Mtpa) have been neglected. Consequently, such qualitative source-sink analysis could be altered at a local level by early opportunities. The criteria retained for this analysis are:

1. Concentration of CO_2 sources,
2. Availability of storage resources.

We also tried to diversify storage possibilities (DSF and DOGF) in function of local actual and past O&G activities. Finally, for each identified project, we ran the development workflows and the cost and development time models in order to evaluate for such a given project, its probability of success, its cost and development time to reach bankability status.

Additionally, in order to provide an insight on the IEA 2050 recommendation achievement (3,400 bankable projects), we assumed that most of 2020 projects will reach end of their lifetime by 2050 (30 years of injection). It means that new projects will have to replace them in 2050. Following the storage development workflow, cost, and development time model results, we have evaluated the required number of projects to achieve this goal.

3.1.2. Second step

As explained earlier, the bottom-up quantitative approach could not integrate the non technical potential failure causes of storage projects. This cause ranges from political issues to public acceptance, regulatory barriers, overall economic context, and lack of incentives to tackle carbon emissions, lack of financial support, project developer internal strategy or economic situation.

The failure ratio resulting from these causes may simply be obtained by comparison between Global CCS Institute databases from 2009 and 2010: identifying the projects present in 2009 and absent in 2010 leads to an evaluation of this failure ratio.

The difference between 2009 and 2010 Global CCS Institute databases may also provide an indication of the supplementary number of storage projects that should be

[8] http://www.ieaghg.org/index.php?/20091223127/co2-emissions-database.html

developed to achieve the IEA recommendation. However, unpredictability and unknowns lead us to recommending that results of this second step should be taken with the extreme caution. As an example, the financial crisis and its consequences on financing of industrial stakeholders to invest in CCS technologies were totally unforeseen in the summer of 2008. Similarly, the today worldwide context of nuclear energy development which shows a possible decrease of this power source was totally unpredictable before Japan earthquake and Fukushima accident in March 2011.

Therefore, we benchmarked these results with another approach which considers only one of the key components of non technical failure causes: the presence of public funding. The existing incentives for cleaner technology and particularly CCS are limited. CO_2 price is for instance considered too low to generate significant private investment in the technology. Therefore, most of the storage projects will proceed only if they manage public support and funding. Based on this observation, and taking into account current public funding promises and technical bankability, we deduced the number of projects likely to achieve bankability.

Finally, as discussed earlier, all this approach only integrates potential CO_2 storage projects in Deep saline Formation or Depleted Oil and Gas Fields. However, CO_2 Enhance Oil Recovery can play a very important role for storage deployment in the first years of deployment. This role is discussed in the last part of the methodology in relation of previously obtained results.

3.2. Construction of Suitability Map and Analytical Tools

The following sections present the tools: existing CO_2 storage project mapping, storage resources mapping, project phasing and storage development workflow(s), costs and development time and CO_2 sources mapping. A full description of each tool is given in the Appendixes C to G.

3.2.1. Existing Storage Projects Mapping

One mandatory step to perform the study was to construct a reliable storage projects database.

Several databases of storage projects exist on line. Most notably, the online databases from IEA GHG[9], Global CCS Institute[10], MIT[11], Bellona[12], Scottish Centre CCS[13] and CO2CRC[14] were regularly browsed to identify new project announcement and location. The DOE-NETL project database[15] along with the Global CCS Institute CCS status report [22] were enhanced with compilations of news releases collected by Geogreen. There is some uncertainty on most of the storage location in the databases as quite often the CO_2 source may be easily located whereas the storage point is more vague (e.g. North Sea or Otway basin). Whenever the nature of the storage part of the project was known (onshore or offshore, DSF or DOGF), it was included in the database.

The categories of the projects in the database are as follows:

- Activity status
    - Active
    - Stand-by
    - Abandoned
- Project nature
    - Saline aquifer
    - Depleted oil field
    - Depleted gas field
    - EOR
- Phasing
    - Phase 0: global CO_2 storage potential and capacity on a regional scale
    - Phase 1: Desk Based assessment - Storage ready
    - Phase 2: Licensing exploration license, Site confirmation and characterization, Injection test and licensing
    - Phase 3: Licensing demonstration or commercial, Construction and start up demonstration or commercial, Injection and storage demonstration or commercial
    - Phase 4: Closure

[9] http://www.co2captureandstorage.info/search.php
[10] http://www.globalccsinstitute.com/resources/projects/map
[11] http://sequestration.mit.edu/tools/projects/map_projects.html
[12] http://www.bellona.org/ccs/ccs/Tema/project?at=
[13] http://www.geos.ed.ac.uk/sccs/storage/storageSitesFree.html
[14] http://www.co2crc.com.au/demo/worldprojects.html
[15] http://www.netl.doe.gov/technologies/carbon_seq/database/index.html

- Scale
  - Research
  - Pilot
  - Demonstration
  - Commercial / Industrial
- Location
  - Onshore
  - Offshore

The EOR category refers to CO_2-EOR projects that include a Measurement, Monitoring, and Verification (MMV) activity.

The following Figure 6 is showing all 124 projects that include a storage part, and that are included in Geogreen database. A list of the considered projects is given in Appendix B

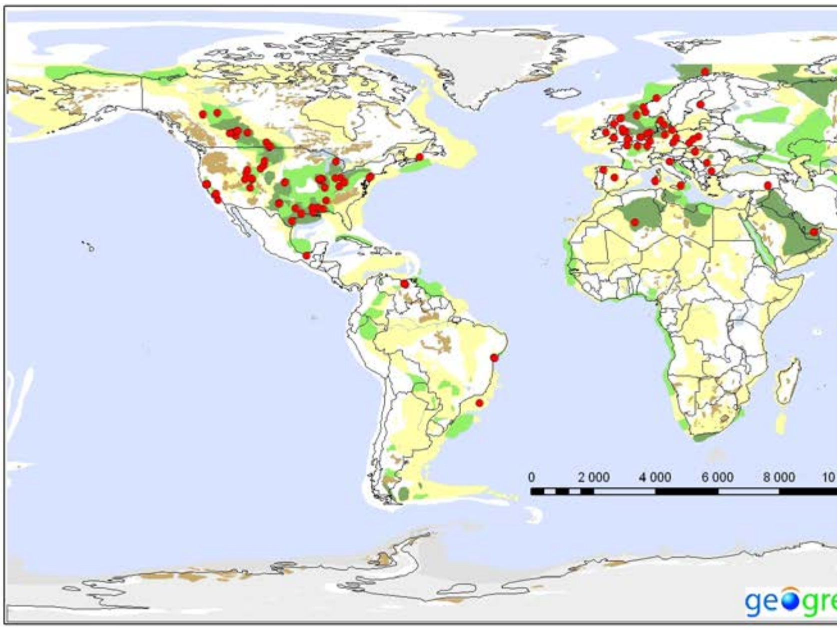

Figure 6: Publicly announced storage projects (Feburary 2011)

3.2.1.1. Selection of Projects

Reaching the status of bankability means that enough elements exist in order to take an investment decision for industrial scale development. After such bankability is reached, two to three years at least might be needed for the project to be fully operational. Consequently, reaching the IEA 2020 deployment recommendation in terms of number of industrial projects means that these projects have to reach bankability not later than 2016-2018 (see section 4).

Given the time needed to reach the status of bankability, the above recommendation (2016-2018) can be reached only if a project is today active.

From the global project database described in section 3.2.1, a subset which contains 68 planned and announced storage projects (Figure 7) was selected according to the following criteria:

1. Only large scale ones, either in Phase 1 or Phase 2 are part of this subset,
2. EOR projects that include MMV are part of this subset,
3. The currently or soon-to-be operational DSF projects such as Sleipner, In-Salah, Snøhvit, Gorgon, and the EOR projects such as Rangely, Sharon Ridge, Weyburn, Salt Creek, which already reached their bankability and will be counted in the overall projects at 2020 time scale are not part of this 68 subset of projects.

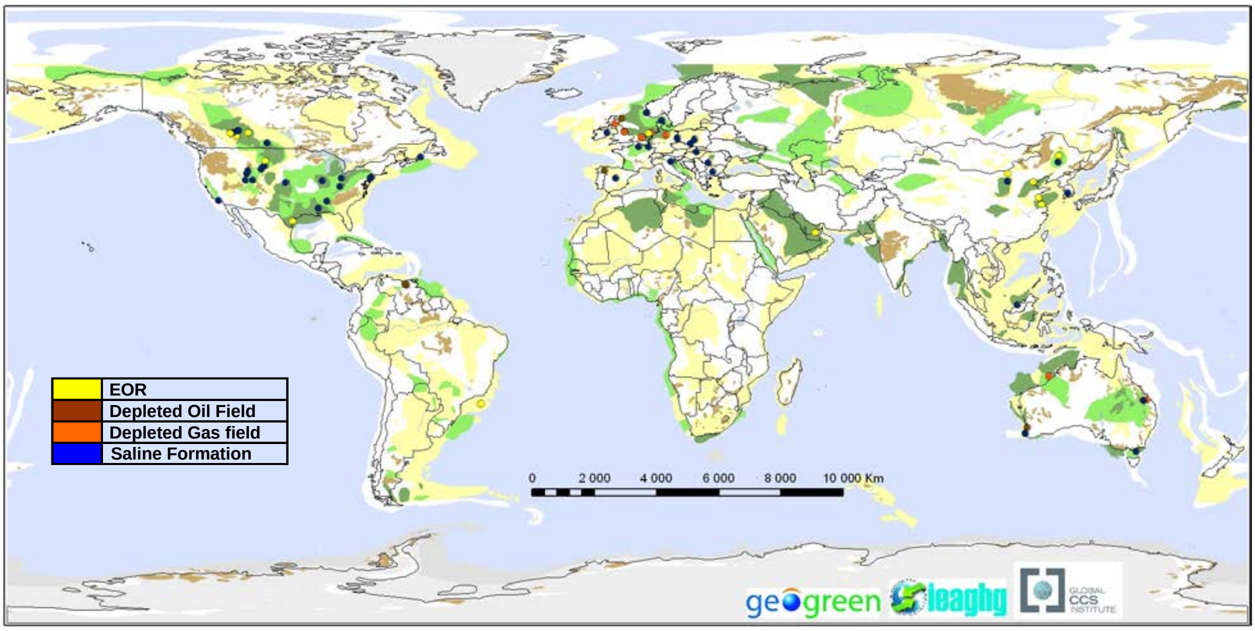

Figure 7: Planned and announced large scale storage projects candidates for bankability (February 2011)

The different storage types breakdown (Figure 8) as follows: 58% Deep Saline Formation projects, 21% CO_2-EOR and 21% Depleted Oil and Gas Fields.

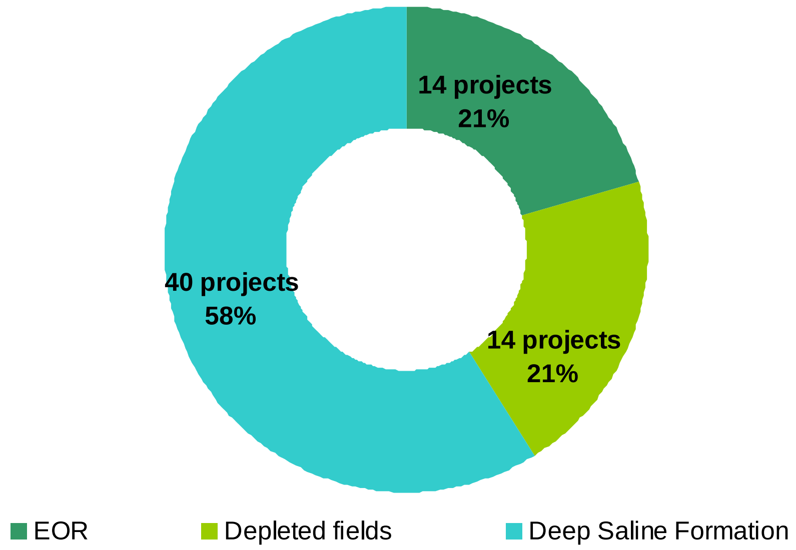

Figure 8: Breakdown of the large scale active planned storage projects

At regional level, this breakdown stands as follows (Figure 9):

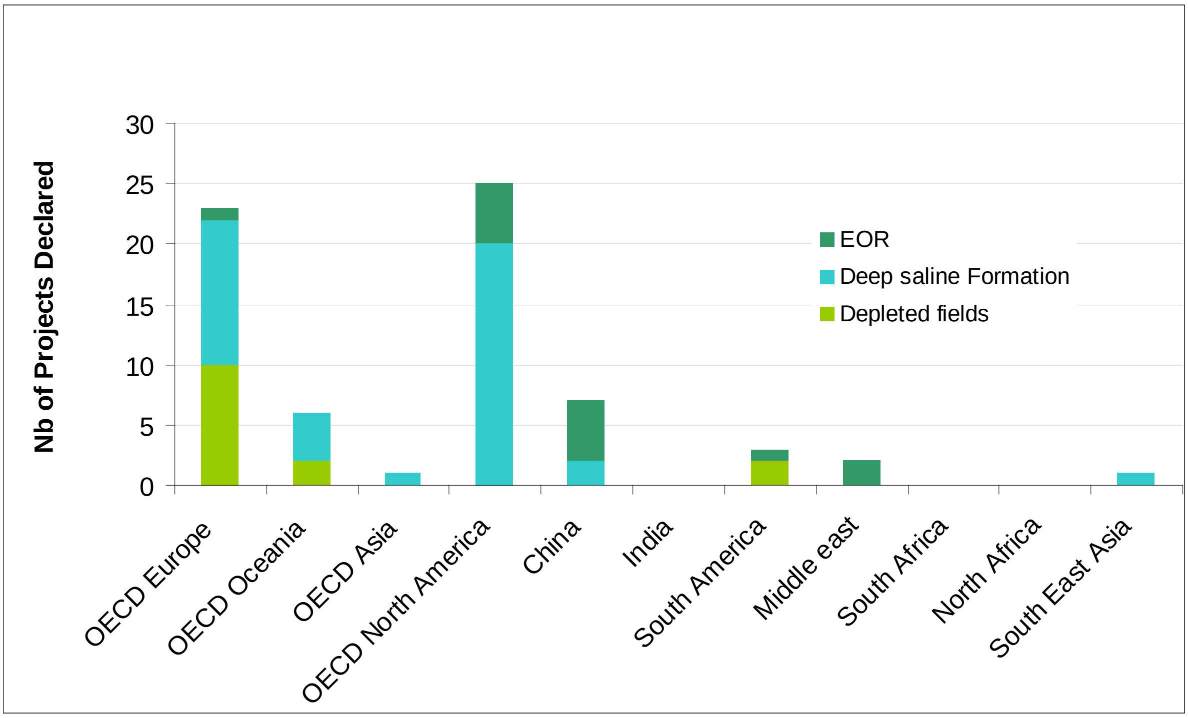

Figure 9: Regional and type breakdown of planned storage projects either in Phase 1 or 2 as of February 2011

3.2.1.2. Comparison with Global CCS Institute database

As of March 2011, the large scale storage projects in the Global CCS Institute database [22, 23] are split as follows (Figure 10): 38% deep saline formation projects, 48% CO_2-EOR and 14% Depleted Oil and Gas Fields without the 4 CO_2-EOR projects and 4 DSF projects soon-to-be or in operation. The Global CCS Institute database has about 100 large scale CCS projects. However, some projects had no identified storage or were either capture only or hub projects. In the projects with identified storage, a significant share 48% are targeting some valuation of the CO_2 through EOR operations either on a one to one basis from the capture or through connection to a CO_2 pipeline network. This is particularly acute in North America where most CO_2-EOR projects are located (Figure 11) and China where only CO_2-EOR projects are considered in the Global CCS Institute database. The storage projects in the Global CCS Institute database are located either in OECD Europe and OECD Oceania (Figure 11).

In the present study, the focus being slightly different from Global CCS Institute, the project database was enhanced in Europe mainly for DSF projects, South America and some of the CO_2-EOR projects were not retained as no information was available for the Measurement, Monitoring and Verification (MMV) activities (see section 3.2.2.3).

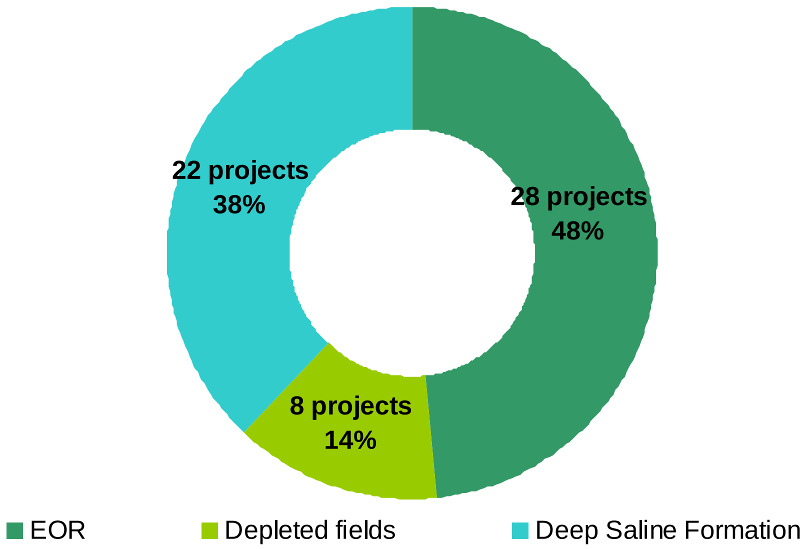

Figure 10: Breakdown of the planned large scale storage projects in Global CCS Institute database as of February 2011

At regional level, this breakdown stands as follows (Figure 11):

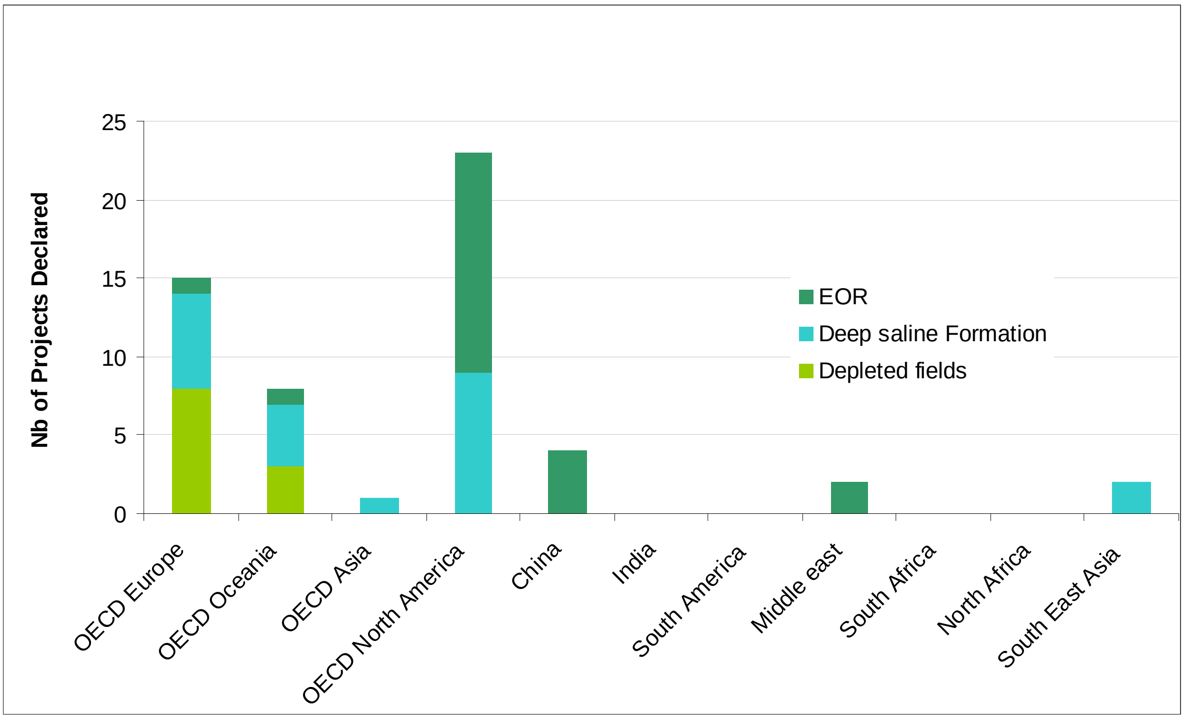

Figure 11: Regional and type breakdown of planned large scale storage projects from the Global CCS Institute database as of February 2011

3.2.1.3. Other Potential Candidates for Bankability in the 2010 – 2020 Decade

In the selection of 68 projects shown in section 3.2.1.1, 14 projects were not included, because they are reported to be today on stand-by. However, would they resume shortly, they could become additional candidates for reaching the status of bankability in 2016-2018. Were also not accounted for the 8 projects currently in or near operations (4 DSF and 4 CO_2-EOR)

3.2.2. Storage Suitability Mapping

As mentioned earlier, the level of knowledge of a sedimentary basin or a geological province has a significant influence over CO_2 storage characterization success probability, costs and, ultimately, development time. Therefore we need to know the suitability ranking (please refer to chapter 2) of the geological province where the different storage projects are located in order to run the CO_2 storage characterization workflows and determine success probabilities, costs and development times needed.

We used as a starting point the prospectivity map established by IPCC [46] in 2005, and the geological map of the world established by CCGM [12]. Additionally, all currently published storage assessment information was included in a consistent manner [9, 15, 29, 53].

Various CO_2 storage mapping initiatives are taking place worldwide as illustrated in Figure 12.

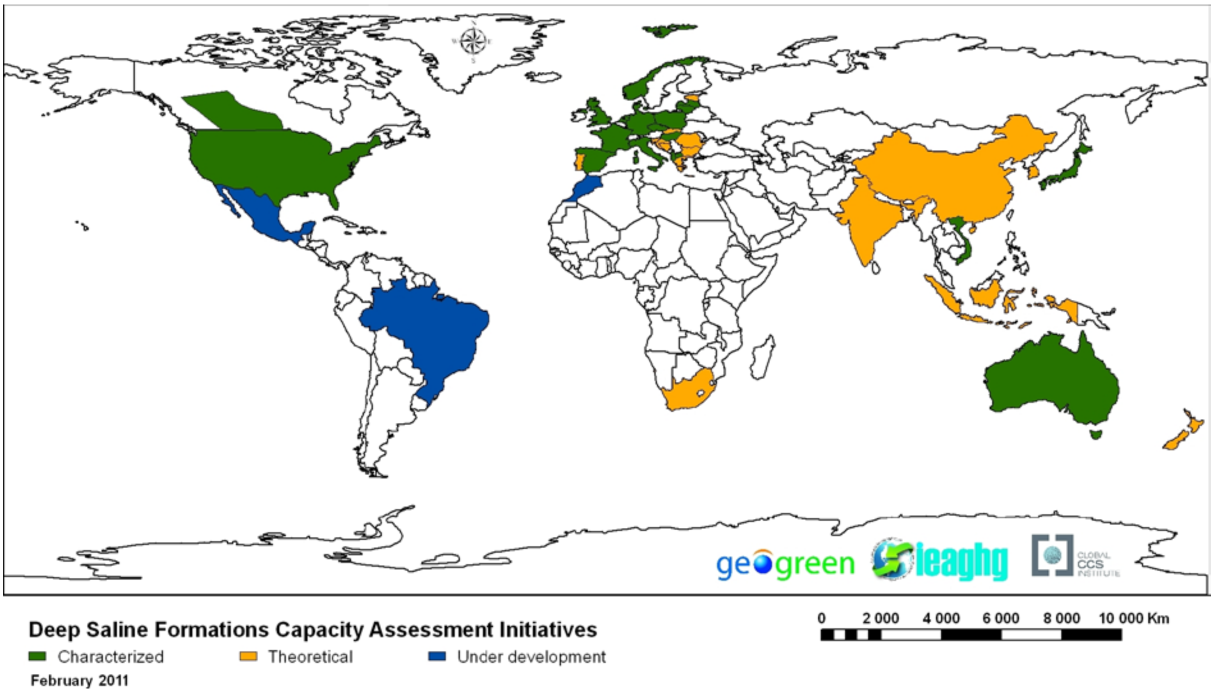

Figure 12: Storage resource assessment initiatives available at the time of the study

As the initiatives for storage resources and capacity assessment are limited to a few countries and in order to identify possible future development in other parts of the world we have used geological information to build the storage suitability map.

3.2.2.1. Deep Saline Formation Suitability

The process of map building is detailed in Appendix A. Once the prospectivity map was updated with recent regional studies, information was challenged with the exploration status of the various basins [25]. The map of exploration status edited in 2000 does not correspond to the current exploration status. Consequently the map was updated (Figure 13) with Geogreen internal knowledge.

This updated exploration status was used to specify the suitability of the basins at world scale where there was a lack of information. Indeed, when an area has not been heavily explored, the knowledge over its geology is supposed to be poorer than in heavily explored areas. This information about exploration status was used only in countries and areas where no public information is available about CO_2 capacity. For instance, the map of exploration status was used for Russia and not for Australia, Europe nor USA.

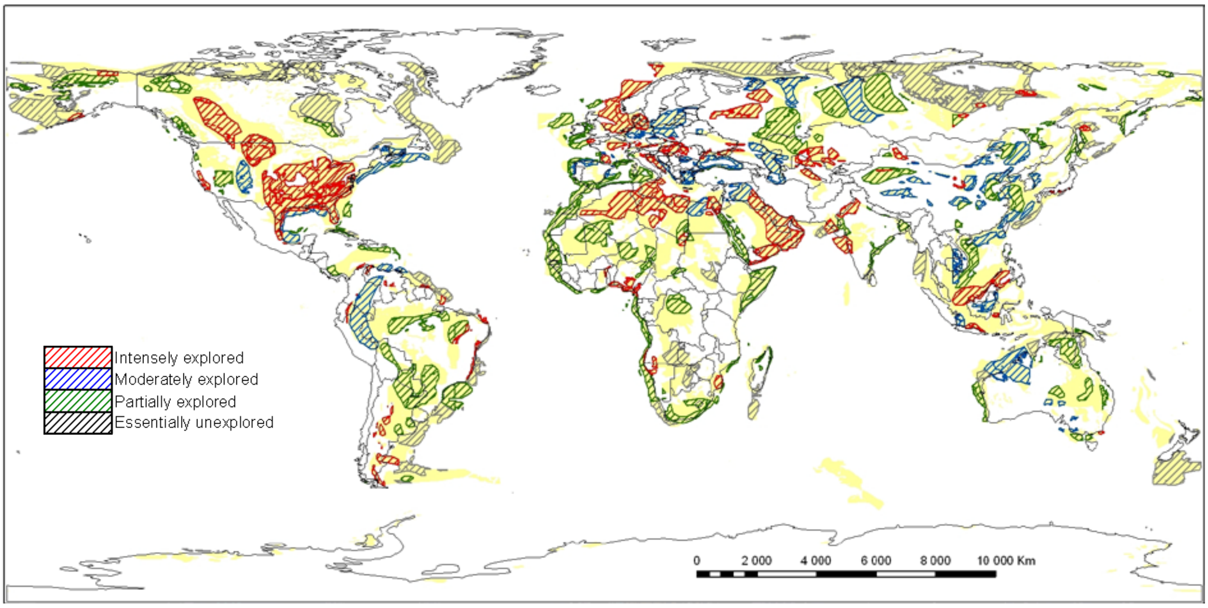

Figure 13: Exploratory Status of World Basins (modified from Halbouty, 2000)

Furthermore, the world natural seismicity map was used to discriminate seismic active zones that storage projects must avoid as much as possible, for storage safety achievement.

The map of storage suitability proposes a ranking in four levels for sedimentary basins: highly suitable, suitable, possible, and unsuitable. The ranking “unproven” is used for basaltic formations, and extrusive volcanic rocks.

The rankings “Highly suitable” and “suitable” stand for areas where geological knowledge is good and where, at regional level, major geological characteristics seem appropriate for CO_2 storage.

Similarly, areas labelled as “possible” are areas where the geological knowledge is limited and where the basin might have the necessary characteristics to host storage projects. It means that exploration is needed to increase knowledge over the area in order to confirm its potential for CO_2 storage.

The higher the ranking of suitability, the higher the success ratio of a given storage project is to reach bankability. However, a project can fail to reach bankability in a highly suitable area, and succeed in reaching it in a possible area.

The following map (Figure 14) gives the world geological storage suitability as proposed by Geogreen in March 2011:

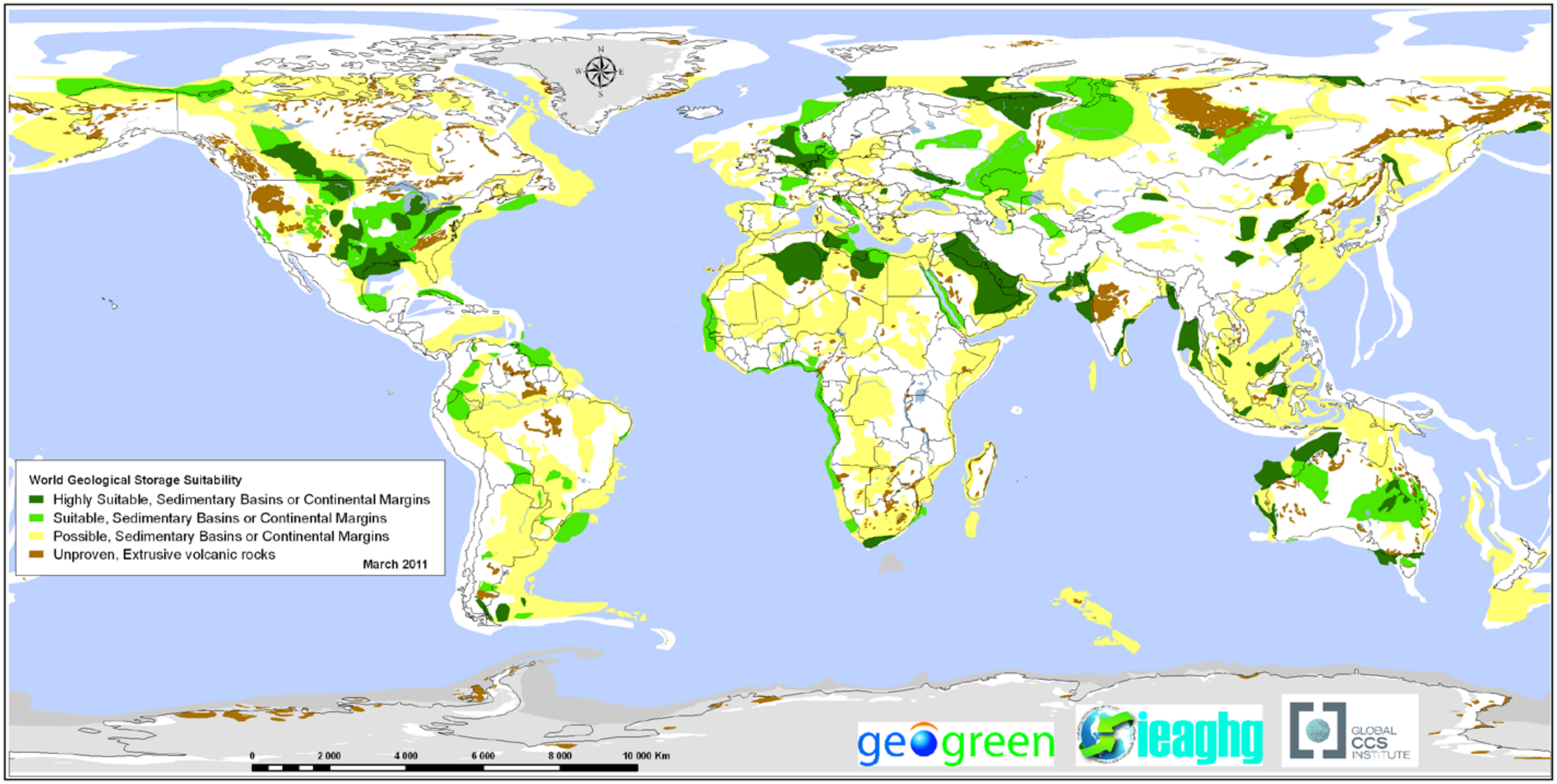

Figure 14: World Geological Storage Suitability

3.2.2.2. Depleted Oil and Gas Fields

Depleted oil and gas fields represent an interesting opportunity for CO_2 storage. Indeed, they are generally well known through their historical production.

However, not all former fields can be used as CO_2 storage for various reasons (this list is not exhaustive):

- Caprock integrity might be compromised for CO_2 injection:
  - Mechanical deformation due to field depletion
  - Geochemical issues in presence of CO_2
- The injectivity for CO_2 injection might be poor (injectivity potentially compromised through fracture closing due to pressure drop, or an active aquifer might have filled a large part of the available porous volume).
- Important number of existing producing wells might disqualify a depleted field for CO_2 storage. Indeed, existing wells is the most important risk of leakage of CO_2 storage.
- Incompatibility of existing wells (steel, cement plug …) or surface installations with CO_2 or CO_2-rich streams.

Moreover, their size is not necessarily suited to the storage needs of industrial emitters during 30 years. It is envisaged that for such volumes (between 30 and 150 Million tonnes of CO_2), a group of fields or cluster will be needed. In that case, each small field will have to undergo a bankability assessment process.

Finally, there is a specific time window of opportunity for each field. The depletion date depends on the price of oil or natural gas, the cost of production of a given field and the dismantling obligation after field closure. When a field is declared depleted, it does not mean that there are no more hydrocarbons to produce, it means that it is not possible within current hydrocarbon price and production costs to generate profit.

The third criterion is linked to regulatory factor. In some jurisdiction (North Sea for instance), there is an obligation to dismantle the surface installations within a few years after end of production. In that case, it is no longer viable to come back to reopen the field for further production or CO_2 storage. Indeed, a huge investment will be needed to check the abandoned wells compatibility with CO_2 injection requirements.

It is therefore difficult to foresee without any data if a field is suitable for CO_2 injection and when it is available for CO_2 injection.

In the present study, it was not possible to make detail assessment of each field since data belong to field operators and is of strategic importance for their own asset valuation.

To identify storage opportunities in depleted oil and gas fields we followed the stepwise methodology described earlier:

1. In order to identify the gap between current effort and IEA 2020 recommendation, we listed all existing storage projects and identified the status of their development.

2. Once the gaps were quantified on a regional basis, we performed a qualitative source-sink matching to identify storage resources close to the emission centre. If an important mature (more than 30 years of production) oil and gas province was located next to an emission centre, we considered likely that a depleted field would be available for CO_2 storage. This approach might be invalidated by rising oil and gas prices as explained earlier.

3.2.2.3. CO_2 Enhanced Oil Recovery

CO_2-EOR Contribution to storage Deployment

CO_2-EOR is nor a new neither an exotic technology. More than 100 projects inject CO_2 and produce over 250,000 barrels per day of incremental oil in the U.S [33]. Nevertheless, only a few of these projects are considered as true CO_2 storage project. Indeed, in order to consider a CO_2 Enhanced Oil Recovery operation (which aims at increment of oil production) into a CO_2 storage operation over the long term, a project should at least respect 2 elements:

- The first element to be considered is the inclusion of Measurement, Monitoring and Verification (MMV) activities. These activities are necessary to verify and prove that CO_2 is really stored and in which amount. This is particularly required within carbon cap and trade systems (ETS).
- The second element should be CO_2 recycling from field production facilities down to the subsurface.
- The CO_2 should be anthropogenic

Currently, 18 EOR projects with suitable MMV activities are identified worldwide following the Global CCS Institute (4 already in operation[16], 14 planned).

As underlined by many studies, the contribution of CO_2-EOR to the global effort of CCS could be very important. A study conducted by IEA GHG in 2009 [33] identified a global CO_2-EOR storage potential of about 65Gt taking into account CO_2 demand and offer. Under certain conditions, and particularly including expected large refineries and hydrogen plants in the Middle East, CO_2-EOR storage potential could reach between 140Gt to 320Gt. This latter conclusion was based on an assessment that assumed a CO_2 cost (compression and transportation) to the EOR operator of US$ 15 per tonne and a world oil price of US$70 per barrel.

[16] Rangely, Sharon Ridge, Weyburn, Salt Creek

However, several limitations should be pointed out to policy makers in the context of our study and IEA 2020 recommendations.

Limitations to CO_2-EOR Development

- *Not all fields are eligible to CO_2-EOR*

  First, candidate fields to CO_2-EOR operations should possess some key properties in terms of structure and oil composition in order to be eligible. Some of the key parameters conditioning EOR operations are given below:

  1 Field oil gravity (density) should be superior to 17.5°API. It means that it is not possible to perform CO_2-EOR within heavy oil fields (criteria used by DOE to evaluate the EOR potential of ten US basins[17]).
  2 Minimum Miscibility Pressure (MMP)[18] should be inferior to the maximum Allowable Pressure (MAP)[19] for CO_2 (MMP < MAP (miscible CO_2)). It means that the minimum pressure at which the CO_2 mixes with field's oil is less than the maximum pressure at which the CO_2 can be injected within the field (without creating dangerous mechanical issues). Otherwise, if MMP is greater than MAP, the injection efficiency is much lower (immiscible injection).
  3 Mechanical integrity of the field should be sufficiently preserved to ensure CO_2 long term storage without leakage. Indeed during field depletion (production phase), field original mechanical integrity might have been compromised and faults and fractures might have been reactivated creating leakage pathway to CO_2
  4 Geochemical integrity of the field and particularly, cap rock behaviour during CO_2 injection should be checked since long term geochemical reaction may take place and dissolved CO_2 in brine may chemically react with the cap rock either inducing self sealing or porosity-enhancement reactions depending upon the chemical composition of the CO_2-rich brine, cap rock and storage formations.
  5 The producing well pattern has to be adapted to CO_2-EOR. In offshore fields for instance, there are generally less producing wells and spacing between them can be significant. The distance between injector wells and producing wells might be too important for the CO_2 to efficiently sweep the area. In that case CO_2 injection efficiency could decrease. There is no CO_2-EOR project offshore so far.

  All these factors limit the above mentioned potential for CO_2-EOR.

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[17] http://www.fe.doe.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html.

[18] Minimum Miscibility Pressure (MMP) is a function of pressure, temperature and oil composition

[19] The Maximum Allowable Pressure for CO_2 injection (MAP): MAP = reservoir depth * 0.6 psi/ft (ARI criteria).

- *In small to medium fields, CO_2 recycling limits the potential to store CO_2 from the source*

Part of the CO_2 injected for EOR purpose will necessarily flow to producing well (CO_2 breakthrough) and will have to be recycled. The volume of the produced CO_2 will increase overtime so as required CO_2 volumes from capture are decreasing to sustain EOR process as illustrated in Figure 15.

This is not an issue for large oil fields that can store a lot of CO_2 and where CO_2-EOR implementation is performed step wise (the entire field is gradually submitted to CO_2-EOR). In this configuration, CO_2 from the source can be fully stored for years.

Figure 15 shows conceptually this case where after some years of production, part of CO_2 from the source (red line in Figure 15) is replaced by the CO_2 produced together with oil and recycled (yellow line in Figure 15). The straight green line at the top of the Figure 15 represents the volume captured at the source. One can see that there is a mismatched between the green (what is captured) and the red lines (what is needed at the field). Moreover, CO_2-EOR injection strategy requires flow variation which can further increase the observed mismatched.

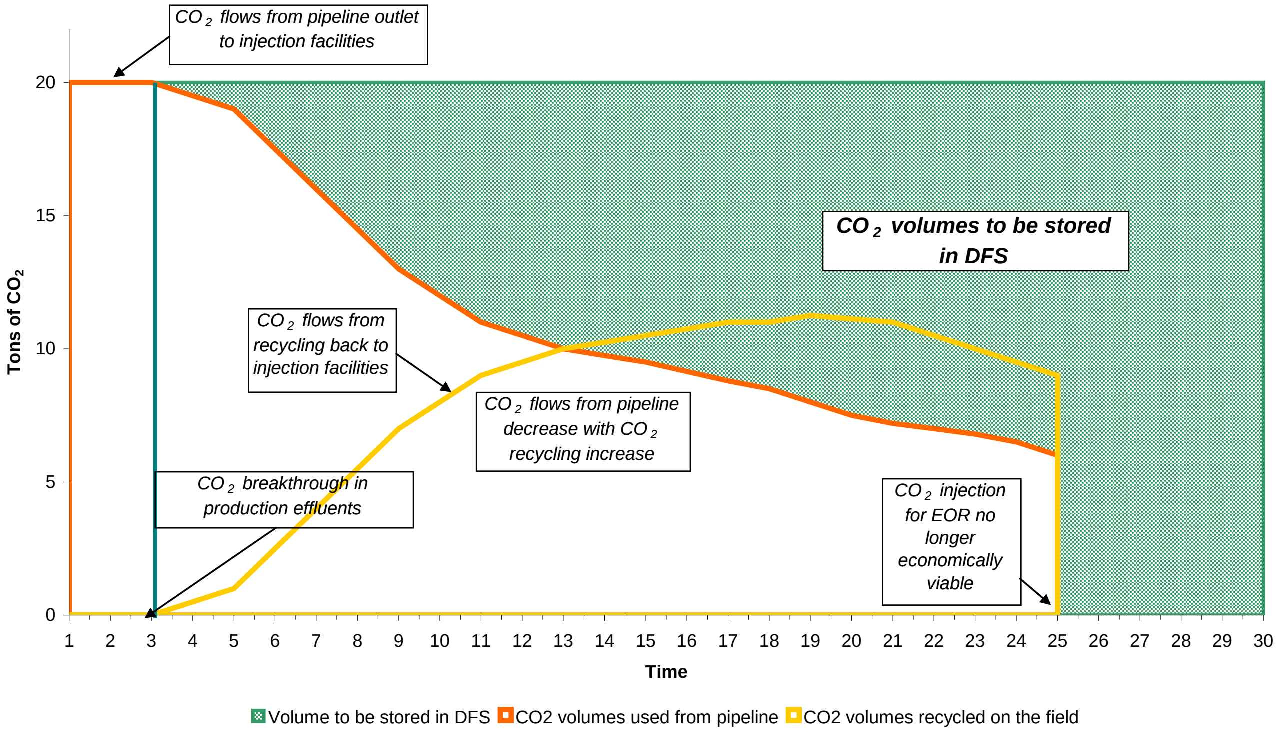


Figure 15: Conceptual profiles of CO_2 volumes required in an EOR project and remaining volumes to be stored in DSF

As the objective is to mitigate climate change, one has to cope with this excess of CO_2. There are 2 main possibilities:

- Other fields in the vicinity or next to CO_2 supply chain may be lined up for CO_2-EOR to guarantee a constant CO_2 uptake. This clustering strategy is a possible response to both recycling and CO_2 injection strategy issue. It is however likely that a buffer storage site be needed to cope with significant CO_2 needs variation.

- A buffer site (DSF or DOGF) for CO_2 storage is developed in order to store the excess of CO_2 next to the existing field or along the CO_2 supply chain. This buffer storage site should be ready when CO_2 requirements for the oil field will start declining.

To further stress this point, we would like to point out a recent study [16] which similarly concluded that CO_2-EOR projects shall not drive storage projects deployment unless saline formation storage is developed along with the considered EOR project.

- *CO_2 procurement cost can limit CO_2-EOR potential*

  One has to understand that DSF / DOGF storage and CO_2-EOR projects are two different approaches of CO_2 storage. In the first one, the drivers are the emitted CO_2 price versus the cost of storage. In the CO_2-EOR case, drivers are the oil price and the CO_2 procurement cost. Indeed, in the latter, the objective is to maximize profit from a given asset. As mentioned by NRC [47], "*the single largest deterrent to expanding production from CO_2-EOR today is the lack of large volumes of reliable and affordable CO_2. Most of the CO_2 used for EOR today comes from natural CO_2 reservoirs, which are limited in capacity.*" Of course a higher oil price would ensure better flexibility for CO_2 procurement.

- *Stored CO_2 Responsibility Issue*

  The last comment concerns less a limitation of CO_2-EOR potential rather than an issue to be tackled in order to allow its large scale deployment. It concerns the long term responsibility issue of stored CO_2. This is a critical aspect when CO_2-EOR is considered under an emission regulation scheme where an operator get credits (or does not have to pay for emissions) when storing CO_2. This is not compatible with the usual blow down practice at field abandonment. Indeed, the emitter objective is to get rid of its CO_2 and the EOR operator objective is to produce incremental oil. Taking responsibility of the stored CO_2 is not in the business culture of these actors. It is not sure whether an EOR operator will accept long term liability for stored CO_2 and negotiation about CO_2 procurement could be challenging on this point.

To conclude, CO_2-EOR has a significant role to play to quick start the climate change mitigation strategy and IEA 2020 recommendation achievement. However, one should know that DSF or DOGF storage projects should be associated with such CO_2-EOR. These "associated projects" will most probably have to be developed within a few years after CO_2-EOR project start, and could ensure climate change mitigation objectives are met.

Inclusion of CO_2-EOR within the Study

As mentioned earlier (see section 3.1), we first did not take into account CO_2-EOR within the study in order to give policy maker an idea of the required effort. In a second step, we evaluated the contribution of CO_2-EOR to match IEA 2020 recommendations.

However, this study did not address the costs aspects of the CO_2-EOR contribution, i.e. the cost to develop an EOR project. The reasons for this choice are detailed here below:

1. CO_2-EOR main development driver in the coming decade is the potential incremental oil production rather than CO_2 emission storage because CO_2 storage incentives are weaker than the oil price incentives. Therefore, the first steps of the "bankability" analysis are generally performed in fields where operators seek to increase lifetime and revenues from existing assets. The result of this assessment will then lead the operator to look for CO_2. Desk based studies for CO_2-EOR assessment is therefore a cost, either integrated in the oil field operator business model, or shared between CO_2 emitters and field operator, which ultimately depends upon internal negotiations. As such, we did not wish to integrate this cost which is not yet part of the CO_2 storage business model.

2. Each field is different in terms of structure, producing mechanism and produced oil characteristics. It is therefore difficult to generalize CO_2-EOR bankability costs estimates.

3.2.3. Storage Project Phasing

Storage development is an iterative process that can be symbolized by a logical workflow in which one step can be achieved when the previous ones have been successful. Such workflows have been split into specific sub-tasks depending on the type of project (DSF, DOGF), the suitability of a given area, and its location (onshore shallow water, deep sea). Each sub-task is qualified with:

1. A probability of **success**, which depends on suitability of the area where the project lies,
2. A probabilistic distribution of **cost**, including regional cost factors, which depends on the type (DSF, DOGF) and on the environment (onshore, shallow water, deep sea), and
3. A probabilistic distribution of **completion time**, which depends depend on the type (DSF, DOGF) and on the environment (onshore, shallow water, deep sea).

Taking into account these 3 characteristics lead to a key result of the present study: <u>probabilistic distributions of success costs and development time are associated to each project</u>. The above mentioned CO_2 storage development workflows are described in Part 4.

Project development phasing for an onshore Deep Saline Formation (DSF) project up to bankability is shown in Table 1.

Table 1: Development phasing for a deep saline formation onshore storage project

Type of study	Phase	Major costs items
National based ***Non exclusive surveys***	**Phase 0 Screening**	**First desktop studies**
Project based ***Exclusive surveys***	**Phase 1 Desk Based assessment**	**Desktop studies, where possible seismic reprocessing and existing wells logs analysis** **(inluding communication on project)**
	Licensing Exploration Permit	**Administrative engineering and follow-up**
	Phase 2 Site confirmation & characterization	**Studies and engineering for this phase (including monitoring actions, equipments and monitoring (soil, gravimetric, Insar))** **Seismic acquisitions 2D** **Seismic acquisitions 3D (on CO_2 future plume only)** **Civil Engineering** **Drilling CO_2 well with rotary rig (including 20% contingency including Mob/demob)**
	Licensing Injection test	**Injection test permitting**
	Phase 2 Injection Test	**Studies and monitoring** **Injection test duration** **CO_2 injection cost**
Bankable		

Phase 0 corresponds to “state-led” initiatives to map global CO_2 storage potential and capacity on a regional/national scale.

After this initial stage, exclusive surveys (Phase 1) led by industrial stakeholders (with state helps in the first storage development years), are performed.

Phase 1 corresponds to the feasibility study stage for a specific project and will be desk based assessment performed from Phase 0 results (when applicable) and other existing data. Some reprocessing of existing seismic and well data might be performed when available. The length and costs of this phase depends on the quantity and quality of the available data.

At the end of Phase 1, should its results be positive, an exploration license is supposed to be applied to relevant authorities for development of aquifer projects (site confirmation phase), while we suppose that solely an authorization for well drilling and/or workover for injection test would be applied to the same authorities for a project of CO_2 storage in a depleted hydrocarbon field.

This site confirmation phase called Phase 2 is split in two parts:

1. Exploration and site characterization
2. Injection test

The first part of Phase 2 aims at acquiring local information to properly define the storage geological environment with additional seismic acquisitions and well drilling. The second part of Phase 2 is aimed at an injection test in order to finalize storage site characterization, injectivity assessment, containment mechanisms, and any elements making it possible to define the adequate industrial scale development.

At the end of this phase, the bankability of a storage project is then known.

As mentioned earlier we have developed iterative workflows to describe the process of characterization from Phase 0 up to end of Phase 2 (bankability). These workflows are described in next part (see Part 4).

3.2.4. Models for Cost and Completion Time

The objective of the models for cost and completion time for storage bankability assessment is to give a fair representation of development costs, time and success ratio up to bankability stage when limited local information and inputs are available. It has also to be sound and coherent worldwide. Additionally, various parameters enter into the cost structure of a storage site assessment. For these reasons, a statistical approach based on historical data (whenever available) has been followed.

These models are described in Appendixes C to G. They were elaborated using both statistical approaches based on existing data from Oil and Gas, Underground Storage and Geothermal industries, and meetings with experts. The software used to develop these models for cost and time is @RISK™ v5.0 edited by Palisade.

The steps that were followed to develop these models are described below:

1. Identification of main costs items for each phase
2. Identification of inputs needed to determine cost items, time needed for development and potential failure rate
3. Identification of variability (with historical data when available) of all cost items
4. Modelling
5. Model robustness testing

Two sets of constraints on general costs structure for Phase 0, Phase 1 and Phase 2 (see Table 1) are modelled:

- Local constraints:
    - Storage context
        - Physical: depth, rock formation…
        - Status of exploration
    - Surface context
        - Availability of a CO_2 source for an injection test
        - Local workforce costs and equipment availability for field work (seismic acquisition and drilling)
- Time constraints:
    - Market price of necessary equipment in a specific area
    - Cost evolution of R&D activities related to storage projects (decrease with time– see Section C.1.1 in Appendix C)

As market conditions depend on the local context (country/region) where the project takes place, workforce and equipment costs differ. To take into account this cost differential from country to country, cost factors have been developed.

On the development time standpoint, the time needed for each step has been evaluated following similar industry experience. Concerning licensing process (licensing for exploration and /or for injection test), we have considered that the evaluation by relevant authorities of an application file might take longer in the early years of development of storage (up to 2020) due to the lack of experience of both administrative authorities and operators to deal with the new regulation.

3.2.5. Mapping of CO_2 Sources

One of the goals of the study is to identify where efforts should be located to match IEA recommendations. For that purpose we identified major emitting regions or basins worldwide to see where storage early opportunities could be launched to cope with IEA 2020 recommendation.

The IEA GHG database[20] of CO_2 emission sources was used for this purpose. We updated the database in several countries (South Africa, India, Saudi Arabia, and Brazil) where inconsistencies were identified.

20 http://www.ieaghg.org/index.php?/20091223127/co2-emissions-database.html

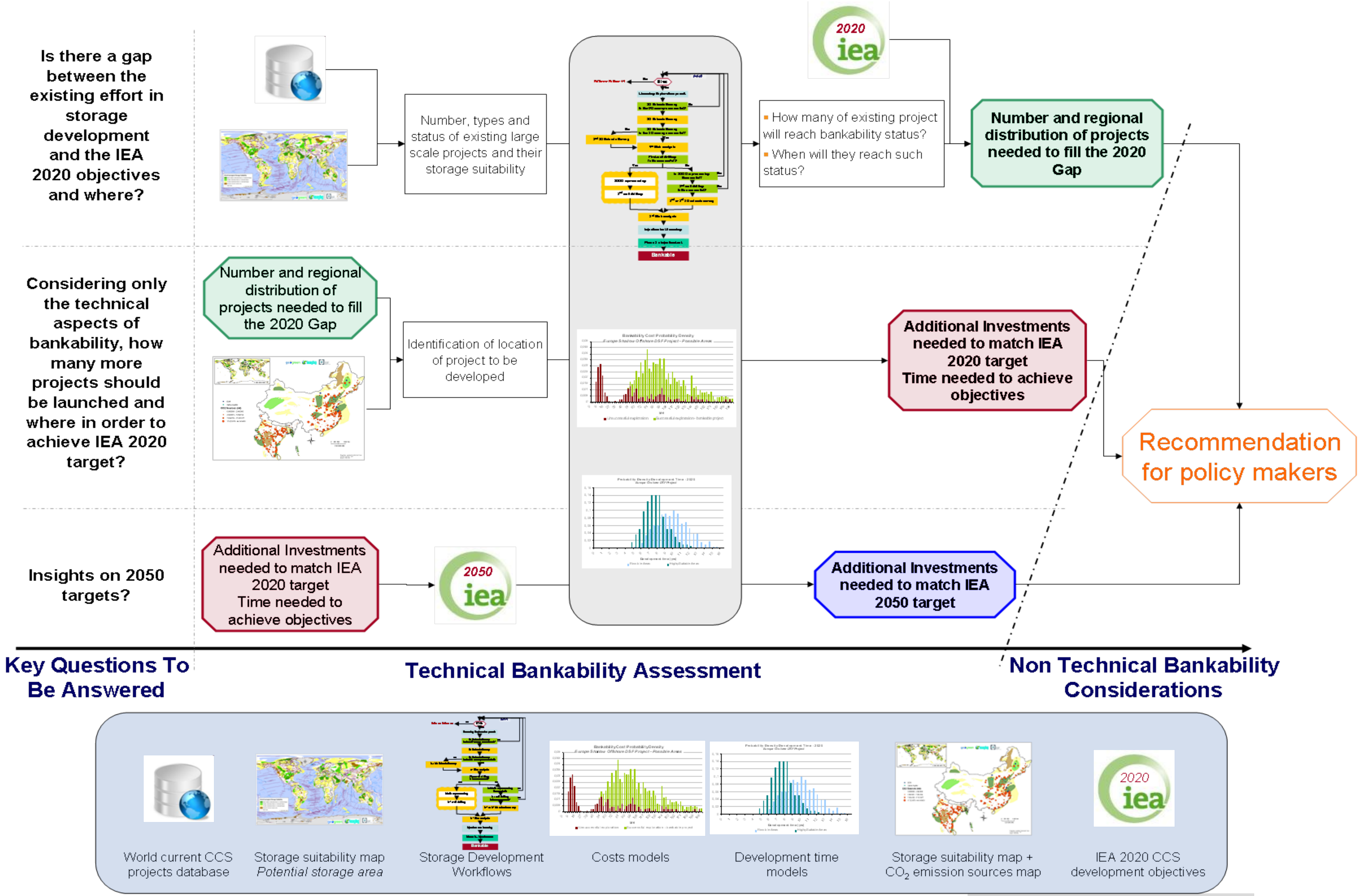
3.3. Overall Workflow

The workflow of this bottom-up analysis integrates the principles explained in section 3.2 and is presented on Figure 16.

The central role played by the storage development workflows and associated models of cost and development time is clearly illustrated in the workflow (central greyish area).

Next Page:

Figure 16: Global workflow of the study "storage gap analysis for policy makers"



geogreen ieaghg GLOBAL CCS INSTITUTE

4. STORAGE PROJECT DEVELOPMENT WORKFLOW

4.1. Assumptions

The workflows are built under the assumptions that a stringent storage regulation will be in force in all countries. This stringent regulation model is based on the European concept developed in the EU directive[21]. A license for exploration is supposed to perform all works necessary to confirm the suitability of a preselected area. An authorization for injection test of CO_2 is also supposed: we assume that the start-up of facilities construction for industrial injection cannot be granted by relevant authorities without a proper CO_2 injection test in the case of DSF project.

Storage exploration is an uncertain and iterative process that depends on many parameters (location and type of target). In this bottom-up approach, we have developed these workflows from first desk assessment of a potential storage to final bankability status, taking into account the possible failures. One of the key issues that these workflows must handle is how such iteration follows a failure (reservoir not found or not suitable in the area, cap rock not found or not suitable in the area). A maximum number of “loops” (re-performance of some works like seismic survey, or well drilling essentially) have been authorized.

The maximum number of loops depends on the suitability of the area (see Figure 17): the lesser the knowledge, the larger the number of loops. This leads ultimately to higher exploration cost.

Whatever the case for DSF, the number of wells required to reach bankability is assumed between two and six. This assumption does not give the number of wells needed for the commercial injection but only the number of wells needed to ensure a storage site is bankable.

The minimum of two wells considers that at least two wells may be necessary to conduct interference tests and to monitor the injection tests. These tests are aimed at gaining sufficient knowledge on the characteristics of the reservoir, cap rock, and upper aquifers[22].

The maximum of six wells drilled implies that different “loops” occurred within the workflow. Each loop considers various data acquisitions and re-interpretations. As explained in the following sections, it also implies that a large area is assessed for storage bankability. If the storage bankability has not been reached after all these steps, and considering the significant amount of time and money spent at this stage, we consider the project has failed.

We based our assumptions on similar industries, given the small number of active storage projects worldwide. We extrapolated statistics based on Geogreen and its shareholders

[21] Directive EC31/2009

[22] After the characterization phase the monitoring well could be transformed in injection well if the injection strategy requires it.

experiences in O&G exploration, underground hydrocarbon storage and geothermal development.

Finally, we supposed that storage projects when deployed after having successfully reached bankability, would inject between 1 and 3 Million tonnes of CO_2 per year (Mtpa) for 30 years: each project can be considered as a "100 Mt project". Bigger projects are considered as a multiplication of such "elementary" projects. The number of workflows necessary to develop a given global storage capacity is considered to stay the same: 100 projects of 100Mt require 100 workflows, and 50 projects of 200Mt also require 100 projects workflows: the workflow must be run on two different locations.

The following list summarizes the main assumptions of these workflows:

- Storage characterization is an iterative process that could be modelled through an iterative workflow.
- Level of knowledge on a geological province has an impact on the time and costs needed to develop a storage project and, therefore, on the development workflows.
- The development workflows depend widely on regulation stringency. A stringent regulation similar to the European one has been supposed for every country. This has an impact on the licensing process and requirements on data collection before getting approval.
- A minimum of two wells and a maximum of six wells will be drilled to determine the bankability of a storage site.
- The success rates refer to technical success ratios in similar industries.
- The workflows were designed for storage sites with a capacity of 100Mt.

The following sections describe the storage development workflows to reach bankability, for the case of deep saline formations (DSF) and depleted oil and gas fields (DOGF), both for onshore and offshore locations.

4.2. Deep Saline Formation Onshore

4.2.1. Workflow Description

Deep Saline Formation storage projects may offer the most promising storage potential in terms of aggregate capacity. However, as compared to other types of CO_2 storage, limited information is available for desk based assessment.

Desk based assessment:

The objective of the first desk based assessment is to collect and interpret existing and available geological information at a regional/sedimentary basin scale. Such information originates from past underground activities in the area: fresh water production, geothermal activities, O&G activities, Underground Gas Storage, mining, etc. However, data available from such activities are generally not sufficient to properly characterize the future storage site. Indeed, they are not necessarily targeting the same layers, are not geographically focused on the expected storage site location, and did not include the required information.

Consequently, the acquisition of new local data is necessary. Figure 17 is showing the successive steps and potential loops that are supposed to reach bankability for a DSF onshore project from end of Phase 1 (see Table 1).

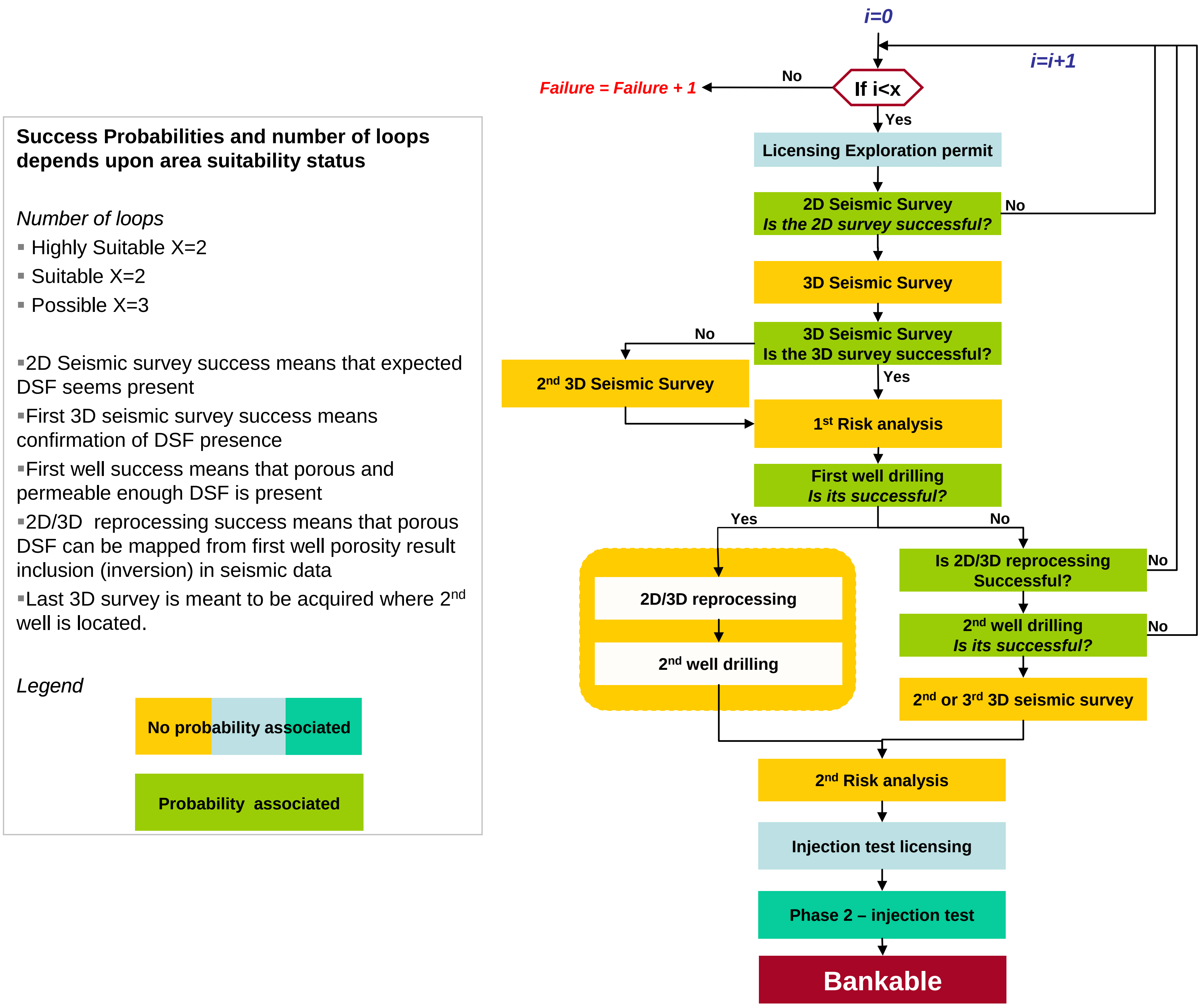


Figure 17: Development workflow up to bankability for Deep Saline Formation (DSF) onshore project

Please note that when a failure occurs in the workflow shown on Figure 17 above, it is considered that the suitability over the area has improved from its original status. Actually, new dataset has been acquired (at least one 2D seismic survey), therefore improving the overall "geological" knowledge of the area.

It is obviously impossible to create a workflow that maps all storage characterization possibilities for CO_2 storage project. However, the assumptions enable modelling of 50 to 100 different scenarios.

2D Seismic survey(s)

As described in Part 3, the first step after the desk based assessment is to apply for a license to explore the area. The licensing process, when it is required, varies widely from one region to another in terms of duration and content. However, we assume that CO_2 storage will develop within a stringent policy. The exploration license will be given for an area that can be very large (several thousands of square kilometres). One of the first new dataset supposed to be acquired is a 2D seismic survey, aimed at understanding the subsurface geometry, including fault patterns in the target area of the storage. The extent of this acquisition depends on the existing knowledge on the targeted area. It can range from a few tens kilometres to several hundred (See C.2.1.1 for further details).

Such 2D survey is used (after processing and interpretation) to acquire 3D detailed seismic data on the best potential area of the exploration license.

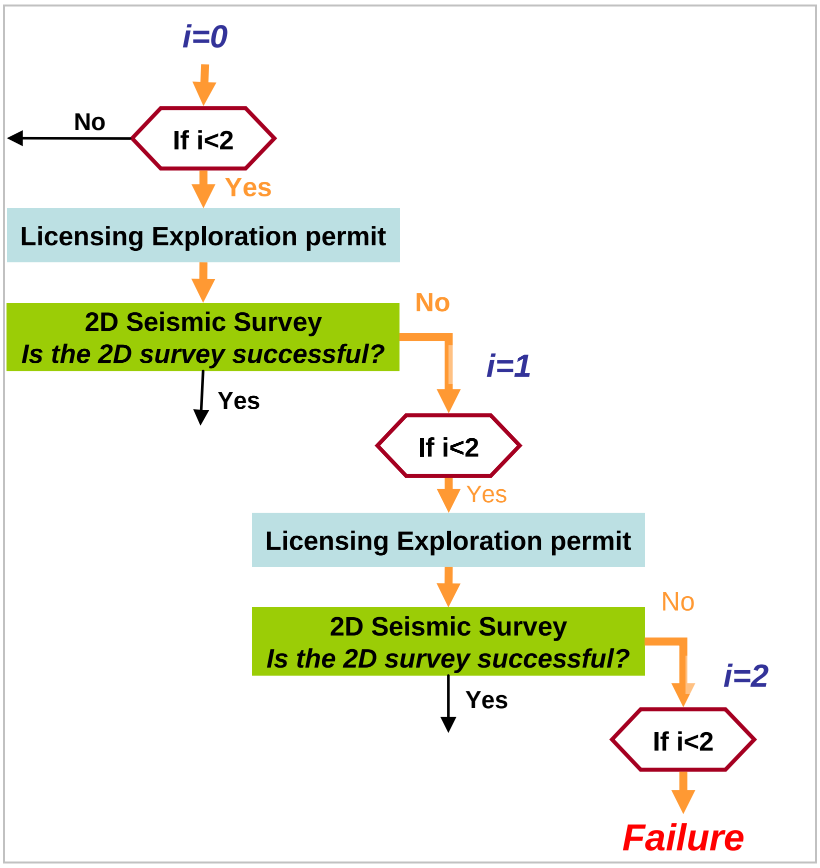


Figure 18: Deep Saline Formation Onshore Storage Project- Case of two successive 2D seismic survey failures

If the results of the 2D seismic survey are not positive (doubtful presence of cap rock, of reservoir, too many faults, etc.), the project developer would rather select a new area for performing a new 2D seismic survey, than going directly to well drilling. In the proposed workflow, the maximum number of times the project developer has the opportunity to acquire

2D seismic survey depends on the suitability (see section 3.2.2) of this area: two times for areas either highly suitable or suitable, and three times otherwise (Figure 18).

When suitability is high or good enough, the definition of the storage site area is based on better knowledge acquired in Phase 0 and Phase 1, and the probability of success of the 2D survey is greater (see comments in Table 1). Figure 18 shows the case of two successive failures of 2D seismic surveys: the effective actual workflow followed is orange coloured in this example.

3D seismic survey(s)

Whereas the 2D survey gives information on the surroundings of the future storage site, the 3D acquisition will detail information over the sedimentary pile, including potential reservoir characteristics (porosity, fractures, and detailed fault pattern). It might also serve as a baseline for 4D seismic monitoring[23]. This 3D survey area is supposed to be in the range of 100km^2 to 200km^2.

If the 3D seismic survey processing and interpretation (including inversion to obtain a porosity information) confirm the expected potential for CO_2 storage (suitable reservoir and caprock, no faults in the expected area of injection, etc.), and after a necessary risk analysis, a first well can be drilled to calibrate the local properties of caprock and reservoir layers. When the 3D seismic survey is not positive (not good enough supposed reservoir properties, discontinuous caprock for instance), another 3D seismic survey can be acquired on a different location within the area of the 2D survey (see Figure 19). However, we consider quite unlikely that none of the two 3D surveys do not show a potential for CO_2 storage, if the 2D showed such a potential. Therefore, the proposed workflow does not loop back to the 2D seismic level as shown in Figure 19.

