METHODOLOGIES AND TECHNOLOGIES FOR MITIGATION OF UNDESIRED CO_2 MIGRATION IN THE SUBSURFACE

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METHODOLOGIES AND TECHONOLOGIES FOR MITIGATION OF UNDESIRED CO_2 MIGRATION IN THE SUBSURFACE

Key Messages

- Migration of CO_2 can occur via engineered or natural pathways. Mitigation methods related to wells are the best established.
- Measures related to natural pathways are likely to be via pressure management methods.
- There are many novel technologies available, though current mitigation plans for existing projects include only mature technologies. However, mitigation plans should be flexible to take account of newer technologies when they become available and allow holisitic decision making
- All mitigation and remediation plans should be site-specific and risk-based.

Background to the Study

Site characterisation for each potential geological storage site is carried out to identify those where it is extremely unlikely that any CO_2 leakage would occur. Extensive Risk Assessments and MMV plans will be performed and designed for each selected site. However, it is also important to have a mitigation and remediation plan in place in the unlikely event that migration of CO_2 out of the storage complex occurs.

A primary role of risk management is to drive the development of the monitoring program to be best equipped to identify unexpected movement of CO_2 in the subsurface, either within the target zone or beyond, but prior to any potential migration to the near-surface. As part of the risk management structure, methods for mitigating, preventing and, if needed, remediating, adverse effects related to any unexpected behaviour will be part of the overall MMV and operating plans.

Many of the methods for mitigation span a range of specialties, and have not often been part of ongoing discussions on aspects of geologic storage; however, regulators, operators, and some laypersons are interested in methods that can mitigate unpredicted CO_2 movement.

Mechanisms that could lead to migration out of the storage complex and potentially leakage to the atmosphere or seepage into potable aquifers could include equipment failure e.g. wells, fault activation due to over-pressurisation, geochemical reactions between the CO_2 and the caprock and migration through weak points in the caprock. There are therefore a number of leakage/ migration scenarios that will need to be considered.

In the case of migration up wells and leakage to the surface, there are known methods for reparation that are used in other industries, such as the oil and gas industry, these include replacing the injection tubing and packers and plugging leaks behind the casing with cement. Mud can be pumped down an interception well in case of well blow out. Wells that cannot be repaired may be plugged and abandoned.

CO_2 may also migrate out of the storage formation, either from fractures in the caprock or migration through the caprock if the capillary threshold pressure is exceeded. There are a number of possible solutions to this, including reduction of pressure in the storage formation by stopping/ reducing injection or increasing the number of wells. Extracting formation water from the storage reservoir may allow steering of the CO_2 plume and will reduce the pressure. The pressure could also be increased in the overlying aquifer or upstream by water injection, thus forming a pressure barrier. It may also be possible to plug with low permeability materials.

In case of migration out of the confining structure from an unknown cause, the first step would be to stop injection, then begin investigation into the source of the migrating CO_2, by checking pressure and well logs and reviewing the local geology. Using this information, shallower zones can be drilled to locate the source and migrating CO_2 can be controlled by lowering the pressure in the storage zone or creating a hydraulic barrier. It may also be able to be plugged and the storage operation may have to be reconfigured to take account of the new information.

If CO_2 were to migrate into potable groundwater, any accumulations of CO_2 can be removed by drilling wells to intersect and extract them. CO_2 can also be extracted in the dissolved phase using extraction wells and aerating it. If the groundwater has been contaminated by other substances that have been mobilised by CO_2, then pump and treat methods may need to be applied. Hydraulic barriers could also be used to immobilise and contain the contaminants.

Leakage of CO_2 could adversely affect the vadose zone, ecosystem and surface water all of which would need remediating. CO_2 can be extracted from soil-gas by vapour extraction techniques by drilling wells. As CO_2 is a dense gas, it could be collected in subsurface trenches, extracted and reinjected or vented. Acidification of the soils from contact with CO_2 could be remediated by irrigation or drainage.

There also needs to be a consideration of leakage into the atmosphere. For large releases spread over a large area, dilution may occur from natural atmospheric mixing, otherwise fans could be used.

There have recently been modelling studies, looking at using extraction wells to remove CO_2. Some preliminary results show that this method may work fairly well on smaller plumes, but appear less effective with larger plumes. However, remediation of larger plumes may be more effectively carried out by simultaneous CO_2 extraction and injection of water.

CO_2GeoNet, a consortium based in Europe, was commissioned by IEAGHG to undertake this study.

Scope of Work

The driver behind this study is to develop a report built on the on the previous IEAGHG report on methods of leakage mitigation (2007/11). The proposed study should focus on current mitigation and remediation methods that may be applied or considered in site specific conditions in the event of unpredicted CO_2 migration.

Each geological storage site will have an adaptive site specific monitoring plan, based on a risk assessment. Detection of a significant irregularity may involve supplementing the monitoring program, in order to detect a possible leak and if necessary engaging mitigation measures.

A survey of mitigation methods should be provided; an example of the type of methods may include: decreasing injection rate or bottom hole pressure, drilling additional injection wells, relocating injection wells (potentially within the existing storage complex or in a separate and distinct unit), drilling pressure relief wells, performing well workovers, injecting chemical barriers, hydraulic barriers, triggering new processes within the MMV program, or cessation of injection and plugging and abandoning wells.

Certain practices including well remediation may be considered standard industry practice. However, some novel methods may be needed for mitigating unexpected CO_2 migration and remediation of the effects of leaked CO_2.

This will involve a review of:

- The state of knowledge of novel and standard mitigation and remediation practices
- Associated costs of the technologies and methodologies needed

Following this should be a review of mitigation plans in place on current/ past/ future CO_2 storage projects, where available. These can be compared and analysed to produce a recommended process to produce a mitigation and remediation plan.

The contractor was referred to the following recent IEAGHG reports relevant to this study, to avoid obvious duplication of effort and to ensure that the reports issued by the programme provide a reasonably coherent output:

- Remediation of Leakage (ARI, 2007/11)
- Potential Impacts of CO_2 Storage on groundwater (CO_2GeoNet, 2011/11)
- Caprocks for Geological Storage (CO2CRC, 2011/01)
- Pressurisation and Brine Displacement (Permedia, 2010/15)
- Safety in Carbon Dioxide Capture, Transport and Storage (UK HSL Laboratory, 2009/06)
- Resource Interactions for CO_2 Storage (CO2CRC, 2013/08)

Findings of the Study

This study reviewed the current available and novel technologies; considered the costs and benefits of mitigation methods; and then reviewed existing mitigation plans and regulatory guidelines. Undesired CO_2 migration also includes seepage into overlying formations, which may not necessarily reach the surface as well potential leakage to the atmosphere or water column.

Mitigation and Remediation Techniques

Migration from the storage formation may occur via engineered or natural pathways. Engineered pathways may be through abandoned or operational wells, either through poor completion and plugging, over-pressurisation, chemical degradation close to the well environment or by well failure. Natural pathways may be faults, fractures or more permeable zones in the caprock, which could be present before injection or caused by injection induced processes; CO_2 migration may also be caused by exceeding caprock capillary entry pressure or occur at a spill point.

The choice of mitigation measure will strongly depend on the nature of the CO_2 migration/ leak, with intervention from engineered pathways likely to stem from oil and gas industry experience. In other cases fluid management techniques or novel methods may be more appropriate.

Wells consist of the wellbore casing, tubing and packer (when the wellbore is active), and cement (which is also used to plug and abandon a well). For active wells, the packer represents a leakage pathway, though experience gained in the oil and gas industry provides good practice of designing, executing and maintaining wellbore integrity. There are various methods of intervention, which will depend on the origin of the leak. The wellhead (or welltree) may be repaired, the packer replaced; if the leak is located in the injection tubing string, the tubing may be pulled out and repaired and if leakage occurs through the casing or cemented annulus, squeeze cementing may be performed; a casing patch can also be used against casing leaks and swaging allows restoring a casing that would have been deformed. Any leakage that cannot be mitigated through the installed wellhead or welltree requires a full work over of the well: a plug is set to isolate the reservoir and the well is subsequently killed by filling it with a heavy kill-fluid to avoid a blowout.

Wells can be relatively easily monitored, whereas undesired CO_2 migration away from the wellbore may be more difficult. This could be through a fracture, or series of fractures in the caprock, which may be less well understood and thus corrective measures are likely to be through pressure management and injection operation management solutions. The first solution would be to stop pressure increase or decrease pressure in the storage formation, by ceasing CO_2 injection and/or extracting fluids (CO_2 or brine). A second solution could be the creation of a pressure barrier in the overlying geological strata to prevent or minimise CO_2 migration. Enhancing non-structural trapping in-situ or ex-situ may also help decrease the risks of CO_2 migration. Even if CO_2 storage is planned to be permanent, an ultimate intervention is CO_2 back-production, which may also be considered for small plumes in overlying aquifers.

Novel technologies may also be considered. Many of these were developed for other industries, but could be applied to or adapted for CO_2 storage. Geopolymer cement displays higher strength and better resistance to acid than conventional Portland cement and may be considered instead, though in many cases Portland cement may be considered adequate. Novel technologies could also be used in cases where conventional and standard technologies might not be applicable. Foams and polymer or inorganic gels have been traditionally used in the oil industry and can have several functions, such as sealants, and relative permeability or mobility modifiers. The use of nanoparticles in gels and foams or for mobility control is also under development. Biofilms have also been proposed as bio-barriers, which could help prevent migration of CO_2 through the caprock by blocking potential migration pathways.

While the purpose of mitigation measures is to avoid an impact or reduce its magnitude, additional methodologies could be implemented to remediate the impact and restore the environment. CO_2 migration may potentially lead to an impact on groundwater aquifers, the unsaturated zone and surface assets such as human health, ecosystems or other activities. Remediation measures specifically dedicated to impacts of CO_2 are poorly documented, but extensive data and experience on measures to remediate impacts already exist in various fields such as soil clean-up, aquifer repair and intrusion of gas in buildings treatment. Therefore, based on the analogy with impacts stemming from other activities, methods can be divided between passive methods, such as the monitored natural attenuation, and active methods. Monitored natural attenuation relies on in-situ natural processes (physical, biological, chemical) and could be used to reduce the mass, toxicity, mobility, volume, or concentration of contaminants in soil or groundwater. Active methods, such as, pump-and-treat, air sparging and reactive barriers are used to remediate impacts, comparable to potential CO_2 leakage into a groundwater aquifer. There have also been laboratory studies on additional breakthrough technologies for aquifer remediation using microbes, such as bacteria. Potential impacts in the unsaturated zone could be remediated through soil vapour extraction or pH adjustment. Standard remediation techniques to decrease gas concentrations in indoor environments such as sealing the openings, pressurisation/depressurisation or ventilation systems could be contemplated in the case of CO_2 intrusion. In the event of leakage into the atmosphere, natural mixing is often seen as sufficient to disperse the CO_2; nevertheless in the case of topographic and meteorological conditions that would favour gas accumulation, active measures could be used, such as air jets or large fans. Ecosystem restoration could also be undertaken in case of damage to protected habitat or species.

Cost Benefit Analysis

If an irregularity is detected the operator needs to decide on a series of actions, which can include further monitoring, mitigating the undesired CO_2 migration and/ or remediating adverse impacts. From an operational perspective, the maturity of a technology is essential to ensure its feasibility. Among the technically feasible measures, it is necessary to consider the efficiency (impacts avoided in a given time period) and costs (economic costs and potential environmental negative impacts of the measure). Detailed assessments of risk scenarios will need to be site specific though can be based on generic operational tools and elements.

Cost benefit analysis, Cost-Effectiveness Analysis and Multi-Criteria Analysis have been used in the decision process of environmental clean-up interventions. Cost-benefit analysis is a comparison between the costs and benefits of a scenario. In the case of mitigation or remediation action implementation, the scenario is the choice of a measure, or a combination of several measures. The cost being the direct cost of the implementation of the measure, the benefits can be defined as the difference between the impacts avoided and the potential additional impacts caused by the measure itself. To be comparable with direct costs, benefits are formally defined as the difference in economic effects of these impacts in such analyses.

Previous studies reviewed are the 2007 IEAGHG report, the 2010 EPA report and the 2011 ZEP report. The 2007 IEAGHG report does not specify whether mitigation/remediation of old abandoned wells during the site selection and planning and construction phase are covered by the remediation cost or in the basic cost. For the US EPA, it is clear that the costs for preparing the site are incurred at the front-end of the project and separated from undesired migration/ leakage developed or discovered later during operation of the injection site.

In the three studies, there are three different ways identified to estimate mitigation and remediation. The IEAGHG study has based its calculation on input of known cost for a suite of operations (e.g. repairs, plugging of wells, new contingency wells or wells needed for remediation to create positive pressure barriers) and multiplied by an assumed expected number of occurrences in the lifetime of the storage project. The USEPA (2010) treated it as a percentage of capital cost and new equipment cost. In addition they opted for a contribution of $0.10 per ton of stored CO_2 to a remediation fund and insurance (this was not shown to be included in the results table). The Zero Emission Platform assumes a fixed value of €1.00 per tonne stored CO_2, in order to make the cost per tonne completely transparent and may be updated as further information becomes available.

Several methods exist to monetise impacts. The revealed preferences approach examines actual behaviour in markets or nonmarket activity, to infer the value that people place on avoiding impacts. The stated preferences approach is a survey-based set of methods that pose hypothetical situations and ask peoples willingness to pay for avoiding specific damage to an ecosystem or to make choices across different options.

Estimating the direct cost of remediation technologies needed is essential from an operational point of view. Few data exist in the literature; though studies have been performed to estimate the global cost of CO_2 storage and present costs of potential mitigation and remediation interventions. In addition, some elements of cost have been reviewed based on the consultation of experts, such as regarding intervention on wells since as this can be directly compared the petroleum industry. Relevant estimation of costs of other technologies is not currently possible due to poor experience in mitigation and remediation related to CO_2 storage. Costs of remediating wells vary according to the location of the intervention. Offshore operations are much more expensive than comparable onshore activities and the regional location will affect the price as well. Calculations from IRIS in-house data and the petroleum industry are used, which show different costs associated with well remediation, Table 2.

Table 2: 1 Estimated total costs range for different mitigation methods. All costs are in M€. Offshore 1 : Norway, US Gulf of Mexico, Brazil, West Africa ; Offshore 2: UK and DK ; Onshore 1 : Europe and Middle East; Onshore 2 : USA

	Offshore 1		Offshore 2		Onshore 1		Onshore 2	
	Low	High	Low	High	Low	High	Low	High
Killing of a well	1.5	7.9	1.2	7.5	0.7	6.9	0.6	6.7
Wellhead and welltree repairs	1.5	7.9	1.2	7.5	0.7	6.9	0.6	6.7
Packer replacement	4.7	10.8	3.5	9.6	1.3	7.4	0.9	7.0
Tubing repair (with workover)	4.7	10.8	3.5	9.6	1.3	7.4	0.9	7.0
Tubing repair (no workover)	0.2	0.4	0.15	0.3	0.07	0.14	0.06	0.11
Squeeze cementing	2.3	8.4	1.8	7.9	0.9	7.0	0.7	6.8
Patching casing	6.9	13.0	6.2	12.3	5.0	11.1	4.7	10.8
Repairing damaged or collapsed casing	0.5	6.6	0.5	6.6	0.5	6.6	0.5	6.6
Plugging of a well	6.0	8.0	4.2	5.6	1.2	1.6	0.6	0.8
Abandoned wells	6.7	13.3	4.7	9.3	1.3	2.7	0.7	1.3
Stopping surface blowout	20.0	53.3	14.0	37.3	4.0	10.7	2.0	5.3

Existing Mitigation and Remediation Plans

A review of existing corrective and remediation measures plans (both in the CCS and in some non-CCS related industries) and a literature review on intervention plan set up have been performed. The panel (14 companies contacted, 8 participants) consists of operators and/or service companies in CO_2 storage as well as natural gas storage. Publically available corrective measures or risk management plans have also been considered. The key messages found were:

- All mitigation and remediation plans should be site-specific and risk-based. The corrective measures plan containing risk-reduction actions is included in the risk management process and is closely linked to the risk assessment and monitoring plans. The plan is usually public; it has been reviewed by stakeholders and updated over time as new information becomes available. Formats of corrective measures plans are very diverse, which may be explained by the different legislations, which sometimes only give limited and non-detailed guidelines compared to other mature industrial fields.
- Corrective measures and methods proposed mostly involve remediation of injection or abandoned wells or are directly related to operational aspects such as reducing CO_2 injection rate. Drilling new wells or applying breakthrough technologies are seen as ultimate measures and the development of new remediation measures on impacts is often judged unnecessary given the experience in environmental clean-up.
- Despite the importance of the initial plan, the decision protocol should be flexible in order to allow holistic decision making. The detailed intervention process cannot be included in the plan submitted during storage permit application; it will be decided by the team

(operator and competent authority) in place at the time of detection of an irregularity. The contingency plan should, however, help that team to have a holistic view on the issues and to balance the technical feasibility, the benefits (avoided impacts), the economic costs and the potentially negative impacts of implementation of corrective measures.

Expert Review Comments

The study was reviewed by 10 experts from academia and industry, and was overall very positive. All issues were considered in the final report and include updating the wells section to explain how Portland cement may still be a favoured and reliable method in some cases.

Conclusions

Potential actions for avoiding, reducing or correcting impacts caused by unwanted CO_2 migration have been reviewed. There is a large discrepancy between different techniques available in the literature with respect to their maturity and therefore some measures may not be operationally available at the present time. The operational feasibility of a given measure is dependent on additional criteria, especially on the balance between benefits (impact avoided) and costs (economic direct costs and potential negative environmental impacts). Elements and generic tools for such analysis have been reviewed in this study; however, any detailed assessment needs to be site specific and specific to a given risk scenario. This technical and operational knowledge is the basis for intervention strategy to be set up according to existing regulations.

Most of the measures come from the experience in mitigation or remediation of other kinds of risks and impacts (oil and gas industry and environmental clean-up). Even if the analogy might be meaningful, CO_2 geological storage brings new conditions. Therefore, there is a need for research on how the measures could be adapted to the specific conditions of CO_2 geologic storage. For instance, remediation measures originated from the environmental clean-up field are very much referenced but their applicability to CO_2 migration potential impacts have been hardly studied, contrary to technologies from the oil and gas sector, which form the basis of the measures proposed in the literature or submitted in existing remediation plans.

Development of new measures tailored to undesired CO_2 migration is also needed. Some theoretical concepts have been proposed for instance in terms of pressure management; however, their feasibility has to be proven through experimental tests, in-situ deployment, or experimentations at a scale in between the lab and the field following detailed modelling and simulation studies. Similarly as presented in this study, some breakthrough technologies are being developed; however, their development is at an early stage and therefore much effort is needed to integrate them in the portfolio of mitigation and remediation measures.

Operators and regulators will need a comprehensive description of each measure in order to make a knowledgeable choice. The purpose of the measure, the time needed for implementation, the associated economic costs, the maturity or the environmental impacts of a measure are key elements that need to be assessed. The review performed in this study gives these elements when available. However, there is a lack of such information and therefore extensive work is needed to fill this gap.

One of the main challenges related to mitigation and remediation in the fields of CO_2 storage is to choose the best possible way to intervene, and to do so at a reasonable cost. Moreover, a negotiation may take place between operators and regulators regarding a specific event because they do not share the same objectives. A method, based on multicriteria analysis, (and/or cost-benefit analysis) and adapted to the context of mitigation and remediation of irregularities in CO_2 storage could help to support informed, shareable and more acceptable decisions. The development of such methods might require the creation of specific tools for assessing the effectiveness of a measure, or for damage assessments. In particular, numerical simulation tools combined with meta-models could be used for computing effectiveness of measures for a number of pre-defined scenarios. For damage assessment, data and figures used in future analyses could be shared for building best practices and improve robustness of future analyses.

In practice, the success of an intervention will be highly dependent on the knowledge of what happened. This implies knowing the risks or impacts to be treated: up to now CO_2 migration through the overburden is not well understood (e.g. the mechanisms underlying the migration of CO_2 across several geological formations), and therefore the potential impacts cannot be well characterised. A deeper understanding of the mechanisms related to migration of CO_2 can also improve interpretation of monitoring data. This gap is also due to lack of experience and feedback in the new field of CCS. Research on migration processes should then be pursued.

The intervention plan should, at a given date, mention the technologies available according to the state of knowledge. The measure selection criteria needed for a knowledgeable choice should be also part of this plan. The plan should be reviewed and updated to allow the integration of any new measures or any new information that may change the ranking list of measures or the associated information.

The mitigation and remedial actions should be linked with the risk scenario selected during the risk assessment process and each measure should be related to the irregularities it mitigates; in addition the methods described in the monitoring plan should be mentioned in the mitigation plan. It will allow identification of monitoring techniques available for detection and characterisation of irregularities, that would trigger intervention, and the monitoring techniques able to assess the efficiency of this intervention.

The choice and design of the measure is dependent on the situation. The plan should be generic proposing adapted measures to a potential situation. However, it should be able to help as much as possible the decision-making if a deficiency occurs. Therefore, the tools or processes leading to the design of the most relevant mitigation and remediation strategy could be specified in such a plan. The final decision will be ultimately made when migration/ leakage occurs taking into account the specificity of the situation and the considerations of both the operators and regulators. This has to be done according to specific decision-making tools that need to be developed.

Recommendations

Mitigation measures will need to be site specific for each project with a range of risk scenarios considered. Any corrective measures plan will also need to be updated as more methods become feasible.

As more projects come on line there will be more information of proposed corrective measures plans as well as more generic tools. It is recommended that IEAGHG continue to follow this topic as more information becomes available. This should be mainly through the research networks (namely the risk assessment, modelling and monitoring networks).

The European Network of Excellence on Geological Storage of CO_2
Association

Methodologies and technologies for mitigation of undesired CO_2 migration in the subsurface

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Executive summary

CO_2 capture and storage full-scale implementation and acceptance are dependent on the assurance of the safety of the storage process especially with regards to potential CO_2 leakage, defined as any migration out of the storage complex. A proper risk-management process should be set up for this aim, including assessing the risks specific to a given storage site, monitoring the site to detect any potential loss of confinement, mitigating any potential leakage and remediating possible impacts. This report is focused on the last two steps, specifically on the methodologies and technologies for mitigation and remediation of undesired CO_2 migration in the subsurface.

An increased interest is directed on mitigation and remediation issues, notably to comply with new regulations. Despite the lack of consistent terminology – corrective measure plan in Europe, emergency and remedial response plan in the USA or well operations management plans in Australia – the existing regulations require plans detailing how CO_2 leakage risks can be dealt with.

This report first provides a comprehensive state of knowledge of mitigation and remediation practices. Some of these practices rely on the experience gained from other domains. Experience from the oil and gas industry provides for instance good practices when it comes to designing, executing, maintaining or improving wellbore integrity. According to the origin of the leakage, various interventions may be contemplated. The wellhead may be repaired, the packer replaced; if the leak is located in the injection tubing string, the tubing may be pulled out and repaired, and if leakage occurs through the casing or cemented annulus, squeeze cementing may be performed; in certain cases a casing patch can also be used against casing leaks and swaging allows restoring a casing that would have been deformed. Any leakage that cannot be mitigated through the installed wellhead requires a full work over of the well. The aforementioned techniques concern operational wells but most of them could be also deployed in abandoned wells with poor integrity. Good plugging and abandonment practices must be followed for an injection well at the end of its operative period and for the re-plugging of existing leaking abandoned wells. A large portfolio of repair or plugging options is therefore available to mitigate any leakage through accessible leaking wells.

Additional techniques, based on pressure management are proposed for mitigating potential migration of CO_2 through the caprock. A first solution would be to curb the pressure increase or to decrease pressure in the storage formation, locally or globally, and temporarily or permanently by ceasing the CO_2 injection and/or by extracting fluids. Pressure control strategies are nevertheless mostly described as preventive measure to be considered during the design of the injection scheme. A second solution could be the creation of a pressure barrier in the overlying geological strata to prevent or minimize CO_2 leakage out of the storage complex. Enhancing non-structural trapping is also proposed to decrease the risks of CO_2 migration. This has been contemplated in an overlying aquifer in which the CO_2 would have migrated and in the storage reservoir.

Finally, even if CO_2 storage is planned to be permanent, an ultimate intervention is CO_2 back-production, which may also be considered for potential small leakage plumes remediation in overlying aquifers.

Some novel (breakthrough) technologies are being developed and provide new opportunities for further improvement of existing technologies and for the development of more advanced CO_2 leakage mitigation tools. Geopolymer, which presents a high strength and strong resistance to acids, are thus foreseen as a potential alternative option for well cementing. Foams and polymer or inorganic gels, which have been used traditionally in the oil industry, could provide several functionalities for controlling the migration of CO_2 within the storage unit, thus enhancing some storage mechanisms and delaying the upward movement of the CO_2 plume, and CO_2 leakage outside of the storage formation. The use of nanoparticles in such gels and foams for mobility control is also under development; finally biofilms have been proposed as bio-barriers for preventing potential CO_2 migration.

While the purpose of the previous mitigation measures is to avoid an impact or reduce its magnitude, additional methodologies could be implemented to remediate a potential impact and restore the environment. CO_2 leakage may indeed potentially lead to an impact on the groundwater aquifers, the unsaturated zone and surface assets such as human health, ecosystems or other activities. Remediation measures specifically dedicated to CO_2 storage impacts are poorly documented, but extensive data and experience on measures to remediate impacts already exist in various fields such as soil clean-up, aquifer repair and remediation of gas intrusion into buildings. Therefore, based on the analogy with the impacts stemming from these activities, the methods can be classically divided between passive methods, such as the monitored natural attenuation, and active methods. Monitored natural attenuation relies on *in-situ* natural processes (physical, biological, chemical) and could be used to reduce the mass, toxicity, mobility, volume, or concentration of contaminants in soil or groundwater. Regarding active methods, pump-and-treat, air sparging and reactive barriers are classically used to remediate impacts similar to those possibly encountered in groundwater aquifers impacted by CO_2 leakage. Some laboratory studies on additional breakthrough technologies for impacted aquifer remediation using microbes, such as bacteria, are also mentioned in the literature. Potential impacts in the unsaturated zone could be remediated through soil vapour extraction or pH adjustment. Standard remediation techniques to decrease gas concentrations in indoor environments such as sealing the openings, pressurization/depressurization or ventilation systems could be contemplated in the case of CO_2 intrusion. In the event of leakage into the atmosphere, natural mixing is often seen as sufficient to disperse the CO_2; nevertheless in case of topographic and meteorological conditions that would favour gas accumulation, active measures could be used (air jets or large fans). Ecosystem restoration actions could also be undertaken in case of damage to protected habitat or species.

From an operational perspective, the selection of the most suitable action will depend on multiple criteria such as the maturity of the technique, its efficacy – notably the impacts avoided and the time needed for the measure to be efficient –, and its costs – economic and environmental. This choice is obviously site-specific and situation dependant; in the report, some generic elements are nevertheless given for each measure on the maturity and on intervention specifications. Different decision-making frameworks are available to support stakeholders in that choice helping them to balance the costs and the benefits supplied by the implementation of mitigation and remediation actions. Direct economic costs of mitigation and remediation have been estimated in previous studies, which all point to the fact that external data are scarce but can to some extent be obtained from e.g. the petroleum industry. The little experience in CO_2 geological storage mitigation operations makes irrelevant cost estimation for non-mature technologies and technologies from other fields that would need adaptation. In the report, quantitative costs are therefore estimated for well intervention, with different scenarios covering different types of storage (onshore/offshore) and different geographical locations. In addition, qualitative elements allowing rough costs estimation are given for other measures. These costs can then be balanced against the benefits of the related measures. From the viewpoint of society as a whole, the main methodology is the Cost-Benefit Analysis (CBA). In a CBA, induced and avoided damages (benefits) resulting from the application of one mitigation technique are assessed; this is classically done with generic methodologies such as revealed preferences and stated preferences approaches. However, more than just costs and benefits, uncertainties may be the main driver for the final decision. These uncertainties can be reduced with the monitoring set-up and prior knowledge of the migration mechanisms. Furthermore, other frameworks may be used to help in the choice of the most suitable mitigation or remediation measures, as for instance cost-effectiveness analysis or multicriteria analysis. These additional methods may be more practical to implement for operators.

In addition to technical and operational considerations, there is also a need of gathering the best practices in terms of intervention plan elaboration. CO_2 geological storage is now implemented in several places around the world, and in such projects risk management procedures are being set up and mitigation techniques are integrated in case of deviation from the expected behaviour of the storage complex. Regulatory requirements are now in place and need to be followed. Several guidelines or guidance documents mentioning the mitigation and remediation measures plan have been issued. International standards, specific or not to CO_2 geological storage, also propose generic workflow for risk management and guidelines for the risk treatment stage. In this study a survey of existing corrective and remediation measures plans (both in CCS and in some non-CCS related industries) and a literature review on intervention plan set up have been performed. Publicly available corrective measure or risk management plans have also been considered. The key messages are the following:

- The mitigation and remediation measures plan should be site-specific and risk-based. The corrective measures plan, containing risk-reduction actions, is included in the risk management process and is closely linked to the risk assessment and monitoring plans. The plan is usually public, has been reviewed by stakeholders, and updated over time as new information becomes available. Formats of corrective measures plans are very diverse. This may be explained by the difference in legislations, which sometimes only give limited and non-detailed guidelines compared to other mature industrial fields.
- In terms of content, the corrective measures and methods proposed in the plans mostly imply actions on wells (intervention on injection wells or abandoned ones) or directly related to operational aspects such as reducing the

CO_2 injection rate. Other pressure management techniques, such as drilling of new injection or pressure relief well are generally seen as ultimate measures. The technologies judged not mature enough (breakthrough technologies) are not contemplated for the moment and the development of new remediation measures on impacts is often judged unnecessary given the experience in environmental clean-up field.

- Despite the importance of the initial plan, the decision protocol should be flexible and seen as a support for decision-making at the time of the irregularity detection. The detailed intervention process cannot be included in the plan submitted during the storage permit application but will rather be decided by the team in place (operator and competent authority) according to the specificities of the irregularity. The contingency plan should, however, help that team to have a holistic view on the issues and to balance the technical feasibility, the benefits (avoided impacts), the economic costs and the potentially negative impacts of the measures implementation.

This study covers several aspects of mitigation and remediation (technical, operational and in terms of implementation of the mitigation and remediation strategy) and therefore different kinds of recommendations can be given. Research directions are suggested in the report for filling the existing gaps in terms of technical answers to mitigate unpredicted CO_2 migration. Concerning the implementation perspective, best practices regarding the mitigation plan set up and the intervention in case of unwanted CO_2 leakage are provided.

General introduction and objectives

CO_2 permanent containment is one of the main concerns of operators and regulators implementing CO_2 geological storage. Low permeability caprocks are viewed as a major element for a safe containment of the CO_2 in the target storage formation (IEA-GHG, 2011a); as a result any potential pathway is of major concern since it may allow buoyant CO_2 to migrate along and reach an overlying formation or be emitted at the surface, potentially impacting drinking water resources (as identified in IEA-GHG, 2011b) or sensitive stakes at the surface.

Following the terminology of the EC Directive on the geological storage of carbon dioxide (EC, 2009), in this report undesired migration or leakage of CO_2 is defined as any migration out of the storage complex. Such a migration may occur via two different types of pathways:

- *Engineered* pathways, i.e. abandoned and operational wells (for injection or observation). Leakage can occur through these wells in case of 1) poor completion and plugging, 2) too high over-pressurization, 3) chemical degradation close to the well environment, and 4) well equipment failure;
- *Natural* pathways like faults or more permeable zones in the caprock. These natural paths within the geological system may exist prior to the beginning of the storage operations or be created by the injection-induced processes (pressure-induced fracturing or reactivation, geochemical degradation of the caprock sealing properties); CO_2 migration may also be allowed due to overpressure exceeding the caprock capillary entry pressure or occur at a spill point of the storage site.

Managing such risk scenario is of first importance and a dedicated site-specific strategy has to be set up. The storage safety is then guaranteed through an adequate site selection and characterization leading to the choice of a site where the evolution of the CO_2 plume and potential impacts of the storage are judged acceptable. On this given site, a specific risk management process should be carried out to anticipate the potential deviations from this acceptable behaviour. The International Standard ISO 31000 (ISO, 2009) proposes a framework dedicated to the risk management: after having set the scope of the risk management (*context establishment*), a proper *risk assessment* shall ensure the selection of the site-relevant risk scenarios (*risk identification*), the estimation of the risk level through the computation of the consequences and of the likelihood of the scenarios (*risk analysis*) and the comparison with acceptable thresholds (*risk evaluation*). When the risk level is assessed as unacceptable, options need to be implemented either to modify the likelihood of occurrence or the potential consequences of the scenario; this last step is the *risk treatment* stage. *Monitoring* of the risk management process shall notably allow the detection and characterization of the potential deviations with respect to the expected evolution scenario and the efficiency assessment of the risk treatment measures. *Risk communication* during all the different stages with the stakeholders involved in the project is essential for a transparent and understandable process.

The study presented in this report is focused on the *risk treatment* stage, more specifically on the methodologies and technologies for mitigation and remediation of unpredicted CO_2 migration in the subsurface. To date this subject has not been widely treated although it is currently receiving more attention from the industrial and scientific communities. This evolution may be linked with the new regulations on CO_2 geological storage that specify requirements on mitigation and remediation methods: the European Directive on the geological storage of carbon dioxide (EC, 2009) imposes, in the storage permit application, the inclusion of *a description of measures to prevent significant irregularities* as well as *a proposed corrective measures plan*. The United States Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells (US EPA, 2010a) require operators to submit an *emergency and remedial response plan* in the permit application. In Australia, the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Australian Government, 2011) and the associated regulations (Australian Government, 2012) require *well operations management plan*, which should include explanations on how the risks can be dealt with.

A comprehensive knowledge of mitigation techniques is therefore needed to meet these requirements, which can be summarized with the three following issues:

1) Technical issue – the first challenge is to determine which technologies may be adapted to avoid, reduce or correct any potential impacts induced by a CO_2 migration, either acting on the source, on the transfer pathway or directly on the impacts. In other words, these are the scientifically conceivable measures;
2) Operational issue – from an operational perspective, the maturity of a technology is essential to ensure its feasibility. The achievability of one measure is dependent on additional criteria especially on the balance between the benefits (impact avoided) and the costs (economic costs and potential environmental negative impacts of the measure), and the uncertainties with which they are estimated. The uncertainty of the benefit of a measure is mainly dependent on the accurate characterisation of the irregularity. The second challenge is therefore to specify properly those criteria for the measures and to develop tools to assess the achievability of each conceivable measures;
3) Implementation issue – the third challenge is, from the knowledge available at a given time, to produce an intervention plan as required by the above-cited regulations. This should answer to the identified risk events, and also prepare the operator and the competent authority to make an informed decision for choosing the best mitigation and/or remediation option at the time of the detection of an abnormal behaviour in the CO_2 storage complex.

The technical issue has already been tackled and there have been technical papers devoted to specific techniques aiming at reducing the potential risks and impacts of CO_2, based on existing work in other fields (e.g. oil and gas industry, soil or water remediation) or developed specifically for CO_2 storage. A review of this experience has been gathered in the IEA-GHG 2007/11 report devoted to remediation of leakage and particularly focused on intervention on wells (IEA-GHG, 2007). However, since that time, new categories of remediation techniques have appeared. In addition there is a need of comparative data to help operators to select the most adapted measure. Decision-making tools are also required to balance the benefits gained by the implementation of a mitigation measure and its economic costs and potential environmental impacts. Finally, there is a lack of integrated studies on the mitigation plan setting-up process. For instance, no comparison between the different intervention strategies of existing and future CO_2 storage projects has been published. There is thus a need of gathering the best practices for mitigation of undesired CO_2 migration based on the scientific literature and experience gained in CO_2 geological projects.

In line with these statements, the IEA Greenhouse Gas R&D Program (IEA-GHG) has ordered a new literature and experience review on the methodologies and technologies for mitigation of undesired CO_2 migration in the subsurface with the following purposes:

- *Review of the state of knowledge of novel and standard mitigation and remediation practices;*
- *Review of the associated costs of the technologies and methodologies needed;*
- *Comparison and analysis of mitigation plans in place on current, past or future CO_2 storage projects, where available.*

Accordingly, this report is divided in three chapters. The first one is dedicated to the description of mitigation and remediation measures based on a comprehensive literature review. The second chapter gives elements for the comparison of the different techniques, both quantifying the direct economic costs of mitigation and remediation measures, and giving elements on methodologies that could be used to balance these costs and the benefits of the measures implementation. The third chapter is a review of the existing plans and guidelines for building such plans. Recommendations are proposed according to the outcomes of the whole study.

Chapter 1. Review of mitigation and remediation techniques

This section is dedicated to a comprehensive literature review of techniques that can be deployed in order to mitigate an undesired CO_2 migration in the subsurface or to remediate possible impacts. The experience in the use of mitigation or remediation techniques is limited in the CO_2 geological storage field and the methods and techniques mentioned in literature are mainly adapted from other domains such as oil and gas industry or environmental clean-up. Some of these techniques have been tested and applied in several conditions that may be close to CO_2 geological ones, whereas some others are niche technologies but have been considered relevant to address challenges encountered in CO_2 sequestration applications. All of them are gathered in this section, which should be considered as a state of knowledge of mitigation and remediation practices, should they be standard and technically feasible at the present time or innovative and under development.

We recall here the semantic definition of mitigation and remediation as they have been considered in this study: mitigation techniques are used to avoid an impact to occur or to reduce its magnitude by acting on the leakage (e.g. repair to a leaking element, or action on the leakage driving force) while remediation techniques are applied to the impact in order to restore the environment.

As mentioned in the general introduction, migration can occur through two main pathway types: man-made (abandoned and operational wells) and natural (such as existing faults, fractures and high permeability regions). The choice of the appropriate measure depends strongly on the nature of the leak. The intervention on leakage through man-made pathways (well remediation) stems from the oil and gas industry experience and, in certain cases, operations are standard. However, in other cases, the operator may not be able to rely on well engineering experience, and may have to turn to fluid management techniques or new breakthrough technologies for modifying the leakage paths or fluid properties. This is true for most cases of leakage through natural pathways. In the case of impacting CO_2 migration, measures may be applied to remediate environmental impacts. We divided our literature review according to these four kinds of mitigation and remediation measures: interventions on wells, fluid management practices, breakthrough technologies and remediation measures on potential impacts.

For each measure and when possible, are provided a technical description of the intervention technique, qualitative cost elements (a reflection on more quantitative cost and benefits elements is included in Chapter 2), time elements (intervention delay, efficiency time duration) as well as a discussion on the maturity of the technique.

We want here to stress that the measures should be integrated in a whole risk management strategy. The scope of this study is focused on the risk treatment stage; the choice and design of an adapted intervention strategy especially presuppose (a) an accurate detection and characterization of the irregularity to be treated prior to the intervention, and (b) a characterization of the irregularity evolution after the mitigation or remediation operations. This highlights the strong link between the monitoring stage and the treatment one. Even if monitoring is out of the scope of this study, the reader should be aware that the efficiency of any mitigation and remediation practice is highly dependent on the observed behaviour of the storage site.

1.1. INTERVENTIONS ON WELLS

Ide et al. (2006) state that pre-existing wells and wellbores are high-permeability pathways through the crust, and as such represent zones of elevated risk to CO_2 storage projects. Although current well closure and abandonment technologies appear to be sufficient to contain CO_2 at most sites (see IEA-GHG, 2009 for well plugging and abandonment techniques), individual wells may suffer from a variety of factors that limit their integrity, including improper cementation, improper plugging, overpressure, corrosion, and other failure conditions.

The typical design of a modern well is shown in Figure 1. The well is constructed using several types of casing. Surface formations are often lose and unconsolidated and due to this the surface hole will need to be cased off with a *conductor casing* before any drilling can take place. This is followed by *surface casing* set to protect groundwater, unconsolidated formations, provide primary well control, support other casing, and case off lost circulation zones. Surface casing is cemented back to surface and is normally the first casing to support of secondary well control equipment such as a diverter or Blow Out Preventer (BOP). Typical depths are on the order of 300-1200m. Inside the surface casing is the *intermediate casing*. Amongst other this casing gives protection against well blowout, lost circulation during drilling and isolated gas pockets. It also serves to protect tubing against corrosion. This casing is cemented at least 200 m above the casing shoe in the previous casing.

Production casing is the fourth type of casing and is run from surface down to the zone to be produced and adds structural integrity to the wellbore. This string would normally be the longest string run and may often be cemented in stages so as not to break down the lower formation. Casings must also be of such quality that they can withstand particularly corrosive media in the well (H_2S, CO_2 etc.). It must also be of sufficient strength to contain the formation pressure that will migrate to surface. The design and material must be selected in order to cover the expected life span of the well.

As a last option *liners* are run into the well. This could be to cover a lost circulation zone or to extend an old well once the new section has been drilled. More often it is because there is no reason to have it all the way to surface or that the well head cannot take the added weight. A production liner once run will be cemented into place with an overlap some 150m up inside the last casing string.

Cementing is the process of placing cement in the annulus between the casing and the formation exposed to the wellbore. It involves mixing of dry cement with water and additives to form slurry. The cement slurry is displaced down through the casing and up the wellbore annulus. The cement slurry is then allowed to set thus bonding the external casing to the formation. The purpose of cementing is to 1) provide zonal isolation, 2) protect casing from corrosion, 3) prevent caving of hole, 4) provide a means of controlling pressure, 5) provide strength to weak formations, 6) reduce the weight hanging on the wellhead, and 7) close an abandoned well or a well section. Rather than completely filling all of the annulus with cement, to fulfil the mentioned purposes it is normally not necessary to cement more than ca. 100-300 m above the bottom of each casing section (Jørgensen, 2011). This depends on the casing, and type, under consideration as well as formation fracture gradient, time and associated costs.

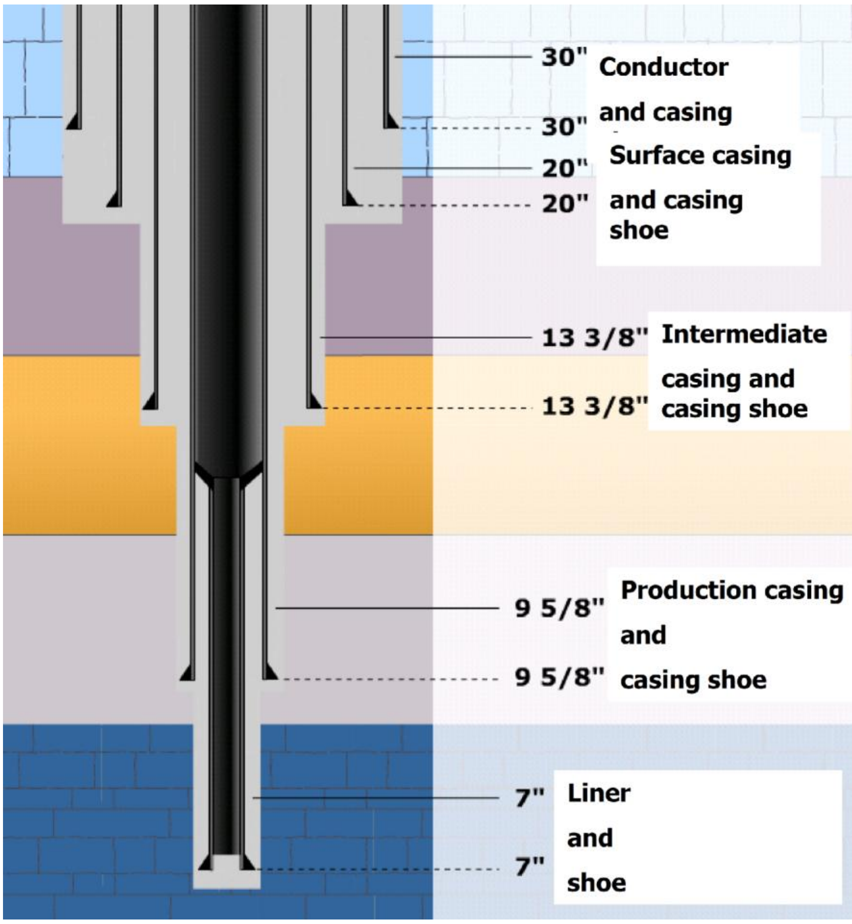


Figure 1 – A schematic drawing of a typical North Sea well showing different casing types. Note that it is a normal practice to cement the lower 100-300 m of a casing section (Jørgensen, 2011.

Leakage of a well can occur through the wellbore, through the annulus between well tubing and casing, or on the outside of the casing. Gasda et al. (2004) list 6 different pathways for abandoned wells (Figure 2). For active injection wells packers represent a possible leakage pathway. The resulting leakage will be as a fugitive emission or a fluid.

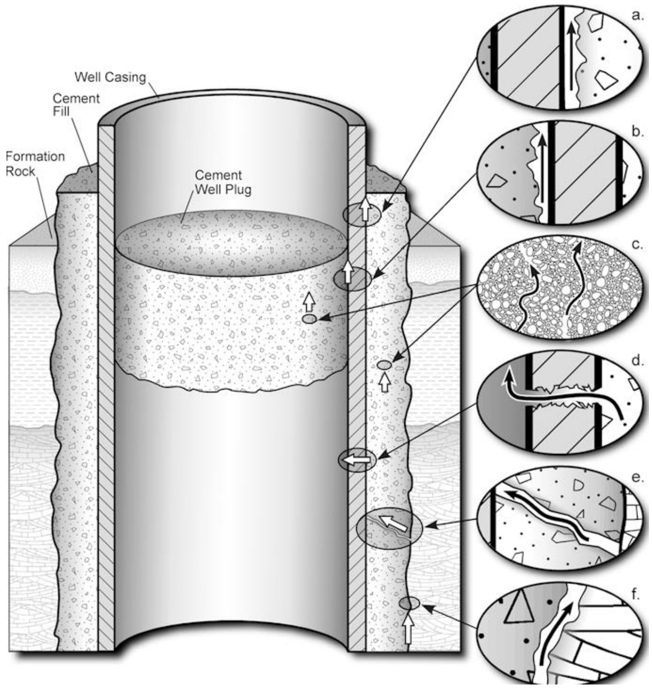


Figure 2 – Possible leakage pathways in a well. a) Between casing and cement; b) between cement plug and casing; c) through the cement pore space as a result of cement degradation; d) through casing as a result of corrosion; e) through fractures in cement; and f) between cement and rock (from Gasda et al., 2004)

CO_2 gas injected into a wet environment will react in order to establish a chemical equilibrium with the water phase accordingly:

$CO_2(g) = CO_2(aq)$

$CO_2(aq) + H_2O = H_2CO_3(aq)$

The carbonic acid readily dissociates in the water forming bicarbonate and carbonate ions:

$H_2CO_3 = HCO_3^- + H^+$

$HCO_3^- = CO_3^{2-} + H^+$

With increased input of CO_2 the equilibrium is driven towards higher CO_2 in the water phase resulting in lower pH and formation of a very corrosive environment for materials such as cement and steel.

Portland cement contains $Ca(OH)_2$ and is commonly used in petroleum wellbores where it may get in contact with CO_2 enriched waters and form calcium carbonate as shown in the chemical reaction:

$Ca(OH)_2 + CO_3^{2-} + 2H^+ = CaCO_3 + 2H_2O$

The process is referred to as *cement carbonation* and results in a lower porosity as the calcite takes up more space than the dissolved $Ca(OH)_2$. This may at first seem as a self-healing process forming a protective sheet around the cement reducing diffusion rates of CO_2 into the pores of the cement. If wet CO_2 is still available the formed $CaCO_3$ can dissolve and overall degradation of the cement continues.

Laboratory experiments performed under reservoir conditions indicate that degradation rates are varying, from less than 0.01 m to 12.36 m per 10^4 years (Table 4 in IEA-GHG 2009 report and references therein). Despite for this apparent high potential for chemical cement degradation there is evidence from field cases suggesting that actual cement degradation rates are low. Two studies of cement field samples, the SACROC Unit in West Texas that has been exposed to CO_2 over 30 years during CO_2-EOR operations (Carey et al., 2007) and another from a natural CO_2 producer (Crow et al., 2010) indicate that the $CaCO_3$ only shows limited degree of leaching. Rather carbonation process appears to have some capability of healing pathways. For a recent review on degradation rate experiments and field study experience see Zhang and Bachu (2011).

The acid CO_2 environment is also corrosive on metal casing. The main corrosion reaction in steel can be expressed as

$$Fe(s) + 2H^+(aq) \rightarrow Fe^{2+}(aq) + H_2(g) ,$$

where solid iron is unstable and dissolves into ions in solution leaving a corroded surface behind. As the process continues over time a leakage hole may form in the casing. It is important to realize that the reaction will only take place in the presence of water. Injection of pure and dry CO_2 is therefore not expected to cause corrosion problems (Nygaard, 2010). As for the case of cement degradation, availability of water is probably limited in actual field situations (IEA-GHG, 2009).

In addition to chemical degradation of cement and casing steel, it is also important to address mechanical deformation of well cement and casing. Important migration pathways may form at the interfaces between cement and casing and cement and caprock (Figure 2), and can be a result of poor cementing jobs (Barclay et al., 2002) and or cement shrinkage (Ravi et al., 2002). Failure of cement sheets can occur under stress caused by high injection pressures and/or temperature cycles may result in the development of fractures.

There is also the possibility of well deformations due to decompaction of the reservoir as the pressure increases during injection of CO_2. Though the reservoir rock and well or plug cement have similar mechanical properties, the casing steel has an elasticity modulus that is significantly higher and the strain level at the cement-steel interface may result in debonding and subsequently formation of micro-annuli at the interface. To reduce chance of developing these kinds of mechanical well integrity problems it is therefore important that the cementing jobs are thoroughly executed and not flawed by e.g. poor mud removal, decentralised casing (especially in deviated wells), or unnecessary cement shrinkage (Barclay et al., 2002; Ravi et al., 2002). However, if the CO_2 storage reservoir is a depleted oil or gas field the presence of older wells that were completed and abandoned prior to CO_2 injection may not have been subject to recent regulation and higher standards (IEA-GHG, 2009).

In the following description of mitigation measures it is assumed that procedures for identification of CO_2 leak type and position in the well have been completed. See IEA-GHG (2007) p.124-127 for descriptions and methods that can be applied to identify mechanical and fugitive leaks in wells.

In this section, qualitative cost elements are provided. For quantitative cost estimates associated with the different measures, based on relative well operation cost between different regions of the world and whether they are applied in an onshore or offshore setting, please refer to section 2.1.2 and Table 9.

1.1.1. Wellhead (and welltree) repair

For offshore installations on fixed platform the wellhead is located on the platform deck, whereas for a floating installation the wellhead is located on seafloor. Figure 3 illustrates general differences in the design and construction of the two different welltrees. Onshore the wellhead design is in principle similar to the platform case.

The wellhead and welltree should be the first item to be checked prior to any in-depth leak detection investigation. Wellhead equipment, including valves, flanges, etc., can easily be inspected and repaired due to their above ground location (IEA-GHG, 2007a).

For subsea installations this may not be an equally simple investigation to perform and any repair will involve use of well service vessel and remotely operated vehicle (ROV) (McGennis, 2001). Depending on the technical problem the leakage may be stopped and repair carried out at the sea bottom with the welltree in place. More severe damages may require that the welltree is removed and brought to the well service vessel or even onshore for repair. Removing the welltree requires that the well is securely plugged and perhaps even killed while the repairs are being carried out.

If wellhead has suffered severe damage and even deformation of its parts one may initially apply other methods such as video or 3D modelling photogrammetry inspection of the wellhead (Maccormick et al., 2011; Sloan et al., 2011). Comparison of the 3D model with as-built drawings are subsequently used to design bespoke tools to ensure well integrity, customised cutting tools for removing damaged wellhead parts, and design of new replacement parts (e.g. gasket, flanges etc.) making it possible to return the blowout preventer (BOP) and rest of the welltree to the wellhead.

Cost for operations are dependable on the damage and whether the mitigation requires a work over, i.e. if the well has to be killed by setting a plug to isolate the reservoir followed by filling the string with a kill fluid (cf. section 1.1.7). The cost for repair of the wellhead and/or welltree will have to be added.

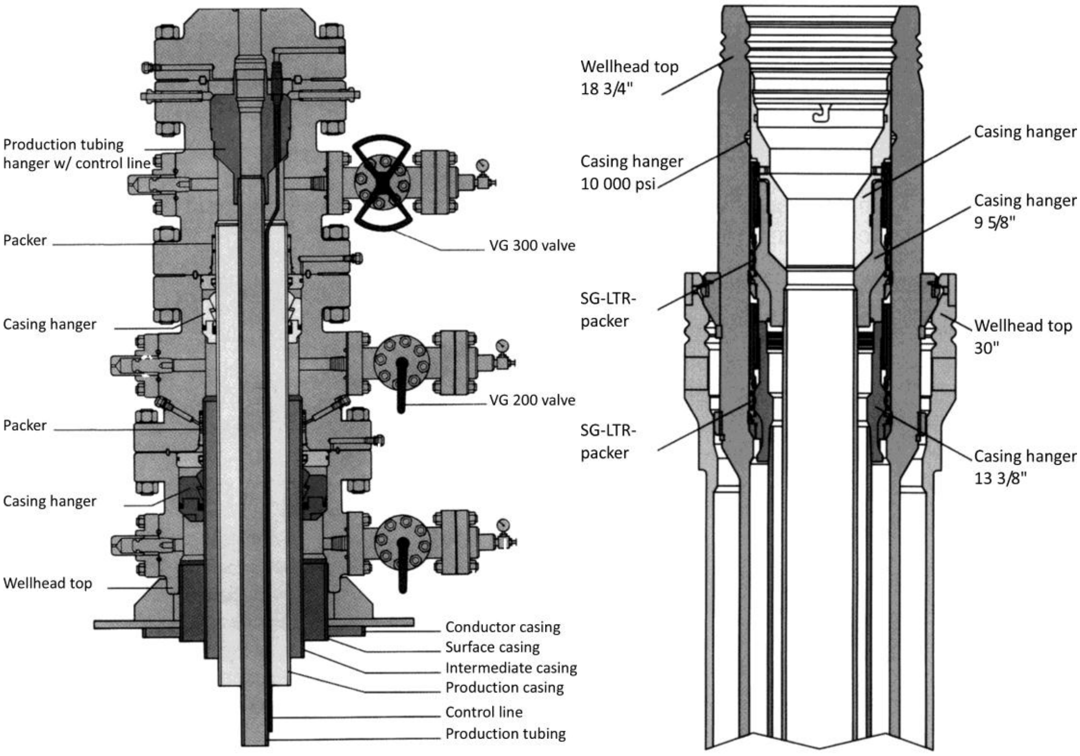


Figure 3 – Illustrations of wellheads on a fixed platform (left) and on the subsea. Modified from Jørgensen (2011)

1.1.2. Packer replacement

Packers are used to isolate the annulus from the rest of the well and to attach the tubing to the production casing. Packers can generally be divided into permanent and retrievable types, the latter being only for short term operations such as drill stem testing, fracturing, squeeze cementing etc. The permanent packers have two locking systems with opposite directed cone-shaped surfaces; this way the packer can withstand larges forces in both upward and downward direction. Between the two locks there is a packer element made of elastic synthetic material that insures the sealing between casing and tubing. If annular pressure is lost while casing and tubing can be shown to be intact, it is likely a packer sealing element that is leaking.

If the packer is of the retrievable type the packer and the tubing injection string can be retrieved from the well and replace by a new packer. For mechanically set packers the packer and tubing are run into the hole together and it is attached/locked in place by rotation, the application of weight-loaded force, or a combination of both (IEA-GHG, 2007; Jørgensen, 2007). Some packers can be pulled out and reset by ordinary completion units, however if a packer has begun to leak over time it is advisable to replace it rather than resetting it as a new leak may develop in future.

A leaking permanent packer is removed by use of a packer mill. The milling of the packer generates debris and it is important that this is recovered from the well before the well is returned to operation again. Traditionally, removing the packer has been a two-step process where milling operation is followed by a retrieving operation pulling out remaining packer parts and recovering debris flushing the well. More recently Haugthon and Connell (2006) presented method simultaneously milling and retrieving permanent production packers. Their system has been shown to reduce milling and trip times considerably in several wells.

The removal and replacement of a production/injection packer will take about 2 weeks and involve a workover including killing of the well, welltree removal, tubing retrieval and packer removal.

1.1.3. Tubing repair

If the leak is located in the injection tubing string, the tubing can be pulled out by a completion unit and the leaking joint can be replaced. While the string is out of the well it is important to do a thickness inspection and visually inspect it to assess the state of the individual joints and then replace any part that shows signs of wear and tear. After inspection and repairs are completed the string can be run back into the well and pressure tested to ensure well integrity (IEA-GHG, 2007).

Instead of pulling the tube out from the hole it may also be possible to apply an expandable casing patch (cf. section 1.1.5 below). This can be done with the welltree in place and may therefore not require a workover. The cost will depend on the length. If the tubing has to be pulled out and replaced, the cost will be comparable to packer replacement (cf. section 1.1.2).

1.1.4. Squeeze cementing

Squeeze cementing is applicable for repairing a faulty casing, within the cement or between cement and casing or rock (Figure 2). It may also be used to stop migration between separate zones of the reservoir. Squeeze cementing is normally performed at the time of running the casing, however it may be used as a mitigation method as well.

Squeeze cementing works by using pump pressure to inject or force a cement slurry into the leaking path. Depending on the remediation need, squeeze cementing operations can be performed above or below the fracture gradient of the exposed formation, using high pressure squeeze and low pressure squeeze, respectively.

Low pressure squeeze technique is probably more efficient in placing a controlled amount of cement in a problem area of the well. The area is isolated by setting packers above and below. Pressure is achieved by pressuring up on the cement and allowing the cement to filter out on the formation creating a block in the annulus or in the fractures of the primary cement and casing. Once the cement slurry has hardened or dehydrated to a sufficient extent, no more fluid will be displaced. Excess cement in the well may have to be removed by milling. This method is the industry standard corrective for a loss of casing integrity.

If the casing is severely damaged the milling process may result in increased damage to the casing. Cirer et al. (2012) proposed to use an epoxy reinforced fiberglass (ERFV) pipe inside the well and pump the cement into the annulus between the casing and the ERFV (see Figure 4). Since the ERFV does not contain cement it can be used to guide the milling tool and secure that the operation will not violate the restored well integrity.

The operation may take 5 days including work over operations.

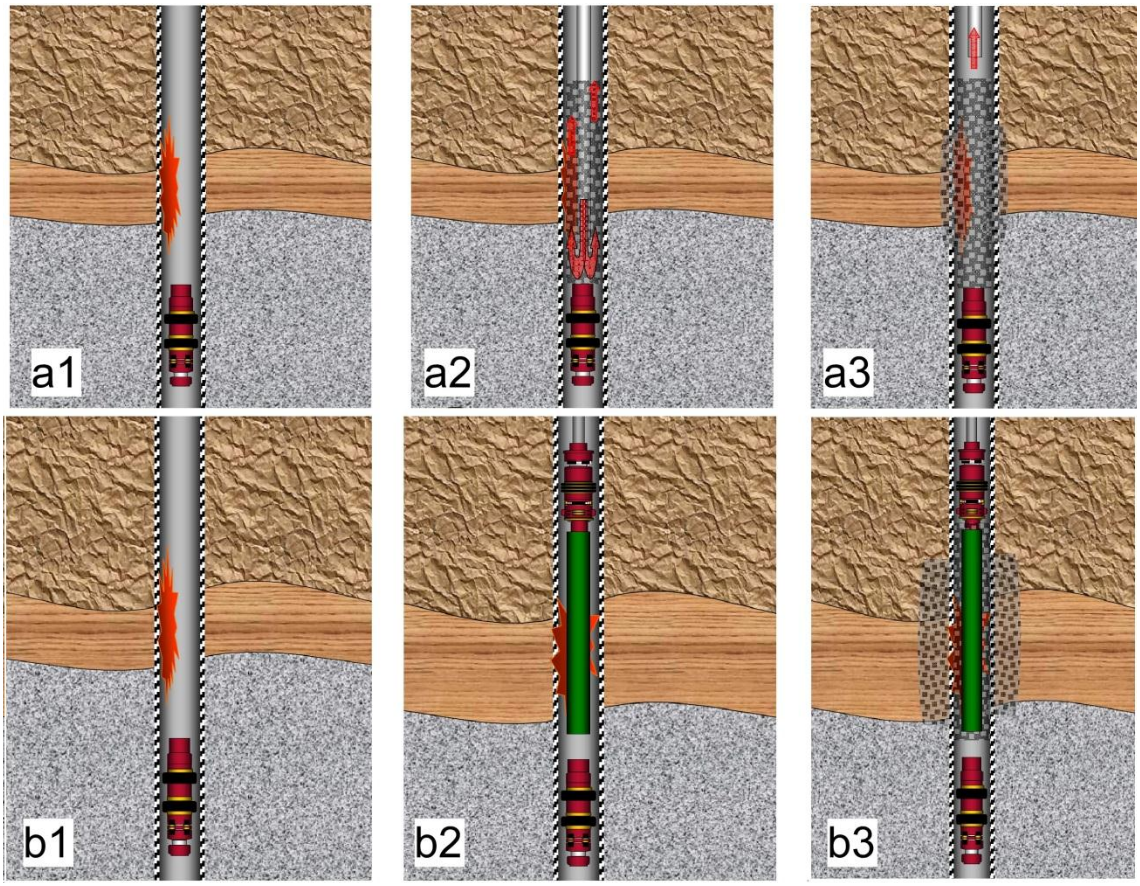


Figure 4 – Two different approaches to cementing a casing damage. Figures a1 through a3 show a conventional approach where the damage section of the well is filled competely with cement. Figures b1 through b3 present a different approach where cement is only present in the anunulus outside the epoxy reinforced fiber glas tube shown in green This reduces the amount of cement needed and the ERFV can be used as a guide for safe milling and cleanup operation afterwards (Cirer et al., 2012).

1.1.5. Patching casing

This method can be an alternative to squeeze cementing for repairing casing leaks. In general a casing patch is positioned over the leaking area in the well and pressed against the casing forming a tight metal-metal or metal-elastomer-metal seal. The patch may also be used to provide strengthening of corroded or otherwise weakened casing or completion equipment. An example of such a system is shown in Figure 5.