[23] 4D seismic monitoring: repetition at fixed interval in time of a 3D seismic acquisition on a given area to monitor evolution of gases within the geological layer. This is one of the monitoring techniques used in the Sleipner case.

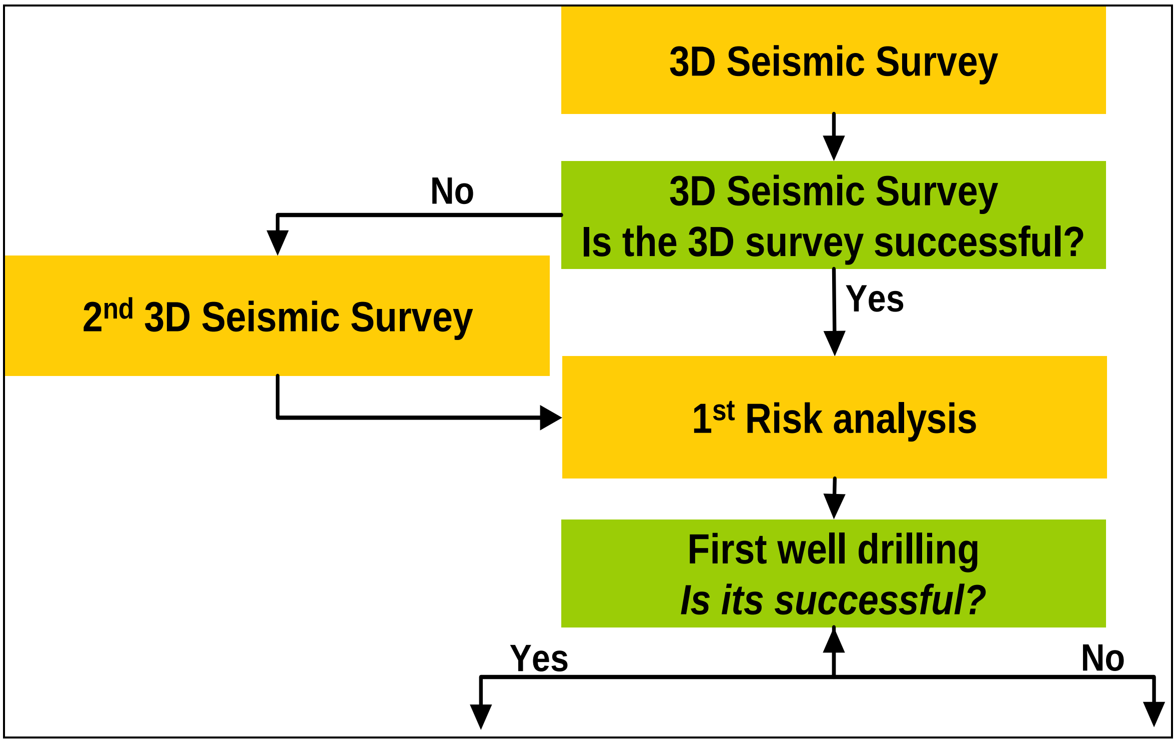


Figure 19: Deep Saline Formation Onshore - Logic trail for 3D seismic survey

Exploration well drilling

If the data (well logs, core samples, production test, maximum pressure test for the caprock, etc.) acquired during the first well drilling show that the properties of the layers are good enough (the well has found a porous reservoir and the corresponding caprock both with satisfactory properties – i.e. mechanical, petrophysical...), a second well should be drilled to perform a production interference test, and ultimately the CO_2 injection test (see section 4.1). In that case, we consider that no probability of failure should be linked to this second well if the first one has been successful.

However, if the first well is not successful, we assumed that a reprocessing of the whole seismic dataset (2D/3D) and an update of the 3D geological model will be carried out. These actions will define whether or not a suitable location can be identified in the surrounding area of the unsuccessful first well. Within the workflow, a negative result of this step of reprocessing and model update would mean that the selected area is not appropriate and the project has to be relocated (new exploration license).

If the step of reprocessing and model update shows that it is possible to find another location, then another well will be drilled. If the results of this second well are negative, the project will obviously have to be relocated. Nevertheless, if the new well is successful another 3D seismic acquisition might be needed on this new well area. Actually, the new well location may be offset from the original 3D seismic survey which may not cover anymore the future extent of the CO_2 plume.

Injection test

These tests are essential to ensure administrative authorities and public acceptance of storage project.

Prior to the injection test authorization application, a final risk analysis has to be performed. It should allow identification of the different risks but also monitoring and verification measures to be implemented as well as foreseen mitigation/remedy actions.

No probability of success was associated with the injection test. It is considered that sufficient information has been gained from the seismic surveys, well drilling, production and interference test. The injection test purely serves at defining the appropriate number of injection wells for the commercial (industrial) scale deployment. One shall note that this assumption has been made for the sake of simplicity. In practice, a risk exists that the final injectivity of the site is not as good as expected. The consequence of such a poor injectivity is, besides the increased number of wells for industrial scale, a possibility of increased investment aimed at water (brine) production for releasing pressure inside the porous volume for the injected CO_2.

Figure 20 shows one possible actual workflow (orange colour) to achieve bankability status for a project in a poorly explored area. The grey rectangle at bottom of Figure 20 highlights the route not considered in this instance.

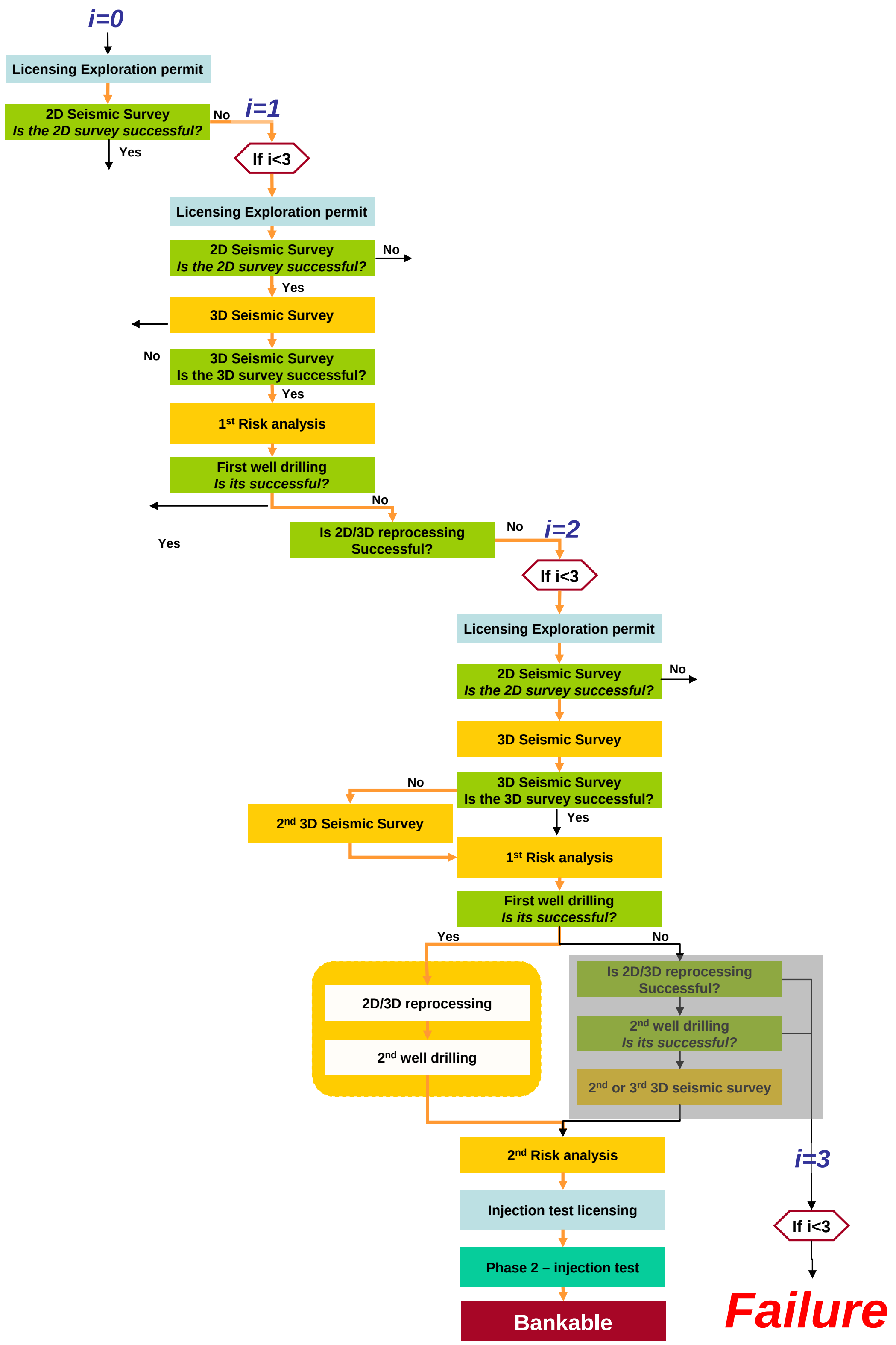


Figure 20: Deep Saline Formation Onshore - example of workflow development for exploration in poorly explored geological province

4.2.2. Probabilities of Success

The following Table 2 is showing the example of success ratios for deep saline formation onshore projects. Probabilities were assessed according to an experts' panel of Geogreen and its shareholders staff. One shall note that:

- 2D and/or 3D seismic success means that the reservoir exists where the seismic has been acquired and successfully processed and interpreted,
- Success of a well means that the well has found a porous and permeable reservoir, and the corresponding caprock,
- Number of loops means the maximum re-performance of works that is allowed in order to obtain positive results (success). This number limits the overall cost up to bankability. If after such a number of loops a project has failed to reach bankability, it then starts again from scratch on another area of the sedimentary basin where (or close to) it is located.

Reaching bankability with just one workflow (no loop in the project development) is directly related to suitability ranking of the given geographical area. If we include the maximum amount of loops allowed, then the success ratio is largely increasing for the 3 categories of suitability ranking. For the areas ranked as "possible", as soon as a loop is made, then the probability associated to a given step is taken from the "suitable" row. The reason behind is that the first steps (2D / 3D seismic surveys, well drilling) are bringing local information on the area, and therefore the knowledge of the project team has increased. This explains why the overall success ratio with the 3 loops is high, as compared to the initial elementary probabilities.

Table 2: Probabilities of success of development steps works for a deep saline formation onshore project

	Probability to succeed in passing from one step to the other for an onshore deep saline aquifer project							
Suitability status	**2D acquisition**	**First 3D survey if 2D successful**	**First well if 3D survey successful**	**3D reprocessing if first well unsuccessful**	**Second well if 3D repocessing successful**	**Number of loops of workflow up to bankability**	**Success ratio no loop**	**Success ratio total nb of loops**
Highly suitable	0,75	0,85	0,85	0,90	0,95	2 for 2D seismic+ well, 2 for 3D seismic	54%	93%
Suitable	0,65	0,75	0,75	0,75	0,80	2 for 2D seismic+ well, 2 for 3D seismic	36%	78%
Possible	0,30	0,40	0,40	0,40	0,45	3 for 2D seismic+ well, 2 for 3D seismic	5%	66%

It is here important to compare with similar industries success ratios. If we compare with O&G exploration, the ratios of success without loop (which is the basis of comparison in that case) seem compatible depending on the area. Indeed, they might be a bit higher than in O&G because geological characteristics can be good for DSF storage and not for an O&G project in the same area:

- CO_2 storage in DSF does not need structural trapping: an open monocline could be suited. Such a monocline would be considered as a failure in O&G exploration. This storage technique is called Migration Assisted Gravity Trapping (MAST) [7].
- Similarly, a good water bearing reservoir is a failure in O&G and a good point for DSF.

4.2.3. Costs and time

The costs and development times issued from this workflow (modelling assumptions are presented in C page 153 are presented below for European projects. Regional differences are shown in Appendix F page 200.

Cost

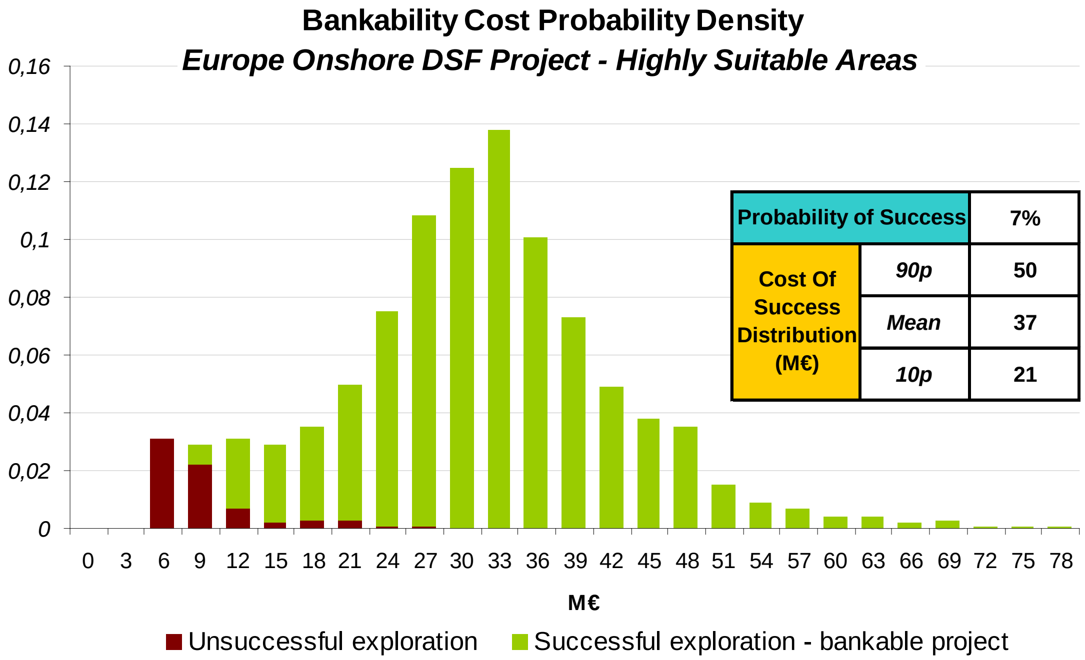
Figure 21 shows the distribution of costs versus probability for projects in highly suitable and possible areas (results for suitable areas are presented in Appendix C page 153). In Figure 21, red bars represent the cost of failed exploration. That is to say the amount of money invested in project that does not reach bankability stage. On the contrary, green bars in Figure 21 represent the costs of reaching bankability for successful projects. The main results of the distribution[24] of costs versus probability associated to these graphs are presented: 10^{th} percentile, mean and 90^{th} percentile. This means that 80% of storage characterization costs will be within the given range.

One shall first note (Figure 21) that there are important differences between the shown distributions of “highly suitable” and “possible” areas. First, the failure (red) bars are obviously more important in terms of volume when the geological province is not well known. This is translated by the lower success rate in “possible” areas than in “highly suitable” areas. Then, the cost of failure in “highly suitable” areas is lower (ranging from 6 to 21M€) than in “possible” areas (from 6 to 60M€). This means that a project located in “possible" areas might have to survey wider surface (Seismic surveys) and drill more wells in order to find a bankable storage site.

These projects are represented by the tail of the red bars distribution which ranges from 48 to 75M€. Such failure costs means that up to six wells have been drilled and that several 2D/3D seismic surveys have been conducted.

The successful bankability cost distribution (green bars) is of normal shape with the majority of values grouped around the mean of the distribution for “highly suitable” areas, while it is more widespread in “possible” areas. In other words, the probability of a project in “highly suitable” areas to have cost close to the mean is higher than in “possible” areas.

[24] It is also important to note that the sum of all probabilities associated to costs equals 1.



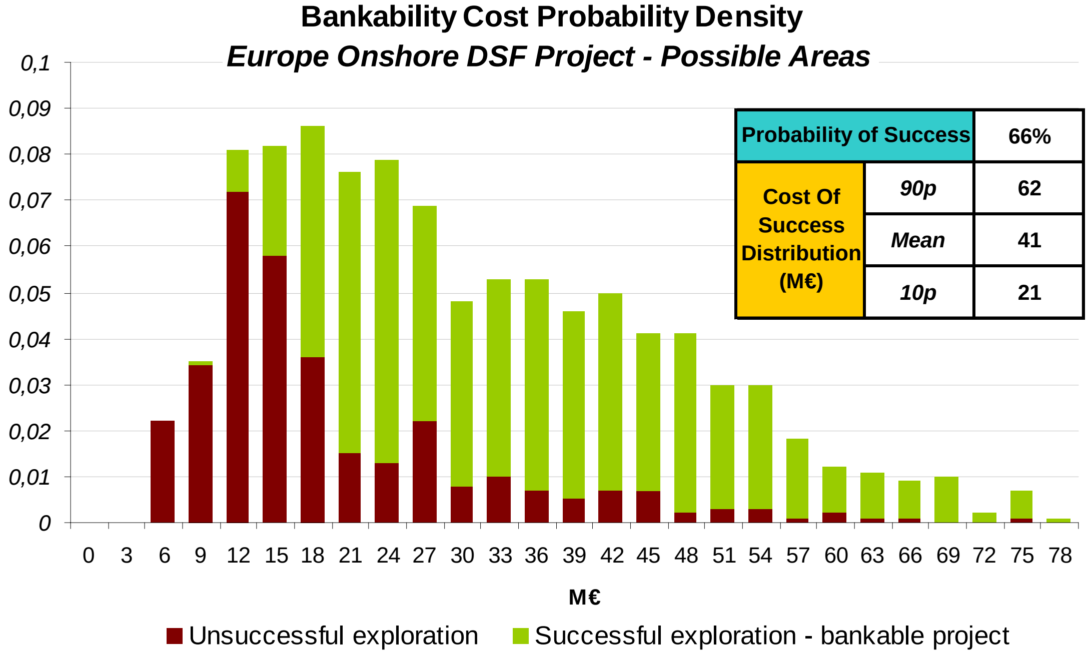


Figure 21: Deep Saline Formation Onshore - Bankability Cost For European Project in highly suitable and Possible Areas

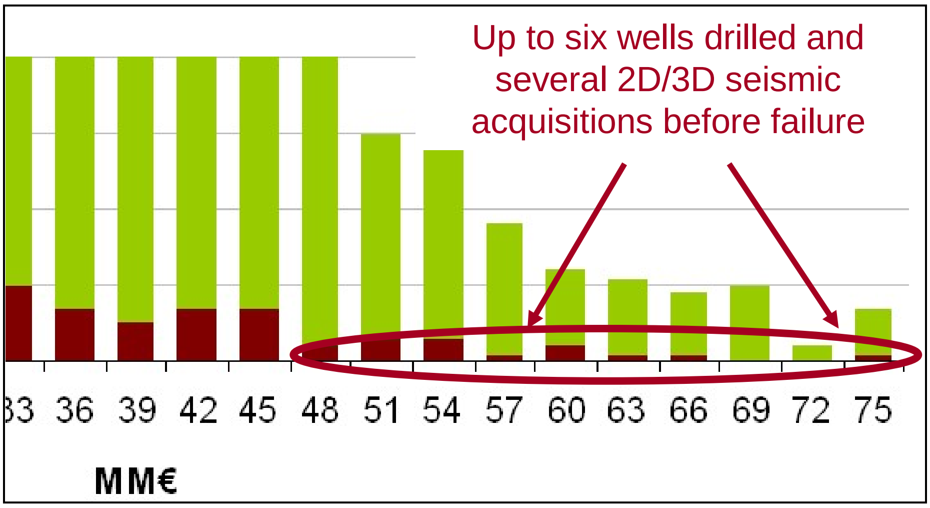


Figure 22: Deep Saline Formation Onshore - Failure Costs For Possible Areas

Two noticeable similarities can be drawn with observed costs in the Underground Gas Storage industry (UGS)[25] [55]. Indeed, this industry has been operating for decades. The characterization requirements are quite similar to those we suggest for CO_2 storage, except that a structural trap is generally necessary. Firstly, 80% of UGS projects in aquifer have costs close to the average value, and 10% to 15% of UGS projects are well above this average. Figure 22 is actually showing the same shape. Secondly, exploration costs for UGS projects count for 25% of overall storage costs, which are ranging around USD 150 millions[26] (+/-50%) for a 500 million sm^3 working gas UGS project. The corresponding amount of 20 to 55 million USD for such exploration costs is very similar to the results we obtain in our study for the technical bankability cost.

Time

CO_2 storage project development time is critical if one wants to achieve the deployment recommendations of IEA scenarios. Figure 23 below shows the distribution of time for “highly suitable” and “possible” areas. There is a clear increase of about two years for the global project development time up to bankability from “highly suitable” to “possible” areas. The storage characterization in “possible” areas is more iterative (more loops will be performed in the workflow) due to the higher risk of failure at each step. Therefore, more steps might be needed to achieve bankability. The time distribution for “possible” areas is flatter than for “highly suitable” ones, once again due to the global uncertainty level of the “possible” areas.

After reaching the status of bankability, a project needs 2 to 3 more years to become fully operational (construction of facilities). It means that between 7 to 14 years might be needed to obtain an operational project in “highly suitable” areas.

[25] There are around 85 UGS in Aquifer facilities worldwide [26]
[26] Not considering cushion gas

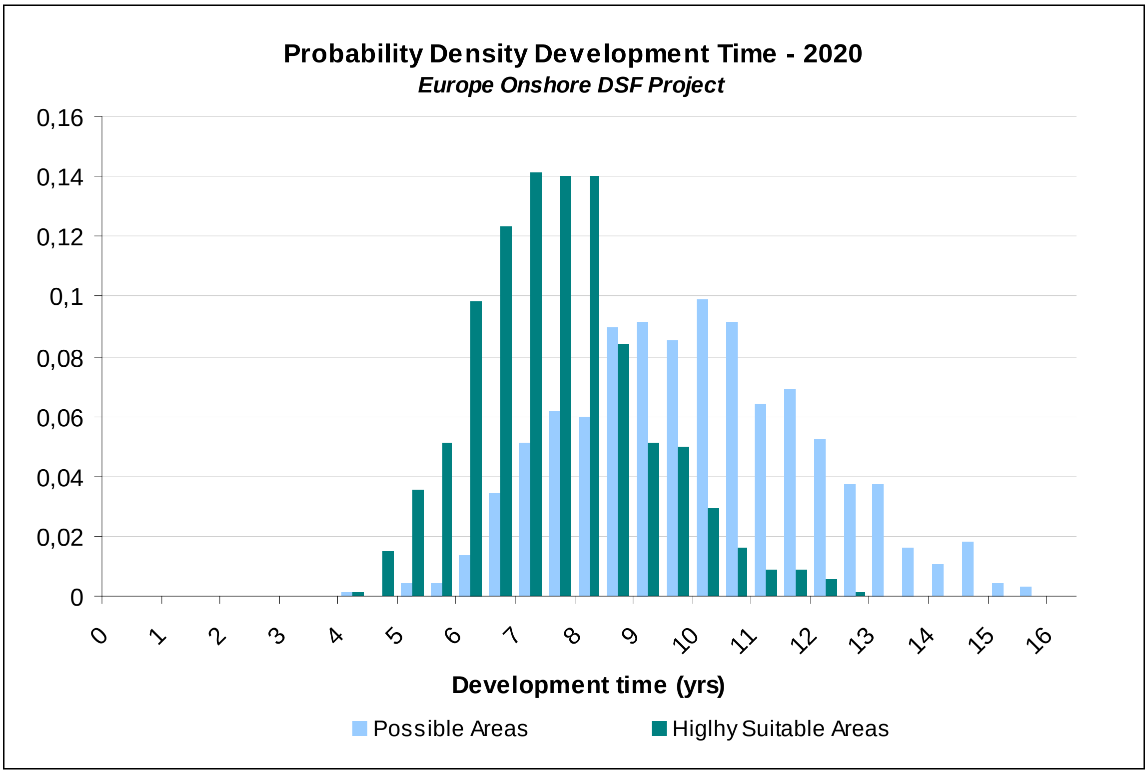


Figure 23: Deep Saline Formation Onshore – Development Time Distribution For Highly Suitable and Possible areas

A simple comparison between development times of real CO_2 storage cases with the timelines mentioned here may be difficult. Real cases seem to have been developed much quicker. For example, the In-Salah project[27] was developed in just a few years, but at a time where no specific regulation existed, and CO_2 is injected in the very same formation as the gas bearing one. It means that regulatory and exploration times have been saved.

However, it is possible to benchmark the proposed development times with Underground Gas Storage (UGS) projects in DSF. The time for development of natural gas storage worldwide ranges from 4 to 10 years [13], with an average value of 8 years for natural gas storage projects in aquifers.

Finally, the result of the proposed model is very sensitive to regulatory framework which was assumed to be stringent in every country.

[27] In Salah Project is operated by BP, Statoil and Sonatrach http://www.insalahco2.com/

4.3. Deep Saline Formation Offshore

4.3.1. Workflow Description

Offshore Deep Saline Formation characterization process differs from onshore one. Indeed, technologies and costs are different. An onshore well cost ranges between 1 and 5M€, while it will range between 10 and 30M€ or more in an offshore environment. Figure 24 is showing the successive steps and potential loops that are necessary to reach bankability for a Deep Saline Formation (DSF) offshore project. We remind that the shown workflow starts after the desk based study level has been achieved, which means that an area of exploration has been identified using existing data.

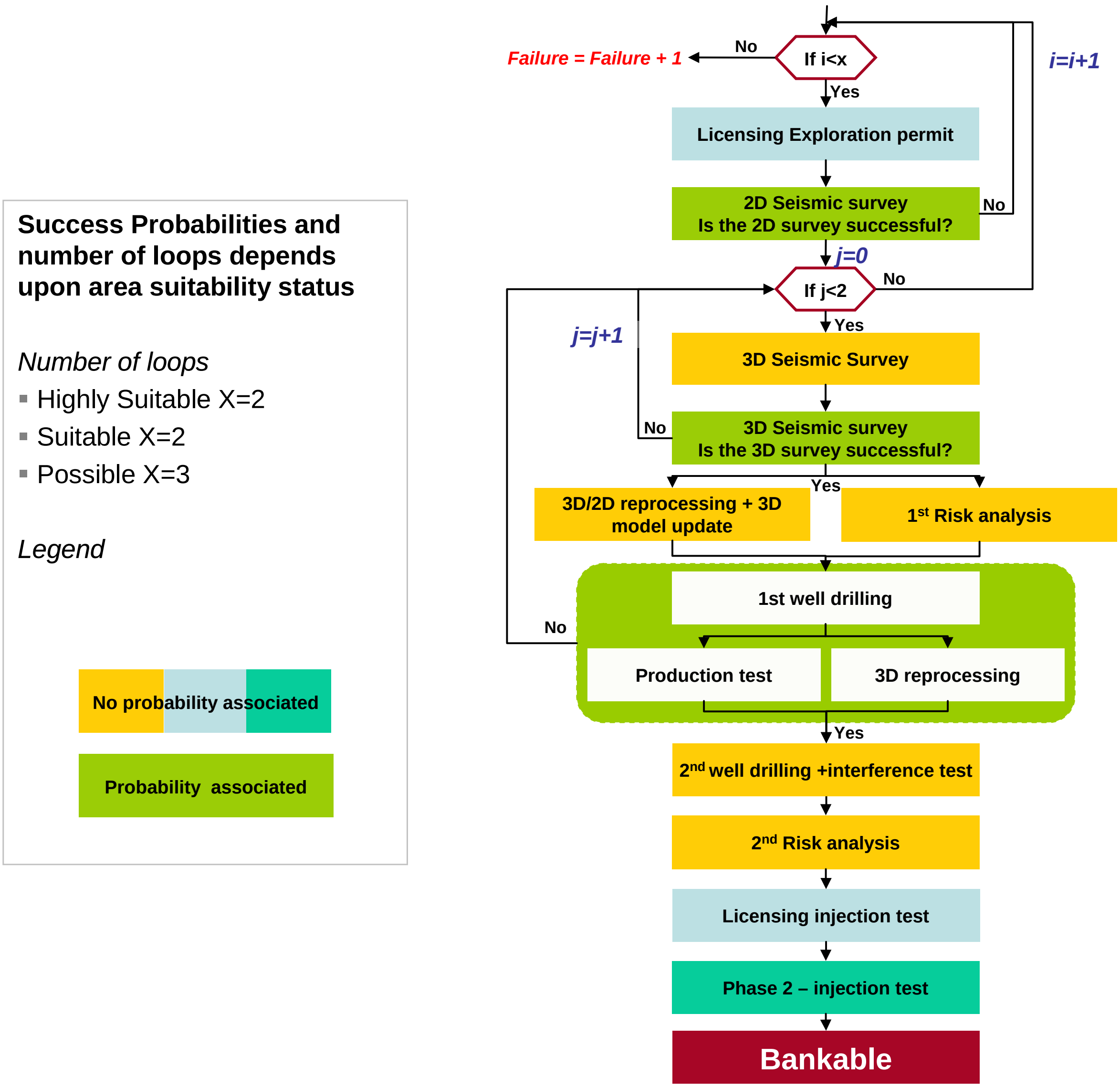


Figure 24: Development workflow up to bankability - DSF offshore project

The same workflow is supposed for shallow water environment and deep offshore, but exploration costs incurred are different as explained in Appendix C page 175.

The maximum number of loops depends upon the suitability of the area (see Figure 14– section 3.2.2.1). The lesser the knowledge, the larger the number of loops, and therefore the costlier the bankability shall be.

One shall note that the first part of the workflow is similar to the onshore one. An exploration license has been applied to the national relevant authority. Once granted, a 2D seismic survey will be performed. The main difference with onshore context is that the 2D seismic is easier to acquire and generally concerns wider areas (see Appendix C page 175). Therefore, the chance of finding a suitable area for CO_2 storage is increased.

Similarly to an onshore context, a 3D seismic acquisition will be performed on the potential storage site area. The offshore 3D seismic campaigns are easier and cheaper than onshore ones. The area covered with the 3D campaign is then wider than in an onshore case. Additionally, seismic processing is faster for offshore data than for onshore ones.

3D digital geological model will be updated with the new information from the 3D dataset. A first risk analysis will be performed. This first risk analysis will help defining the appropriate well design. New well data (logs, coring, production test) will enable characteristics to be calibrated (petrophysical, mechanical, and chemical properties of the reservoir and cap rocks), and the future injection strategy will be defined.

However, if the results of the 3D seismic survey or those of the well and of the injection tests are negative, it is possible to redo the whole process (3D acquisition and well drilling). As a wide area will be screened by the 2D seismic, an alternate location may be identified for a new 3D seismic survey and well drilling. A maximum of two of these 3D acquisitions are assumed in this workflow. Two possible logic paths are presented in the figure below:

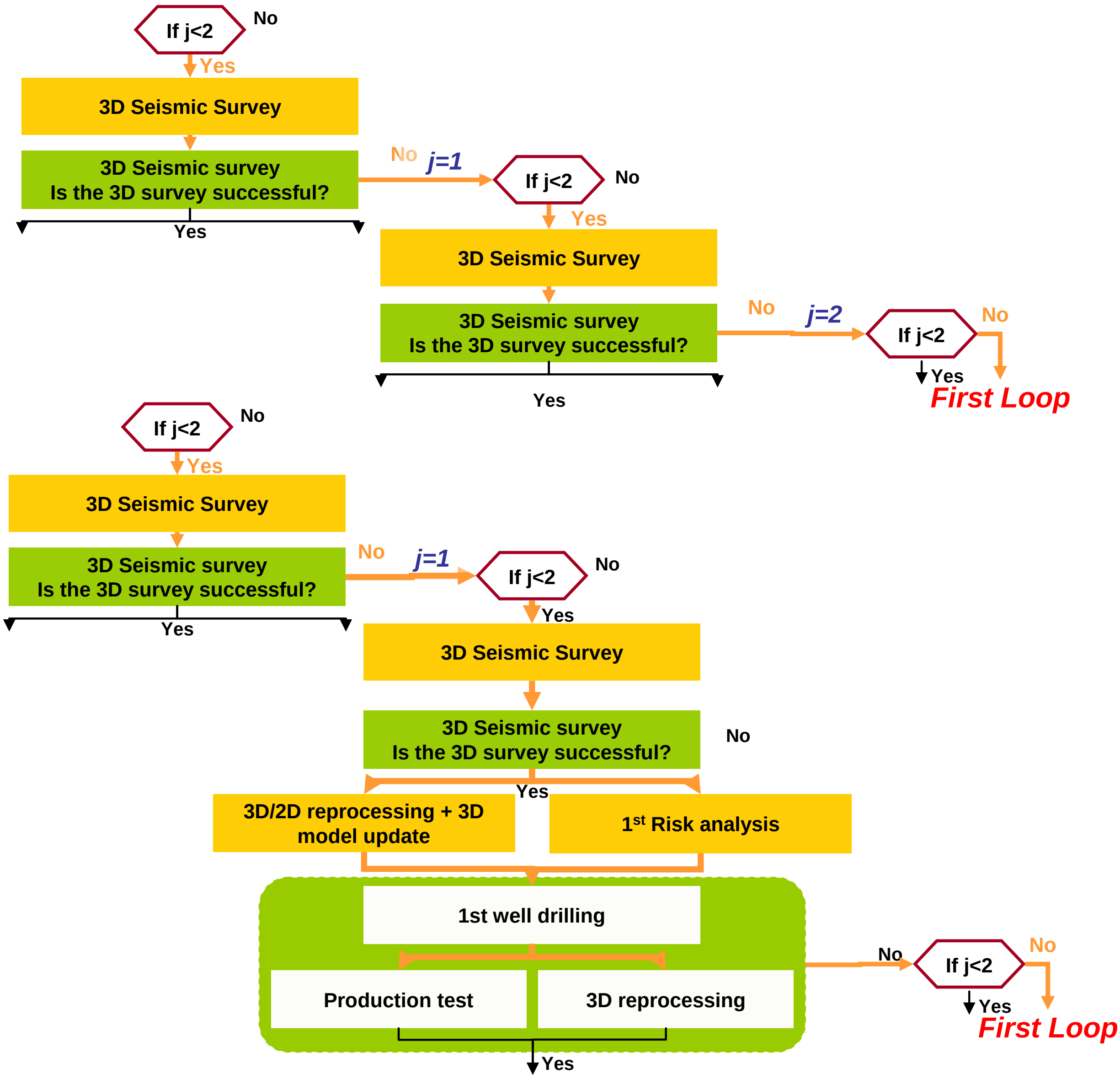


Figure 25: Deep Saline Formation Offshore: Examples of workflow logic path

If this loop (Figure 25) does not give positive results, it is legitimate to change the area of the project and to restart from a 2D seismic acquisition somewhere else. The proposed workflows have been conceived to assess the technical bankability, and not the financial bankability.

If the first well and associated tests are successful, a 2nd well will be drilled. No probability is attached to the second well drilling: in offshore conditions, this second well is drilled only if and when the first well is successful, and the 3D reprocessing has shown a positive area.

As for the onshore case, up to six wells might be drilled before a project is abandoned.

The workflow ends with a 2nd risk analysis prior to the CO_2 injection test licensing process. This study assumes that a very stringent regulatory framework that would require injection test onshore and offshore.

As for onshore project we tried to benchmark the proposed workflow with existing offshore projects: Sleipner [41] and Snøhvit [45] both operated by STATOIL. Similarly to what has been observed in onshore case comparison, our proposed workflow seems quite longer than these real cases. But Sleipner was developed with the use of an existing hydrocarbon production platform, and many wells were drilled for gas production purpose through the Utsira formation before CO_2 injection took place. Snøhvit was also developed in conjunction with hydrocarbon production. The targeted CO_2 reservoir formation is below the hydrocarbon producing formation and was penetrated by 15 of 17 exploration wells which have informed characterisation of the storage site [45]. In both cases, the characterisation was estimated with enough confidence during the Oil and Gas exploration phase itself to save time for DSF characterisation and to drill only one well for CO_2 injection.

4.3.2. Probabilities Of Success

The following Table 3 is showing the example of success ratios for offshore DSF projects. Probabilities have been assessed according to an experts' panel from Geogreen and its shareholders' personnel. One shall note that:

1. Success of a well means that the well has found a porous and permeable reservoir, and the corresponding caprock,
2. 2D and/or 3D seismic success means that the reservoir is highly probable where the seismic has been acquired, thanks to appropriate inversion aimed at effective porosity block definition,
3. Number of loops means the maximum re-performance of works that is allowed in order to obtain positive results (success). This number limits the overall cost up to bankability. If after such a loop number a project has failed to reach bankability, it then starts again from scratch on another area of the sedimentary basin where (or close to) it is located.

Reaching bankability with just one workflow (no loop in the project development) is directly related to suitability ranking of the given geographical area. If we include the maximum amount of loops allowed, then the success ratio is largely increasing for the 3 categories of suitability ranking. For the areas ranked as "possible", as soon as a loop is made, then the probability associated to a given step is taken from the "suitable" row. The reason behind is that the first steps (2D / 3D seismic surveys, well drilling) are bringing local information on the area, and therefore the knowledge of the project team has increased. This explains why the overall success ratio with the 3 loops is high, as compared to the initial elementary probabilities.

Table 3: Probabilities of success of development steps works for an offshore DSF project

	Probability to succeed in passing from one step to the other for an offshore deep saline aquifer project					
Suitability status	**2D acquisition**	**First 3D survey if 2D successful**	**First well + Production test + 3D reprocessing if 3D survey successful**	**Number of loops of workflow up to bankability**	**Success ratio no loop**	**Success ratio total nb of loops**
Highly suitable	0,85	0,90	0,85	2 for 2D seismic+ well, 2 for 3D seismic	65%	95%
Suitable	0,75	0,85	0,75	2 for 2D seismic+ well, 2 for 3D seismic	47%	87%
Possible	0,50	0,60	0,50	3 for 2D seismic+ well, 2 for 3D seismic	15%	71%

Success ratios with no loop are larger for offshore projects than for onshore ones. Given the much higher costs of offshore well drilling, it is supposed that offshore 2D and 3D seismic surveys are much larger than for onshore projects (offshore 3D average area is around 800km², to be compared to 180km² onshore), and therefore the probability to find a suitable area with good reservoir quality is considered as higher than for onshore.

However, the failure cost (cost associated with exploration / test works performed without reaching bankability) is much higher for offshore than for onshore projects due to higher unit costs.

4.3.3. Costs and time

Cost

The costs and development times supposed in this workflow (modelling assumptions are presented in Appendix D) are presented below for European projects.

Figure 26 shows the density of probability of costs for projects in "highly suitable" and "possible" areas for shallow offshore projects (results for suitable areas are presented in Appendix H) As explained for onshore DSF projects (see section 4.2.3), red bars in Figure 26 represent the cost of failed exploration, which stands for the amount of investment in a project that does not reach bankability stage. On the contrary, green bars in Figure 26 represent the costs of reaching bankability for successful projects. The main results of the distribution[28] of costs versus probability associated to these graphs are presented: 10th percentile, mean and 90th percentile. This means that 80% of storage characterization costs will be within the given range.

[28] It is also important to note that the sum of all probabilities associated to costs equals 1.

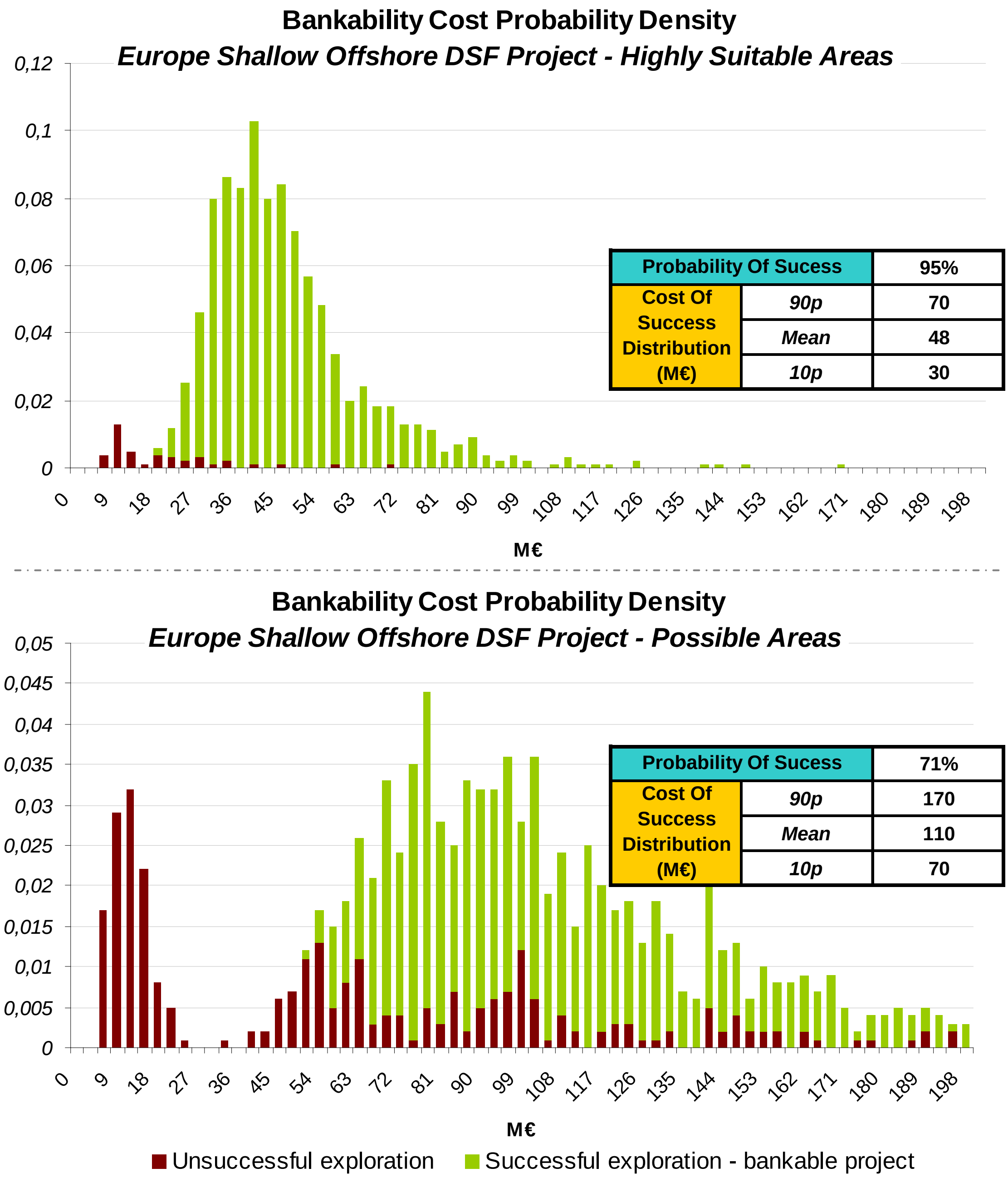


Figure 26: Deep Saline Formation Shallow Offshore - Bankability Cost For European Project in highly suitable and Possible Areas

There is a significant difference between “highly suitable” (HS) and “possible” (P) areas. In highly suitable areas, the distribution is contained below 100M€ whereas it spreads up to 200M€ in the possible case. The cost of failure distribution (red bars in Figure 26) stays below 40M€ in the highly suitable case while it blows up to 200M€ in the possible case.

Indeed, in highly suitable areas, the geology is well known and 3 consecutive failures at the 2D/3D seismic surveys levels will most probably lead to the project abandonment. However, the possibilities to fail in “possible” areas are more important. The failure (red) peak in front of the distribution and centered on 15M€ shows that chances to fail three time in a row at the 2D/3D seismic survey level is significant. In unknown areas, 2D/3D seismic acquisitions will allow to eliminate potential areas for reasons such as for instance: lack of caprock, too shallow reservoir, existing faults…

One can also notice that the failure distribution is widespread as shown on the Figure 27 below, which is a focus of previous Figure 26, highlighting the lower part of the density of probability axis (vertical axis). The overall result shows that even if the possibility to fail offshore characterization is lower than in onshore case (see section 4.2.3); the cost of the failure and therefore the financial risk is higher.

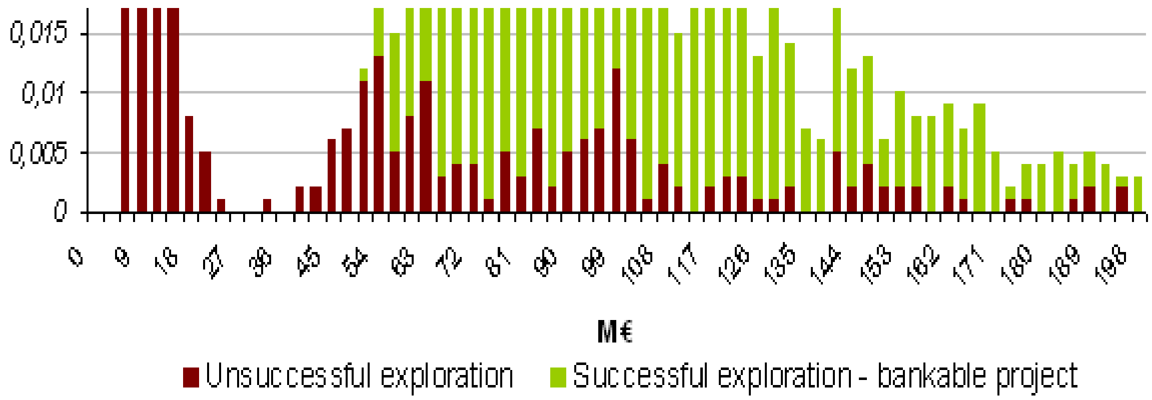


Figure 27: DSF offshore failure cost distribution

<u>Time:</u>

The development time distributions (Figure 28) are very different for “highly suitable” and “possible” cases. The “highly suitable” distribution is narrower (6 years overall range) with a peak value around 9 years. The “possible” area distribution is flatter, ranging from 6 years up to 19 years.

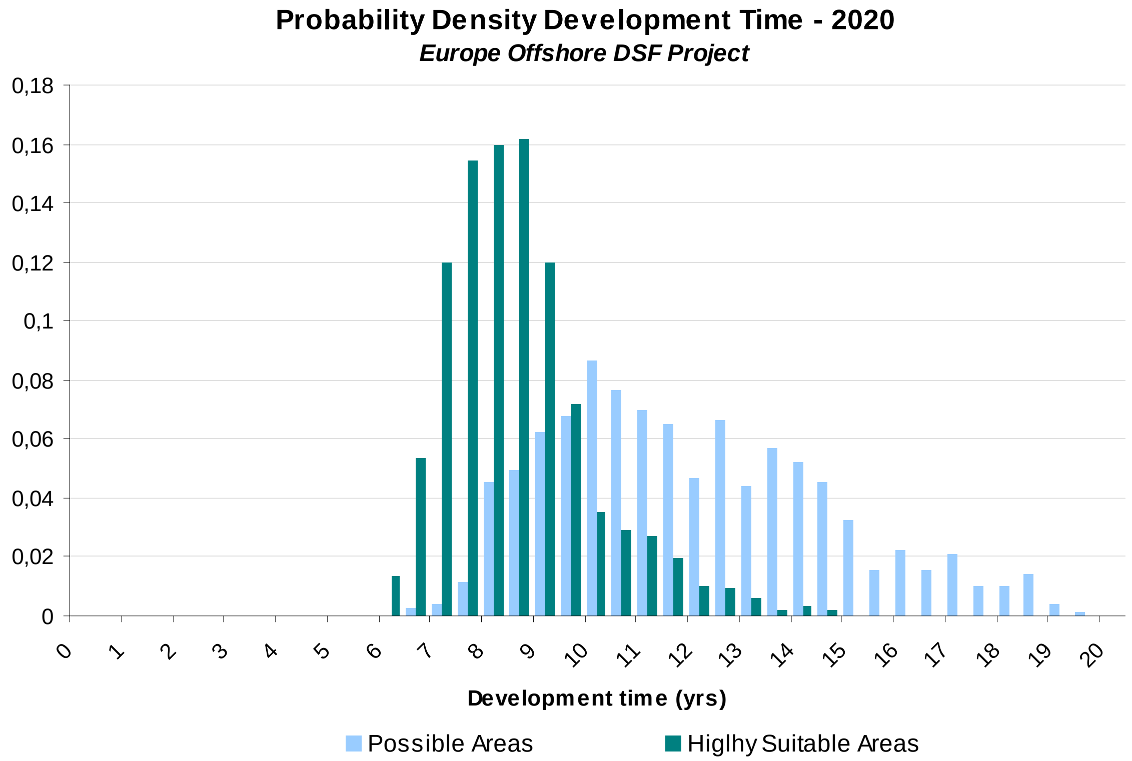


Figure 28: Deep Saline Formation Offshore – Development Time Distribution For Highly Suitable and Possible areas

4.4. Depleted Hydrocarbon Field

4.4.1. Workflow

In the proposed workflow to reach bankability is that, conversely to storage in aquifer, there is no possible loop in the development workflow for depleted hydrocarbon fields. In case of failure, the field is purely abandoned, since there is no possible move to another location.

Figure 29 is showing the development workflow for a storage project in a depleted oil and gas field onshore or offshore. Phase 0 is supposed to be based upon databases and analytical first screening. Phase 1 desk based assessment, as compared to the development of a deep saline formation project, is based upon the review of proprietary data belonging to the oil operator. Again taking as a basis experience in conversion of depleted fields for underground storage of hydrocarbon, we think appropriate to count one full year for performance of a first analysis of well data, reservoir engineering results, 3D modelling and/or geological/production data. Such a first analysis makes it possible to know whether keeping or not on with the project.

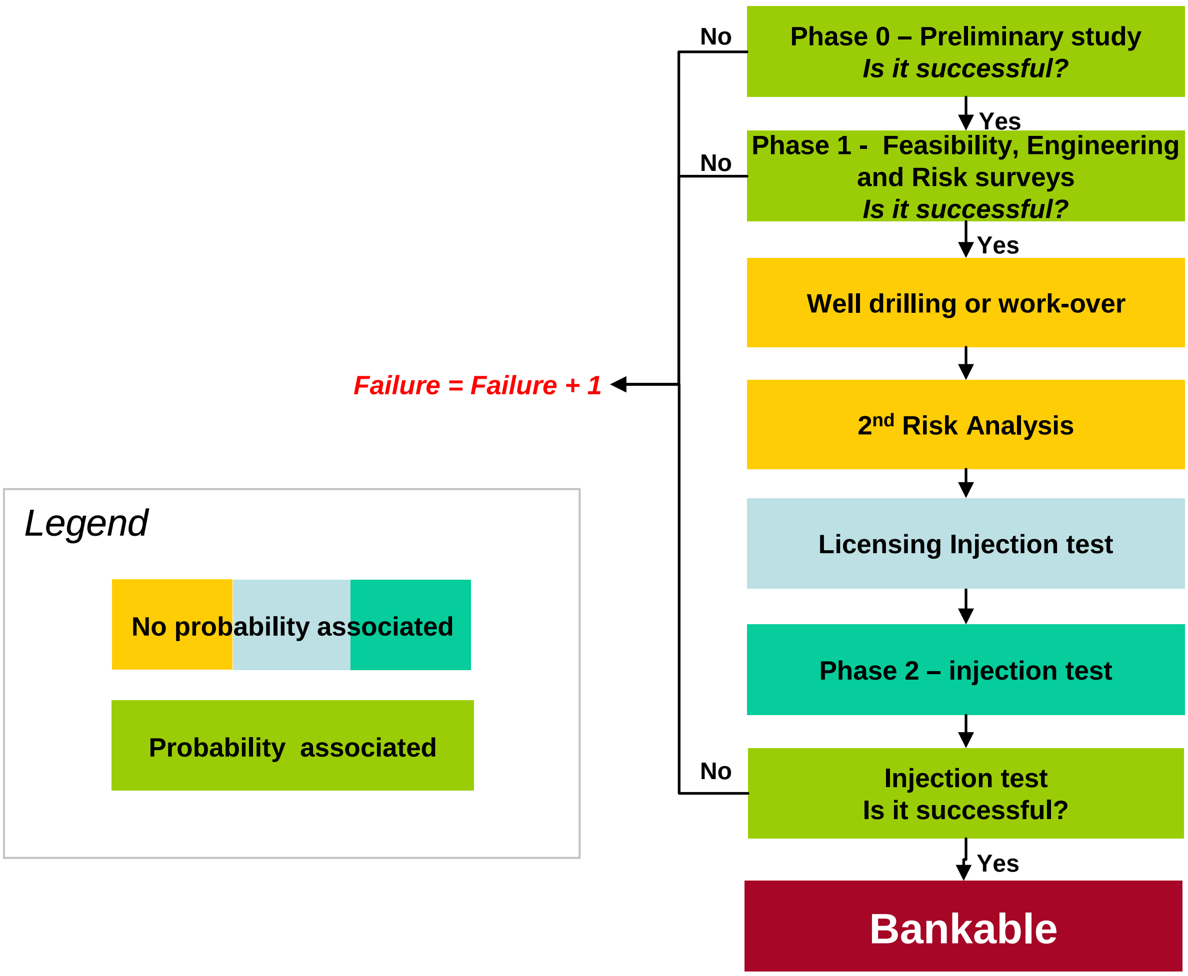


Figure 29: Development workflow up to bankability - Depleted hydrocarbon field

After the first part of Phase 1 (desk based assessment), it is possible to eliminate fields on basic criteria such as caprock integrity, level of water flooding from an existing active aquifer, injectivity. Indeed, injectivity in a depleted field might be compromised through fracture closing due to pressure drop, or an active aquifer might have filled a big part of the available porous volume. If the field passes these first hurdles, a 3D geological model will be built, or the existing one will be enlarged, and history matched with production data. Once the injection strategy is defined, existing well will be worked over or new wells might be drilled. Usually, old wells are re-entered to firstly verify their integrity, and if integrity is okay, secondly to install new CO_2 compliant completion equipment.

Once again, we remind the reader that these workflows assume a stringent storage regulatory framework is in place. Injection tests are required for CO_2 storage in order to verify that no unforeseen chemical reaction or mechanical disturbance will arise in the field environment. One has to know that some European countries required injection tests prior authorisation granting for a similar storage industry: reconversion of a depleted field in Underground Hydrocarbon Storage.

4.4.2. Probabilities Of Success – Depleted Hydrocarbon Field

Table 4 is showing the probability of success (for both onshore and offshore projects) of achieving the major steps included in the workflow of Figure 29. Basically, since offshore fields have generally a smaller number of producing wells than onshore ones, then it is considered that the overall leakage risk associated with CO_2 injection is smaller. As a consequence, the overall success ratio is slightly higher for offshore cases.

The preliminary study is supposed to reject half of the projects in depleted oil fields. We suppose that water invasion can affect such rejected fields, preventing them to be efficiently converted into CO_2 storage. This first screening may seem quite selective, but it shall allow cost of failure to be very low (only desk based studies). The situation for depleted gas fields is different. Firstly, water invasion is considered slightly lower, and as compared to oil fields, the reduced number of wells makes them slightly better (less risky) candidates.

Table 4: Probabilities of success of development steps works for depleted hydrocarbon field storage projects

		Preliminary study	Field detail assessment if preliminary study successful	Injection tests if field detail assessment is successful	Success ratio
Onshore	***Depleted oil field***	0,50	0,90	0,50	23%
	Depleted gas field	0,60	1,00	0,90	54%
Offshore	***Depleted oil field***	0,50	0,90	0,70	32%
	Depleted gas field	0,80	1,00	0,90	72%

These results are quite in line with Underground Gas Storage industry where depleted field reconversion has been performed for the last 50-70 years.[29]

4.4.3. Cost and Development Time

Cost

Figure 30 shows the costs to reach bankability for onshore and offshore Depleted Gas Fields (DGF) projects in Europe that can be compared to DSF cases shown on Figure 22 and Figure 26.

The first thing to notice on the figure below is the failure peak (red bars) between 0 and 6M€ in both onshore and offshore cases. This peak represents the costs of failure at the preliminary study level (first column Table 4). It translates the high failure rates at this level of characterization (40% onshore; 20% offshore). It also shows that the costs characterization pattern differs widely from DSF case. Indeed, the majority of failed characterization will occur at a “limited costs” desk based level whereas some fields works (seismic surveys, well drilling) are generally needed in DSF case to be sure an area is not suitable. The failure potential is limited once this first step of characterization is passed (as shown by the presence of very small red bars or failure costs after the first peak). DGF characterization costs and failure costs are smaller than DSF ones which tend to show that DGF CO_2 storage characterization is less risky.

Offshore DGF characterization costs is quite similar to the onshore one (27M€ instead of 22M€). The reason for that is the existence of wide array of data to be inputted in models as well as the presence of existing infrastructures which limits the costs of field works.

If we compare offshore DGF and offshore DSF, there is a clear gap in cost (27M€ for DGF and between 47 and 110M€ for DSF). Once again, this is due to the presence of facilities

[29] There are around 450 UGS in Depleted fields worldwide – source B. Hugout, SPE 38245

onsite (DGF case) and to the nature of characterization. Very few drilling will occur and field work will be mainly focus on well recompletion. The CO_2 injection can also be conducted from the existing platform which saves costs significantly.

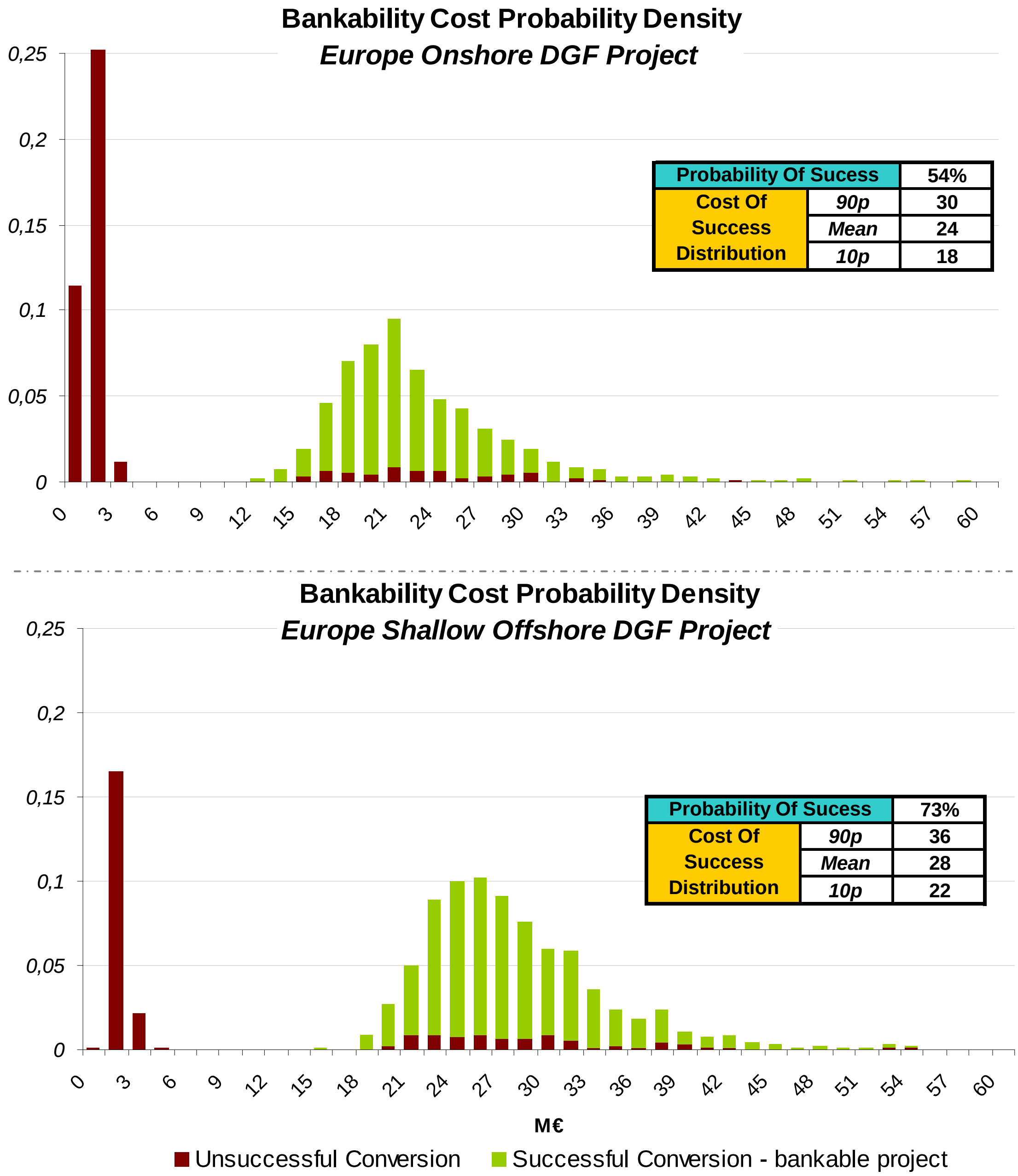


Figure 30: DGF Onshore/Offshore - Bankability Cost For European Projects

These cost distributions presented here is similar in shape to what has been observed in Underground Gas Storage in depleted field industry[30] [55] 80% of the projects have costs close to the average but some projects (10 to 15%) have cost well above this average. This is shown by the long tail of the cost distribution (Figure 30)

If we compare with the UGS in depleted fields industry, we can see that our results are higher. In the above mention UN report, they estimated the investment costs in depleted field to be around USD 200 millions[31] (+/- 50%) for the biggest (1000 millions of cubic meter). They estimated the exploration/characterization cost to represent 6% of this amount. That is to say around USD 12/15 millions. This corresponds to the lower range of the costs shown in our model. However, we considered a stringent regulatory framework for the first projects with mandatory CO_2 injection tests which can be very expensive when no CO_2 is available in the vicinity of the storage site. Natural gas injection into a depleted field requires less well workovers/drilling of monitoring wells than CO_2. Indeed, CO_2 corrosive properties often mandate a re-completion of wells. This adds significantly to the costs and explains the observed difference.

<u>Time:</u>

Figure 31 shows the development time for onshore and offshore DOGF in Europe.

In average and in both cases, 6 to 7 years would be needed to convert an existing field to CO_2 injection. Indeed, even if the field structure is quite well known, one should not forget that CO_2 injection for the purpose of climate change mitigation requires a high level of study and a long licensing process as explained in section 3.

Both distributions are similar even if the offshore one is shifted by 6 months. Indeed, as infrastructures are in place, the storage characterization process is similar.

It is noteworthy to mention that the window of opportunity issue is critical for offshore storage. For instance, in the North Sea, offshore installations have to be decommissioned within a short period after the end of production. It means that there is a limited time window to use the existing installations and wells for CO_2 injection before decommissioning. Once decommissioned, it will be very expensive to come back on a field to do $CO_{2,}$ reopen wells or perform CO_2 compliant workovers.

[30] There are around 85 UGS in Aquifer facilities worldwide – source B. Hugout, SPE 38245
[31] Disconsidering cushion gas

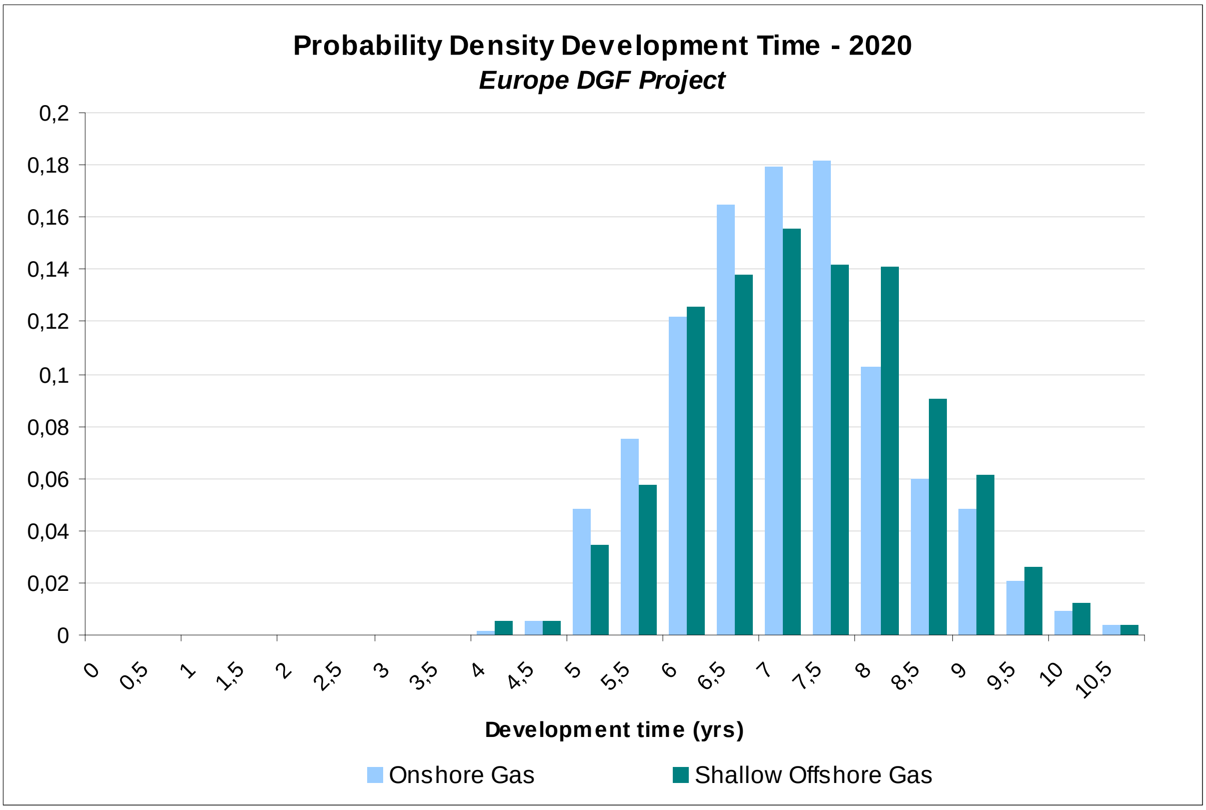


Figure 31: DGF – Development Time Distribution Onshore/Offshore

The time for development of natural gas storage worldwide ranges from 4 to 10 years according to different sources [13], with an average value of 5 years for natural gas storage projects in aquifers.

4.5. CO_2 Enhanced Oil Recovery

As mentioned in section 3, we do not examine in detail all CO_2-EOR potential worldwide in this report. We however recognize the contribution it could make to achieve storage development objectives. We give in these section only insights about CO_2-EOR projects development times. We consider only projects that have the objective to effectively store the CO_2 (not the project which only goal is to produce incremental oil). As explained in section 3.2.2.3, we have not addressed the costs aspect of CO_2-EOR projects.

CO_2-EOR projects development time depends widely on applicable regulation and field operator appetite for risk (investment ahead of schedules or license granting…). During this work, the development workflow and times are estimated to reach bankability in the following table:

Table 5: CO_2-EOR: Insights on Development Time

CO_2 - EOR	IEA GHG Timing min	IEA GHG Timing max
Phase 1 Desk Based assessment	*0,5*	*1*
Licensing EOR Test	*0,1*	*0,5*
Phase 2 - Construction and Well assessment	*0,5*	*1*
Phase 2 - Injection Test	*0*	*0,5*
Bankable		
Total	*1,1*	*3*

CO_2-EOR development workflow is similar to DOGF ones. The first desk based assessment aims at collecting field data and production history into 3D geological and dynamic models (if not already existing). These models will be then used to determine if CO_2 sweep efficiency meet the economical and technical targets for that particular field given its structure, characteristics and oil properties. It will also help identifying the best location for CO_2 injectors and defining the associated Measurement, Monitoring and Verification (MMV) programme.

In most countries, a license will then be requested. It is particularly true for countries where CO_2 quotas or credit[32] will be given for CO_2 storage.

On Table 5, one can see that development times for CO_2-EOR projects up to bankability can be very short (between 1 and 3 years) provided all the economic drivers are present (rewarding oil price).

[32] Credit where a Carbon Cap and Trade or Emission Trading Scheme is or will be implemented

Key Messages on Storage Development Costs and Times

The CO_2 storage development workflows presented in this section are in line with what has been experienced in the decade old Underground Gas Storage industry. We therefore strongly believe in the above presented results and would like to catch policy makers' eyes on the following conclusions:

1. **Storage bankability assessment is long**
   - Between 5 and 15 years are needed to achieve bankability for deep saline formations and some depleted fields. This means that the project starting date definition is driven by the storage implementation lead time.
   - Storage site bankability assessments take time because it is an iterative process. It has to be conducted according to stakeholders' wishes in order to not jeopardize future commercialization due to public acceptance issues.
   - Development time is very sensitive to licensing and environmental issues**.** Those issues can count to more than half of the overall time needed to develop a storage site.
2. **… but is a limited investment as compared to the overall chain**
   - For onshore projects, storage bankability assessment costs represents in average less than 10% of capture plant costs (over 0.7bn€ for 550MW power plant capture costs following Global CCS Institute Global Status of CCS 2010 report). For few very offshore projects, this can rise up to more than 20%.
3. **Storage bankability assessment is not always technically successful**
   - When considering all possible iterations within the corresponding workflows to reach bankability stage, technical success ratios are between 60 and 90% for aquifers, between 20 and 30% for depleted oil fields and between 50 and 70% for depleted gas fields.
4. **The level of geological knowledge over an area has a significant impact on storage development cost and time up to bankability**
   - Bankability development costs time vary widely depending on localisation, geological structures and level of knowledge of the area (up to more than 100% variation).
   - A good knowledge over a geological province will allow spotting the best location without necessarily engaging huge characterization works.
5. **CO_2 Enhanced Oil Recovery (EOR) and Depleted Oil and Gas Field can represent early opportunities for some countries**
   - CO_2-EOR (1-3 years) and DOGF (4-10 years) lead time are often shorter than for DSF (5-15 years).
   - The contribution of these resources to the global effort is limited by the following factors:
     - They are not distributed evenly between countries (oil and gas producing provinces).
     - Not all fields can be converted to CO_2 storage/ EOR.
     - There is a specific time window of opportunity that can be used for conversion of the field.

5. GAP ANALYSIS TO MEET BANKABILITY RECOMMENDATIONS DURING THE NEXT DECADE

After having explained the storage development workflows (previous section) and following the global study methodology (see section 3), we used the developed analytical tools in order to answer the following question:

Is there a gap between the existing effort in storage development and the IEA 2020 recommendations and where?

We adopted a step wise approach in order to answer these questions:

1. Analysis of the gap on the technical perspective and including only “non EOR / pure storage” projects. In this section, we want to show what the industry can technically deliver for these type of projects
2. Analysis of the gap on both technical and non technical perspective only “non EOR / pure storage” projects. This section gives insights on the importance played by the non technical factors in achieving 100 projects by 2020.
3. Analysis of the contribution of EOR to the overall. The important role that CO_2-EOR can play within storage development is discussed in this section.

5.1. Storage Bankability 2020 - Technical Bankability Aspects for Deep Saline Formation and Depleted Fields

5.1.1. Number of Projects the Industry Can Deliver VS IEA 2020 Recommendation

This section gives the key outcomes of the gap analysis between existing efforts and IEA 2020 recommendations only for DSF and DOGF. It deals only with the technical aspect of the bankability. A discussion is proposed in section 3.2.2.3 and 5.3. The analysis has been carried out on all preselected projects as described in section 3.2.1 and following the storage development workflows as described in section 4. Results have been aggregated at regional level.

IEA 2020 Recommendation VS current effort

Figure 32 shows the gaps between existing projects and IEA recommendations at worldwide scale.

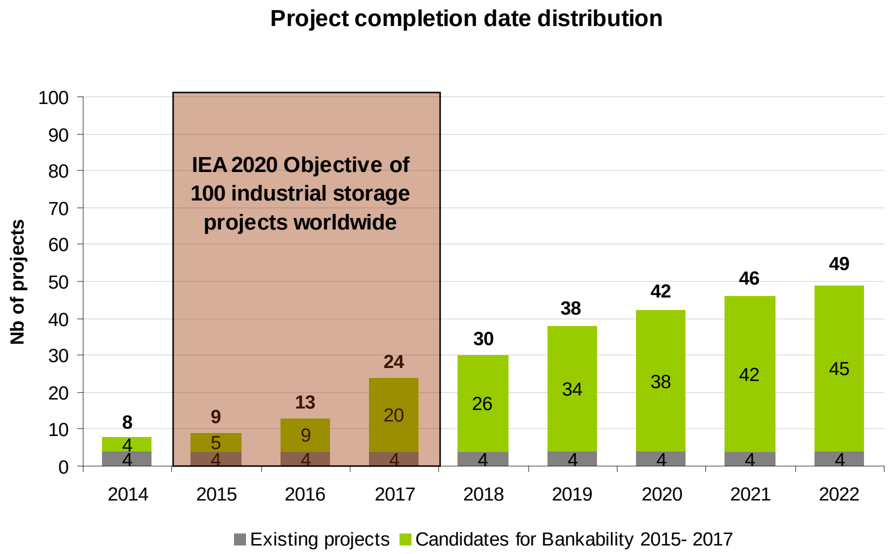


Figure 32: Yearly distribution of projects reaching technical bankability among the 54 candidates+4 existing DSF projects

First, we remind the reader that only technical bankability is assessed in this section (see section 3.1). This shows only what is technically feasible without taking into account economics/ political or public acceptance aspects. Moreover, we considered for this figure only the average development time of projects and not all the development time distribution as shown in section 4.

As of today, and counting the 4 existing large scale DSF projects, it seems that only 24 to 30 new projects could probably reach bankability soon enough for being industrial projects by 2020 (projects within the light brown area in Figure 32). Almost the same number will still be within the bankability assessment phase by 2018. It means that these projects will start commercial injection 2 to 3 years later if they are successful. With existing efforts, only 49 projects (45 being developed and 4 already bankable) will be considered bankable by 2022.

Therefore, only 28 to 30% of IEA recommendation for 2020 deployment is achievable with the existing effort, but G8 objectives seem to be largely achievable on technical grounds alone. However many other non technical risks will need to be taken into account. Up to 49% of the IEA recommendation might be achieved by 2025 with existing effort again on the basis of technical risk consideration.

Regional Distribution of the Current Effort

Figure 33 gives the regional distribution of existing storage projects (brown bars in Figure 33), number of projects likely to be bankable following our analysis (green bars in Figure 33) as compared to IEA Recommendations (blue bars in Figure 33).

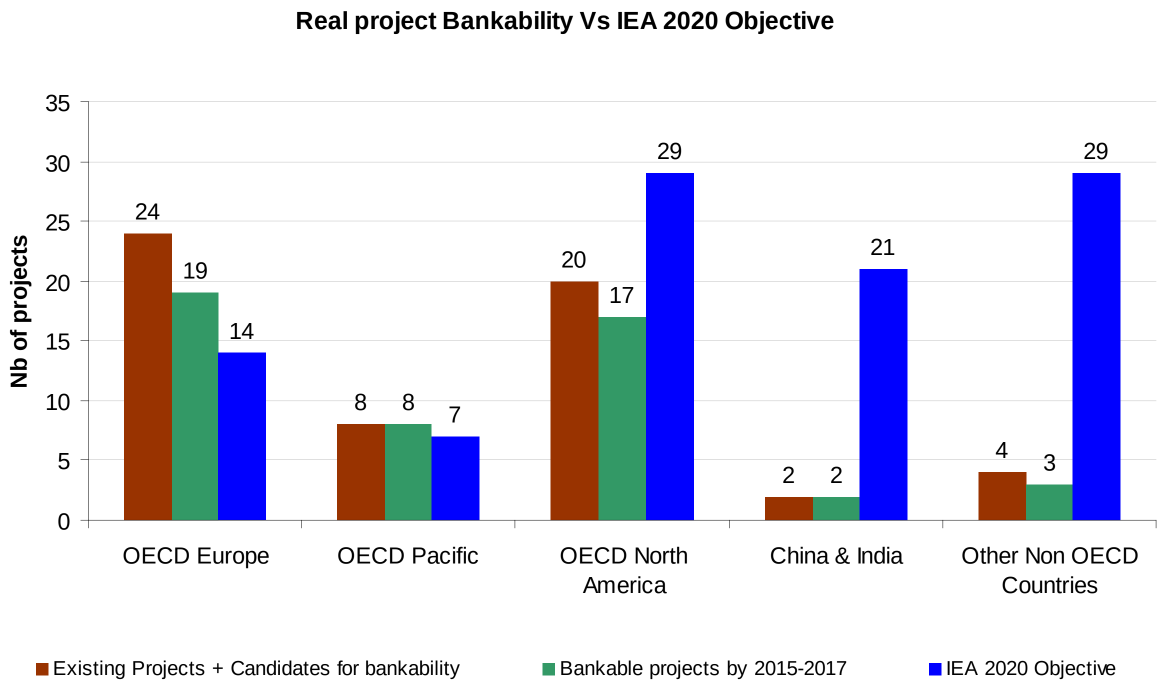


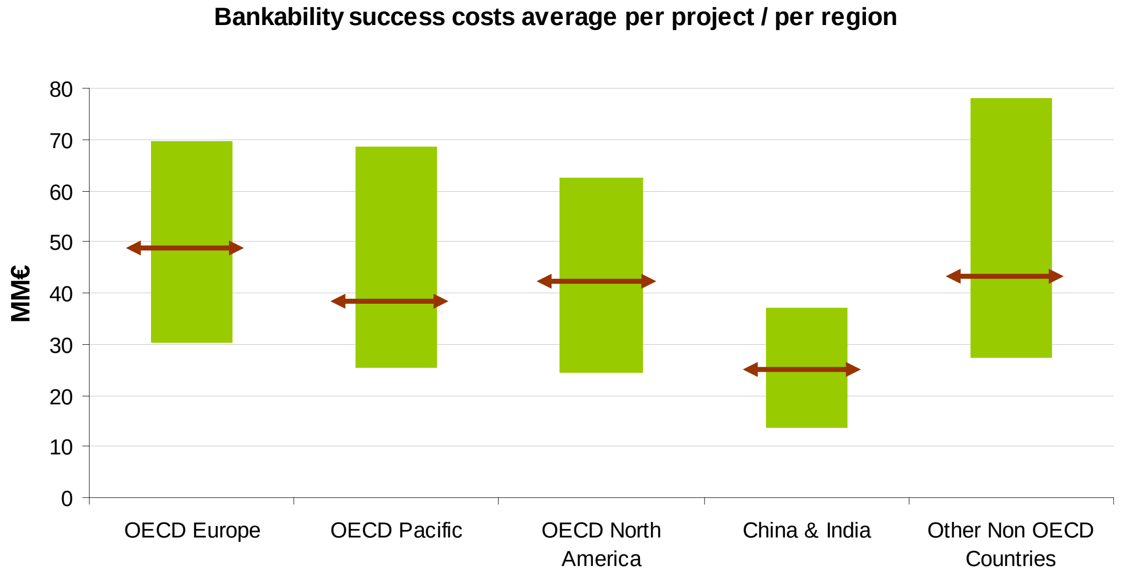
Figure 33: Result of analysis – Technically Bankable projects in 2015-2022

On a regional basis, OECD countries are closer to IEA recommendation than non OECD countries. There is a huge effort to be performed in non OECD countries in order to match IEA and climate change mitigation objective.

Additionally issues linked to funding, incentives or stakeholders' acceptance can decrease the above figures.

Cost of Current Effort

On a cost standpoint, bankability success cost worldwide for the 45 projects for which the bankability will be assessed during the present decade can range between 1150M€ and 2750M€ (average: 1950M€ overall). Figure 34 is showing the average success cost of projects reaching bankability on a regional basis. Despite the regional differences in costs, one can see that the cost of reaching bankability for each region is always below 80M€ with an average around 45M€ worldwide.



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 34: Regional success cost

Average probabilistic failure ratio is in the range of 15%. It means that technically, industry is able to deliver 85% of the storage projects. The cost of failure worldwide is estimated to be between 75M€ and 295M€ (average: 175M€). This represents an average of about 20M€ per project for the 9 failed projects (54 projects originally, 45 will reach technical bankability stage).

As previously mentioned (see section 4.6), the cost of failure is very low as compared to the potential benefit of this technology. If we spread the cost of failure of these 9 projects considering that they will store 1Mtpa during 30 years, it represents less than 1 cent of euro per tonne stored (0.01€/t).

5.1.2. Number and Localisation of New Projects to Fill the Gap

In the study database, we discarded some projects that have been announced and have performed some works (having gone through Phases 1 and/or part of phase 2) but where no activity has been registered since then: these projects are on stand-by. If we add these projects that are located in North America, as they are mentioned in section 3.2.1.3, then, following the same probabilistic approach as described in section 4 above, we have an additional number of candidate projects for reaching bankability, part of them reaching it effectively. The following Figure 35 and Figure 36 are showing these additional projects on a global basis versus IEA recommendations and on a regional basis.

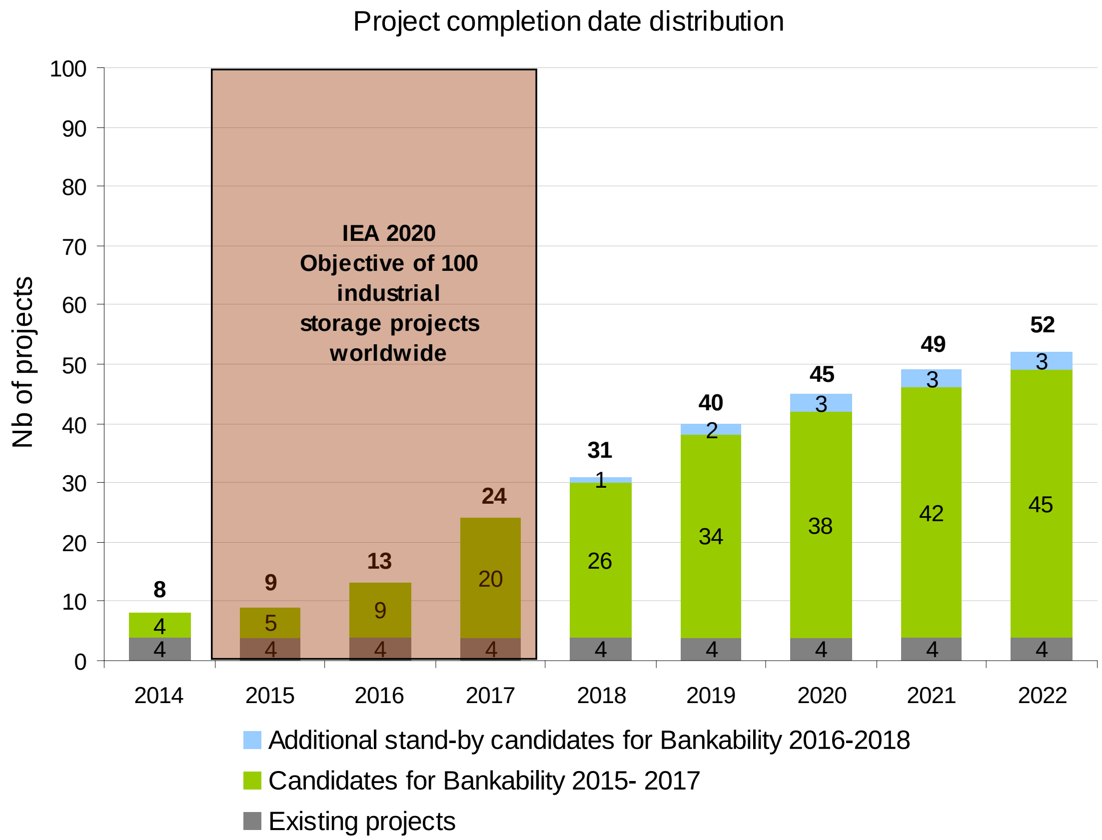


Figure 35: Yearly distribution of projects reaching bankability among the 68 candidates

Finally, we can consider that 48 projects are able to reach bankability up to 2022 in addition to the 4 existing projects, should the projects on hold be resumed soon enough. However, the major question mark concerns China, India, and other non OECD countries where our present analysis shows that the potential number of projects is far below IEA recommendations.

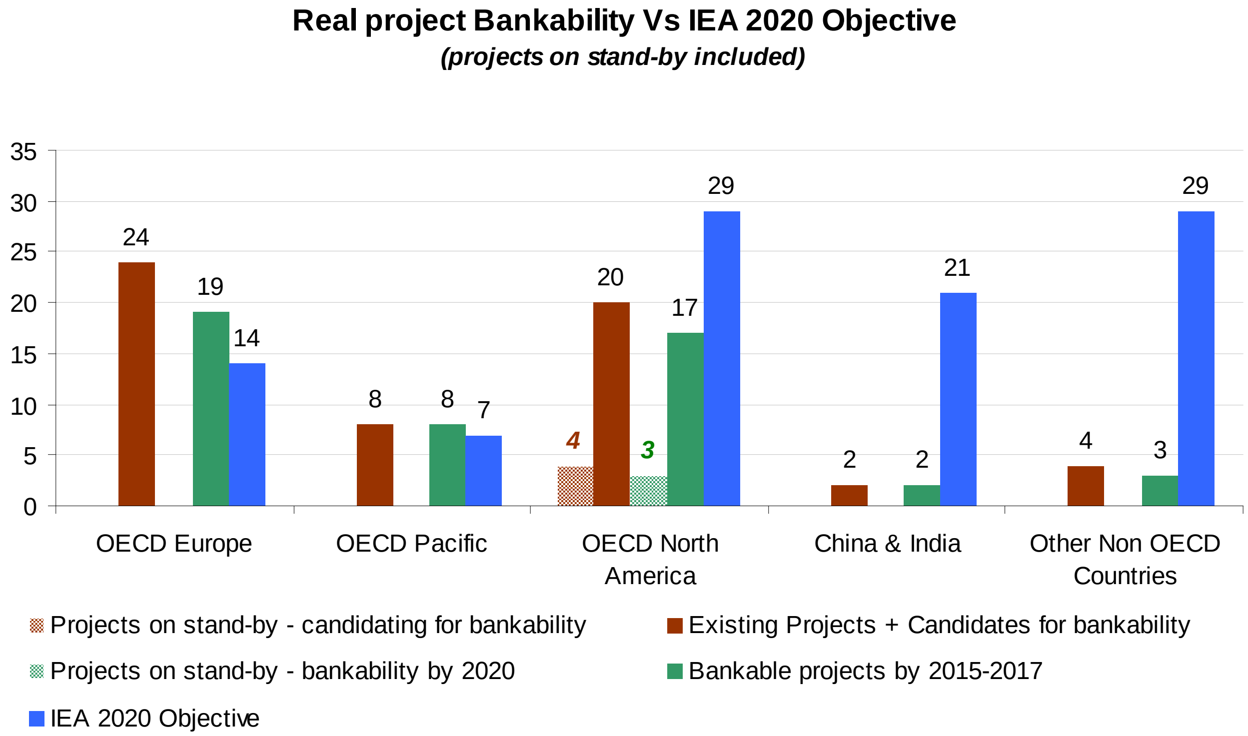


Figure 36: Result of analysis - Bankable projects up to 2020

As an important gap exists between the IEA 2020 recommendations and the existing effort for pure (not EOR related) storage projects, it is necessary to identify where storage projects should be developed to match the storage deployment recommendation.

5.1.2.1. Location of Projects to be developed to achieve the IEA Recommendation

This analysis requires a first assessment of source-sink matching on a regional basis. For such a quick-look assessment, the CO_2 emission sources below 1 Mtpa have been neglected. Consequently, such qualitative source-sink analysis could be altered at a local level.

The following Figure 53 explains the methodology for China and India. Similar maps and analysis can be found for the other parts of the world in Appendix I page 218.

Figure 53 presents existing CO_2 power or industrial sources, and suitability areas for China and India. A simple qualitative source / sink matching indicates areas for these two countries where storage characterization projects should be launched not later than 2012 to reach bankability between 2020 and 2022. These locations have been chosen in order to characterize the potential of areas close to CO_2 emission hubs where no storage project currently exists.

For China and India, 23 areas where it could be interesting to develop a storage assessment programme can be identified. These new areas are indicated by deep blue coloured circles. Among them there are:

- 7 shallow offshore Highly suitable DSF
- 3 Shallow offshore possible DSF
- 6 onshore Highly suitable DSF
- 2 onshore possible DSF
- 4 onshore depleted
- 2 offshore depleted

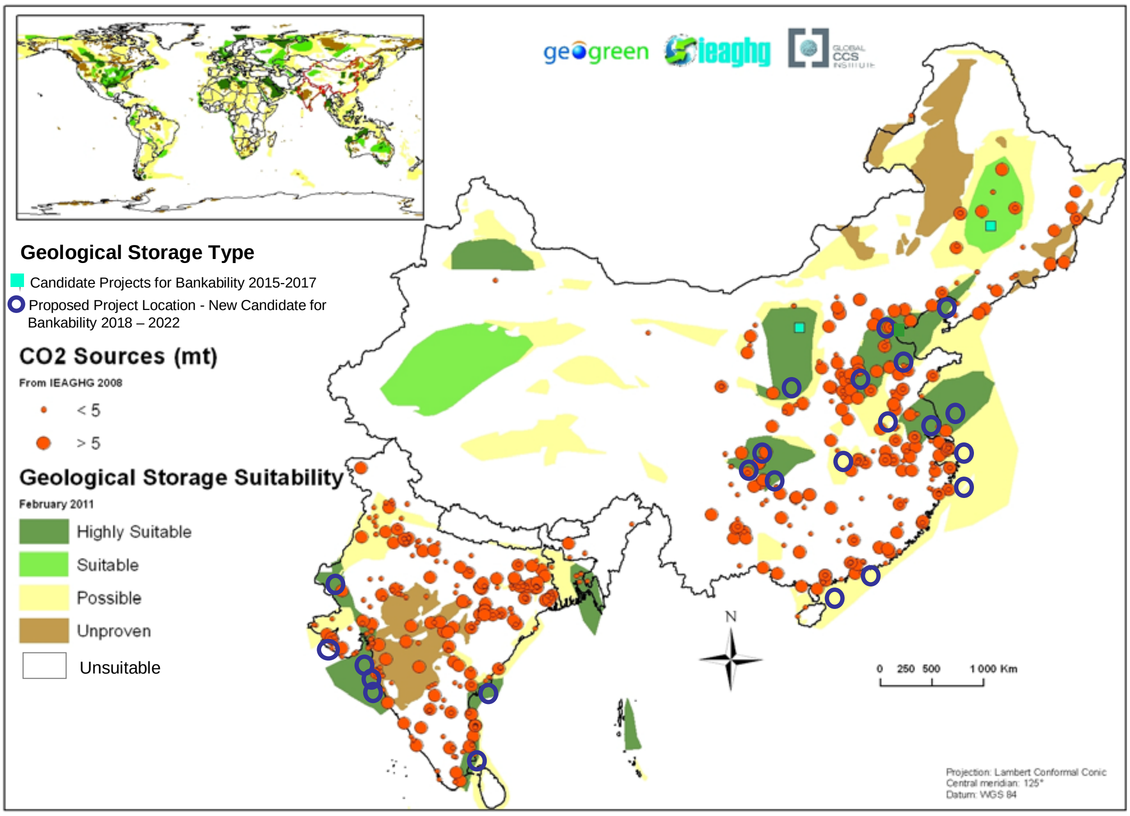


Figure 37: China and India - Additional candidates for bankability 2020-2022

Following the same probabilistic approach of success as developed in section 4, these 23 candidates could bring 19 additional bankable projects, therefore reaching IEA recommendation for the area if we consider only DSF and DOGF projects.

Such additional projects would have the following cumulated success, and probabilistic failure cost. This gives an average characterization success cost per project of 36M€ largely below OECD one (Figure 38). The overall cost of such characterization programme for 23 projects would be between 400 and 900M€ with an average value around 700M€.

Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 38: Success and failure costs - additional candidates for bankability China and India

The 4 failed projects would represent a total loss between 30 and 130M€ for this region. If this failure cost is ventilated over the successful projects, it represents between 1.5 and 7M€ per successful projects. The following table gives per region the number of additional areas where a storage characterization programme should take place in order to match the 2020 IEA recommendation:

Table 6: Number Per Region of New Areas That Should Be Characterizd

			Other non OECD countries		
	China and India	**OECD North America**	**South America**	**Africa**	**South East Asia**
Number of existing projects (active+stand by) achieving bankability following storage development workflows	2	20	3		
IEA 2020 target	21	29	29		
Number of project that should be developed in order to reach target following storage development workflows	**23**	**10**	**7**	**6**	**6**
Onshore					
Deep Saline Formation - Higly Suitable	*6*	*1*			
Deep Saline Formation - Suitable		*3*	*1*		
Deep Saline Formation - Possible	*2*	*1*	*3*		
Depleted fields	*4*	*2*	*2*	*1*	
Offshore					
Deep Saline Formation - Higly Suitable	*7*			*1*	*1*
Deep Saline Formation - Suitable		*1*		*2*	*2*
Deep Saline Formation - Possible	*3*	*1*			
Depleted fields	*2*	*1*	*1*	*2*	*3*

5.1.2.2. Number and Timing of Projects to be Developed to Achieve the IEA Recommendation

As stated before, G8 2020 objective might be achieved with DSF/DOGF projects only (please refer to section 3.1.1), would the current framework of incentives and subsidies be effective.

However, our analysis has also shown that IEA recommendation of 100 industrial storage projects active by 2020 will not be met with current effort. This conclusion includes only pure storage projects (without EOR). With current effort, only 49 projects would be bankable by 2022 (in 2015-2017, only 24 projects would be bankable, leading to 24 industrial projects by 2020). This is shown by the grey and green bars in Figure 39.

In order to fill the gap and taking into account non EOR projects only, the addition of new projects to be launched (Phase 1) not later than 2012 would make it possible to reach the objective with a five years delay as shown by the blue and orange coloured bars on Figure 39.

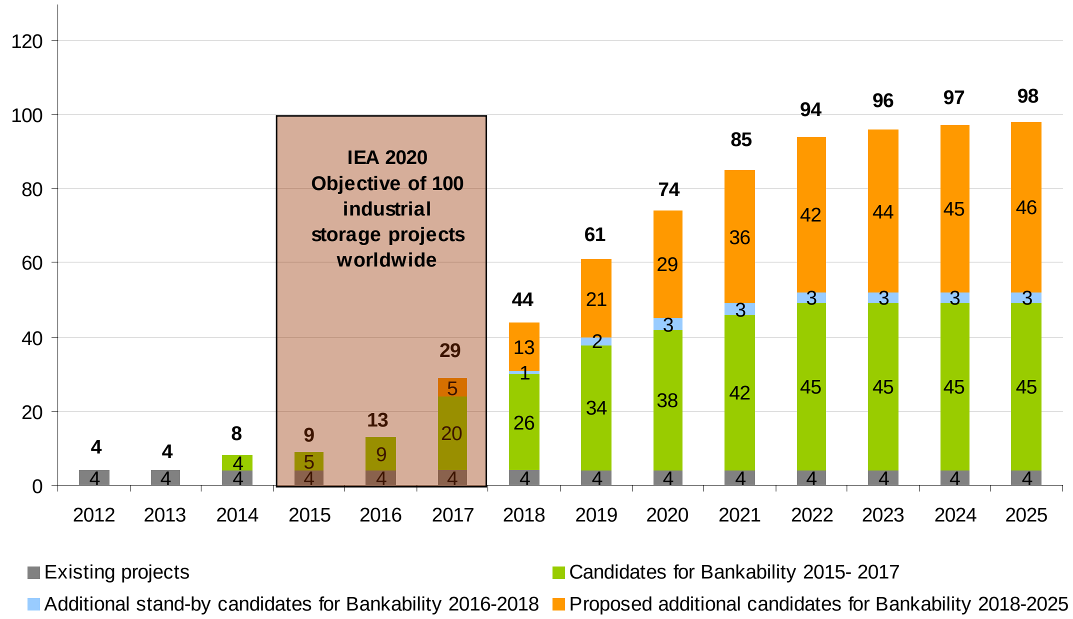


Figure 39: Yearly distribution of projects reaching technical bankability up to 2025

The global delay observed as compared to IEA recommendation is due to the time needed for proper CO_2 storage development: between **6 and 12 years**[33] are necessary to achieve bankability of a storage site (depending on the reservoir and caprock quality, and on the geological knowledge of the area – see section 4.6)

[33] For 80% of projects

On a global level and considering only technical aspect of bankability for pure storage project (storage without Enhance Oil Recovery), more than 120 projects should be developed worldwide to achieve 100 projects by 2025 (Figure 40).

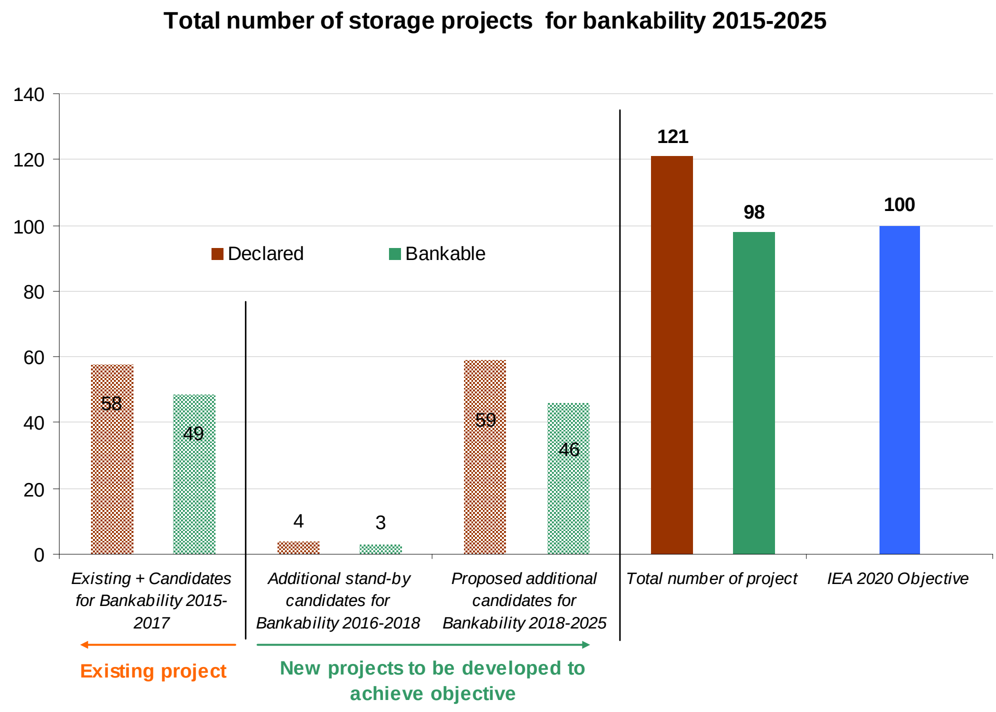


Figure 40: Total number of technically bankable projects up to 2022 vs IEA worldwide recommendation

Of these 120 storage assessments, only 58 are already launched and even fewer have adequate financing as it will be discussed later (see section 5.2). It means that the same number (59 new projects + 4 projects on hold that have to be reactivated) should be launched from January 2012 onward in order to achieve the recommendation. There are obviously regional disparities in term of objectives as shown on Figure 41.

On this figure, one can see that the CO_2 storage industry can technically deliver the required number of projects following IEA 2020 recommendations in Europe and in Oceania. However, not including EOR potential role, there are too few pure storage projects under development to reach the recommendation for North America taking into account its huge required contribution to the global effort.

A special effort should be put on non OECD countries in order to match recommendations. The current effort is not sufficient to meet climate change mitigation objectives (stabilization of CO_2 atmospheric concentration to 450ppm).

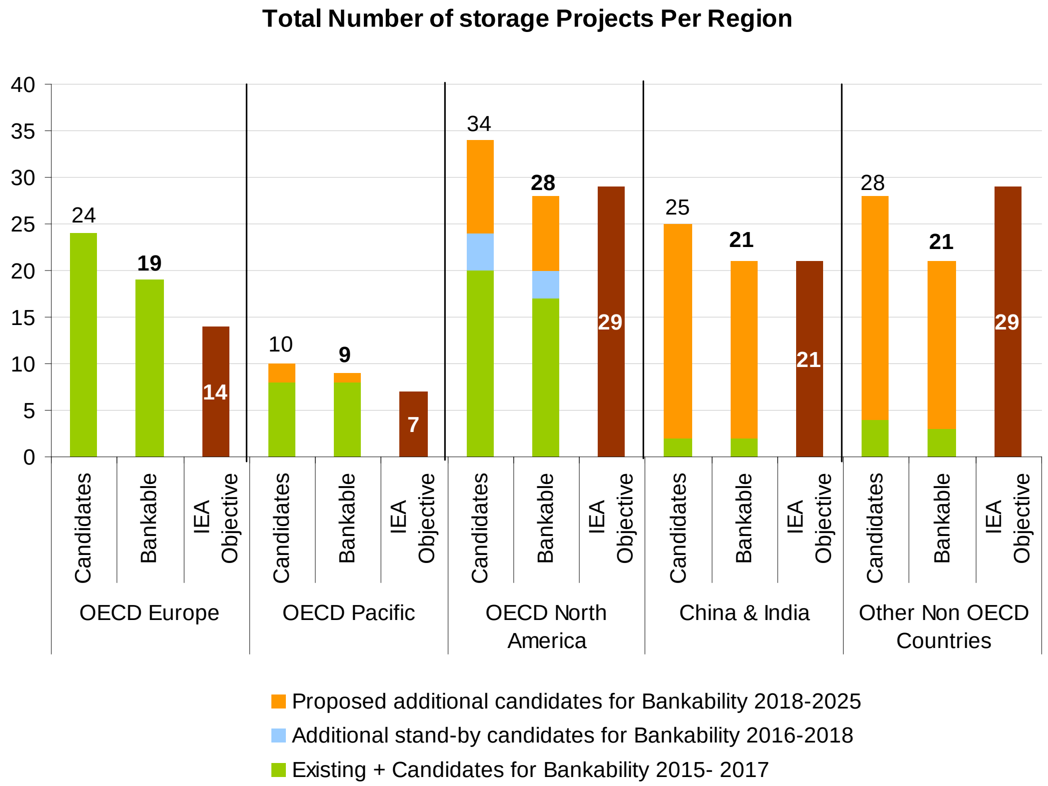


Figure 41: Regional breakdown of storage projects reaching technical bankability in 2015-2025

A discussion on the current means engaged as regard to IEA 2020 recommendation is proposed in section 5.2.

5.1.2.3. Success Costs of Storage Characterization to Meet 100 Projects

In this section, we examine what would be the cost of reaching the recommendation only considering pure storage project (not EOR).

Figure 42 and Figure 43 give an overview of the global and average success costs to achieve 98 commercial projects by 2028 (98 bankable storage projects by 2025 meaning that 120 projects should be developed). OECD Pacific is the most expensive area from the average cost point of view (Figure 43), given the number of offshore projects.

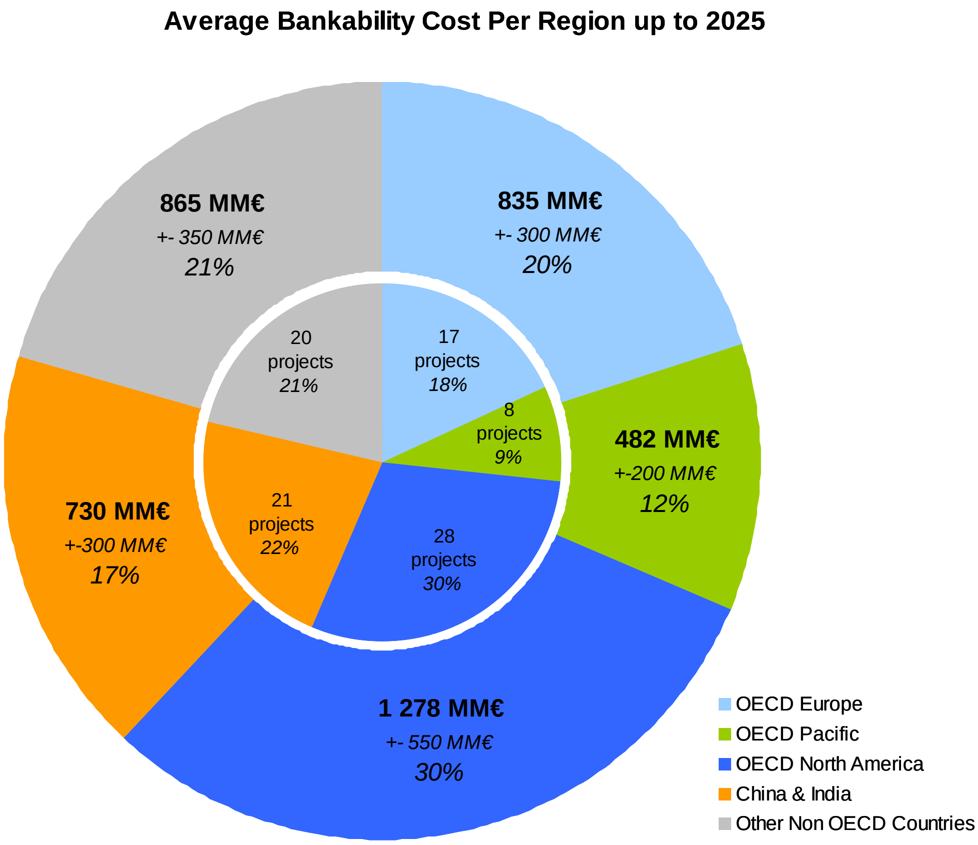
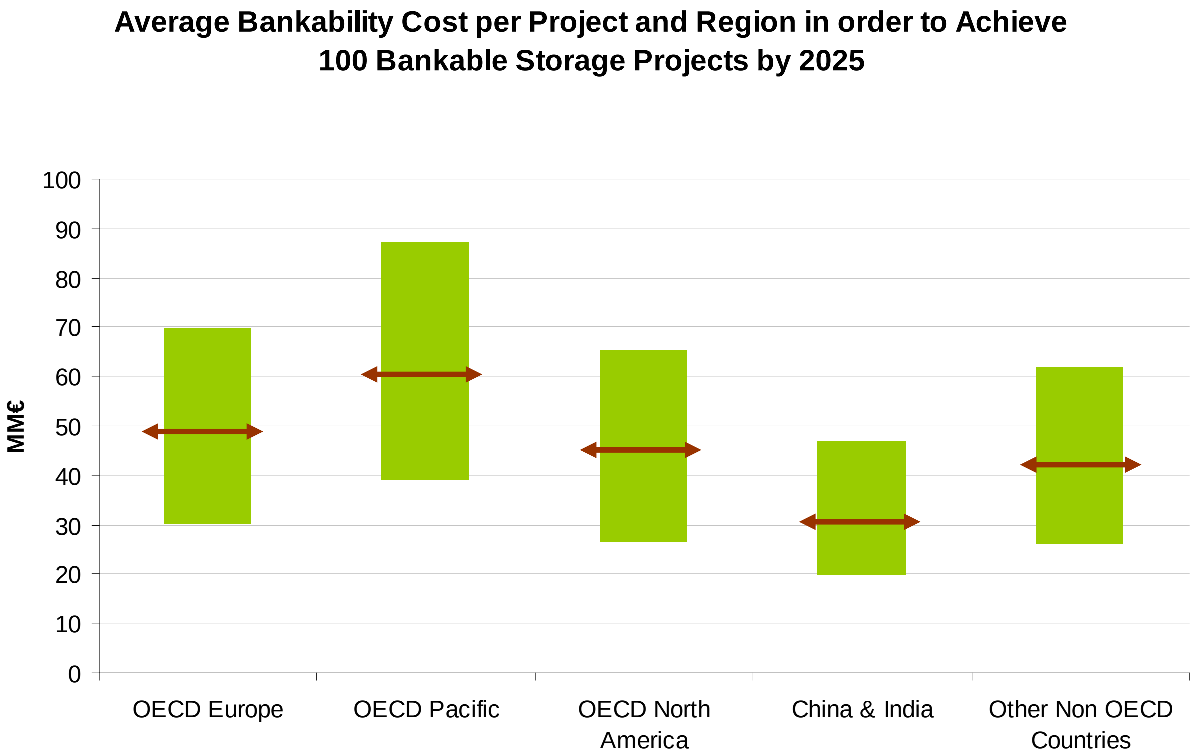


Figure 42: Global investment and storage projects breakdown - 98 bankable projects by 2025

The overall required investment lies between 2.5 and 5.9bn€ for 94 storage projects (excluding the 4 projects already or close to be active), giving an average of 25 to 60M€ per project. Following Figure 43 is showing the regional breakdown average of these costs.



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 43: Regional breakdown of average success cost per storage projects to achieve 94 bankable projects by 2025

As stated earlier, we assumed that each storage site should receive 100 Million tonnes of CO_2, leading to bankability costs for storage between 0.3 and 0.5€ per tonne of CO_2 stored over the whole project lifetime. Compared to capture costs, storage bankability assessment costs are marginal. Indeed, the Global CCS Institute report [23] on CCS costs shows capture costs between 45 and 85€[34] per tonne of avoided CO_2 for power plants and depending on the technology used (between 15 and 40 € per tonne for capture on industrial processes).

Finally, storage bankability assessment costs are marginal as compared to the rest of the CCS chain but needs time, which stresses the importance to start bankability assessment phase early in CCS project lifetime.

[34] Costs are presented in USD in the GCCSI report. This study used a 1.3 dollar-euro exchange rate

Key Messages on Required Number of Projects - 2020 Gap Analysis

Excluding CO_2 EOR projects and non technical aspects of bankability (i.e. financing, economic context, public acceptance, political priorities…), we can draw the following conclusions on the achievement of CCS deployment recommendation in 2020:

1. **IEA 2020 recommendation of 100 commercial projects is not reachable by 2020 with current number of candidates**
    - The industry is technically able to deliver 45 projects out of the 54 under development by 2022. Counting the already developed projects, the actual effort allows reaching 49 % of the 100 projects needed.
    - Taking into account the type of projects in development as well as their location, an overall probabilistic failure rate of 15% is modelled.
2. **A huge effort has to be performed in developing countries to stay on track with 450 ppm target**
    - On the technical standpoint, OECD Europe has enough projects already launched in order to meet IEA 2020 regional recommendation.
    - Even if North America is leader in CCS development, additional projects are needed to meet IEA 2020 regional recommendation
    - More than 45 technically bankable projects (45% of the needed 100 projects) are missing in developing countries
3. **Launching immediately more than 60 new storage bankability assessments can lead to almost 100 technically bankable storage sites by 2022 / 2025**
    - Due to intrinsic storage site development time, reaching IEA recommendation of 100 industrial projects by 2020 is not feasible. Including construction time, 100 projects development target might only be reached by 2028
    - All regions but one (Africa) could meet IEA recommendation with this 8 years delay. For Africa, excluding South Africa, the apparent lack of emission sources makes it difficult to suppose the development of enough projects.
    - The modelled global probabilistic failure rate of these 100 projects is around 20%

Delays due to economic, regulatory, or public acceptance causes will certainly jeopardize the achievement of the global recommendation as it will be discussed later on in section 5.2.

5.2. Storage Bankability 2020 –Non Technical Bankability Aspects for Deep Saline Formations and Depleted Fields

The bottom-up quantitative approach evaluated the number of projects that the CO_2 storage industry could technically deliver. However, this approach could not integrate the non technical potential failure causes of storage projects. They range from political issues to public acceptance, regulatory barriers, overall economic context, and lack of incentives to tackle carbon emissions, lack of financing support, project developer internal strategy.

Two approaches can be proposed to quantify the role of these factors on project cancellations and delays:

1. From the number of cancelled project between the last two issues of Global CCS Institute Global Status of CCS: Even if these results should be taken with caution, they may be used to estimate the general failure rate of projects (including technical and non technical causes).

2. From existing financing schemes supporting CCS deployment: Indeed, as discussed in this section, the incentives (for instance carbon quotas price) are not sufficient to drive private investment alone.

We will first comment on the two main non technical causes of project cancellation (funding and public acceptance) and then discuss the results obtained with the different approaches.

5.2.1. Major Causes of Non Technical Failure - Funding and Public Acceptance

Many types of incentives for CCS deployment are available with different objectives [22]. The principle is to give a cost to CO_2 emission. In Europe, a carbon cap and trade system (Emission Trading Scheme) gives a price to industrial carbon emissions since 2005. This tool seems to be the favoured one worldwide to mitigate CO_2 industrial emissions. The CO_2 price is however too low to justify the wide scale use of CCS[35] and is limited to some world regions. Indeed, as CCS is not fully integrated into Kyoto CDM[36], the global signal given to CCS technology[37] deployment is negative.

Note: In Australia, starting on 1 July 2012, the carbon price will start at $23 **per** tonne, rising at 2.5 per cent a year in real terms. From 1 July 2015, the carbon price will be set by an ETS.

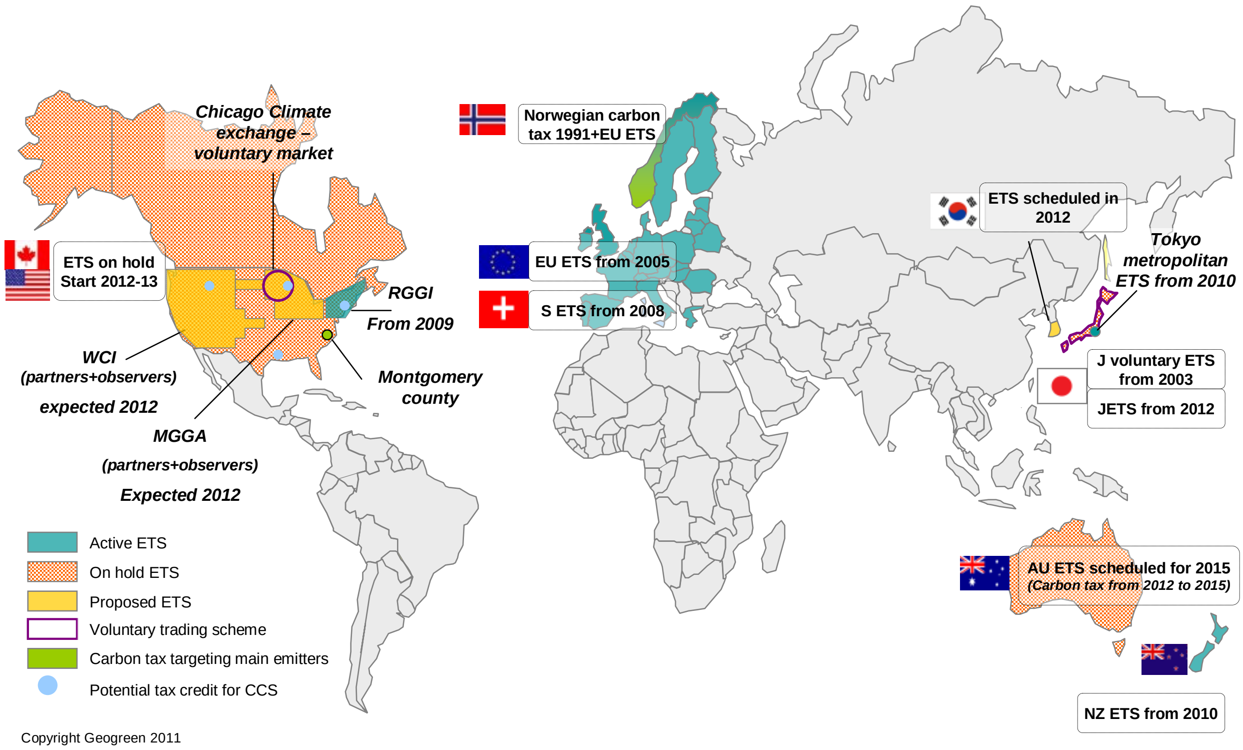
Figure 44 gives an overview of emission trading scheme (ETS) worldwide, Europe and New Zealand being the only areas where an ETS is truly active. Other areas like North America

[35] With current technology and costs, some CCS projects could be viable at a price above 40-60€/ton
[36] Clean Development Mechanism is a Kyoto protocol Carbon compensation mechanism
[37] CCS was accepted under CDM in Cancun conference. However, there are still a lot of work before a CCS CDM methodology is accepted

and OECD Asia are still in planning/proposal phase and are not expected to be implemented before 2012-2015[38].

Additionally, the weak climate mitigation policies that follow the climate negotiations (successor to Kyoto protocol) make it quite unlikely for CO_2 price to drive private funding only into CCS.

Therefore, public funding is definitely needed in order to develop storage projects, prepare a wide scale deployment and match IEA 2020 recommendations.



Note: In Australia, starting on 1 July 2012, the carbon price will start at $23 per tonne, rising at 2.5 per cent a year in real terms. From 1 July 2015, the carbon price will be set by an ETS[39].

Figure 44: Proposed and Current Emission Trading Scheme Worldwide

The last issue of the Global CCS Status report [23] identified around 21bn€[40] of promised funding worldwide dedicated to large scale CCS demonstration projects (Figure 45). Proposed funds are aimed at developing from 25 to 37 “complete CCS chain” industrial projects.

[38] It took about 5 years for the European ETS to be effective
[39] Securing a clean energy future - The Australian Government’s Climate Change Plan. Commonwealth of Australia 2011 -ISBN 978-0-642-74723-5
[40] 1,4 euro-dollar exchange rate

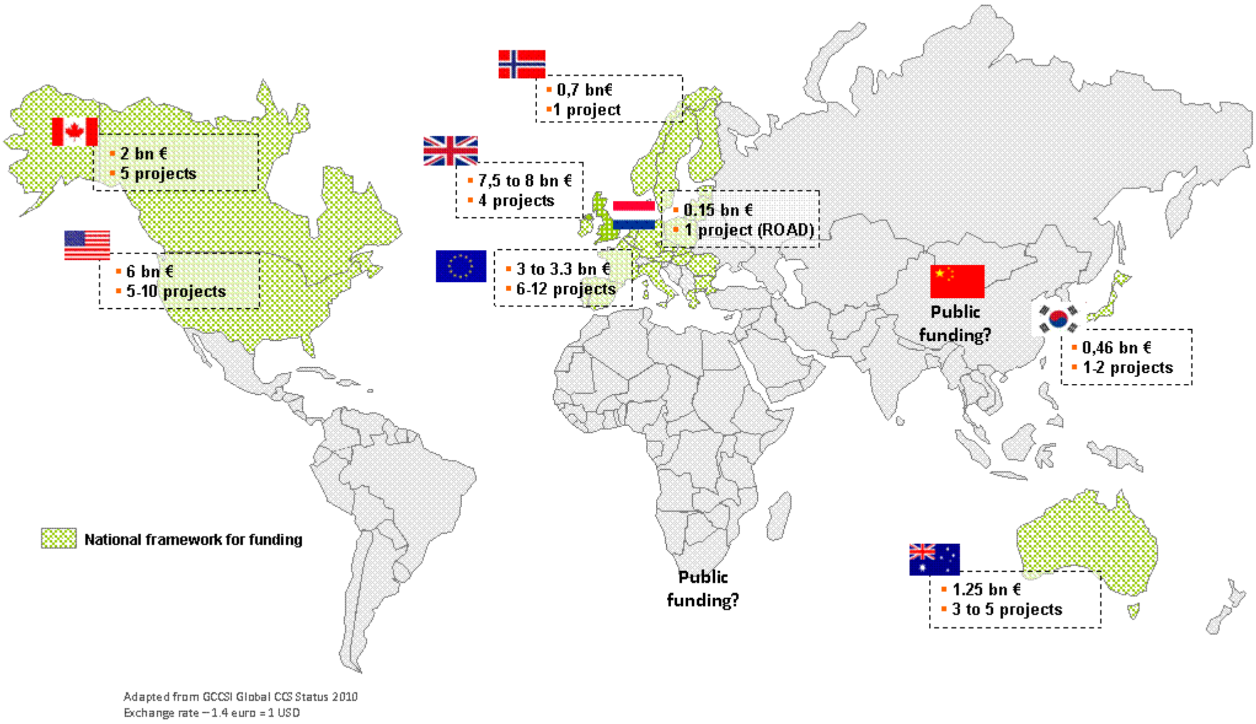


Figure 45: Proposed Current Public Funding for CCS Projects

Another significant source of project failure is public acceptance of CCS projects. This concerns mainly onshore projects, and has caused cancellation of various projects worldwide. Reasons for public opposition are various. The main ones are the lack of/inadequate communication from project developers, lack of government support and lack of benefits for local communities.

There are no silver bullet solutions for public acceptance. Public acceptance depends on local culture and practice in front of industrial projects. There are for instance some issues related to public acceptance currently in Vattenfall Jänschwalde project. Despite a very active communication from the project developer, the lack of apparent benefit for the local population seems to be a major roadblock. Additionally local benefits generated by extra jobs on capture site do not impact the community located close to the storage site.

Government and political support is strongly needed for storage deployment in order to give confidence to both private investors and public stakeholders that CCS technologies are an appropriate response to part of our climate change issue.

All three above mentioned public concerns must be answered. Addressing one of them only is not sufficient to ensure project success. Shell Barendrecht project is a case study to that extent.

5.2.2. Observed Failure Rate in Global CCS Institute databases

The first approach we adopted to evaluate the non technical failure causes of CCS project is to compare the 2009 and 2010 CCS projects database of Global CCS Institute [23]. This gives a first glance of what could be the overall failure/cancellation rate of CCS projects.

However, unpredictability and unknowns lead us to recommending that results of this second step are taken with the highest caution. As an example, the financial crisis and its regional impacts on state financing and interest of industrial stakeholders to invest in greener technologies was totally unpredictable in summer 2008. Similarly, the today worldwide context of nuclear energy development which shows a possible decrease of this power generation was totally unpredictable before Japan earthquake and Fukushima accident in March 2011.

The figure below from Global CCS Institute report [23] shows the difference between the two databases:

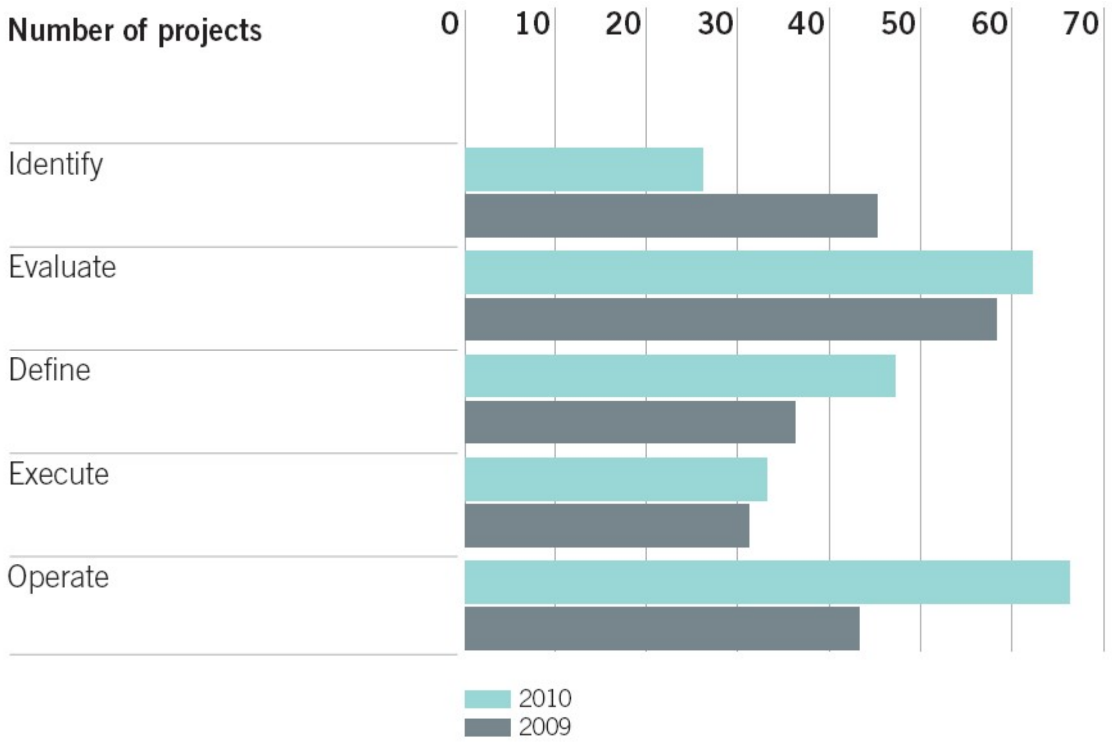


Figure 46: All active and planned projects by asset lifecycle in 2009 and 2010 [23]

In 2009, 62 Large Scale Integrated Projects (LSIP) were present in the database. 77 LSIP have been identified in 2010. However in 2010, 22 of the 62 projects identified in 2009 were cancelled (9) or delayed (13) and have been removed from Global CCS Institute database. The cancelled/delayed projects concern mainly DSF storage projects (about 4 CO_2-EOR delayed projects). These projects were generally at “identify, Evaluate and Define” stage. If we consider only cancelled projects, it gives an annual cancellation rate of 15%. If we take into account non EOR delayed projects (from which some could be considered cancelled), this rate rises to 30%. This gives a high estimate of failure rate.

In the above defined 120 projects candidate for bankability (see section 5.1.2) there are 93 projects (34 already defined + 59 to launch) in Phases 0 and 1 (corresponding to "identify, Evaluate and Define" Global CCS Institute stage). If we apply the annual cancellation rates above defined, consider Phase 1 duration between 1 to 2 years and assume that projects are submitted to the failure rate only once, the number of projects to be developed in order to reach the IEA 2020 recommendation is:

- High Estimate: almost 50 additional projects should be developed as compared to the 59 projects previously defined. That is to say 110 projects should be launched by 2012. This gives an overall success ratio of 60%.
- Low Estimate: almost 25 additional projects should be developed as compared to the 59 projects previously defined. That is to say 85 projects should be launched by 2012. This gives an overall success ratio of 70%.

Finally, following this approach, the failure ratio taking into account both technical and non technical aspects of bankability is between 30 and 40% of all projects and between 85 and 110 new projects are needed to achieve the IEA 2020 recommendation. Extrapolating on this result, it also means that over the 54 existing CCS large scale projects only between 32 and 38 projects would reach bankability. This further deepens the gap between current effort and IEA 2020 recommendation.

5.2.3. Financing Limitation to Storage Projects Developments

As seen previously, CCS technologies are not viable for now because of the lack of incentives. Public investments are most needed in order to convince industrial stakeholders to launch the necessary investment. Indeed, being such a first mover is a cost burden on the capture side (which represents most of the CCS cost) because the installed technology will suffer from heavy cost and lack of return on experience.

The current proposed funding schemes (around 21 billion Euros promised to CCS in developed countries) target between 25 and 37 projects. With current incentives and carbon price, the level of public funding is not sufficient for 37 projects to even reach financial balance (less than 560M€ average per full scale CCS project). Indeed, in Europe which has set a carbon price through EU ETS, the expected level of financing is 50% of eligible costs[41]. However, as mentioned in Global CCS Institute recent study [23], the capital cost for capture on power combustion is at least 0.7 billion Euros up to 1.5 billion Euros. This amount does not include transport and storage capital expenditures or operational costs. Finally, if we consider that a minimum of 50% of project costs should be financed for a project to be financially balanced, between 0.5 and 1 billion Euros at least[42] should be dedicated to each project to ensure its success. Following this assumption and taking into account the regional

[41] NER 300 financing scheme
[42] Offshore are more expensive for instance

spread of funding as proposed in Figure 45 shows that only between 18 and 25 projects[43] would be pursuing their work up to the bankability stage.

Even if we assume that current funding schemes will allow the targeted project to reach bankability stage, we also have to include the potential failure for technical reasons (15-20% failure rate estimated in previous section) to this number.

Finally, following this approach, between 14 (low case) and 21 (high case) existing projects will be bankable by 2018-2022 (section 5.1). The 4 existing DSF storage projects have to be added to this number.

With current funding promises, considering only "pure storage project" and taking into account technical bankability success rate even G8 objective of 20 commercial project will hardly be achieved by 2020. The gap between IEA 2020 recommendation and existing financial effort for CCS project would be between 91 and 103 projects.

5.2.4. Extra Public Funding Needs to Obtain 100 Bankable Storage Sites by 2020

There are currently not enough funds available to start the required number of projects. The legitimate question is then:

What is the required level of funding to achieve the IEA 2020 recommendation considering only storage project technical bankability?

We evaluated the additional public funding needed in order to launch the above mentioned number of projects (technical bankability). In this section we assume that the number of projects wished by governments (for instance 4 for UK, 6 to 12 for EU) where adequately financed[44]. We then deduced the number of projects to be financed considering the technical bankability success factor and the cost of developing such project.

As there are no existing incentive for the private sector to invest in storage bankability assessments (neither CO_2 price nor strong political will to mitigate CO_2 emissions), we assumed that between at least 50[45] and 75% of the storage bankability assessment phase should be financed. Indeed, due to storage development times (see section 4.6) bankability assessment investment has to be committed well ahead project commercial injection. Without strong incentive, it is unlikely that private stakeholders will commit themselves with CO_2 storage assessment between 6 and 10 years ahead of expected commercial start-up.

With these assumptions, Figure 47 gives the remaining required public financing to be dedicated to storage site bankability assessment per region in order to achieve 98 bankable storage projects by 2025 (**technical bankability**). The two levels of possible investment from public authority (50 and 75% of costs) have been assumed to build Figure 47.

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[43] North America – 8 to 15 / Europe from 3 to 6 (not including extra financing from member state) + Norway 1+ UK 4 / Australia – from 1 to 2 / South Korea 1
[44] This is a different approach from the one developed in section 5.2.3
[45] This corresponds to the level of European Mechanism NER 300 funding

Figure 47 shows for the OECD Europe case (section 4) that given the success ratio, 22 candidates for bankability can lead to 17 bankable projects. As of today, UK, EU, Norway and Netherlands announced funding for 11 up to 17 storage projects. Left hand side column for OECD Europe shows the remaining required financing to reach 17 bankable projects (22 storage bankability assessments) if 17 projects are financed (minimum additional funding). The right hand side column gives the required maximum additional funding if only 11 projects are financed as of today. Each bar is calculated under the two assumptions of public funding share inside a project. Obviously is funding promised are not respected, the incremental investment necessary in storage bankability assessment will be higher.

We adopted the same methodology for other part of the World as shown on the next page (Figure 47).

In Figure 47, the global amount of investment needed to reach IEA 2020 recommendation is around 950M€ if all promised funds are delivered to existing projects and if it is assumed that a public funding of 50% may trigger private investment. It represents 2.7bn€ if promised funding is kept to the minimum and if a funding of 75% of bankability assessments costs is required to trigger projects.

Finally, not taking into account EOR contribution, the funds necessary to ensure that storage development will not be a roadblock to achieve 100 projects technically bankable by 2025 is limited to a bit more of 10% of the fund committed so far to CCS deployment .

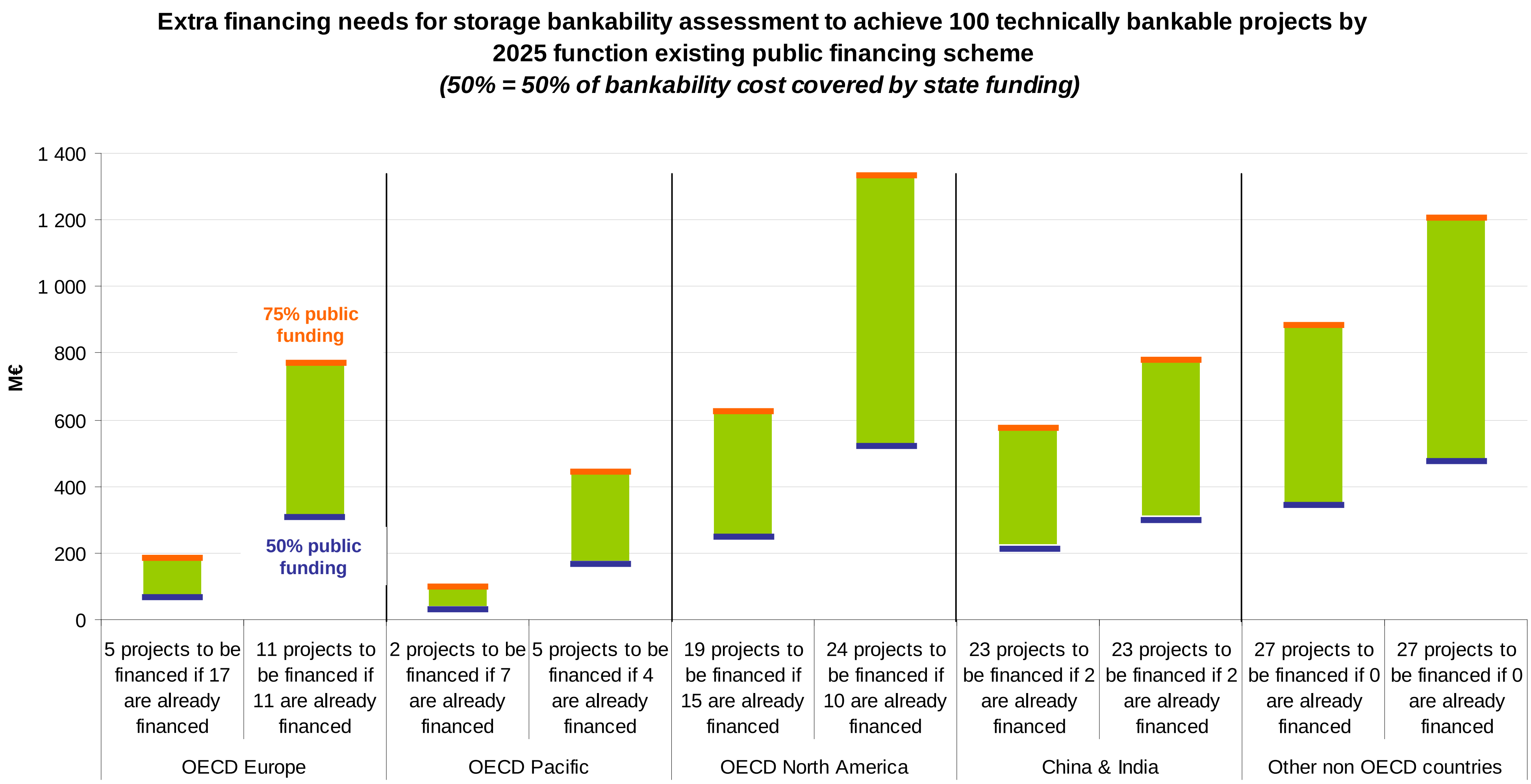

Figure 47: Extra Public Funding Needs Per Region Function of Share of Bankability Cost Financed by Public Funding - 100 Technically Bankable Projects by 2025

Key Messages on Required Funding - 2020 Gap Analysis

Without the potential role of CO_2-EOR, we can draw the following conclusions on the achievement of CCS deployment recommendation in 2020 as stated by IEA analysis:

1. **Past CCS projects cancellation rates show the importance of regulation, public acceptance and financing**
    - The observed failure rate is between 30 and 40% whereas the technical one has been estimated to about 15 to 20% on a global level
    - Considering this fact, of the 54 existing CCS large scale projects only between 32 and 38 projects would reach bankability.
    - This further deepens the gap between current effort and IEA 2020 recommendation. More than 85 new projects should be started by 2012.
2. **Current public funding promises for CCS projects are far from being sufficient at world scale to reach climate change mitigation objectives**
    - The presently promised 21 billion Euros for large scale CCS projects concern only developed countries. There are no current major public funding announcements from developing country although their expected contribution to the overall effort of CCS deployment is close to 50%
    - This level of funding will allow only between 14 and 21 projects worldwide to be financially balanced.
    - Even G8 objective of 20 large scale commercial CCS projects might not be achievable
    - Taking into account what CCS industry is able to technically deliver, it is possible to obtain 100 bankable storage sites by 2025 only if between 85 and 97 storage bankability assessments are financed by 2012.
3. **Public funding of storage bankability assessment could efficiently remove the storage development time roadblock to achieve quick CCS commercial build up**
    - There are currently no specific incentives for private stakeholders to engage without subsidies in such projects.
    - Funding such assessments would bring 100 bankable storage sites by 2025. This would allow starting wide scale CCS deployment when incentives and technology cost are adequate.
    - Between 1 and 3bn€ extra public funding support would allow launching enough storage bankability assessments to have 100 storage sites ready by 2022 / 2025
    - In the most expensive case, this represents only 10% of the fund committed so far to CCS deployment.

5.3. Storage Bankability 2020 – CO_2 Enhanced Oil Recovery Contribution

The analysis conducted in this study showed that when considering DSF and DOGF storage projects, the IEA 2020 recommendation will only be met if an important effort in storage bankability assessment is performed as 59 to 110 projects are needed.

As explained in section 3.2.2.3, CO_2-EOR can significantly contribute to achieve this target. 4 industrial CO_2-EOR projects[46] are already matching the criteria to be considered as CO_2 storage projects and 14 others are planned. The storage potential has been estimated in previous study to be around 65Gt [33]. However, regional distribution and development time remain unknown.

As it is very difficult to assess the number of CO_2-EOR projects (see section 3.2.2.3) that might be deployed by 2020, we decided to adopt a region per region qualitative approach considering the following point:

- Cost and revenue drivers
    - Oil price is likely to rise in the coming decade following various analyses[47] which might provide extra incentive for oil field operator to transform their assets into CO_2-EOR assets.
    - CO_2 capture incentives (CO_2 price) are still inexistent in many part of the world. No CCS CDM Methodologies might be implemented before 3 to 5 years. OECD main markets apart from Europe and New Zealand will not have a CO_2 price before 2012-2015. Moreover, with current policies, CO_2 price will remain too weak to offset capture costs of most technologies until 2020 in the existing and future market.
    - An existing CO_2 transport infrastructure suppresses the hurdle of the initial investment in CO_2 pipeline transport.
- Region potential for EOR – see Figure 13.