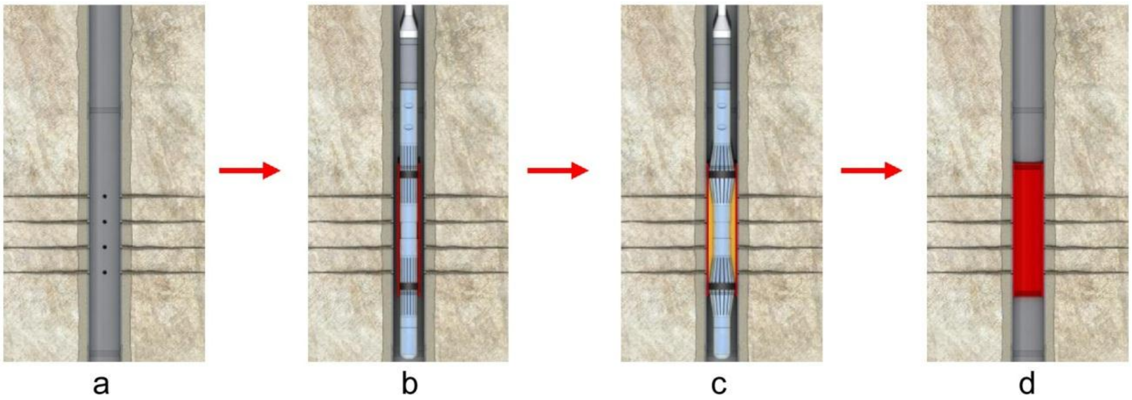


Figure 5 – Example of the working process of installing an internal expandable casing patch. a) Zone of leakage in the well where expandable casing is to be placed. b) The HETS assembly tool including an expansion tool, a downhole hydraulic module and the new expandable casing is positioned in section of the leak. Wireline tools may be used to controll the position of the casing at correct depth. c) Hydraulic pressure is applied to expand the casing patch to conform with the inside surface of the casing, liner or tubing wall. d) Removal of expansion tool leaving a combination of metal-metal and elastomer seal. (READGroup, 2012b)

In the case where it is more economical to replace the casing above and below a damaged section this can be done using expandable casing patch (tie-back) connections. This technique creates a hydraulic and gas-tight connection between the old and new casing. It preserves the internal diameter of the well.

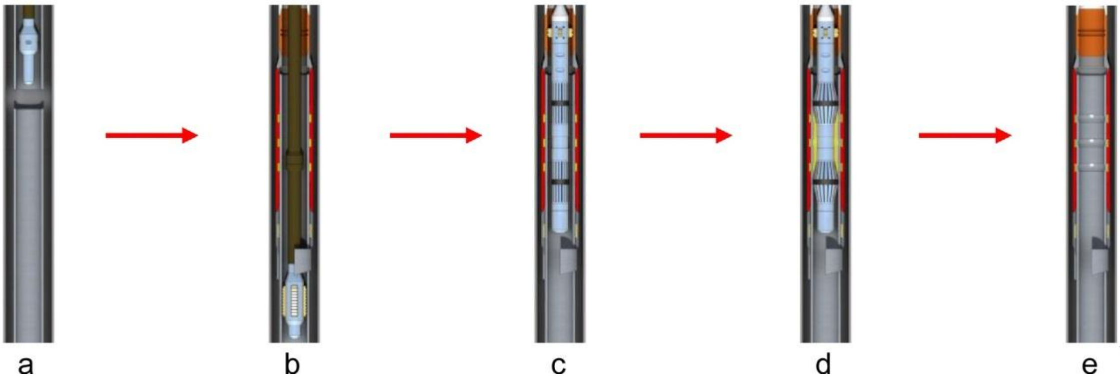


Figure 6 – Schematic description of external applied expandable casing patch. A) Cutting of casing and removal of the upper section. b) External casing patch (HETS-EP) is attached to the new casing and placed in the well over the old casing stub. c) Expansion tool is run into the well and positioned at high precision in the casing patch. d) Hydraulic pressure is applied expanding the old casing into depressions of the HETS-EP. e) Removal of the expansion tool leaving a metal-metal gas tight connection with no internal casing restriction.(READGroup, 2012a)

Many examples of successful application of the technique have been published (e.g. Chustz et al., 2005; Daigle et al., 2000; Storaune and Winters, 2005). The use of expandable casing has over the past 10-15 years become a standard technique in the petroleum industry and is today capable of serving more than remediation of well integrity problems. Durst and Ruzic (2009) provide a comprehensive list of applications where expandable tubular facilitate improved well stimulation and the use of advanced well completion.

The operation may take a week.

1.1.6. Swaging

If casing has become deformed or has collapsed into the well due to external pressure, it can be restored to its previous use through *swaging*. This method involves the use of a swaging tool acting as a circular wedge forcing the tubing or casing wall out with its steel jaws as it is driven through the deformed or collapsed section of the well. The pressure exerted by the swage can exceed 50 tons per square inch.

The swaging can be used to expand a liner or tube and fit it to the inner wall of the well similar to the patching casing described in section 1.1.5.

1.1.7. Killing of a well

Any leakage that cannot be mitigated through the installed welltree and Blow Out Preventer (BOP) requires a full workover of the well. At all times a well is required to have at least two barriers between the reservoir and the surface (cf. section 1.1.8). Hence before removing the BOP and welltree from the top of the well, it has to be temporarily plugged. A plug is set to isolate the reservoir (the primary barrier) and the well is subsequently killed by filling it with a heavy kill-fluid (the secondary barrier) to avoid a blowout.

Setting the plug will require a wireline (WL) operation or for horizontal or inclined wells a WL with a tractor or coiled tubing. Plugging operation may take 1-2 days for the WL operation. Afterwards removal of the plug and kill-fluid is an additional day’s work.

1.1.8. Plugging and abandonment of a well

The aggressive nature of CO_2 means that good practices must be followed in relation to plugging and abandoning a well. This section addresses not only how to deal with plugging an injection well at the end of its operative period, but is relevant as a method for dealing with leaking abandoned wells.

The requirements for plugging and abandonment (P&A) of wells are defined by national or local safety authorities. They generally set standards for when and where to use cement plugs across underground sources of drinking water, across hydrocarbon production zones and open perforations in casing as well as squeezing cement into non-cemented, cased holes. In addition there are commonly requirements to have at least two barriers.

The present requirements are to a large extent formulated with address to plugging oil and gas wells and variations between the different regulations may reflect regional variations in geology or challenges of the reservoirs.

In the IEA-GHG 2007/11 report (IEA-GHG, 2007) there are detailed references and discussions of guidelines and regulations. Some of the source documents (preferably from US) have been included in full text in the Appendix section of the above-mentioned report. Similar descriptions of practice can be found in e.g. NORSOK D-010 (2004) for the Norwegian Continental shelf, Guidelines for the Suspension and Abandonment of Wells (2009) for the UK sector, Mining Regulations of the Netherlands WJZ02063603 (2003)

NORSOK D-010 has defined well barrier acceptance criteria for the function and type of well barriers in Table 1. The function of a well barrier and plug can be combined if it fulfils more than one of the objectives, but at no time can a secondary well barrier be the primary well barrier for the same reservoir.

A permanent well barrier should have the following properties:

a) Impermeable;
b) Long term integrity;
c) Non shrinking;
d) Ductile – (non-brittle) – able to withstand mechanical loads/impact;
e) Resistance to different chemicals/ substances (H_2S, CO_2 and hydrocarbons);
f) Wetting, to ensure bonding to steel.

Table 1 – Function and type of well barriers (NORSOK D-010, 2004).

Name	Function	Purpose
Primary well barrier.	First well barrier against flow of formation fluids to surface, or to secure a last open hole.	To isolate a potential source of inflow from surface.
Secondary well barrier, reservoir.	Back-up to the primary well barrier.	Same purpose as the primary well barrier, and applies where the potential source of inflow is also a reservoir (w/ flow potential and/ or hydrocarbons).
Well barrier between reservoirs.	To isolate reservoirs from each other.	To reduce potential for flow between reservoirs.
Open hole to surface well barrier.	To isolate an open hole from surface, which is exposed whilst plugging the well.	"Fail-safe" well barrier, where a potential source of inflow is exposed after e.g. a casing cut.
Secondary well barrier, temporary abandonment.	Second, independent well barrier in connection with drilling and well activities.	To ensure safe re-connection to a temporary abandoned well, and applies consequently only where well activities has not been concluded.

Based on the practice from the Norwegian continental shelf a P&A workflow can be as follows:

- *Planning, acquirement and mobilisation of suitable vessel* for the P&A. All equipment and materials needed for the operation should be present before starting the work;
- *Kill the well* by replacing the well fluid with a heavier fluid. If problems with loss of fluid to the formation occur, it is important to be prepared for such events and have enough kill fluid available. The Christmas tree can be removed at this stage but a blowout preventer (BOP) should be in place;
- *Pull tubing and completion equipment*;
- *Perform a diagnostic logging to assess the conditions of the well*;
- *Plug reservoir and potential cross-flow.* If it is not possible to remove tubing or completion in the lower part of the well it is important that permanent plugs are installed through and inside the tubing string;
- *Log, cut/pull intermediate casing and setting extra plugs;*
- *Set top plug;*
- *Removal of upper part of surface casing, conductor and wellhead*. This will involve cutting of casing at a depth of ca. 5 m below surface. The cutting can be done by special tools.

For CO_2 injection wells the P&A requirements need to address the very corrosive nature of CO_2 when it comes in contact with the cements and casing materials normally used for oil and gas wells. Randhol et al. (2007) propose new procedures and design for safe plugging of CO_2 injection wells. The possibility that casing corrosion will create channelling and that shrinkage or expansion of casing and cement can lead to formation of micro-annuli (Figure 2) lead them to propose a list of 5 requirements that the sealing elements should provide and comply with:

a) Multiple pressure barriers;
b) Avoiding underground cross-flow between layers;
c) Zero transmissivity;
d) Chemically inert;
e) Provide sufficient bonding strength.

A chemical inert sealing material is not likely to exist so it is recommended that the requirement should be a material that has proven stability over time. From the discussion of chemical degradation in section 1.1 and in particular the studies of field cement samples by Carey et al. (2007) and Crow et al. (2010) oil well cements may be suitable and fitting as a long lasting sealing material.

The requirement of sufficient bonding strength may also be difficult to deal with in practical terms as there exists no useful definition of bonding strength. It is therefore not possible to define a value that can be said to be « sufficient ». If micro-annuli form they are likely to form as a result of an excessive parting force.

Figure 7 and Figure 8 show the ideal design of a CO_2 storage well before and after plugging proposed by Randhol et al. (2007). Most notable is the complete removal of production casing and liner. The reason is that the casing inevitably will corrode at a much faster rate than that for wells without CO_2. The cement plug represents the main barrier. The well then is filled with a non-corrosive completion fluid and a second barrier is placed at the top of an impermeable bed higher up in the well. Again the casing is removed by a milling tool before setting a cement plug. At the surface there is a third barrier. An illustration of proposed permanent P&A is shown in Figure 9.

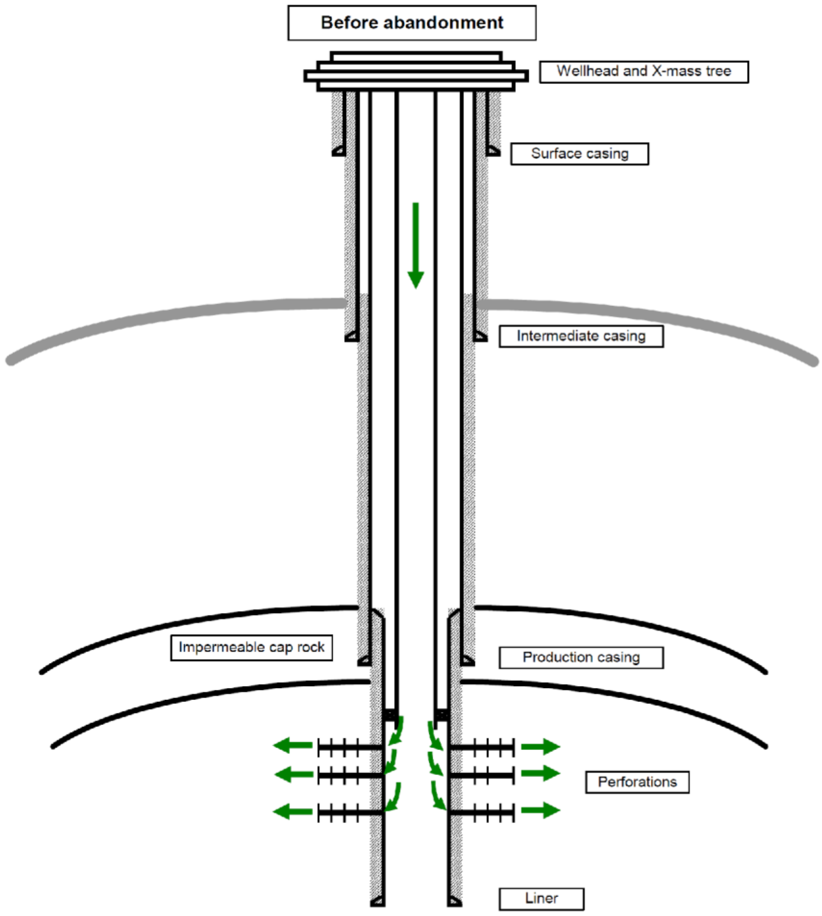


Figure 7 – CO_2 storage well before abandonment. (After Randhol et al. 2007)

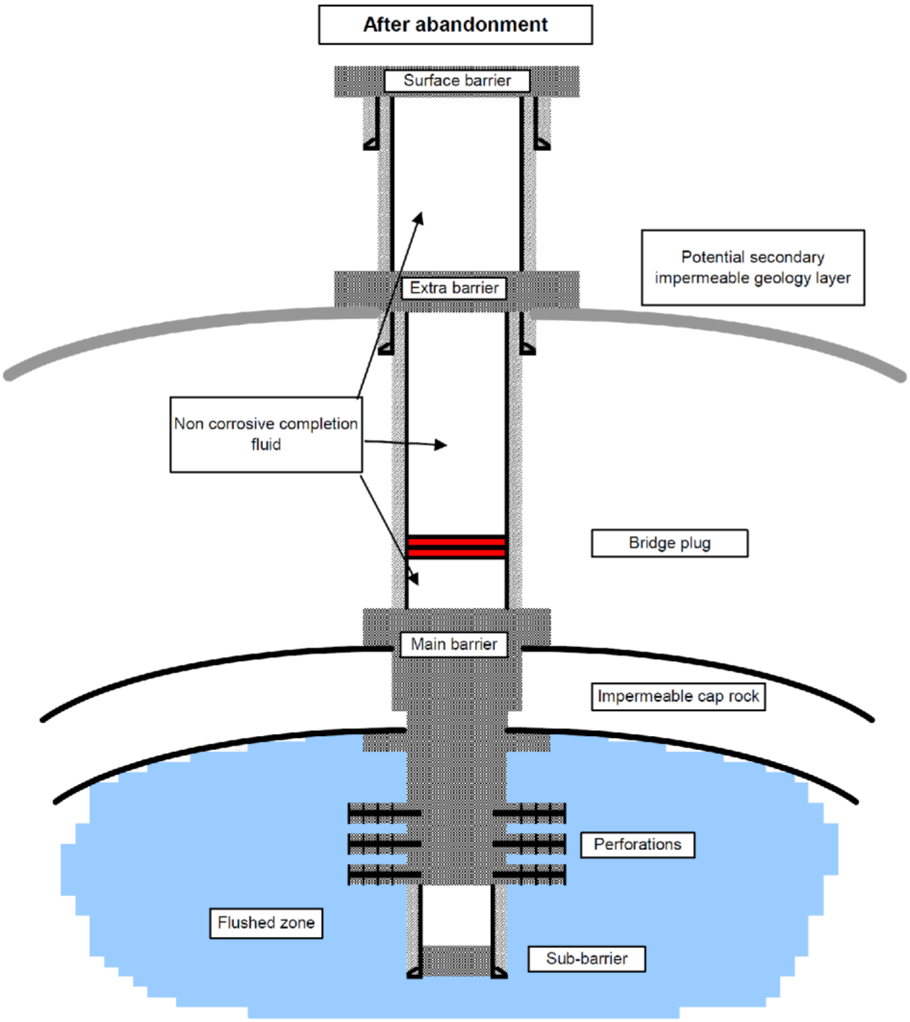


Figure 8 – CO_2 storage well after abadonmnent. (After Randhol et al. 2007)

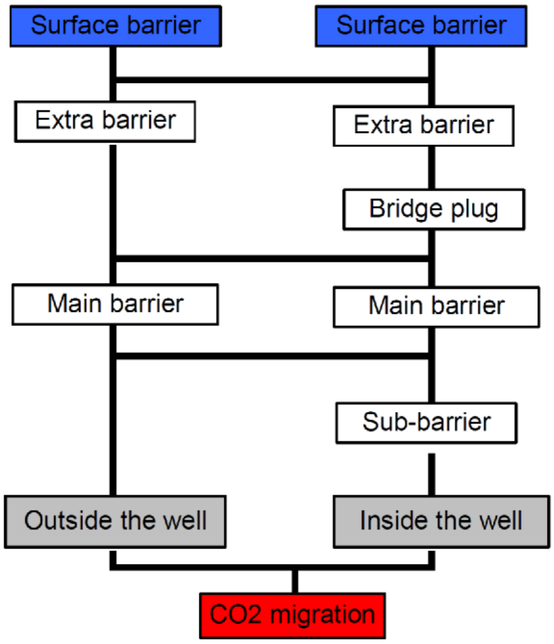


Figure 9 – Flow diagram illustration of the well barriers after abandonment. (After Randhol et al. 2007)

1.1.9. Managing abandoned wells

According to Friedmann (2007) and Nicot (2009) abandoned wells are more likely to leak due to (a) improper abandonment practices, (b) abandonment procedures that have not been followed properly, or (c) well-abandonment not designed for long-term protection (e.g. well seal failure) and thus posing a CO_2 leakage risk if the spreading CO_2 plume intersects such a well, thus possibly creating a pathway for vertical leakage of CO_2 either to the surface/ocean or to overlying fresh-water aquifers.

Though mapping and assessing of potential leaking from abandoned wells should be addressed during the storage evaluation process prior to injection, some wells may not be discovered until after injection has started or even finished. Depending on the condition of the particular well, the measures needed for mitigation and remediation must be selected accordingly to ensure adequate seal against the continued fluid and CO_2 migration. Operation on the well will require setting up a rig above the location of the leaking well and applying any necessary method (see previous sections in this chapter) to stop the leak. Finally the well must be replugged (section 1.1.7) according to the national legislation.

1.1.10. Stopping surface blowout

A blowout is the uncontrolled release of CO_2 gas from a well after all pressure systems have failed. If the main barrier (e.g. tubing, packers, or the primary seal) is lost this in itself does not result in a blowout. It should be possible to avoid breaching of any secondary barriers by reducing injection and/or remediating the migration within the wellbore.

In many respects a CO_2 blowout can be considered similar to hydrocarbon blowout. However, there are some differences that should be kept in mind (ScottishPower CCS Consortium, 2011; Skinner, 2003):

- A CO_2 injection well will at the beginning of its lifetime have lower pressures whereas a petroleum production well has lower pressures towards the end. The higher pressures at end of injection life coincide with increasing age of materials and equipment potentially increasing probabilities of a blowout;
- The risk of pollution to the environment is generally less than for petroleum wells, as the released CO_2 will result to extra outlet to the atmosphere and not result in e.g. oil spills;
- CO_2 is denser than air while hydrocarbons tend to be lighter. Both types are toxic, but CO_2 will concentrate closer to ground level;
- Risk of fire and explosions are negligible, but it may be connected with extreme cold conditions. This large and sudden temperature change may threaten integrity of material (brittle fractures);
- Particles of solids (e.g. dry ice or hydrates) may form from the extreme cold and be expelled from the well at high speeds with the potential of injuring people.

The potential for a blowout for a well-planned injection operation is very low. However, this possibility should not be excluded. Therefore it must be considered in the planning and management of the injection and storage site and integrated in contingency plans. Skinner (2003) report on three events of CO_2 blowouts and concludes that preventive measures such as regular inspection and maintenance of the Blow Out Preventer Equipment (BOPE), and installation of additional BOPE on suspect wells are the key elements in reducing probability of blowouts from CO_2 injection wells .

Stopping a blowout requires killing the well through injection of heavy fluids. The weight of kill fluid will form a new seal hindering CO_2 from flowing out from the well. This measure is relatively quick to apply and may at best be carried out within hours or days.

If the reason for the blowout is caused by missing or damaged wellhead or tree the situation is complicated by the extreme cold and toxic conditions. The specific circumstances and risks should be assessed before any decision is taken to attempt stopping the blowout (ScottishPower CCS Consortium, 2011). If special tools need to be designed and fabricated or transported to the site, this result in longer response time before the leakage is under control, possibly day to weeks.

If one cannot access the wellhead it can be a solution to bring in a rig and drill a relief well to lower the pressure and bring the leakage through the damaged well under control. The design of the relief well is similar to that for a hydrocarbon well. The intersection point is likely to be relative deep, i.e. near the lowest casing within the reservoir section. It is important that the formation does not fracture under the pressure of the escaping fluids (ScottishPower CCS Consortium, 2011).

The cost of drilling a new relief well is dependent on length and/or time needed to stop the leakage and take control over the surface blowout on the first well. It is also dependant on the offshore/onshore location of the well.

1.1.11. Conclusion

As a summary of this section, each well intervention technique is reported in Table 2 with precisions on the aim of these measures.

Table 2 – Summary of proposed techniques for mitigation of leakages from wells

Main objective	Mitigation techniques
Wellhead and welltree inspections and repairs	For above ground installations inspections/repairs of valves, flanges etc. are relatively easy as they are accessible (IEA-GHG, 2007a). Subsea cases require use of remotely operated vehicles (ROV). Depending on the severity and nature of the problem the well may be securely plugged while operations are performed (McGennis, 2001; Maccormick et al., 2011; Sloan et al., 2011).
Replacement of a leaking packer	Retrievable packers can be removed in a wireline operation (IEA-GHG, 2007a; Jørgensen and Haugland, 1998). Permanent packers are removed by milling (Haughton and Connell, 2006).
Replacing or repairing leaking or damaged tubing	Pull and replace string (IEA-GHG, 2007a). Repair using an expandable patch (Chustz et al., 2005; Daigle et al., 2000; Durst and Ruzic, 2009; Storaune and Winters, 2005).
Repairing a leaking casing or preventing migration between separate reservoir zones through annulus	Squeeze cementing (IEA-GHG, 2007a; Cirer et al., 2012).
Replacing or repairing leaking or damaged casing	Repair casing using an expandable patch (Chustz et al., 2005; Daigle et al., 2000; Durst and Ruzic, 2009; Storaune and Winters, 2005).
Repairing deformed or collapsed casing	Swaging (IEA-GHG, 2007a).
Shutting down an injection well or repairing leaking old abandoned well	The requirements for plugging and abandonment (P&A) of wells are defined by national or local safety authorities – cf. IEA-GHG, 2007a for examples from North America; NORSOK D-010 (2004) for the Norwegian Continental shelf, Guidelines for the Suspension and Abandonment of Wells (2009) for the UK sector, Mining Regulations of the Netherlands WJZ02063603 (2003). Design and procedures for plugging and abandoning (P&A) of CO_2 injection wells are described by Randhol et al. (2007).
Stopping a surface blowout	Well killing and drilling of a relief well (Skinner, 2003; ScottishPower CCS Consortium, 2011).

1.2. FLUID MANAGEMENT TECHNIQUES

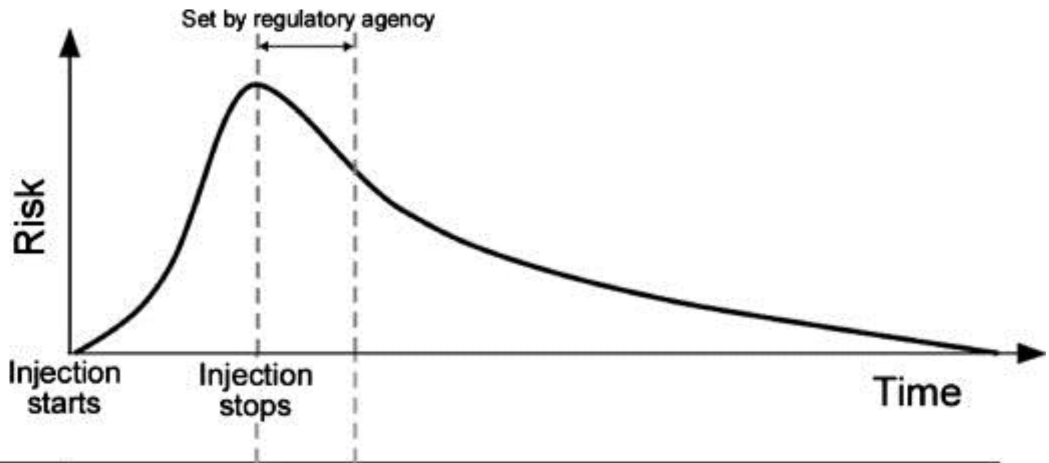
Leaking wells are a priori accessible, which enables the monitoring and diagnosis of the leakage, and there is a portfolio of repair or plugging options available, as presented in the previous section. Contrarily, for a potential CO_2 leakage occurring at locations away from an existing well (injection, abandoned or observation) such as through an injection-induced fracture of the caprock or following reactivation of an existing fault, there is clearly a significant issue of how one could/would address such a problem, the effectiveness of the existing solutions, their implementation as well as the required time. Other significant issues are related to the “reaction” time required to (a) detect the abnormal behaviour, (b) locate the leakage area, (c) identify the leakage source, (d) quantify the leakage (e.g. in kg/s), (e) evaluate and design potential solutions to maximize efficiency, (f) access the leakage source and (g) implement the selected solution. Finally, the potential cost associated with the implementing of the identified solution is another major concern.

As a result of the possibly poorly understood leakage and limited repair options, the corrective measures considered in case of geological failure consist mostly in pressure management or injection operation management solutions. Such immediate and simple solutions would be to (a) stop the pressure increase or decreasing the pressure in the storage aquifer, locally or globally and temporarily or permanently (b) create a pressure barrier in the overlying geological strata to prevent or minimize CO_2 leakage, (c) produce the injected CO_2 back, either locally or globally, and (d) enhance non-structural trapping mechanisms.

These measures are presented in the following, focusing on the corrective options applied to the source of the CO_2 migration (storing aquifer) and on the transfer pathways. If a CO_2 leakage has impacted a target such as a potable groundwater aquifer, similar types of fluid and pressure management strategies could be used, as described in section 1.4 devoted to the remediation measure on impacts.

1.2.1. Pressure relief in the storage formation

Potential over-pressurization of the storage formation may lead to caprock failure, leakage, or uncontrolled displacement of brine, as presented in IEA-GHG 2010/04 (IEA-GHG, 2010a). The storage reservoir pressurization reaches a peak at the end of CO_2 injection, and then decreases to a long-term equilibrium. According to Bachu (2008), this explains notably that the risks associated with the CO_2 storage increase through the operational period, and decline during the post-injection period, as shown conceptually in Figure 10.



Operational Period	Active	Closure	Post-Closure	
Monitoring Frequency & Resolution	High	Targeted	Decreasing	Low
Liability	Operator and/or Emitter		Provincial Agency	

Figure 10 – Conceptual risk profile over time (after Bachu, 2008).

Natural processes of brine and rocks compression, as well as dissolution of CO_2 into the brine formation through density-driven convection will naturally decrease the pressure build-up in the formation, as presented in IEA-GHG 2010/04 (IEA-GHG, 2010a). This study however notes that weak density difference between CO_2-saturated and unsaturated brine could hinder this last process, and concludes that "compressibility of storage formation rock and pore fluids and dissolution of CO_2 are unlikely to make major contributions to the alleviation of pressurization". Operational choices are therefore necessary for making a large difference on the pressurization of the reservoir.

Stopping the CO_2 injection may be considered as a mitigation technique since the pressure relief in the storage formation can be sufficient for reducing leakage, or preventing the CO_2 plume from reaching a leakage pathway. Since it might not be sufficient for preventing CO_2 leakage outside the storage reservoir, accelerating and enhancing strategies such as drilling new injection wells, producing at the injection well or brine extraction at a distant location may be considered: Le Guénan and Rohmer (2011) for instance investigated and compared means of controlling the overpressure by ceasing the CO_2 injection, extracting CO_2 at the injection well or extracting brine at a distant well for a CO_2 storage scenario applied to the Paris basin.

It should still be noted that in the case where the over-pressurization has created a new leakage pathway through, e.g., fault reactivation and hydraulic fracturing, these created cracks and reactivated faults may not totally close with the sole pressure relief. This mitigation option can therefore not be sufficient for stopping a CO_2 leakage if the mobile plume reaches these areas, due to buoyancy effects and viscous forces.

This last case is an argument for considering pressure control strategies in the injection plan, and not as a sole mitigation option. Estimation of pressurization and brine displacement over time in the case of CO_2 storage, as well as potential effects on caprock and fault integrity have been reviewed in IEA-GHG 2010/15 report (IEA-GHG, 2010b). Different injection strategies are presented in the IEA-GHG 2010/04 report (IEA-GHG, 2010a) notably with the purpose of limiting the overpressure created by the CO_2 injection, and therefore to avoid creating leakage pathways through e.g. fault reactivation. The reader is referred to this report for a comprehensive study on these strategies. In addition, we present here three examples from scientific publications using brine production wells, increasing the number of injection wells and/or using horizontal wells:

- Lindeberg et al. (2009) consider the possibility of using up to 210 producers and injectors for a hypothetical very large scale injection of 0.15 Gt/year in the Utsira formation. The extracted brine is disposed in the sea, which should be possible, regarding the current applicable Norwegian legislation;
- Hatzignatiou et al. (2011) have evaluated the storage potential of the deep saline aquifers in Central Bohemian basin for of 2 million tons of CO_2 per year within a single storage project. In three of the proposed injection design options, the authors included two brine extraction wells in order to maintain the formation pressure relief wells as close as possible to initial conditions. At the CO_2 breakthrough, these wells were either shut-in or left operational, leading to a back production of two thirds of the injected CO_2. These three cases allowed the injection of the target volume and were a necessary condition for reaching this objective, along with an optimistic absolute permeability field;
- Bergmo et al. (2011) proposed an injection scheme combining a CO_2 vertical injection well through the height of the formation with a simultaneous brine extraction through a horizontal well (Figure 11). The authors investigated its application to the Johanson and the South Utsira aquifers in Norway, which are candidates for injection of CO_2 shipped out via pipeline from the Norwegian coast.

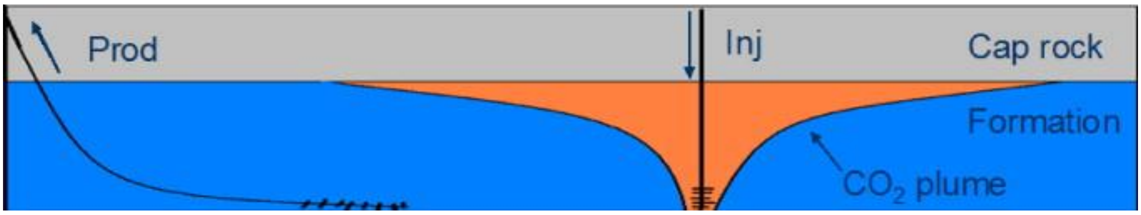


Figure 11 – Simultaneous CO_2 injection and water production to limit the pore pressure increase created by the CO_2 storage. From Bergmo et al., 2011.