Then, looking at the qualitative source sink matching carried out in section 5.1; we assessed the potential contribution of EOR to the global CCS deployment achievement. Only large scale projects (>1Mtpa) were taken into account. Indeed, there are many local opportunities in small fields for CO_2-EOR which is beyond the scope of this study.

[46] Rangely, Sharon Ridge, Weyburn, Salt Creek
[47] IEA World Energy Outlook, Chatham House, German Army, GMO investment fund

5.3.1. Contribution of CO_2-EOR within Current Financing Effort

Following the philosophy developed in section 5.2.3, we first estimate the contribution of CO_2-EOR within current funding context.

The current level of funding limits the number of projects that can be developed. One of the advantages of CO_2-EOR is to partially offset the costs of CCS. However, even in that case, the economics of the projects are not guaranteed without public funding particularly for the capture part.

In order to analyse what would be the CO_2-EOR contribution to IEA 2020 recommendation in that context, we first assumed that EOR is able to offset storage and transport costs. We also assumed, as in section 5.2.3, that 50% of the cost of capture is financed. That is to say that public financing support for CO_2-EOR CCS project is thus reduced to 0.25 to 0.75 billion Euros (as compared to 0.5 to 1 billion Euros as previously stated). Finally we took into account the current regional repartition of funding as shown on Figure 45 and that all currently proposed projects are technically bankable[48].

These assumptions lead to:

- Fully finance the 5 CO_2-EOR projects in North America and leaving between 4 and 7 billion Euros for DSF and DOGF project development.
- Fully finance the CO_2-EOR projects in Europe leaving 12 and 13 billion Euros[49] for DSF and DOGF projects development.
- Fully finance projects in developing countries
    - 1 in Brazil
    - 5 in China (we assumed that all projects will find adequate financing)
    - 2 in Middle East

With these assumptions, the number of DSF and DOGF projects that would be financed and technically bankable is:

- North America: 4 to 14 projects resulting in 3 to 12 projects technically bankable
- Europe: 8 to 10 projects resulting in 6 to 9 projects technically bankable
- Australia: 1 to 2 projects resulting in 0 to 2 projects technically bankable
- South Korea: 1 project resulting in 0 to 1 projects technically bankable

Finally, if all CO_2-EOR projects get sufficient financing to proceed with CO_2 commercial scale injection and succeed technically, the overall number of projects reaching bankability by 2018-2022 is between 24 and 38. If we add the 8 existing projects (4 DSF / 4 CO_2-EOR), we reach 32 to 46 projects bankable by 2022.

[48] 5 projects in North America, 1 project in Europe, 5 in China, 1 in Brazil, 2 in the Middle East
[49] NER 300; CCS Levy, Norway financing

When comparing with the numbers obtain in section 5.2.3, CO_2-EOR can increase by 70 to 80% the number of projects that can reach bankability with current funding effort. Nonetheless, even if CO_2-EOR projects are faster to develop, the IEA 2020 recommendation will not be reached in time due to the developing time required for DSF projects which still represent a significant share of the storage projects portfolio.

5.3.2. CO_2-EOR Regional Potential to Meet IEA 2020 recommendation

As seen in the previous section, existing CO_2-EOR projects play a significant role in reducing the gap between current funding efforts and IEA 2020 recommendation. The following section gives insights on how many CO_2-EOR could possibly be developed by 2020 and how those could further fill the existing gap. Table 7 below summarizes the different drivers influencing CO_2-EOR development. Obviously, oil price increase is an incentive for EOR development for all world regions.

As described, the potential contribution of EOR per region is very important within the current context since it can kick starts the deployment of CCS.

Next page:

Table 7: CO_2-EOR Qualitative Potential Assessment

	Cost and Revenues			**Region Political Behavior Toward EOR**	**Region Potential For CO_2 Capture**	**Region Potential For EOR**	**Potential Outcome**
	CO_2 Transport Infrastructures	***Oil production cost***	***CO_2 Capture Incentives (CO_2 price)***				
OECD North America	+ there is already a good CO_2 transport infrastructure (3000km of pipelines + Canada is building a CO_2 trunk line in Alberta	~ Medium cost -High cost (offshore)	-Limited incentives toward emission mitigation (tax incentives -CO_2 cap and trade has been postponed → Carbon price signal will come lately in the decade	+ Very in favor of CO_2 EOR to increase domestic oil production	+Huge potential onshore located	+ High: has been estimated to be around 78 to 85 Mt of CO_2 per year by ARI in 2010 (high range) + Huge potential onshore	**On top of the 5 already planned projects, the other five projects needed to reach the target could easily be developed**
OECD Europe	- No existing large scale CO_2 transport infrastructure	~ Medium cost (onshore) -High cost (offshore)	+ World biggest cap and trade → Strongest Carbon price signal	+ See potential to continue economic growth in north sea province -growing momentum against oil producer in western Europe	+significant potential around the North Sea and in Eastern Europe	*Mainly offshore in North Sea ageing field -Onshore in Eastern Europe but number of wells issues for leakage	**On top of the already planned projects, may be 2 to 4 projects could be developed by 2020 if funding are in place for CO_2 capture cost**
OECD Asia		~ Medium cost (onshore) -High cost (offshore)	- Limited incentives toward emission mitigation (tax incentives -CO_2 cap and trade not in place → Carbon price signal will come lately in the decade	+ In favor	~ many CO_2 sources sometime far from oil and gas province	- Limited potential	**Limited potential to few projects in the coming decade. We assumed zero to two projects might be developed by 2020**
China		+ Low cost (onshore)	-Limited to CDM which should not be available before 2014-2016 for CCS → Weak Carbon price signal will come lately in the decade	+ very in favor + Ready to incentivize extra production	+huge potential of capture due to intense economic development	+ important in North East China	**On top of the 5 already planned projects, 5 to 10 projects or more could easily be developed by 2020**
India		+ Low cost (onshore) -High cost (offshore)		+ very in favor + Ready to incentivize extra production	+huge potential of capture due to intense economic development	*Some onshore potential * Potential offshore	**1 or 2 projects onshore could be developed by 2020 in western oil province. Offshore project development seems unlikely within this time horizon**
South East Asia		-High cost (offshore)		+ very in favor + Ready to incentivize extra production	+huge potential of capture due to intense economic development	*Potential is located offshore mainly	**Some projects might be developed (0-2) by upstream industry due to local CO_2 availability (NG treatment or field with high CO_2 content)**
South America		+ Low cost (onshore) -High cost (offshore)		+ Brazil in favor of pre salt CO_2 reinjection ~ no hurdle	* Potential for capture in some area not necessarily nearby oil province	*Some mature field onshore (Brazil, Venezuela) * Offshore presalt Discovery (Brazil)	**Some projects (0 - 2) might emerge in Venezuela onshore due to ageing field and CO2 availability from NG treatment. There is also a potential for EOR projects onshore Brasil (0-2) as well as within pre-salt production framework* (3-4)**
Middle East		+ Low cost (onshore)		- Not ready for wide scale. There is no need within current context for EOR technologies. It would send a wrong signal to market if the biggest producers were in need of EOR to sustain there production + Will to gain technical knowledge	- Limited CO_2 sources available in regard to the capacity	+Huge onshore potential	**On top of the two existing projects, between 2 -5 projects might be developed in the Middle East for knowledge building purpose**
Africa - North Africa		~ Medium cost (onshore)		~ no hurdle	- Limited CO_2 sources available in regard to the capacity	*Significant onshore potential	**Due to the lack of CO_2 sources and incentives to capture CO_2, the potential is limited. Zero to two projects might emerge by 2020**
Africa - South Africa		~ Medium cost (onshore) -High cost (offshore)		~ no hurdle	* Important Coal consumption for power and coal to liquid production but not well located (not nearby oil provinces)	*Potential is located offshore mainly	**There is an apparent mismatched between source and sink but some projects (0- 2) might be developed**
Africa - West Africa		-High cost (offshore)		~ no hurdle	- Limited CO_2 sources available in regard to the capacity	*Potential is located offshore mainly	**There is a lack of CO_2 sources. Some projects might be developed (0-1) by upstream industry due to local CO_2 availability (NG treatment or field with high CO_2 content)**

** Injection within the same reservoir but not necessarily EOR*

5.3.3. Number of Project Needed and Corresponding Financing Needs to Match IEA Recommendation

Overall between 26 and 56 CO_2-EOR projects (including the 14 existing ones) might be developed within the current framework if adequate incentives are put in place. Indeed, to be qualified as CO_2 storage project, a Measurement Monitoring and Verification (MMV) programme as well as the recycling of produced CO_2 should be implemented.

In developing countries, the incentives to do so are not in place since no carbon credit could be gained for such activity. The acquisition of CO_2 credit linked to CO_2-EOR injection within the CDM framework is an issue in current climate negotiation and might not be possible before 2020 if ever, due to the nature of the mechanism. An international financing mechanism allowing CO_2 credit monetization would obviously enhance CO_2-EOR economic efficiency and convince the project developers to effectively store CO_2. If not, the project will remain driven by incremental oil production without any climate change mitigation purpose.

Without CO_2 credit monetization for CO_2-EOR, the development of CO_2-EOR storage in developing country will not be guaranteed.

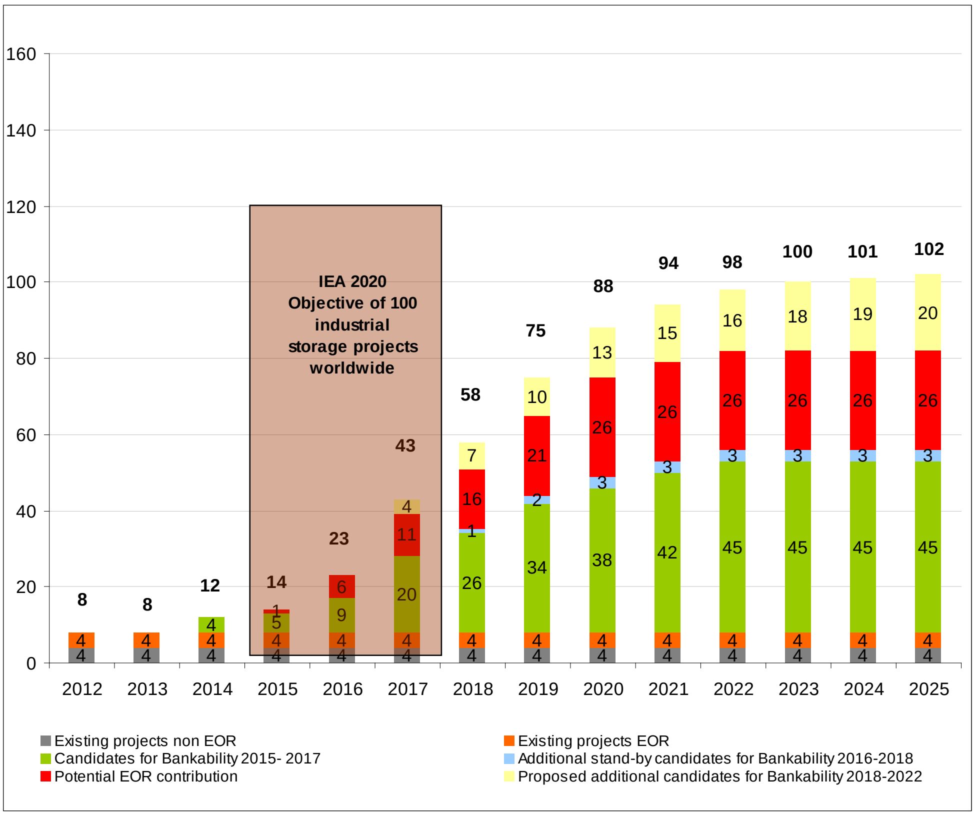

Figure 48: Cumulative distribution of the number of projects with CO_2-EOR Low case (23 projects)

Figure 48 gives an overview of the project completion as compared to IEA recommendation if only 26 projects (14 existing projects+12 new projects) are developed by 2020 (we considered a uniform distribution of completion date between 2015 and 2020).

The number of additional storage projects needed is reduced by 26 (in comparison with Figure 39) meaning that about 30 new storage bankability assessments are needed worldwide by 2012 to reach IEA 2020 recommendation. Nonetheless, the inclusion of CO_2-EOR projects does not allow reaching the IEA 2020 recommendation of 100 projects by 2020 due to the storage development time.

In the low case (26 CO_2-EOR projects), and considering that no public funds would be necessary for CO_2 storage bankability assessments[50] in oil fields, the needs for public investment in new storage bankability assessment could be reduced by about 50% (30 projects instead of 59). 0.47 billion Euros will be needed if all promised funds are delivered to existing projects and if a public funding of only 50% may be assumed to trigger private investment. 1.3 billion Euros will be needed if funding promises are kept to the minimum and if a funding of 75% of bankability assessments costs is required to trigger projects.

Considering the same hypothesis and the less likely high case, (54 EOR projects), very little additional funding would be needed to achieve the IEA 2020 recommendation.

Inclusion of CO_2-EOR would decrease public funding to reach IEA 2020 recommendation of 100 projects. However, due to the recycling issue (see 3.2.2.3), field clustering or/and development of an associated DSF storage might still be needed in order to cope with CO_2 volumes coming from capture and CO_2-EOR injection strategy.

Moreover, public acceptance issues over CCS- CO_2-EOR project funding should not be neglected in some regions. Indeed in time of public financial austerity, public acceptance issue of CO_2-EOR funding might jeopardize project developments.

[50] No funding allowed for the bankability assessment assumes that oil field operators will take in charge this phase. This is arguable and will depend strongly on each country. We made this assumption for the sake of simplicity

Key Messages – CO_2-EOR Contribution to CCS Development

CO_2 Enhanced Oil Recovery is neither an exotic nor a new technology. It has the potential to offset some of CCS costs due to the incremental oil production. This is a precious advantage in a context of weak incentives to tackle CO_2 industrial emissions. The following conclusions should be added to the ones given in section 4 on page 86.

1. **In the current financing framework, CO_2-EOR has the potential to increase by 70 to 80% the number of projects that can reach bankability**
    - Assuming CO_2-EOR projects need less financing to proceed with commercial scale injection and that all of them succeed technically, there could be 18 CO_2-EOR projects worldwide by 2015-2018.
    - With current funding, it means that 32 to 46 projects will have reached bankability by 2022.
    - Nonetheless, even if CO_2-EOR projects are quicker to develop, the IEA 2020 recommendation will not be reached in time due to the developing of DSF projects which still represent a significant share of the portfolio.
2. **CO_2-EOR could decrease public funding to obtain 100 bankable storage projects by 2022-2025**
    - The need for extra public funding could be reduced up to 50% if we assume that EOR storage bankability assessments costs are to field owner charge (which might not trigger investment at all).
    - Only between 0.5 and 1.5bn€ extra public funding support would allow launching enough storage bankability assessments to have 100 storage sites ready by 2022 / 2025
    - This does not remove the need for public funding for the capture and transport part of the chain if global incentives are too weak to justify private investments (low CO_2 price for instance).
3. **On the mid/long term, CO_2-EOR projects might need the development of nearby aquifer storage projects in order to cope with CO_2 volumes fluctuations (recycling and EOR strategy)**
    - Medium term, field clustering or/and development of a DSF storage nearby might be needed in order to cope with volumes coming from capture and CO_2-EOR injection strategy.
    - Indeed, part of the CO_2 injected for EOR purposes will necessarily breakthrough at the producing well and will have to be recycled. This recycled flow of CO_2 will increase overtime so as CO_2 from the emission source (capture) is decreasing with time.
    - This is an issue for small to medium size fields.
4. **Public acceptance issues over CO_2-EOR project funding should be considered**
    - There are regional discrepancies in public opinion towards CO_2-EOR projects. Government policies differ also widely depending on overall countries context.
    - In time of public austerity due to financial crisis public acceptance issue of CO_2-EOR funding might jeopardize projects development.
    - Current debate on shale gas production, particularly in Europe, might damage public's trust

5.4. Policy Makers: What to Take Away from 2020 Storage Bankability Analysis

This bottom-up study used several approaches to evaluate the gap between the existing effort in term of policy and public funding and the level of development of storage we should reach by 2020 if we were to stabilize CO_2 level in the atmosphere to 450ppm by 2100 (2°C increase by 2100).

The objective of this study is to allow policy makers to better understand:

1. Whether a sufficient number of "bankable" storage projects exist to meet the storage needs implied by the current global commercial-scale CCS deployment goals,

2. Where the gaps exist, globally and regionally speaking, if the number of bankable sites is found to be insufficient, and

3. How to fill such gaps through appropriate work programs (including estimated timing and costs).

The first section addresses the first two questions; the second section gives insights on what should be done to obtain 100 bankable storage sites by 2022-2025.

5.4.1. Take Away from the IEA 2020 Storage Recommendation Gap Analysis

Our analysis stressed the following points:

1. **CO_2 storage deserves more attention from policy makers and emitters**

   Storage site bankability assessments take time because it is an iterative process. It has to be conducted according to stakeholders' wishes in order to not jeopardize future commercialization due to public acceptance issues. The level of geological knowledge over an area has a significant impact on storage development costs and times up to bankability

   Storage bankability assessment for Deep Saline Formation and Depleted Fields take time and is on the critical path of CCS deployment. Indeed taking into account technical aspects and regulation needs between 6 to more than 15 years in worst cases can be needed to develop a storage site up to bankability.

   Most of the existing projects might achieve storage bankability between 2017 and 2020 and be commercial by 2018-2023. The required investments are marginal as compared to overall CCS chain capital needs. It represents generally less than 10% of the latter.

   However, as the cost of this part of the chain is less important than capture cost and because it is usually not the core business of emitters, there are less focuses on storage development.

A lack of investment in the storage part in the first years of development would lead to important delays in CCS projects starting dates and development objectives achievement.

But there are limited incentives or public funding to convince private stakeholders to invest in storage bankability assessment. Private investors do not invest ahead in CO_2 storage development because the risk reward is insufficient. The current incentives in place are not appropriate to justify these investments and public funds are needed.

2. **The current number of projects is not appropriate to deliver 100 commercial projects by 2022-2025**

There is a structural storage bankability assessment failure rate of 15 to 20% at world level linked to technical factors. Only taking into account what the industry can technically deliver and non EOR projects, the gap of commercial projects by 2025 is around 60.

Non technical failure causes like financing, public acceptance and regulation can be very important and further deepen the gap. If we take into account past observed cancellation rate of CCS project for non EOR projects, only between and 30 and 40 of the actual 54 large scale project would make it up to bankability. In that context, the gap of commercial projects by 2025 would be more than 85 projects.

The regional distribution of the gap is as follow:

- On the technical standpoint, OECD Europe has enough projects launched in order to meet IEA 2020 regional recommendation
- Even if North America is leader in CCS development, additional projects are needed to meet their regional recommendation
- More than 45 technically bankable projects (45% of the needed 100 projects) are missing in developing countries

3. **The existing incentives and funding schemes are not adapted to the climate change objectives**

The actual 21 billion Euros promised for large scale CCS projects concern only developed countries. Currently, there is no major public funding announcement for developing countries although their expected contribution to the overall effort of CCS deployment is close to 50%

- Worldwide, this level of funding will allow only between 14 (32) and 21(46) projects without (with) CO_2-EOR to be financially sound and developed.
- Even G8 objective of 20 large scale commercial CCS projects might not be achievable in the study time window without CO_2-EOR

Taking into account what CCS industry is able to technically deliver, it is possible to obtain 100 bankable storage sites by 2025 only if between 85 and 97 storage bankability assessments are financed by 2012. Only between 1 and 3bn€ extra public funding support would allow launching enough storage bankability assessments to have 100 storage sites ready by 2022 / 2025

One should mention that no financing is presently proposed for Africa, South America, India, China and South-East Asia although their contribution to the global effort is expected to be around 45%.

4. CO_2-EOR is an opportunity that might decrease public funding on the short term but is not available in all regions

In the current financing framework, CO_2-EOR has the potential to increase by 70 to 80% the number of projects that can reach bankability.

The necessary public funding to achieve 100 bankable projects by 2022-2025 could be decreased of 50% and range from 0.5 to 1.5bn€, if CO_2-EOR projects are included. Actually, we assume that the necessary assessment costs for bankability of CO_2-EOR projects are made by the oil field operators themselves for the sub-surface part, with no contribution from public funding. This does not remove the need for public funding for the capture and transport part of the chain if global incentives are too weak to justify private investments (low CO_2 price for instance).

The contribution of these resources to the global effort is limited by the following factors:

- On mid-to-long term, CO_2-EOR projects might need the development of nearby aquifer storage projects in order to cope with CO_2 emission reduction needs (constant flow rate over the plant life time)
- They are not distributed evenly between countries (oil and gas producing provinces).
- Not all fields can be converted safely to CO_2 storage or CO_2-EOR.
- There is a specific time window of opportunity that can be used for conversation of the field. This window of opportunity depends on each field producing costs versus oil and gas prices

Public acceptance issues over CO_2-EOR projects funding should not be neglected. In time of financial austerity, public acceptance of CO_2-EOR funding might jeopardize project developments and therefore diminish CO_2-EOR contribution to storage in some regions. Moreover, the current debate about shale gas production in some countries, particularly Europe might damage public's trust towards project developers.

5. **All type of storage will contribute to the global effort**

   Choice upon one or the other will depend on the location of the source relative to storage options, costs and development times of the storage site option and, obviously, non technical parameters such as economic context and public acceptance.

   Depleted Oil and Gas fields and CO_2-EOR suffer from various limiting factors such as their location limited to oil and gas producing provinces, the impossibility to convert safely all the fields and the time window issue. There is a specific time window of opportunity that can be used for conversation of the field. This window of opportunity depends on each field producing costs versus oil and gas prices and can be difficult to foresee.

   Deep Saline Formations present a huge potential but is not well known and need much more time and money to be developed.

5.4.2. Filling the Gap by 2020

The following 5 actions should be taken to develop CCS to the scale needed to mitigate global warming.

1. **Improve the knowledge of subsurface in areas where large volumes of CO_2 might be captured in order to save development time for future commercial CCS projects.**

   To avoid further delay in meeting IEA recommendation, the first phase of CO_2 storage development, generally a national or regional level capacity assessment, should be launched rapidly by policy makers. This phase, 1 to 2 years long, provides a framework for discussion and development of local storage projects. The following Figure 49 shows the areas where such an effort should be focussed on. In these areas, extensive oil and gas production data if made available, could lead to initial capacity characterization with the use of desk based assessment only (no need for new data acquisition in this first step).

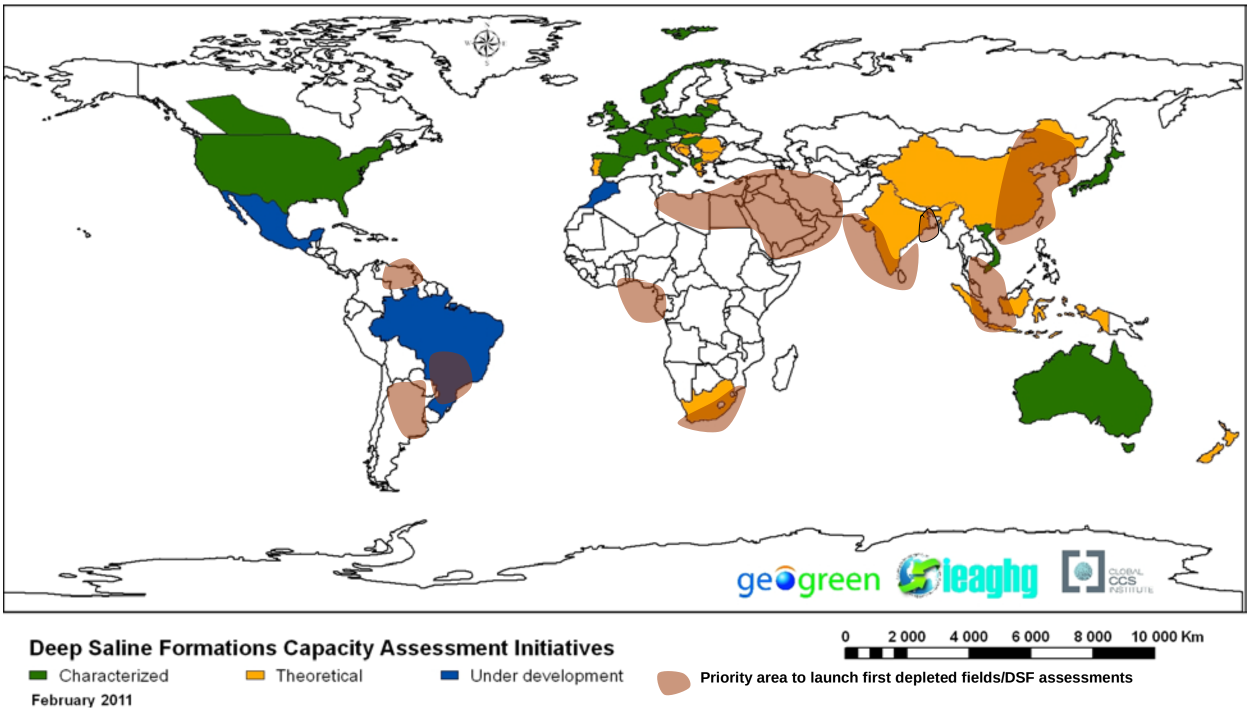

Figure 49: Required regional storage resource assessment studies to avoid further delay

2. **Ensure regulatory framework is suitable for CO_2 storage and support project developers towards public acceptance to reduce non technical failure causes**

In addition to project financing issues, there are two other causes of non technical failure for storage project development: not adapted regulatory framework and public acceptance issues.

Having a regulatory framework for CO_2 storage is very important for the project developers to evaluate the cost and time effort needed in the characterization phase. Indeed, regulatory framework for industrial CO_2 storage will have an impact on CO_2 storage characterization process.

As an example of key regulatory aspects, the issue of medium to long term liabilities is very important to settle for project developers, since it impacts the costs and risks of the project.

Public acceptance is another key issue to be addressed. It is particularly true for onshore storage projects. Active government support and proper local communities up-front involvement is mandatory to make public understand the key reasons and outcomes of CCS deployment. There is a long way to go in order to promote CCS benefits for climate change mitigation, territorial development, societal and local stakeholders. A recent study on public awareness toward CCS in the EU[51] in 12 EU countries showed the amount of work to be performed on this point:

- Only one in ten (10%) said they had heard of CCS and knew what it was.
- Nearly half of the respondents (47%) agree that CCS could help the combat climate change. However, only around a fourth (23%) said that they do not agree with this.
- When asked about what impact CO2 would have on the environment, however, over a third (35%) indicated that they thought the impact would be 'very high' and just under half (48%) thought it would have 'a fairly high impact'.
- A high proportion of respondents felt that they 'would not benefit' from CCS technology if it was used in their region (38%), whilst just under a quarter (23%) thought that they 'would benefit'.

Generally, people would be concerned about CCS technology if an underground storage site for CO_2 were to be located within 5km of their home. Overall, six in ten (61%) people would be worried, of which just under a quarter (24%) said they would be 'very worried'.

3. Increase or create incentives for private stakeholders to launch bankability assessment as soon as possible to avoid further time delays

As shown previously, there is not enough public funding to ensure 100 bankable projects by 2020 or even 2025. There are also very limited incentives for private investors to invest in storage bankability assessment although this phase is time consuming (4 to 10 years or more), and represents a marginal cost as compared to the overall CCS investment.

It would therefore be wise to finance storage characterization programs in order to have storage site ready when emission mitigation incentives will be sufficient to sustain private investment in CCS (expected between 2020 and 2030).

This storage characterization programs should be preferably located next to important CO_2 emission hubs.

If we consider CO_2-EOR contribution, our analysis shows that at least 42 large scale new storage bankability assessments (30 DSF/DOGF and 12 EOR) should be launched by 2012 in order to obtain 100 storage sites by 2025. This represents an extra public funding requirements of between 0.5bn€ and 1.5n€ worldwide if we consider that CO_2-EOR bankability assessment costs are met by field operator and if private investors step in storage characterization when 50 to 75% of the costs are subsidised.

[51] PUBLIC AWARENESS AND ACCEPTANCE OF CO_2 CAPTURE AND STORAGE Conducted by TNS Opinion & Social at the request of Directorate-General for Energy - SPECIAL EUROBAROMETER 364, May 2011

However, there are huge regional discrepancies in terms of financing. While some countries like the US or China, can widely use CO_2-EOR to match IEA 2020 recommendation, others regions like Europe, OECD Asia and Africa have source-sink matching difficulties.

In order to launch necessary storage development in emerging economies, an international mechanism should be developed to allow fund transfer from the North to the South. It is not clear whether or not the Kyoto Clean Development Mechanism is adapted to this mission. CDM stream of revenue is available only when the projects as started and storage bankability has already been assessed. Nevertheless, as mentioned earlier, the CO_2 price perspectives are not sufficient to convince private investors of developing storage projects at the needed scale.

4. Increase or create incentives to provide a business case to CCS

The inclusion of CCS under CDM mechanism in Cancun is a first good step to provide a revenue stream to projects in developing countries. However, the perspectives over CCS-CDM methodology acceptance timeline are still uncertain. As shown in this study, storage development in developing countries can be less costly than in developed countries.

Lack of revenue stream to these projects could jeopardize the achievements of storage development ambition.

5. Capitalize on low cost industrial early opportunities and BECCS

CCS is often associated with coal or fossil fuel power generation because the power sector is a huge contributor to CO_2 emissions. However, as mentioned in IEA World Energy Outlook and Energy Technology Prospective, almost half of global CCS deployment should concern emissions from other industrial sectors.

Opportunities of low cost capture exist for industrial sources with high CO_2 purity. These “easy to capture” sources are located in industrial basin worldwide and storage bankability assessment efforts should be focussed in consistency with their locations.

Such interesting opportunities can be identified in developing countries. Among them we can mention bio ethanol production associated with CCS (that can create carbon negative emissions), natural gas processing, ammonia and fertilizer production, and refining activities under development in Africa, Middle East, South East Asia, China and India.

As they might potentially be carbon sinks for CO_2 from the atmosphere, the Biomass Energy with CCS projects [24] might be an efficient early opportunity as long as the biomass is grown in an environmentally responsible way. Such projects may catch up part of the delay in implementation of the GHG mitigation objectives, since biomass being carbon neutral, more carbon is stored than emitted. Policy makers should provide these projects with an adequate framework to monetize non anthropological stored CO_2. Such early opportunities have been recently studied by UNIDO [54].

Finally, we would like to stress the importance of early planning of storage development and assessment. In a decarbonised world a CO_2 storage site can be an incentive for development of territories and industrial areas.

Good examples of this concept are the CCS hubs presently being studied like the Tee Valley in UK, the Rotterdam Climate Initiative in the Netherlands. Alberta province[52] in Canada is also betting on territorial development by subsidising a CO_2 transport network where sources and sinks could be connected.

[52] Alberta Carbon Trunk Line

6. Gap Analysis To Meet The Recommendation Of Bankable Project Beyond 2020

This section gives insights on the global deployment of CCS beyond the 2020 timeline.

6.1. Number, Costs and Timing of Projects

IEA CCS Road Map [29] estimates that 3,400 CCS commercial projects are needed by 2050 in order to cope with IEA Blue Map recommendations (450ppm CO_2 atmospheric concentration by 2050) [30].

Following our analysis and even if there is enough public funding/incentives worldwide to achieve 100 bankable projects by 2022-2025, most of those projects will reach the end of their operational life by 2050. Indeed, CCS project operation life (without taking into account post closure periods) is estimated to be between 20 and 40 years.

As mentioned previously, CO_2-EOR contribution might fade on the long term due to the declining need for CO_2 (see section 3.2.2.3 - CO_2 recycling). For the sake of simplicity and even if CO_2-EOR will have a very significant role to play up to 2050 and beyond, we made the strong assumption that the 3,400 projects needed by 2050 are either DSF or DOGF CO_2 storage. We therefore consider that by that time CO_2 transport networks will be developed enough for CO_2-EOR storage being backed by DSF and DOGF CO_2 storage sites. This is to provide an estimate of the effort to be made during the next 40 years.

Table 8 shows the number of projects to be developed by 2050. It takes into account a low range of technical failure rate assumed at 10% because of improved CO_2 storage knowledge after 2030. This is the results of the different projects and storage assessment programs performed during the 2010-2030 period. Consequently, around 3,750 storage projects should be assessed for bankability by 2045-2048 to achieve 3,400 industrial projects.

Table 8: Gap of bankable projects between 2025 and 2050

<table>
<tr><th></th><th colspan="3">Number of Projects</th></tr>
<tr><th></th><th>IEA 2050 objectives</th><th>Considered bankable by 2025</th><th>To be developed to reach 2050 target</th></tr>
<tr><td>OECD Europe</td><td>315</td><td rowspan="6">MOST STORAGE PROJECTS REACHING END OF LIFE BY 2050</td><td>346</td></tr>
<tr><td>OECD Pacific</td><td>275</td><td>302</td></tr>
<tr><td>OECD North America</td><td>590</td><td>649</td></tr>
<tr><td>China & India</td><td>950</td><td>1 045</td></tr>
<tr><td>Non-OECD countries</td><td>1 270</td><td>1 397</td></tr>
<tr><td>Total world</td><td>3 400</td><td>3 739</td></tr>
</table>

Considering the same breakdown in terms of type of projects (onshore/offshore, deep saline formation, depleted fields) as for the 2025 recommendation (technical bankability see section 5.1) as well as the same nominal injection rate (1 to 3 Mtpa) the worldwide storage bankability assessment cost would be around 112 billion € for the 3,739 projects as shown on Figure 50. One shall note that for non-OECD countries, a breakdown has been assumed proportionally to expected CO_2 emissions in 2050.

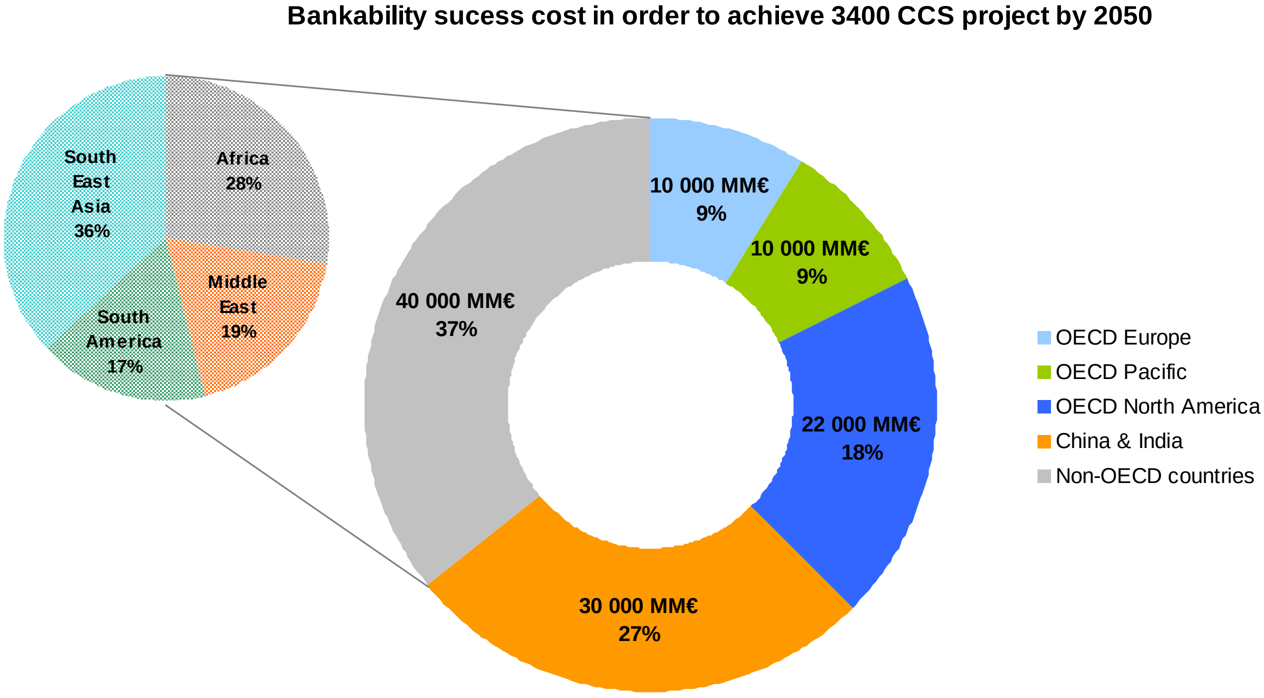

Figure 50: Estimated Assessment of regional costs for storage bankability to achieve IEA 2050 recommendation

In terms of regional distribution one has to note that storage capacities are largely exceeding CO_2 emissions forecasts in several regions: for instance, the Middle East, Russia or Africa. On the other hand, regions like India, Japan and southern Europe present a deficit of storage capacity as compared to their expected CO_2 emission volume. The apparent lack of storage resources makes it difficult to suppose the development of numerous projects in these areas (more than 600 projects in IEA Blue Map Scenario). However, one can suppose, that development of long distance CO_2 transport might have to play an important role for those areas.

Depending upon the maturity of the different world oil provinces, significant storage opportunities may arise as the global hydrocarbon production is expected to decrease.

For example, most of the North Sea oil and gas fields should be reaching the end of their commercial life and may therefore be new bankable opportunities as DOGF storage projects. On the other hand, EOR or EGR opportunities may develop in the Middle East which might trigger development of CO_2 transportation infrastructures and DSF storage opportunities (see section 3.2.2.3).

In terms of development time, the first thing to note is that, as experience is gathered by stakeholders and authorities (stabilized regulatory framework), development time after 2020 should be slightly lowered of 20% as compared to currently assessed development time (see Figure 51).

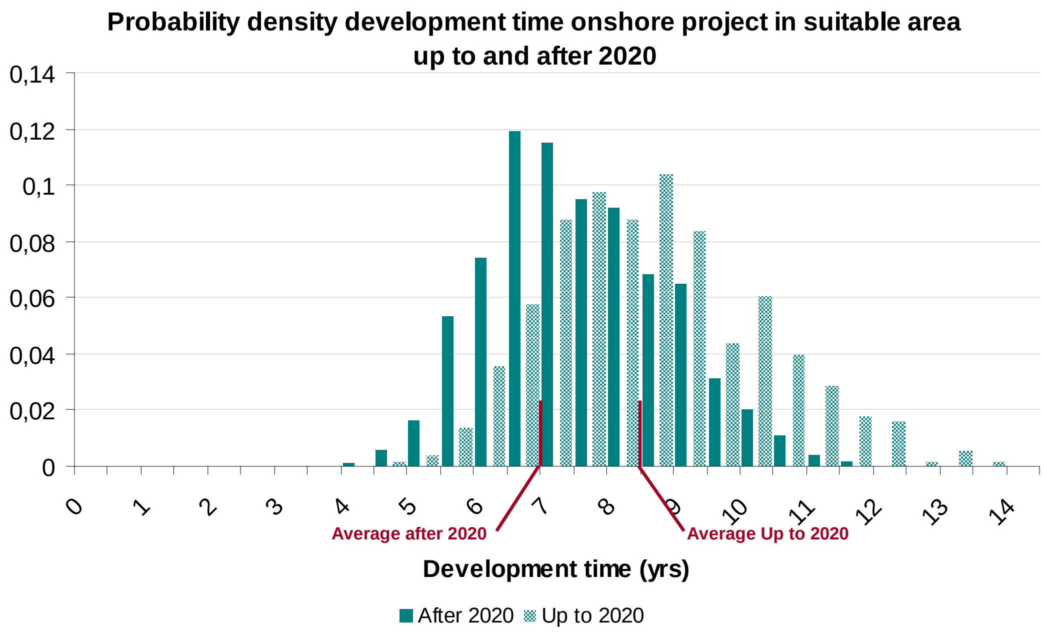

Figure 51: Storage project development time up to bankability before and after 2020

Three key comments should be given about these overall results:

1. Storage development time:

   In some regions there might be a difference for development time from the storage development workflows presented in part 4 which concern CCS development up to 2020 / 2030. One of the strong assumptions taken in these workflows is the compulsory CO_2 injection tests before declaring storage site. This assumption might have to be softened in the decade after initial CCS deployment. As the industry will gain experience, CO_2 injection test might not be needed routinely everywhere. This step might be skipped in some regions where the geological formations are very well known due to previous injection and where the regulatory framework allows it. This could save considerable time and money for storage bankability assessments.

2. Project success rate:

   Over the longer term, the worldwide knowledge of storage suitability will increase with the number of bankable projects in the various regions. Such increase will improve the technical success ratio of storage projects.

3. Project size and implications:

In 2050, while some of the initial projects may be running out of storage capacity (those developed for 2020 IEA recommendations), new storage projects would have to cope not only with the CO_2 emissions not stored before but also with the existing ones that can no longer be stored. Therefore, the nominal storage size might increase as compared to present assumptions made in IEA Blue Map scenario. The 3400 projects target should be looked at in terms of yearly injected volume rather than pure number of projects.

As the nominal storage size might increase, each storage will have an increased "influence area" (CO_2 footprint and overpressure impacted area) inside a geological basin (DSF storage case)[53]. Consequently, fewer overall number of storage projects can be developed for a given amount of CO_2 volume.

As fewer storage projects must be developed, it is compulsory that CO_2 transportation infrastructures are developed as hubs and networks. These networks should spread from the newly need-to-be-developed storage projects and from emission sources [47]. As the emission sources may be pooled together towards transport trunk lines, similarly the storage projects may be interconnected to ensure mitigation of injection risk between the different storage sites as illustrated in Figure 52. Some projects are presently developing this philosophy (Rotterdam and Alberta initiatives).

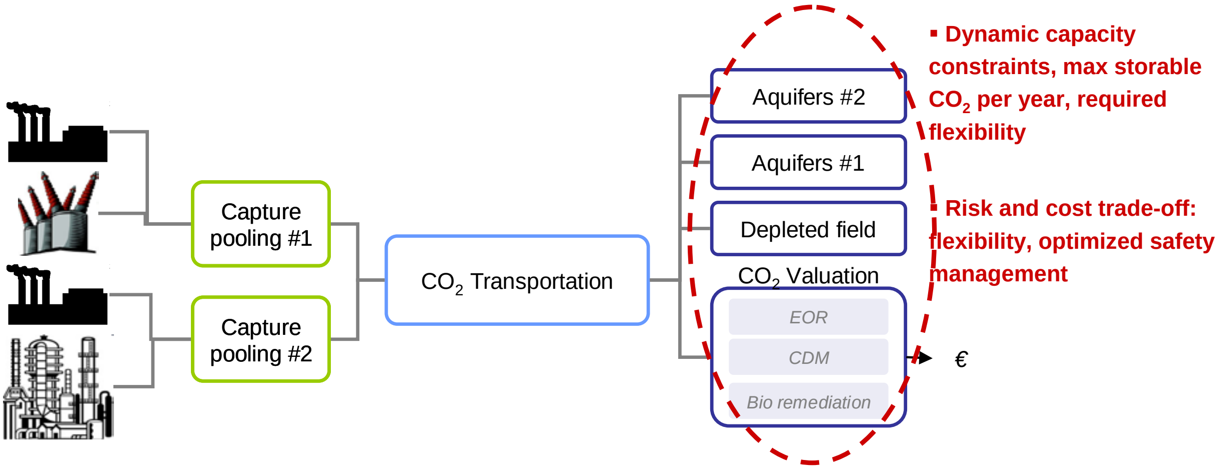

Figure 52: Example of an integrated network between sources and storage options

[53] Also called dynamic capacity.

6.2. Policy Makers: What to Take Away from 2050 Storage Bankability Analysis

The four main facts exposed in this short qualitative analysis on CO_2 storage development beyond 2020 and 2030 are:

1. **Storage development will reduce and success rate will increase** due to the better subsurface and CO_2 storage mechanism knowledge.
2. **Storage site developed in 2020 might reach end of life by 2050** and will have to be replaced by new injection sites.
3. **There are important** regional variations in term of capacity and source sink matching that will imply the development of a significant CO_2 transport infrastructure if we want to cope with climate change mitigation objective.
4. **More than 100bn€ needed to develop 3,750 storage bankability assessments over the screened period**. This should be supported by private stakeholders if the necessary incentives are in place.

Some key challenges will have to be faced in the decades to come to reach this ambitious development targets:

1. **Behaviour of CO_2 in the subsurface must be carefully assessed** and adequate tools developed. This is a critical point to define the numbers of projects that can be developed in a given area and assess their long term interferences.
2. **CCS network development is the next critical step for sound storage projects deployment.** Many R&D projects are currently underway. The importance of storage networks in terms of territory development and jobs creation as well as their feasibility should be broadly assessed. All storage options must be considered in a timely manner to ensure long term storage availability.
3. **Long distance and cross-border issues for CO_2 transport will have to be addressed for countries with limited national storage capacities.** This is a major challenge in terms of cost, regulation, and public acceptance. Joints efforts between industrial and public stakeholders seem necessary to develop such infrastructures.

APPENDIXES

A. Suitability Map Build Up
B. List of Selected CCS Projects for 2020 Target
C. Cost Model Assumptions for DSF Onshore
D. Cost Model Assumptions for DSF Offshore
E. Cost model assumptions for DOGF onshore and offshore
F. Regional Cost Factors
G. Development Times Assumptions
H. Costs and Time Models Results
I. Technical Bankability Gap Analysis 2020 – New Projects Needs
J. References

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A.SUITABILITY MAP BUILD-UP

To establish the World Geological Storage Suitability map, data at different scales have been used. The approach used a “top-down” analysis to update the world-scale map with regional CO_2 storage resource and capacity maps when available. This World Geological Storage Suitability map aimed at identifying suitable areas for geological storage

A.1. Methodology and assumption for the suitability map

The world geological storage suitability map is based upon the world geological storage IPCC prospectivity map [46] created in 2005.

A review of the different data on storage capacity and resource assessment around the world was made to complement the global map with regional information from local and regional initiatives. A lithological world map was used to improve the lithological repartition.

Consistency checks were applied in different regions at all steps of the map elaboration to challenge the hypothesis used.

The next step was to define an appropriate ranking valid for every country. This ranking was inspired from the existing capacity assessments [9, 15, 29, 53].

Where no information was available, the basin exploration status [25] was used to assess the general geological knowledge that exists on a specific area. The natural seismicity map was used to discriminate seismic active zone that storage will avoid as much as possible.

A.2. Data Sources for the Different Regions

The different sources used to elaborate the suitability map are as follows:

- North America: Canada, USA
- South America including Mexico
- Europe : European Union and former Eastern bloc countries
- Africa
- Middle East
- Oceania: Australia, New Zealand
- South East Asia: Malaysia, Vietnam, Indonesia, Japan
- Central Asia: China, India

A.2.1. World Scale

The initial map of world prospectivity was elaborated in 2005 by IPCC [46] and proposed the following ranking of sedimentary basins:

- Highly Prospective
- Prospective
- Non-prospective.

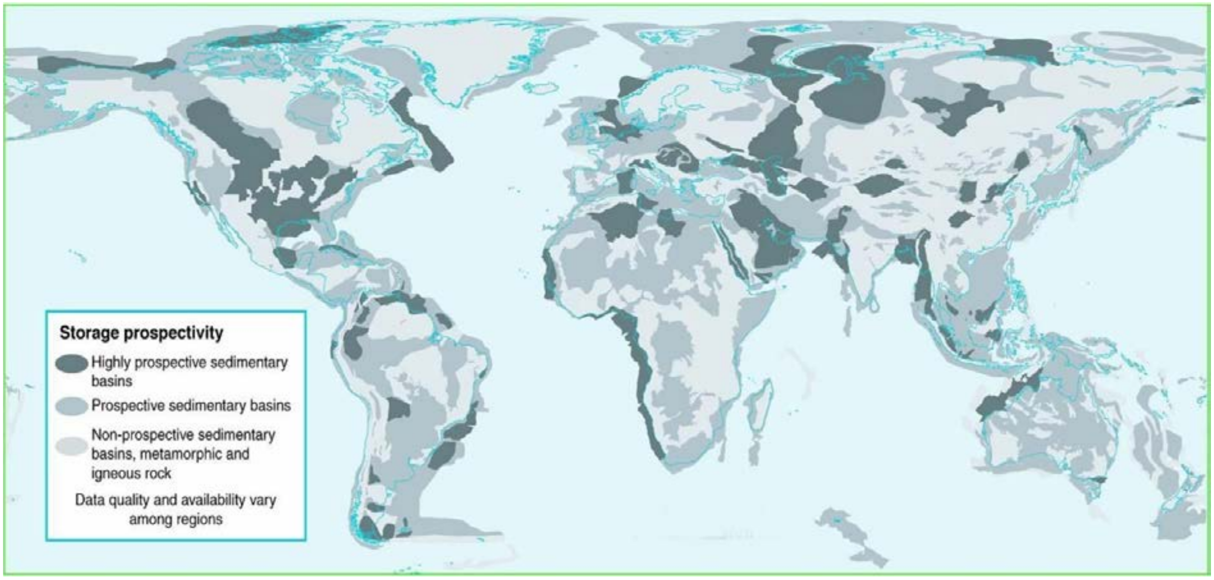

Figure 53: Prospective areas in sedimentary basins where saline formation, oil and gas fields, or coal beds may be found [46]

This map (Figure 53) represents a qualitative assessment of the likelihood that suitable storage exits in a given area based on available information. The quality of information differs from one region to another. As mentioned in the IPCC report [46], this map is subject to changes over time when new information and new studies are performed on regional basis. It is noteworthy to mention that several regional assessment studies were performed or are ongoing around the world. Here below are some of the main studies used:

- NETL North America Atlas [53]
- Europe GeoCapacity [20]
- PNNL Studies on China [15]
- CARBMAP in Brazil [39,40]
- Saneri South African Atlas [13]
- IEA GHG study on India [29]

- CST Atlas on Australia [9]

The map presented in Figure 6 summarizes the availability of the information about the assessment of CO_2 geological storage potential in regions addressed in this study.

To compensate the lack of publicly available information on areas like Russia, North Africa or Middle East, the geological map of the world [12] was used.

The map presented in Figure 51 extrapolated from the data available allows identifying seven geological domains of importance as a first step identification of CO_2 geological storage potential:

- Sedimentary basins
- Continental margins
- Extrusive volcanic rocks
- Endogenous rocks
- Oceanic crust
- Seamount, oceanic plateau, anomalous oceanic crust
- Glaciers.

We used these lithological properties to refine existing IPCC map (Figure 53) and to distinguish the sedimentary basins from other geological domains.

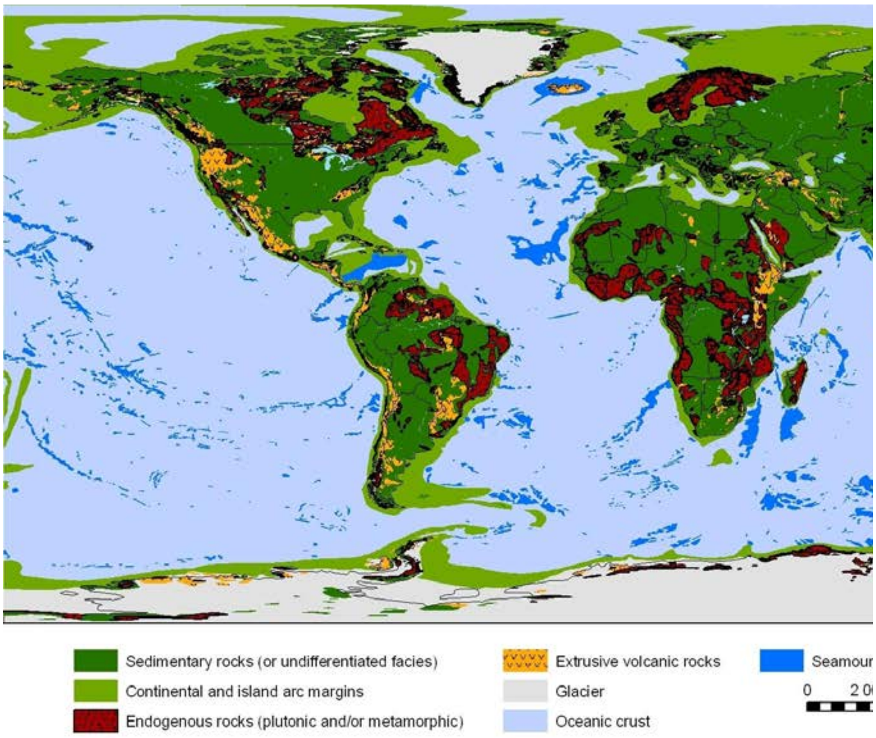

Figure 54: Lithological map of the world (modified from Commission for the Geological Map of the World)

After separating non sedimentary areas from sedimentary basins, the next step was to define an appropriate ranking.

Such a ranking should serve to identify storage gaps for CCS industrial deployment by 2020 and beyond. After analysis of the various rankings in the published geological storage assessment studies, a common scale was defined for a world consistent analysis: a four level scale and a special category for basaltic rocks have been used.

The final ranking is, for sedimentary basins and continental margins:

- Highly Suitable
- Suitable
- Possible
- Unsuitable

And for extrusive volcanic rocks (basalts)

- Unproven

The deep offshore, water depth of more than 1500m, was considered as "Unsuitable" area due to cost reasons.

A.2.2. Regional Improvement

After having defined the appropriate ranking, we improved IPCC original map with regional maps that have been released after 2005 and up to now.

This section sums up the different regional or local sources used to improve the world suitability map (Figure 14).

Examples of such improvements are given in sub-sections below.

A.2.2.1. Australia

The study conducted by Australian CCS Taskforce [9] carried out a detailed ranking of the Australian basins. Using a probabilistic approach they created a five levels ranking: Highly Suitable, Suitable, Possible, Unlikely, and Unsuitable.

The ranking seen above was adapted on Australia. In addition the extrusive volcanic rocks have been highlighted. New Zealand has been considered as unsuitable only due to a high natural seismicity risk.

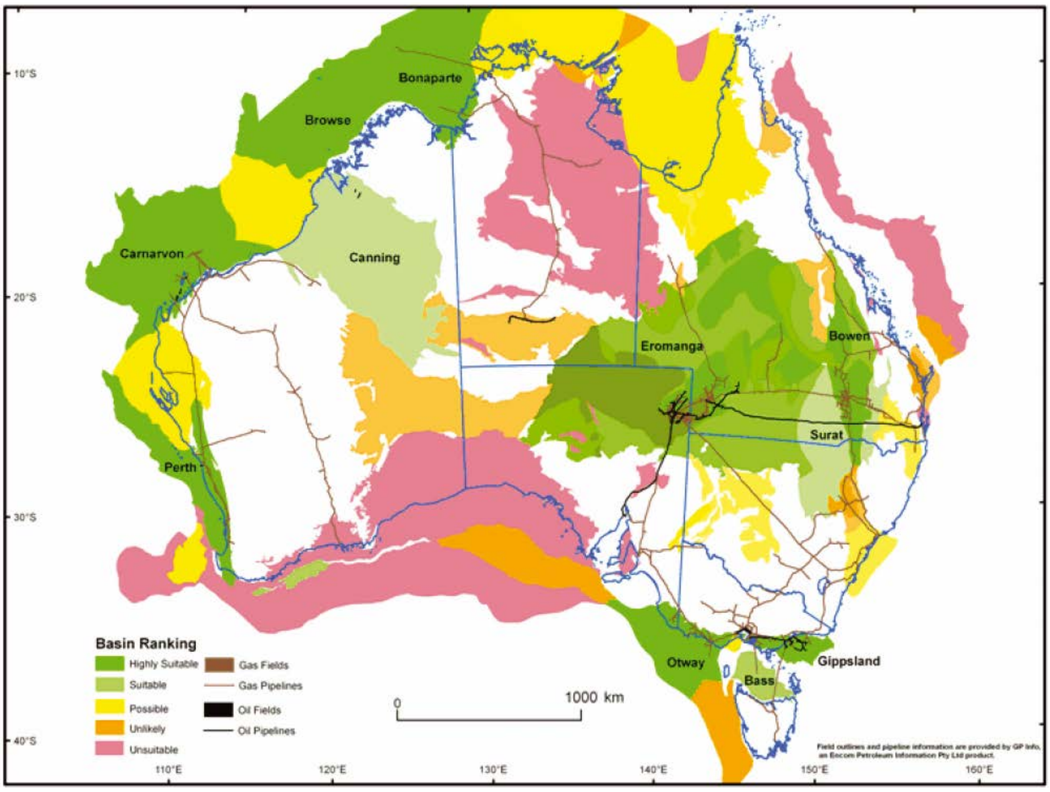

Figure 55 : CCS Taskforce interpretation of Australia storage capacity [9]

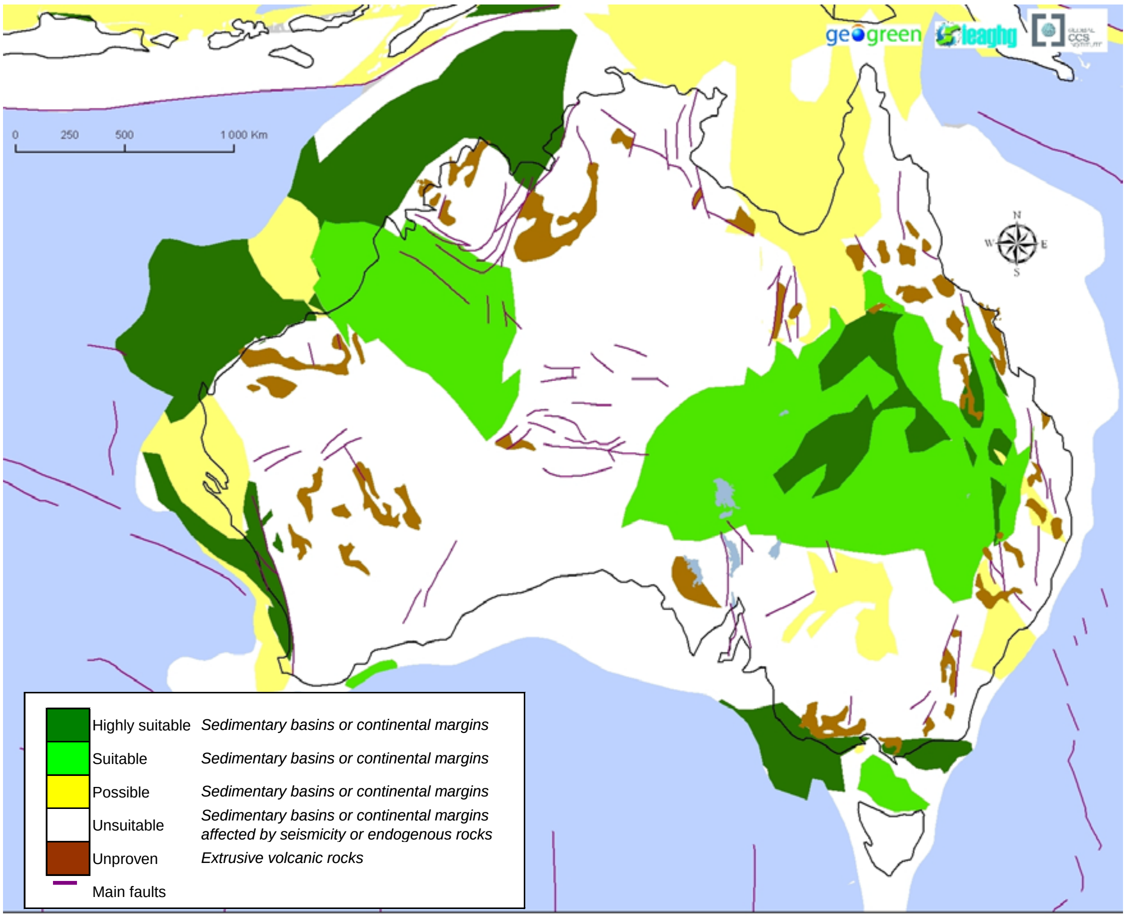

Figure 56: New assessment of storage suitability for Australia.

A.2.2.2. India

The map of storage potential in India [29], proposed by IEAGHG - 2008 has the same logic of ranking, with only three levels:

- Good
- Fair
- Limited

As for Australia the extrusive volcanic rocks have been highlighted in the new proposed version (see Figure 58).

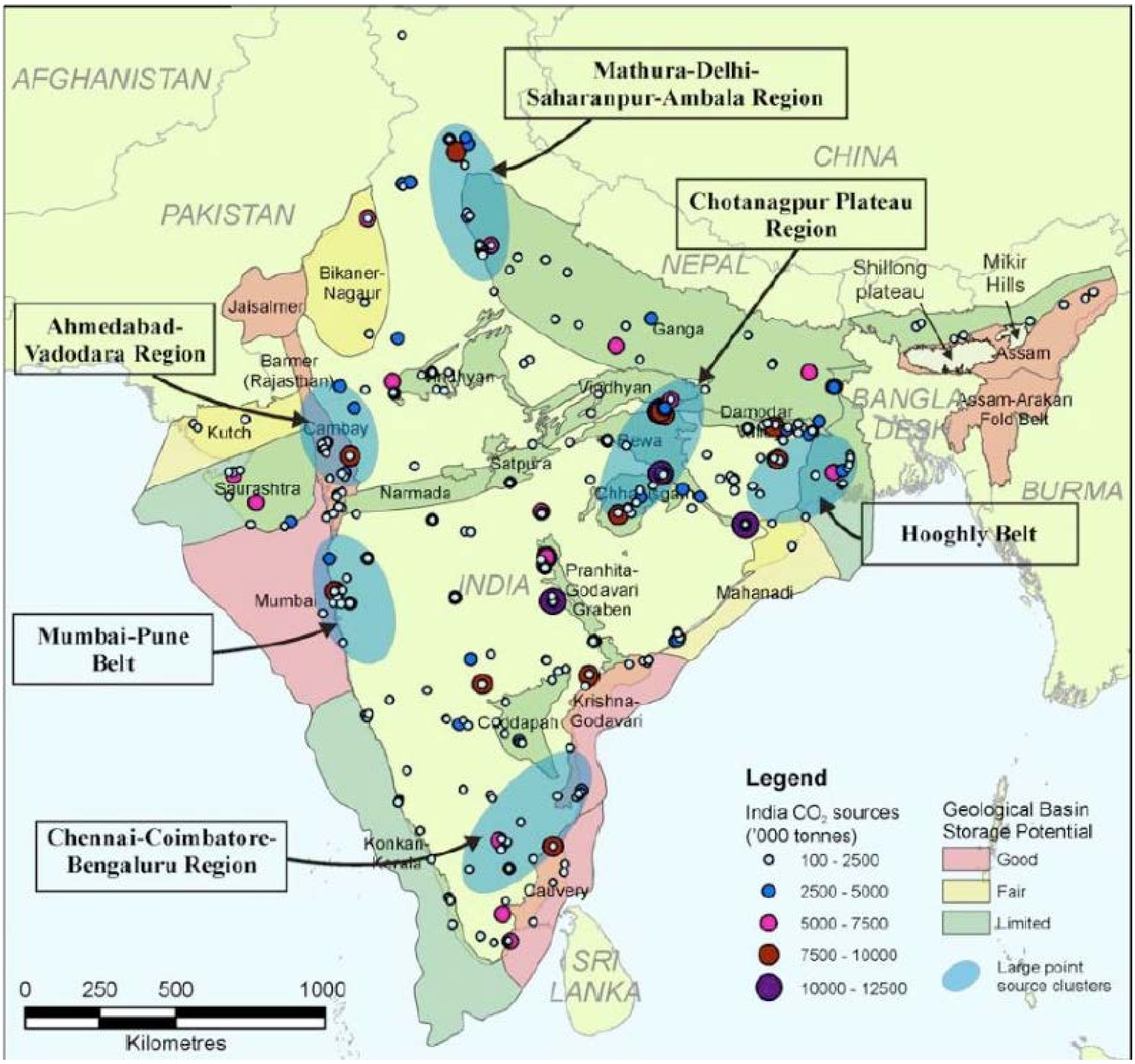

Figure 57 : IEAGHG 2008 interpretation

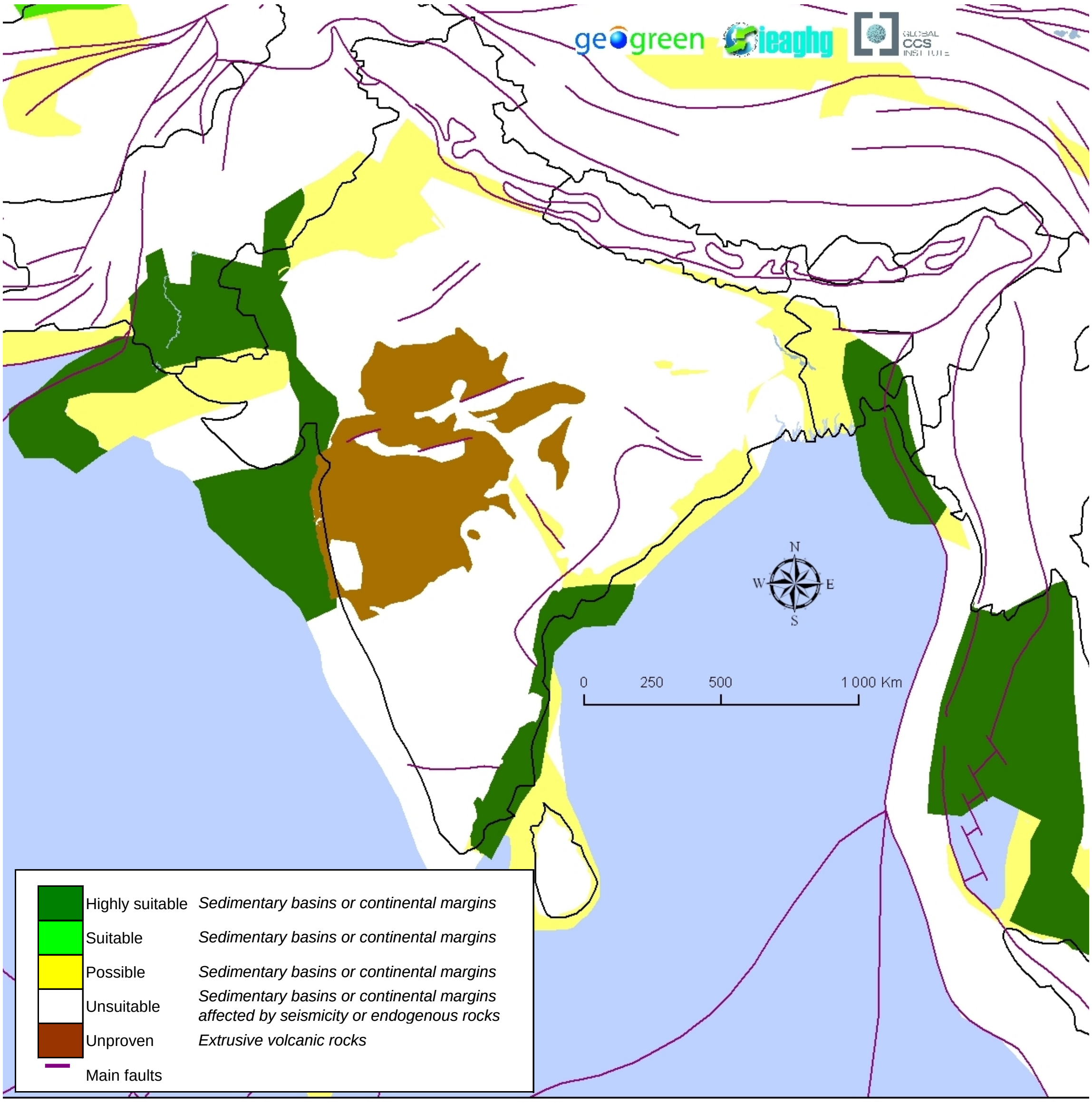

Figure 58: New assessment of storage suitability for India

A.2.2.3. China

The study from Pacific Northwest National Laboratory (PNNL) [13] and the works of Dahowski *et al* [15], of Finlay *et al* [21], of Le Nindre *et al* [42], of Li *et al* [44], and of Jiao *et al* [36] have been used for China to improve the IPCC's map (Figure 53).

These documents propose a good description of the storage possibilities in deep saline formations, oil and gas fields and coal fields. The following Figure 59 and Figure 60 are derived from these references.