The possibility of using dedicated wells to extract the formation brine for alleviating the storage unit pressure was also examined in a recent review work (IEA-GHG, 2012). Results from simple 3D simulation studies in four CO_2 storage case studies covering a large geographical span (Ketzin – Germany, Zama – Canada, Gorgon – Australia, Teapot Dome – USA) and a wide range of geological conditions were presented in an effort to investigate the impact of various CO_2-injection/brine-production strategies, and reservoir properties on the potential implementation of commercial-scale storage projects. The option of surface CO_2 dissolution into extracted brine and then reinjected into storage formation (ESDA process which is described in section 1.2.3) was also considered. The economic potential of the extracted brine was considered based on its potential beneficial use (e.g., desalination) as well as other brine disposal options. The IEA-GHG (2012) study concluded that for the (a) Ketzin case – with total dissolved solids (TDS) > 200,000 ppm, brine extraction and reinjection is not likely to be an issue, (b) Zama hydrocarbon bearing structure - the extracted brine (180,000 mg/lt < TDS < 223,000 mg/lt) could be reinjected into an overlying formation or used as a source for geothermal energy extraction; (c) Gorgon deep saline formation (DSF) - with a brine of TDS around 23,250 mg/lt, the brine extraction provided the most beneficial results with respect to injected CO_2 plume and pressure maintenance compared to the other three cases, with the extracted brine potentially utilized in a natural gas field or disposed in the ocean depending on the presence or not of hydrocarbons and/or radioactive elements and its relative high temperature; (d) Teapot Dome – with a TDS of 9263 mg/lt with the presence of some hydrocarbon the water extraction appeared to have beneficial impact on the reservoir pressure and CO_2 plume management, which is translated to an increased volume of potentially stored CO_2.

1.2.2. Hydraulic barrier

The hydraulic barrier considers the case of a CO_2 leakage from the storage reservoir to an overlying aquifer that is not deemed a sensitive asset. It consists in injecting brine into the overlying aquifer to increase the pressure just above the leak for countering the CO_2 buoyancy and the storage reservoir over-pressurization that are driving this leakage (see Figure 12).

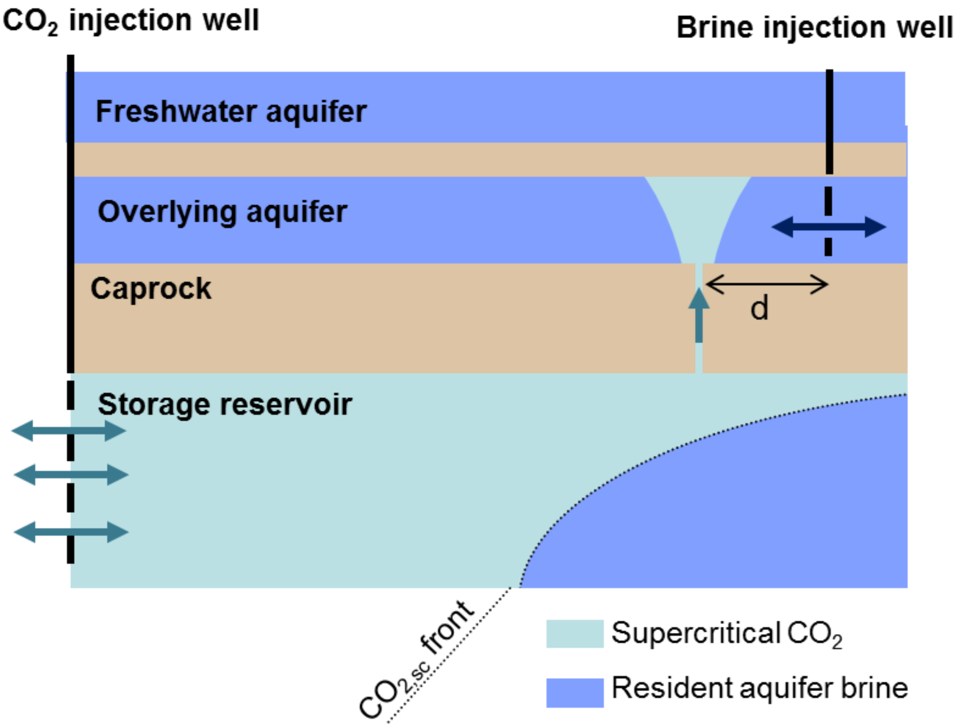


Figure 12 – Representation of the generic leakage and hydraulic barrier scenario. Adapted from Réveillère et al., 2012.

Hydraulic barriers are used as a preventive or corrective measure in pollution engineering. For instance, production or injection wells can be used for locally modifying the hydrogeology in order to protect the drinking water against salt water intrusion, which is one of the most widespread forms of groundwater pollution in coastal areas (Parrek et al., 2006; US EPA, 1999).

Several authors have considered applying this method to CO_2 storage. It is for instance mentioned in Benson and Hepple (2005) and IEA-GHG (2011b). Réveillère and Rohmer (2011) evaluated the applicability, both as corrective and preventive measures, of using a hydraulic barrier to stop the upward migration of CO_2 through a leak from a storage reservoir to an overlying aquifer. Implementing a hydraulic barrier requires considering many operational and strategic issues: delays, cost and technical possibility of re-using a former injection well or drilling a new one, availability of the brine, efficiency of the injection, mechanical integrity of the overlying aquifer and rapidity of the measure. Most of these issues might hinder the applicability of hydraulic barrier and restrain its design.

It is notably hard to evaluate the applicability of a hydraulic barrier without knowing its main design parameters, such as the duration of the injection and the flow rate necessary for stopping leakage. Supposing that the first action is to cease the CO_2 injection, Réveillère et al. (2012) use a mechanical criterion for guaranteeing that the brine injection in the shallower aquifer will not cause fracturing due to tensile failures;

then, they ensure that the pressure build-up created by the brine injection will be sufficient for preventing the leakage due to the pressurized storage aquifer and to the CO_2 buoyancy. The authors conclude that the distance of the brine injection well compared to the leakage appears as the most critical parameter. Hydraulic barrier may be efficient if applied in the immediate vicinity of the leakage plume; however, it may be an impractical solution at long distances since, to be efficient, it requires injecting over a long time period (i.e. large quantities of brine) and that the leakage has already decreased due to the relaxation of the pressure after the stop of the CO_2 injection.

1.2.3. CO_2 plume dissolution and residual trapping

In-situ enhancement of dissolution and residual trapping

Trapping the mobile CO_2 plume may be considered as a remediation option both for the injected CO_2 plume in the storage reservoir and/or a secondary accumulation in an overlying aquifer. These mitigation measures allow relying on residual and geochemical trapping rather than on structural trapping, that might not be sufficient e.g. in case of initially undetected failures in the caprock over the CO_2 plume or abandoned wells. The measure relies on a brine flow over the CO_2 plume, which will enhance dissolution and residual trapping. This brine flow may be either natural, i.e. due to groundwater flow (Juanes et al., 2010) or engineered, as a consequence of a brine injection (Nghiem et al., 2009; Qi et al., 2009; Manceau et al., 2010).

The natural groundwater flow in the storage aquifer is a first mechanism that will chase and sweep the injected CO_2 plume over time, ensuring the dissolution and residual trapping of the supercritical CO_2 (Figure 13). The capacity and the speed of this natural remediation option largely depend on the local hydrogeology of the injection formation.

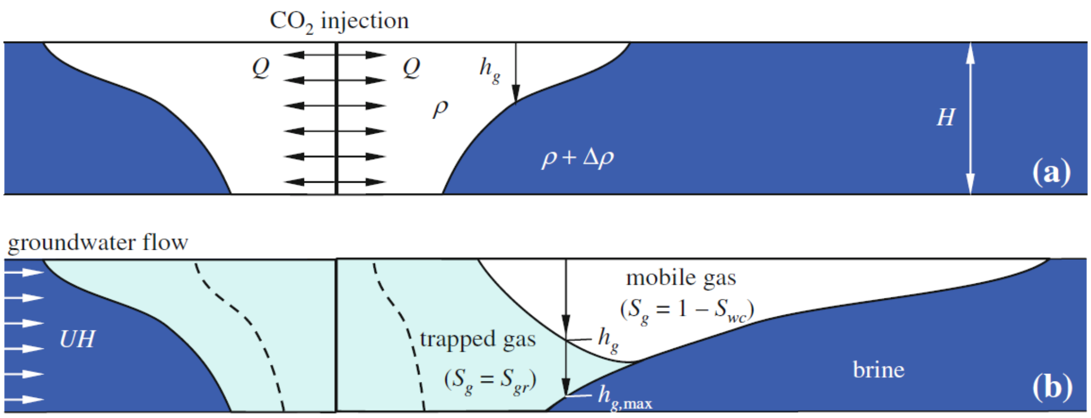


Figure 13 – Conceptual representation of the two different periods of CO_2 migration in a horizontal aquifer: a injection period and b post-injection period with groundwater flow. From Juanes et al. (2010)

In order to accelerate the wetting of the CO_2 plume and its trapping (residual and dissolution), an active remediation option consists in injecting unsaturated brine through the former CO_2 injection well or through a distant one. This has been considered for trapping small leakage plumes (Esposito and Benson, 2012) or the injected CO_2 plume (Manceau et al., 2010). The latter case requires large brine injection flow rate and induces overpressure, which raises several issues including the geo-mechanical integrity of the reservoir and potential brine leakages.

Estimating the capacity of the natural or active trapping of the CO_2 plume at basin scale can be done using approximate analytical solutions (Juanes et al., 2010; Manceau and Rohmer, 2011) or numerical models with implemented dissolution and residual trapping modules (e.g. Doughty, 2009).

The choice of relying on residual trapping mechanisms might be a design option chosen prior to the beginning of the storage. Qi et al. (2009), for instance, proposed to inject both brine and CO_2 in order to enhance CO_2 dissolution and residual trapping. Leonenko and Keith (2008) designed a new reservoir engineering method, which consists of pumping brine from regions where the aquifer is undersaturated into regions occupied by CO_2 thus accelerating dissolution. Another option for enhancing non-structural trapping is that the CO_2 should be injected at very low rates thus allowing sufficient time for the residual, dissolution and mineral trapping mechanisms to become more prominent, thus reducing the possibilities of establishing a free CO_2 plume against the caprock, as proposed by Kumar et al. (2005).

Ex-situ CO_2 dissolution and saturated brine injection

Alternatively to the techniques aiming at enhancing non-structural trapping, an option is to use surface or ex-situ dissolution in order to store dense CO_2-saturated brine. This technique has been proposed as a storage design by several authors, but not as a corrective measure. It is presented in this report as a preventive measure, or as major change of the injection strategy in order to rely on non-structural trapping.

Some authors have proposed the use of this extraction/CO_2-dissolution/injection process whereby the saline aquifer brine is extracted via production wells, the captured CO_2 is dissolved into the extracted brine on the surface using high pressure/temperature mixing vessels and the CO_2-laden brine is re-injected into the storing formation (see for example, Leonenko and Keith, 2008; Burton and Bryant, 2009; Eke et al., 2011a and 2011b). A simplified diagram of this process is illustrated on Figure 14 (Burton and Bryant, 2009).

The CO_2 solubility into saline brine is very low and is normally around 2-3% by mass (Burton et al., 2009). This process is meant to “advance” the slow CO_2 dissolution mechanism and to negate the buoyancy forces since the CO_2-laden brine is now slightly denser than the aquifer CO_2-free brine. The extraction/injection process could be viewed as the means of eliminating the risk of a buoyancy-driven migration of the stored CO_2 and also mitigating the pressure build-up during the injection period.

Although the extraction/CO_2-dissolution/injection process appears to be an attractive solution, it may be hampered due to the following reasons: (a) reservoir heterogeneities which will greatly affect the injected CO_2-laden brine movement into storage formation and a potential communication between injectors and producers – this may cause the increased risk of producing CO_2-saturated brine; (b) increased pressure regimes near the injectors which will reduce the CO_2-laden brine injectivity over time, increase natural fracture apertures, reactivate existing faults, etc.; (c) decreased pressure regimes near the extractors which may cause the intrusion of fluids from overlying (especially in case where the caprock is not sealed or does not exist) and underlying formations; (d) the required large number of injection/production wells to enable the process; (e) large costs associated with the increased well number and the required surface facilities (pressure mixing vessels, high pressure distribution lines, etc.); (f) detailed geological description of the aquifer to be able to optimize wells locations since formation understanding is often limited in saline aquifers; (g) possibilities of near well mineralization which may further reduce the well injectivity or large mineral dissolution that may threaten the reservoir integrity, as shown in André et al. (2007); and (h) deployment difficulties both onshore (extent of high pressure/temperature network of distribution lines) and offshore (potential lack of sufficient space to deploy required surface facilities).

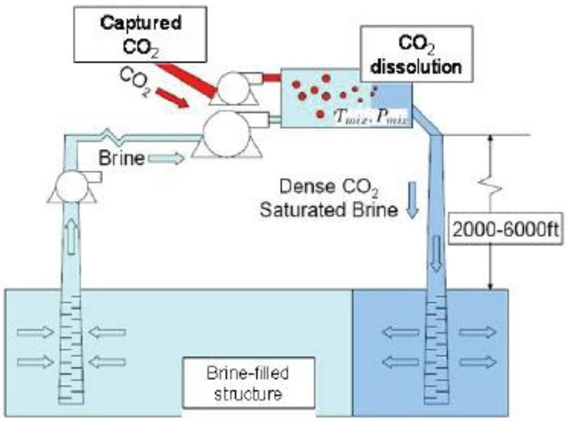


Figure 14 – Surface CO_2 dissolution in brine – Extraction/Surface-CO_2-Dissolution/Injection process (Burton and Bryant, 2009).

Earlier studies have not addressed the storing formation heterogeneity issue. Recently, Tao and Bryant (2012) recognized its importance in reducing the CO_2 storage utilization efficiency. The authors developed an optimal control strategy of the injection/production wells to maximize the CO_2 storage utilization efficiency in a random and a correlated heterogeneous formation. Tao and Bryant (2012) stated that the storage formation capacity is determined by the arrival of the CO_2-saturated brine at any location along the contour of the bubble-point pressure. They proposed two objective functions (to improve areal sweep and utilization efficiency) managing to delay the arrival of injected CO_2 front to the bubble-pressure contour and resulting to improved formation storage utilization. However, the cases considered were simplified and in realistic reservoir models the improved formation utilization could be marginal.

Based on the results of the recent review work (IEA-GHG, 2012), discussed in more details in section 1.2.1, simulation results from simple 3D simulation studies in four CO_2 storage case studies showed that for the Ketzin case the high brine salinity (TDS >

200,000 ppm) the ESDA option is not practical since it will require very large brine volumes to achieve the desired level of CO_2 dissolution, but for the Teapot Dome case with a high quality formation water the possibility of using the ESDA process is feasible.

1.2.4. CO_2 back production

CO_2 storage is planned to be permanent. The European Commission Directive on CO_2 geological storage (EC, 2009) for instance states in the first Article, second paragraph, that *the purpose of environmentally safe geological storage of CO_2 is permanent containment of CO_2*. Nevertheless, the back production of the stored CO_2 may be considered for several reasons:

- Use of the CO_2 as a product in various industrial processes (e.g. Enhanced Hydrocarbon Recovery in a depleted oil and gas field);
- As a remediation measure, if the site is less suitable than anticipated (e.g. initially undetected abandoned well or fault) (Benson and Hepple, 2005). We also include here the partial back production of the injected CO_2, e.g. of a small secondary CO_2 plume under a confining layer with risks to migrate to protected targets.

CO_2 is stored as mobile and trapped gaseous/supercritical CO_2, in its ionic form (dissolved CO_2) and in mineral form after geochemical reactions of the dissolved CO_2. As a mitigation option, the objective of CO_2 back production should be limited to mobile gaseous/supercritical CO_2, since other trapping mechanisms are sufficient to ensure that the injected CO_2 remains in the storage formation. Theoretically, all the CO_2 stored in the formation can be produced back, besides the CO_2 that is stored in the form of mineral trapping: brine with dissolved CO_2 can be produced back, and pore-scale trapped CO_2 can be dissolved, and then produced back (in its ionic form). However, as pointed out by Rohmer et al. (2009), the achievable back production ratio in real sites is limited by the complex and heterogeneous nature of the geological storage, which is in addition partially known and where various phenomena occur with sometimes very large time scales.

Partial or total back production of the injected CO_2 has not been tested yet in CO_2 geological storage sites, and only few studies directly address this question. However, this is technically very similar to a leak in an open well, which has been the focus of many studies in the CO_2 geological storage literature using both analytical and numerical models (Pawar et al., 2009, Nordbotten et al., 2009, Humez et al., 2011). It is also similar to the production of CO_2 from natural CO_2 reservoirs, or to natural gas (possibly from CO_2-rich reservoir) production. Gaseous CO_2 back production will therefore face similar challenges than natural gas extraction, and will benefit from the experience of this industry (number and positioning of wells, benefits of horizontal wells, etc.)

The sole study directly considering large-scale back production of stored CO_2 is Akervoll et al. (2009) who assessed the back production of CO_2 after 15 years of storage in the Utsira formation (Norway), as presented in Figure 15. Their results suggest that 47.7% of the injected CO_2 can be produced within 7 years of production through a single horizontal well. The authors note that the recovery efficiency is low in this relatively flat and layered formation, which creates thin CO_2 plumes with very large lateral extensions. They suggest that such formations are *less suitable for reproduction of CO_2 compared to formations with a significant dome seal or dipping structures sealed by faults*.

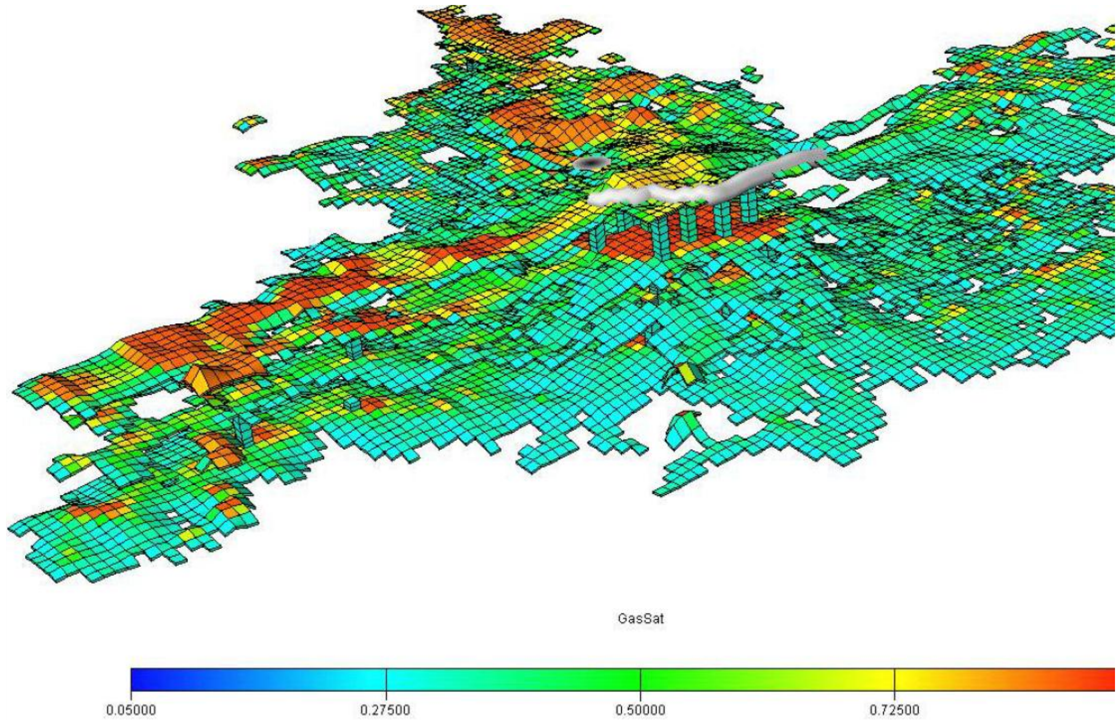


Figure 15 – CO_2 saturation in the top layers of the UTSIRA formation model used for testing the back producing of the stored CO_2 through an horizontal well (shown as a white trajectory). From Akervoll et al., 2009.

Back production of small leakage plumes has also been studied by Esposito and Benson (2012). They showed a better removal of small vertical plume relatively to large thin plumes of CO_2 (gravity tongues) at the top of the aquifer, which also induces the co-production of large quantity of brine that has to be managed.

1.2.5. Conclusion

As a summary of this section, each fluid management technique is reported in Table 3 with precisions on the aim of these measures.

Table 3 – Summary of proposed fluid management techniques for mitigation of CO_2 migration in the subsurface.

Main objective	Mitigation techniques
Decrease the pressure in the storage formation	Pressure control strategies (preventive measure): Lindeberg et al., 2009; Hatzignatiou et al., 2011; Bergmo et al.; 2011; IEA-GHG, 2010; IEA-GHG, 2012. Stopping the injection, production at the injection well, fluids extraction from additional wells (corrective measure): Le Guénan and Rohmer, 2011.
Counteract the buoyancy and pressure gradient driving the CO_2 migration	Hydraulic barrier: Benson and Hepple, 2005; IEA-GHG, 2011; Réveillère and Rohmer, 2011; Réveillère et al., 2012.
Avoid migration of buoyant CO_2 by enhancing dissolution and residual trapping	In-situ enhancement of trapping modes due to natural processes (groundwater flow) or to brine injection, in the storage reservoir or in overlying aquifers (in case of secondary accumulation): Leonenko and Keith, 2008; Nghiem et al., 2009; Qi et al., 2009; Manceau et al., 2010; Juanes et al., 2010; Manceau and Rohmer, 2011; Esposito and Benson, 2012. Ex-situ CO_2 dissolution and saturated brine injection: Leonenko and Keith, 2008; Burton and Bryant, 2009; Eke et al., 2011a and 2011b; Tao and Bryant, 2012.
Partial removal of injected CO_2	Partial CO_2 back production from the injection aquifer or from overlying aquifers (in case of secondary accumulation): Benson and Hepple, 2005; Rohmer et al., 2009; Akervoll et al.; 2009.

1.3. BREAKTHROUGH TECHNOLOGIES

Means of controlling unwanted fluids migration from underground geological strata do exist and are traditionally applied in the oil & gas, hydrogeological and waste storage industries. The specific requirements for CO_2 geological storage (e.g., time duration, fluid mobility, storage site pressurization) and the continuous improvement of existing well intervention solutions as well as the current advances in emerging technologies provide new opportunities for either more advanced CO_2 leakage mitigation tools or further improvement of already existing technologies.

This section aims at describing such breakthrough technologies reviewed in the literature for mitigating and remediating the undesired migration of the CO_2 plume. In this chapter, the following categories of existing and breakthrough technologies are identified based on an exhaustive literature review: 1) conventional Portland and geopolymer cement, 2) use of foams and gels, 3) use of nanoparticles and biofilms to enhance the sequestration of CO_2 and reduce/eliminate any potential risk for CO_2 leakage. Generally, we focus on deep, large-scale solutions to address CO_2 leakage from the caprock either at high or low rates. CO_2 leakage and mitigation solutions though a wellbore have been addressed in section 1.1. However, some of the proposed solutions for mitigating wellbore CO_2 leakage could also be addressed by certain solutions presented in this subsection.

1.3.1. Conventional Portland and Geopolymer Cement

The use of Conventional Portland Cement (CPC), as an isolation agent to control behind-casing/formation communication and provide zonal isolation and integrity of wells has been an issue for a long time in the oil and gas industry (see for example Deremble, 2010; Loizzo and Duguid, 2006; Gasda et al., 2004). Over the years, several researchers have attempted to rectify this weakness of the CPC system to provide full isolation of the formation/behind-casing annulus and identify remedies to address fluid communication among subsurface strata and wellbore (see for example Loizzo et al., 2011; Watson and Bachu, 2009; Barlet-Gouedard, 2006; Talabani et al., 1993a and 1993b).

In the oil and gas industry, Portland cement in various forms – squeeze cement, cement containing special chemicals, foamed cement, grey-water cement solutions, microfine cement – has been the most widely applied (often overused) for wellbore or near wellbore solution to address water channels behind pipe, casing leaks or perforation isolation problems (Sydansk and Romero-Zerón, 2011). It should be pointed out that the cement ability, in any form, to penetrate into the formation matrix for distances larger than few inches is very limited for applied pressure below formation parting pressure. This fact, in addition to cement shortcomings during setting, makes the CPC a non-attractive solution for addressing larger scale (even close to wellbore) formation heterogeneities or well completion deficiencies. The most promising cement application is the isolation of a target zone at the bottom of the well without leakage behind the pipe (Rolfsvåg et al., 1996).

In carbon dioxide storage projects, long-term isolation and integrity of CO_2 injection wells, or observation and abandoned wells penetrating the storage formation, should be improved to avoid unwanted leakage of the stored CO_2 to the overburden strata and potentially to the atmosphere. Another important element in CO_2 storage projects is the ability of the materials used for the well completion to maintain a chemical resistance to supercritical CO_2 over a significant long time period compared to traditional oil, gas or water wells.

Geopolymer is an amorphous alumina-silicate cementitious material that displays a relatively higher strength, excellent volume stability, as well as better durability and resistance to acids when compared to CPC. Since geopolymer possesses higher strength and better acid resistance compared to CPC – in addition to its lower (10-30%) manufacturing cost, 50% lower energy requirements, and 90% lower CO_2 emission during manufacturing – it could be one of the most viable options to replace CPC in CO_2 sequestration well cementing (Nasvi et al., 2012). Geopolymer's strong resistance to corrosion is based on the production of Na_2CO_3 or K_2CO_3, with the pH dropping only to 10-10.5 from 12-13 (note that in the CPC, the pH drop could be as low as 7-8 which in combination to the production of $CaCO_3$ leads to the development of a corrosive environment) (Davidovitch, 2005).

Nasvi et al. (2012) conducted a laboratory investigation to evaluate the (a) stress-strain variations and crack propagation stress thresholds and (b) failure strain and orientation for geopolymer samples cured at temperatures in the range 23^oC to 80^oC. Based on their study on geopolymer, the authors concluded that: (a) the optimal curing temperature for higher compressive strength is 60^oC, (b) Young's modulus and Poisson's ratio increase with curing temperature up to 70^oC, (c) in general, stress thresholds increase with curing temperature, and (d) failure of geopolymer-based well cement will be highly brittle for deeper wells and well sections.

1.3.2. Foams and Gels

Foams and polymer or inorganic gels have been traditionally used in the oil industry to counteract production of unwanted fluids (water and/or gas) and also divert injected fluids into formation regions which have been poorly swept, thus containing significant amounts of mobile oil.

The deployment of chemical solutions primarily aims at obtaining customized solutions dependent on the specific problem. Kabir (2001) ranks the use of chemicals based on their functionality as: (a) sealants (temporary or long lasting); (b) relative permeability modifiers; (c) weak sealant relative permeability modifiers; and (d) mobility control or flow diverting chemical flooding systems (viscous/foam flooding, selective plugging).

Surfactant-stabilized foams are generally used for mobility control in gas-based enhanced oil recovery processes (see for example, Schramm, 1994; Rossen, 1996; Hatzignatiou et al., 2012). The use of foams as conformance control agents has found a limited use in the oil industry up to now. Their complex nature, the difficulty in controlling their strength *in-situ* in the formation, and the limited use in economically viable conformance control applications have hindered them from becoming the first-choice solution. However, the use of new technologies, such as nanotechnology, could lead to an improved stability foam for conformance control application (Sydansk and Romero-Zerón, 2011).

Several types of polymer-based such as movable gels, pH-sensitive polymers, BrightWater, microball, preformed particle gel, etc., have appeared in the literature in the last few years (for a summary see for example Sheng, 2011; Sydansk et al., 2005). Inorganic gels such as silicate gels have also resurfaced and been evaluated for applications to control unwanted fluids in oil-produced reservoirs (see for example Stavland et al., 2011a; Stavland et al., 2011b; Skrettingland et al., 2012; Hatzignatiou et al., 2013). In particular, the use of inorganic silicate solutions appears to be promising since CO_2 could be used as a gelation agent to accelerate the injected system gelation.

The selection, design and deployment of the appropriate mobility-controlled agent are type specific and require, among others, the proper characterization of the storage site (including geological structure and geometry, formation characteristics, formation water salinity, formation pressure and temperature, pH level, etc.) as well as the CO_2 leakage location, type and size.

In general, deployed gels have the objective to reduce the permeability of an existing fluid conduit, thus reducing/controlling the leakage of a high mobility fluid such as that of the stored CO_2. The existing high-conductivity pathway could be located near an injection well or away from it. The injected chemicals, in general, have good injectivity (i.e., low viscosity) enabling them to be deployed at distances away from an injection well. Once in place, an appropriate technique is employed, dependent on the deployed system that triggers the gelation process which leads to the development of a gel-like system that reduces significantly the permeability of the leakage pathway. The placement of the original fluids is also technology dependent and is also affected by the type and completion of the existing well(s). “Surgical” placement of these fluids, yielding the best possibilities for controlling unwanted fluids migration, may require the use of a sidetracked or dedicated slim-hole well. This itself not only increases the cost for controlling a potential CO_2 leakage, but it is also time consuming which means that the CO_2 continues to leak outside of the storage unit with undesirable consequences at either one or both the subsurface and surface environments.

Polymer Gels

Polymer macromolecules are linked together by crosslinkers (normally metal ions or metallic complexes) forming a viscous gel in the formation. When reservoir temperatures are in excess of 121^{o}C the use of organic crosslinking agents may be more appropriate. Polymer gels have mostly been used for water shut-off applications, and can be used for both sealing and disproportionate permeability reduction. [1]

Polymers, both polyacrylamides (PAM) and biopolymers, are mainly used for water shut-off applications. PAM polymers have a good ability of plugging of pores or fissures, because of their viscosity and the formed gel strength. Biopolymers have the ability to form physical network above critical concentration. Generally, as a result of the limited strength, they are not suitable for fracture treatment and more suitable for plugging pores or fissures (note that the gel strength will be a function of the treated zone width, fracture aperture, etc.). There are also ungelled polymers/viscous systems, which have the ability to reduce the water permeability more than the oil permeability. The advantages with these systems are that they can be bullheaded into an un-fractured well without zonal isolation. On the other hand, they are not strong enough to seal vugs and big voids, and there is also a risk of reducing the oil permeability. General issues with polymers are gelation control, adsorption and deep penetration, because of the viscosity.

Micro Gels

- **Movable Gels**

Movable “soft” microgels are effective means for deep reservoir injection profile control and/or Disproportional Permeability Reduction (DPR) systems.[2] Microgels are formed at polymer concentrations below the critical overlap concentration of polymer and are dominated by intra-molecular crosslinking. Discontinuous microgels are low-concentration acrylamide-polymer gels formed at the surface with a very narrow particle-size distribution (Chauveteau et al., 2003).

- **BrightWater®**

BrightWater® is nano-sized or micro-sized, crosslinked polymer particles, which are designed to swell approximately 10 times their original size when exposed to a given high temperature. BrightWater® has found recent deep-reservoir applications. BrightWater is one of such gels introduced and field-applied by Frampton et al. (2004) and Pritchett et al. (2003); generally, it has found applications in reservoirs with temperatures up to 141^{o}C and salinities of up to 120,000 ppm.

- **Colloidal Dispersion Gels (CDG)**

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[1] Water shut-off is the process used in the oil industry to reduce water production from a given oil field while maintaining existing oil production levels.

[2] DPR systems are deployed in an oil-producing zone with the objective to reducing water production rate whereas having a smaller impact on the oil production rate.

Colloidal Dispersion Gels (CDG) can be described as bulk gels that require low polymer and crosslinker concentrations, thus making the injection of large volumes economical while permitting in-depth placement (Mack and Smith, 1994), but their field application is rather limited due to their rather restricted reservoir temperatures of less than 91°C and a salinity range of up to 5000mg/l (Coste et al., 2000). According to Mack and Smith (1994) high molecular weight polymers with large degree of hydrolysis yield better gels, the polymer-to-aluminium ratios of 20:1 to 100:1 work the best, the CDG system they used worked well up to 30,000 ppm TDS, and the reaction rate should be slow enough to provide sufficient in-depth placement.

- **Preformed Particle Gels (PPG)**

Micrometre – to millimetre-sized Preformed Particle Gels (PPG) have been developed and field-tested to overcome potential *in-situ* gelation drawbacks related to polymer gel crosslinking (Coste et al., 2000; and Bai et al., 2007). The main difference of PPGs with the microgel systems is due to swelling time and ratio as well as particle size. PPGs are mainly used to treat fractures or fracture-like channels and designed to withstand temperatures up to 121^{o}C and salinities up to 300,000 mg/l (Bai et al., 2007).

pH Sensitive Gels

Deep reservoir placement of pH sensitive polymers has been introduced by Al-Anazi et al. (2002). In general, a polyelectrolyte, which can create a molecular-network microgel in solution, is placed in a high conductivity path. The injected fluid reacts with formation minerals (e.g., carbonate) and experiences an increase in pH which causes the polymer to swell up to 1000 times of its own volume and drastically increase its apparent viscosity (Choi et al., 2006); the viscosity characterization was reported by Huh et al. (2005). These polyelectrolytes (e.g., anionic derivatives of polyacrylic acid) may form rigid gels in the porous media which can resist applied pressure gradients, can be broken down with the use of a mild acid wash and flowback (if and when it is required), are sensitive to the presence of divalent cations resulting to precipitates (thus requiring the use of a formation preflush to reduce/eliminate such tendencies) and exhibit temperature tolerance (at least up to approximately 82^{o}C).

Figure 16, presented by Choi et al. (2006), displays the achieved gel apparent viscosities as a function of the solution pH and the polymer (Carbopol) concentration. For all polymer concentrations, the apparent gel viscosity increases at about pH=3.5, and gel apparent viscosities of well over 5000 cp could be developed for polymer concentrations larger than 300 ppm when pH is higher than 4.5.

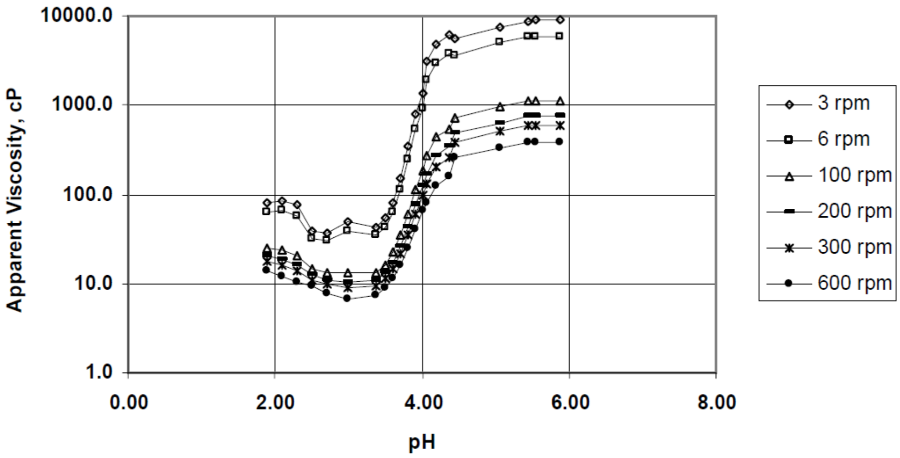


Figure 16 – Apparent viscosity of Carbopol 934% as a function of pH for various polymer concentrations (Choi et al., 2006)

The impact of the acidic environment in a CO_2 sequestration process needs to be evaluated and the impact of pH reduction on the gels' strength and stability quantified in order to establish safe application boundaries.

Sweatman et al. (2012) report the use of low-cost special sealants, referred to as Chemical Remediation Systems (CRS), which can be pumped directly to the leakage path to control and remediate CO_2 leakage both inside and outside of the storage formation. The authors referred to latex-based and silicate/polymer sealant systems which can be activated by contact with CO_2 to create a rigid, semi-rigid or flexible sealant. These CRS fluids could be deployed using spacers to avoid contamination while moving from the surface to the treatment location.

The issues of gel strength, its durability and viability in a mildly acidic environment created due to the presence of created carbonic acid needs to be taken into consideration while designing the type of the deployed chemical system and the created gel. For instance, there are some chemical systems that produce high-strength gels which are resistant to the created acidic environment. Such gels require the use of mild to strong hydroxide-based chemicals to be gradually eroded in case of an incorrect placement.

Silicate Gels

Silicate gels have been used in the oil and gas industry to control unwanted water production and for near wellbore applications. Their effectiveness in controlling the flow of unwanted fluids is due to their: (a) deep penetration that can be achieved into the treated zone because of the low initial (i.e., prior to gelling) silicate fluid viscosity, (b) good thermal and chemical stability, (c) low cost, (d) environmental friendliness, and (e) easy "removal" in case of an unexpected deployment failure (Lakatos et al., 1999).

The mobility reduction that can be achieved though the use of silicate gels is demonstrated clearly in Figure 17 for a silicate train injected through Bentheim core samples by Stavland et al. (2011b). This figure also provides indications of temperature effects on the effectiveness (developed strength) of a silicate gel.

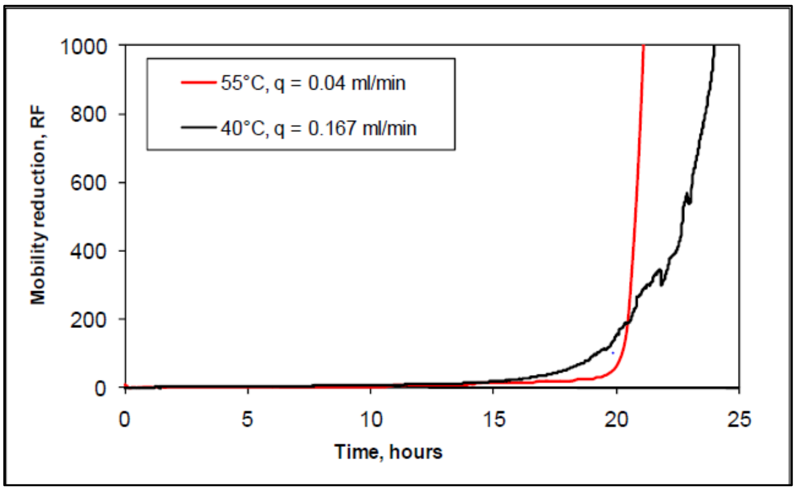


Figure 17 – Mobility reduction for silicate train injected through Bentheim core samples at two different temperatures (Stavland et al., 2011b)

There are several papers in the literature that address the application of silicate gels to combat unwanted fluid intrusion and production. Jurinak and Summers (1991), for example, reported the use of silicate gels in several well interventions such as water-injection-profile modification, water-production control and remedial casing repair with a mixed success. The authors stated that compared with other types of gels, silicate gel is relative inexpensive, environmentally friendly and flexible. The disadvantages of silicate gels may be their blocking effect and the gelation mechanisms. More specifically, the silicate gel tends to shrink during time, thus reducing the gel's blocking effect. Finally, since the gelation of silicate is a function of pH, temperature and concentrations of the reacting components, the gelation time might be difficult to control as its mechanisms have not been fully understood.

Jurinak and Summers (1991) provided three field example applications of silicate gels for: (a) modifying the water injection profile during water flooding in a multilayered system due to permeability contrast, (b) controlling the water production via early-time well perforations which were initially cement squeezed and unsuccessfully treated with a cement re-squeeze job when communication developed at a later stage of the well's production history, and (c) casing repairs in three shallow injection wells caused by mildly corrosive brackish water (see Figure 18).

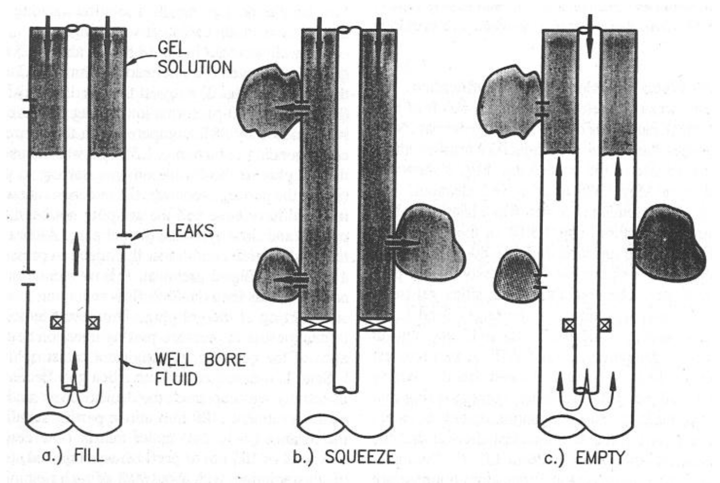


Figure 18 – Casing leak treatment possibilities using silicate gels (Jurinak and Summers, 1991).

Herring and Milloway (1999) reported a successful gas shut-off application of silicate gels at the Prudhoe Bay field of Alaska stating that large volumes of used silicate gel provided an impermeable barrier against the gas influx at high temperature conditions. Lund et al. (1995) have also reported another field application of deep silicate gel treatment at the Gullfaks field in the North Sea. Rolfsvåg et al. (1996) reported the use of 4000 m^3 of gelant Na-silicate solution injected at Gullfaks Norwegian offshore oilfield in a watered out zone to reduce water production. That well treatment followed a previous one at the same field but in a different well, and consisted of a 1 wt% KCl brine preflush, injection of non-gelling 0.5 wt% alkaline Na-silicate, injection of gelant with increasing concentration of pH reducing agent and Na-silicate, and a postflush of 1 wt% KCl to displace the gelant away from the injection well and finally followed by a 14-day well shut-in. The authors reported a 13% decrease of the water-cut and increased oil recovery from the Lower Rannoch formation achieved through the gel placement at a distance of around 20 m into the treated zone.

Skrettingland et al. (2012) have reported the single well pilot test at the Snorre Norwegian offshore oilfield for an in-depth water diversion using a sodium silicate system. The pilot test was carried out following a comprehensive evaluation of the in-depth formation plugging in the laboratory and design of the silicate system. The objective of the test was to confirm the ability to form in-depth permeability restrictions in the formation. The field observed results were interpreted from injectivity and repeated falloff pressure measurements which demonstrated the expected permeability reduction.

Finally, several researchers have experimented with the strength of a silicate gel by utilizing polymers or other chemicals to enhance the stability, durability and strength of silicate gels. For example, Burns et al. (2008) presented a new generation of gel, composed of sodium silicate, an initiator and a polyacrylamide, for casing repairs and deep penetration conformance control termed Silicate Polymer Initiator (SPI) gel. The resulting gel is more elastic and display delayed gelation control compared to traditional silica gels. Depending on the sodium-silica/initiator ratio, weaker (ratio between 0.5 to 1.1) or firm (ratio between 1.1 to 2.0) could be formed depending on the intervention requirements, the temperature, pH level and gelation time. However, since SPI gels contain polymer they are sensitive to brine salinity and presence of divalent cations.

Lakatos et al. (2009) also provided laboratory results that demonstrated the beneficial use of polymers in conjunction with silicates to enhance the viscosity of the created silicate gel (see Figure 19). Other authors have reached to similar conclusions (see for example Usaitis, 2011).

In general, the use of gels for controlling the movement of CO_2 within the structure or leakage out of the storage unit should be viewed as time-dependent solution. Issues such as gel strength, durability, dehydration, temperature, acid and bacterial resistance, etc. are of a concern and the appropriate system should be sought after, designed and implemented to enhance the properties and duration of the deployed gel system.

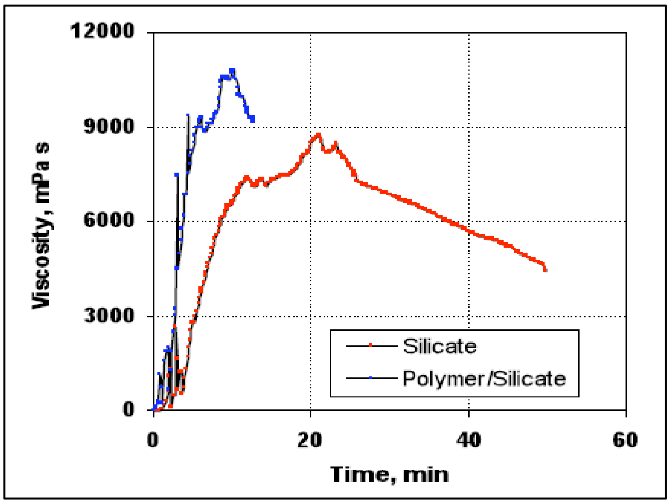


Figure 19 – Effect of polymer content on the gelation rate and gel viscosity - SiO_2 = 50 g/l; Polymer – 2 g/l (Lakatos et al., 2009).

1.3.3. Nanoparticles

Nanoparticle-based applications for mitigating undesirable CO_2 leakage from the storage formation have recently appeared in the literature. This subsection provides a brief description of some of the applications nanoparticle (NP)-based technology can find to control CO_2 leakage.

Nanoparticle Use in Foams

Since surfactant-stabilized CO_2 foams are generally weak, due to their long-term stability and surfactant adsorption loss, Yu et al. (2012) proposed the use of nanoparticle-stabilized CO_2 foam. According to their results, supercritical CO_2 foam was successfully generated in a tube with the aid of nanoparticles. The authors also observed that an increase of the brine salinity and temperature leads to a reduction of the CO_2 foam, whereas when pressure increases more CO_2 foam was generated. Finally, Yu et al. (2012) concluded that the addition of surfactant to the nanosilica dispersion improved CO_2 foam generation. This finding is encouraging for developing strong and easy-to-develop foams for practical applications for oil and gas as well as carbon sequestration applications.

Nanoparticles for Mobility Control

DiCarlo et al. (2011) reported measurements of flow pattern and in-situ saturations observed when n-octane displaced brine that contained dispersed surface treated silica nanoparticles. The authors reported displacement fronts which are more spatially uniform, and with a later breakthrough, compared to a control displacement with no in-situ nanoparticles. This finding along with pressure measurements which were consistent with the generation of a viscous phase (emulsion) suggest that a nanoparticle stabilized emulsion formed during displacement suppressed the viscous instability. Finally, the authors stated that generated non-wetting phase droplets at the leading edge of a drainage displacement are preserved when nanoparticles adhere to the fluid/fluid interface.

Figure 20 illustrates the measured average pressure drop for two flooding experiments with n-octane injected in a Boise sandstone core samples initially filled with: (a) 2% brine (control experiment – without nanoparticle case) and (b) 2% brine with 5% silica nanoparticles (nanoparticle case). According to the results illustrated in Figure 20, the measured average pressure drop (and thus the emulsion phase mobility) for the control experiment (without nanoparticles) is 2.5 times lower than the one recorded for the case in which nanoparticles were used. CT scan images also illustrate that the water saturation behind the flooding front is much higher for the nanoparticle case compared to the controlled one, thus leading to lower fluid mobility.

Nanoparticle Use in Silicate Gels

Following previous studies which demonstrated that the addition of water-soluble polymers to silicates could provide improved stability and flexibility of the resulting gels (see subsection 1.3.2), Lakatos et al. (2012) investigated recently the use of nanoparticles (NP) to potentially replace polymers in silicate-based gels. The authors conducted laboratory studies to investigate the gelation mechanism, rheological properties, flow behaviour and nanoparticle type and size on the resulting silicate gels. Lakatos et al. (2012) concluded that SiO_2 nanoparticles are compatible with silicate solutions and the stability of the resulting SiO_2/silicate system depends significantly on the size and concentration of NP: the smaller the size, the more stable and the higher the concentration and the less stable the resulting system. In addition, as the concentration of NP increases, the viscosity of the SiO_2/silicate system increases too whereas, for a given catalyst concentration and temperature conditions, the setting time is reduced.

These results clearly indicate that the use of NP could be used to yield even better and more efficient silicate systems for field applications to control, limit or even eliminate potential CO_2 leakage through heterogeneities in the caprock and/or formation.

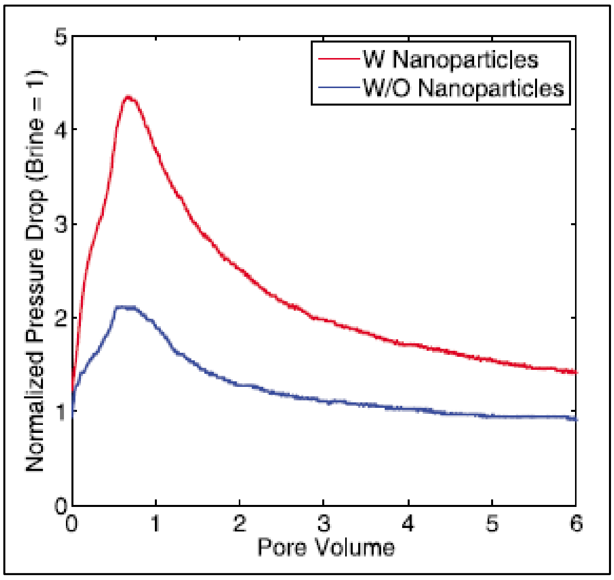


Figure 20 – Normalized measured pressure drops as a function of time for n-octane injection with and without nanoparticles (DiCarlo et al., 2011).

Nanoparticle Use in CO_2 Sequestration

Addition of nanoparticles to injected CO_2 has been also proposed by Javadpour and Nicot (2011) to enhance CO_2 sequestration and reduce CO_2 leakage risks in deep saline aquifers by increasing the density contrast between the CO_2-rich brine and the resident brine. According to the authors, the addition of nanoparticles will decrease the instability onset time and increase convective mixing due to CO_2 diffusion into the resident brine. Both metallic nanoparticles and depleted uranium oxide were proposed to reduce CO_2 leakage risks. The authors assumed that the nanoparticles do not adsorb onto the rock surface or impair the formation permeability. The use of waste materials, depleted uranium oxide nanoparticles, and their inherent leakage risk is an issue that needs to be addressed.

Singh et al. (2012) conducted a simulation study to investigate the use of nanoparticles to enhance CO_2 storage in deep saline aquifers by expediting convective mixing and decreasing the CO_2 buoyancy flow. Based on their numerical results, the authors concluded that the injected NP-CO_2 plume dissolves deeper and moves less laterally than the normal (i.e., without NP) CO_2 plume. Therefore, the faster mixing and decrease CO_2 buoyancy could reduce the chances for CO_2 leakage through the caprock and also obviate some of post-CO_2 injection monitoring costs.

1.3.4. Biofilms

Bacteria in natural environments tend to be attached to solid surfaces. The attached cells when embedded in extra-polymeric substances (EPS) are protected against harsh conditions. The assemblage of the microbial cells encased within protected EPS attached to a solid surface is known as a biofilm (Lewandowski and Beyenal, 2007; Lappin-Scott and Costerton, 2003).

Biofilms have been proposed in the past as means to control the spread of, and treat, a contaminant plume into the subsurface formations (Cunningham et al., 2003). Naturally, they have been also proposed as bio-barriers which could help preventing the leakage of stored supercritical CO_2 through the caprock by blocking leakage pathways (Cunningham et al., 2009; Mitchell, et al., 2009). Figure 21 illustrates the concept of biofilm barrier application to control supercritical CO_2 (sc CO_2) leakage through the storage formation caprock. According to the authors, this could be achieved by injecting biofilm-forming organisms and growth nutrients and controlling the spatial extent and mass of the biofilm. Naturally, the created biofilm could also protect well cement from an “attack” by the CO_2-rich brine.

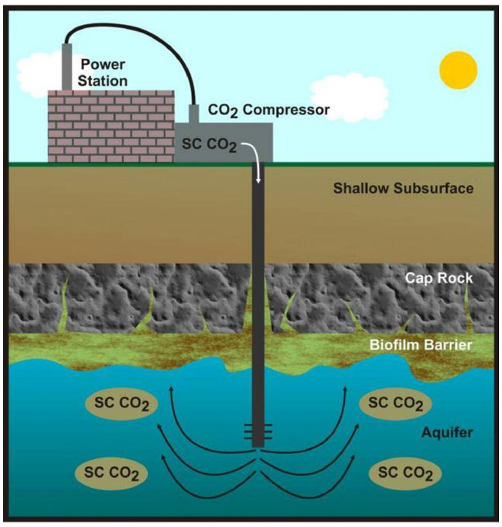
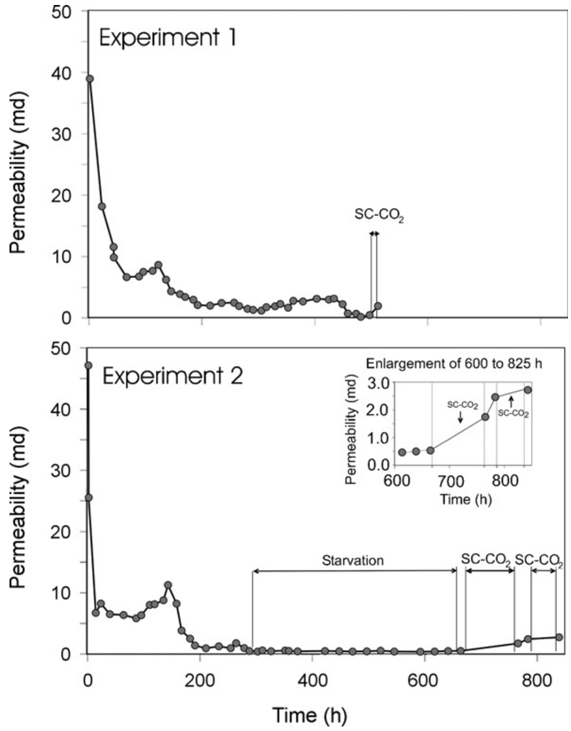
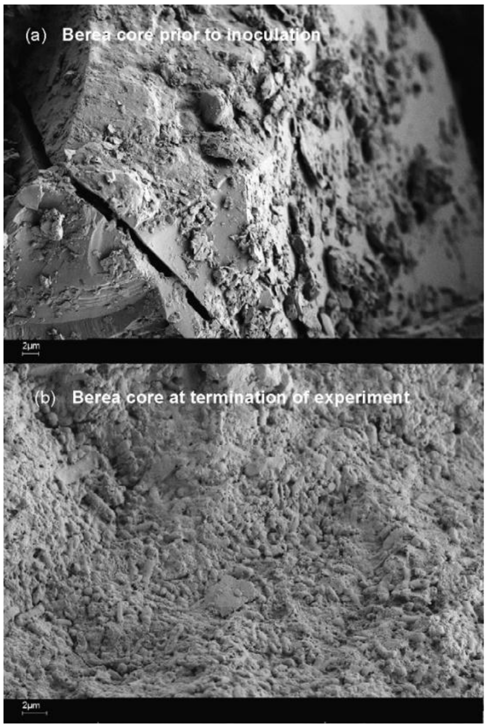


Figure 21 – Schematic diagram illustrating the concept of biofilm barrier application to control supercritical CO_2 (sc CO_2) leakage through the storage formation caprock (after Mitchell et al., 2009).

Mitchell et al. (2009) conducted core flooding experiments measuring the permeability reduction over time with the core exposed part of the time to supercritical CO_2. In both experimental results presented in their work the reduction of permeability with the biofilm generation in the porous medium is clearly demonstrated. The authors provided also Field Emission Scanning Electron Microscope (FESEM) images of a Berea sandstone core prior to inoculation, displaying clearly the mineral surfaces free of microorganisms, and at the end of the experiment with the assemblage attached to the mineral surfaces (Figure 22).

The initial concept of the biofilm utilization to control a potential leakage of supercritical CO_2 was enhanced to an "engineered biomineralization" proposed by Cunningham et al. (2011) and Mitchell et al. (2010). The authors noted that if the biofilm spatial distribution can be controlled, then it could potentially create a long-term stable low permeability zone by "encouraging microbially catalysed biomineralization". More specifically, Mitchell et al., (2010) envisioned the use of biofilms and biominerals to (a) enhance CO_2 formation trapping by pore clogging and CO_2 leakage reduction:, (b) biofilm-enhanced mineralization of carbonate minerals (i.e., mineral trapping), (c) biofilm-enhanced solubilisation of CO_2 (solubility trapping), and (d) improve protection of injection well casing (see Figure 23).





(1) (2)

Figure 22 – (1) Core permeability change vs. time for two experiments and with the core exposed to supercritical CO_2 (sc CO_2) and (2) FESEM images of a Berea sandstone core (a) prior to inoculation displaying clearly the mineral surfaces free of microorganisms and (b) at the end of the experiment with the assemblage attached to the mineral surfaces (after Mitchell et al., 2009).

In general, the presence of H_2S-generating sulphate-reducing bacteria may create localized corrosion of the well's casing and adverse interaction with its cement used for zonal isolation. Therefore, appropriate means to protect the well (casing and cement) against the potential presence of H_2S should be a concern that needs to be addressed when biofilms are further developed and fine-tuned to CO_2 storage settings.

Ebigbo et al. (2010) developed and tested a numerical model capable of simulating the development of a biofilm in a CO_2 storage reservoir. The model describes the growth of the biofilm (Monod kinetics), two-phase (water and CO_2) flow and transport in the geological formation, and the interaction between the biofilm and the flow processes; it also includes among others the effects of biofilm growth on the formation permeability, but it does not account for neither the CO_2 solubilisation nor the mineral trapping mechanisms. The authors tested their numerical model by comparing simulation results to experimental data (Taylor and Jaffé, 1990) and found discrepancies between the two which they attributed to both idealized modelling and experimental issues encountered in the lab. Some of the model shortcomings mentioned by Ebigbo et al. (2010) are based on the assumptions that the biofilm density is constant, the biofilm decaying model used may not be adequate, and simplified relationship between the formation permeability and biomass decay. Finally, the model was applied by the authors to a synthetic field-scale test case to simulate mitigation of CO_2 leakage through the caprock using biofilms.

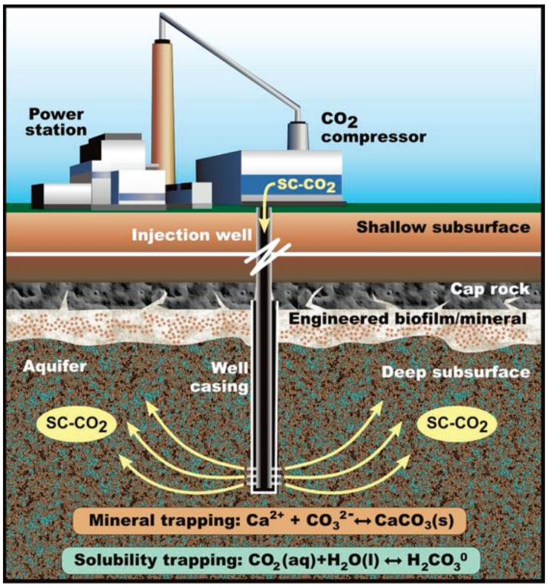


Figure 23 – Schematic diagram illustrating the concept of microbially enhanced CO_2 storage (after Mitchel et al., 2010).

The main issue of this technology is the inability to effectively control the biofilm generation and growth as well as its proper placement within the formation to the locations of the highest risk of a CO_2 leakage or of an already developed leakage. The authors seemed to focus mainly on potential CO_2 leakage pathways generated in the vicinity of an injection well (Cunningham et al., 2011; Mitchell et al., 2010 and 2009; Ebigbo et al., 2010). Although this technology provides another possibility for mitigating near wellbore CO_2 leakage, it currently does not seem to be able to control or prevent potential CO_2 leakage in locations away from the injection well which may also provide high risks of caprock failure, membrane seal breakdown, or reactivation of existing fractures and faults.

1.3.5. Conclusion

Several techniques have been presented which have been tested and used in other industries for controlling unwanted fluids migration from underground geological strata and/or diverting injected fluids within the reservoir unit. Some emerging technologies have also been introduced since they may provide new opportunities for either more advanced CO_2 leakage mitigation tools or further improvements of already existing ones.

The potential application of some of these techniques depends strongly on the location of the undesired CO_2 migration and the leakage severity. Depending on the formation and leakage-path properties, some of these techniques may serve as short- to intermediate-term solutions until a more permanent one (e.g., a sidetracked or new relief well in case of a major leakage) can be placed to address long-term solutions.

1.4. REMEDIATION MEASURES ON POTENTIAL IMPACTS

The previous sections presented measures to mitigate any potential CO_2 leakage, by acting on the source or on the transfer pathway. This section is devoted to the possibilities of dealing with the remediation of the impacts of CO_2 migration, should these impacts occur.

Remediation of impacts could be defined in different ways depending on the context of implementation and on the goals to be achieved. The European Directive on Environmental liability (2004/35/CE) which establishes a framework for prevention and remediation of environmental damage defines a remedial measure as "*any action, or combination of actions, including mitigating or interim measures to restore, rehabilitate or replace damaged natural resources and/or impaired services, or to provide an equivalent alternative to those resources or services*" (EC, 2004).

The European Directive differentiates three types of remediation, thus complementing the above definition:

- The primary remediation, which "*is any remedial measure which returns the damaged natural resources and/or impaired services to, or towards, baseline condition*";
- The complementary remediation, which "*is any remedial measure taken in relation to natural resources and/or services to compensate for the fact that primary remediation does not result in fully restoring the damaged natural resources and/or services*";
- The compensatory remediation, which "*is any action taken to compensate for interim losses of natural resources and/or services that occur from the date of damage occurring until primary remediation has achieved its full effect*".

An undesired migration of CO_2 will be composed of CO_2 potentially associated with others substances called associated substances in this report. The associated substances may have three different origins: they could be co-injected with CO_2, obtained by chemical reactions or carried by the CO_2 flux. Associated substances may include H_2S, SO_2, NO_X, radon, methane, heavy metals, organic compounds and other trace elements (IEA-GHG 2011b, IEA GHG, 2007b).

According to the IEA-GHG (2007a, 2007b), the potential compartments[3], which may be impacted by an undesired CO_2 migration, are considered to be (Figure 24):

- The groundwater aquifers (confined or unconfined);
- The unsaturated zone (or vadose zone);
- Surface assets (including: human health, ecosystems and other activities).

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[3] In the framework of the European Directive 2004/35/CE, the environmental damages are divided between damages to protected species and natural habitats, water damages and land damages

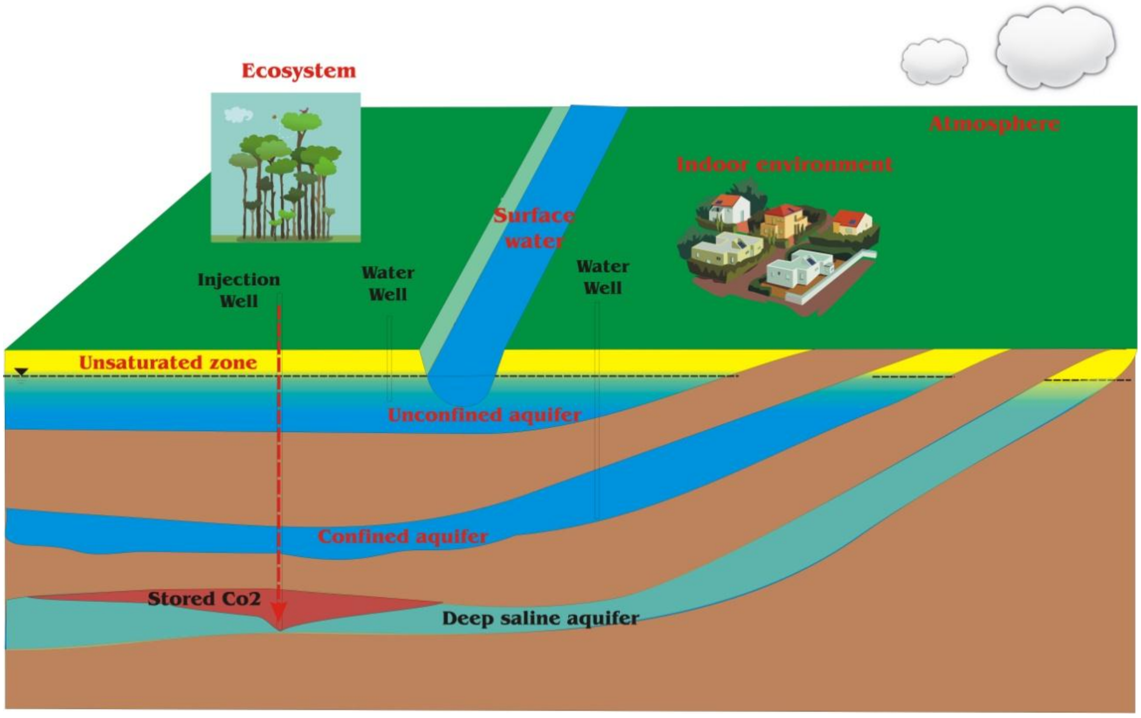

Figure 24 – Potential compartments impacted by an undesired CO_2 migration (in red).