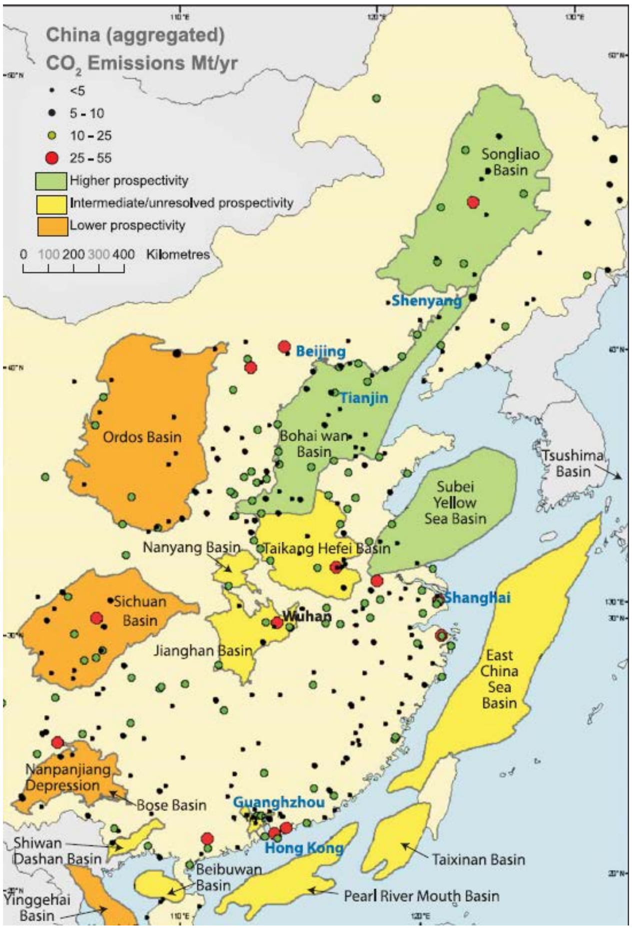

Figure 59: China basin prospectivity

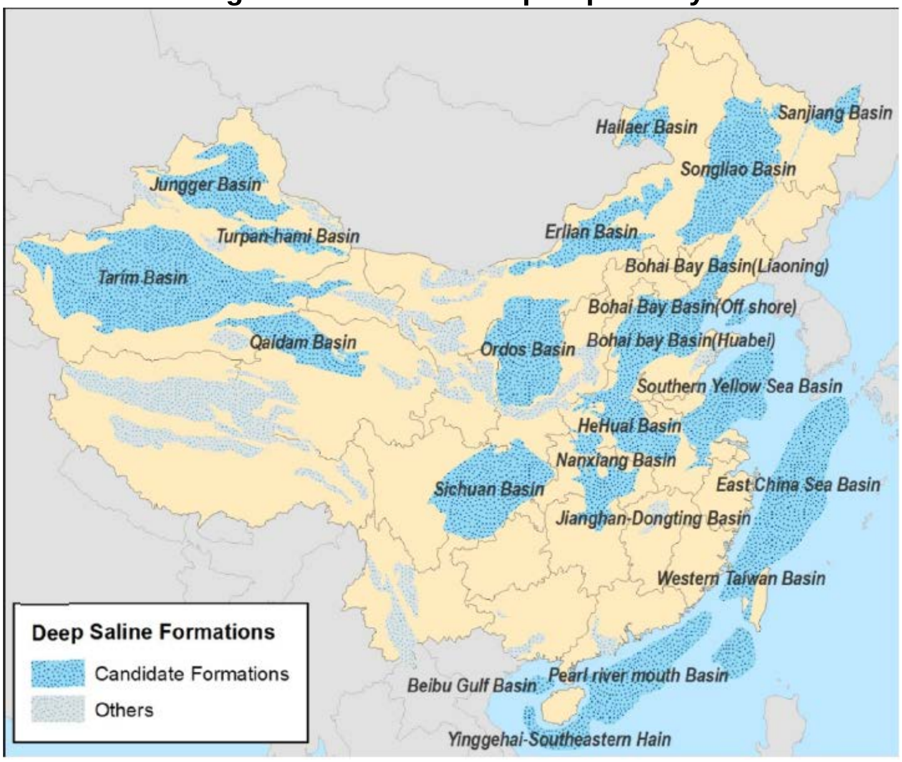

Figure 60: China Deep saline prospectivity

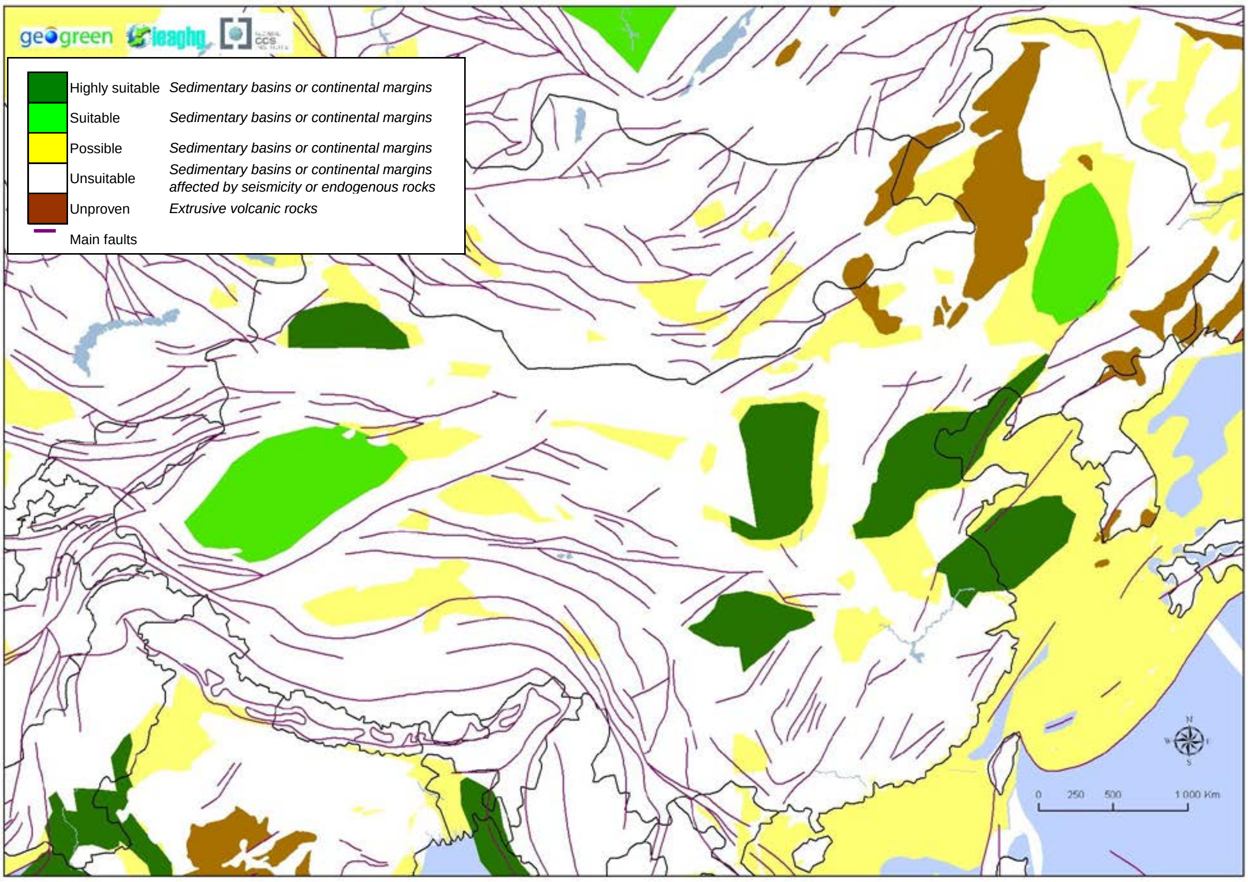

Figure 61: New assessment of storage suitability for China

A.2.2.4. South-East Asia

For the South-East Asian countries, the map from IPCC (Figure 53) was too global. The work presented by ICTPL [28] proposed some interesting details of the potential storage capacities at a country level.

Additionally the report from Pacific Economic Cooperation (APEC) on South East Asia countries [3] has also been used.

The work of Huh *et al* [27] and Dooley for PNNL [17] has been used for Korea.

The works of Best *et al* [5] and of Indonesia CCS working group [35] were used for Indonesia.

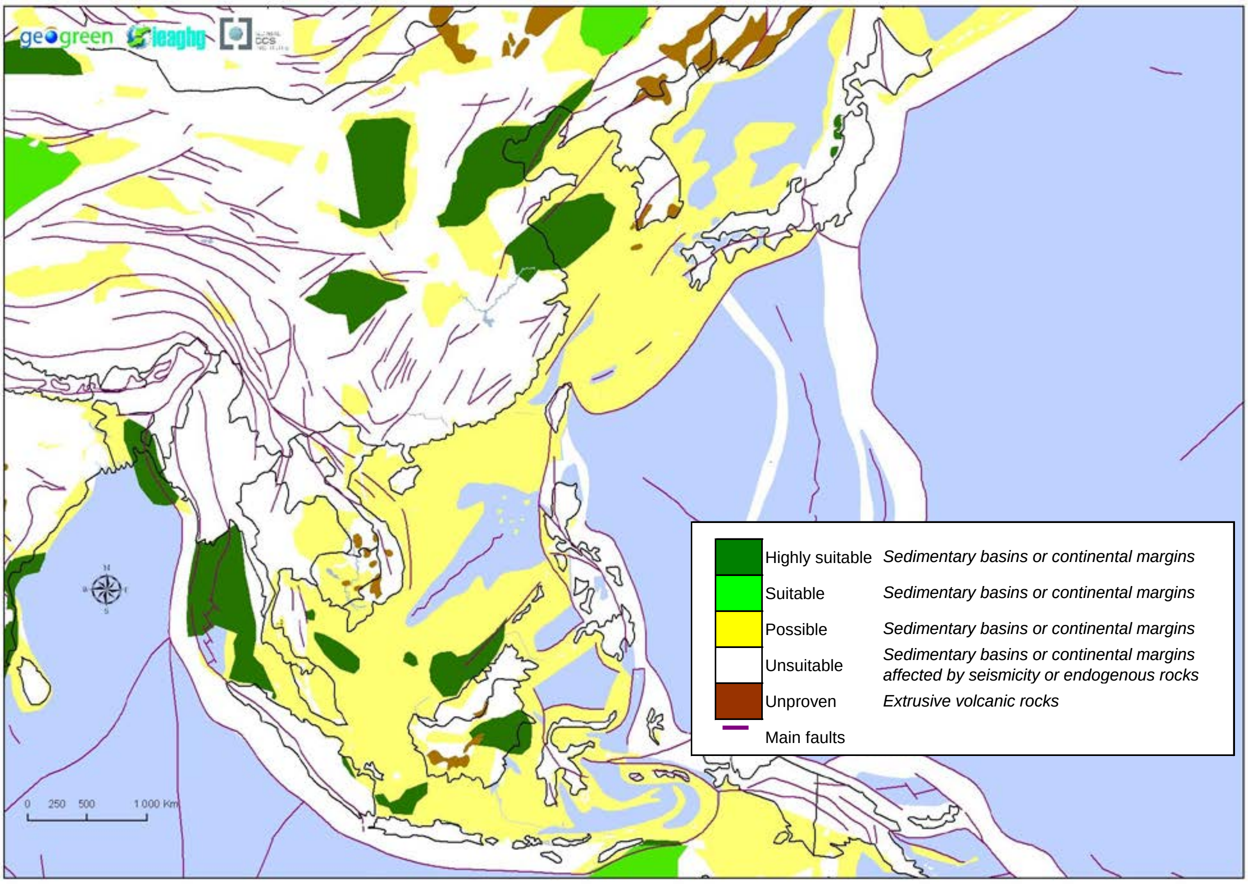

Figure 62: New assessment of storage suitability for South-East Asia

A.2.2.5. Europe

In Europe, the results from EU GeoCapacity project [20] were used. This project assessed European capacity for geological storage of CO_2 in following countries: Bulgaria, Croatia, Czech Republic, Denmark, Estonia, France, Germany, Greece, Hungary, Italy, Latvia, Lithuania, Netherlands, Poland, Romania, Slovakia, Slovenia, Spain, and UK.

The presentation of Carneiro [11] was used to improve the information about the Portuguese aquifers. The work of Okandan *et al* [50], and Ersoy [19] were used for Turkey.

The work of Wilkinson *et al* [60] improves the information about North Sea storage.

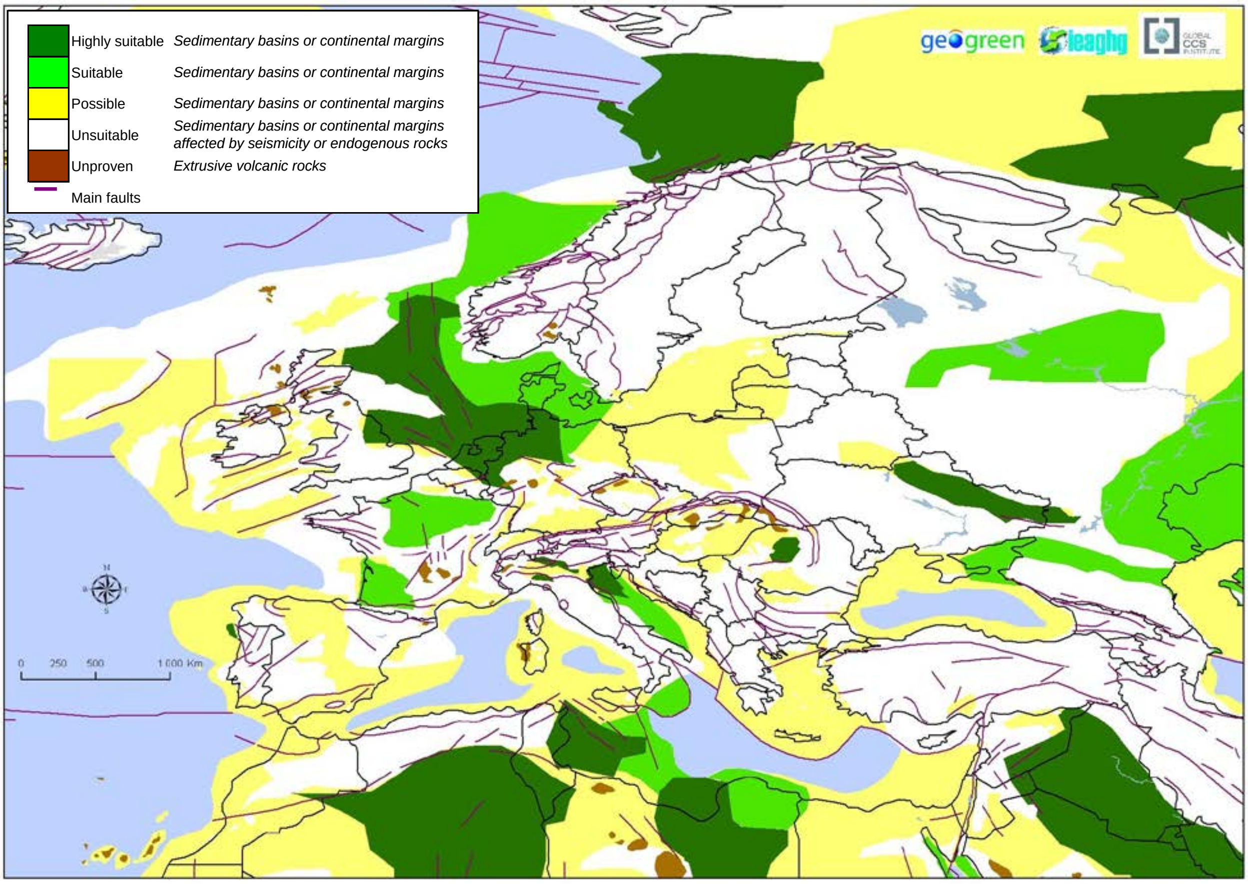

Figure 63 : New assessment of storage suitability for Europe

A.2.2.6. North America

The Carbon Sequestration Atlas of the United States and Canada edited by NETL was used for the US and North West Canada.

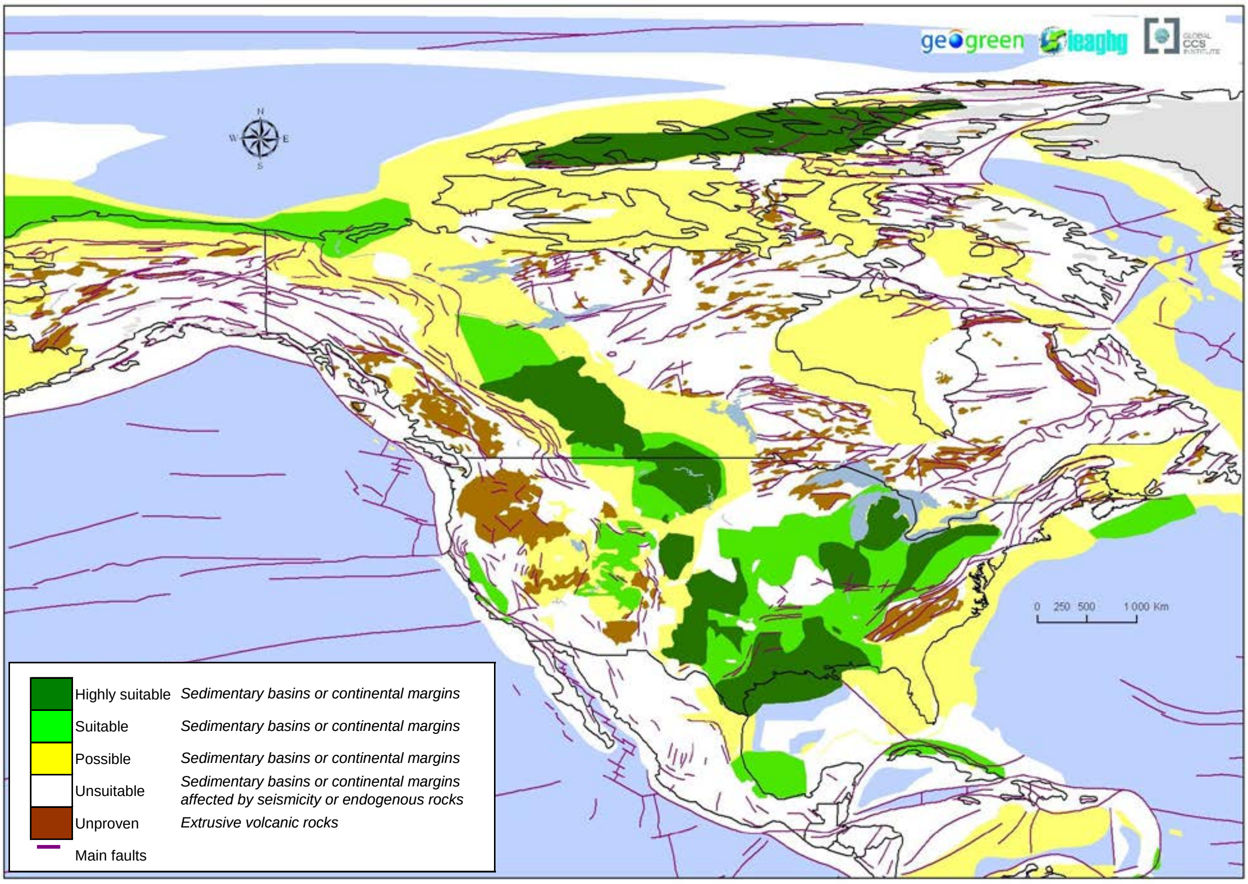

Figure 64 : New assessment of storage suitability for North America

A.2.2.7. South America

The most recent information about South America is focussed on Brazil. The data come from the project managed by PUCRS [39, 40].

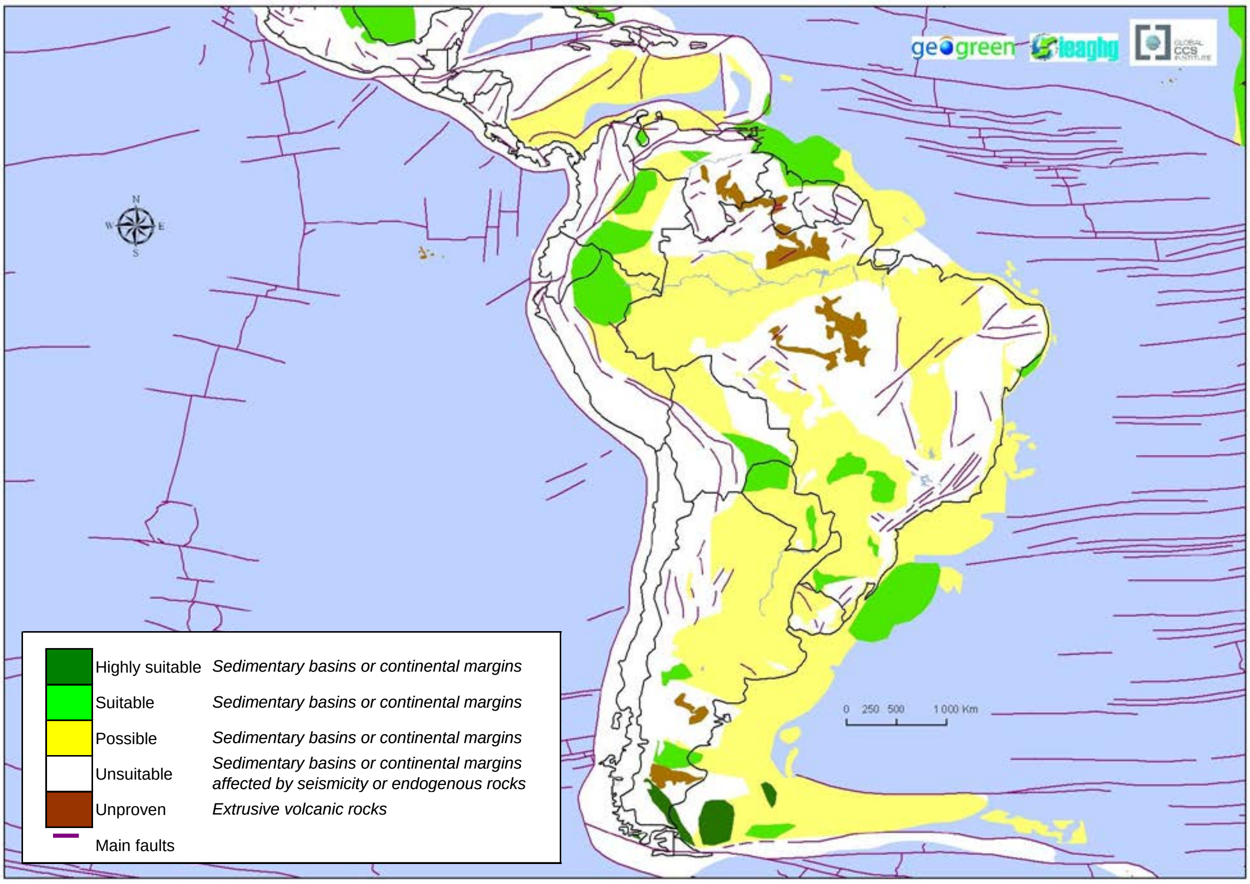

Figure 65: New assessment of storage suitability for South America

A.2.2.8. Africa

The main area studied for CO_2 storage is South Africa. The atlas information [13] from the carbon sequestration project financed by the Department of Minerals and Energy of South Africa and the CSIR has been used. The works of Campher *et al* [7], Cloete [13] and Viljoen *et al* [59] permitted to improve the information on South Africa.

A program is under development in Morocco but there is no information was made available at the time of the study.

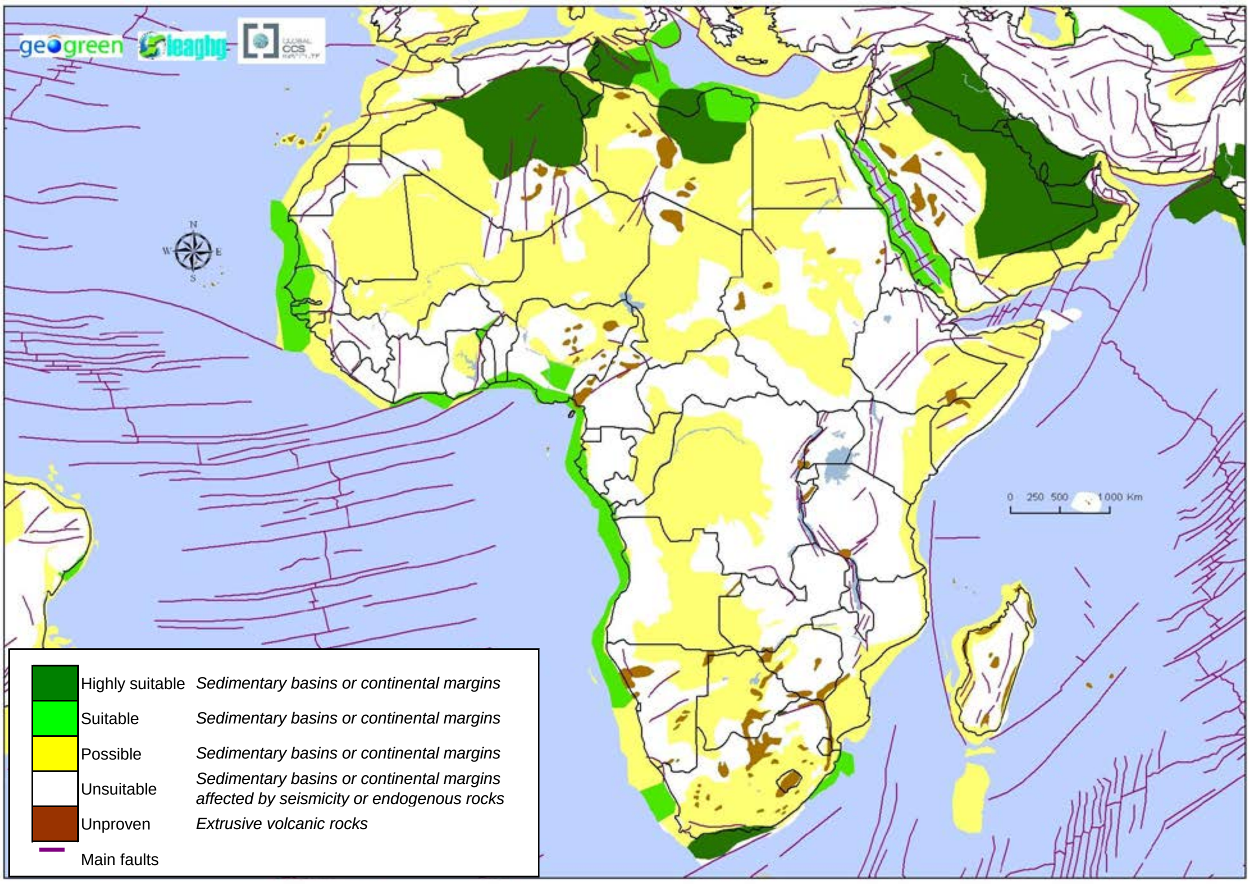

Figure 66: New Assessment of storage suitability for Africa

A.2.2.9. Middle East

There is not a lot of information on Middle East countries concerning CO_2 storage suitability.

To increase the precision in this area, the repartition of oil and gas field proposed by USGS was used.

As is detailed below the natural seismicity was used to precise the IPCC map (Figure 53). In the Middle East, Iran was classified as unsuitable area because of a very high seismic hazard except along the coast of the Persian Gulf.

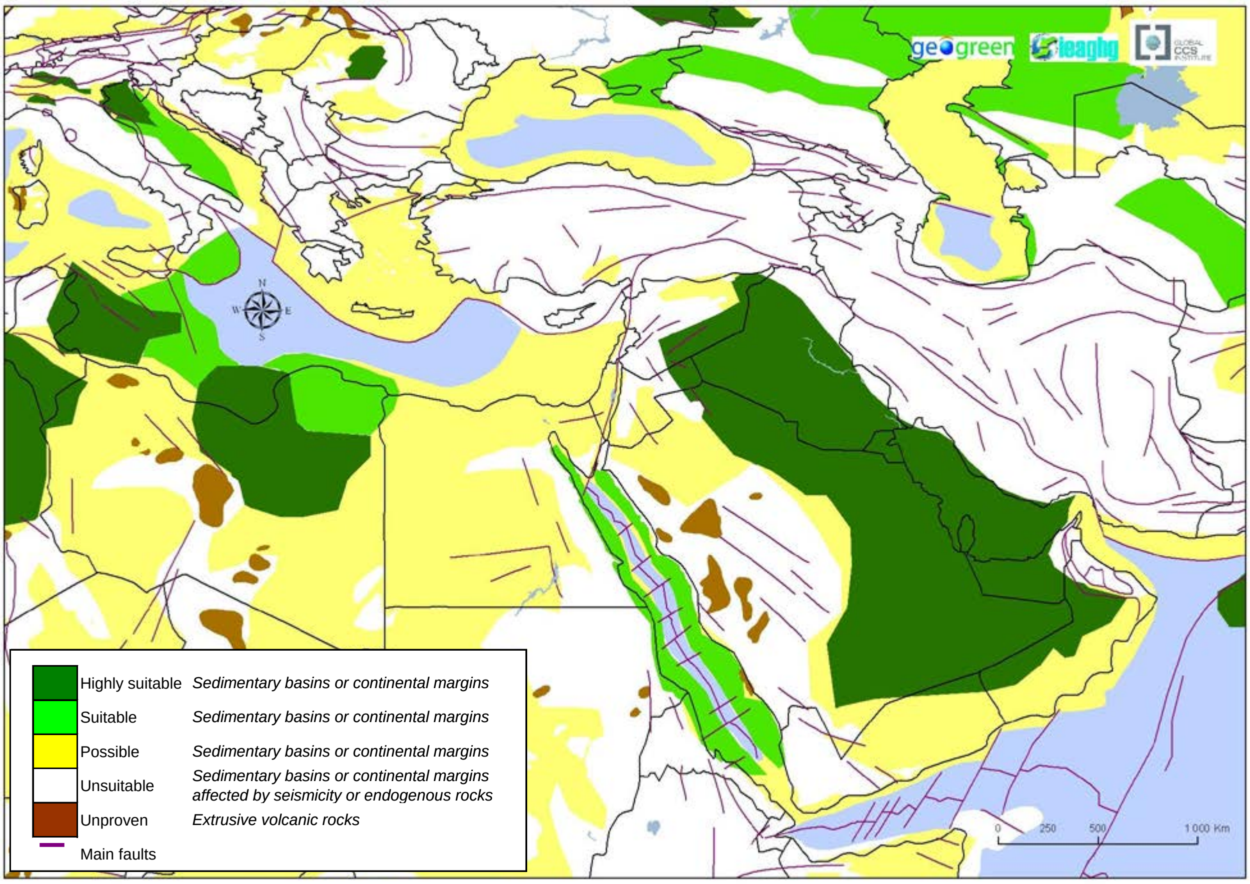

Figure 67: New Assessment of storage suitability for Middle East

A.2.3. Natural Seismicity

The natural seismicity being able to play a role into fault reactivation, areas potentially affected must be discarded from storage sites selection, because potentially leading to either some damage caused to the surface facilities of the storage, or to leakage through fault re-opening .

In the map below (Figure 68), all areas where the seismic hazard is qualified of "Very High" and "High" have been ranked as unsuitable.

This hypothesis is based on MSK scale[54].

[54] The MSK scale created in 1964, gets its name from three European seismologists Medvedev, Sponheuer and Karnik. It is a twelve levels scale based on: the intensity of the seism, the type of construction, the density of population at the moment when the seismic event occurs.

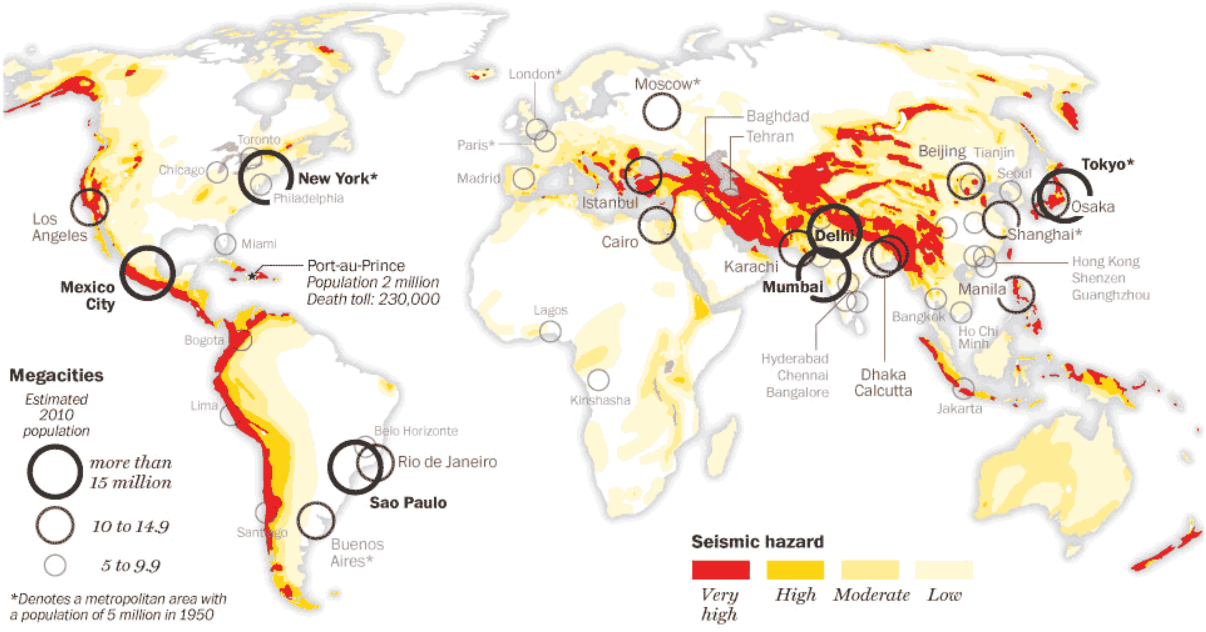

Figure 68 : World Seismic Hazard

SOURCE: Global Seismic Hazard Assessment Program, United Nations Population Division | Laris Karklis/The Washington Post - February 23, 2010

B. LIST OF SELECTED CCS PROJECTS FOR 2020 RECOMMENDATION

The following projects (Table 9) were selected from available databases (IEA GHG, Global CCS Institute, MIT, Bellona, Scottish Centre CCS and CO2CRC) on the basis their current status in February 2011 for bankability status at 2015-17 horizon. For some storage project, information about storage type and location were no publicly available at the time of the study

Table 9: List of projects in the storage database of the study as of February 2011

Region	Country	Project Name	Project Type	Geological Storage Type	On-/offsho
Asia	China	Ordos CTL 3Mt Demo	Integrated CCS	Porous media	Onshore
Asia	China	Lianyungang Ultra-critical PC Unit	Integrated CCS	EOR	Onshore
Asia	China	Japan-China Daqing CO2-EOR	Transport, Storage, and Valorisation	EOR	Onshore
Asia	China	PetroChina Jilin Basin CO2-EOR	Integrated CCS and Valorisation	EOR	Onshore
Asia	China	Subei Oilfield CO2-EOR	Transport, Storage, and Valorisation	EOR	Onshore
Asia	China	GreenGen - Phase III EOR Scenario	Integrated CCS and Valorisation	EOR	Onshore
Asia	China	Near Zero Emissions Coal for China (NZEC) Phase III	Integrated CCS and Valorisation	Porous media	Onshore
Asia	China	Gaobeidian Post-Combustion Capture Demo	Integrated CTV	Porous media	Onshore
Asia	South Korea	Korea-CCS1	Integrated CCS	Saline aquifer	NA
Asia	Malaysia	Bintulu CCS project	Integrated CCS	Saline aquifer	NA
Europe	Bulgaria	Maritsa	Integrated CCS	Saline aquifer	Onshore
Europe	Czech Republic	NW Bohemia Clean Coal	Integrated CCS	Saline aquifer	Onshore
Europe	Denmark	Aalborg (Nordjyllandsvaerket)	Integrated CCS	Saline aquifer	Onshore
Europe	Denmark	Kalundborg	Integrated CCS	Saline aquifer	Onshore Offshore
Europe	Finland	FINNCAP - Meri Pori (D)	Integrated CCS	EOR	Offshore
Europe	Finland	FINNCAP - Meri Pori (D)	Integrated CCS	Saline aquifer	Onshore
Europe	France	France Nord	Storage	Saline aquifer	Onshore
Europe	France	ULCOS	Integrated CCS	Saline aquifer	Onshore
Europe	France	C2A2 (Le Havre)	Integrated CCS	Combined	Offshore
Europe	France	C2A2 (Le Havre)	Integrated CCS	Combined	Onshore
Europe	Germany	Altmark Sequestration	Storage	Depleted gas field	Onshore
Europe	Germany	Janschwalde	Integrated CCS	Saline aquifer	Onshore
Europe	Germany	Greifswalde	Integrated CCS	TBD	Onshore
Europe	Germany	IGCC CCS	Integrated CCS	Saline aquifer	NA
Europe	Hungary	Matra CCS project	Integrated CCS	Combined	Onshore
Europe	Ireland	ULYSSES Sequestration	Transport and Storage	Saline aquifer	Offshore
Europe	Italy	Porto Tolle	Integrated CCS	Saline aquifer	Offshore
Europe	Italy	Carbo mine Sulcis	Integrated CCS	ECBM	Onshore
Europe	Italy	SEI - Saline Joniche	Integrated CCS	Saline aquifer	Onshore

Europe	Netherlands	ROAD (Rotterdam Afvang en Opslag Demo)	Integrated CCS	Depleted gas field	Offshore
Europe	Netherlands	Nuon Magnum IGCC	Integrated CCS	Depleted hydrocarbon field	Offshore
Europe	Netherlands	Pegasus	Integrated CCS	EOR	Offshore
Europe	Netherlands	Rotterdam CGEN (D)	Integrated CCS	Combined	Offshore
Europe	Netherlands	Essent Project (D)	Integrated CCS	Combined	Onshore Offshore
Europe	Norway	Karsto	Integrated CCS	Saline aquifer	Offshore
Europe	Norway	Sleipner	Integrated CCS	Saline aquifer	Offshore
Europe	Norway	Snøhvit CO2 Injection	Integrated CCS	Saline aquifer	Offshore
Europe	Norway	Halten CO2 Project (Draugen-Heidrun)	Integrated CCS	Combined	Offshore
Europe	Norway	Mongstad BKK (Mongstad)	Integrated CCS		Offshore
Europe	Poland	CCS Belchatow	Integrated CCS	Saline aquifer	Onshore
Europe	Poland	Kędzierzyn-Koźle	Integrated CCS	Saline aquifer	Onshore
Europe	Poland	Siekierki	Integrated CCS	Depleted oil field	Onshore
Europe	Romania	Romanian 500MW Project	Integrated CCS	Porous media	Onshore
Europe	Spain	La Robla	Integrated CCS	Saline aquifer	Onshore
Europe	Spain	OXY-CFB 300	Integrated CCS	Depleted oil field	Onshore
Europe	Turkey	Bati Raman	Storage	EOR	Onshore
Europe	United Kingdom	"Oxycoal 2" / Renfrew	Integrated CCS	Depleted hydrocarbon field	Offshore
Europe	United Kingdom	Hatfield	Integrated CCS	Depleted gas field	Offshore
Europe	United Kingdom	Scottish Power - Longannet and Cockkenzie Project	Integrated CCS	Depleted gas field	Offshore
Europe	United Kingdom	Peterhead Hydrogen Power Plant	Integrated CCS	Depleted hydrocarbon field	Offshore
Europe	United Kingdom	BP-Peterhead Hydrogen Power Plant/Miller Field Project	Integrated CCS	Depleted oil field	Offshore
Europe	United Kingdom	Kingsnorth	Integrated CCS		Offshore
Europe	United Kingdom	Tilbury Clean Coal Power Station (D)	Integrated CCS		Offshore
Europe	United Kingdom	DRYM (Onllwyn, South Wales)	Integrated CCS		Offshore
Europe	United Kingdom	E.ON Ruhrgas Killingholme IGCC	Integrated CCS		Offshore
Europe	United Kingdom	Eston Grange, Teeside (Northeast England)	Integrated CCS	Depleted gas field	Offshore
Middle East	United Arab Emirates	Masdar (D) (S)	Integrated CCS	EOR	onshore
Middle East	United Arab Emirates	Hydrogen Power Abu Dhabi (HPAD)	Integrated CCS	EOR	onshore
North Africa	Algeria	In Salah Gas Storage Project	Integrated CCS	Saline aquifer	Onshore
North America	Canada	CCS Nova Scotia Project	Integrated CCS	Saline aquifer	Onshore
North America	Canada	Fairborne Energy Clive CO2-EOR	Storage and Valorisation	EOR	Onshore

North America	Canada	Pioneer Demo Project	Integrated CCS	Saline aquifer	Onshore
North America	Canada	Husky CO2 Injection	Integrated CCS and Valorisation	EOR	Onshore
North America	Canada	Aquistore Project	Transport and Storage	Saline aquifer	Onshore
North America	Canada	Heartland Area Redwater Project (HARP)	Storage	Saline aquifer	Onshore
North America	Canada	Quest CCS Project (Storage Location)	Integrated CCS	Saline aquifer	Onshore
North America	Canada	Penn West Pembina CO2-EOR Project	Storage and Valorisation	EOR	Onshore
North America	Canada	Fort Nelson PCOR Project (Storage Location)	Integrated CCS	Saline aquifer	Onshore
North America	Canada	Zama (PCOR) Field Validation Test	Integrated CCS	EOR	Onshore
North America	Canada	Weyburn CO2 EOR (Cenovus Energy)	Storage and Valorisation	EOR	Onshore
North America	Canada	Apache Canada Midale CO2-EOR	Storage and Valorisation	EOR	Onshore
North America	Mexico	Pemex CCS	Integrated CCS and Valorisation	EOR	Onshore
North America	United States	Gulf of Mexico Miocene CO2 Site Characterization Mega Transect	Storage	EOR	Offshore
North America	United States	KGS Sequestration Project	Storage	Saline aquifer	Onshore
North America	United States	Rocky Mountain Storage Formation Characterization	Storage	Saline aquifer	Onshore
North America	United States	Terralog Wilmington Graben Offshore Storage Test (WESTCARB)	Storage	Saline aquifer	Offshore
North America	United States	Wyoming Storage Formation Characterization	Storage	Saline aquifer	Onshore
North America	United States	SECARB Saline Reservoir Test	Storage	Saline aquifer	Onshore
North America	United States	SWP Farnham Dome Deep Saline Sequestration (D)	Storage	Saline aquifer	Onshore
North America	United States	Cheshire CCS Demo (AEP)	Integrated CCS	Saline aquifer	Onshore
North America	United States	Entrada Injection Test at La Veta (SWP)	Storage	Saline aquifer	Onshore
North America	United States	FutureGen2.0 (Oxyfuel)	Integrated CCS	Saline aquifer	Onshore
North America	United States	PurGen One (Tri-State)	Integrated CCS	Saline aquifer	Offshore
North America	United States	Teapot Dome	Storage	Saline aquifer	Onshore
North America	United States	Two Elk Storage Characterization	Storage	Saline aquifer	Onshore
North America	United States	Wolfe County Deep Saline Test	Storage	Saline aquifer	Onshore
North America	United States	Black Warrior Saline (University of Alabama and Rice U.)	Storage	Saline aquifer	Onshore
North America	United States	Encore Bell Creek EOR Project	Storage and Valorisation	EOR	Onshore
North America	United States	Sandia Newark Basin Assessment	Storage	Saline aquifer	Onshore
North	United	Bakerfield EOR for HECA	Integrated CCS and	EOR	Onshore

America	States		Valorisation		
North America	United States	Citronelle Oil Field - SECARB Anthropogenic Test	Storage and Valorisation	EOR	Onshore
North America	United States	ADM Phase III Sequestration (MGSC)	Integrated CCS	Saline aquifer	Onshore
North America	United States	SECARB Early Test (Cranfield)	Storage and Valorisation	EOR	Onshore
North America	United States	Kimberlina Project Phase III (WESTCARB/CES)	Integrated CCS	Saline aquifer	Onshore
North America	United States	Mountaineer CCS Demo (AEP)	Integrated CCS	Saline aquifer	Onshore
North America	United States	Oyster Bayou CO2-EOR	Storage and Valorisation	EOR	Onshore
North America	United States	SWP Paradox Basin - Aneth Oil Field Test	Storage and Valorisation	EOR	Onshore
North America	United States	Michigan Basin Geologic Test (MRCSP)	Storage	Saline aquifer	Onshore
North America	United States	MGSC Sugar Creek CO2 EOR Hopkins County Test	Storage and Valorisation	EOR	Onshore
North America	United States	Rangely-EOR Project	Storage and Valorisation	EOR	Onshore
North America	United States	SACROC CO2-EOR	Storage and Valorisation	EOR	Onshore
North America	United States	Sharon Ridge CO2-EOR	Storage and Valorisation	EOR	Onshore
North America	United States	FutureGen 1.0 - Jewett	Integrated CCS	Saline aquifer	Onshore
North America	United States	FutureGen 1.0 - Tuscola	Integrated CCS	Saline aquifer	Onshore
North America	United States	Rosetta-Calpine Gas Storage Test (WESTCARB)	Storage	Depleted gas field	Onshore
North America	United States	Rosetta-Calpine Saline Storage Test (WESTCARB)	Storage	Saline aquifer	Onshore
North America	United States	TAME Phase III Large-Volume Injection (MRCSP)	Integrated CCS	Saline aquifer	Onshore
North America	United States	Taylorville IGCC (Tenaska)	Integrated CCS	Saline aquifer	Onshore
North America	United States	Shell Carbon Storage Project (Multi-source to Storage)	Integrated CCS	Saline aquifer	Onshore
North America	United States	C6 Resources Test Injection (Northern California CO2 Reduction Project)	Storage	Saline aquifer	Onshore
South America	Brazil	CO2 immiscible Buracica	Storage	EOR	Onshore
South America	Brazil	CO2 Injection TUPI	Integrated CCS	EOR	Offshore
South America	Brazil	Miranga	Storage	EOR	Onshore
South America	Venezuela	Maracaibo	Integrated CCS	Depleted oil field	Onshore
South America	Venezuela	San Joaquim	Integrated CCS	Depleted oil field	Onshore
Oceania	Australia	Browse LNG Development	Integrated CCS	Depleted gas field	Offshore
Oceania	Australia	Coolimba Coal	Integrated CCS	Depleted hydrocarbon field	TBD
Oceania	Australia	Callide-A Oxy-fuel Project	Integrated CCS	Depleted gas	Onshore

				field	
Oceania	Australia	Gippsland Storage Demo	Storage	Saline aquifer	Offshore
Oceania	Australia	Gorgon	Integrated CCS	Saline aquifer	Onshore
Oceania	Australia	Moomba CCS	Integrated CCS	EOR	Onshore
Oceania	Australia	Zerogen - Phase 2	Integrated CCS	Saline aquifer	Onshore
Oceania	Australia	Perth Demo	Storage	Saline aquifer	Onshore
Oceania	Australia	Surat Demo	Storage	Saline aquifer	Onshore

C. ONSHORE DSF COST MODEL ASSUMPTIONS

This appendix presents the probabilistic cost modelling of the different steps of the Deep Saline Formation onshore development workflow (section 4.2 page 58). The main properties of all cost functions used to model engineering costs, R&D costs up to bankability, and phases development items are presented in this section. The text refers to the different phases of storage development as explained in part 3.2.3 page 51.

C.1. Cost Phasing

C.1.1. R&D cost requirement for Storage project in first development years

R&D needs will evolve and are assumed to reduce with time. This evolution is taken into account in the cost model to calculate expected development costs or remaining development costs of a storage project from 2010 to at least 2020.

Actually, R&D is most needed in storage site development phase on methodological and technical standpoints. A “R&D cost requirement” factor curve has been developed to allow the expected calculation of R&D costs of each project within the period 2010 to 2030 when CCS is expected to reach full commercial deployment.

Before 2020, this R&D will mainly be supported by state aid or subsidies. After 2030, it is expected that R&D will still be needed but on a project basis at an industrial level. As such, R&D costs associated to a project development are decreasing with time.

As all costs are based on 2011 values, “R&D cost requirement” evolution factor is supposed to be equal to 1 in 2011.

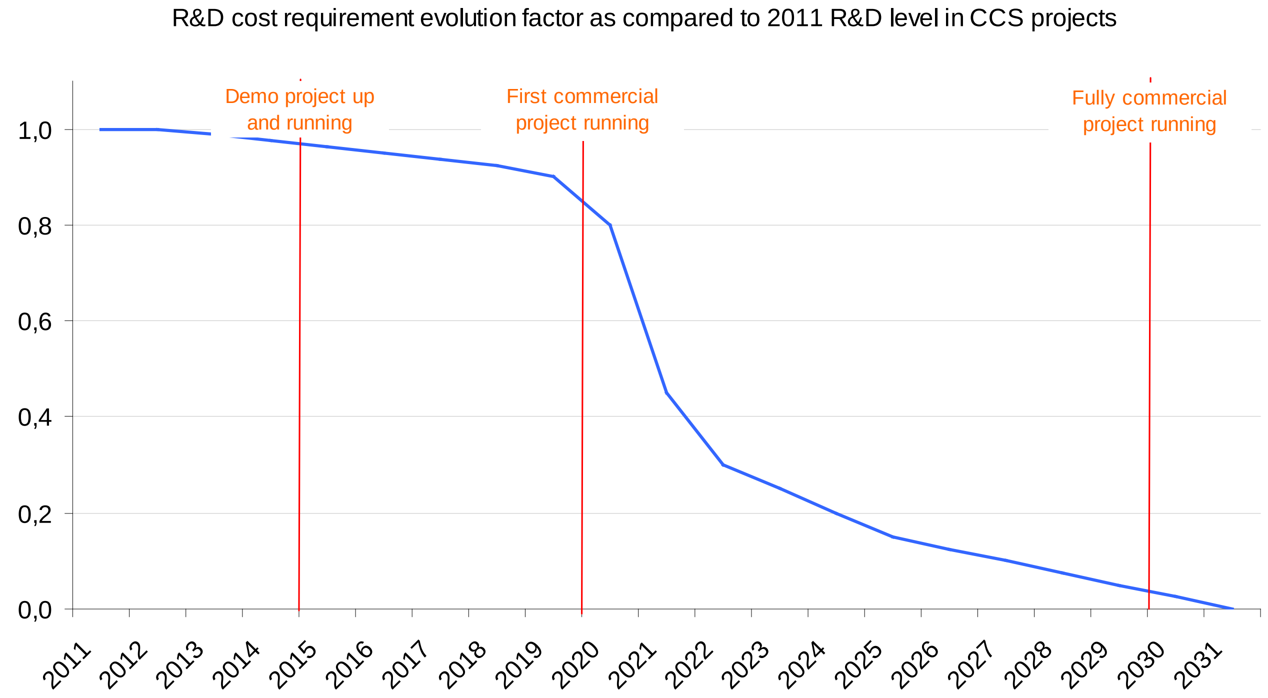

Figure 69: R&D needs evolution factor as compared to 2010 R&D needs

It is considered that R&D needs will remain strong until the first industrial demonstration projects come online in 2015[55]. These needs will start to slowly decrease as projects number increases and will then decrease sharply during early commercial deployment after 2020. Indeed, the main hypothesis is that first commercial deployment will happen when state R&D goals for CO_2 storage will be mostly achieved, and consequently R&D cost requirement will decrease.

C.1.2. Studies and Engineering for All Phases: Hypothesis and Modelling

This section only provides the hypothesis for costs estimates for the studies and engineering part of each phase. Details for the costs evaluation of field works are provide in next sections.

Studies and engineering are performed all along storage site bankability assessment. Moreover, as detailed in previous section, R&D works is strongly present in all phases during CCS first development years (2015 to 2020).

Costs of desk based engineering and studies have been mainly estimated using Geogreen own database. Average cost for each phase is representing a fair estimate of studies cost for

[55] In Europe, the NER 300 fund first call should finance 6 to 8 projects that have to start operating by end 2015. In the USA, CCS task force announced that up to 10 commercial demonstration projects should be financed by 2016.

several projects based in Western Europe. Geogreen then estimated the low and high ranges values for these studies. Probabilities distributions have been then determined to match these values. Geogreen assumed that lognormal type distributions properties where appropriate to model most of these costs distributions. Indeed, it allows a larger drift of the values beyond the average (long tail distribution). This represents the possible cost drifts in studies if unforeseen issues occur.

C.1.2.1. Phase 0 - Screening

As stated previously for projects of storage in aquifers, this phase is a non exclusive survey on a regional or national basis. Some countries have already achieved this phase like the USA with the Natcarb atlas[56,57], the EU with Geocapacity project[58], and Australia with the CCS Task Force[59]. Other countries are performing such assessments at the time of the study (South Africa, Brazil) as illustrated in Figure 12.

Associated with this state funded studies, R&D developments are taking place on these assessments projects. These are the two mains costs items for this phase.

Following IEA GHG website, public funding for above cited programs are:

- US DOE for Natcarb: 6M$
- EU for Geocapacity: 2.6M€

For this kind of project, public funding generally represents between 25 and 100% of overall project cost. The remaining cost is often funded by project participants.

Funding varies greatly from country to country. It is difficult to foresee the cost of these first desk based assessments for this phase in all regions. For the sake of simplicity, we have chosen to use a statistical uniform distribution to represent the cost variations and the uncertainty about their final cost.

Geogreen assessed that the limits of this cost distribution for a country the size of France or Germany are as follows:

- Min: 0.5M€
- Mean: 0.75M€
- Max: 1M€

The associated R&D program cost has been calculated as a factor of this first desk based assessment. A log normal distribution has been used to represent this factor:

- Min: Studies cost * 1/3 (25% funding)
- Mean: Studies cost * 1 (50% funding)

[56] NETL, Carbon Sequestration, Atlas of the United States and Canada, 2nd Edition, NETL, 2008
[57] PCO2R, PCOR Partnership Atlas, 3rd Edition, Energy & Environment Research Center (EERC), NETL, 2009
[58] EU Geocapacity, Assessing European Capacity for Geological Storage of Carbon Dioxyde, EU Geocapacity, 2009
[59] Carbon Storage Taskforce, National Carbon Mapping and Infrastructure Plan – Australia: Concise Report, Department of Resources, Energy and Tourism, Canberra, 2009

- Max: Studies cost * 2 (100% funding)

It is then multiplied by a country factor as discussed in Appendix F of this document.

C.1.2.2. Phase 1 – Desk Based Assessments

From this phase onward, costs are project specific (exclusive studies) led by industrials or group of industrials.

After the state led Phase 0 studies to perform a source-sink matching, specific studies are needed to identify a storage site and assess its characteristics. This work is performed during Phase 1 through reprocessing of seismic data and existing well logs in order to build geological 3D storage complex models. This phase allows also identifying missing information for complete storage complex characterization.

From Geogreen in-house database on European projects, the cost of this phase is around 1.5M€. Geogreen estimated that the low range is half of this cost and the highest range twice this estimated cost. We associated a lognormal statistical distribution to these values.

As for Phase 0, important R&D program will be performed during early years of deployment. Geogreen estimated these needs between 0.5 to 2M€ with an average of 1M€. We applied the same distribution as for Phase 0 costs.

Costs have then to be adjusted following R&D curve defined in section C.1.1 and with country cost factors that will be discussed in Appendix F of this report.

C.1.2.3. Exploration license

After this Phase 1 and if the gathered elements enable a positive decision, the project will proceed to Licensing Phase. Administrative engineering and follow-up is estimated to cost between 0.2 and 0.7M€ with an average of 0.3M€. A lognormal distribution has also been applied to these costs. Indeed, administrative engineering costs may drift if there are complications in the licensing process. It is particularly possible for the first demo projects.

C.1.2.4. Phase 2 – Site confirmation and characterization

In this phase, three main cost items have been identified:

- Studies and engineering
- Seismic acquisitions either 2D or 3D
- Well drilling, data acquisition (and water production test for aquifer projects)

The studies and engineering in Phase 2 consists in the engineering of the confirmation program, the processing and analysis of acquired data, the update and correction of Phase 1 built model as well as the definition of injection test strategy and baseline acquisition.

Additionally, an important part of the program concerns R&D needs, particularly to establish assessment methodologies, monitoring strategies and to test and develop appropriate monitoring technologies.

The studies and engineering costs have been modelled with a log normal distribution with an average of 3M€, a 10 percentile of 2 and 90 percentile of 4.5M€ whereas associated R&D program in 2011 is modelled by a lognormal distribution (Average=2M€; 10p=1; 90p=3,5M€).

It is noteworthy to mention that communication costs are included in these costs.

C.1.2.5. Injection Test Licensing

Prior to injection test, an authorization is supposed compulsory in most regions. Obviously, preliminary work to obtain this authorization will differ between competent authorities and countries. We assumed the same cost distribution as for the exploration license.

C.1.2.6. Phase 2 - Injection Test

As previously, studies and engineering costs have been estimated for the associated studies and monitoring. A normal distribution was assumed to represent these costs.

It is noteworthy to mention that R&D program is considered as, at least, twice as expensive as studies and monitoring costs. It is modelled with a lognormal distribution to represent the possible drifting cost of new technologies and methodologies testing.

C.2. Cost Items

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C.2.1. Seismic Surveys

Seismic acquisitions will be needed during exploration and characterization phase. However, the number of kilometres that needs to be acquired depends greatly upon the global knowledge of the underground in the studied area (that is to say, the possibility to obtain data from previous underground exploration). Indeed, fewer acquisitions will generally be needed in heavily explored area than within area where limited exploration took place.

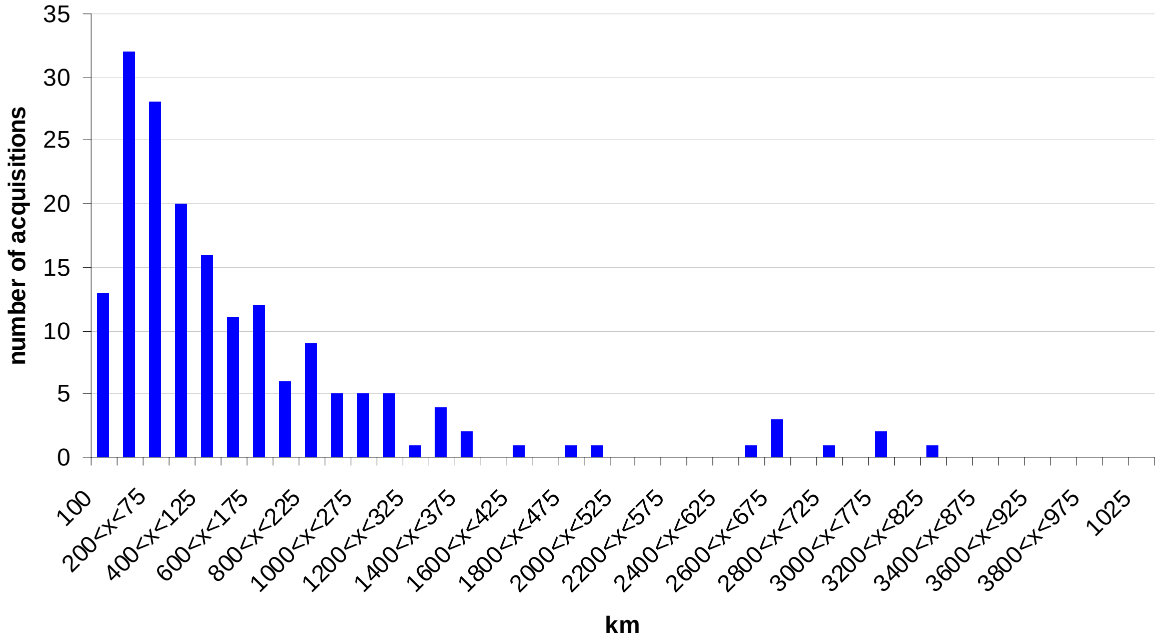
The models developed take into account the suitability of the area (detailed in Appendix A) where the project is developed. We supposed that due to a better geological knowledge, less data acquisitions is necessary in highly suitable area than in possible areas.

Similarly, there are fewer contingencies to drill in heavily explored Oil and Gas areas since geological context is already quite well characterized.

C.2.1.1. 2D Seismic Surveys

2D seismic is needed to improve structural model definition. Depending on the area where the project is located, 2D seismic acquisitions might have been partially or totally performed over the storage complex (area of review).

In order to determine a probability distribution of the number of kilometres generally acquired during a 2D seismic survey, Geogreen used APPEA[60] data base of Australian 2D seismic campaigns from 1993 to 2009. After appropriate data processing, the acquisitions length (in km) distribution is presented in Figure 70 below:



Source APPEA

Figure 70: Onshore 2D acquisitions length distribution (km)

According to Figure 14, the sedimentary basins in Australia (where the data come from) are ranked mainly as being highly suitable to suitable for CO_2 storage. Geogreen decided to define the Australian available data as a basis for suitable area. From the historical distribution, an analysis allowed defining a model distribution for the length of seismic acquisitions in suitable area. A lognormal distribution with a mean of 147 (same as the historical one) and with 10[th] and 90[th] percentiles equalling 20 and 328 respectively seems to fit well the historical data as shown in Figure 71.

[60] Australian Petroleum, Production & Exploration Association http://www.appea.com.au/industry/statistics.html

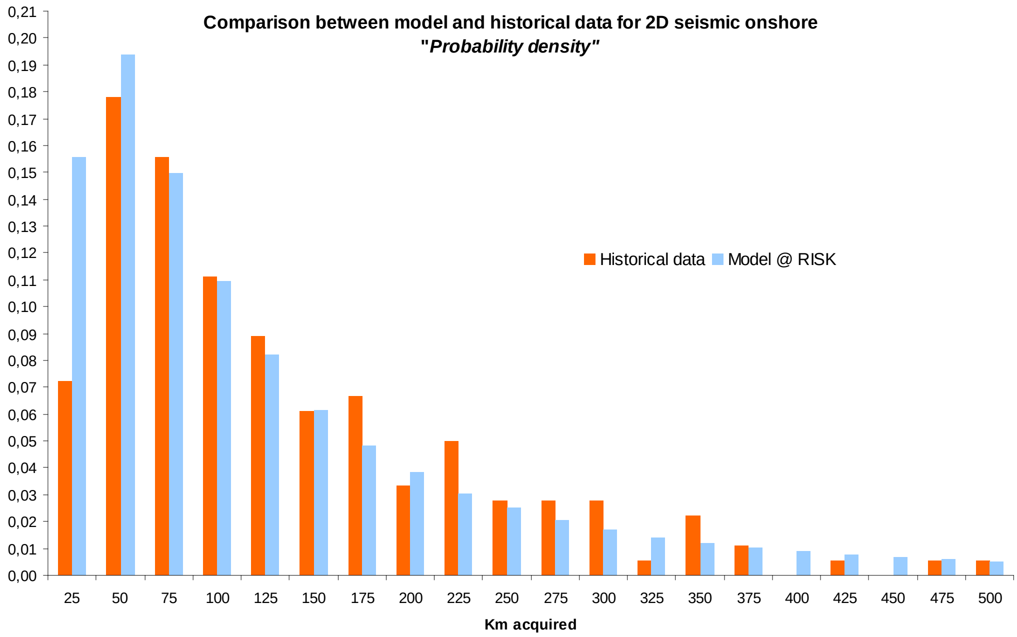


Figure 71: Comparison between model and historical data for 2D seismic acquisitions onshore in moderately explored area

To finally represent actual 2D seismic acquisitions length in function of the "area suitability status", the distribution mean is simply shifted between the different areas. In highly suitable areas, the distribution has been shifted by 25km below the "moderately explored" average. For the possible suitability status categories, the distribution has been shifted by 100km above the "suitable area" average. Figure 72 gives the main parameters of the four distributions as well as the shape of the distribution.

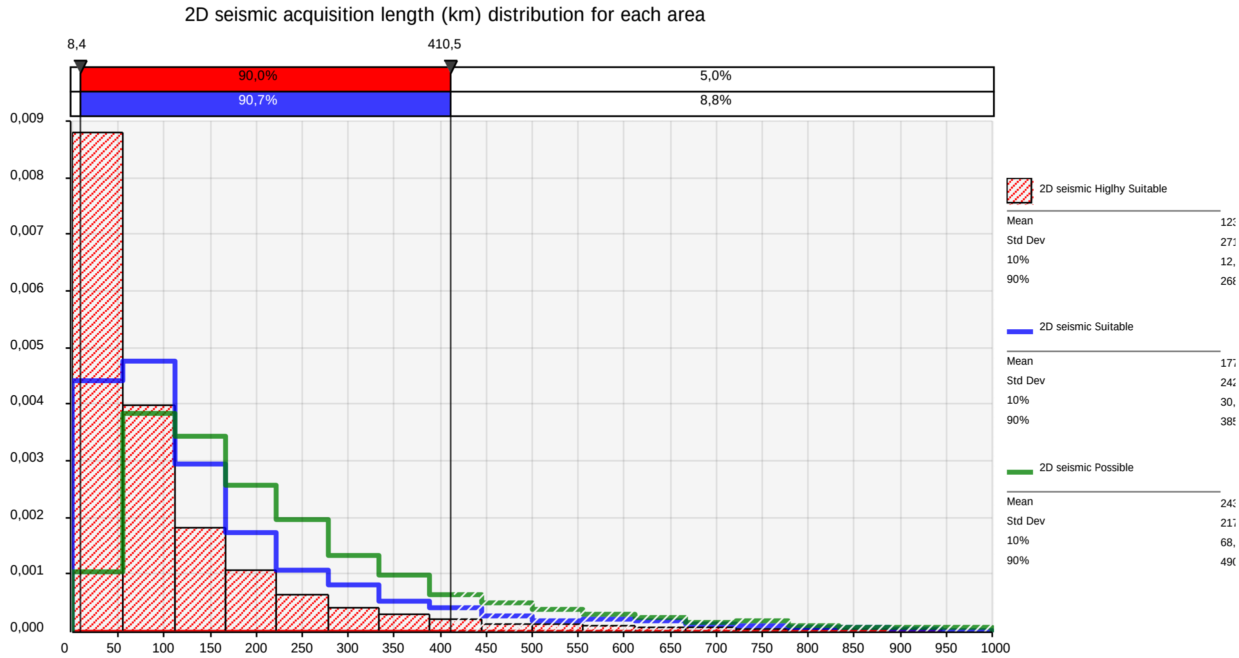


Figure 72: 2-D seismic acquisition distribution for all O&G explored area

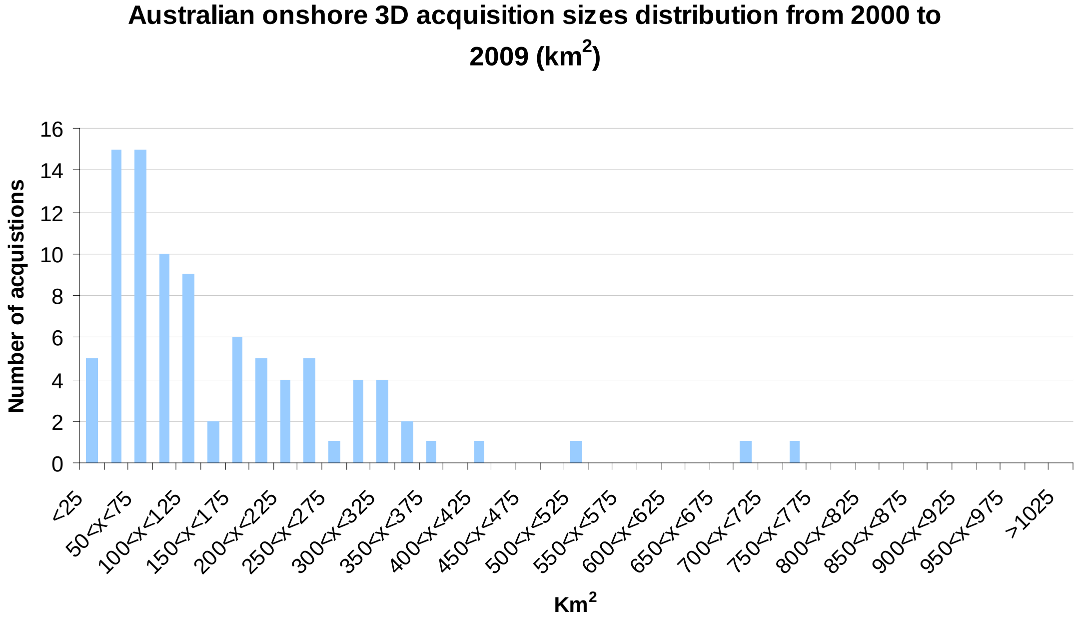
The 2D seismic acquisition cost has been calculated from recent 2D surveys costs in Europe. A normal distribution with the following properties has been chosen to model cost variation:

- 10th percentiles – corresponding to low range encountered: 11 000€/km
- Mean – corresponding to average cost encountered: 13 000€/km
- 90th percentiles – corresponding to high range encountered: 15 000€/km

These costs include equipment mobilization/demobilization. This hypothesis introduces a small distortion since it tends to underestimate the cost for small acquisitions while it slightly overestimates it for large ones. Cost factors have been introduced to take into account the regional differences (see Appendix F).

C.2.1.2. 3D Seismic Survey

A 3D seismic survey will also be needed to fully characterize the structure of the storage complex (area of review). Geogreen used the same data base (APPEA data base) as for the 2D seismic surveys. The onshore 3D seismic acquisition size is given below for Australia between 2000 and 2009.



Source APPEA

Figure 73 : Australian 3-D seismic acquisition size distribution from 2000 to 2009

One can see on this figure that the main part of the distribution is located below 125km^2. The use of 3D seismic for CO_2 storage site characterization makes it difficult to imagine that less than 100km^2 (square of 10km*10km) are acquired. Indeed, this acquisition will be used as a baseline for storage site monitoring (on top of structural characterization needs). For the same reason, this acquisition is independent to the fact that the area is suitable or not.

Taking into account the fact that the plume might extend over few kilometres, a 100km^2 3-D seismic acquisition is a minimum. In order to take into account this parameter, the original distribution has been shifted to place its 10th percentiles to 100km^2.

Figure 74 shows the probability density and gives the main properties of the chosen model for 3D seismic acquisition sizes.

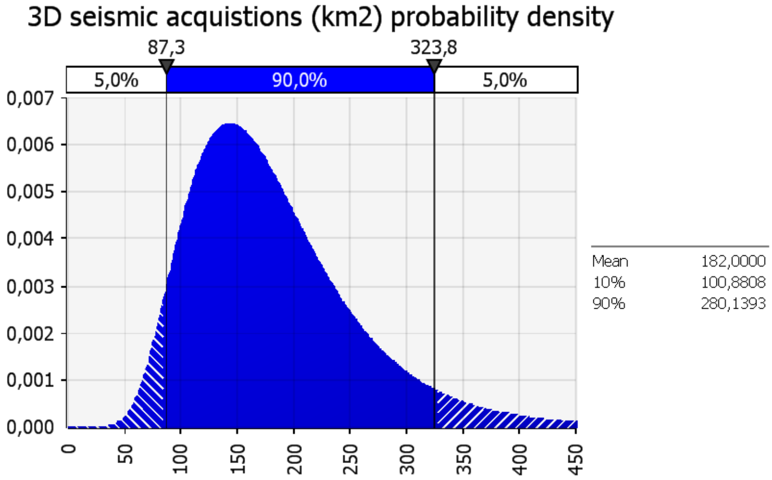


Figure 74: 3-D seismic acquisitions model probability density

Figure 75 shows the comparison between the model and Australian historical data (2000-2009) for 3D acquisition sizes onshore.

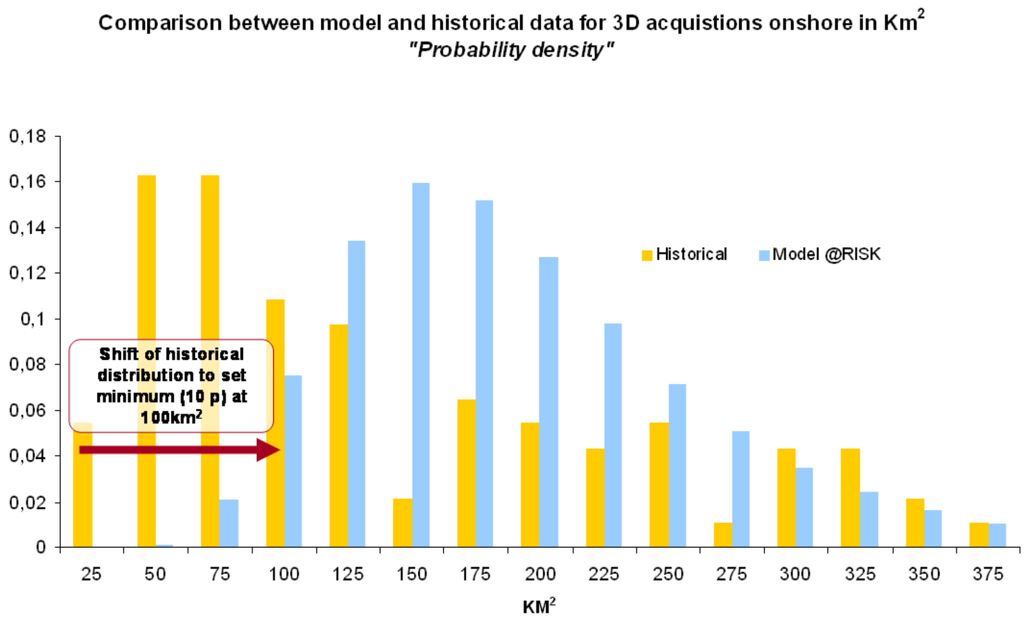


Figure 75: Comparison between model and Australian historical data for 3-D acquisitions onshore km^2

As for 2D seismic costs, 3D seismic costs have been calculated from recent surveys in Europe. A normal distribution with the following properties has been chosen to model cost variations:

- 10th percentiles – corresponding to low range encountered: 30 000€/km
- Mean – corresponding to average cost encountered: 40 000€/km
- 90th percentiles – corresponding to high range encountered: 50 000€/km

These costs include equipment mobilization/demobilization. As for 2D seismic acquisition, this hypothesis introduces a small distortion since it has a tendency to underestimate the cost for small acquisitions while it slightly overestimates it for large ones.

C.2.2. Drilling CO_2 Well

Well drilling will be needed to locally calibrate the analysis and obtain data on storage complex and targeted reservoir, cap rock, and control levels, through coring and well logging.

The drilling process and needs are described in section 4. As described in the storage development workflows up to bankability a minimum of two wells and up to 6 wells might be drilled to confirm storage bankability. If no technical hurdles are encountered two wells are expected to be drilled (one injector + one monitoring) in order to be able to perform and monitor injection tests.

C.2.2.1. Civil Engineering

Civil engineering costs are estimated from recent works in Europe. The chosen distribution is a lognormal one with the following parameters:

- 10th percentile – corresponding to low range: 0.1M€
- Mean – corresponding to average cost: 0.2M€
- 90th percentile – corresponding to high range cost in limited access area: 0.5M€

C.2.2.2. Drilling Cost

Drilling costs are depending on many parameters. It is critical to determine which are the most important to be modelled in order to define a realistic distribution for these costs. The CO_2 injection well cost were recently estimated in Australia [10].

This estimation took into account several parameters such as:

- Well depth
- Drilling time
- Rig and support/service daily rate
- Steel cost for well completion (a CO_2 injection completion have been designed within the cost model)

As it is not the purpose of this cost model to create a CO_2 injection well cost model, Geogreen simplified the well cost model from the Australian Carbon Storage Taskforce [10]. However, some key regional inputs are changed according to drilling regional market costs (see Appendix F).

The key parameters selected for the cost model are the following:

- Well depth
- Drilling time
- Rig and support/service daily rate
- Multiplying factor allowing finding well total cost from the rig and support/service total cost (function of the daily rate and the drilling time). It is based on calculated total well costs [10].

The first step was to create a well depth distribution. Once again, APPEA publicly available data were used to estimate this distribution.

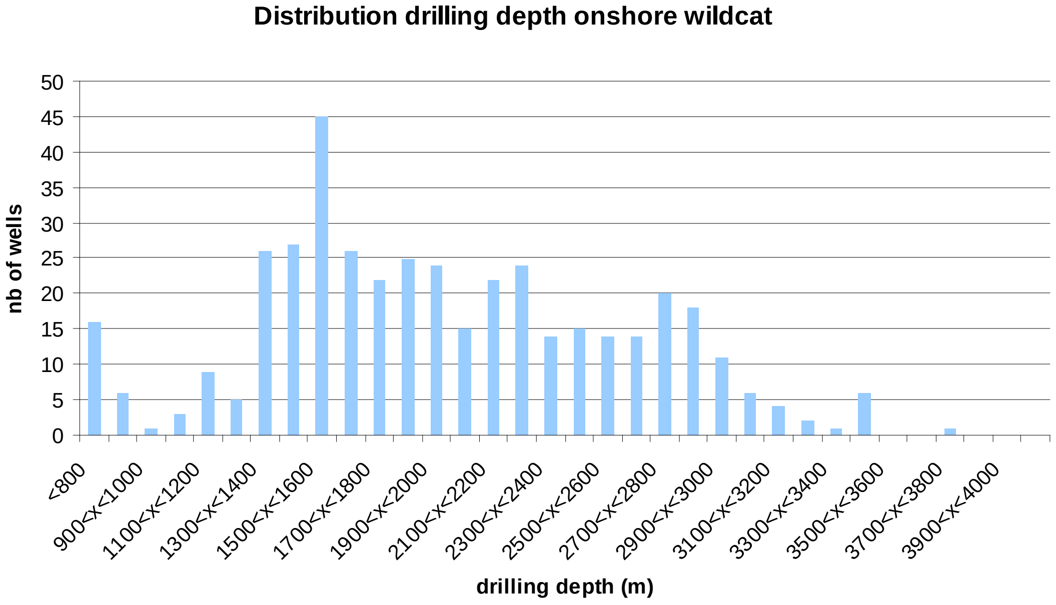


Figure 76: Drilling depth distribution for wildcat well in Australia 2000-2009

As Australia is a vast country presenting diversified geological structures, this distribution will be used for worldwide extrapolation.

The matching distribution for the drilling depth model is a log normal distribution with the following characteristics:

- 10th percentiles – corresponding to low range: 1 100 meters
- Mean – corresponding to historical average: 2 000 meters
- 90th percentiles – corresponding to high range: 3 000 meters

However, this distribution has been cut off at 800 meters since, above that limit CO_2 cannot be stored in its supercritical phase which is not appropriate for industrial scale CO_2 storage.

Figure 77 shows the matching between Australian historical data and modelled distribution.

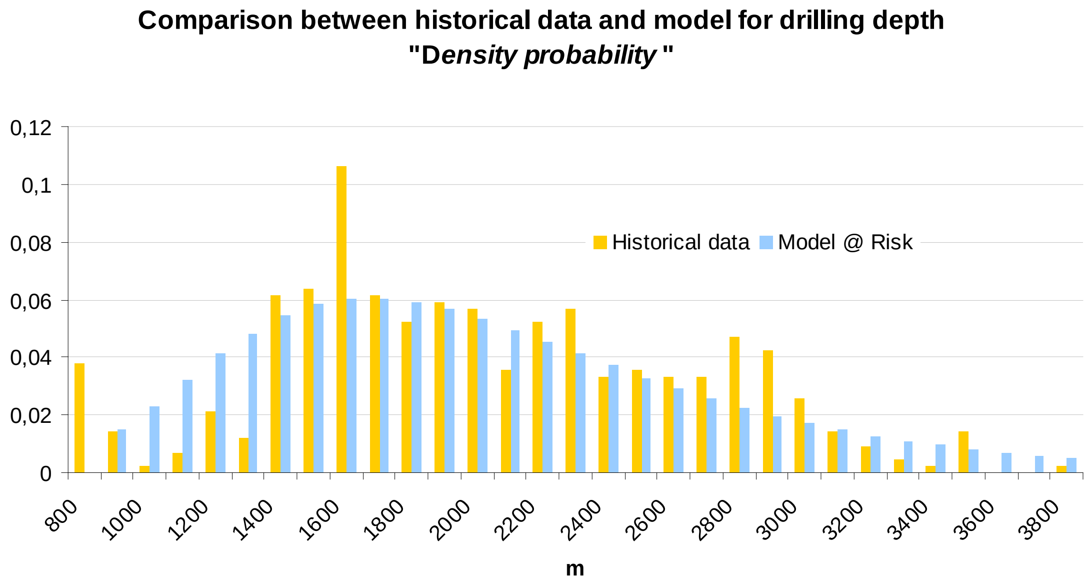
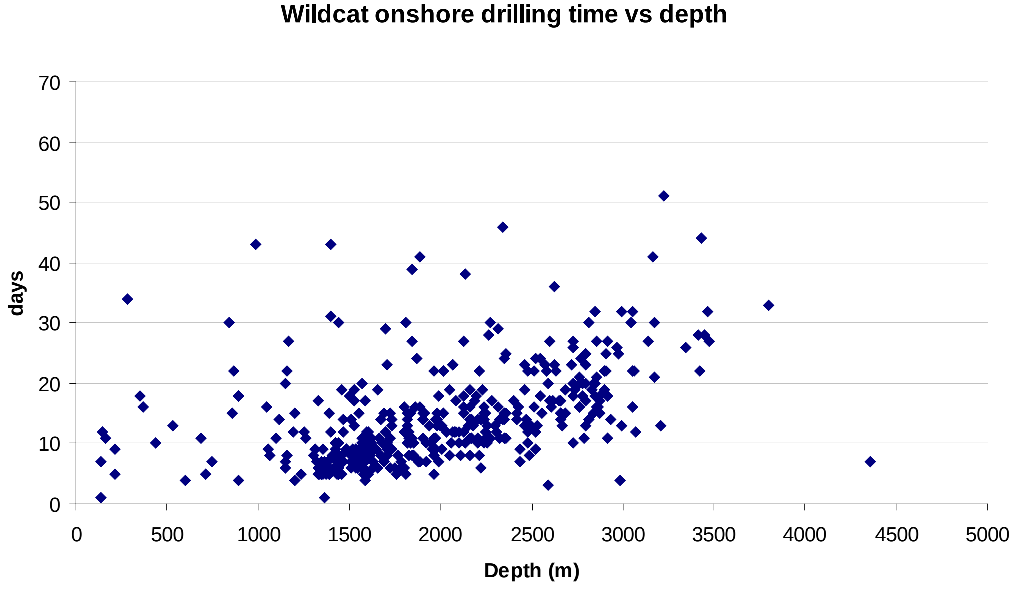


Figure 77: Comparison between Australian historical data and model for drilling depth

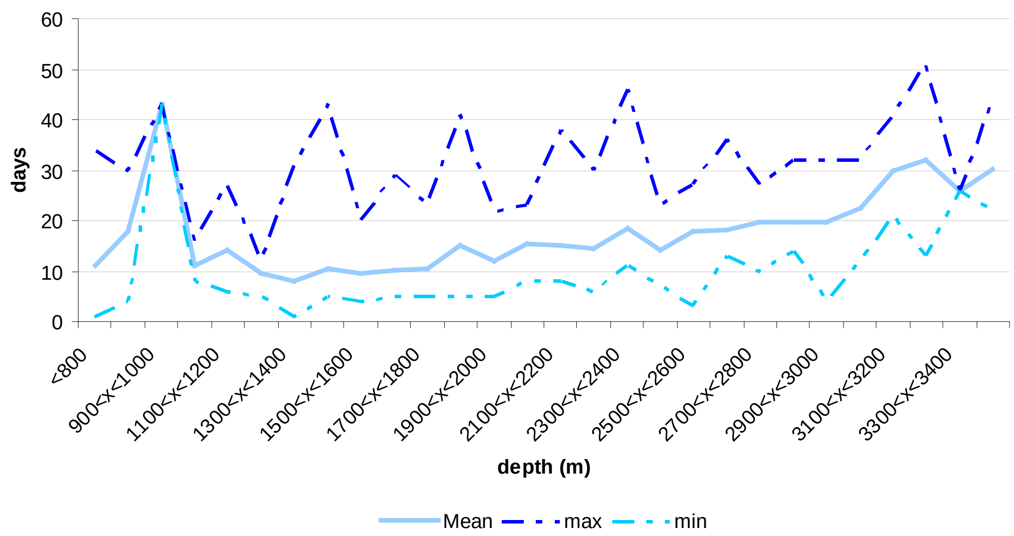
Time needed to complete the well obviously increases with depth as shown in Figure 78. This figure shows the drilling time in function of well depth for Australian onshore wildcat. As explained below, this type of wells have little to do with CO_2 injectors. However, this is the only available data to build mathematical correlation between depth and drilling time. This correlation will then be corrected to take into account the longer drilling time of a CO_2 well. The next step computes the relationship between drilling time and well depth even if it is highly random has can be seen in Figure 78.



Source APPEA

Figure 78: Wildcat onshore drilling time versus depth

APPEA data have been sorted out in order to identify the average, minimum and maximum drilling time in the range 800 to 3500m. The result is shown below[61]:



Source APPEA

Figure 79: Averag drilling time per well for onshore wildcat

[61] It is noteworthy to mention that these charts have been cleaned from out of scope data (corresponding to suspended well drilling)

From Figure 79, there is an important variation between values. The maximum value for a given depth can be 200% higher than the average and the minimum can represent only 50% of average drilling time.

A linear regression has been performed on the average values. As mention earlier, the O&G wildcat well drilling time data shown in Figure 79 have little to do with CO_2 injection well drilling time. There are generally less coring and logging performed for an O&G wildcats than for a CO_2 storage site assessment. Therefore the mean value was corrected to increase drilling time for coring and logging purpose.

As for 2D seismic acquisitions, drilling time is more or less dependent on existing exploration status. Indeed, when an area is already well explored, drillers will know better how to deal with each geological layer. The map presented in Figure 14 was used to determine in which area each project is located before running the storage development workflows. As the historical data average linear regression is at the low end of what we can expect for a CO_2 well, we decided to assign it to highly suitable areas. Finally, and in order to be consistent with previously chosen hypothesis, the same factor as for 2D seismic acquisition between each exploration area has been chosen (see section C.2.1.1).

Following these remarks, the characteristics of modelled functions for drilling time are as follows:

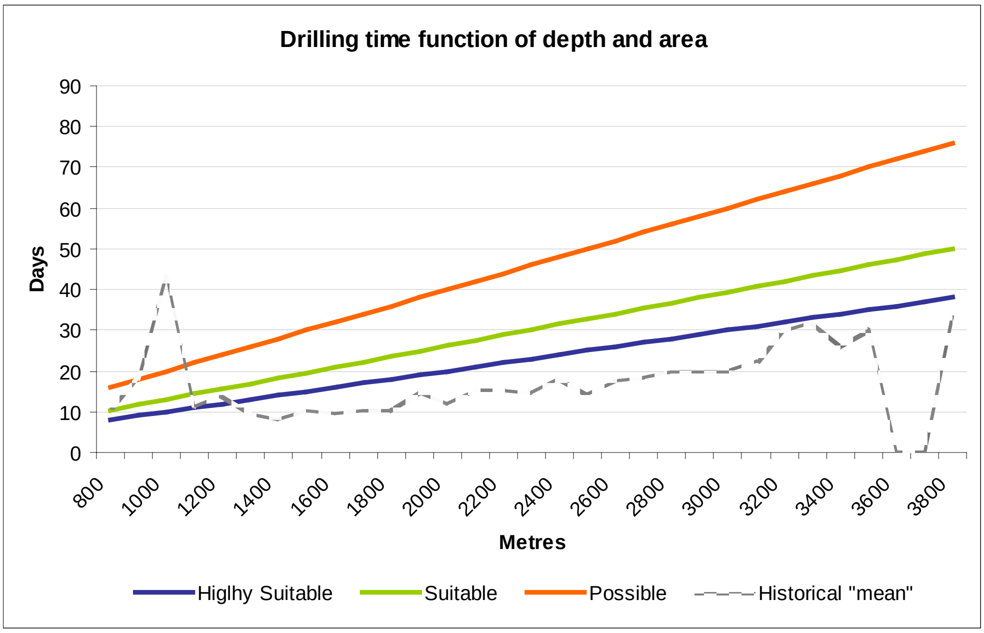


Figure 80: Drilling time versus time - model

These linear functions are then multiplied by a log normal distribution with the following characteristics to model uncertainties around drilling time as shown on Figure 79:

- 5th percentiles – corresponding to -50% (max =-50% from average): 0,5
- Mean – corresponding to average: 1
- 95th percentiles – corresponding to +100% (max=+200% over average): 2

C.2.2.3. Contingency for Drilling Time

Contingency for drilling time evolves with the number of wells drilled. It decreases when more wells are drilled. Classical ratios are assumed for this contingency:

- Intensely and moderately explored area contingency for the first well: 10%
- Partially and un explored area contingency for first well: 25%

These contingencies halve for each new well.

C.2.2.4. Rig and Service/Support daily rate

A normal distribution centered on average encountered costs has been chosen:

- 10th percentiles – corresponding to low range: 20 000€/day
- Mean – corresponding to average: 30 000€/day
- 90th percentiles – corresponding to high range: 40 000€/day

C.2.2.5. Mob/demob

A normal distribution centered on average encountered costs has been chosen:

- 10^{th} percentiles – corresponding to low range: 750 000€
- Mean – corresponding to average: 1 000 000€
- 90^{th} percentiles – corresponding to high range: 1 250 000€/day

C.2.2.6. Multiplying Factor to Obtain Final Well Cost

Geogreen used Carbon Storage Taskforce analysis [10] to determine a factor between their calculated costs (with CO_2 injection completion depending on steel price) and the rig + service/support total cost for each well. Carbon Storage Taskforce analysis [10] defined two scenarios for Rig and associated service/support rate: One for a low oil price (50$/bbl), and one for high oil price (100$/bbl). Taking into account current global context, only the 100$/bbl rate scenario was used. The following Figure 81 gives an overview of the difference between the scenarios as well as the difference between final CO_2 well costs [10] and rig+support daily rate function of the depth. One can see that curves evolutions are correlated with each other, which justifies the use of a multiplying factor.

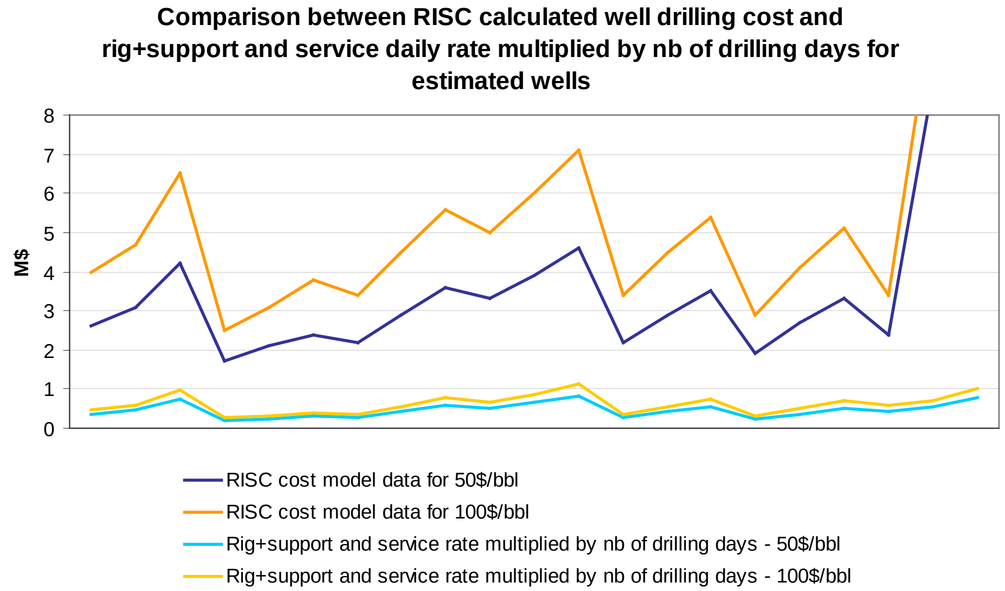


Figure 81: Comparison between Carbon Storage Taskforce well cost and rig + support/service cost for each well

The regression on this factor is shown below (Figure 82) and is well fitted by a logarithmic function:

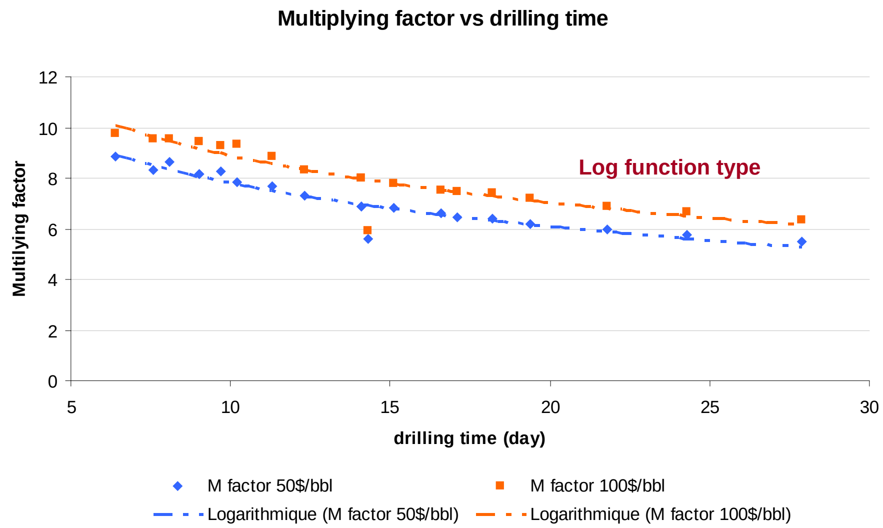


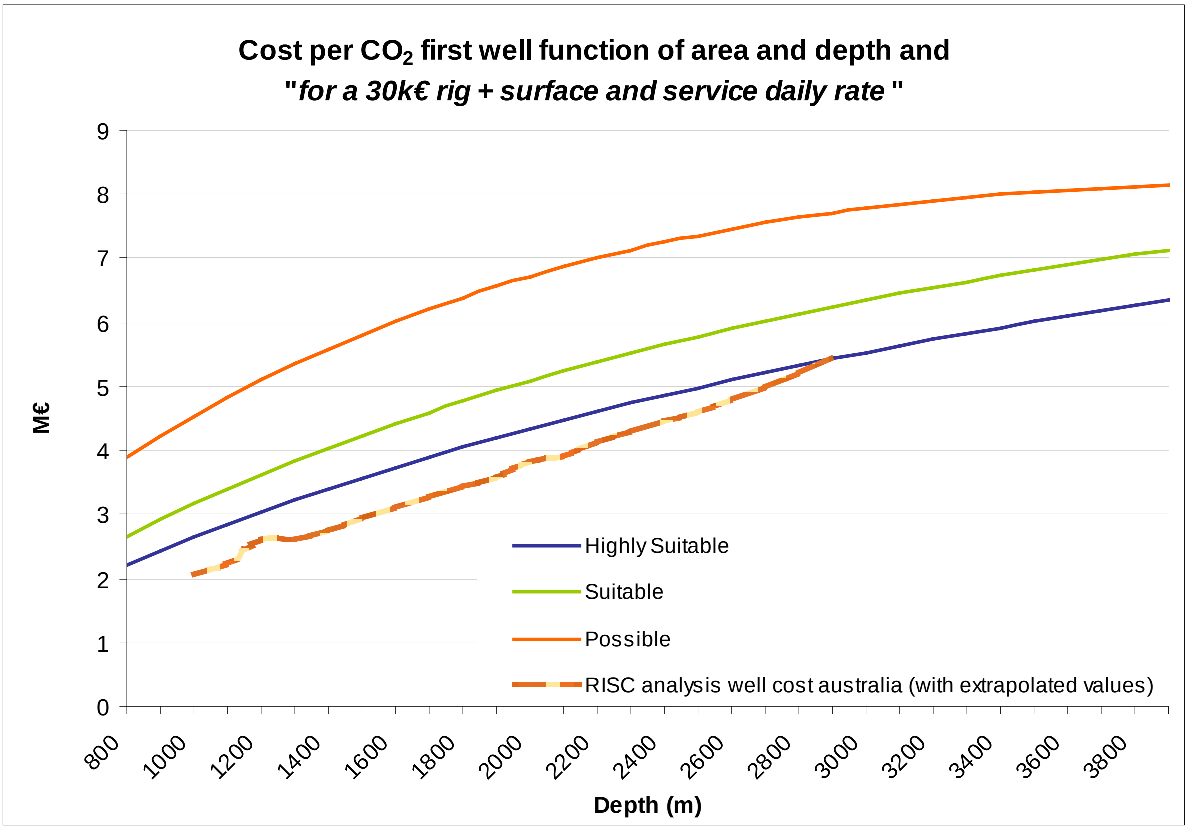
Figure 82: Multiplying factor vs drilling time

C.2.2.7. Final Drilling Cost

The final drilling cost is found by multiplying the drilling time plus the corresponding contingency (function of drilled depth) per the rig + support/service daily rate (depending on each area – see Appendix F) and per the multiplying factor.

It is noteworthy to mention that first drilled well is more expensive since it includes a higher contingency as well as the rig mob/demob costs. Indeed, the model removes 0.5 M€ to the second and third well drilling costs.

Figure 83 shows the average cost of a first CO_2 well function of drilled depth and suitability status. It considers a rig + support daily rate of 30k€. It also gives the calculated cost for Australian CO_2 injection well drilling[62] [10]. Carbon Storage Taskforce calculated cost [10] is lower than the current calculated cost partly because the wells are not in the same locations. Indeed, the drilling costs presented are for Europe. Correction factor will be applied to correct regional disparities for drilling and seismic equipment.



Note: A conversion rate of 1.3 dollar/euro was used

Figure 83: Cost model per wildcat well function of area and depth

Figure 84 below presents the CO_2 wild cat well costs distribution in suitable areas following the hypothesis explained above

[62] Some extrapolations have been made from original data to be able to plot the graph

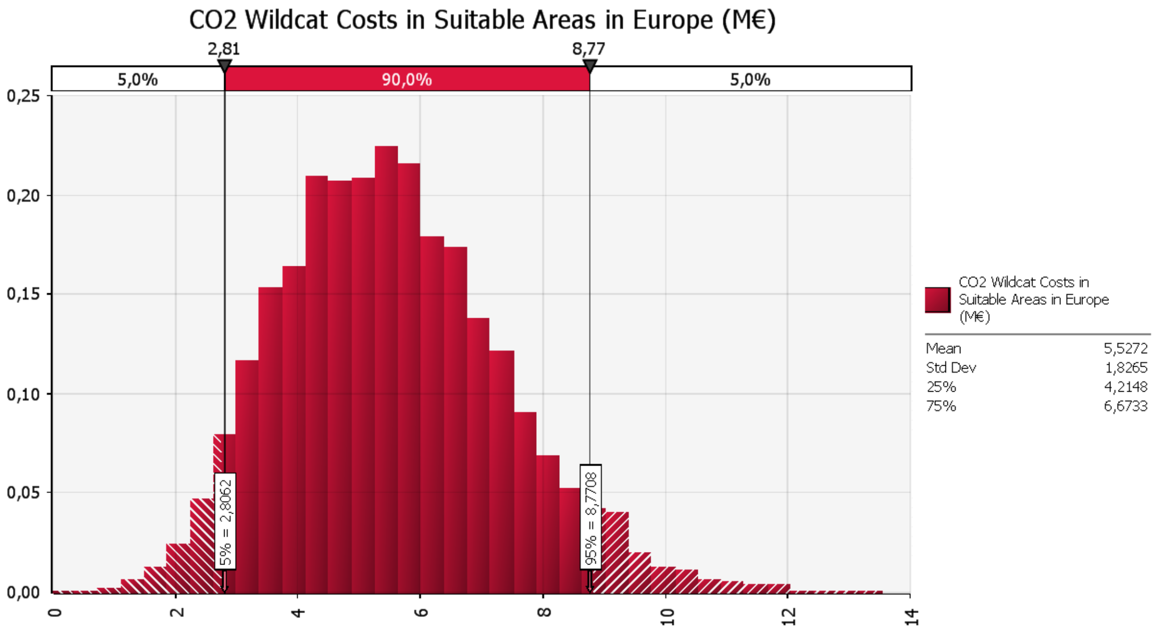
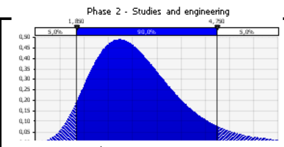
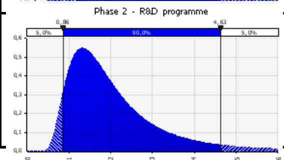
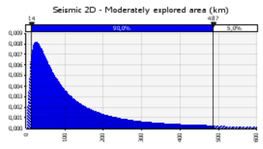
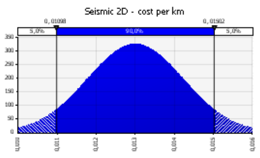
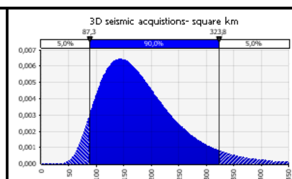
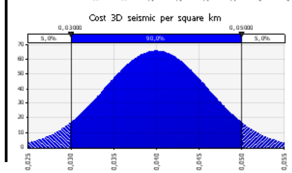
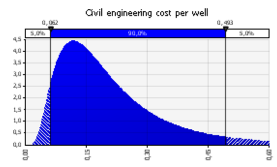
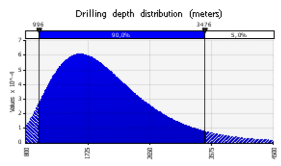
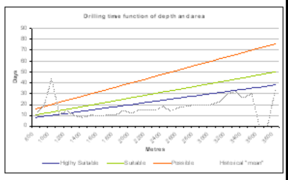
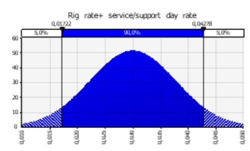
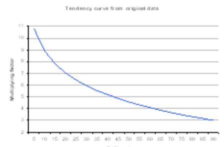


Figure 84: CO_2 wildcat costs distribution in suitable areas in Europe

C.2.2.8. Synthesis of cost calculations for phase 2 – Confirmation and Characterization

A synthesis of all hypotheses made to build phase 2 cost models is given in Table 10.

Table 10: Model synthesis of Phase 2 - site confirmation & characterization

Phase	Item taken into account into simulation	unit	Low range (P10 or min)	Mid range	High range (P90 or max)	Type of distribution	Comments
Cost for an European onshore storage site assessment in 2010							
Phase 2 - Site confirmation & characterization	**Studies and engineering for this phase (including monitoring actions, equipments and monitoring)**	M€	2	3	4,5		Described previsouly
	R&D program on methodology and monitoring techniques during CCS first deployment years	M€	1	2	3,5		Described previsouly
	Seismic acquisitions 2D						
	Number of kilometers acquired						
	In highly suitable areas	km	*12*	*122*	*276*		Same distribution but mean shifted -25 km
	In suitable area	km	*20*	*147*	*328*		Lognomal distribution based on historical data
	In possible area	km	*40*	*197*	*417*		Same distribution but mean shifted 150 km
	Cost per kilometers (including eventual damage)	M€	0,011	0,013	0,015		Normal distribution based on European average 2D seismic acquisitions costs per km (Mob/demob considered included into cost)
	Total	*M€*	***Multiplication between "number of kilometers acquired" (function of suitability area status where the project is located) and "cost per kilometers"***				
	Seismic acquisitions 3D (on CO_2 future plume only)						
	Number of square kilometers acquired	Km^2	100	180	280		Done only to focus on future CO_2 plume. It is considered that a square of 10*10 km is a minimum to fulfill this purpose. A lognormal distribution hs been used to model the acquired surface
	Cost per square kilometers (including eventual damage)	M€	0,03	0,04	0,05		Normal distribution based on European average 3D seismic acquisitions costs per km^2 (Mob/demob considered included into cost)
	Total	*M€*	***Multiplication between "number of square kilometers acquired" and "cost per square kilometers"***				
	Civil Engineering						
	Cost per well	M€	0,1	0,2	0,5		Lognormal distribution
	Total cost	*M€*	***Multiplication between "number of wells" and "cost per well"***				
	Drilling CO_2 well (including Mob/demob; coring; logging; completion)						
	Drilling Depth	m	1 100	2 000	3 000		Log normal distribution defined on historical data with a cut off to exclude all values below 800 meters
	Drilling time per well		For 1000m drilled		For 3500m drilled		Linear function
	In highly suitable areas	*day*	*10*		*35*		Same factor between each "Suitability Status" area than for 2D seismic acquisitions
	In suitable area	*day*	*12*		*42*		
	In possible area	*day*	*16*		*56*		
	Contingency for drilling *(decreasing for each new well)*						
	Contingency first well	*% day*	*10%*		*25%*		10% for Highly and Suitable areas 25% for Possible
	Contingency second well (if any)	*% day*	*Half of previous contingency*				
	Rig + service/support daily rate	M€/day	0,02	0,03	0,04		Normal distribution. Average defined as RISC analysis Rig+serice/support rate 100$/bbl case
	Multiplying factor *(between Rig+service/support cost for a well and total well costs following RISC analysis for CO_2 well drilling)*			*LN function from RISC analysis*			Ln function from RISC analysis
	Total drilling costs	M€	***Addition of each well costs. Each well costs are different because of the contingency rate which is decreasing after each new well drilling. Moreover, drilling rig mob/demob is taken into account only for the first well (0.5M€). Well costs: Multiplication between "Rig + service/support daily rate", the "Drilling time per well" (function of drilled depth and Suitability Statusof the area) and "multiplying factor" for each well.***				

C.2.3. Phase 2 – CO_2 injection tests

Injection tests are the last step for full site characterization before assessing the storage site bankability in the hypothesis of a stringent regulation scenario (see section 4.1 page 57). It is necessary to verify pressure and flow behaviour inside the storage formation and to qualify capacity and injectivity of storage site. These parameters will have a key influence on the economics of the future industrial injection site since they control the number of wells required to accommodate the industrial flow rate.

CO_2 availability for injection test is a major driver for tests costs. Indeed, the capture plant planning is studied generally to start commercial operation when the storage site is ready. Therefore, CO_2 from the plant might not be available for the injection test and the CO_2 will have to come from other sources. These sources can be other CCS projects but in the first years of development very few of these sources will be available. Other possibilities are existing industrial sources of CO_2 used for food market for example. These sources are not necessarily located closed to storage site. All these options have different costs and logistic issues. That is why we identified three main possibilities for injection test CO_2 procurement. We assigned probabilities to each scenario as follows:

1. A capture facility located nearby the storage site is able to provide CO_2 for injection test. We considered that actually, only 10% of the storage sites present this characteristic.
2. No capture facility or CO_2 source is located nearby the storage site:
    a. A capture facility related to the project is available for storage site test in vicinity of the storage site (few hundred kilometres). Taken into account the small number of projects already developed, we considered that actually, only 20% of the storage sites present this characteristic.
    b. No capture facility related to the project is available for storage site test in vicinity of the storage site. For the same reasons than in the previous case, we considered that actually, 70% of the storage sites present this characteristic.

The following paragraphs describe the cost calculations for the three cases

C.2.3.1. Onsite Capture Facility for Injection Testing

In this case, the CO_2 can be transported to the site directly per pipeline since the distance is considered, in <u>this model</u>, inferior to 10km[63]. Indeed, even if there is a risk of the storage site evaluation not to be successful (i.e. storage site is not bankable or does not offer sufficient economic performance to start industrial injection), laying a pipeline for a short distance is less expensive than transporting liquefied CO_2 per truck.

The cost of capturing CO_2 is not considered in the cost model since it is attributed to the capture facility project costs. Costs considered in this case are only the pipeline laying and onsite piping and valves system. Cost distribution was modeled with a cost of 0.5M€ per kilometer for a distance between 2 and 10kilometers.

[63] In practice a case by case analysis has to be performed to determine the threshold where laying a pipeline offers better economics than transporting liquefied CO_2 per trucks.

C.2.3.2. Capture Facility for Injection Testing

When capture site is too distant from injection test site, a liquefied CO_2 transport must be envisaged. Truck transport has been considered. To calculate CO_2 injection test costs, test duration is a key parameter.

It has been considered that injection will last between 6 and 18 months. Thus, for injection testing, it has been estimated that between 5 and 15 trucks per day would be needed. As each liquefied CO_2 transport truck can transport about 23 tonnes of CO_2, the range of CO_2 volume necessary for injection testing is between 10 000 and 120 000 tonnes of CO_2 over injection testing period.

As CO_2 has to be injected in supercritical state and to be able to test different injection flow rates, on-site surface storage tanks and pumps are needed. The size of these tanks and pumps depends upon injection test strategy. Individual buffer storages (surface tank) of 30 to 50 liquefied CO_2 tonnes cost between 0.2 and 0.5M€. Taking into account additional piping and pumps for supercritical injection, the minimum cost of the injection test facility is around 1M€. It may reach up to 3.5M€ with several surface tanks.

C.2.3.3. Capture facility related to the project

As in the first case, when a capture facility is related to the project, no cost has been considered for the CO_2 provision. Only liquefied CO_2 transport costs are added to the injection test facilities costs in that case. From in-house data base, cost of CO_2 transport daily costs are:

- 100 km, 5 trucks a day: 3 000 €/day
- 200 km, 10 trucks a day: 8 000 €/day
- 300 km, 15 trucks a day: 15 000 €/day

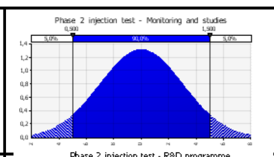
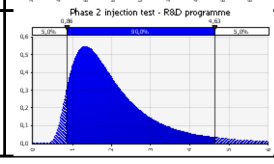
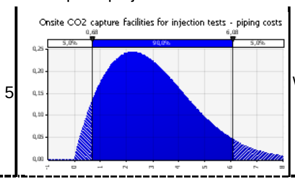
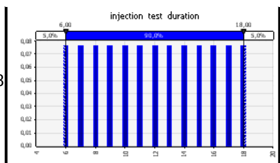
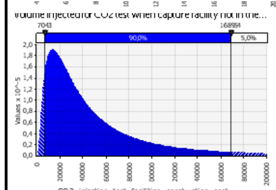
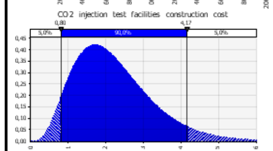
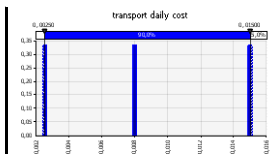
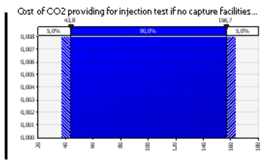
It is then multiplied by supposed test duration defined previously.

C.2.3.4. No capture facility related to the project

When no capture facility is available for CO_2 injection testing (for example if the capture facility related to the project is not ready), CO_2 must be bought from industrial providers. As production and demand for CO_2 (mainly for food industry) is highly dependent on local constraints, price is also very dependent. The cost considered per tonne of CO_2 delivered to the injection test is between 50 and 150€. It is then multiplied by CO_2 volumes needed for injection test.

C.2.3.5. Synthesis of cost calculations for phase 2 – Injection tests

Table 11: Model synthesis of Phase 2 - injection test

Cost for an European onshore storage site assessment in 2010							
Phase	**Item taken into account into simulation**	**unit**	**Low range (P10 or min)**	**Mid range**	**High range (P90 or max)**	**Type of distribution**	**Comments**
Phase 2 Injection Test	**Monitoring and studies**	M€	0,5	1	1,5		Described previsouly
	R&D program injection test during CCS first years	M€	1	2	3,5		Described previsouly
	CO_2 injection test cost (depending availability of CO_2 source for injection test)		CO_2 injection test cost depends upon CO_2 source availability and proximity. A test is performed from GIS IEA GHG developed model to determine either or not a close CO_2 source is available. 2 differents cost calculations will be performed depending of test results				
	1 - If Onsite CO_2 capture (no technical limit to CO_2 injected)	Test	1 - In this case, there is no need to bring in CO_2 with truck or train. CO_2 injection test will be realised with project captured CO_2. Only piping will be needed to bring the CO_2 onto the well at the supercritical form (no need to pass through a liquid phase transport). CO_2 capture cost is not included in the storage project but is considered as a capture project cost.				
	Piping and valves construction	M€	1	3	5		Piping and valves construction is estimated to be arround 0.5M€/km. Distance between source and well has been considered between 2 and 10 km*. A log nomal distribution has been chosen to represent these costs. This cost is not dependant on CO_2 volumes needed for test.
	2 - If no capture onsite or in close vicinity		2 - The necessary CO_2 is then transported on site at its liquid phase with train or trucks. There are two cases possible:				
	Injection test duration	Month	6	12	18		Uniform distribution between 6 and 18 months for injection test duration
	Volume injected for CO_2 test	Ton of CO_2	10 000	55 000	120 000		The CO_2 volume needed to be transported for the test is a key parameter to determine cost and depends over injection test strategy chosen. Corresponding to volumes transported by 23 tons truck during injection test period (20 days a months) by about 5/10/15 trucks a day. A log normal distribution has been used.
	Injection test facilities construction (including buffer storage)	M€	1	2	3,5		For CO_2 injection test, onsite buffers storage to store liquified CO_2 and pumps to inject it at supercritical phase at desired injection rate for test. Injection facility costs is estimated between 1 M€ (for at least one tank +one pump) to 3.5 M€.
	A - If CO_2 capture facility (linked to project) available for test at less than 300km	Test	A - The capture facility of the project is ready to provide CO_2 for CO_2 injection test. (A test run on IEA GHG project's GIS is performed). In this case captured CO_2 cost is not taken into account into injection test cost. It is taken by the capture project. Only liquified CO_2 transport cost as well as onsite injection facility cost are taken into account.				
	Transport daily cost	M€/day	0,003	0,008	0,015		Only trick transport has been considered. Same probability for each. Cost for truck transport 100, 200, 300 km/ ;5/10/15 trucks a day. One truck = 23 tons of CO_2
	Total transport cost for test	*M€*	***Total CO_2 truck transport cost is a multiplication between transport daily cost, number of months and number of days per month (20)***				
	B- If No CO_2 capture project available for test	Test	B - There are no associated capture project to the storage site or it is not ready to provide CO_2 for injection test. In this case, liquified CO_2 is bougth to an industrial provider for injection test.				
	Cost per ton of CO_2	€/ton	50	100	150		The cost per ton of CO_2 delivered considered depends on local industrial market production capacities anbd consumption. It is considered that it can be between 50 and 150€/ton of CO_2 delivered to injection test storage site.
	CO_2 buying to third party (function of test duration)	*M€*	***Multiplication between "colume injected for CO_2 test" and "Cost per ton of CO_2"***				
	Total CO_2 injection cost for studied case	*M€*	**** Case 1: Cost of piping and valces construction * Case 2: **A: Injection test facilities construction costs + total transport costs for test **B: Injection test facilities construction costs + CO_2 buying to third party costs***				
Bankable							

* This distance is an hypothesis for costs calcultations. Nevertheless, a case by case analysis is needed to assess breakeven distance between trucks or pipeline transport for CO_2 injection tests.

The results of the cost modeling of each step of the onshore DSF storage development workflow are exposed in the Appendix H.

D. OFFSHORE DSF COST MODEL ASSUMPTIONS

This section presents the different cost items of the offshore storage bankability development workflow presented on section 4.3 page 71. The main properties of all cost functions used to model engineering costs, R&D costs up to bankability, and phase development items are included.

Cost of infrastructures and facilities needed for industrial injection are not taken into account and should be added to the bankable cost for assessing CCS project industrial cost.

D.1. Cost Phasing

D.1.1. R&D cost requirement for Storage project in first development years

R&D needs will evolve and are assumed to reduce with time. This evolution is taken into account in the cost model to calculate expected development costs or remaining development costs of a storage project from 2010 to at least 2020 (see Appendix C for full description of R&D effort modelling).

D.1.2. Studies and Engineering for All Phases: Hypothesis and Modelling

Studies and engineering are performed all along storage site bankability assessment. Moreover, as detailed in previous section, R&D works is strongly present in all phases during storage first development years (2015 to 2020).

Costs of desk based engineering and studies have been mainly estimated using Geogreen own database. Average cost for each phase is representing a fair estimate of studies cost for several projects based in Western Europe. Geogreen then estimated the low and high ranges values for these studies. Probabilities distributions have been then determined to match these values. Geogreen assumed that lognormal type distributions properties where appropriate to model most of these costs distributions. Indeed, it allows a larger drift of the values beyond the average (long tail distribution). This represents the possible cost drifts in studies if unforeseen issues occur.

D.1.2.1. Phase 0 and 1 – Screening and desk based assessments

The same assumptions than for aquifer onshore cost models have been taken (see section C.1.2.1 and C.1.2.2).

D.1.2.2. Exploration license

After this Phase 1 and if the gathered elements enable a positive decision, the project will proceed to Licensing Phase. Administrative engineering and follow-up is estimated to cost between 0.2 and 0.7M€ with an average of 0.3M€. A lognormal distribution has also been applied to these costs. Indeed, administrative engineering costs may drift if there are complications in the licensing process. It is particularly possible for the first demo projects.

D.1.2.3. Phase 2 – Site confirmation and characterization

In this phase, three main cost items have been identified:

- Studies and engineering
- Seismic acquisitions either 2D or 3D
- Well drilling, data acquisition (and water production test for aquifer projects)

The studies and engineering in Phase 2 consists in the engineering of the confirmation program, the processing and analysis of acquired data, the update and correction of Phase 1 built model as well as the definition of injection test strategy and baseline acquisition.

Additionally, an important part of the program concerns R&D needs, particularly to establish assessment methodologies, monitoring strategies and to test and develop appropriate monitoring technologies.

The studies and engineering costs have been modelled with a log normal distribution with an average of 3M€, a 10 percentile of 2 and 90 percentile of 4.5M€ whereas associated R&D program in 2011 is modelled by a lognormal distribution (Average=2M€; 10p=1; 90p=3.5M€).

It is noteworthy to mention that communication costs are included in these costs.

D.1.2.4. Injection Test Licensing

Prior to injection test, an authorization is supposed compulsory in most regions. Obviously, preliminary work to obtain this authorization will differ between competent authorities and countries. We assumed the same cost distribution as for the exploration license.

D.1.2.5. Phase 2 – injection Tests

As previously, costs have been estimated for the associated studies and monitoring. A normal distribution was assumed to represent these costs.

It is noteworthy to mention that R&D program is considered as, at least, twice as expensive as studies and monitoring costs. It is modelled with a lognormal distribution to represent the possible drifting cost of new technologies and methodologies testing.

D.2. Cost Items

D.2.1. Seismic Surveys

Seismic acquisitions will be needed during exploration and characterization phase. However, the number of kilometres that needs to be acquired depends greatly upon the fact that data exist from previous underground exploration (suitability). Indeed, fewer acquisitions will generally be needed in heavily explored area than within area where limited exploration took place. Moreover, seismic acquisition offshore is much cheaper than onshore seismic acquisition due to the technology used. Therefore, generally, seismic exploration campaigns are developed on wider area.

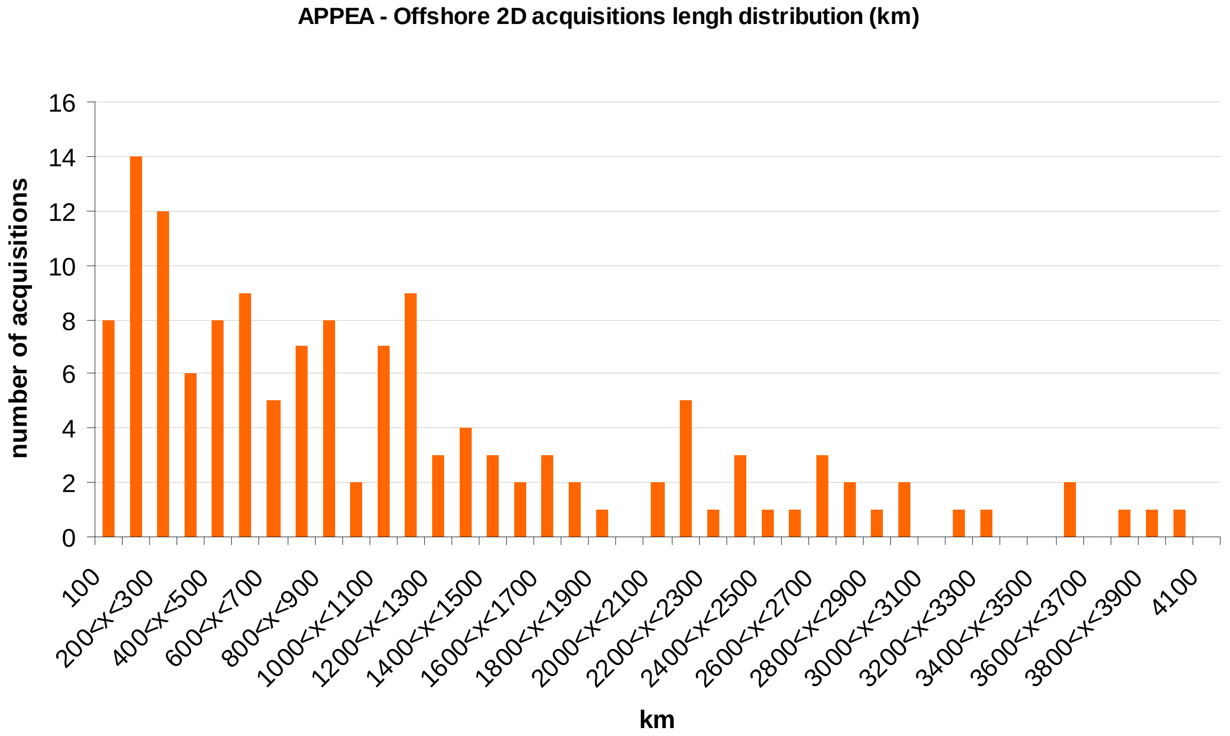
Similarly, there are fewer contingencies to drill in highly suitable areas since geological context is already quite well characterized.

Using the GIS developed for the study, it is possible to determine in which area a storage project is located. With this information, the model will give a different distribution law corresponding to the expected amount of data available in each area.

D.2.1.1. 2D Seismic Surveys

2D seismic is needed to improve structural model definition. Depending on the area where the project is located, 2D seismic acquisitions might have been partially or totally performed over the storage complex (area of review).

In order to determine a probability distribution of the number of kilometres generally acquired during a 2D seismic survey, Geogreen used APPEA data base of Australian offshore 2D seismic campaigns from 1993 to 2009. After appropriate data processing, the acquisitions length (in km) distribution is presented in Figure 83 below:



Source APPEA

Figure 85: Offshore 2D acquisitions length distribution

On the contrary to onshore model, no distinction in length of acquisition has been made for offshore 2D seismic acquisitions between different areas. Indeed, due to cheaper cost, the length of the 2D seismic is almost 10 times higher than onshore one for highly suitable area. This is a significant 2D seismic study that should provide project developers with sufficient data to evaluate whether or not the area is interesting for CO_2 storage development. Thus, there is no need to discriminate areas in function of their suitability.

A Weibull distribution with a mean of 1500 (same as the historical one) and with 10^{th} and 90^{th} percentiles equaling 200 and 3300 respectively seems to fit well the historical data as shown in Figure 86.

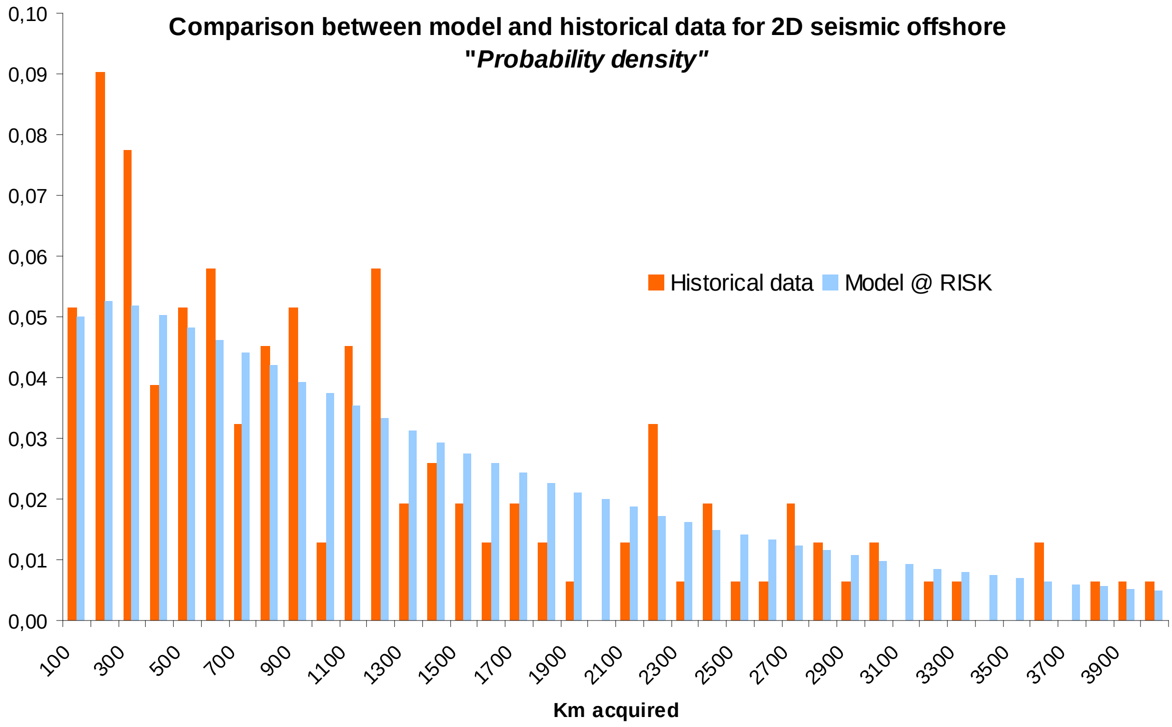


Figure 86: Comparison between model and historical data for 2D seismic acquisitions offshore

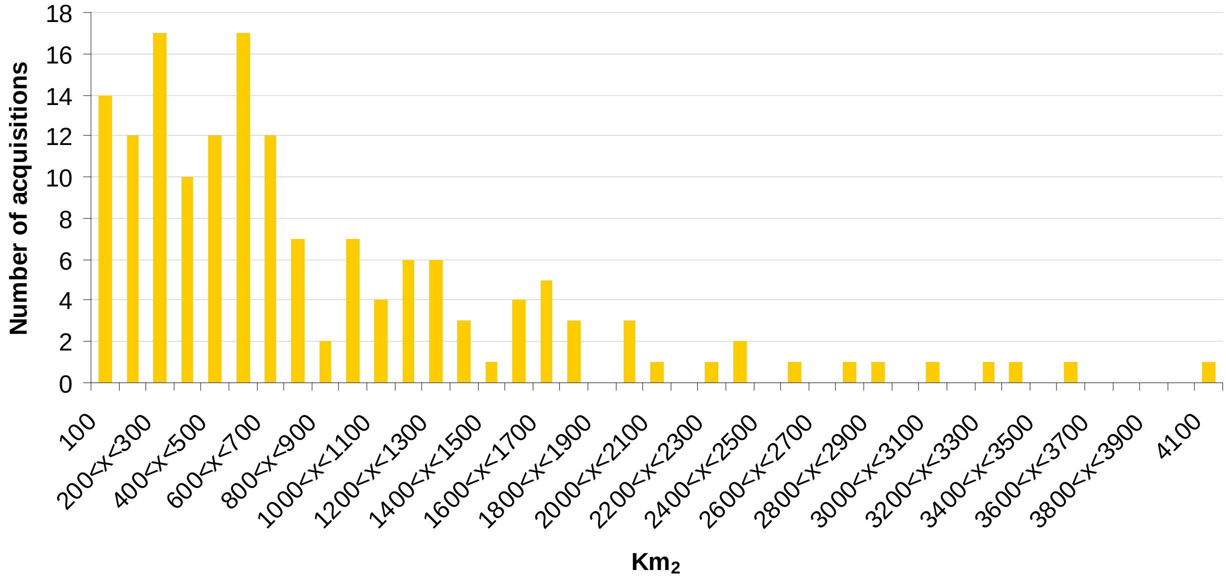
The 2D seismic acquisition cost has been calculated from recent 2D surveys cost in Europe. A Lognormal distribution with the following properties has been chosen to model cost variation:

- 10th percentiles – corresponding to low range encountered: 3000€/km
- Mean – corresponding to average cost encountered: 6 000€/km
- 90th percentiles – corresponding to high range encountered: 10 000€/km

These costs include equipment mobilization/demobilization and treatment. It is considered that the acquisition is about 10 to 20 times more expensive than the treatment. Costs factors presented in Appendix F have been developed to take into account regional differences.

D.2.1.2. 3D Seismic Survey

A 3D seismic survey will also be needed to fully characterize the structure of the storage complex (area of review). Geogreen used the same data base (APPEA data base) as for the 2D seismic surveys. The offshore 3D seismic acquisition size is given below for Australia between 2000 and 2009.



Source APPEA

Figure 87: Australian 3-D seismic offshore acquisition size distribution from 2000 to 2009 (km^2)

Figure 87 shows that the main part of the distribution is located below 800km^2. Offshore acquisition area is more important than in the onshore case due to cheaper acquisition costs.

The use of 3D seismic for CO_2 storage site characterization makes it difficult to imagine that less than 100km^2 (square of 10km *10km) are acquired. Indeed, this acquisition will be used as a baseline for storage site monitoring (on top of structural characterization needs). For the same reason, this acquisition is independent to the fact that the area has been explored or not.

Figure 87 shows the comparison between the model and Australian historical data (2000-2009) for 3D acquisition sizes offshore.

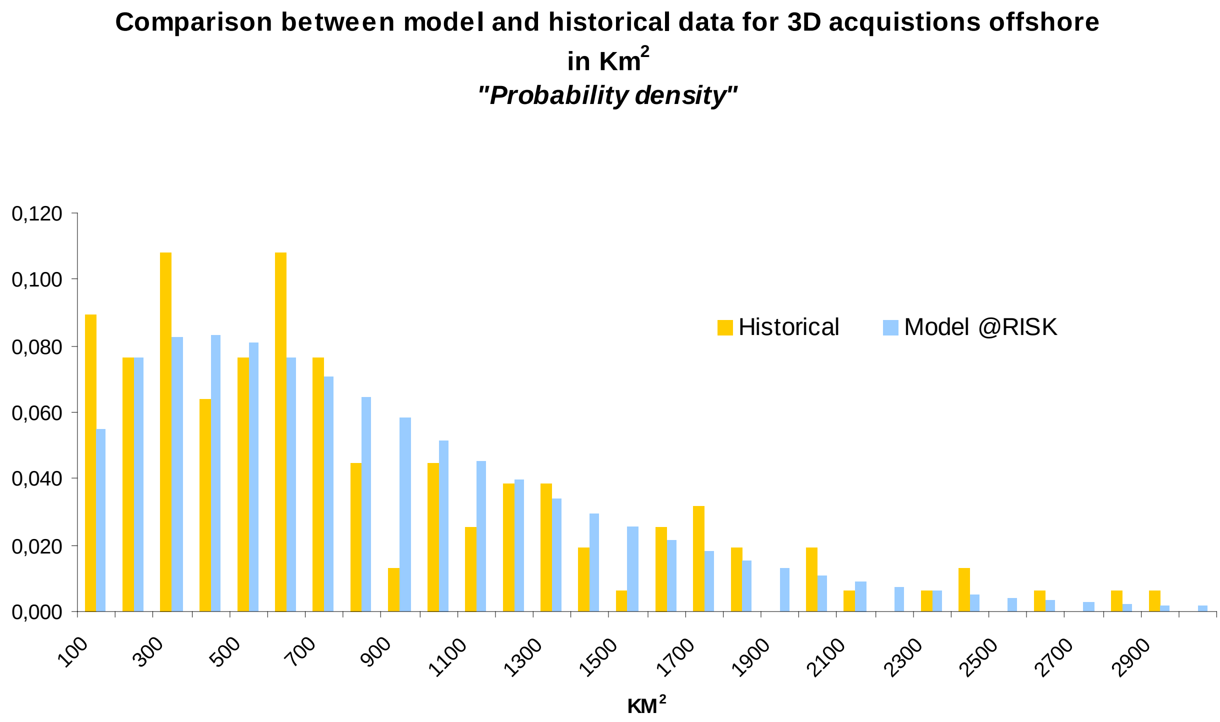


Figure 88: Comparison between model and Australian historical data for 3-D acquisitions offshore km²

As for 2D seismic costs, 3D seismic costs have been calculated from recent surveys in Europe. Costs factors taking into account regional differences are presented in Appendix. A lognormal distribution with the following properties has been chosen to model cost variations:

- 10th percentiles – corresponding to low range encountered: 4000€/km^2
- Mean – corresponding to average cost encountered: 8 400€/km^2
- 90th percentiles – corresponding to high range encountered: 14 000€/km^2

These costs include equipment mobilization/demobilization.

D.2.2. Drilling CO_2 Wells

Well drilling will be needed to locally calibrate the analysis and obtain data on storage complex and targeted reservoir, cap rock, and control levels, through coring and well logging.

The drilling process and needs are described in section 4. As described in the storage development workflows up to bankability a minimum of two wells and up to 6 wells might be drilled to confirm storage bankability. If no technical hurdles are encountered two wells are expected to be drilled (one injector + one monitoring) in order to be able to perform and monitor injection tests.

D.2.2.1. Drilling Cost

Offshore drilling costs are depending on many parameters. It is critical to determine which are the most important to be modelled in order to define a realistic distribution for these costs. Carbon Storage Taskforce recently estimated offshore CO_2 injection well cost for Australia [10].

This estimation took into account several parameters such as:

- Well depth
- Drilling time
- Rig and support/service daily rate
- Steel cost for well completion (a CO_2 injection completion have been designed within the cost model)

As it is not the purpose of this cost model to create a CO_2 injection well cost model, Geogreen simplified the well cost model from the Carbon Storage Taskforce [10].

The key parameters selected for the cost model are the following:

- Well depth
- Drilling time
- Rig and support/service daily rate which depends on the water depth
- Multiplying factor allowing finding well total cost from the rig and support/service total cost (function of the daily rate and the drilling time). It is based on Carbon Storage Taskforce calculated total well costs [10].

The first step was to create a well depth distribution. Once again, APPEA publicly available data were used to estimate this distribution.

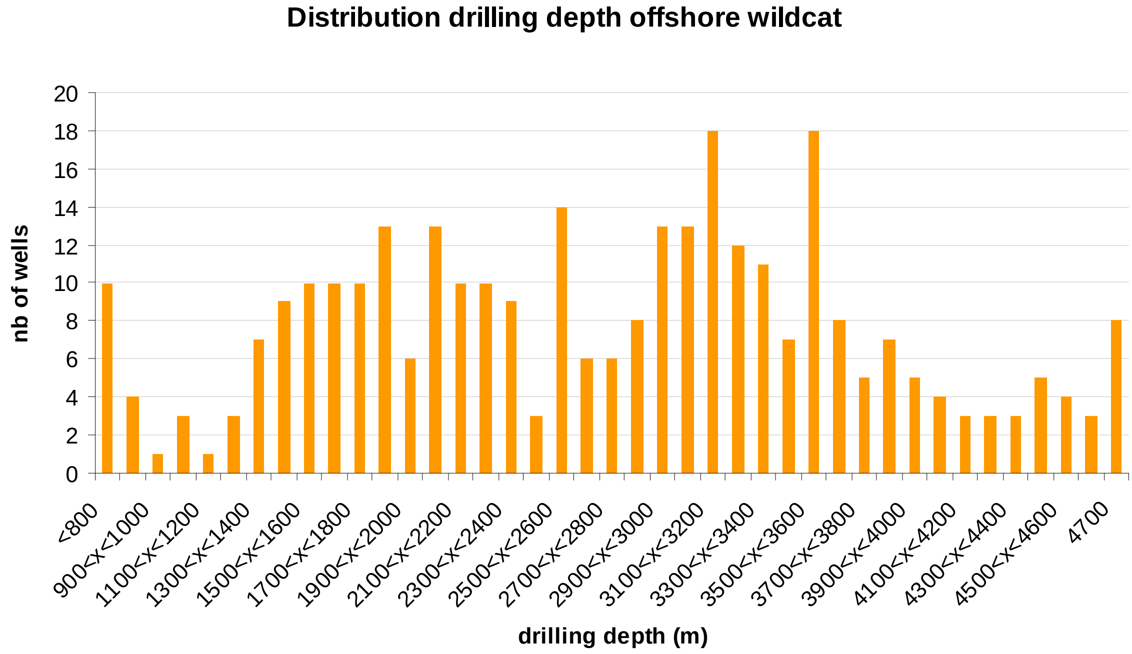


Figure 89: Drilling depth distribution for wildcat well in Australia 200-2009

The historical data shows a very wide and flat distribution. In order to simplify our approach, the same depth distribution has been used for both onshore and offshore wells. This distribution takes into account the fact that CO_2 storage will not occur above a depth of 1000 meters for security reasons. Very deep projects are also less likely to happen due to the capital cost required and the additional energy needed to inject at such depth in deep saline formations.

This distribution for the drilling depth model is a log normal distribution with the following characteristics:

- 10^{th} percentiles – corresponding to low range: 1 100 meters
- Mean – corresponding to historical average: 2 000 meters
- 90^{th} percentiles – corresponding to high range: 3 000 meters

However, this distribution has been cut off at 800 meters since, above that limit, CO_2 cannot be stored in its supercritical phase which is not appropriate for industrial scale CO_2 storage.