Given the specificities of remediation techniques to an impact, this section describes the measures according to the impacts on these three types of compartments. In each subsection, the potential impacts are specified in order to present the associated possible intervention strategies. The measures are presented without prejudging the necessity of the measure implementation: the action level (level above which a measure is necessary) is out of the scope of the study.

Extensive data and experience on measures to remediate impacts already exist in various fields such as soil clean-up, aquifer repair, intrusion of radon in buildings, etc. The measures can be of several kinds as explained by Khan et al. (2004): biological, physical and chemical processes (individually or combined) may be used in order to lower the pollution to an acceptable level.

Remediation measures specifically dedicated to CO_2 storage impacts are poorly documented. To our knowledge, no remediation project following impacts of CO_2 leakage after geological storage has ever been implemented. Due to this lack of data, this section will be based on cases of pollutions potentially analogous to those expected in case of CO_2 leakage.

Whatever the context and the objective of the remediation, the choice of the appropriate remediation measures (or of the measures combination) to be implemented is situation-dependent. According to Khan et al. (2004), the remediation intervention should be designed according to the site conditions, the contaminants type and source, the possibility of source control measures as well as the potential impact of the remedial measure.

The evaluation of the different remediation alternatives for a specific impact is generally done according to the following criteria (EC, 2004):

- Estimated effectiveness of the measure to the damage (restoration of the damage, prevention against future damage, avoidance of collateral damages);
- The time needed for the restoration of the environmental damage;
- The cost of implementation;
- The potential impacts of each option on public health and safety.

In addition to the measure itself, the preliminary analysis leading to an accurate evaluation of the impacts is highly important. This assessment is only possible if an adapted monitoring system is implemented. The monitoring and detection system is out of the scope of this study, and therefore this section is exclusively focused on the remediation techniques. However, when monitoring is part of a remediation technique, it is fully explained.

1.4.1. Remediation techniques for impacted groundwater

Potential impacts of undesired CO_2 migration in groundwater

A comprehensive study on potential impacts of CO_2 geological storage on groundwater resources has been carried out in 2011 (IEA-GHG, 2011b). According to the scope of this report, (mitigation and remediation techniques of undesired CO_2 migration in the subsurface), we focus on the impacts due to the CO_2 migration from the storage aquifer to groundwater aquifers. Other impacts (brine displacement and associated flow system disruption) are thus not considered. According to this study, CO_2 migration from the storage formation into an overlying aquifer may potentially have impacts on the pressure head, acidity (reduced pH), mobilization of metals, and transport of contaminants with the CO_2 (e.g. dissolved organic compounds).

The main processes that may lead to these impacts in the aquifer are (cf. IEA-GHG, 2011b):

- Migration of dissolved organic compounds, as supercritical CO_2 is an excellent solvent for organic compounds;
- Mineral dissolution increasing the mineralisation of the water and the release of associated trace elements;
- Precipitation of carbonates and other secondary minerals resulting from rock alteration;
- Co-precipitation and sorption of metals, which may act as either a contaminant trap or source;
- Changes in microbial activity;
- Aqueous complexation of cations that can promote solubility (organic, chloride, bicarbonate complexes);
- Modifications in flow (influencing the transport).

It has to be noted that the main impacts of CO_2 release in a freshwater aquifer are very site-specific as the processes depend on the characteristics of the aquifer (flow, temperature, pH, Eh). Moreover, this list is based on experimental studies (both laboratory and field), on natural analogues and on numerical simulations since no monitoring results are available for groundwater quality changes after an unexpected CO_2 migration from a storing deep saline aquifer.

This lack of available data and literature in the field of CO_2 geological storage is even more significant for the measures that might be used to remediate these impacts. The presented remediation actions are therefore listed by means of analogy with existing measures currently used to remediate groundwater contamination.

Proposed measures

According to the impacts above mentioned, a list of effects to be remediated can be deduced:

- Accumulation of gaseous CO_2;
- Presence of dissolved CO_2 and acidification of the aquifer;
- Presence of contaminants either stemming from the injected CO_2 stream, displaced or released due to the CO_2-fluid-rock interactions (associated substances such as mobilized metals and organic compounds).

As mentioned before, no clean-up techniques have been developed specifically for CO_2 geological storage potential impacts on groundwater. However, these effects have been treated in other fields. We propose in this section to present the techniques used in such cases and to discuss their applicability for CO_2 migration impacts on a case by case basis.

- **Monitored natural attenuation**

General description

The first measure is a passive technique called monitored natural attenuation (MNA). This remediation measure is commonly used for pollution by organic pollutant (petroleum related products, chlorinated solvents etc.) and under certain conditions for inorganic contaminants (US EPA, 1999).

It relies on *in-situ* natural physical, biological, chemical processes to reduce the mass, toxicity, mobility, volume, or concentration of contaminants in soil or groundwater (US EPA, 1999; Kahn and Husain, 2003). Natural processes include biodegradation, dispersion, dilution, sorption, volatilization, and chemical or biological stabilization, transformation, or destruction of contaminants. When natural attenuation is used as a remediation technique, an adequate monitoring plan has to be set up to follow the evolution of the pollution across time. Actually, although natural attenuation relies on natural processes, the implementation of this remediation measure requires an appropriate monitoring to check its effectiveness and to ensure that the risks due to pollution are appropriately managed.

Very detailed investigation is necessary to determine the applicability of natural attenuation. Cost and time to perform preliminary studies could then be higher than those required for active remediation techniques. However, long term costs may be lower than for others technologies (US EPA, 2004). The time needed for remediation with natural attenuation is generally considered longer than with active remedial measures. The duration of remediation varies extremely depending on site-specific conditions. A reasonable time frame for natural remediation is a few years (US EPA, 2004); in certain conditions it can nevertheless last decades. If the expected duration is more than a generation, or 30 years, the project may not be considered viable (Carey et al., 2000).

Potential applicability to CCS

Natural attenuation is commonly used in environmental clean-up of aquifers. However, to our knowledge, monitored natural attenuation has not been used in the field of CO_2 geological storage mainly because of the absence of established impacts on aquifer. According to the US EPA (1999), natural attenuation may reduce the potential risks due to contaminant through three ways (discussed according to the potential impacts of an undesired migration of CO_2):

- Reduction of pollutant concentrations and thus of the exposure level. Monitoring the dissolution, dilution and mineralization of gaseous CO_2 is a way to mitigate an unexpected gaseous CO_2 accumulation (Benson and Hepple, 2005). The dilution of other contaminants associated substances such as metals through diffusion or advective processes (due to the groundwater flow for instance) may reduce the contaminant concentrations at an acceptable pace. Based on modelling of intrusion of CO_2 on a glauconitic-sandstone aquifer, Vong et al. (2011) showed that the concentrations of dissolved Pb and Zn and Cd decrease due to natural attenuation when the leakage is stopped;
- Reduction of constituent mobility and bioavailability. This can be achieved through chemical, biological reaction or sorption onto the soil or rock matrix. Those processes might be used to remove unexpected pollution due to mobilized toxic compounds;
- Transformation of contaminants to another less toxic product (or another form of contaminants). This could be achieved by biodegradation or chemical abiotic reactions. It might be a possible way of remediation in case of pollution by associated substances potentially present in a leaking flow or by substances released in the environment following mobilization due to acidification (metals, organic compounds).

For the case where natural attenuation is not feasible, some active measures might be applied: methods used for remediation of volatile organic compounds (VOCs) and consisting of transferring the gaseous plume to the vadose zone might be adapted to unconfined aquifers (see air sparging below). Regarding confined aquifer, the presence of mobile gaseous CO_2 can be remediated through extraction or through the enhancement of gas trapping, i.e. dissolved in the groundwater or immobilized due to residual trapping (see injection extraction below). In case of the potential presence of dissolved CO_2 or of contaminants in the aquifer, pump and treat techniques might be used (see pump and treat and reactive barrier below).

- **Pump-and-treat**

<u>General description</u>

The pump-and-treat technique aims at remediating the contaminated section of an aquifer by extracting the contaminated water before treating it at the surface. This technique can be used for different pollutants (organic compounds, VOCs, dissolved metallic compounds) depending on the treatment technique used at the surface. According to its quality, the extracted and treated water might be discharged to special treatment centres, to the wastewater network, to surface water or re-injected to groundwater (Colombano et al., 2010).

The pump-and-treat technology can be designed either to restore the aquifer or to limit the pollution by hydraulically containing the contaminants plume (US EPA, 1997; Bayer et al., 2002); some strategies are illustrated on Figure 25.

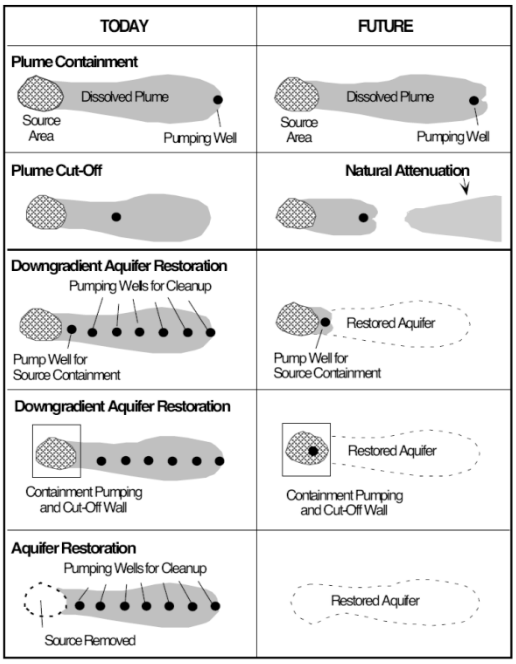

Figure 25 – Several ground-water contamination remediation strategies using pump and treat technology (US EPA, 1997)

The efficiency of this measure depends mainly on the aquifer properties (Khan et al., 2004) and flow conditions, which determine the pace of extraction, and aquifer heterogeneity that might prevent some parts of the plume to be extracted. Even if the pump-and-treat technology can be applied to a broad range of pollution (US EPA, 1997), the pollutants considered impact the efficiency of the measure (e.g. volatility of the pollutant, sorption potential).

The cost and intervention delay are highly site specific and depend notably on (Colombano et al., 2010):

- The extraction and injection scheme needed;
- The treatment system at the surface (depends on the pollutants treated);
- The extracted water storage facilities required;
- The monitoring system to follow the evolution of the water flow and quality.

Potential applicability to CCS

The pump-and-treat technology is widely used for a broad range of pollutants (organic, mineral, in free phase or dissolved). It is often considered as one of the most common aquifer clean-up technologies (Bear and Sun, 1998). According to Benson and Hepple (2005) this technology might be used in case of the presence of dissolved CO_2 or other contaminants in groundwater (associated substances such as mobilized metals and organic compounds). Once the water is pumped, CO_2 could be removed from water by aeration. Extraction technology can even be used in case of gaseous accumulation in groundwater (this point is further discussed in the injection extraction technique section below).

- **Air sparging**

General description

Air sparging or air stripping aims at diminishing the concentrations of volatile organic compounds (VOCs) dissolved in unconfined aquifers by enabling a phase transfer from a dissolved state to a vapour phase (US EPA, 1994). The gases are then extracted from the unsaturated zone to be biodegraded or treated. According to Khan et al. (2004), air sparging can be appropriate for VOCs sorbed to soils and trapped in the pores below the water level, in the capillary fringe.

Air sparging consists in injecting a contaminant-free air below or within the polluted zone in order to volatilize the contaminants that are either adsorbed or dissolved in the saturated zone. The gases containing the contaminants are then vented through the unsaturated zone where they can be collected and treated. This technique can be associated to soil vapour extraction technique described in the unsaturated zone section. The combined technique can then allow the treatment of both saturated and unsaturated zones.

The injected air may also favour biodegradation by increasing the dissolved oxygen concentration in the saturated zone (Adams and Reddy, 2003).

The applicability and efficiency of air sparging depend on several parameters (US EPA, 1994; Khan et al., 2004):

- Vapour/dissolved phase partitioning, which characterizes the transfer from the dissolved state to the vapour one. It is a significant factor in determining the rate of contaminant that can be transferred to the vapour phase;
- Formation characteristics: for instance, silt and clay sediments are not appropriate for this technology;
- Aquifer permeability that influences the air-injection rate and thus the mass transfer rate: for instance, according to Kirtland and Aelion (2000), formations with permeability below 10^{-3} $cm.s^{-1}$ might not be adapted to air sparging. The aquifer homogeneity is also important as it controls the gas flow: preferential mitigation pathways might be prejudicial since the remediation might not be ensured for the whole contaminated zone and since the injected air could flow out of the vapour extraction control area;
- Homogeneity of soil permeability impacts the migration pathways followed by the gases and can make difficult vapours extraction.

The time needed for remediation is generally relatively low (less than 3 years) compared with other remediation techniques (US EPA, 1994).

<u>Potential applicability to CCS</u>

Air sparging has been used for several decades in order to reduce concentrations of VOCs. The analogy between CO_2 and VOCs has been discussed notably by Rohmer et al. (2010) and Zhang et al. (2004). At surface conditions, CO_2 presents similarities with VOCs:

- Density of CO_2 (1.81 kg/m^3 à 25°C) is of the same order of magnitude with VOCs (Falta et al., 1989);
- Viscosity of CO_2 has an intermediate value between water and air;
- CO_2 is a volatile compound; the vapour pressure and Henry's law constant of gaseous CO_2 reach the values of 58.5×10^5 Pa and 1.41 (at 20°C), respectively.

Therefore, air sparging could theoretically be used in case of dissolved CO_2 and additional contaminants, with properties similar to VOCs (de Lary and Rohmer, 2010).

However, despite the similarities presented above, two main differences between VOC and CO_2 should be considered (Rohmer et al., 2010): (a) CO_2 is harmless at low concentration whereas numerous VOCs are deleterious to human health and the environment at low dosage, (b) in case of an unexpected leakage from a geological storage the CO_2 may migrate upward (from reservoir to surface) whereas during usual pollution by VOC, due to leaks or spills, the pollutant migrates mainly downward or laterally. The applicability and necessity of using remediation techniques adapted to VOCs for CO_2 migration impacts should then be assessed taking into account these elements.

Moreover, air sparging can be only implemented on unconfined aquifers, in order to allow the gas migration out of the aquifer. It is not a relevant measure for confined aquifers that could be impacted at higher depth for instance.

While air sparging mainly depends on the volatilization of pollutants, pollutant biodegradation in groundwater aquifer can also be enhanced through air injection (some variants with oxygen or nutrients exist as well); the remediation technique is then called biosparging. In case of potential impacts of undesired migration from CO_2 reservoirs, this aerobic biodegradation might be used to treat specifically organic compounds pollution should this pollution occur (however, it is not adapted for dissolved CO_2 because CO_2 is rather a product of degradation).

- **Permeable reactive barrier (treatment wall)**

General description

The permeable reactive barrier aims at removing contaminants from groundwater by physical, chemical or biological processes occurring when groundwater flows across a barrier installed for these purposes. A permeable reactive barrier consists of a permeable zone made of reactive material and placed perpendicular to the groundwater flow thus intercepting the entire contaminated plume. When crossing the barrier, the pollutants react with the treatment wall material (e.g. precipitation, sorption, oxidation/reduction, fixation, degradation). According to the US EPA (1996), treatment walls can either trap directly the contaminants or transform them into harmless products.

Several types of reactive barriers have been designed; the treatment wall can be continuous (the entire barrier is reactive) or in a funnel-and-gate configuration. In the latter case, the plume is driven through impermeable walls to the reactive barrier (Colombano et al., 2010).

Khan et al. (2004) stated that treatment costs using the reactive barriers are not available, but are likely to be highly site-dependent. They notably depend on (Colombano et al., 2010):

- The dimensions and depth of the plume;
- The excavation technique;
- The reactive material and the material set up technique;
- The monitoring system associated to the treatment wall.

The time needed for a complete removal of the pollution is also situation dependent and mainly influenced by the contamination significance.

Potential applicability to CCS

This technology has been applied in a relatively large number of sites and used generally to treat organic pollutants and metal contamination of groundwater (Colombano et al., 2010); it is however a rather recent technique (Kahn et al., 2004). In case of CO_2 geological storage impacts remediation, this technique has been quoted by Benson and Hepple (2005) as a potential technique for the removal of mobilized trace elements. However, most of the reactive barriers have been constructed digging a trench and filling it with appropriate material. Therefore this technology is rather limited to shallow depths (Vidic and Pohland, 1996), which reduces its applicability to potential impacts of CO_2 geological storage.

- **Injection-extraction**

General description

Fluid management techniques to mitigate potential undesired CO_2 migration have been presented in section 1.2. While it has been shown that these measures could be used on the source of the CO_2 migration (storing aquifer) and on the transfer pathways (i.e. overlying non-sensitive aquifers), fluid and pressure management strategies have also been proposed for the remediation of impacted groundwater aquifers.

These techniques have been proposed and presented by Esposito and Benson (2012). Different options can be considered based on fluid management in case of an accumulation of gaseous CO_2 in groundwater; their aim could be to:

- Extract the mobile gaseous CO_2 and find appropriate ways to re-use/eliminate it (see above : pump and treat);
- Decrease the quantity of mobile CO_2 in the groundwater aquifer;
- Extract the dissolved CO_2 to limit the acidification and potential consequences on the groundwater aquifer.

The potential methods to satisfy these objectives are extraction and injection techniques as well as combinations of both. Extraction wells can be drilled down to the CO_2 plume level, or existing wells can be used, in order to extract the fluids containing both gaseous and aqueous phase containing dissolved CO_2. Esposito and Benson (2012) present several remediation cases. For instance, according to the leakage situation, vertical or horizontal wells might be used, which modifies the measure efficiency. With this technique, it is possible to extract all the mobile CO_2; some CO_2 immobilized through residual trapping may still be left in the aquifer. Injection wells can be drilled, or existing wells can be used, to inject water with the purpose of enhancing the CO_2 dissolution as well as the residual trapping. Dilution and dispersion of the dissolved CO_2 might also be increased with this technique, which decreases the risk of aquifer acidification. Combination of water injection followed by fluid extraction through one or several wells is an additional possibility studied by Esposito and Benson (2012). For this case, a particular attention should be given to the exsolution of CO_2 that occurs due to the pressure decrease during the extraction phase.

In case of impacts on a given section of an aquifer, a hydraulic barrier may be created to control the migration of the contaminants (see Benson and Hepple, 2005 for instance). The principle is similar to the measure presented in section 1.2.2 applied here on impacted groundwater aquifers.

The efficiency of these techniques is highly dependent on:

- Leaking plume distribution (size of the plume or the presence of a significant gravity tongue);
- Groundwater aquifer properties (permeability, anisotropy or presence of heterogeneities);
- Injection-extraction configuration (number of wells, location and spacing or injection and extraction rates).

The technique costs and intervention delay are also situation dependent. The main factors influencing these parameters are the following: well drilling necessity for injection/extraction wells, water pumping/injection and management (treatment, disposal for instance), and associated monitoring system. The potential operational issues linked with fluid management corrective measures are further discussed in Réveillère et al. (2012).

Potential applicability to CCS

The measure is theoretically applicable. However, several issues need to be tackled in the case of the remediation of CO_2 migration in a groundwater aquifer. First of all, water injection will lead to the aquifer pressure increase, which needs to be modelled and monitored in order to avoid induced fracturing or hydrodynamic impacts. Water injection presupposes water availability and transport towards the injection site while fluid extraction implies treatment and disposal facilities. The water quality issue has to be studied according to the impacted aquifer specificities in the case of water injection. Finally, application of this measure implies the detection of the leakage and precise knowledge of the plume location, which, in some situations, might not be straightforward.

- **In-situ remediation with microbes**

Breakthrough technologies potentially applicable to mitigate an undesired CO_2 migration have been presented in section 0. One can present an additional breakthrough technology for impacted aquifer remediation using microbes such as bacteria. Bacteria have indeed the potential to biologically induce CO_2 mineralization into solid carbonate phases by a reaction called bioalkalinization. Bioalkalinization appears to be a ubiquitous phenomenon possible with various bacteria metabolisms. This reaction could allow the precipitation of solid carbonates because of the metabolic activities of microorganisms. Thus, in addition to mineralization of CO_2, Dupraz et al. (2009) suggested that the induced pH increase could help counterbalancing the acidification provoked by the CO_2 injection. In contrast with the addition of a base solution, which causes localized precipitation at the injection point, the gradual increase of pH due to bacteria could provoke a wider spreading of the precipitation (Ferris et al., 2004).

Moreover, Mitchell and Ferris (2005) suggested that the biologically induced co-precipitation of contaminants (e.g. heavy metals) with calcite precipitates could be a long term remediation option for contaminated groundwater.

Few data are available about the cost and applicability at large scale of techniques relying on bacteria in the field of carbon storage remediation since results are essentially based on small scale (batch) laboratory experiments (Dupraz et al., 2009; Menez et al., 2007; Mitchell et al., 2010).

1.4.2. Remediation techniques for impacts in the unsaturated zone

In this study the unsaturated zone is considered as the portion of the subsurface situated above the groundwater table. It is composed of soil and rock. The porosity of this medium is filled with air and water. Extensive measures and experience are available to remediate pollutions on the unsaturated zone.

Possible impacts on the unsaturated zone

A storage site would be selected to minimise risks to the environment; if a CO_2 leakage from the reservoir did occur, it could be from a discrete point source (e.g. leakage from abandoned well) leading to localized impacts (IEA-GHG, 2007b). However, in case of an uncontrolled leakage, impacts on the environment could be larger (West et al., 2005). A summary of the possible impacts on the unsaturated zone in case of unexpected behaviour of a geological storage is provided below (Benson et al., 2002; IPCC 2005; IEA-GHG 2007b; US EPA, 2008):

- Lowering of soils pH and associated impacts (damage on soil ecosystems and damage on economic activities relying on soil such as forestry and agriculture);
- Accumulation of gaseous CO_2 (and potentially associated substances such as H_2S) in soils leading to asphyxiation of associated biota (plants, crops, soil-dwelling animals and microbes);
- Leaching or mobilization of heavy metals or organic compounds due to soil acidification;
- Changes in bio-geo-chemical processes occurring in soil (due notably to acidification and to reactions with associated substances) leading to alteration of nutrient balance (e.g. phosphorus) and potentially affecting ecosystems and agriculture/forestry.

It is worth noting that in case of an undesired CO_2 migration in the unsaturated zone, the CO_2 concentration in soil may be locally significant (IEA-GHG, 2007b) because CO_2 tends to accumulate in the soil porosity (whereas in atmosphere it generally tends to disperse quickly, see section 1.4.3). High CO_2 concentrations in soil, until nearly 95 %, could be measured on natural sites where deep geological CO_2 is degasing (Carapezza et al., 2003; Farrar et al., 1999), whereas usual concentrations are in the range of 0.2 to 4% (IPCC 2005).

Proposed measures in the unsaturated zone:

Most of the measures presented in this section are similar to those presented for groundwater aquifers. However, some intervention parameters and constraints in the unsaturated zone may not be the same as in the case of groundwater pollution, meaning that the applicability of these measures has to be discussed specifically for each situation.

- **Monitored natural attenuation**

General description

This measure is mentioned above for potentially impacted aquifer; refer to this section for a general description (p.68).

Potential applicability to CCS

Natural attenuation is commonly used in environmental clean-up of soils. However, to our knowledge, monitored natural attenuation has not been used in the field of CO_2 geological storage mainly because of the absence of established impacts in the unsaturated zone. In the field of geological storage of CO_2, Oldenburg and Unger (2003) and Zhang et al. (2004) have shown that the unsaturated zone could have a potential to naturally attenuate CO_2 leakages. The only available study in the field of CCS has been carried out by Zhang et al. (2004) showing, through modelling, that natural attenuation of a CO_2 plume in the unsaturated zone could be effective, even if it may take 10 years or more to remediate the plume. This technique is also mentioned in Benson and Hepple (2005) and Sweatman et al. (2010). According to the US EPA (1999), natural attenuation may reduce the potential risks due to contaminant by three ways, which can be discussed according to the potential impacts of an undesired migration of CO_2:

- Reduction of pollutant concentration and thus of the exposure level. This mechanism might be effective for a natural remediation of gaseous CO_2 as suggested by Zhang et al. (2004) from a modelling approach. Their results showed that half of a 900 tons CO_2 plume is removed by natural attenuation in about 3 to 8 years depending of the thickness of the horizon (2 to 35 m). Concurrently, the CO_2 concentration in soil decreases significantly (Figure 26). The attenuation is due to migration and dispersion/dilution in the atmosphere, in the porosity of soil layers and in the saturated zone. Barometric pumping[4] (due to natural cyclic variation of atmospheric pressure) reinforce the removal rate of CO_2 due to a larger flux to the atmosphere;
- Reduction of constituent mobility and bioavailability. This can be achieved through chemical, biological reaction or sorption onto the soil or rock matrix. Those processes might be used to remove hypothetical pollution due to associated substances or to mobilization of toxic compounds in case of leakage reaching the surface;
- Transformation of contaminants to another less toxic product (or another form of contaminants). This could be achieved by biodegradation or chemical abiotic reactions. This way does not seem to be appropriate for remediation of CO_2 in soil because CO_2 is rather a product of degradation. Nevertheless, it might be a

[4] Barometric pumping is due to difference of pressure between soil and atmosphere. When atmospheric pressure decreases, a gas flux from soil to atmosphere is established. As the pollutant tends to be dispersed rapidly in the atmosphere, when atmospheric pressure increases it is nearly fresh air of the atmosphere which enters back in soil.

possible way for remediating pollution by associated substances potentially present in a leaking flow or by mobilized substances following soil acidification (metals, organic compounds).

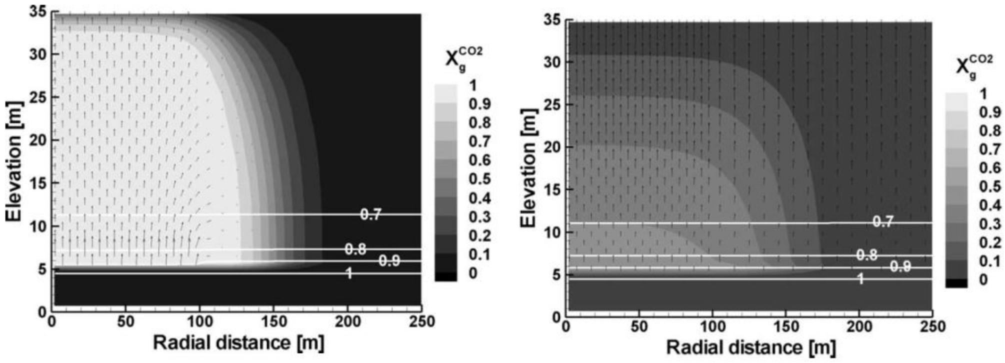

Figure 26 – Left: initial condition (plume of 900 tons of CO_2 in the unsaturated zone). Right : after 10 yers of natural attenuation with barometric pumping (Zhang et al., 2004). X_gCO_2 is the mass fraction of CO_2 in the unsaturated zone.

- **Soil vapour extraction**

General description

Soil vapour extraction (SVE), also known as soil venting or vacuum extraction, is an *in-situ* treatment technology which aims at reducing concentrations of volatile and some semi-volatile constituents in the unsaturated zone. This technique is based on the establishment of a low pressure gradient in the unsaturated zone in order to force gases flowing towards extraction wells (US EPA, 2004; Zhang et al., 2004). Once the vapour phase is extracted from soil, it is generally treated with different processes depending on the nature of the pollutants.

Numerous SVE design options are possible. A typical SVE system is depicted on Figure 27. Depending on the size of the impacted zone and on site specific conditions, one or more wells could be drilled on the polluted area. A well may be horizontal or vertical. It is cased usually with appropriate PVC pipes from 2 to 14 inches diameter and screened. The position and the depth of the screen take into account the soil stratification, the shape of the plume of contaminant and the depth of the water table. The well is connected to an extraction blower that is chosen to fit with the designed pressure vacuum and extraction flow rate. Then the gas is piped to a vapour treatment system if direct emission in the atmosphere is not planed and/or not allowed.

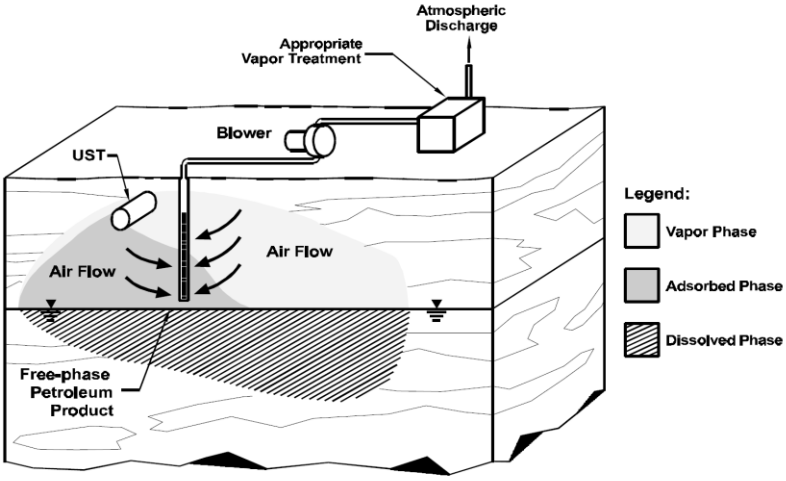

Figure 27 – Sketch of a Typical SVE system for petroleum products (US EPA, 2004).

Detailed screening flow charts to evaluate whether or not SVE could be an appropriate remediation technique are available in the soil clean-up literature (e.g. US EPA, 2004). The most important parameters to make this evaluation are summed-up below:

- Volatility of the constituents to be removed: according to the US EPA (2004), the vapour pressure should be higher than 0.5 mm Hg (about 66 Pa) for SVE to be applicable. As CO_2 vapour pressure is 58.5×10^5 Pa at 20°C in surface condition (Rohmer et al., 2010), CO_2 has the potential to be removed efficiently by SVE;
- Intrinsic permeability of soil (Poulsen et al., 1999): the US EPA (2004) considers that in soils with permeability lower than 10^{-14} m², SVE efficiency will be marginal;
- Soil liquid saturation and soil layering may have a strong influence on the transport of gases in the unsaturated zone (Khan et al., 2004);
- Thickness of the unsaturated zone and depth of the water table: SVE is generally not appropriate for sites with a groundwater table less than 1 m below the land surface.

If the SVE is the appropriate technology, a key aspect of the design of the clean-up project includes the consideration of the well Radius of Influence (ROI). From US EPA (2004), the ROI is defined as *the greatest distance from an extraction well at which a sufficient vacuum and vapour flow can be induced to adequately enhance volatilization and extraction of the contaminants in soil*. This parameter depends on numerous factors including soil permeability, depth of groundwater and soil heterogeneity. It may vary from some meters to 40 meters. It could be estimated from pilot on-field study or from modelling. Others key parameters to consider, along with the ROI, are the pressure vacuum and the vapour extraction flow rate. Those parameters are necessary to calculate the number of wells, the costs and the remediation duration. Extensive design information and guidance document to assist the SVE practitioner are available in soil clean-up field (e.g. US Army Corps of Engineers, 2002).