Figure 90 shows the matching between Australian historical data and modeled distribution.

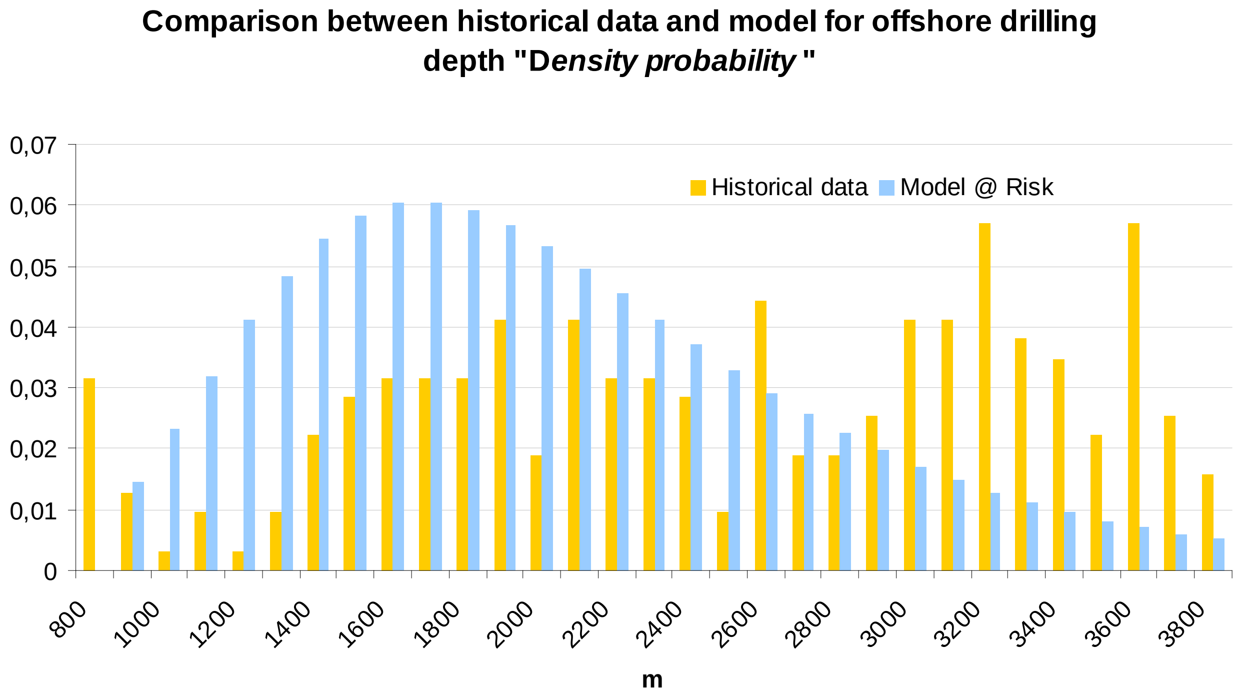
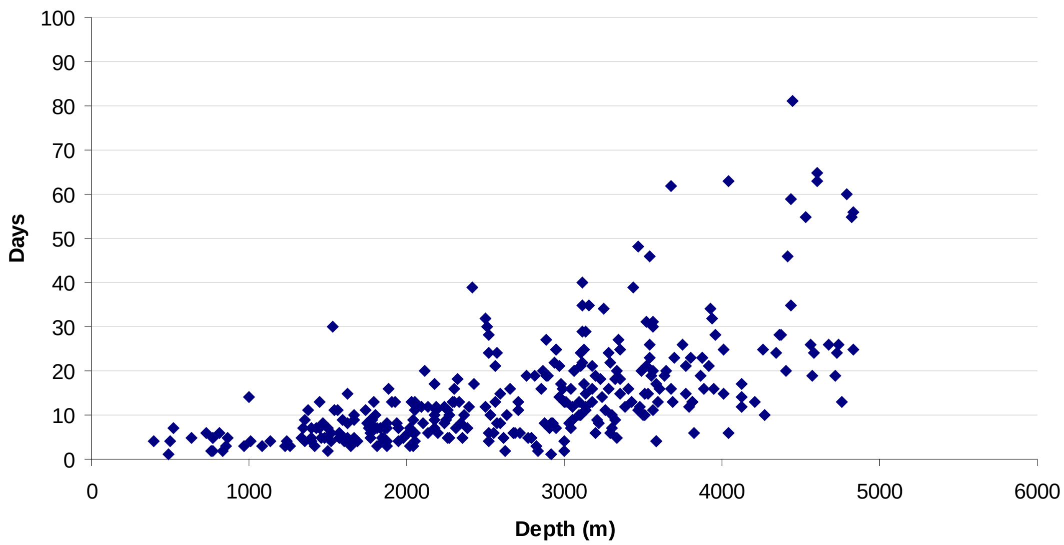


Figure 90: Comparison between Australian historical data for offshore drilling depth and model for drilling depth

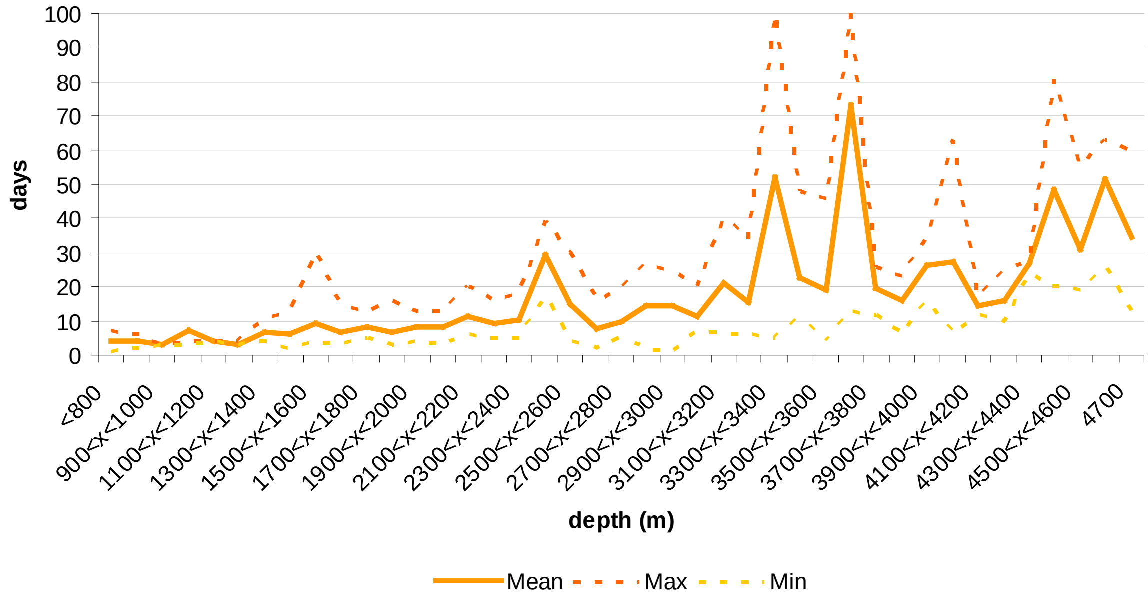
Time needed to complete the well obviously increases with depth as shown in Figure 110. The next step computes the relationship between drilling time and well depth even if it is highly random has can be seen in Figure 91.



Source APPEA

Figure 91: Wildcat offshore drilling time versus depth

APPEA data have been sorted out in order to identify the average, minimum and maximum drilling time in the range 800 to 3500m. The result is shown below[64]:



Source APPEA

Figure 92: Average drilling time per well for offshore wildcat

Figure 92 shows that there is an important variation between values. The maximum value for a given depth can be 75% higher than the average and the minimum can represent only 50% of average drilling time. A linear regression has been performed on the average values.

The use of O&G wildcat for a CO_2 well model definition needs some comments. CO_2 wells and O&G wildcats have little in common since the need for characterization in the CO_2 case is far more important that in the O&G case. In the CO_2 case, the storage complex must be characterized whereas only the caprock and the reservoir need to be analyzed in the O&G case (less coring and logging length). The drilling time will therefore be more important in the CO_2 case. However, there are no data currently available for CO_2 wells. We used O&G wells data and then increased the drilling time to take into account the extra need for characterization in the CO_2 well case.

As for 2D seismic acquisitions, drilling time is more or less dependent on existing exploration or suitability status. Indeed, when an area is already well explored, drillers will know better how to deal with each geological layer. As explained in section 3 page 32, we used the map presented in Figure 14 to determine in which area each project is located and then apply the development workflow and subsequent cost models.

[64] It is noteworthy to mention that these charts have been cleaned from out of scope data (corresponding to suspended well drilling)

We followed exactly the same methodology as the one developed in section C.2.2.2 particularly to differentiate the drilling time between the different levels of suitability of an area using linear approximations:

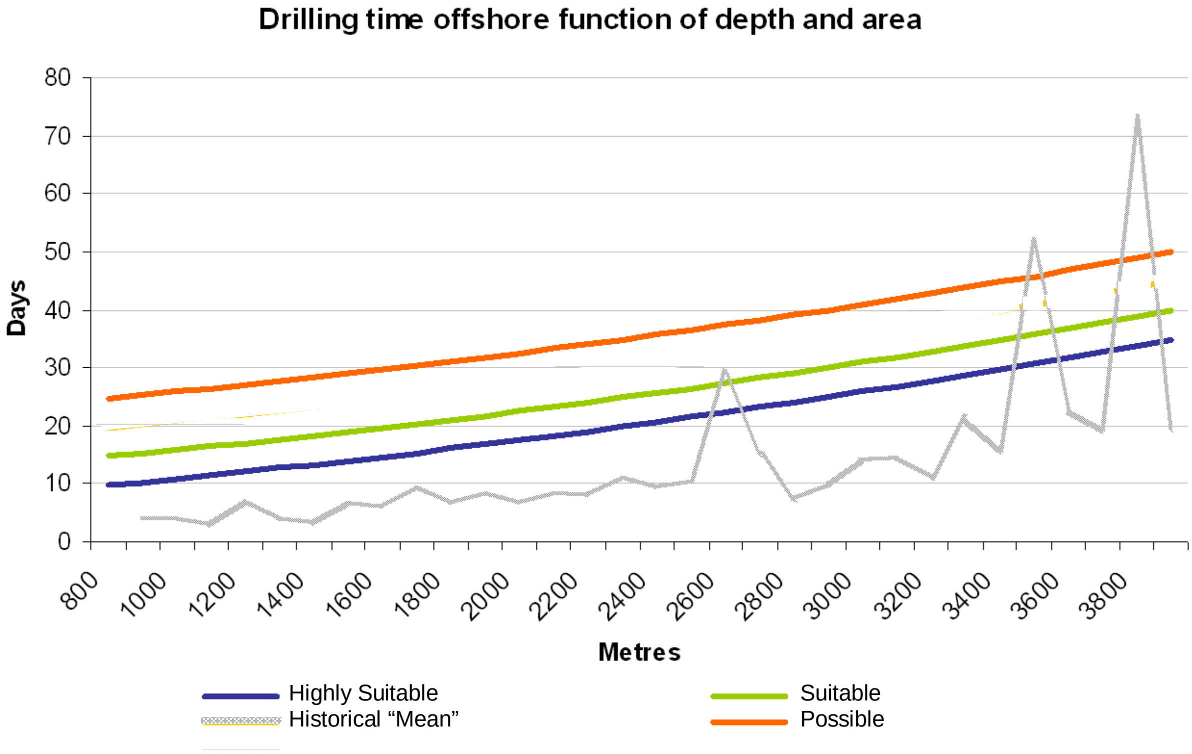


Figure 93: Estimated drilling time versus time

However, due to the underlying uncertainty of offshore drilling we add an uncertainty factor within this function. We chose a log normal distribution with the following characteristics to model uncertainties around drilling time as shown on Figure 92:

- 5th percentiles – corresponding to -25% (max =-50% from average): 0,75
- Mean – corresponding to average: 1
- 95th percentiles – corresponding to +75% (max=+75% over average): 1,75

Next figure shows the reader the different couples (drilling depth / drilling time) for highly suitable area we were able to model using this methodology (5000 outputs):

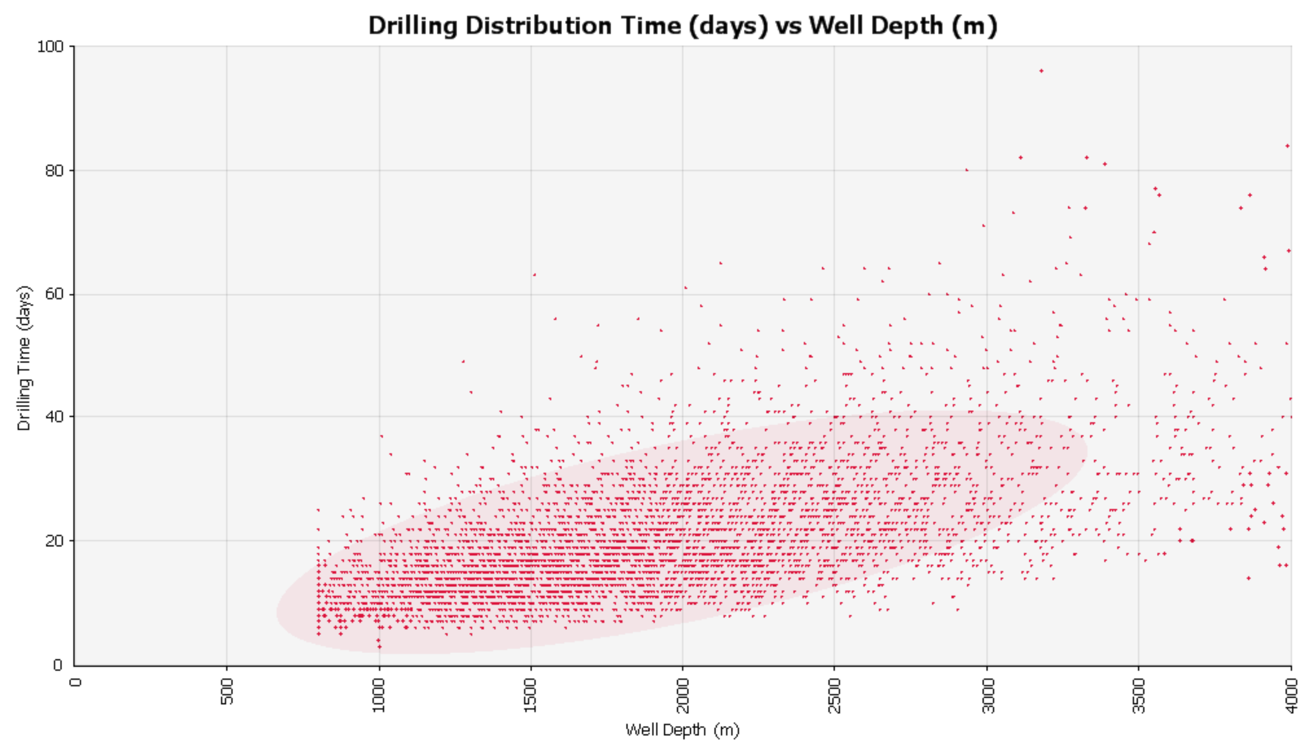


Figure 94: DSF Offshore - Drilling Distribution Time vs Well Depth

The red ellipse on the figure above represents a confidence level of 75% (assuming underlying bivariate normal). This means that 75% of the values are included in this ellipse.

D.2.2.2. Contingency for Drilling Time

Contingency for drilling time evolves with the number of wells drilled. It decreases when more wells are drilled. A classical ratio is assumed for this contingency (35%).

These contingencies halve for each new well.

D.2.2.3. Rig and Service/Support Daily Rate

For offshore drilling, water depth is very important to determine the type of equipments/vessels needed. In this study, two possibilities have been considered:

- Shallow water: area where water depth does not exceed 200 to 300 meters. In that case, the drilling rigs necessary are generally cheaper on a daily rate basis. For the sake of simplicity, we assumed that the shallow water rigs daily rate were those of jackup rigs. These rigs can operate in 120 to 200m for ultra premium jackups.
- Deep water: areas where water depth exceed 300 meters. In that case, semi-sub drilling vessel has been assumed for cost evaluation.

Rates vary widely from one region to another and depending on market conditions. The uncertainty on rig rate can be as high as 100% from one year to another. We use several industry reports[65] to calibrate the different rig and support vessel rates. Using the same repartition of suitable areas, an increase in daily rates have been assumed depending on the region we where looking at. This is justified by the fact that in areas where O&G activities are low, few rigs are available thus having higher prices.

Lognormal distributions have been used to model rig rates in different regions. Properties of this function are described here below.

Table 12: Offshore - properties of rig rates cost functions

Properties of rig rates+support cost functions (MM€/day)			
	Low range (P10 or min)	**Mid range**	**High range (P90 or max)**
Jack-up rig (Water depth < 100m) - Daily rate			
In intensely O&G explored area	0,12	0,22	0,34
In moderately O&G explored area	0,17	0,26	0,38
In partially O&G explored area	0,21	0,31	0,43
In essentially unexplored O&G area	0,26	0,35	0,47
Semi-Submersible rig (water depth >100m) - Rig+Service Daily rate			
In intensely O&G explored area	0,27	0,37	0,49
In moderately O&G explored area	0,34	0,43	0,55
In partially O&G explored area	0,40	0,50	0,62
In essentially unexplored O&G area	0,47	0,56	0,68

D.2.2.4. Mob/Demob

The mob/demob of drilling vessel and the services needed to install the drilling vessel depends once again over the exploration status. It has been assumed that more days were needed to reach an area where few offshore O&G activities were taking place.

It has been assumed that mob/demob days were charged at 50% of original rig rate since part of the crew operation the drilling rig will not be aboard during its transport.

The assumptions are resumed in the table below:

[65] Kennedy Marr monthly report has been a valuable source of information

Table 13: Offshore - properties of rig + support rates

Properties of rig+support mob/demob (MM€)	Low range (P10 or min)	Mid range	High range (P90 or max)
Nb of days for mob (nb of days)			
In intensely O&G explored area	4	7	10
In moderately O&G explored area	10	15	20
In partially O&G explored area	13	20	27
In essentially unexplored O&G area	20	30	40
Jack-up rig (Water depth < 100m) - Mob/demob cost (MM€)			
In intensely O&G explored area	1	2	4
In moderately O&G explored area	2	5	9
In partially O&G explored area	3	6	12
In essentially unexplored O&G area	4	8	15
Semi-Submersible rig (water depth >100m) - Mob/demob cost (MM€)			
In intensely O&G explored area	2	3	6
In moderately O&G explored area	3	7	12
In partially O&G explored area	5	9	16
In essentially unexplored O&G area	7	12	20

D.2.2.5. Multiplying Factor to Obtain Final Well Cost

Geogreen used Carbon Storage Taskforce analysis [10] to determine a factor between their calculated costs (with CO_2 injection completion depending on steel price) and the rig + service/support total cost for each well. Carbon Storage Taskforce analysis [10] defined two scenarios for rig and associated service/support rate: One for a low oil price (50$/bbl), and one for high oil price (100$/bbl). Taking into account current global context, only the 100$/bbl rate scenario was used. Figure 81 gives an overview of the difference between the scenarios for onshore drilling cost. The correlation observed between the overall cost and the rig +service rate cost can also be identified for offshore costs. This justifies the use of a multiplying factor to find drilling final cost.

The regression on this factor is shown below (Figure 95) and is well fitted by a logarithmic function:

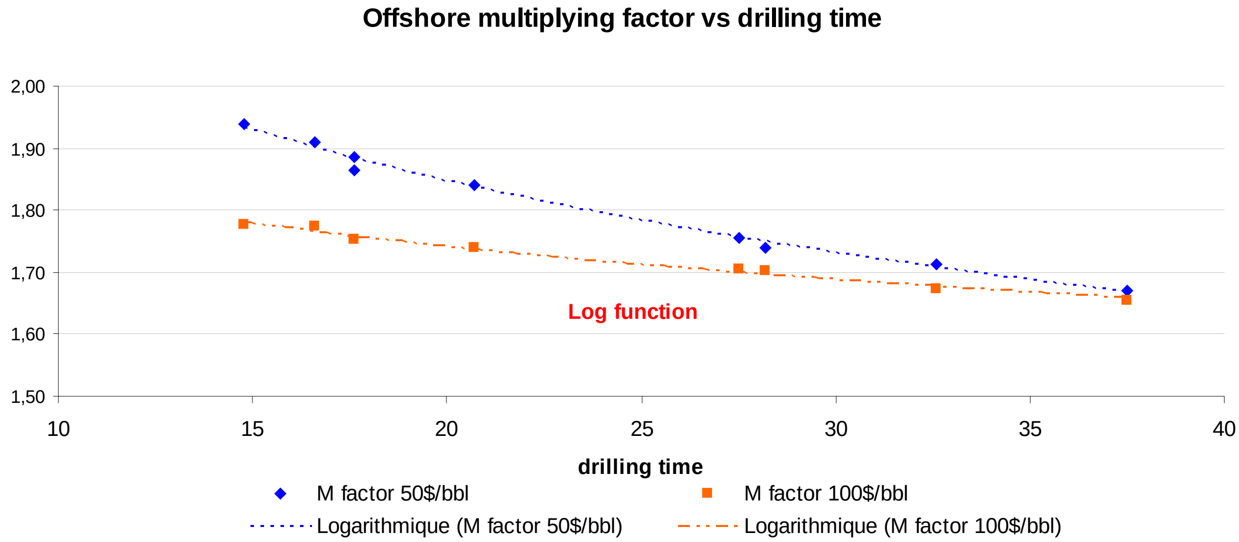


Figure 95: Multiplying factor vs drilling time for offshore

D.2.2.6. Final Drilling Cost

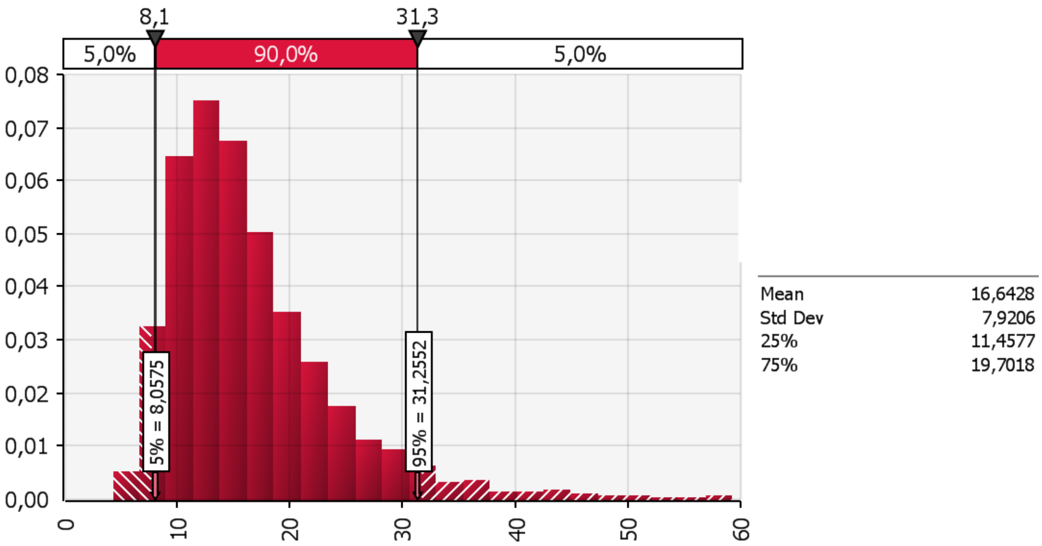
The final drilling cost is found by multiplying the drilling time plus the corresponding contingency (function of drilled depth) per the rig + support/service daily rate and per the multiplying factor.

It is noteworthy to mention that first drilled well is more expensive since it includes a higher contingency as well as the rig mob/demob costs.

Figure 97 shows the average cost of a CO_2 wildcat well function of drilled depth and O&G exploration status area. It also gives the Carbon Storage Taskforce calculated cost [10] for Australian CO_2 injection well drilling[66]. Carbon Storage Taskforce calculated cost [10] is lower than the current calculated cost partly because the wells are not in the same locations. Indeed, the drilling costs presented are for Europe. Correction factor will be applied to correct regional disparities for drilling and seismic equipment.

Figure 96 below presents the CO_2 wild cat well costs distribution in suitable areas (Europe) for shallow and deep offshore following the above hypothesis.

[66] Some extrapolations have been made from original data to be able to plot the graph



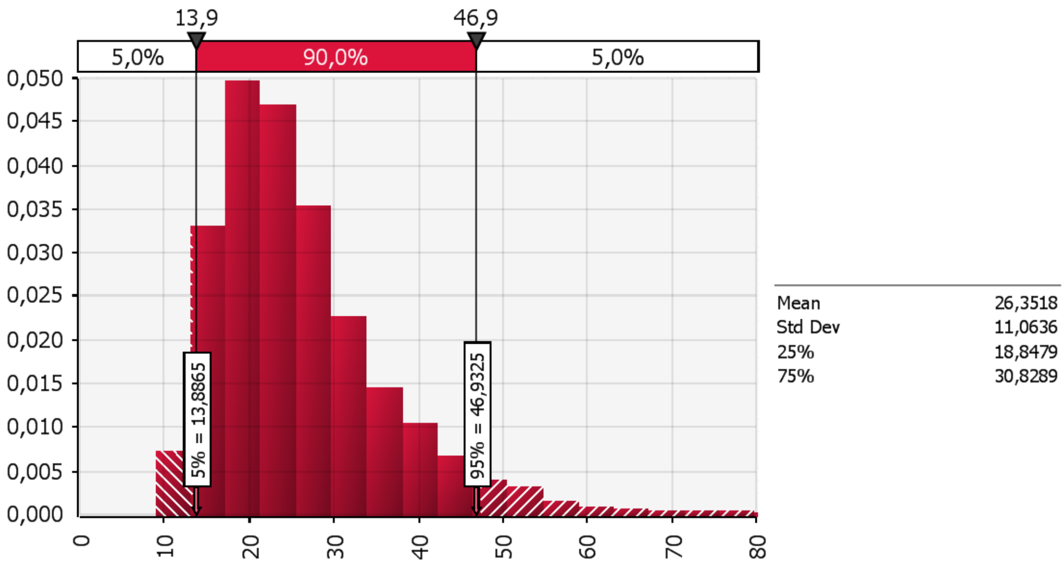
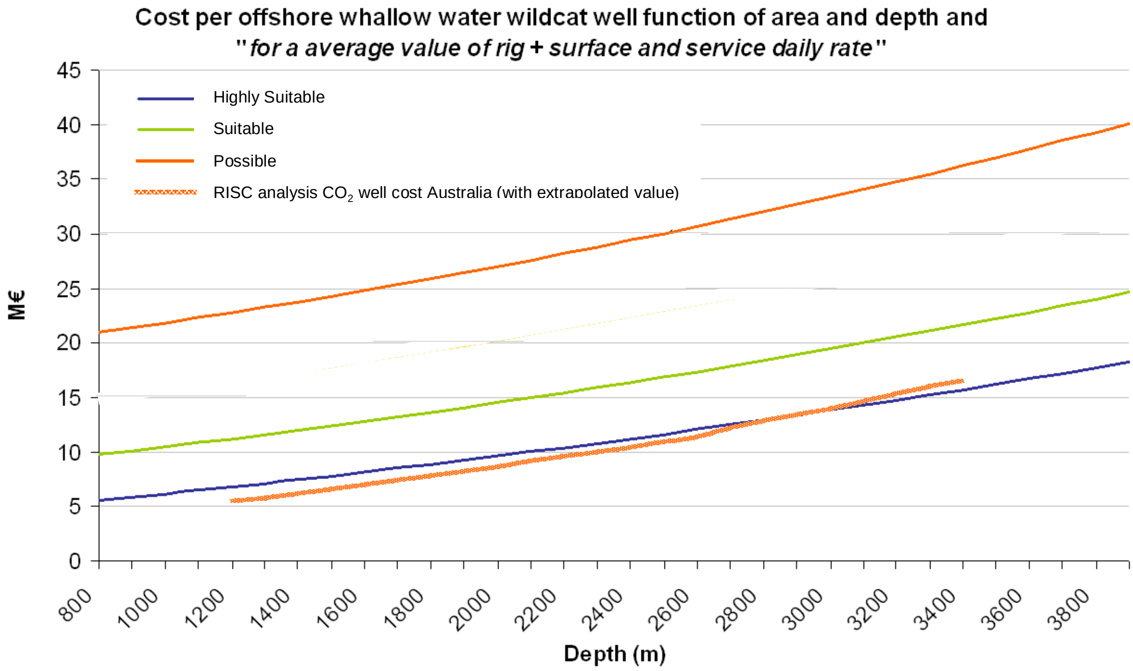


Figure 96 Costs distribution modeled for CO_2 wild cat well in suitable areas in shallow (top) and deep (bottom) offshore Europe



Note: A conversion rate of 1.3 dollar/euro was used

Figure 97: Cost model per CO_2 well function of area and depth

Figure 98 gives an overview of the final modeling for highly suitable shallow offshore areas. The red ellipse represents a 75% confidence level. It has been generated with 5000 outputs.

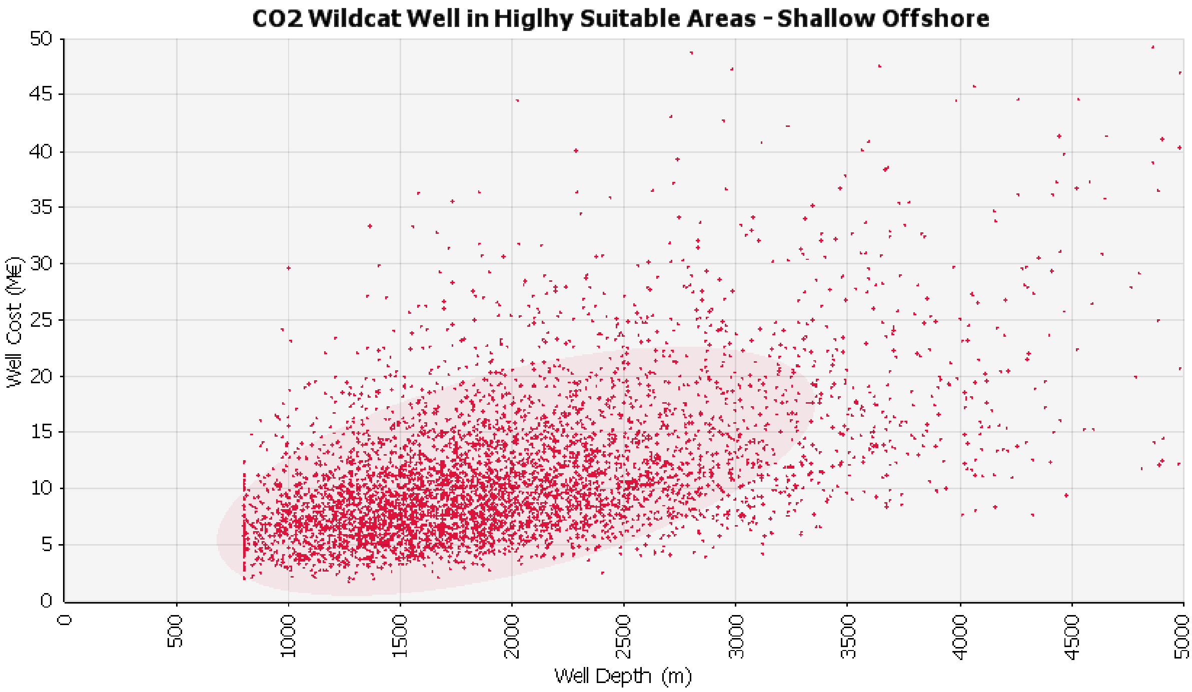


Figure 98: CO_2 wildcat Well Cost Vs Depth for shallow offshore in Higlly Suitable Areas

D.2.3. Phase 2 – Production Tests

When the first two wells are successful and prior to any injection test, a water production test will be performed (see section 4.3.1 page 71) in order to perform interference tests between the two wells and to analyze aquifer fluid flow behavior. This test is scheduled for 20 to 40 days with the drilling vessel after the well is drilled. As limited staff and support will be needed, production tests costs is considered equal to 40% of the rig/support daily rate.

D.2.4. Phase 2 – CO_2 Injection Tests

As stated in part 4 we assumed that CO_2 injection tests were mandatory for all type of storage. Even, if this kind of injection test is not usual as of today, in order to keep consistency with onshore storage requirements, a CO_2 injection has been modeled. Indeed, the same requirements in terms of characterization needs should be adopted for onshore and offshore deep saline formation storage. The injection should take place after the wells drilling and the production and interference tests.

We envisaged two cases for these CO_2 injection tests: Either the project can take advantage of existing O&G infrastructure or not. If it can, CO_2 injection test costs are lower since the injection tests can be developed on the basis of the existing infrastructure. We considered this configuration in 30% of the cases. Injection test costs taken into account are equal to 20% of the injection test costs when no existing infrastructure is present onsite. The costs assumptions for the latter are described below.

The CO_2 injection test duration has been estimated between 20 and 60 days with an average of 30 days. During this period, it will be able to test reservoir's reaction to different injection rate. These tests are shorter than in the onshore case because, the CO_2 transport can be performed by ships which have volumes between 15 000 and 30 000 tonnes of CO_2. In the onshore case, train and truck were considered. Those have capacities between 20 and 1000 tonnes. The use of the ship allows then to perform longer test rather that small repetitive tests.

CO_2 costs has been estimated between 100 and 200€ per tonne for this states (commercial CO_2 capture and transport).

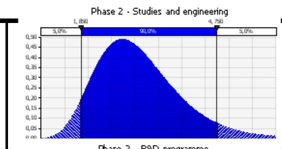
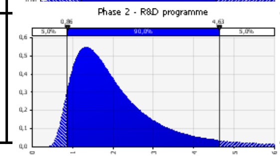
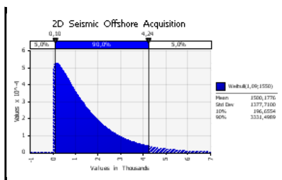
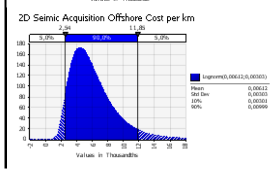
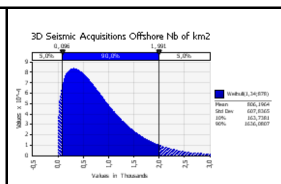
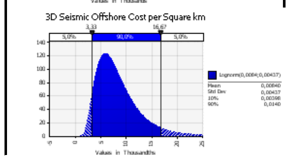
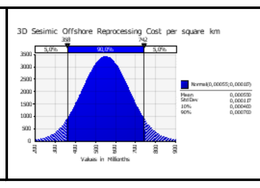
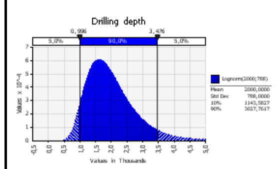
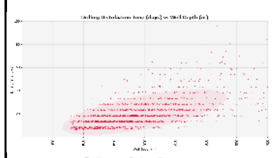
Vessels needed to complete theses costs are ships equipped for injection and monitoring of wells. In this study, the costs linked to the deployment of such injection support vessel have been estimated to 40% of drilling rate+services. This is due to the fact that limited crew will be present on site.

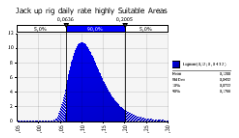
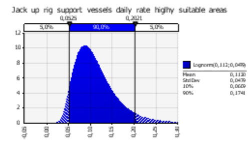
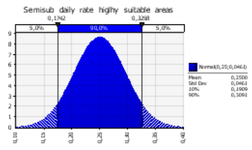
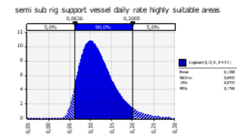
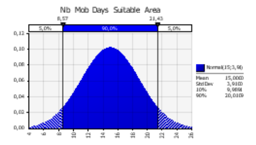
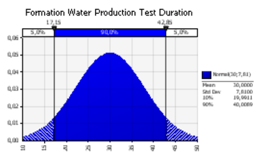
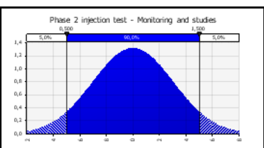
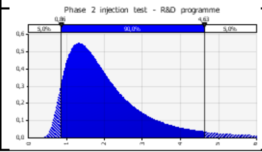
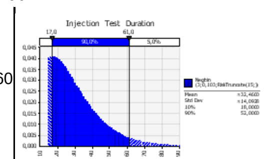
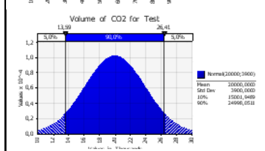
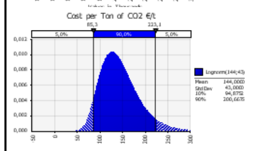
It is noteworthy to mention that at this stage no injection facilities are needed permanently on site. The building of an offshore facility will only take place as soon as the storage site is declared bankable.

Finally, it has to be mentioned that in some cases, CO_2 storage in offshore deep saline formations will be developed along side existing O&G facilities (Sleipner case). In that context, costs of injection are dramatically reduces. It has been estimated that this configuration will occur in 30% of the cases in the decades 2010-2030 and that final injection test cost is 80% lower than the base case.

For instance, in suitable areas, injection tests cost is between 5M€ and 24M€ (average 12M€).

Table 14: Offshore Model Synthesis for Phase 2

Cost for an European onshore storage site assessment in 2010							
Phase	**Item taken into account into simulation**	**unit**	**Low range (P10 or min)**	**Mid range**	**High range (P90 or max)**	**Type of distribution**	**Comments**
Phase 2 - Site confirmation & characterization	**Studies and engineering for this phase (including monitoring actions, equipments and monitoring)**	M€	2	3	4,5		Described previsouly
	R&D program on methodology and monitoring techniques during CCS first deployment years	M€	1	2	3,5		Described previsouly
	Seismic acquisitions 2D						
	Number of kilometers acquired	km	*100*	*1500*	*4200*		Weibull Distribution identifcal for all areas
	Cost per kilometers (including eventual damage)	M€	0,011	0,013	0,015		Lognormal distribution based on 2D seismic acquisitions costs per km (North Sea)
	Total	*M€*	***Multiplication between "number of kilometers acquired" and "cost per kilometers"***				
	Seismic acquisitions 3D (on CO_2 future plume only)						
	Number of square kilometers acquired	Km^2	100	180	280		Weibull distribution based on APPEA data with a minimum of $100km_2$ for CO2 plume
	Cost per square kilometers (including eventual damage)	M€	0,03	0,04	0,05		LogNormal distribution based on 3D seismic acquisitions costs per square km (Mob/demob considered included into cost)
	Total	*M€*	***Multiplication between "number of square kilometers acquired" and "cost per square kilometers"***				
	3D Seismic Reprocessing						
	cost per square kilometers	M€	0,0004	0,00055	0,0007		Normal distribution
	Drilling CO_2 well (including Mob/demob; coring; logging; completion)						
	Drilling Depth	m	1 100	2 000	3 000		Log normal distribution defined on historical data with a cut off to exclude all values below 800 meters
	Drilling time per well						Linear function
	Distribution for drilling time uncertainty (5th p; 50th p; 95th p)		*0,75*	*1*	*1,75*		Linear function calculated on existing APPEA data + introduction of an uncertainty on drilling time. The results is given on the graph on the right
	In higlhy suitable areas	*day*		*Linear function*			
	In suitable areas	*day*		*+5*			
	In possible areas	*day*		*+5*			
	Contingency for drilling *(decreasing for each new well)*						
	Contingency first well	*% day*	*10%*		*25%*		10% for highly and suitable areas 25% for possible areas
	Contingency second well (if any)	*% day*		*Half of previous contingency*			

Phase 2 - Site confirmation & characterization	Rig + service/support daily rate						
	Jack-up rig (Water depth < 200/300m) - Daily rate for Highly Suitable Area						
	Rig	M€	0,06	0,12	0,18		Normal distribution. See Table 11 for other areas
	Service and support vessels rate	M€	0,06	0,10	0,16		Normal distribution. See Table 12 for other areas
	Semi-Submersible rig (water depth >300m) - Daily rate for Highly Suitable Area						
	Rig	M€	0,19	0,25	0,31		Normal distribution. See Table 11 for other areas
	Service and support vessels rate	M€	0,08	0,12	0,18		Normal distribution. See Table 12 for other areas
	Rig Mob/demog						
	In higlhy suitable areas	nb	4	7	10		Normal distributions with different values depending on area suitability
	In suitable areas	nb	10	15	20		
	In possible areas	nb	13	20	27		
	Multiplying factor *(between Rig+service/support cost for a well and total well costs following RISC analysis for CO_2 well drilling)*		*LN function from RISC analysis*				Ln function from RISC analysis
	Total drilling costs	M€	***Each well costs are different because of the contingency rate which is decreasing after each new well drilling. Well costs: Multiplication of rig+support vessel with twice 40%of mob/demob time plusdrilling time and contingencies***				
	Formation water production test duration	Days	20	30	40		Normal distribution for the duration of the test multiplied by 40% of the rig+service rate
	Formation water production cost (performed from the drilling rig)	M€	*To be calculated - cost = 40% of rig+service rate*				
Phase 2 Injection Test	**Monitoring and studies**	M€	0,5	1	1,5		Described previsouly
	R&D program injection test during CCS first years	M€	1	2	3,5		Described previsouly
	CO_2 Injection test	**There are two cases: Either the project is developed without existing o&G infrastructure (case descrive below) or on the basis of O&G infrastructure. In that case, the injection test cost is estimated to be equal to 20% of below calculated costs. We considered that this setting happen in 30% of the cases**					
	Pilot test duration	Days	20	30	60		We considered that, sseing the costs test, the shorter duration might prevail. That is why we choose the distribution describes on the figure on the right.
	CO_2 test volume	t	15 000	20 000	25 000		Normal distribution centered on 20 000 tons of CO_2
	Cost per ton of CO_2	€/t	100	140	200		The cost per ton of CO_2 delivered considered depends on local industrial market production capacities anbd consumption. It is considered that it can be between 100 and 200€/ton of CO_2 delivered to injection test storage site.
	CO_2 carrier + injection support vessel cost	M€/d	cost of support vessel +50%				
	Injection vessel +support cost for test	M€/d	To be calculated - cost = 40% of rig+service rate				
	Total cost injection test	***M€***	**In 70% of cases, costs for the CO_2 injection test is equal to the mob/demob time for the rig + the injection time multiplied by 40% of the rig+support daily rate. To that amount the cost of CO_2 and of the CO_2 carrier should be added. When O&G infrastructure exist on site, only 20% of the above calculated costs is taken into account**				
	Bankable						

E. DEPLETED HYDROCARBON FIELDS COST MODEL ASSUMPTIONS

This section presents the different cost items of the DOGF bankability storage development workflow presented on section 4.4 page 79. The main properties of all cost functions used to model engineering costs, R&D costs up to bankability, and phase development items are included. Development cost and infrastructures needed for industrial injection are not taken into account and should be added to the bankable cost.

E.1. Onshore Depleted Hydrocarbon Fields

Onshore depleted hydrocarbon field cost model is based upon onshore deep saline formation cost model.

Major differences concern the following items:

- Phase 1:
  - Desk based study: Desk based study costs for depleted hydrocarbon fields are between 1 and 3 M€.
  - Data (geological model and production history) must be acquired from former field operator in order to assess field convertibility into CO_2 storage. If the project is not developed by the former field operator, the CO_2 storage developer will have to purchase these data. In a first approximation, this cost has been estimated as equal to Desk based study
  - Comprehensive risk analysis: a comprehensive risk analysis reviewing all potential leakage risks and particularly existing wells leakage potential should be performed. The cost of such an analysis has been estimated between 0.5 and 1.5 M€.
- Phase 2 - Confirmation:
  - Depending of the result of the previous analysis, well drilling is not always necessary. It has been estimated that in 50% of the cases a simple work over will be sufficient to perform an injection test.
  - Well drilling costs are identical than those described for onshore deep saline formations. Contingency applied for this well has been considered as equal to 0 since local geology is considered well known by the operator.
  - Well work over costs is considered between 0.5 and 2 M€
- Phase 2 – injection tests:
  - The same assumptions than those described for onshore deep saline formations have been used.

It is noteworthy to mention that above mention costs concern only bankability costs. All other costs related to industrial development of a storage site such as extra wells plugging/workovers are not included.

E.2. Offshore Depleted Hydrocarbon Fields

Offshore depleted hydrocarbon field cost model a based upon offshore deep saline formation cost model.

Major differences concern the following items:

- Phase 1:
    - Identical considerations than for onshore depleted hydrocarbon fields model have been taken.
- Phase 2 - Confirmation:
    - Depending of the result of the previous analysis, well drilling is not always necessary. It has been estimated that in 50% of the cases a simple work over will be sufficient to perform an injection test.
    - Well drilling costs are identical than those described for offshore deep saline formations (shallow/deep water). Contingency applied for this well has been considered as equal to 0 since local geology is considered well known by the operator.
    - Well work over costs is considered between 2 and 10 M€ (average 5M€).
- Phase 2 – injection tests:
    - The same assumptions than those described for onshore deep saline formations have been used.

It is noteworthy to mention that above mention costs concern only bankability costs. All other costs related to industrial development of a storage site such as extra wells plugging/workovers, platform maintenance/refurbishment are not included.

F. REGIONAL COSTS FACTORS

The costs modelling presented in the previous Appendixes (C, D and E) are based on European costs. However, many of these costs are location dependent. For instance, geophysical works depend on the local market activities (number of drilling rigs available in a given region…) or the civil engineering costs differs in function of local wages. The following section gives the main assumptions for the costs factors modelling.

In order to be able to use our costs modelling and workflows (part 4) for the different regions of the study, we used costs factors to adjust the costs to a given region. For the sake of simplicity we looked at the issue on a regional level and not on a country per country basis.

Cost factors cannot be the same between qualified and non qualified work. That is why we discriminated the costs factors between three categories:

1. Field works: corresponds to the work performed by engineers and qualified technicians to build infrastructures or performed specific data acquisition. The costs of these operations are often higher than the average wage costs of a given region.
2. Civil engineering: corresponds to the non qualified work performed by the local workforce paid at the local average wage.
3. Qualified work: corresponds to the work of engineers and staff performing the study and engineering part of the project. This staff is paid at higher wages than the average regional wage.

In order to determine what could be the cost factors for civil engineering, we looked at the average wages in each region. The table below gives an overview of this different. Data originated form OECD statistics and International Labour Organization mainly.

Table 15: Average Wage Difference Between Region (Source OECD, ILO)

	OECD Europe	OECD Oceania	OECD North America	OECD Asia	South America	South Africa	North Africa	India	China	South East Asia
Average anual wage in USD	40 000	35 000	35 000	30 000	10 000	6 000	4 000	1 000	3 000	3 500
% difference for Europe	100%	88%	88%	76%	25%	15%	10%	3%	8%	9%

The third line of the table gives the percentage of differences with the Europe average wage which is our base case for cost modeling. We cannot take use these percentages directly since we need to include material costs in the overall cost calculation. Finally, we assumed a cost factor of 0.2 (1 being for Europe) for regions having an average annual wage below 20% of European level, we added 0.1 to the percentage of difference with Europe for regions having an average annual wage above 80% and nothing otherwise. We did not have any data for Middle East so we considered that the average wage for this type of work was equivalent to the one of South America region.

For qualified work which is essentially linked to staff wages, we assumed that the cost factor could go below 50% of European cost for developing region and is equal to European costs for regions having an average annual wage above 80.

Field work factor depends heavily on local market condition for rigs and seismic acquisition. In North America and Oceania, the geophysical works are generally lower than Europe due to the size of the market. We assigned a 0.9 factor to these costs. We assumed a 0.7 cost factors o the Middle Easy based on recent available seismic acquisition costs and 0.6 for the rest of developing countries to take into account the lower costs of the workforce in those regions.

Table 16 sums up all hypotheses. Table 17 and Table 18 gives the distribution of the costs factors per item for DSF onshore and offshore costs items.

Table 16: Regional Costs Factors Philosophy

	Cost regional corrective factor										
	OECD Europe	OECD Oceania	OECD North America	OECD Asia	South America	Middle east	South Africa	North Africa	South East Asia	China	India
For qualified work	1	1	1	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
For civil engineering	1	1	1	0,9	0,25	0,25	0,2	0,2	0,2	0,2	0,2
For field work	1	0,9	0,9	0,8	0,7	0,7	0,6	0,6	0,6	0,6	0,6

Table 17: Regional Costs Factors for Onshore Case

Phase	Items taken into account into simulation	Regional Costs Factors for Onshore Case										
		OECD Europe	OECD Oceania	OECD North America	OECD Asia	South America	Middle east	South Africa	North Africa	South East Asia	China	India
Phase 0 - Screening	First desktop studies	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	R&D program during CCS first deployment years	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Phase 1 - Desk Based assessment	Desktop studies, where possible seismic reprocessing and existing wells logs analysis (inluding communication on project)	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	R&D program during CCS first deployment years	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Licensing Exploration Permit	Admistrative engineering and follow-up	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Phase 2 - Site confirmation & characterization	Studies and engineering for this phase (including monitoring actions, equipments and monitoring)	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	R&D program during CCS first deployment years	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	Seismic acquisitions 2D											
	cost per kilometers (including eventual damage)	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Seismic acquisitions 3D (on CO_2 future plume only)											
	cost per square kilometers (including eventual damage)	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Seismic 3D reprocessing	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Civil Engineering											
	Cost per well	1,0	1,0	1,0	0,9	0,3	0,3	0,2	0,2	0,2	0,2	0,2
	Drilling CO_2 well (including Mob/demob)											
	Mob/demob	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Rig rate + service/support day rate	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
Licensing Injection test	Injection test permitting	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Phase 2 - injection tests	CO_2 injection cost (depending availability of CO_2 source for injection test)											
	Piping and valves construction	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Transport daily cost	1,0	1,0	1,0	0,9	0,3	0,3	0,2	0,2	0,2	0,2	0,2
	Injection test facilities construction											
	CO_2 injection test facilities construction (including buffer storage)	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Monitoring and studies during and after injection test											
	Monitoring and studies	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	R&D programme injection test during CCS first years	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Bankable												

Items impacted by "for civil engineering " factor

Items impacted by "for qualified work" factor

Items impacted by "for field work" factor

Table 18: Regional Costs Factors for Offshore Case

		Regional Costs Factors for Offshore Case										
Phase	**Items taken into account into simulation**	**OECD Europe**	**OECD Oceania**	**OECD North America**	**OECD Asia**	**South America**	**Middle east**	**South Africa**	**North Africa**	**South East Asia**	**China**	**India**
Phase 0 - Screening	First desktop studies	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	R&D program during CCS first deployment years	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Phase 1 - Desk Based assessment	Desktop studies, where possible seismic reprocessing and existing wells logs analysis (inluding communication on project)	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	R&D program during CCS first deployment years	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Licensing Exploration Permit	Admistrative engineering and follow-up	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Phase 2 - Site confirmation & characterization	Studies and engineering for this phase (including monitoring actions, equipments and monitoring)	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	R&D program during CCS first deployment years	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	Seismic acquisitions 2D											
	cost per kilometers (including eventual damage)	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Seismic acquisitions 3D (on CO_2 future plume only)											
	cost per square kilometers (including eventual damage)	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Seismic 3D reprocessing	1,0	0,9	0,9	0,8	0,7	0,7	0,6	0,6	0,6	0,6	0,6
	Number of wells											
	Civil Engineering											
	Cost per well	1,0	1,0	1,0	0,9	0,3	0,3	0,2	0,2	0,2	0,2	0,2
	Drilling CO_2 well (including Mob/demob)											
	Mob/demob	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Rig rate + service/support day rate	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Formation water production cost (performed from the drilling rig)	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
Licensing Injection test	Injection test permitting	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Phase 2 - injection tests	CO_2 injection cost (depending availability of CO_2 source for injection test)											
	Injection vessel +support cost for test	1,0	0,9	0,9	0,8	0,7	0,7	0,7	0,7	0,7	0,7	0,7
	Monitoring and studies during and after injection test											
	Monitoring and studies	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
	R&D programme injection test during CCS first years	1,0	1,0	1,0	0,9	0,6	0,6	0,6	0,5	0,5	0,5	0,5
Bankable												

Items impacted by "for civil engineering " factor

Items impacted by "for qualified work" factor

Items impacted by "for field work" factor

G. DEVELOPMENT TIMES ASSUMPTIONS

CO_2 storage development time is a critical parameter for any CCS strategy definition. Similarly to the cost modelling, a development time model has been developed for each step of the CO_2 storage development workflows presented in part 4.

The proposed development time modelling for aquifer and depleted fields storage projects has been assessed through internal review by Geogreen, and challenges through discussions with Global CCS Institute and IEA GHG experts.

Each item corresponds to a step of the development time workflow. It is very difficult to assess regionally the minimum and maximum development time for each value. For instance, the licensing phase time depends on the local regulation. As we could not enter into this level of detail and for the sake of simplicity, we defined ranges of time necessary for each steps. We represented these ranges by assigning uniform distributions.

The workflow methodology we developed shows sequential actions: one action can be performed only one the previous one is completed. This has been done for modelling purpose and do not represent exactly the reality. Indeed, some action can be performed or start before the end of another one. We included this overlapping aspect in our time evaluation.

Table 19 and Table 20 on next pages show the time modelling assumptions for onshore and offshore Deep Saline Formation respectively. For Depleted Oil and Gas Fields, the same values are supposed for the relevant time items (see workflows in part 4.4.1 page 79).

Finally, as mentioned previously, the overall results of this time modelling can be seen in part 4 and in Appendix H.

Table 19: Development Time per Step for Onshore DSF Project

	Time are given in years	Onshore Model Time per Step			
		10p	***Mean***	***90p***	**Comments**
Phase 0 Screening	Studies and R&D	0,5	0,75	1	The time needed for these desktop studies is generally below 1 years
Phase 1 Desk Based assessment	Studies and R&D	0,5	0,75	1	The time needed for these desktop studies is generally below 1 years However, there are often desk based work performed during the administrative engineering phase.
Licensing Exploration Permit	Administrative engineering, license application and award	0,5	1,25	2	The administrative engineering could take between 6 months and 2 years or more. CCS is a new subject to admistration that will be dealt with carefully in order not to jeoparize project public assitance
Phase 2 Site confirmation & characterization	Studies and R&D	0	1	1,5	The study and engineering time during this phase could cumulate between 6 months and 1.5 year depending on the geology complexity, the size of the team and the exploration work forseen
	2D seismic acquisition	0,25	0,43	0,6	Seismic acquisition could take between 3 and 7 months (right of ways, acquisition and processing)
	3D seismic acquisition	0,25	0,43	0,6	
	3D retreatment	0,08	0,2	0,3	The 3D retreatment (reprocessing in function of new data and integration in geological model) itself can take between 1 and 3 months.
	Mob/demob	0,04	0,08	0,15	Onshore the Mob/Demob time can take between 15 days and 1 months and a half depending on the locations of the well and rig.
	First well	Depend on cost model - see appendix D			The drilling time is calculated during the costs evaluation in order to calculate well cost (function of the drilling time).
	2nd well if any	Depend on cost model - see appendix D			
	Water production test	Not applicable fo onshore			We considered that the water production test time was not on the critical path of development and could be perform during CO_2 injection tests licensing. Therefore the associated time is hidden.
Licensing injection test Permit	Administrative engineering, license application and award	0	1	1,5	The administrative engineering could take up to 1.5 years or more. In some jurisdiction, the administrative time associated to the injection test will be small or inexistent because integrated in the exploration licence
Phase 2 injection Test	Injection test duration + data analysis	0,5	1,5	2,5	This ultimate phase will take at least 6 months and 2.5 years depending on the injection tests duration and the post injection monitoring time requested by the administration to fill the commercial license application.

Table 20: Development Time per Step for Offshore DSF Project

	Time are given in years	Offshore Model Time per Step			
		10p	***Mean***	***90p***	**Comments**
Phase 0 Screening	Studies and R&D	0,5	0,75	1	The time needed for these desktop studies is generally below 1 years
Phase 1 Desk Based assessment	Studies and R&D	0,5	0,75	1	The time needed for these desktop studies is generally below 1 years However, there are often desk based work performed during the administrative engineering phase.
Licensing Exploration Permit	Administrative engineering, license application and award	0,5	1	2	The administrative engineering could take between 6 months and 2 years or more. CCS is a new subject to admistration that will be dealt with carefully in order not to jeoparize project public assitance
Phase 2 Site confirmation & characterization	Studies and R&D	0,5	1	1,5	The study and engineering time during this phase could cumulate between 6 months and 1.5 year depending on the geology complexity, the size of the team and the exploration work forseen
	2D seismic acquisition	0,42	0,6	1	Seismic acquisitions and processing are shorter offshore. However, as more data is acquired, more time is needed to process the information and input it into geological model. It could take between 5 and 12 months
	3D seismic acquisition	0,42	0,6	1	
	3D retreatment	0,05	0,08	0,1	The 3D retreatment is shorter offshore due to the technology difference between onshore and offshore acquisition. It can take between 15 days and 1 month.
	Mob/demob	Injection test duration as calculated in appendix E + 10p: 0,02 - Mean: 0,06 - 90p: 0,1			Onshore the Mob/Demob time can take between 15 days and 1 months and a half depending on the locations of the well and rig.
	First well	Depend on cost model - see appendix E			The drilling time is calculated during the costs evaluation in order to calculate well cost (function of the drilling time).
	2^{nd} well if any	Depend on cost model - see appendix E			
	Water production test	Depend on cost model - see appendix E			The water production test time is not hidden in the offshore case since a rig vessel has to be on site. It is equal to the test duration set in the cost model (between 20 and 40 days).
Licensing injection test Permit	Administrative engineering, license application and award	0	1	1,5	The administrative engineering could take up to 1.5 years or more. In some jurisdiction, the administrative time associated to the injection test will be small or inexistent because integrated in the exploration licence
Phase 2 injection Test	Injection test duration + data analysis	Injection test duration as calculated in appendix E + 10p: 0,5 - Mean: 1,25 - 90p: 2			Injection test duration is limited for the reasons given in appendix E. However, similarly to the onshore case, a monitoring and processing time will be needed before license application filling

H.COSTS AND TIME MODELS RESULTS

H.1. Results Completing the Analysis Provided in Part 4

Following figures give complementary information to part 4

Figure 99 gives the bankability costs and development time for DSF onshore in suitable areas and is to be compared with Figure 23 and Figure 21 in part 4.2 page 58.

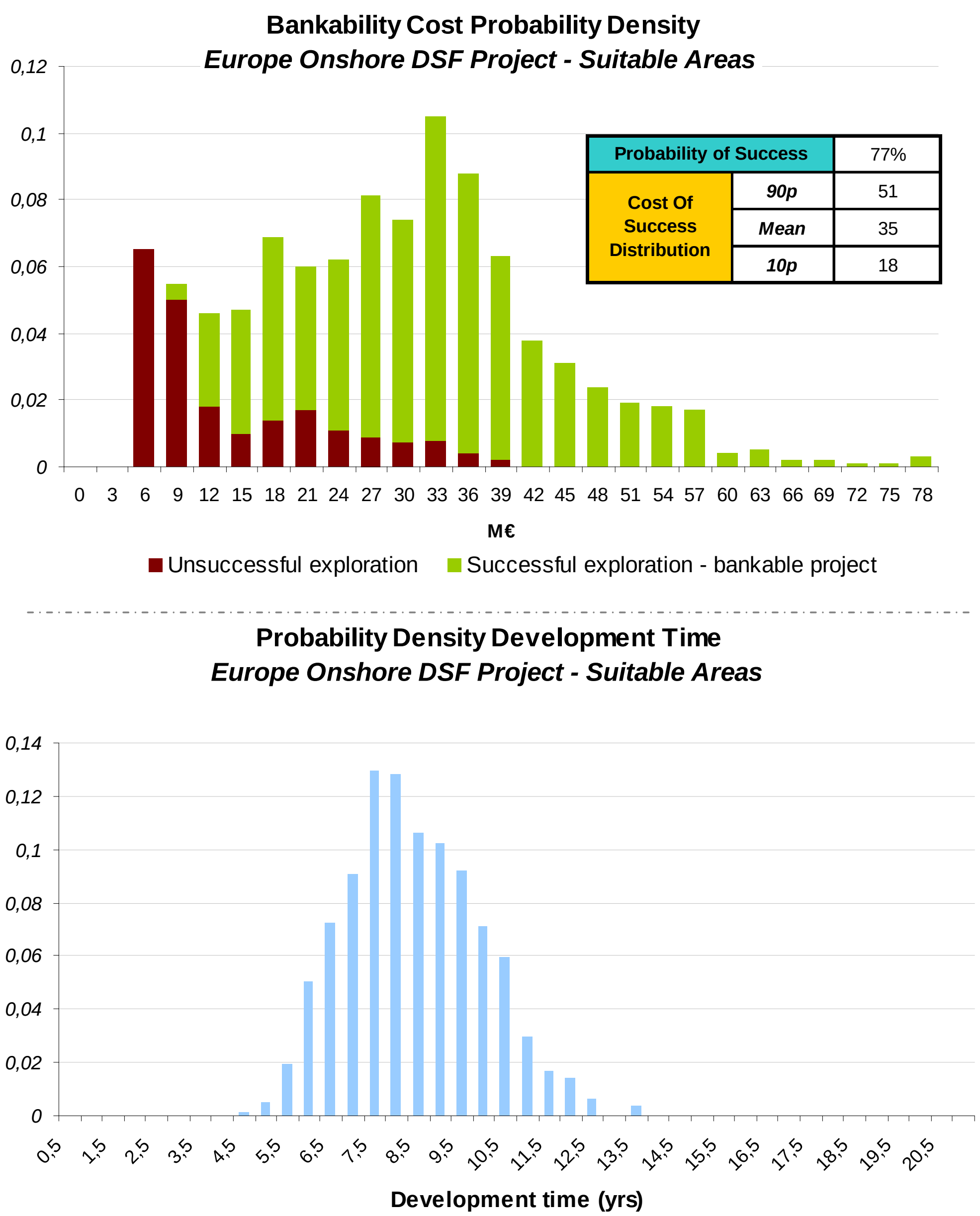


Figure 99: DSF Onshore – Suitable Area – Development Time and Costs Distribution

Figure 100 and Figure 101 give bankability costs and development time for DSF in Suitable areas for shallow and deep offshore respectively. These figures can be compared with Figure 26 and Figure 28 in part 4.3 page 71.