The cost and intervention delays are highly site specific and depend mostly on the following components:

- Preliminary investigation and design;
- SVE system purchase and its set up in the field;
- Functioning of the system (energy cost, monitoring, etc.);
- Demolition of the system.

For sites contaminated with petroleum products, US EPA (2004) indicates costs in the range of 20 to 50 US $ per ton of contaminated soil. Further evaluation is needed to evaluate the likely costs of remediation of CO_2 impacts by SVE.

It is quite difficult to predict the treatment duration (Barnes et al., 2003). Usual treatment time durations for SVE projects vary from 6 months to two years (Khan et al., 2004). Longer treatment times generally mean that the technique is not appropriate or improperly designed.

<u>Potential applicability to CCS</u>

Soil vapour extraction has been used widely for the last 30 years in order to remediate impacts of volatile organic compounds (VOCs) or semi-volatile organic compounds in the unsaturated zone due to spills, leaks and hazardous waste. In the field of environmental clean-up, this technology is mature and has proven its effectiveness on numerous polluted sites; however, it is still not obvious to determine whether or not this technology will be efficient on a specific site (US EPA, 2004). Nevertheless, according to literature, SVE has not yet been used to remove CO_2 from the unsaturated zone. However, this remediation technique has been suggested by several authors in CCS literature (Benson and Hepple, 2005; Rohmer et al., 2010; Zhang et al., 2004; and Sweatman et al., 2010). Numerical simulations from Zhang et al. (2004) and Rohmer et al. (2010) showed that SVE could be, under certain conditions, an effective way to remove CO_2 from the unsaturated zone.

Depending on the situation, some options or modifications could enhance or be most appropriate than basic SVE system, among which:

- Injection and passive inlet wells. They could be used to enhance the transport of pollutant in the unsaturated zone (US EPA, 2004) by injection or passive introduction of air in soil;
- Air sparging (see in section 1.4.1 above). This enhancement expands the remediation possibilities of SVE to the saturated zone (US EPA, 1997). It consists on injecting gas in the saturated zone below or within the polluted zone. The injected gas migrates through the saturated zone and removes pollutant;
- Impermeable surface cover. It decreases or stops the flux at the soil surface (Benson and Hepple, 2005) and prevents short circuiting by the air of the atmosphere during pumping (Zhang et al., 2004);
- Directional drilling. It may enhance pollutant removal rate. As this technology is more costly than vertical wells, it requires a careful cost benefit analysis before implementation (US EPA, 1997);

- Pumping of CO_2 in horizontal trenches. As CO_2 is 50 % denser than air, it tends to accumulate in low lying areas (trenches) where it could be collected and pumped (Benson and Hepple, 2005);
- Groundwater pumping. It could be necessary on sites where water table is too close to the soil surface (US EPA, 2004).

- **pH adjustment**

General description

The objective of pH adjustment is to increase the pH value to remediate soil acidification environmental consequences (damage to ecosystem or crops/forest) or to prevent possible induced impacts (such as leaching of heavy metals due to acidification).

Potential applicability to CCS

Adjustment of pH is carried out for a long time in agriculture fields to improve crop production. Lime is a commonly agricultural supplement used to neutralize acid soils (Cornell University Cooperative extension, 2005; Ristow et al., 2010). CO_2 is an acid gas and in surface condition, the maximum solubility of CO_2 in water (water with equilibrium with 100 % CO_2) is about 1.5 g/l (Oldenburg and Unger, 2004) corresponding to pH of 4 in pure water. Experiments of CO_2 injection in soil at the ZERT field site show a rapid drop of pH from 7.0 down to 5.6 (Kharaka et al., 2009). Thus any leakage of CO_2 in the unsaturated zone may provoke a decrease of pH in the water phase of the unsaturated zone. It is worth noting that the impacts will depend on the natural buffering capacity of soils (IEA-GHG, 2007b). Given these elements, Benson and Hepple (2005) and Sweatman et al., (2010) proposed alkaline supplements (lime) spreading to remediate acidification of soil due to a potential leakage of carbon dioxide in soil. Irrigation and drainage of soil might be another way to adjust the pH of soil by dilution of CO_2 into groundwater and/or by using a pump-and-treat system once the CO_2 is dissolved (Benson and Hepple; 2005).

1.4.3. Remediation techniques for impacts on surface assets

Possible impacts on surface assets

According to the literature (Benson et al., 2002; IPPC 2005; IEA-GHG 2007b; US EPA, 2008), the main potential impacts at the surface, in case of undesired CO_2 migration from reservoir, are the following:

- Accumulation of CO_2 and/or associated substances in surface water leading to modification of chemical properties and associated impacts on biota;
- Intrusion of CO_2 and/or associated substances in building leading to indoor exposure to high concentration of CO_2;
- Release of large quantities of CO_2 and/or associated substances in the atmosphere with subsequent impacts on population or ecosystems;

- Damage on ecosystems (or crop/forestry) due to alteration of the habitat or a direct harm to the biota. This could be due to acidification or direct toxicity of CO_2 or other elements.

Proposed measure at the surface

In this section, we present the measures according to the potentially impacted assets. As mentioned above, remedial measures can be employed on surface water bodies, indoor environment, atmosphere and surface ecosystems.

- **Surface water**

In case of undesired migration from the reservoir, CO_2 (or other associated contaminants) may come in contact with surface waters: rivers, ponds, lakes, etc. If the CO_2 flux exceeds the dissolution capacity of the water, then CO_2 bubbles will form and part of the leaking flux will join quickly the atmosphere. This phenomenon is noted in some sites where geological CO_2 is degassing naturally in a water body (e.g. Laacher see, Germany). However, the remaining part of the leaking flux may dissolve in the water body. As suggested by Benson and Hepple (2005), if the water body is shallow and/or well-mixed (shallow lake or pond) or turbulent (streams or rivers) CO_2 will be quickly released in the atmosphere where it will disperse. In this situation, monitored natural remediation could be an appropriate measure. Nevertheless, in deep stratified lakes, such as Lakes Nyos and Monoun in Cameroon, the CO_2 may accumulate. These very particular lakes are not seasonally overturned and are constantly refuelled by volcanic origin CO_2 springs creating a CO_2 supersaturated layer at the bottom of the crater lakes. Due to a brittle change those lakes erupted dramatically and huge quantities of CO_2 flowed in the valley below leading to the asphyxiation of numerous people and animals (Benson et al., 2002; Stupfel and Le Guern, 1989). A system for degassing the lakes was therefore set up: a vertical pipe between the lake bottom and the surface (Halbwachs et al., 2004) provokes a permanent controlled eruption (Figure 28). As suggested by Benson and Hepple (2005), this measure could be used for degasing deep stratified lakes in case of accumulation of CO_2 leaking from a geological reservoir. However, it is necessary to underline that stratified lakes are very scarce around the globe, thus accumulation in deep stratified lake due to leakage from CO_2 storage seems very unlikely.

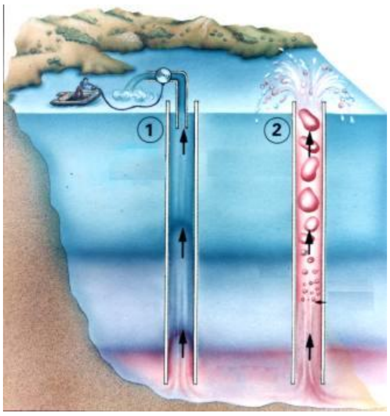

Figure 28 – Degassing system put in place in lake Nyos and lake Monoun (picture from http://mhalb.pagesperso-orange.fr/nyos/).

- **Indoor environment**

If buildings are situated near or above a leakage zone where undesired significant volumes of CO_2 reach the surface, indoor CO_2 concentrations could be higher than normal or even dangerous (de Lary et al., 2012). High CO_2 concentrations have been measured under specific conditions in buildings near natural sites where CO_2 is degasing and above reclaimed mines (e.g. Annunziatellis et al., 2003; Robinson, 2010). To control possible chronic intrusion of gaseous CO_2 into building, Benson and Hepple (2005) and Rohmer et al. (2010) suggest the use of techniques that have been developed to remediate radon or organic compounds presence in buildings.

Usual techniques for remediation of radon intrusion include (Benson and Hepple, 2005; Irish Department of the Environment and Local Government, 2002; US EPA, 2001):

- Sealing the openings in the building to prevent soil gas intrusion;
- Sub-floor (sub-slab) depressurization with passive system or electrical fans to pump soil gases and pipe them outside the building (Figure 29);
- Sub-floor pressurization to force soil gases to migrate away from the building and avoid entering it;
- Ventilation and adjustment of the indoor pressure to reduce or reverse the driving forces which contribute to the entry of soil gases.

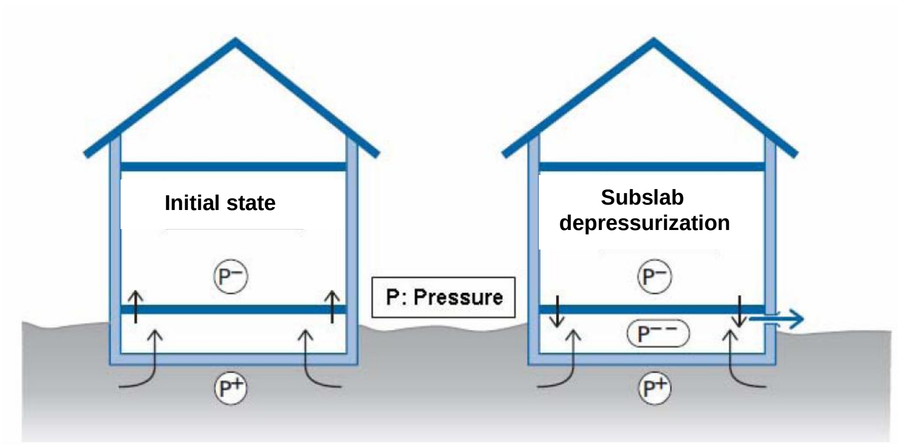

Figure 29 – Subslab depressurization principle (adapted from Collignan and Sullerot, 2008).

In the field of reclaimed coal mines, Robinson (2010) presents and puts in practice several remediation techniques (based on pressurization/depressurization) on a case study home.

However, there are little field data and few experiments about remediation of CO_2 intrusion in buildings, meaning that the maturity of such measures in this field is still low.

- **Atmosphere**

Undesired CO_2 migration in the subsurface could potentially lead to gas releases to the atmosphere. Besides the consequences on the increased greenhouse gas concentrations in the atmosphere, the impact of such releases on human and on the environment has been studied through natural analogues and atmospheric dispersion modelling.

As CO_2 is denser than air, gravity effects could have an influence on the dispersion of a leaking plume (Oldenburg and Unger, 2004). The leakage characteristics, the meteorological and topographical conditions are important inputs to estimate the behaviour of the plume, the exposure level (concentration) and duration. The impacts and associated remediation techniques are therefore site and situation dependent.

Natural analogues show different types of releases, which can be diffuse or more intense and over important or smaller surfaces. For instance, at the Horseshoe Lake site (Mammoth Mountain, U.S.A.) the average quantity of emitted CO_2 is 93 tons/day on a surface of 12 hectares (Gerlach et al., 2001); at Latera site (Italy), 220 kg of CO_2 are emitted per day on one vent of 250 m² (Beaubien et al., 2008). The associated CO_2 concentrations in soil could be very high (up to 95 %). Even in sites with important soil concentrations and high flux such Mammoth mountain, exposure concentration one or two meters above ground, in open atmosphere, is low (two or three times the normal concentration) because CO_2 disperses very rapidly in the atmosphere (Farrar et al., 1999). Furthermore, high leakage rates do not necessarily lead to high exposure because, according to Mazzoldi et al. (2009), high rates associated with high speed release could accentuate the mixing and the dilution of the plume.

A danger could nevertheless exist in case of exposure in poorly ventilated building, in pits dug, in soil or snow and above ground cavities (Farrar et al., 1999). Moreover, as a dense gas, a CO_2 plume might have the tendency to follow the soil surface and some releases might create high concentration zones, notably in topographic depression and during calm and stable atmospheric conditions. Chow et al. (2009) presented for instance the influence on heavy gases dispersion of different topographical and atmospheric situations.

The measures to implement, in case of CO_2 release in the atmosphere, are also site dependent. From Benson and Hepple (2005), at large scale, natural atmospheric mixing would be the only practical method to lead to the natural dilution of CO_2 leakages. Some active measures can be set up for the cases when natural mixing is not enough to disperse the CO_2 plume, like air jets or large fans (Sweatman et al., 2010). However, no application of such measures is referenced in literature.

- **Ecosystem restoration**

Ecosystem restoration can be defined as *re-establishing the presumed structure, productivity and species diversity that was originally present at a site that has been degraded, damaged or destroyed. In time, the ecological processes and functions of the restored habitat will closely match those of the original habitat (UNEP, 2010).*

Ecosystem restoration could be imposed by some regulations (e.g. European Directive 2004/35/CE; EC, 2004) in case of damage of human activities to some highly valuable protected habitat or species. Ecosystem restoration is still an area of on-going research, even if numerous examples of successful restoration projects already exist all around the world (Benayas, 2009; Nellemann et al., 2010).

Depending on the impacts and the site specific conditions, very different actions could be performed: restoring of vegetation or habitat, reintroduction of species, environment clean-up, etc. Natural recovery (recovery based on natural capacity without direct intervention of human) is an option to be considered in the ecosystem restoration process. Generic guidelines for restoration project managers and policy maker have been established (e.g. Clewell et al., 2004). More information is necessary about potential impacts on ecosystem of CO_2 leakages to be able to suggest, for CCS, some appropriate restoration measures.

1.4.4. Conclusion

The table below summarizes the measures suggested in this report for remediation of impacts following a CO_2 leakage. It is necessary to underline that this list of measures is based on literature review, modelling and analogies with other pollutants. No on-field experiment is currently available to assess whether or not a measure could be relevant for the CCS domain.

Table 4 – Summary of proposed measures for impact remediation in the field of CO_2 storage.

Impacted compartment	**Suggested measure**	**Possible application in CCS domain**
Groundwater	Monitored natural attenuation	- Reduction of contaminants concentration: e.g. aqueous CO_2 concentration (Benson and Hepple, 2005), associated substances such as mobilized metals and organic compounds. - Transformation of contaminants into less toxic products: e.g. associated substances such as metals, organic compounds. - Reduction of constituent mobility and bioavailability: e.g. associated substances such as metals, organic compounds.
	Pump-and-treat	- Extraction and treatment of fluids containing dissolved CO_2 or other contaminants (associated substances such as mobilized metals, organic compounds) (Benson and Hepple, 2005).
	Air sparging	- Volatilisation and extraction of dissolved CO_2 and additional contaminants (with properties similar to VOCs) (de Lary and Rohmer, 2010; Rohmer et al., 2010).
	Permeable reactive barrier (treatment wall)	- Trapping through a permeable barrier favouring reactions of mobilized trace elements (associated substances such as metals, organic compounds). (Benson and Hepple, 2005).
	Injection - extraction	- Extraction of the mobile gaseous plume. - Decrease of the quantity of mobile CO_2 in the groundwater aquifer. - Extracting the dissolved CO_2 and potential additional contaminants. (Esposito and Benson, 2012)
	Remediation using microbes	- Adjustment of ground water pH (Dupraz et al., 2009). - Mineralization of dissolved CO_2 (Menez et al., 2007). - Co-precipitation of contaminant (heavy metals) (Mitchell and Ferris; 2005).
Unsaturated zone	Monitored natural attenuation	- Reduction of CO_2 concentration in soil (Benson and Hepple 2005; Sweatman et al., 2010; Zhang et al. 2004). - Transformation or reduction of mobility of contaminants (*e.g.* organic compound, heavy metals).
	Soil vapour extraction	- Extraction of CO_2 (or organic compounds) from soil (Benson and Hepple, 2005; Rohmer et al., 2010; Zhang et al., 2004; and Sweatman et al., 2010).
	pH adjustment (spreading of alkaline supplements, irrigation and drainage)	- Adjustment of soil pH (Benson and Hepple 2005; Sweatman et al., 2010).
Surface water	Passive systems: Natural attenuation	- Reduction of CO_2 concentration in shallow water (Benson and Hepple 2005)
	Active venting	- Removal of dissolved CO_2 in deep stratified lakes (Benson

	system	and Hepple 2005)
Indoor environment	Usual remediation techniques (radon, VOC…): sealing the opening, (de)pressurization, adjustment of ventilation	- Lowering of CO_2 concentrations in indoor air (Benson and Hepple 2005; Rohmer et al., 2010).
Atmosphere	Passive system : Natural mixing	- Reduction of CO_2 exposure in the atmosphere (Benson and Hepple 2005; Sweatman et al., 2010).
	Air jets or large fans	- Reduction of CO_2 exposure in the atmosphere (Benson and Hepple 2005; Sweatman et al., 2010).
Ecosystems	Ecological restoration	- Restoration of impacted ecosystem (if needed).

Chapter 2. Elements of costs and benefits

According to various CO_2 storage and/or environmental remediation regulations in place, the operator is required to mitigate and remediate any leak (EC, 2004, 2009; USEPA, 2010a). If not, the regulator can take the remediation measures and then recover the costs from the operator. However, a lot of techniques that are presented in Chapter 1 can be very costly to implement while a small quantity of CO_2 leaking will generally only cause minor and localised impacts. In this case, it is logical to consider if it is worthwhile to act on the leak. In other terms: are the costs of an intervention balanced by the benefits of correcting an irregularity?

The intention of this chapter is to give elements for answering this question[5]. The main method to balance costs and benefits in the absolute (i.e. from the viewpoint of society as a whole) is Cost-Benefit Analysis (CBA), and it will hence be the main focus point of this chapter. In a cost-benefit analysis, two terms are compared: the cost of a “project” (in our case, a project is the remediation action) is balanced against its benefits (an avoided damage in the case of environmental remediation). The “costs” part is presented first. Cost estimations used in other references are cited and reviewed. New data are provided as well. The main point here is to provide a basic idea of what it costs to implement corrective measures, but each project will need to estimate its own potential intervention costs. The “benefits” part then gives elements and tools for calculating benefits when performing the analysis. An example of economic valuation is provided as well. In addition to CBA, two other frameworks for decision-making are also reviewed: Cost-Effectiveness Analysis (CEA), and Multi-Criteria Analysis (MCA), as they are more practical tools for operators as decision-making supports.

2.1. DIRECT COSTS OF INTERVENTION MEASURES

As stated in Chapter 1, every intervention is situation specific and therefore costs are difficult to estimate without knowing precisely the conditions of implementations. However, some generic elements can be provided, on the costs of classical operations and on the way costs are usually assessed. In the next sections we will first present some examples of how estimates of remediation cost have been obtained previously and present some new costs calculation based on our own in-house data and from the petroleum industry.

[5] It is not the authors’ intention to question the existing regulations, but rather to provide support for the issue of costs vs. benefits. Any decision of intervention should seek acceptance from all stakeholders and approval from the regulator.

2.1.1. Estimation of remediation costs

In the following are presented some of the main studies and methods applied for estimation of remediation cost in CO_2 storage. However, these studies may be difficult to compare directly due to differences in their scope and/or ways of separating cost of the different lifetime phases or cost components.

The first study dealing with mitigation and remediation costs is presented in the IEA-GHG 2007/11 report devoted to the remediation of leakage from CO_2 storage reservoirs (IEA-GHG, 2007). The objective is to investigate remediation of leakage from CO_2 storage reservoirs and the data for cost analysis appear to be derived mostly from onshore examples and experience.

The second study is prepared by the United States Environmental Protection Agency (US EPA, 2010b) in conjunction with the final rule for the new Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration. The objective of the study is to present to the public a cost and risk analysis relative to the consequences of the new rule for geological storage of CO_2. The new rule has been tailored to deal with CO_2 storage projects in relation to the protection of drinking water resources in the United States and it therefore addresses onshore environment only.

The third study is published by the Zero Emission Platform (2011) and attempts to make realistic cost model calculations based on potentially relevant cost components. Models address both onshore and offshore cases.

In terms of cost for mitigation and remediation of leakages from CO_2 storage all studies point to the fact that external data are scarce but can to some extent be obtained from e.g. petroleum industry.

IEA Greenhouse Gas R&D Program, 2007

The cost analysis is viewed from the perspective of prevention and remediation as part of an integrated strategy for storage project. A cost calculation is presented for an example case based on a hypothetical CO_2 storage in a saline aquifer. The main assumptions for the example case are shown in Figure 30 and the results of the calculation of the integrated leak prevention and remediation are provided in Table 5.

The input to the calculation is to a large extent based on information on average costs of individual components such as e.g. remedial cementing jobs to repair simple wellbore leak, cost of contingency wells to replace damaged wells, plugging of a well. Though it is not clearly specified the costs presented seem based on the authors own knowledge and experience from working in the market for drilling, completion and well intervention and as such we have no reason to doubt that the basic figures are realistic for onshore United States.

- The storage site serves one 1,000 MW coal-fired power plant, with 8.6 million metric tons of annual CO_2 emissions. The site will operate for 50 years, with 30 years for CO_2 injection and 20 years for post-closure monitoring.

- An "enhanced" CO_2 monitoring system has been assumed to have been implemented, involving $7 million of pre-operational monitoring (integrated with site characterization), $33 million for operational monitoring (including continuous pressure and atmospheric monitoring and periodic seismic and other geophysical surveys), $10 million for post-closure monitoring and $12.5 million (25%) for G&A/management. As such, this $62.5 million monitoring strategy is consistent with a rigorous site selection program and is highly supportive of the diagnostic systems essential for identifying the sources for CO_2 leakage, should these occur.

- For consistency purposes, we also assume that the CO_2 storage site has 10 CO_2 injection wells, each capable of injecting 2,500 tonnes of CO_2 per day with a 94% operating factor. (This is a highly optimistic CO_2 injection assumption given the effects of two-phase relative permeability, interference among the 10 relatively closely spaced CO_2 injection wells, and the steadily increasing pressure in the saline formation.)

- The CO_2 plume extends radially and underlies an area of about 80 square miles (216 km^2) at the end of 50 years.

Figure 30 – Main assumptions for the example case presentented in IEA Greenhouse Gas R&D Program (2007).

Table 5 – Results of the example case for calculation of representative cost for leak prevention and remediation. Main assumptions are shown in Figure 30. The figures presented are derrived in 2007 (IEA Greenhouse Gas R&D Program, 2007)

	Activity	Mid-Range Costs (millions)	Comments
A. BASIC COSTS			
	1. Site Selection and Project Design	$18.0	Includes 6 observation wells plus other site selection costs
	2. Monitoring and Leak Detection	$62.5	Includes the comprehensive seismic program otherwise included in site selection
	3. Wellbore Integrity	$15.0	Includes multiple periodic ultrasonic cement bond logs and well integrity tests in 10 CO_2 injection wells
	Sub-Total	$95.5	
B. REMEDIATION COSTS (If Needed)			
	1. Locating Sources of CO2 Leaks		
	• Old, Abandoned Wells	$1.0	Assumes 10 leaking, abandoned well surveys
	• New CO_2 Injection Wells	$3.0	Assumes 10 sets of diagnostic logs
	• Caprock/Spill Point	$10.0	Includes seismic and 2 horizontal leak detection wells
	2. Well Plugging	$1.0	Includes plugging of 20 old wells
	3. Well Remediation	$3.5	Includes 10 well remediations and drilling one new CO_2 injection well
	4. Caprock Leakage		
	• Pressure Boundary	$10.0	Includes two horizontal water injection wells plus a water plant
	• Other Problems	Large	May need to abandon original storage site and build a new site
	Sub-Total	$28.5+	
	TOTAL	**$124.0+**	

Remediation costs are calculated from the average cost of the individual cost component and an assumed occurrence of the times a needed action has to be taken during the lifetime of a storage project. The example result shows that remediation costs are estimated to ca. 23% of the total calculated storage project cost.

United States Environmental Protection Agency (2010)

The cost analysis differs from the previous in that it involves many detailed models comparing baseline cost (i.e. previous rule for geological storage wells) with four different rule alternatives of which one (RA3) has now become the new final geological storage rule. The purpose of modelling is to calculate the cost of the rule alternatives and compare it to the benefit obtained for the protection of the drinking water. The cost benefit analysis is not straightforward as there are no quantitative data to support the benefits; instead the different rule alternatives are evaluated for the relative change in terms of increased or decreased risk for drinking water.

The models are carried out for 5 different cases of which 3 are for saline aquifers and 2 for Enhanced Recovery. The main differences and assumptions used are shown in Table 6.

A CO_2 storage project is divided into 9 components and for each component a cost calculation is performed involving a number of subtasks where details of labour cost and burden as well as non-labour unit costs are specified. The nine components are: 1) Site characterization, 2) Area of Review and Corrective Action, 3) Injection well construction, 4) Injection well operation, 5) Mechanical integrity testing, 6) Monitoring, 7) Well plugging, post-injection site care, and closure, 8) Financial responsibility, 9) Emergency and remedial response.

In particular, this last component 9) addressing emergency and remedial response is of interest. The USEPA (2010) realizes that at present there is no available data providing quantitative information on risk or likelihood of leakage occurring. A percentage of the capital costs for well operation (i.e. cost component 4) for each project is assumed to be contributed annually to a fund to account for the possible need for well remediation during operation (Table 7). The cost incurred by the subtask *Repair and replace wells and equipment* corresponds to our definition of mitigation and is set to 1% of initial well and equipment cost. *General failure of containment at site: cost to remove and relocate the* CO_2 falls as well under our definition of mitigation and is set to 1.5% of total capital cost. This way of dealing with estimated cost may be sound but it remains unexplained in the text how the authors have reached to these figures.

Contribution to long-term monitoring, insurance, and remediation is also included but costs are not shown or calculated. The idea is to include a contribution to the remediation fund that is not solely dependent on a fixed percentage of capital cost but is related to the amount of CO_2 being injected.

Since the objectives of USEPA (2010) are to compare cost for different rule alternatives and to evaluate the cost against the obtained relative change in risk of leakage into drinking water, it is not possible to extract a figure for total mitigation and remediation cost.

Table 6 – Description of 5 diferent cases used to evaluate impacts on cost of rule alternatives for geological storage by USEPA (2010).

Characteristic	Type of Project				
	Saline				
	Pilot	Large	Large Waivered	ER	ER Waivered
Depth to Top of Injection Interval (ft)	7,900	7,900	4,400	5,700	3,312
Depth to Bottom of Injection Interval (ft)	8,500	8,500	5,000	5,800	3,412
Metric tonnes capacity at 100% storage efficiency	30,022,272	737,154,000	737,154,000	32,574,981	29,860,399
Storage efficiency	10.0%	10.0%	10.0%	49.4%	49.4%
Area of Review (mi^2) [4]	0.9	23.3	23.8	8.4	8.2
Total Number of wells in Area of Review	5	116	119	167	165
Injection Wells Required (total)	3	4	4	17	16
Tubing Diameter (inches)	6	6	6	4	4
Depth of Stratigraphic Tests (ft.)	2,400	9,350	5,500	2,400	2,400
Number of Monitoring Wells above Injection Zone[1]	1.0	5.8	8.7	2.1	3.1
Number of Monitoring Wells into Injection Zone[1]	1.0	5.8	8.7	2.1	3.1
Depth of Monitoring Wells[2] (feet)	5,783	5,783	4,783	4,192	3,266
Long-string Casing of Monitoring Wells (diam. inches)	5.5	5.5	5.5	5.5	5.5
Injection Period (years)[3]	4	40	40	10	10

Source: Appendix A

Notes:

(1) The number of monitoring wells per site varies according to the RA and the size of the project area assumed for a representative project. Shown are the required number of wells in the pro forma of each project type for the selected RA (RA3).

(2) Well depths shown represent the typical (mean) monitoring well depth. Shown are the figures for RA3. Under RA3 and RA4, one half of the monitoring wells would be drilled to the bottom of the injection zone, while the other monitoring wells for RA3 and RA4, and all monitoring wells for RA1 and RA2, would be drilled to a depth halfway between the bottom of the lowest USDW and the top of the containment formation.

(3) GS projects in oil and gas reservoirs are assumed to operate for 30 years: 20 years under the existing UIC class II well regulations while the site is still used primarily for oil/gas production, and for the remaining 10 years under class VI for the primary purpose of long-term storage. This cost analysis includes costs for ER projects beginning with their transition from production to GS, i.e., 20 years into the 30 year injection period.

(4) The Area of Review is the size of the area estimated to encompass the plume throughout the project lifecycle.

(5) Projects that receive approval of a waiver of the requirement to inject below the lowermost USDW have reduced depth and a higher number of monitoring wells; this information is provided in the pro forma sheets presented in Appendix A of this Cost Analysis.

Table 7 – An example of how USEPA (2010) calculated cost for each of component of a CO_2 storage project; here are shown results of component 4 - well injection operation. Mitigation and remediation (repair and replace wells and equipement, general failure of containment...) are shown in the red frame. Contribution to long-term monitoring, insurance, and remediation fund is outlined in the blue frame.