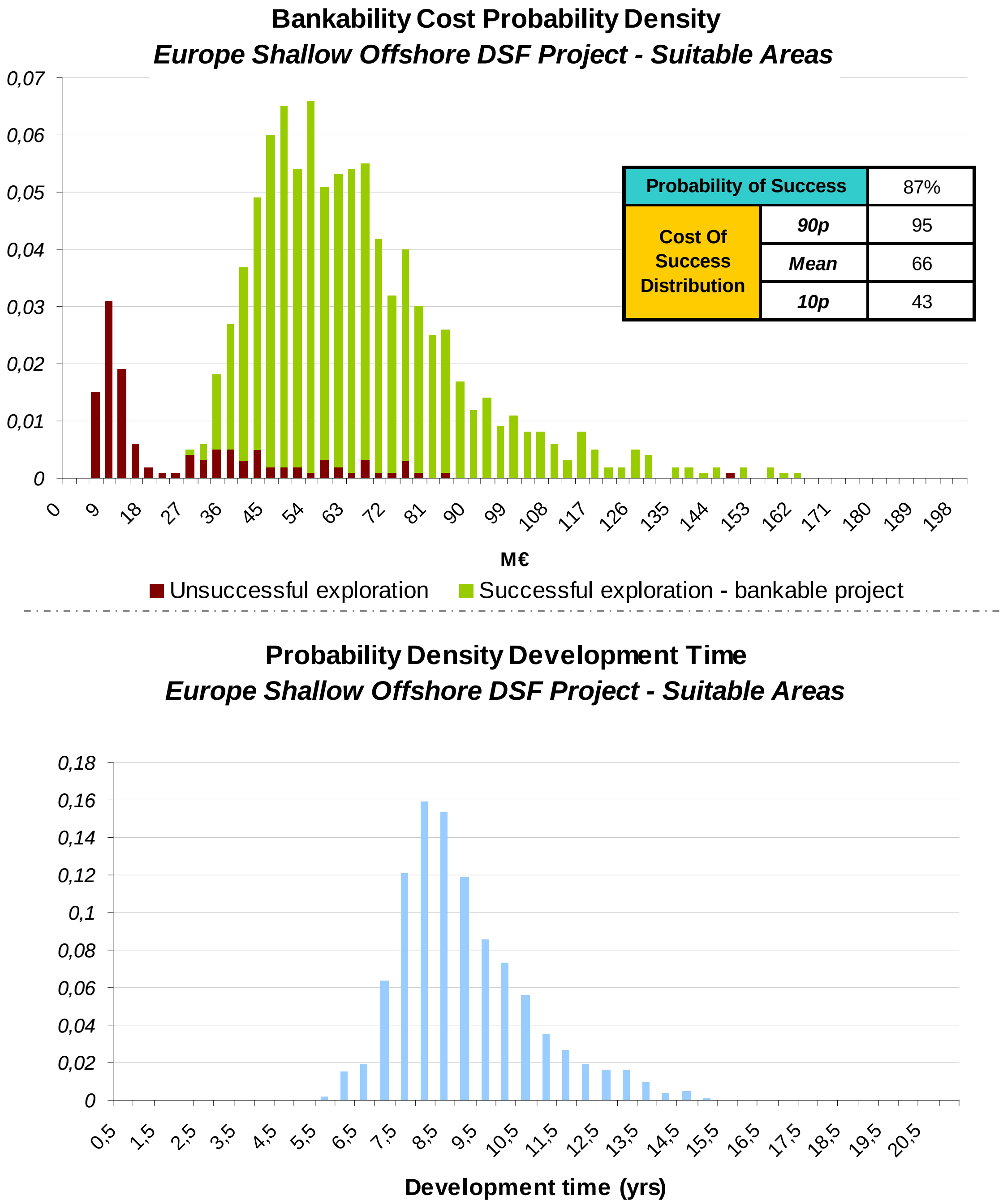


Figure 100: DSF Shallow Offshore – Suitable Area – Development Time and Costs Distribution

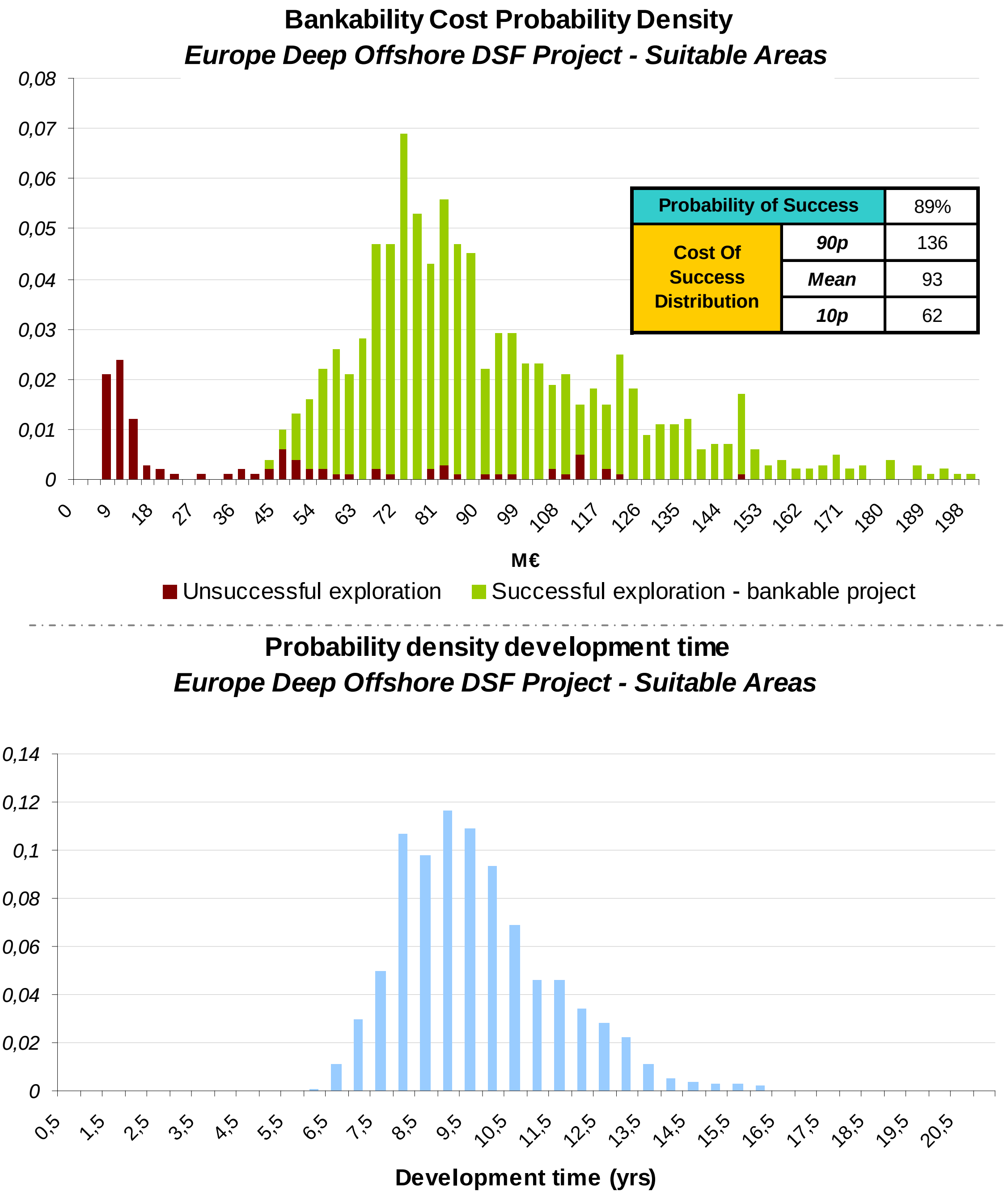


Figure 101: DSF Deep Offshore – Suitable Area – Development Time and Costs Distribution

Figure 102 and Figure 103 give bankability costs for Depleted Oil Fields onshore and offshore respectively. These figures can be compared with Figure 30 and Figure 31 in part 4.4 on page 79 which give the same information for Depleted Gas Fields

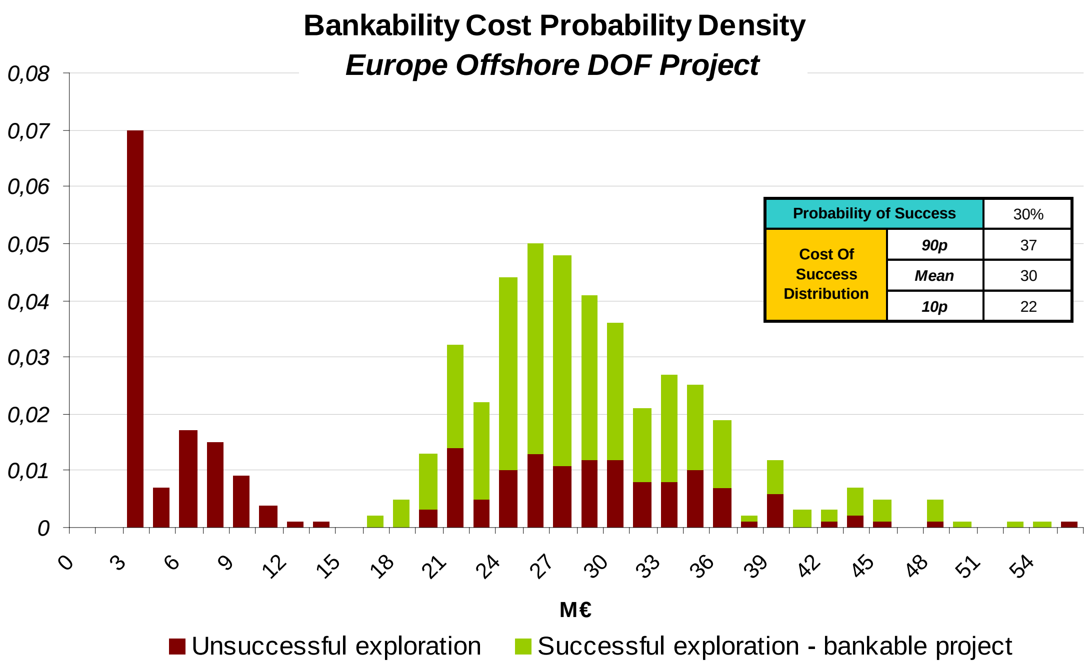


Figure 102: DOF Onshore – Development Costs Distribution

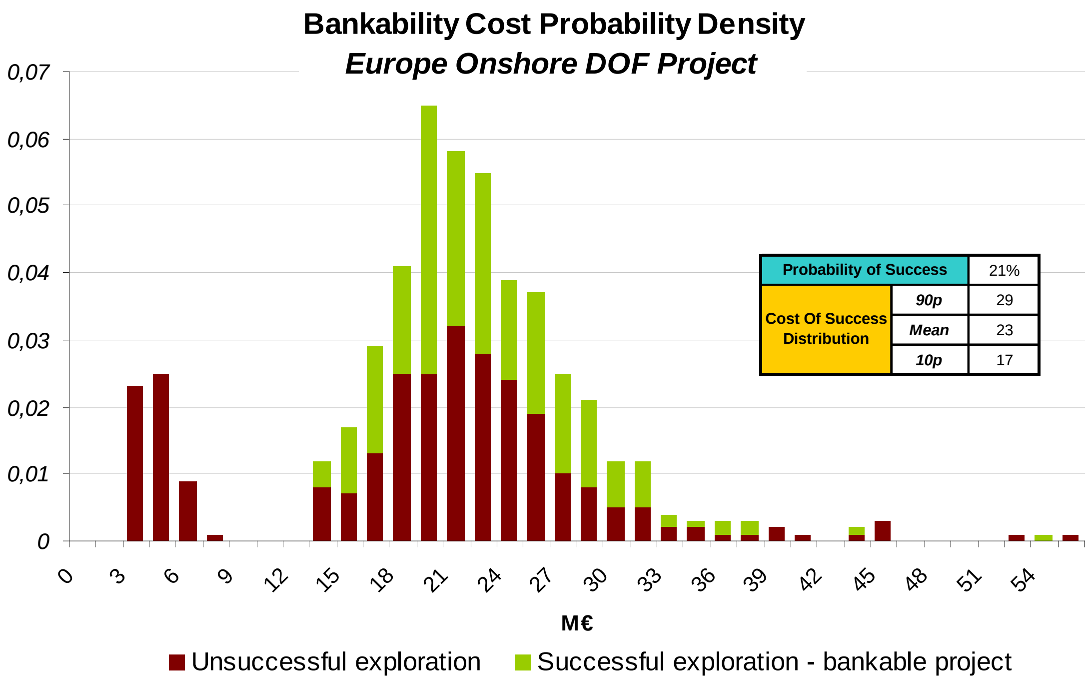


Figure 103: DOF Shallow Offshore – Development Costs Distribution

H.2. Regional Breakdown for Bankability Before 2020 – Suitable Area

The following figures are showing examples of cost variations for different cases.

Figure 104 shows the ranges of costs for the example of onshore deep saline formation project to be developed in suitable areas as defined in suitability map showed on Figure 14.

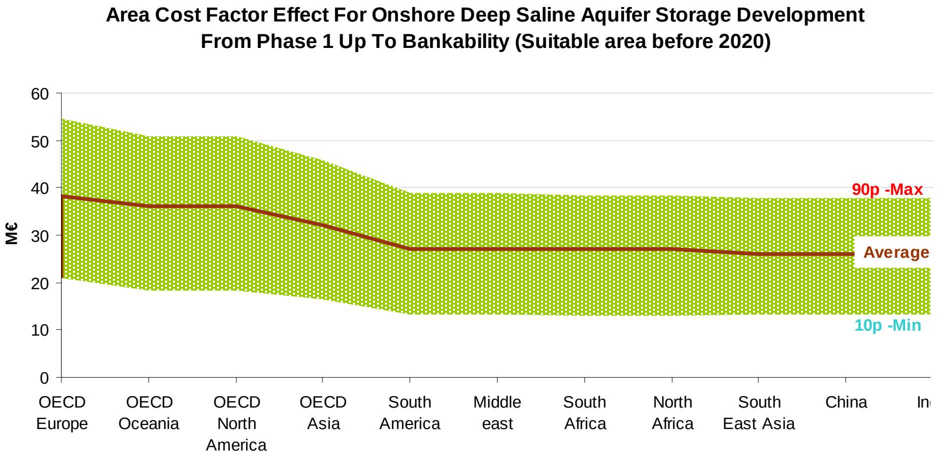


Figure 104: Regional cost breakdown - onshore deep saline formation project - Suitable area

Figure 105 shows the ranges of costs for the example of offshore deep saline formation project (shallow water) to be developed in suitable areas as defined in suitability map showed on Figure 14.

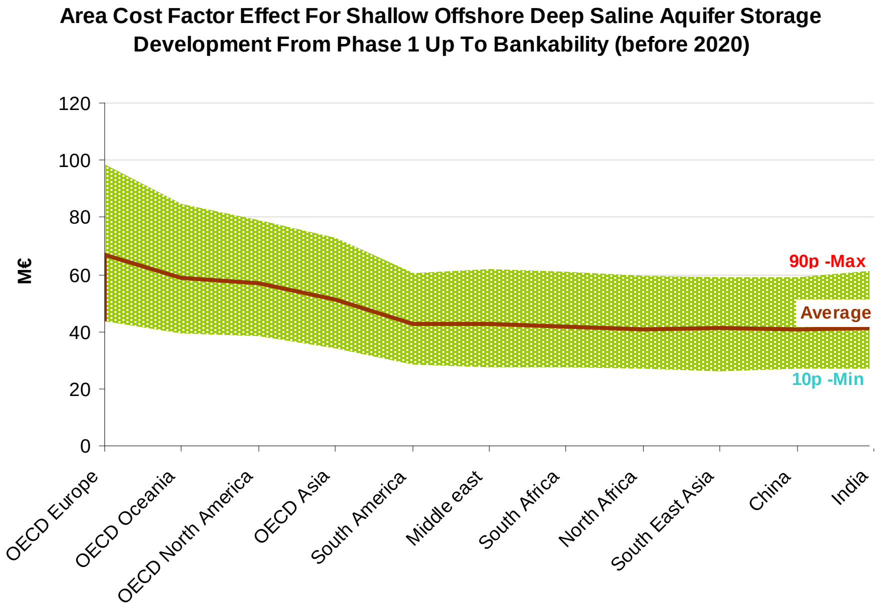


Figure 105: Regional cost breakdown - offshore (shallow water) deep saline formation project - Suitable area

Figure 106 and Figure 107 are showing the cost regional variability for the case of storage project into an offshore (resp. onshore) depleted gas field.

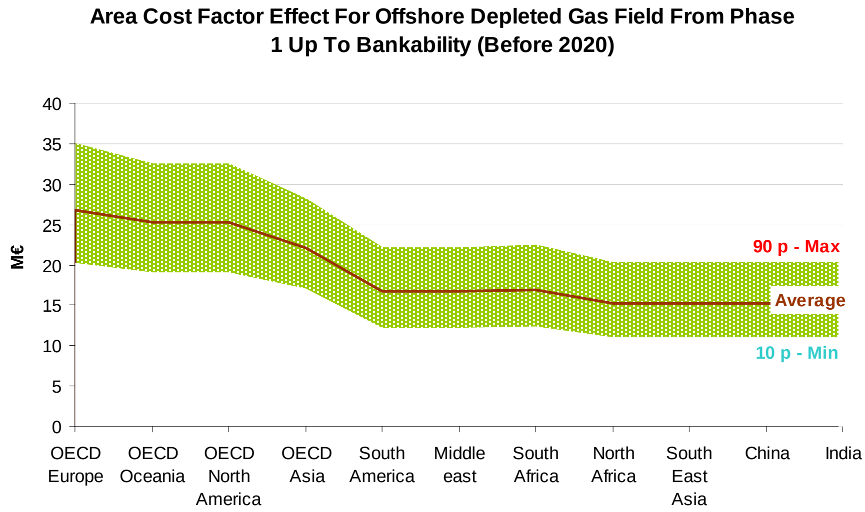


Figure 106: Regional cost breakdown - Offshore Depleted Gas Field

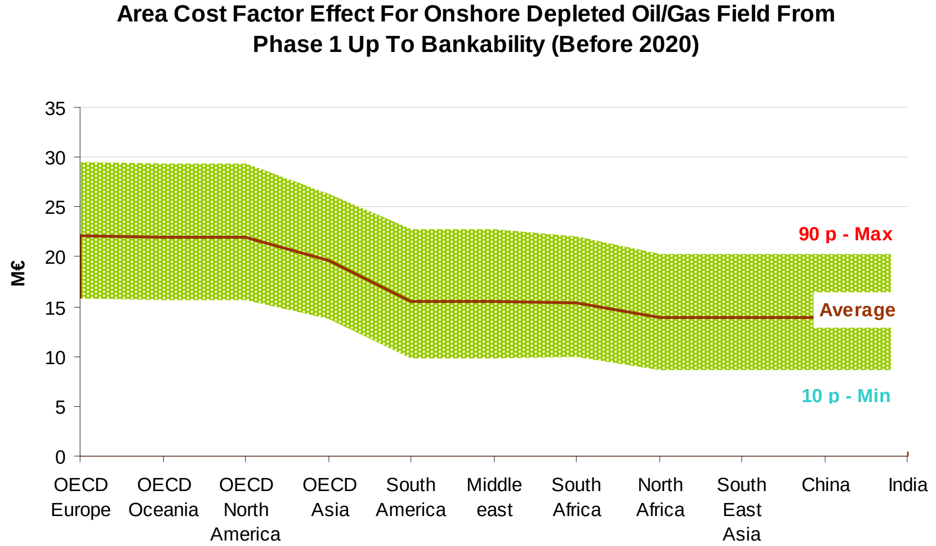


Figure 107: Regional Cost Breakdown - Onshore Depleted Gas Field

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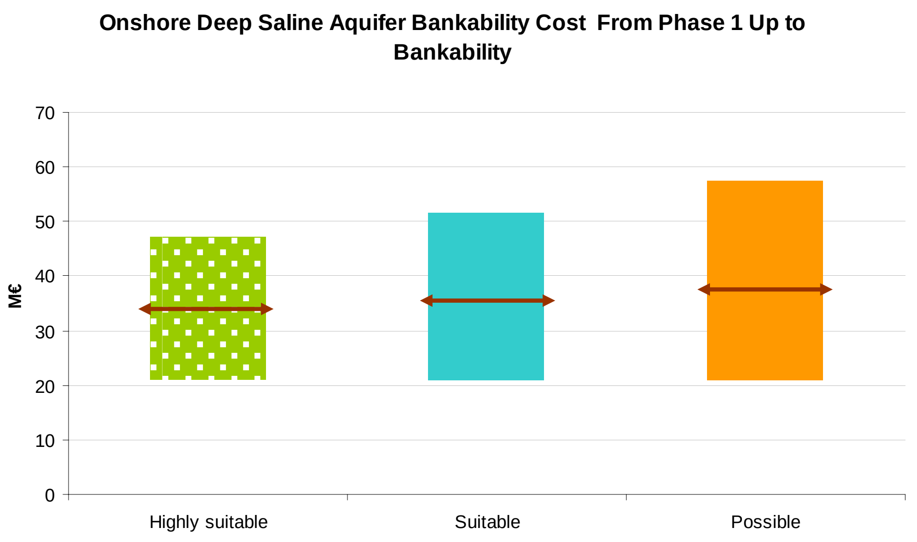
H.3. Success and Failures Rates

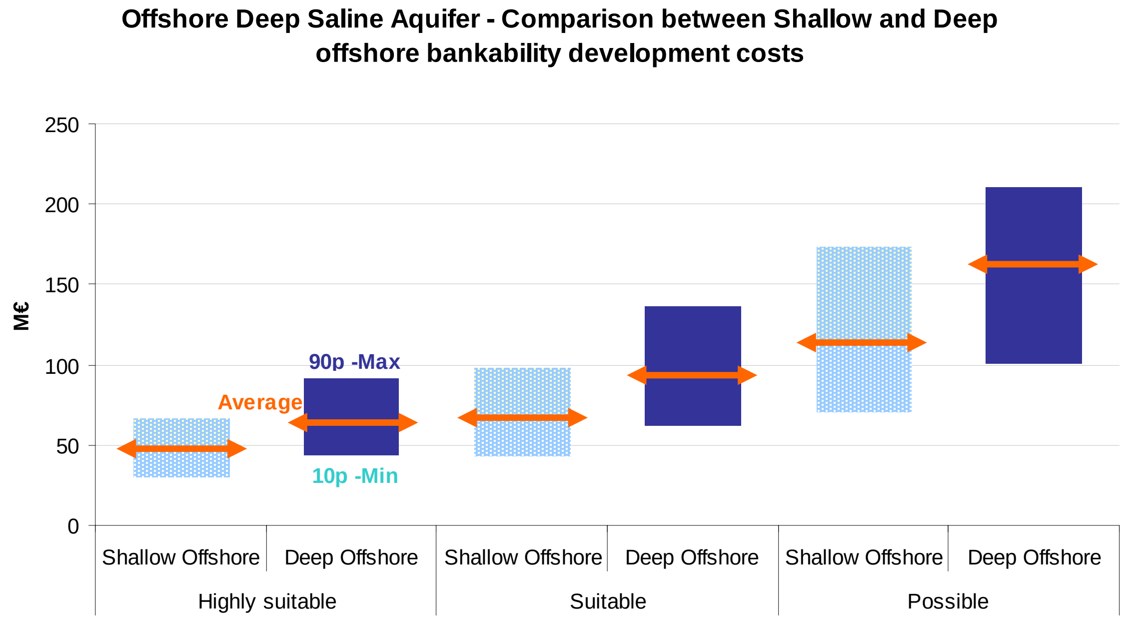
The following figures are showing the variability of success costs from Phase 1 up to bankability for the cases of:

1. Onshore saline formation (Figure 108),
2. Offshore shallow and deep water saline formation (Figure 109),
3. Depleted oil and gas fields onshore (Figure 110),
4. Depleted oil and gas fields offshore (Figure 111).



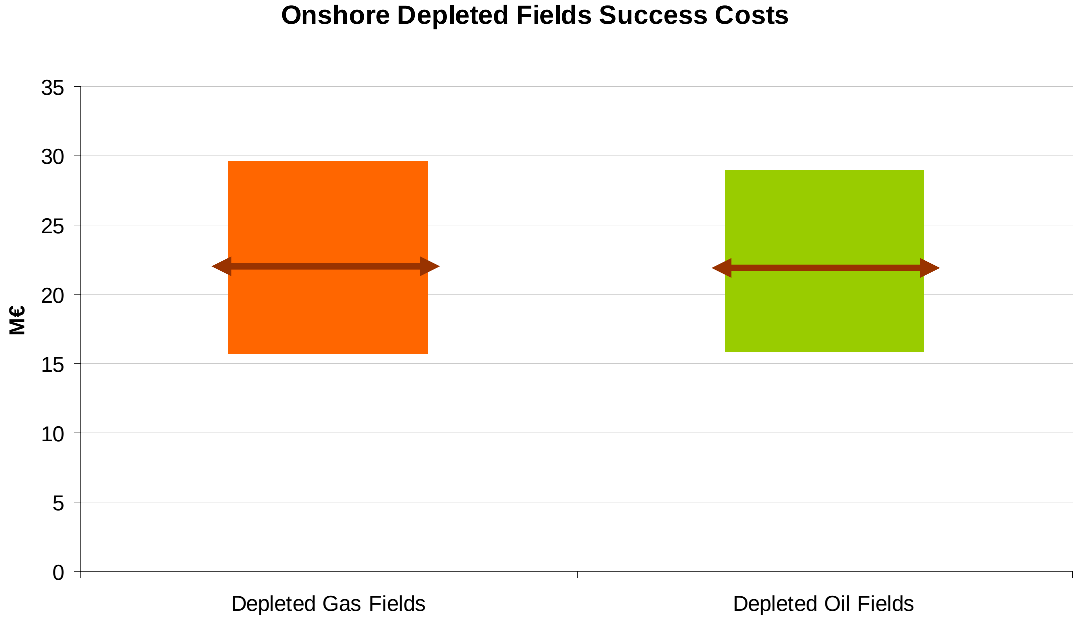
Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 108: Success cost comparison according to suitability - onshore deep saline formation projects



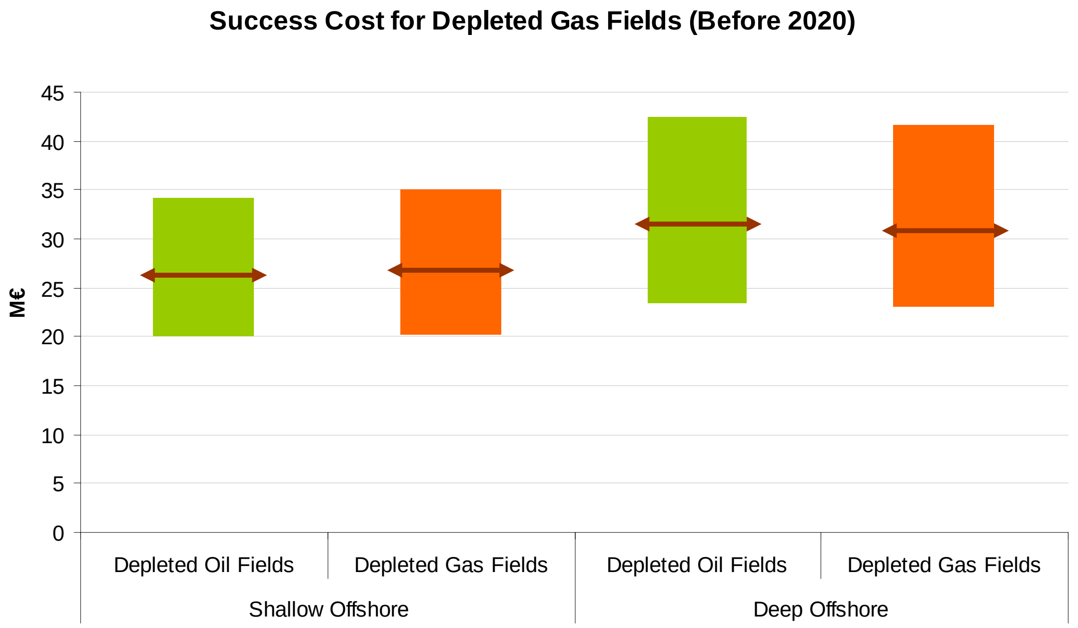
Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 109: Success cost comparison according to suitability - Offshore deep saline formation projects



Note: the line/arrow indicates the mean value (modal value) of the distribution

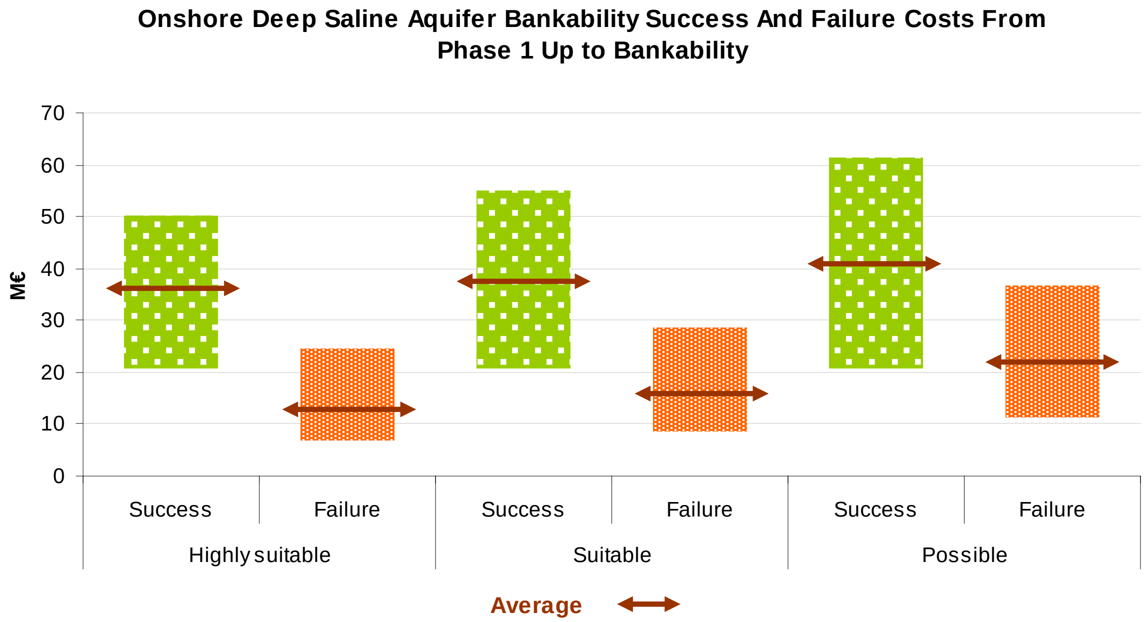
Figure 110: Success cost for onshore depleted fields projects



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 111: Success cost for offshore depleted fields projects

H.4. Overall comparison according to suitability and nature of project



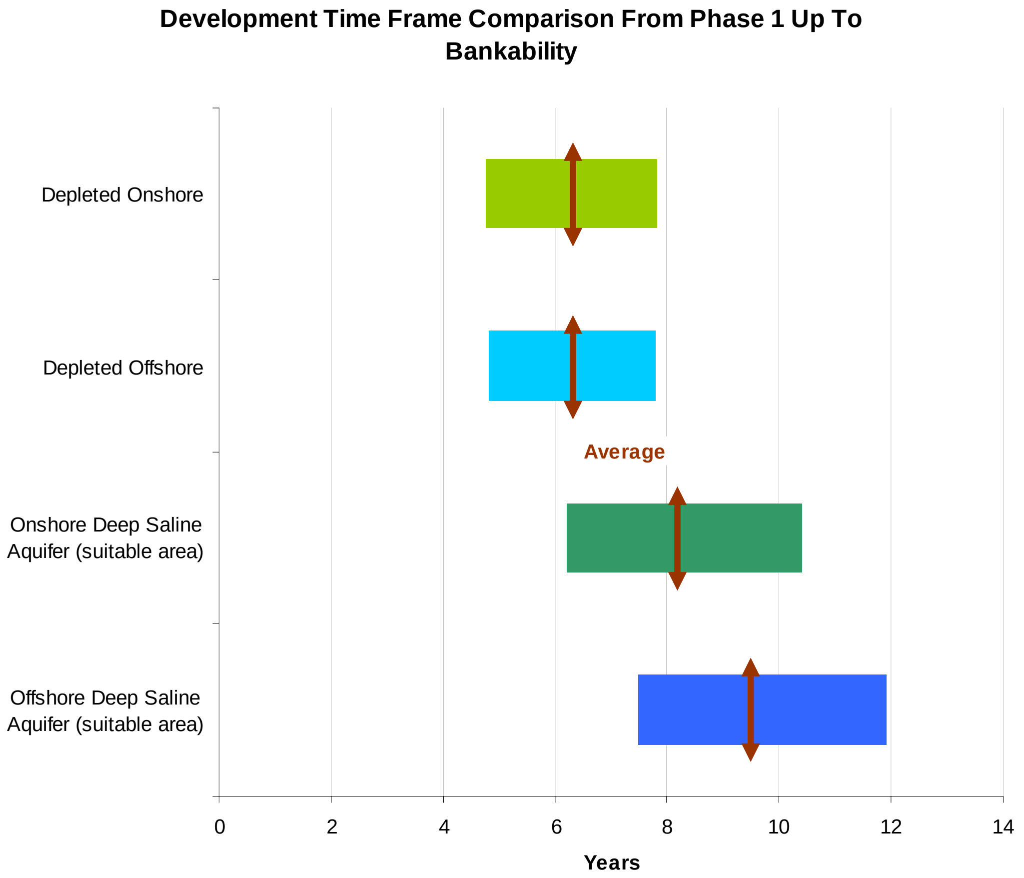
Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 112: Comparison of success and failure costs according to suitability - onshore deep saline formation project

Figure 112 is showing the average and range of variability of both success and failure costs associated with the development of an onshore deep saline formation project. Unsurprisingly, ranges and values are increasing with a lower suitability of a given area.

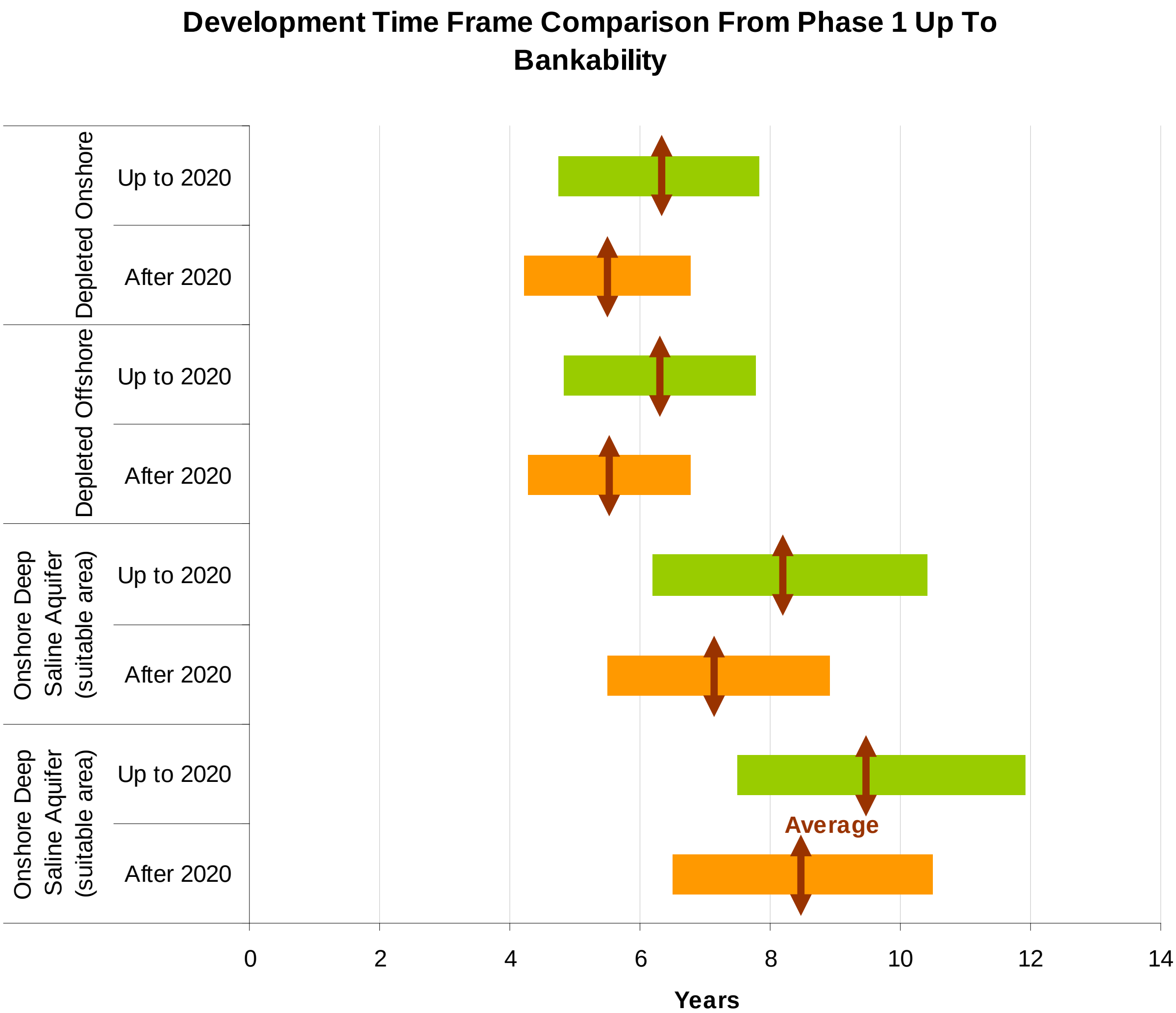
H.5. Time of Development

Figure 113 is showing the development times from Phase 1 up to success to reach bankability. It is noteworthy to mention that beyond the average development times shown with the arrows, the range of values for reaching bankability in 2020 and not beyond, can impact the number of projects of deep saline formation types (both onshore and offshore).



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 113: Development times for storage projects



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 114: Evolution of development times for different storage projects up to and after 2020

I. TECHNICAL BANKABILITY GAP ANALYSIS 2020 – NEW PROJECTS NEEDS

The objective of this analysis is to find where additional storage bankability assessment should be performed in order to achieve the 100 projects by 2025. We remind the reader that in this approach, the 100 projects target does not include CO_2-EOR contribution to the CCS deployment. Please refer to part 5.3 page 110 to see how CO_2-EOR is included in the study. This analysis requires a first assessment of source-sink matching on a regional basis. For such a quick-look assessment, the CO_2 emission sources below 1Mtpa have been neglected. Consequently, such qualitative source-sink analysis could be altered at a local level by early opportunities.

The locations pointed out are merely indicative. They have been chosen in order to characterize the potential of area where no CCS project currently exists and close to CO_2 emission hubs. As mentioned earlier, storage development is often on the critical path of development of CCS projects. Therefore, it is necessary to start characterization ahead of schedule in order not to be constrained by storage assessment issues.

Moreover, the objective of the storage characterization programme is to explore suitability of areas closed to emission hub. Indeed the suitability map (Figure 14) evolves in time. A characterization programme led in a possible area might conclude it should be finally labelled as suitable. The possible label only indicates that the requirements for CO_2 storage could be present in those areas and should be check. This is one of the objectives of this source sink matching.

I.1. China and India

The following Figure 53 shows on the same map of the present CO_2 power or industrial sources, and suitability areas. A simple qualitative source / sink matching indicates areas for these two countries where projects should be launched not later than 2012 in order to reach bankability between 2020 and 2022.

23 candidate projects can be found. Among them:

- 7 shallow offshore Highly suitable DSF
- 3 Shallow offshore possible DSF
- 6 onshore Highly suitable DSF
- 2 onshore possible DSF
- 4 onshore depleted
- 2 offshore depleted

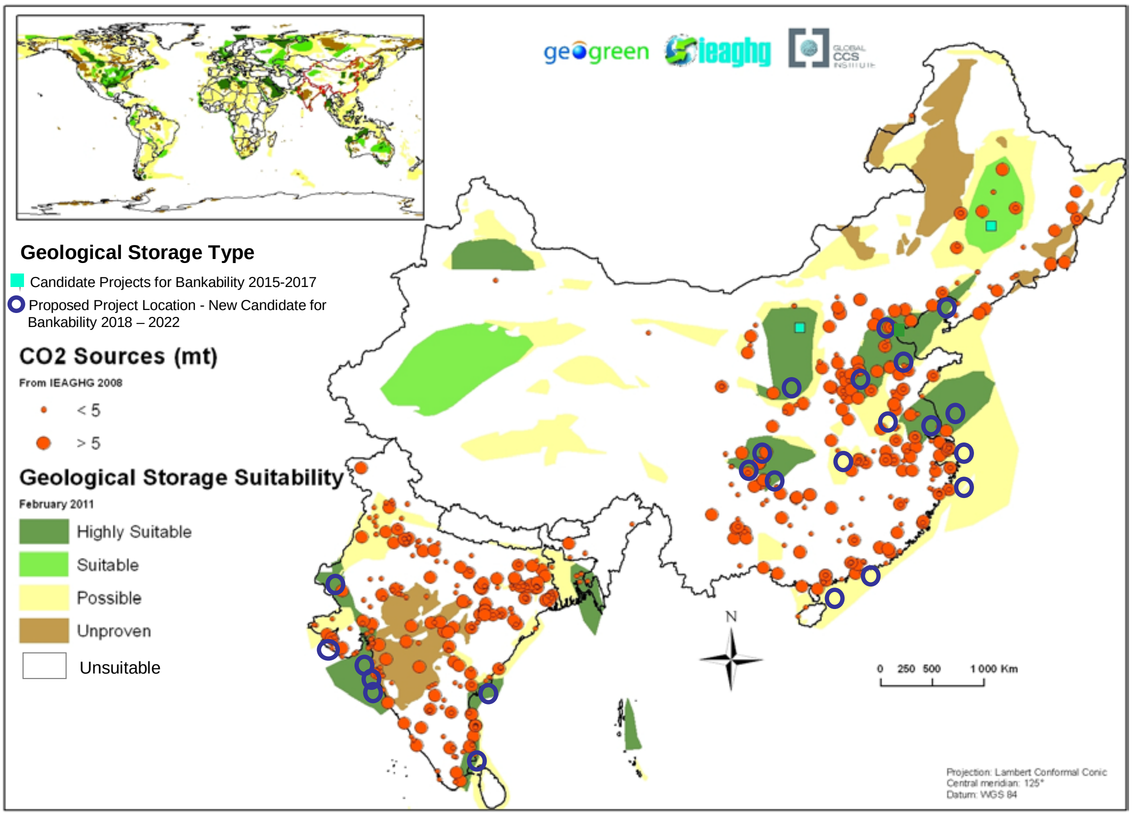
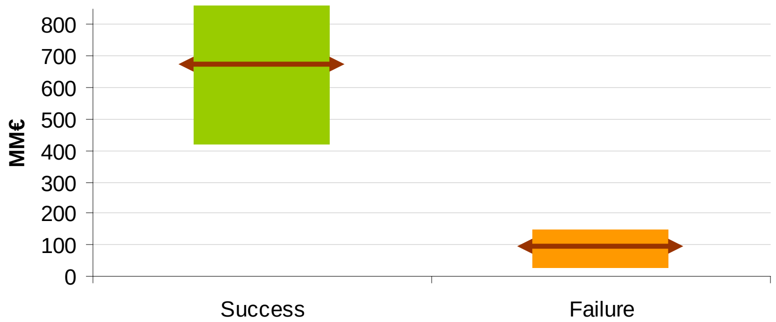


Figure 115: China and India - Additional candidates for bankability 2020-2022

Following the same probabilistic approach of success as developed in section 4, these 23 candidates could bring <u>19 additional bankable projects, therefore reaching IEA recommendation.</u>

Such additional projects would have the following cumulated success, and probabilistic failure cost. This gives an average success cost of 36 M€ largely below OECD one (Figure 116).



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 116: Success and failure costs - additional candidates for bankability China and India

I.2. Other Non OECD Countries

I.2.1. South America

The same approach as seen for China and India was followed for South America. The qualitative source sink matching indicates areas where projects should be launched not later than 2012 in order to reach bankability between 2020 and 2022.

7 candidate projects may be found. Among them:

- 1 onshore suitable DSF
- 3 onshore possible DSF
- 2 onshore depleted
- 1 offshore depleted

The following Figure 117 shows the location of these additional candidates for bankability.

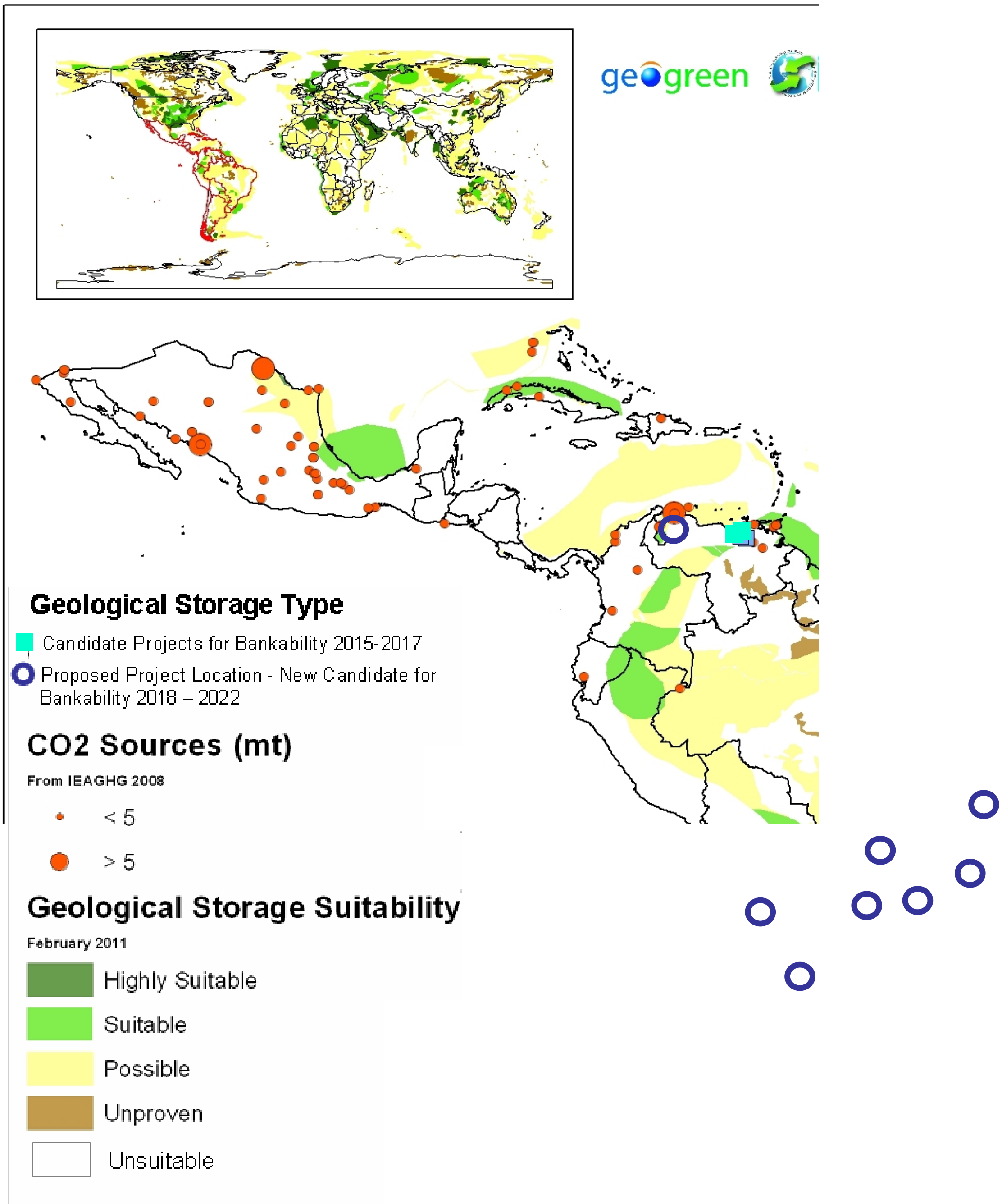
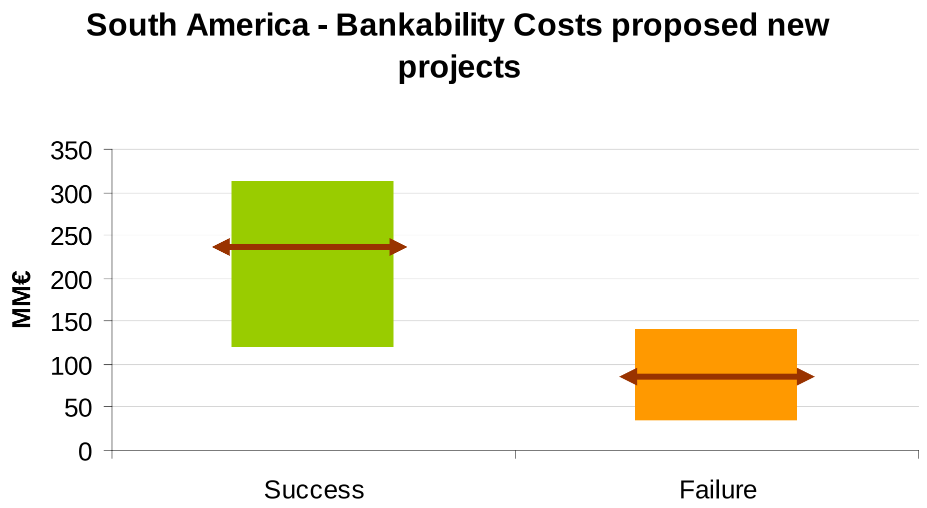


Figure 117: South America - Additional candidates for bankability 2020-2022 – Projects in unsuitable areas are depleted field and not DSF

Following the same probabilistic approach of success as developed in section 4, these 7 candidates could bring 5 additional bankable projects.

Such additional projects would have the following cumulated success, and probabilistic failure cost. This gives an average success cost of 48 M€ (Figure 118) which is above the average success cost for China and India, due to both labour cost and probability of success (storage projects to be developed in possibly suitable areas).



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 118: Success and failure costs - additional candidates for bankability South America

I.2.2. Africa

The same approach as for China, India, and South America was followed for Africa. The qualitative source sink matching indicates areas where projects should be launched not later than 2012 in order to reach bankability between 2020 and 2022. One of the main issues for this region concerns the lack of large scale sources to take advantage of the important storage potential.

6 candidate projects may be found. Among them:

- 1 offshore highly suitable DSF
- 2 offshore suitable DSF
- 1 onshore depleted
- 2 offshore depleted

The following Figure 119 is showing the location of these potential additional candidates for bankability.

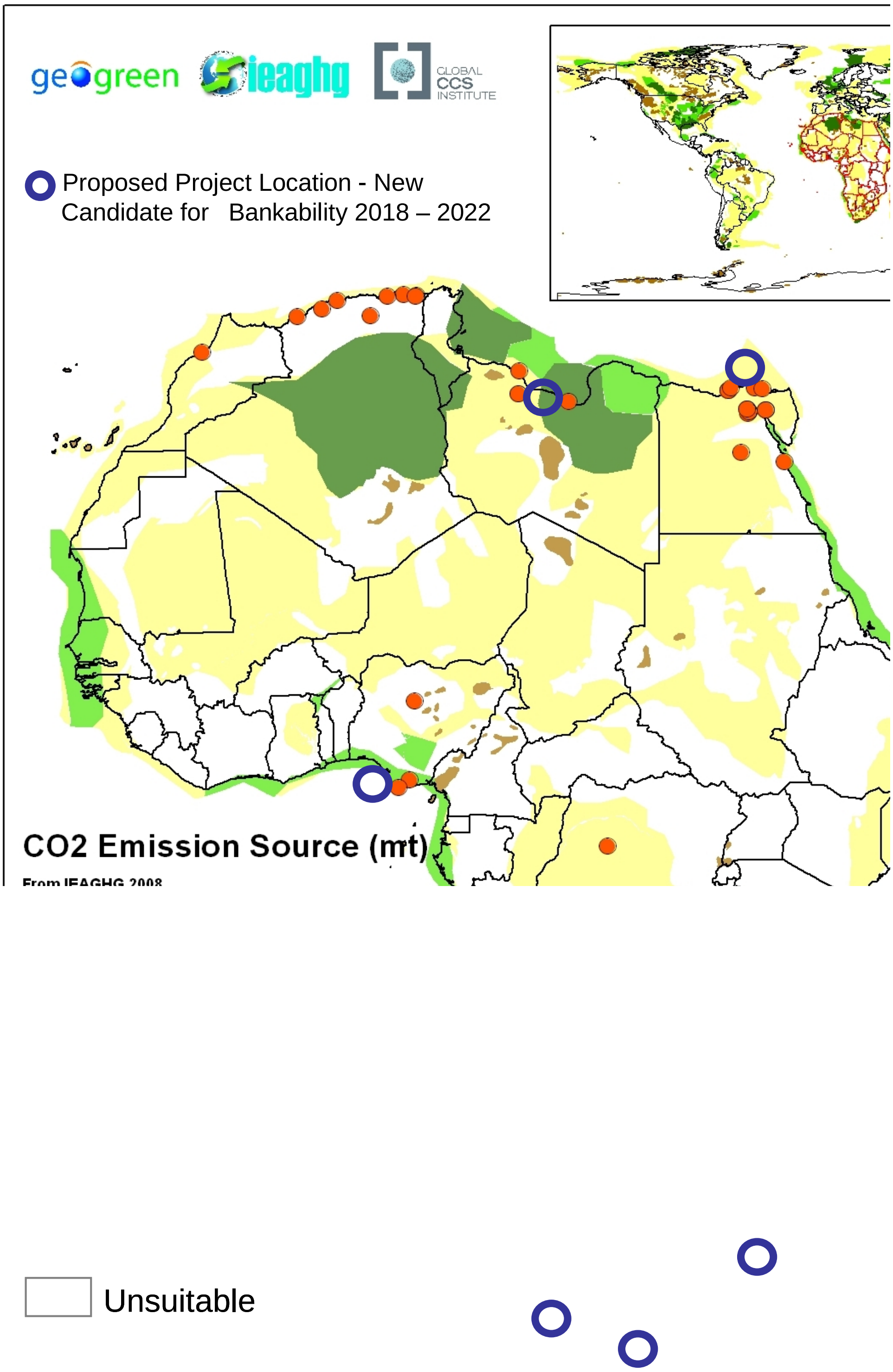


Figure 119: Africa - Additional candidates for bankability 2020-2022 - Projects in unsuitable areas are depleted field and not DSF

Following the same probabilistic approach of success as was developed in section 4, these 6 candidates could bring 4 additional bankable projects.

Such additional projects would have the following cumulated success, and probabilistic failure cost. This gives an average success cost of 50 M€ (Figure 120) which is above the average success cost for China, India, and South America, due to the nature of projects (offshore) with a high probability of success (storage projects to be developed in suitable areas).

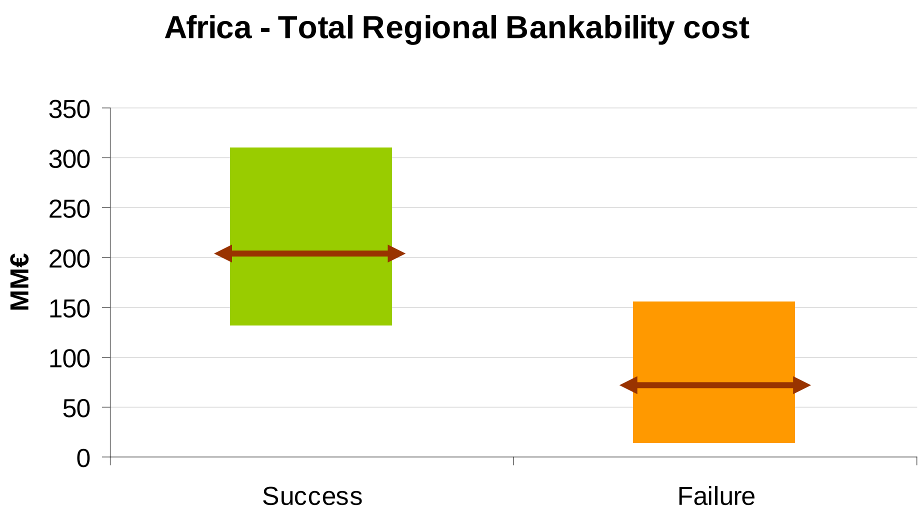


Figure 120: Success and failure costs - additional candidates for bankability – Africa

I.2.3. South East Asia

The same approach as for China, India, South America, and Africa was followed for South-East Asia. The qualitative source sink matching indicates areas where projects should be launched not later than 2012 in order to reach bankability between 2020 and 2022.

We did not consider the development of projects in onshore oil provinces like Java, Borneo and Sumatra due to the lack of nearby large scale sources. On the source standpoint, early opportunities like natural gas treatment can play an important role in those areas (Fields with high CO_2 content). As many of those fields are located offshore, we expect some offshore DSF developments in the area.

6 additional candidate projects can be found. Among them:

- 3 offshore depleted (1 shallow water)
- 2 offshore DSF deep water
- 1 offshore DSF shallow water

The following Figure 121 is showing the location of the additional candidates.

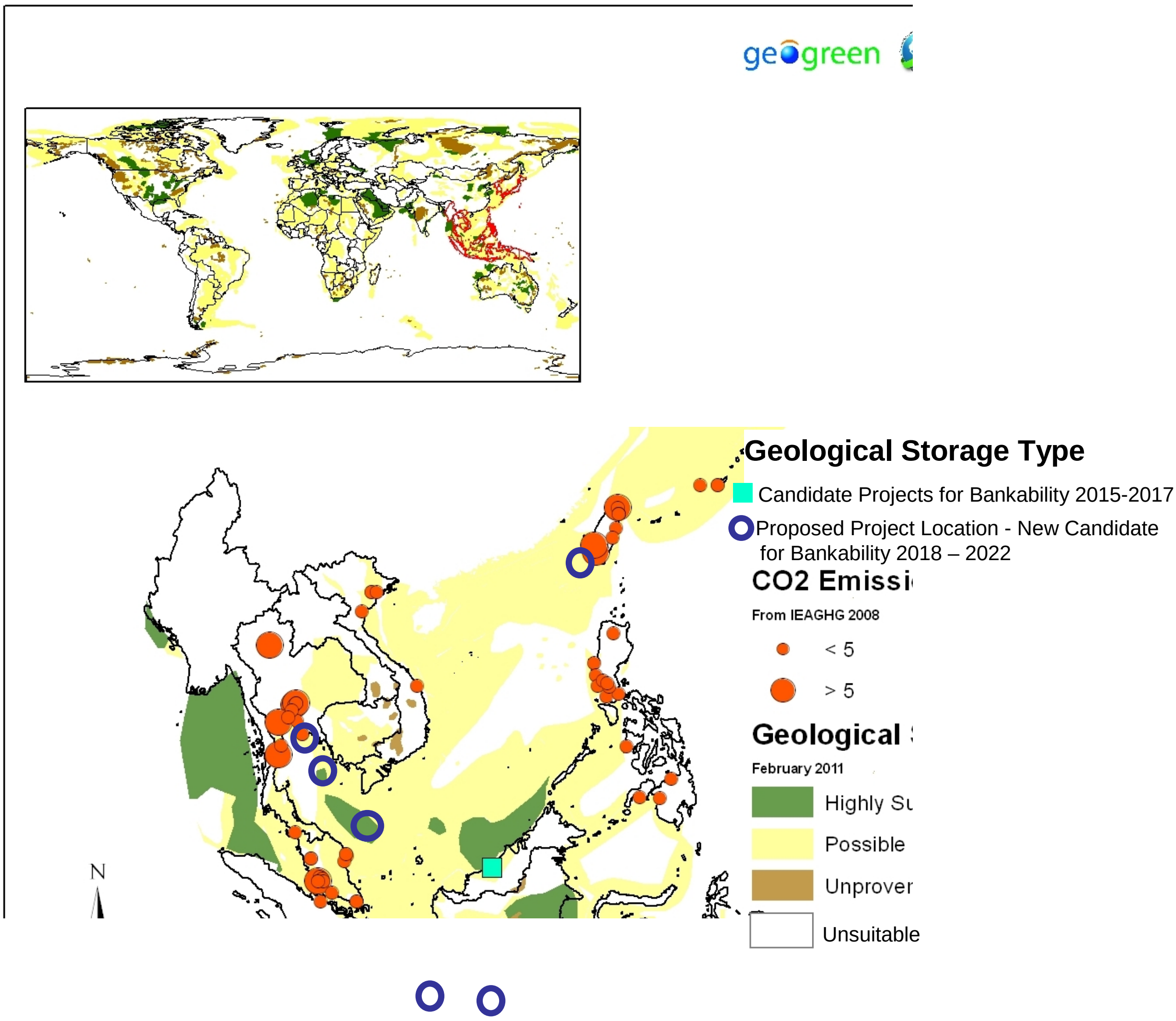
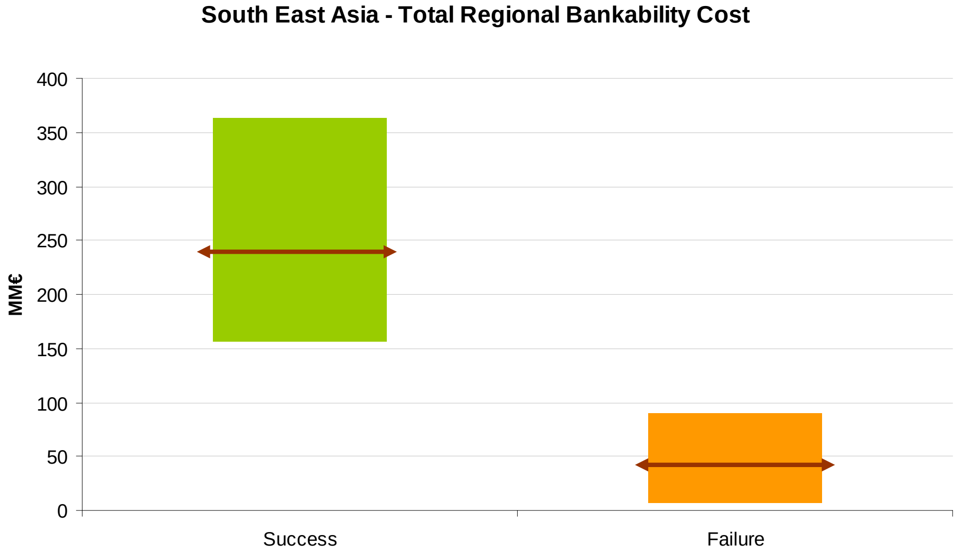


Figure 121: South-East Asia - Additional candidates for bankability 2020-2022

Following the same probabilistic approach of success as was developed in section 4, these 6 candidates could bring 4 additional bankable projects.

Such additional projects would have the following cumulated success, and probabilistic failure cost. This gives an average success cost of 60 M€ (Figure 122) which is above the average success cost for China, India, due to the nature of projects (offshore), half of them being in possibly suitable areas, the other half being in highly suitable areas.



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 122: Success and failure costs - additional candidates for bankability – South-East Asia

I.3. North America and Mexico

On USA and Canada, the qualitative source sink matching indicates areas where projects should be launched not later than 2012 in order to reach bankability between 2020 and 2022. We did not assume the development of new projects in the Canadian Alberta Saskatchewan area since there are a lot of planned projects already in this area. The characterization need is therefore less acute.

The offshore location even if it might be counterintuitive due to the lower onshore storage costs and the availability of reservoirs have been picked up due to favourable source sink matching criteria (Florida), the presence of depleted fields and infrastructure US and Mexican golf of Mexico.

10 additional candidate projects can be found. Among them:

- 3 onshore suitable DSF
- 1 onshore Highly suitable DSF
- 1 onshore possible DSF (Mexico)
- 2 onshore depleted
- 1 offshore depleted (1 shallow)
- 1 offshore possible DSF shallow
- 1 offshore suitable DSF Shallow

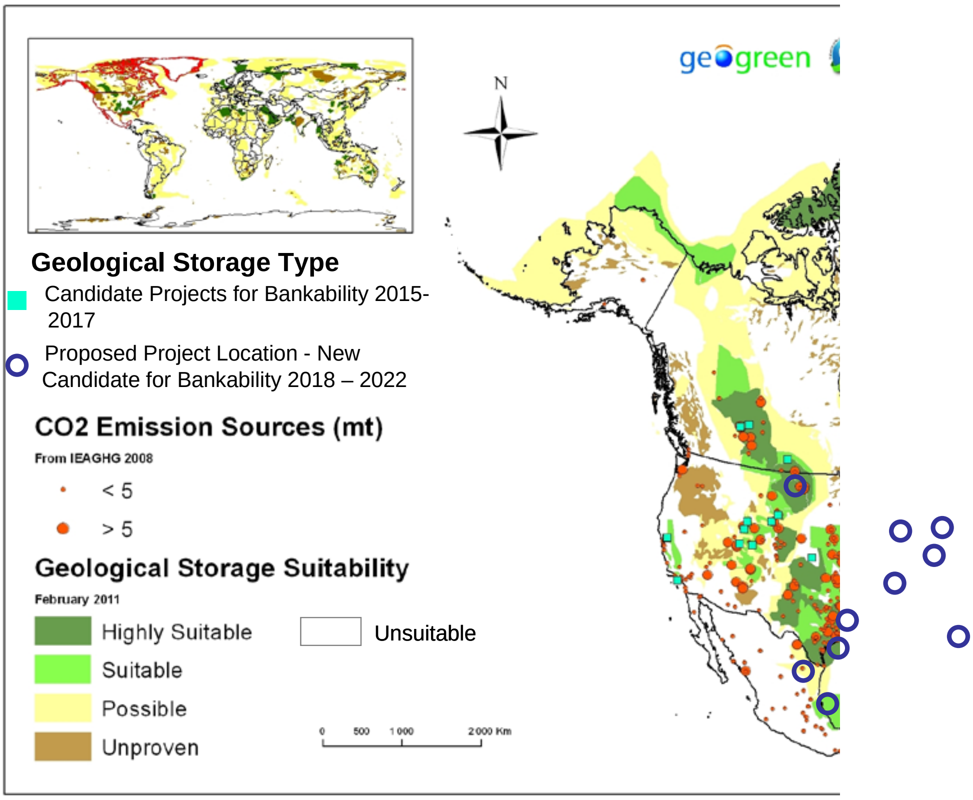
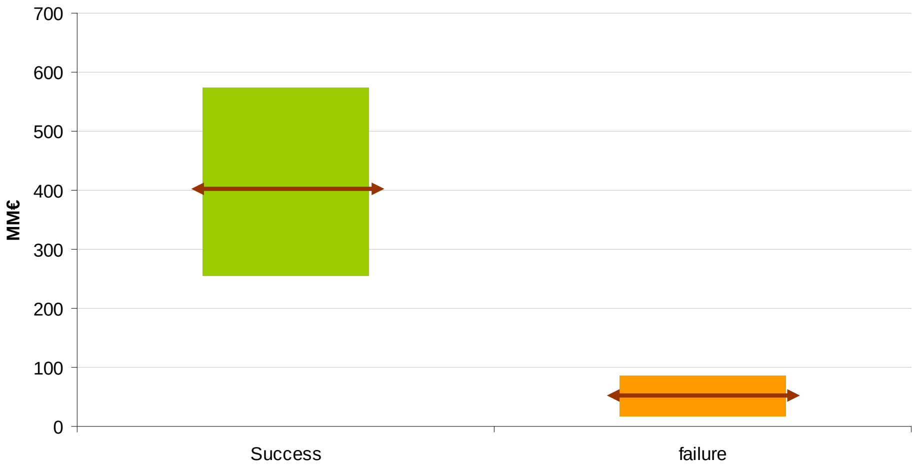


Figure 123: North America - Additional candidates for bankability 2020-2022

Following the same probabilistic approach of success as was developed in section 4, these 10 candidates could bring 8 additional bankable projects. Such additional projects would have the following cumulated success, and probabilistic failure cost. This gives an average success cost of 50 M€ (Figure 124) which is quite low due to nature of project (onshore - suitable areas).



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 124: Success and failure costs - additional candidates for bankability – North America and Mexico

I.4. Middle East

The following Figure 125 shows that a strong potential exists for storage projects in deep saline formation. Given the global CO_2 emissions in the area, the global potential for storage seems to be largely exceeding the local requirements.

Additionally, some projects could be developed over the medium term in depleted fields. Fields availability is a major issue for CO_2 storage. Indeed, with increasing oil prices, fields' lifetime is extending. Their availability for CO_2 storage therefore is difficult to assess. As discussed in section 5.3 page 110, CO_2-EOR potential is really important in this region. However, for political reason, we do not expect the development of many EOR projects. The main driver for EOR projects in this region if for now the knowledge build-up.

We estimate that 5 storage projects could be reasonably developed in this area to cope with present and future emission sources.

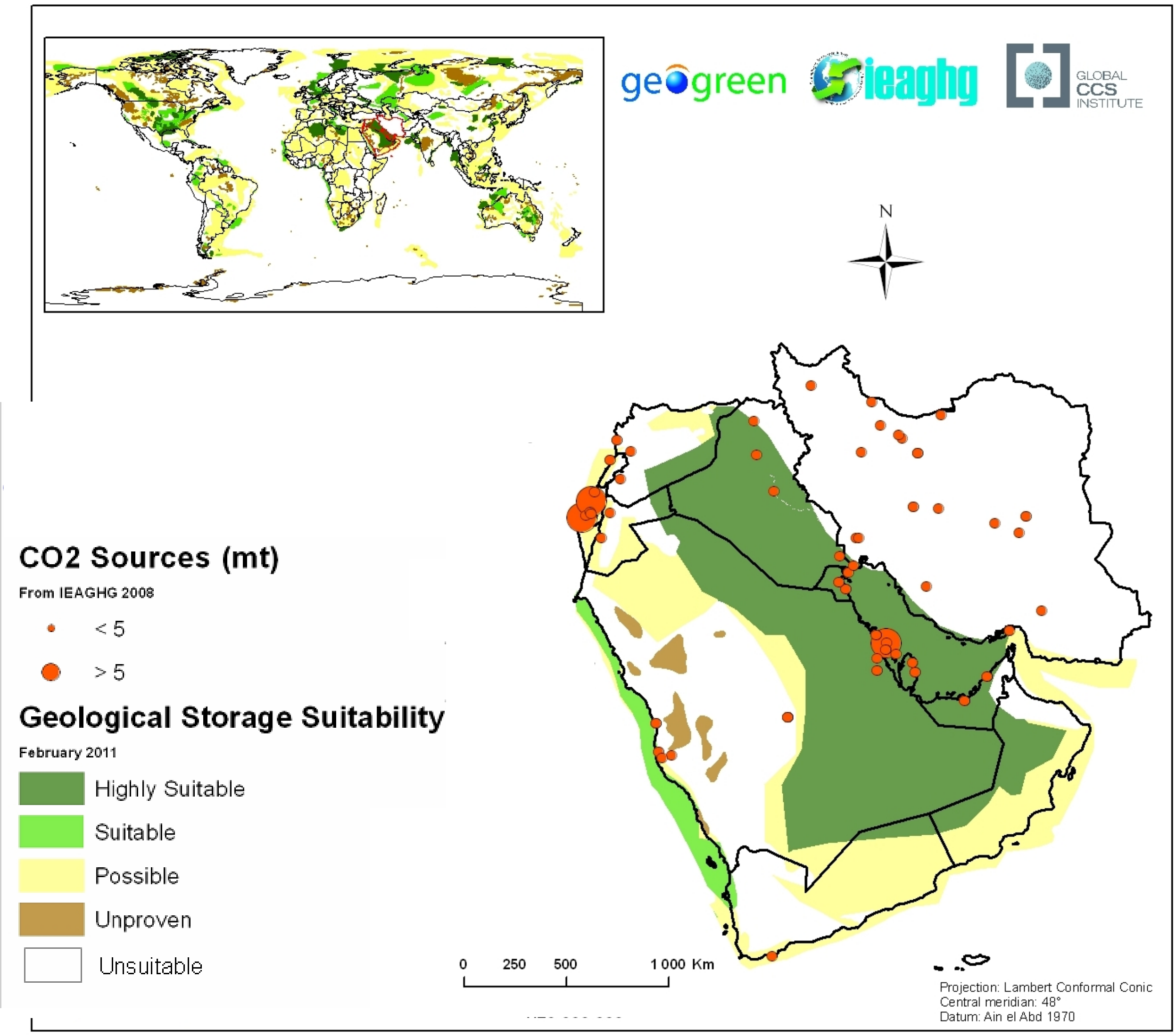
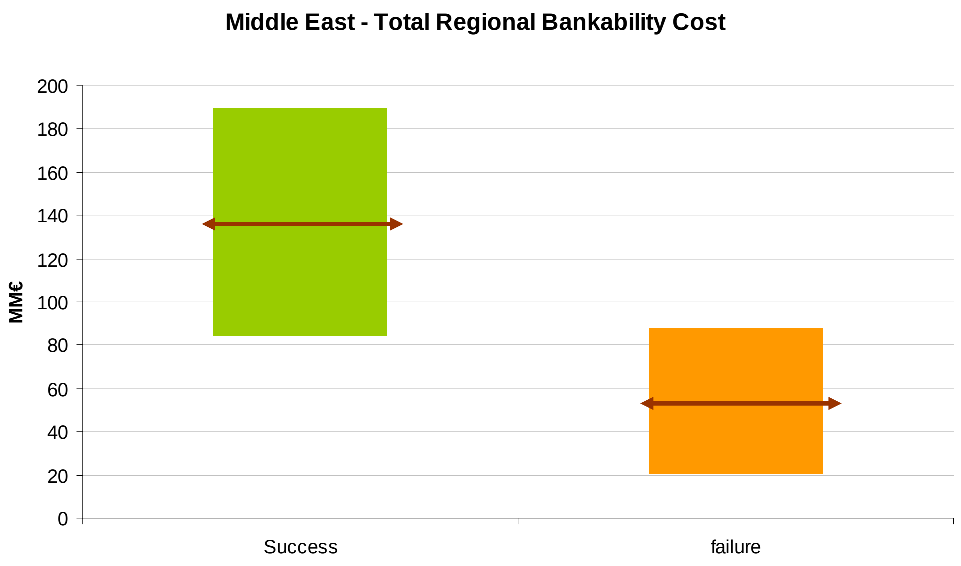


Figure 125: Middle East - Sources and sink situation

Following the same probabilistic approach of success as was developed in section 4, these 5 candidates could bring 5 additional bankable projects.

Such additional projects would have the following cumulated success, and probabilistic failure cost. This gives an average success cost less than 30 M€ (Figure 126) which is the lowest cost on a regional basis (highly suitable areas).



Note: the line/arrow indicates the mean value (modal value) of the distribution

Figure 126: Success and failure costs - additional candidates for bankability – Middle East

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