Compliance Activity	**Labor Cost ($/hour)**	**Labor Burden (hours)**	**Labor Cost ($)**	**Non-labor unit Cost[1]**	**Regulatory Alternative**	**Project Cost Pilot Project - Saline**	**Project Cost Large Project - Saline**	**Project Cost Large Waivered Project - Saline**	**Project Cost Large Project - ER**	**Project Cost Large Waivered Project - ER**
	A	**B**	**C = B*A**	**D**	**EF**		**G**	**H**	**I**	**J**
Develop a corrosion monitoring and prevention program.	$110.62	24	$2,655	N/A	RA0	$ 664	$ 664	$ 664	$ 664	$ 664
					RA1	$ 664	$ 664	$ 664	$ 664	$ 664
					RA2	$ 1,327	$ 1,327	$ 1,327	$ 1,327	$ 1,327
					RA3	$ 2,655	$ 2,655	$ 2,655	$ 2,655	$ 2,655
					RA4	$ 2,655	$ 2,655	$ 2,655	$ 2,655	$ 2,655
Corrosion monitoring: analysis of injectate stream and measurement of corrosion of well material coupons.	$110.62	6 hours/ well	$664	$25/ well $300/sample	RA0	$ 1,417	$ 1,889	$ 1,889	$ 8,027	$ 7,555
					RA1	$ 1,417	$ 1,889	$ 1,889	$ 8,027	$ 7,555
					RA2	$ 2,833	$ 3,777	$ 3,777	$ 16,054	$ 15,110
					RA3	$ 5,666	$ 7,555	$ 7,555	$ 32,109	$ 30,220
					RA4	$ 5,666	$ 7,555	$ 7,555	$ 32,109	$ 30,220
Continuous measurement / monitoring equipment: injected volumes, pressure, flow rates and annulus pressure.	N/A	N/A	N/A	$15,500/well	RA0	$ 46,500	$ 62,000	$ 62,000	$ 263,500	$ 248,000
					RA1	$ 46,500	$ 62,000	$ 62,000	$ 263,500	$ 248,000
					RA2	$ 46,500	$ 62,000	$ 62,000	$ 263,500	$ 248,000
					RA3	$ 46,500	$ 62,000	$ 62,000	$ 263,500	$ 248,000
					RA4	$ 46,500	$ 62,000	$ 62,000	$ 263,500	$ 248,000
Equipment to add tracers.	N/A	N/A	N/A	$10,400/well	RA0	$ -	$ -	$ -	$ -	$ -
					RA1	$ -	$ -	$ -	$ -	$ -
					RA2	$ 7,800	$ 10,400	$ 10,400	$ 44,200	$ 41,600
					RA3	$ 7,800	$ 10,400	$ 10,400	$ 44,200	$ 41,600
					RA4	$ 15,600	$ 20,800	$ 20,800	$ 88,400	$ 83,200
Electricity cost for pumps and equipment.	N/A	N/A	N/A	$0.066/KWh	RA0	$ 142,666	$ 350,296	$ 350,296	$ 305,713	$ 280,236
					RA1	$ 142,666	$ 350,296	$ 350,296	$ 305,713	$ 280,236
					RA2	$ 142,666	$ 350,296	$ 350,296	$ 305,713	$ 280,236
					RA3	$ 142,666	$ 350,296	$ 350,296	$ 305,713	$ 280,236
					RA4	$ 142,666	$ 350,296	$ 350,296	$ 305,713	$ 280,236
Injection well O&M.	N/A	N/A	N/A	$77,500/ injection well $3.10/foot (depth)/ injection well	RA0	$ 311,550	$ 415,400	$ 372,000	$ 1,623,160	$ 1,409,224
					RA1	$ 311,550	$ 415,400	$ 372,000	$ 1,623,160	$ 1,409,224
					RA2	$ 311,550	$ 415,400	$ 372,000	$ 1,623,160	$ 1,409,224
					RA3	$ 311,550	$ 415,400	$ 372,000	$ 1,623,160	$ 1,409,224
					RA4	$ 311,550	$ 415,400	$ 372,000	$ 1,623,160	$ 1,409,224
Pay rent for land use and rights-of-way.	N/A	N/A	N/A	$5.20/acre	RA0	$ 3,155	$ 77,462	$ 79,288	$ 27,791	$ 27,401
					RA1	$ 3,155	$ 77,462	$ 79,288	$ 27,791	$ 27,401
					RA2	$ 3,155	$ 77,462	$ 79,288	$ 27,791	$ 27,401
					RA3	$ 3,155	$ 77,462	$ 79,288	$ 27,791	$ 27,401
					RA4	$ 3,155	$ 77,462	$ 79,288	$ 27,791	$ 27,401
Pore space use costs.	N/A	N/A	N/A	$0.36/metric ton	RA0	$ 270,200	$ 663,439	$ 663,439	$ 579,001	$ 530,751
					RA1	$ 270,200	$ 663,439	$ 663,439	$ 579,001	$ 530,751
					RA2	$ 270,200	$ 663,439	$ 663,439	$ 579,001	$ 530,751
					RA3	$ 270,200	$ 663,439	$ 663,439	$ 579,001	$ 530,751
					RA4	$ 270,200	$ 663,439	$ 663,439	$ 579,001	$ 530,751
Property Taxes & Insurance.	N/A	N/A	N/A	$0.03/$1 CAPEX	RA0	$ 265,328	$ 502,925	$ 384,826	$ 296,776	$ 253,389
					RA1	$ 265,174	$ 541,926	$ 454,403	$ 294,084	$ 259,864
					RA2	$ 284,452	$ 567,630	$ 485,012	$ 305,856	$ 266,988
					RA3	$ 328,058	$ 765,830	$ 638,672	$ 347,748	$ 306,313
					RA4	$ 335,824	$ 777,616	$ 652,994	$ 350,045	$ 308,521
Tracers in injected fluid.	N/A	N/A	N/A	$0.05/ton of CO2 injected	RA0	$ -	$ -	$ -	$ -	$ -
					RA1	$ -	$ -	$ -	$ -	$ -
					RA2	$ 9,382	$ 23,036	$ 23,036	$ 20,104	$ 18,429
					RA3	$ 9,382	$ 23,036	$ 23,036	$ 20,104	$ 18,429
					RA4	$ 18,764	$ 46,072	$ 46,072	$ 40,208	$ 36,858
Contribution to Long-term Monitoring, Insurance, and Remediation Fund.	N/A	N/A	N/A	$0.10/unit CO2 injected	RA0	$ -	$ -	$ -	$ -	$ -
					RA1	$ -	$ -	$ -	$ -	$ -
					RA2	$ -	$ -	$ -	$ -	$ -
					RA3	$ -	$ -	$ -	$ -	$ -
					RA4	$ -	$ -	$ -	$ -	$ -
Repair and replace wells and equipment.	N/A	N/A	N/A	1% of initial well and equipment cost	RA0	$ 88,443	$ 167,642	$ 128,275	$ 98,925	$ 84,463
					RA1	$ 88,391	$ 180,642	$ 151,468	$ 98,028	$ 86,621
					RA2	$ 94,817	$ 189,210	$ 161,671	$ 101,952	$ 88,996
					RA3	$ 109,353	$ 255,277	$ 212,891	$ 115,916	$ 102,104
					RA4	$ 111,941	$ 259,205	$ 217,665	$ 116,682	$ 102,840
General failure of containment at site: cost to remove and relocate the CO2.	N/A	N/A	N/A	1.5% of total capital costs	RA0	$ 33,166	$ 6,287	$ 4,810	$ 14,839	$ 12,669
					RA1	$ 33,147	$ 6,774	$ 5,680	$ 14,704	$ 12,993
					RA2	$ 33,779	$ 6,741	$ 5,760	$ 14,528	$ 12,682
					RA3	$ 32,806	$ 7,658	$ 6,387	$ 13,910	$ 12,253
					RA4	$ 31,484	$ 7,290	$ 6,122	$ 13,127	$ 11,570

Source: GS Cost Model

Notes:

(1) Some cost components include labor burden that is not explicitly shown here.

Sources:

(A) Owner and operator labor cost from Exhibit 5.1.

(B), (D) Owner and operator burden and non-labor unit cost estimates reflect EPA's best professional judgment.

(E) As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(F)-(J) Nondiscounted Project level cost estimates from final GS Rule cost model, which are also presented in Appendix C of the Cost Analysis.

Zero Emission Platform (2011)

This study addresses both offshore and onshore sites in the attempt to calculate realistic cost of CO_2 storage. A selection of six storage cases are presented defined by three factors: 1) Offshore vs. Onshore; 2) Depleted Oil and Gas Fields vs. Saline Aquifers; 3) the possibility of re-using existing wells or not, referred to as legacy wells. Saline aquifers are regarded as initially undeveloped and cases where legacy wells are present are therefore not considered.

Table 8 – Storage cases used in the Zero Emission Platform (2011) study. DOGF = Depleted Oil & Gas Fields; SA = Saline Aquifers; Leg = Legacy wells.

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

The CO_2 storage project lifecycle is divided into three phases. The first is the “potential storage phase”, or pre-FID (Financial Investment Decision) phase which includes an initial screening of multiple sites, the characterization of selected site(s), and the permitting process, leading up to the operator taking FID. The second phase is the operational phase, which includes field development plan, site development with necessary infrastructure and wells, the commissioning of the site and the injection operation. Finally the third phase, also called the post-closure phase, starting with the closure itself, decommissioning of the site and continued monitoring.

A total of 26 cost drivers have been identified and among these 8 are considered of major importance (Figure 31). Remediation costs are included in the cost driver *liability*. The liability is set to 1.00€/ton CO_2 stored as a medium case assumption. Since this estimate is rough and not very easy to constrain a low and high sensitivity range is set to €0.20 and €2.00 respectively. When assuming liability to be directly correlated with the amount of injected CO_2 whatever the storage context, its relative weight is therefore larger for the cases where the overall cost of storage per ton CO_2 stored is smaller, i.e. for onshore cases (Figure 32). The ZEP 2011 authors do not provide any quantitative arguments for the assumption of an average 1€ per tonne. They have included this parameter in the model in order to make calculations transparent and when a better value is known it is easy to update the calculations.

Mitigation cost drivers such as *contingency wells* or *well remediation cost* are considered to have little sensitivity in the cost calculation as either they are considered a minor cost driver or the sensitivity range would be small as the cost driver is well understood from the oil and gas industry experience. In the cost calculations it is expected that 10% of the required number of injection wells is added as contingency with a minimum of 1 well per field. Well remediation costs ranges from nil to 60% of new well costs, based on the possibility of risky wells and the cost of handling them.

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

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

Figure 31 – Eight main cost drivers of Zero Emission Platform (2011).

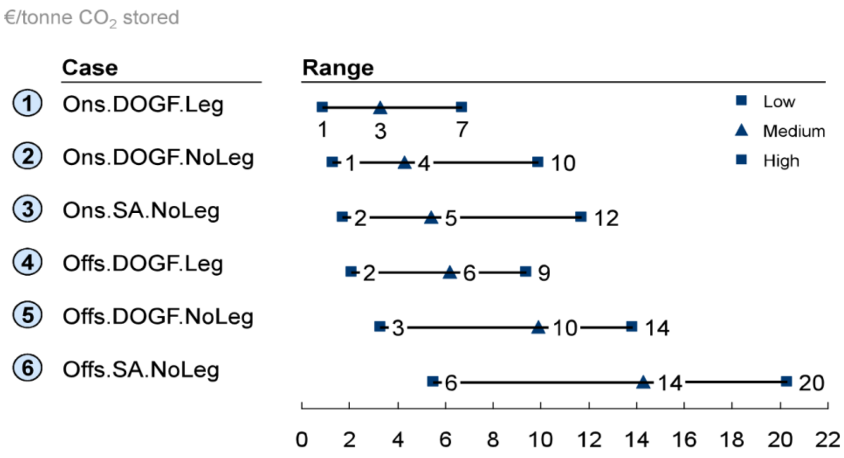

Figure 32 – Storage cost per case, with uncertainty ranges. Triangles correspond to base assumption. The ranges are driven by setting field capacity, well injection rate and liability costs to low, medium (= base), and high cost scenarios (Zero Emission Platform, 2011)

Discussion

The 2007 IEA-GHG report (IEA-GHG, 2007a) does not specify whether mitigation/remediation of old abandoned wells during the site selection and planning and construction phase are covered by the remediation cost or in the basic cost (Table 5). For the USEPA (2010) it is clear that those cost for preparing the site are incurred at the front-end of the project and separated from leakages developed or discovered later during operation of the injection site.

In the three studies presented we have identified three different ways for estimation of mitigation and remediation. Often the approach is a combination of more than one of these. The IEA-GHG (2007a) has based its calculation on input of known cost for e.g. a suite of operations (repairs, plugging of wells, new contingency wells or wells needed for remediation to create positive pressure barriers, etc.) and multiplied by an assumed expected number of occurrences in the lifetime of the storage projects.

The USEPA (2010) treated it as a percentage of capital cost and new equipment cost. In addition they opted for a contribution of $0.10 per ton of stored CO_2 to a remediation fund and insurance (this was not shown to be included in the results table).

The Zero Emission Platform (2011) assumes a fixed value of €1.00 per ton stored CO_2. They argued that "*such an assumption makes the cost of liability per tonne of CO_2 stored completely transparent: that element of the storage cost can easily be subtracted from the total cost and replaced by other estimates of the cost of liability as they arise.*"

2.1.2. Calculation of costs

Calculating cost of mitigation and remediation is difficult as shown in the previous section as long as there is little experience from actual CO_2 storage projects. The experience that can be used is most often from the oil and gas industry.

Qualitative elements on costs have been given on the measures described in Chapter 1, when available. In this section, we propose to provide additional quantitative elements of costs based on the consultation of experts. These elements concern the intervention on wells since this kind of actions can directly be compared to the ones performed in the petroleum industry. A relevant estimation of the costs of other technologies is not possible to date due to the poor experience in CO_2 leakage mitigation and remediation.

The intervention cost is highly site specific but some generic element can be provided: Offshore operations are much more expensive than comparable onshore activities. In addition, on average, costs of an onshore operation in Europe and the Middle East are approximately 20% of the same operation performed on a platform in the Norwegian offshore. We therefore decided to propose different scenarios with relative prices from different parts of the world as shown in Table 9, in order to provide site-specific cost estimations.

Table 9 – Relative well operation cost between different countries and regions of the world.

	Norway	DK/UK	Europe	Middle East	Gulf of Mexico	USA	Brazil	West Africa
Offshore	100 %	70 %			100 %		100 %	100 %
Onshore			20 %	20 %		10 %		

The relative costs of operations between region can be split into two offshore (100% and 70%) and two onshore (20% and 10%) categories. In the following section details on different mitigation methods are presented along with estimated cost range including costs for e.g. kill-fluids etc. Table 10 summarizes the costs based on a division into those 4 categories.

Table 10 – Estimated total costs range for different mitigation methods. All costs are in M€. Offshore 1 : Norway, US Gulf of Mexico, Brazil, West Africa ; Offshore 2: UK and DK ; Onshore 1 : Europe and Middle East; Onshore 2 : USA.

	Offshore 1		Offshore 2		Onshore 1		Onshore 2	
	Low	High	Low	High	Low	High	Low	High
Killing of a well	1.5	7.9	1.2	7.5	0.7	6.9	0.6	6.7
Wellhead and welltree repairs	1.5	7.9	1.2	7.5	0.7	6.9	0.6	6.7
Packer replacement	4.7	10.8	3.5	9.6	1.3	7.4	0.9	7.0
Tubing repair (with workover)	4.7	10.8	3.5	9.6	1.3	7.4	0.9	7.0
Tubing repair (no workover)	0.2	0.4	0.15	0.3	0.07	0.14	0.06	0.11
Squeeze cementing	2.3	8.4	1.8	7.9	0.9	7.0	0.7	6.8
Patching casing	6.9	13.0	6.2	12.3	5.0	11.1	4.7	10.8
Repairing damaged or collapsed casing	0.5	6.6	0.5	6.6	0.5	6.6	0.5	6.6
Plugging and abandonment of a well	6.0	8.0	4.2	5.6	1.2	1.6	0.6	0.8
Abandoned wells	6.7	13.3	4.7	9.3	1.3	2.7	0.7	1.3
Stopping surface blowout	20.0	53.3	14.0	37.3	4.0	10.7	2.0	5.3

The mitigation measures described in section 1.1 are mostly heavy and will require the presence of a derrick as well as intervention with for example a wireline (WL). Operations requiring a derrick on a platform and hence an operation crew run ca. 250-300 k€/day. If it is on a semisubmersible installation day rate for the rig will be on the order 400-550 k€/day.

Killing of a well - Setting the plug will require a wireline (WL) operation or for horizontal or inclined wells a WL with a tractor or coiled tubing. Plugging operation may take 1-2 days and cost 0.03-0.04 M€ for the WL operation. Afterwards removal of the plug and kill-fluid is an additional day work and 0.03 M€ for the WL operation. The cost of temporary killing of a well from an offshore platform (excl. kill-fluid) will be in the range of 1.0-1.5 M€.

Cost of temporary kill-fluid depends on the initial well completion, the volume needed, and the specifications. Prices range from 1300 €/m^3 to 18700 €/m^3 depending on the specifications for the kill-fluid. The amount of fluid needed depends on the diameter and length of hole. The volume of a 1 km deep well with a 9 5/8'' casing is approx. 50 m^3 which corresponds to cost range of 0.07 – 0.9 M€. The cost for kill-fluid itself is not expected to vary much globally.

Packer replacement - The removal and replacement of a production/injection packer will take about 2 weeks and involve a workover including killing of the well, welltree removal, tubing retrieval and packer removal.

Tubing repair - Instead of pulling the tube from the hole it may also be possible to apply expandable casing patch. This can be done with the welltree in place and may therefore not require a workover. The cost will be in the range of 0.2-0.4 M€ depending on the length. If the tubing has to be pulled out and replaced, the cost will be comparable to packer replacement.

Squeeze cementing - The operation may take 5 days including workover operations. The cost for the squeeze cement is not included.

Patching casing - The operation may take a week and will require a full workover.

Plugging and abandonment of a well - Cost for permanent plugging and abandonment of a North Sea petroleum well is on the order 6-8 M€ for a platform operation.

Stopping surface blowout - The cost of drilling a new offshore relief well are on the order of 20-53 M€ depending on length and/or time needed to stop the leakage and take control over the surface blowout on the first well. The corresponding figures for an onshore relief well are in the range of 2-10 M€.

2.2. VALUATION OF IMPACTS

In this chapter, the methodological framework and main concepts will be explained first. The more common methods for economic evaluation are then recalled in the subsequent paragraph. An example of economic evaluation from a recent publication is then shown. The chapter ends with some further consideration: treatment of uncertainties and possible use of option values.

2.2.1. Introduction – methodological aspects

Cost-Benefit analysis (CBA) is a method used to balance costs and benefits of a project. The first use of CBA is to state whether an action is worthwhile or not. A second use is to rank several options, for instance in order to choose the best compromise among the possible mitigation and remediation measures in case of significant irregularity. Some elements of estimation for the more obvious direct costs are presented in the previous section. How these costs can be integrated in a cost-benefit framework is now presented.

In CBA practice, all costs and all benefits impacted by the decision should be taken into account, meaning that it is the best tool for representing the viewpoint of society as a whole. We choose this position in this chapter, as it is not dependent on local regulations or situations, and we can thus make more generic conclusions. However, from the viewpoint of operators alone, Cost-Effectiveness Analysis (CEA) and Multi-

Criteria Analysis (MCA)[6] may be more practical because they allow operators to narrow the analysis to their own regulatory requirements and interests (Pearce *et al.* 2006, Béranger *et al.* 2006, Balasubramaniam *et al.* 2007).

A cost-benefit analysis is a comparison between the costs C and the benefits B of a scenario. In this case, a scenario is defined by the choice of a mitigation/remediation measure, or a combination of several measures, or even inaction. The comparison can either be a difference (i.e. $B - C > 0$) or a ratio (i.e. $B/C > 1$). In the following, the cost C is the direct cost of the implementation of the measure.

Definition of benefits

An irregularity can produce an impact on various assets. These impacts have thus effects on the economic system. *Damage* can be defined by evaluating the negative economic effects of these impacts. An avoided damage can be called *benefit* (Krupnick *et al.* 2011).

If an irregularity creates an impact I, the associated damage is $D(I)$. The function linking damages and impacts is not necessarily linear or continuous. When applying a measure M to correct the irregularity, the residual impact is $I_r(M)$ with $D(Ir) < D(I)$ (e.g. the remaining concentration of CO_2 after pumping is decreased, so that the associated damage is reduced). The deployment of the measure can also generate an additional negative impact $I_a(M)$ (e.g. the impact that can be created by the drilling of a relief well). We can then estimate the final damage once the measure has been performed: $D(M) = D(I_r(M)) + D(I_a(M))$.

The benefit is therefore defined by:

$$B(I;M) = D(I) - D(M) = D(I) - D(I_r(M)) - D(I_a(M))$$

The benefit of a mitigation/remediation measure is the difference between the damage caused by the irregularity and the residual damage after deployment of the measure.

Net Present Values (NPV)

In practice, costs and benefits are also a function of time. For instance when financing a project, the capital expenditure (CAPEX) and the operational expenditure (OPEX) are generally differentiated. The former represents the costs involved at the beginning of the project while the latter represents the regular costs along the lifecycle of the project. Similarly, the benefits of a remediation measure might not be important in the first years of implementation, but will increase after a given time of implementation.

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[6] Risk Management methods (including risk assessment), which is also a very common decision-making framework, seek different objectives and are less relevant for the choice of the actions that need to be undertaken. Indicators of risks and uncertainties can be integrated in the aforementioned methods.

In the CBA practice, the comparison between costs and benefits is evaluated at Net Present Values (NPV) (Pearce et al. 2006):

$$NPV = PV(B) - PV(C)$$

Where $PV(B)$ refers to the gross present value of benefits, $PV(C)$ refers to the gross present value of costs and NPV refers to the net present value (or present value of net benefits).

To incorporate the fact that future costs and benefits should have a lower weight than costs or benefits occurring now, a *discount factor* is commonly introduced in the calculation:

$$DF_t = \frac{1}{(1+\mathrm{s})^{\mathrm{t}}}$$

Where DF_t represents the discount factor, or weight, in period t, and s is the *discount rate*.

Using a discount rate of 0 would mean that a gain of 1€ now has the same value of a gain of 1€ 100 years from now.

A simplified form of the familiar CBA equation is then:

$$NPV = PV(B) - PV(C) = \{\sum_t \frac{B_t}{(1+s)^t} - \sum_t \frac{C_t}{(1+s)^t}\} > 0$$

For the more complete form of this equation, and for details on most issues of CBA calculations, see Pearce *et al.* (2006).

Generally, the period of time is a year. Costs and Benefits are then annualized. In the above equation, t hence represents the year considered, and B_t and C_t are respectively the total benefits and total costs that occurred during year t. One important consequence is that the delay before implementation of a measure must be taken into account by delaying the corresponding benefits. Depending on the chosen discount factor, benefits that would occur too far in the future would be highly discounted.

Example of calculation

In order to illustrate the CBA, two remediation measures are compared given a hypothetical leakage of CO_2 inside a groundwater aquifer.

The damage caused by the various impacts of the CO_2 on the aquifer is estimated to be 100 k€ per year.

A choice has to be made between these two remediation measures:

- A first measure M1, that can be deployed after 1 year, that costs 50 k€ to implement and that reduces the overall damage to 25 k€.
- A second measure M2, that can be deployed after 3 years, that costs 20 k€ to implement and that reduces the overall damage to 5 k€.

The discount rate is set at 5%.

Table 11 summarizes the various data and illustrates the calculation:

Table 11 – Example of a CBA – Comparison between 2 remediation measures.

(in k€)	Year 1	Year 2	Year 3	Year 4	Year 5
Discount factor	0,952	0,907	0,864	0,823	0,784
Damage of leakage	100,00	100,00	100,00	100,00	100,00
M1					
Cost of M1	0,00	50,00	0,00	0,00	0,00
Damage after M1	100,00	25,00	25,00	25,00	25,00
Benefit of M1	0,00	75,00	75,00	75,00	75,00
Net benefit of M1	0,00	25,00	75,00	75,00	75,00
Discounted net benefits of M1	**0,00**	**22,68**	**64,79**	**61,70**	**58,76**
M2					
Cost of M2	0,00	0,00	0,00	20,00	0,00
Damage after M2	100,00	100,00	100,00	5,00	5,00
Benefit of M2	0,00	0,00	0,00	95,00	95,00
Net Benefit of M2	0,00	0,00	0,00	75,00	95,00
Discounted net benefits of M2	**0,00**	**0,00**	**0,00**	**61,70**	**74,43**

The cumulated discounted net benefits can be obtained for both cases (sum of the discounted net benefits over the 5 years):

$$NPV(M1) = 208\ k€$$

$$NPV(M2) = 136\ k€$$

Even though measure M2 is cheaper and more efficient than M1, the fact that the operator needs to wait 3 years before implementation makes it less attractive than M1 for a 5 year time frame. Of course, the result would be different with a longer time frame of decision.

2.2.2. Damage Assessment

As introduced above, a damage is defined by the economic effect of an impact. In other terms, a damage assessment consists in monetizing the impacts.

The two main families of methods for damage assessment are the Revealed Preferences and the Stated Preferences.

Revealed preferences

The revealed preferences approach examines actual behaviour, whether in market or nonmarket activities, to infer the value that people place on avoiding impacts (Krupnick et al., 2011). If the examined good is in a market, then it is relatively straightforward to estimate the damage based on the effect of the impacts on this market. For instance, if CO_2 leaks into a land under cultivation, and if, due to the leak, the owner is unable to sell any crops, then the damage is simply the loss of income for the owner.

For non-market activities, the literature lists several methods (see Pearce et al., 2006 for further details). The most common ones are:

- Hedonic price methods, which uses a market good via which a non-market good is implicitly traded. The most common types of market are property markets and labour markets. For instance one can statistically derive the price of the local environment quality by investigating the prices evolution of private houses with the location.
- Travel costs methods, which derive the value of an area from the number and costs of trips to this area. It is for instance possible to valuate a lake by considering the number of people visiting this lake each year, and the money spent in order to visit the lake.
- Methods based on cost of illness: they infer the willingness to pay to avoid negative effects on health and safety by investigating the market of medical services and products. For example, the costs of the health impacts of air pollution can be valued by looking at expenditure made by affected individuals on drugs to counter the resulting headaches supposed to be caused by some air pollutants.

These are just three of the most common methods of revealed preferences. A large number of other methods exist and can be applied depending on the context and the field of study, as illustrated below in the example of IEC (2012).

As mentioned above, the choice of the method depends on whether the good is traded in a market or not. Examples of market goods that could suffer damages are:

- Agriculture;
- Aquaculture and commercial fishing;
- Buildings and private property;
- Other underground resources such as water, oil and gas, etc.;
- Employee health.

Examples of non-market assets are listed below:

- Public health;
- Public recreation;
- Non-use values (i.e., the willingness of households to pay to avoid environmental damage even though they may never use the environmental amenity themselves);
- Biodiversity and environmental assets;
- Reputation loss for a company.

For some non-market items, it is relatively straightforward to identify linked market such as medicine market for public health or a tourism market for public recreation. It should be noted that these markets are only linked and not strictly equivalent to the assets they represent.

Stated preferences

While the revealed preferences methods relies on the analysis of markets, the stated preferences approach is a survey-based set of methods, primarily contingent valuation and choice modelling, that pose hypothetical situations and then ask people their willingness to pay for avoiding specific damages to an ecosystem (or their own health) or ask them to make choices across outcomes that have multiple attributes, whose levels vary with such outcomes (Krupnick et al., 2011, see Table 12).

The contingent valuation method is the most common stated preferences method. This method first defines a hypothetical situation where a market is created for a non-traded good. A series of questions is then used in order to estimate the willingness of the respondents to pay for this good. Finally, in proper contingent valuation practices, a number of socio-economic statistics must be determined for each respondent of the survey. The main advantage of this method is that it can be used for estimating the value of any type of good, in any kind of analysis (*ex ante* or *ex post*[7]). For example, in case of an oil spill on a beach, the analysts can send questionnaires to people living near the beach in order to ask how much each the people would be willing to pay in order to restore the beach to its normal state. With the answers, the analysts use aggregation methods in order to recover a global "willingness to pay" to restore the beach. For more details, see Pearce *et al.* (2006).

The choice modelling method is an alternative stated preferences method that has gained some interest recently. In this method, a good is described by various attributes, with several performance levels for each attribute. Respondents to the questionnaires are then asked to choose their preferred options (what is their favourite level for each attribute). There are four choice modelling alternatives (Pearce *et al.*, 2006): choice experiments (choose between two or more alternatives), contingent ranking (rank a series of alternatives), contingent rating (score alternative scenarios on a scale of 1-10), and paired comparisons (score pairs of scenarios on similar scale). An example of choice experiments is given in Table 12.

[7] *Ex ante* methods are used in order to assess the potential benefits of future projects. *Ex post* methods are used for assessing the actual benefits of past projects.

Table 12 – Example of a choice experiment question (all data are purely illustrative).

WHICH OPTION FOR REDUCING CO_2 CONCENTRATION IN THE AQUIFER WOULD YOU PREFER, GIVEN THE OPTIONS DESCRIBED BELOW

	Current situation	Option A	Option B
CO_2 concentration	10%	5%	< 1%
pH in the aquifer	4.5	5.5	6.5
Potential for mobilizing substances	high	moderate	Low
Annual cost	0€	50€	100€
Preferred option			

Total economic value

One asset can have several values i.e. both use and non-use values. Use values relate to actual use of the good in question (e.g. a visit to a national park), planned use (a visit planned in the future) or possible use. Non-use value refers to the willingness to pay to maintain some good in existence even though there is no actual, planned or possible use. Use values can be determined by any method, i.e. either revealed preferences or stated preferences. Non-use values can only be determined by stated preferences methods, since by definition those preferences cannot be *revealed*. For example, Figure 33 lists the total economic value of groundwater with the following subdivision. Some terms used are defined below:

- Extractive Use Value: value derived from direct human use of groundwater resources;
- Existence Value and Bequest Value: value that public holds for groundwater independent of their own use (i.e. even without planning to use the water);
- Option Value: value primarily derived from the public willingness to pay to reduce future risks of adverse outcome. Function of both use and non-use values.

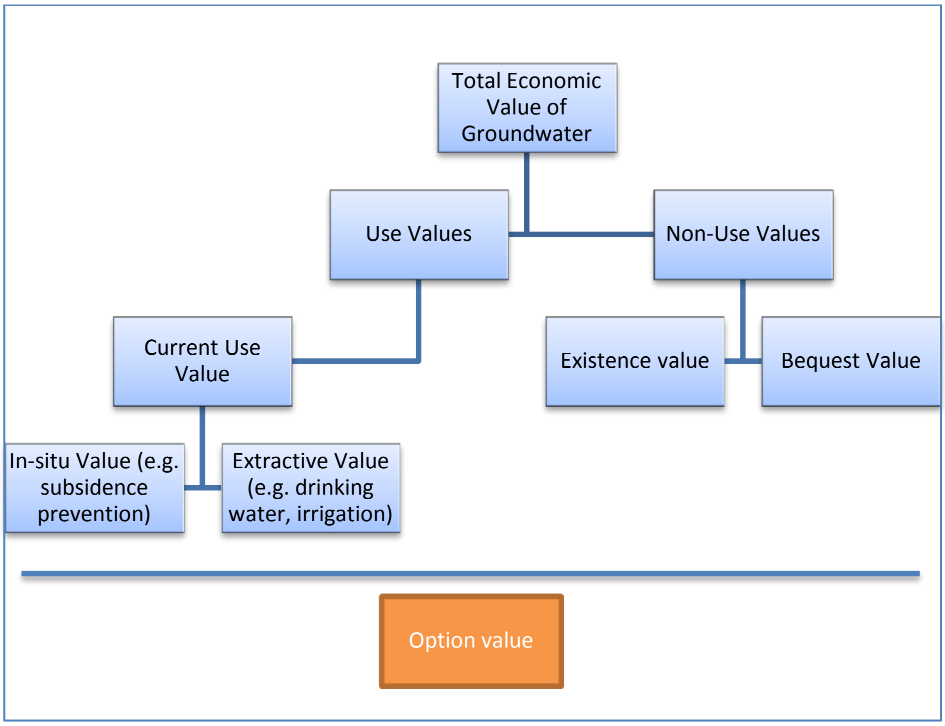

Figure 33 – Groundwater valuation approach (From IEC, 2012).

Example of valuation for human health and CO_2

A lot of literature exists for valuating damages on human health and biodiversity (the reader can refer to Pearce *et al.*, 2006). For human health valuation, the analyst will seek to determine a price that the society is willing to pay in order to protect a life (which is different than putting a price on a human's life). Both revealed preferences and stated preferences methods can be applied in this case:

- A revealed preferences method can investigate a market involved in personal safety (e.g. how much more money are households ready to pay for safer cars?). Insurances or wages can also be used as proxies, but should be used with caution because of inequity issues (i.e. someone whose salary is high should not be better treated by the project than someone with a lower salary).
- A stated preferences method can determine how much a respondent is willing to pay in order to save a life (e.g. by answering the following question: "In 2011, 10 people out of 10M died on the road, how much are you willing to pay for a project that will reduce this number to 5 out of 10M?").

In the case of CO_2 storage, the ton of CO_2 emitted in the atmosphere or in the water column can have a price as in the European Union Emission Trading Scheme. In this case, a typically non-market good (CO_2 emitted by combustion, contrary to food-grade CO_2) is traded on a market and allows analysts to directly use this market price. It represents the cost that society is willing to pay in order to avoid the ton of CO_2 to be emitted in the atmosphere. The damages on global climate change caused by unwanted CO_2 emissions are directly estimated from the cost of CO_2 on the market. This cost does not take into account potential local damages caused by CO_2 though.

Example of a damage assessment in CO_2 storage: IEC (2012)

A recent report written by Industrial Economics (IEC, 2012) proposes a methodology of damage assessment for geological storage of CO_2 and applies it to a realistic site, namely the Jewett site in Texas from the Futuregen 1.0 project. Their solutions for valuating the impacts on human health and on groundwater are presented below. It is important to note that the objective of this study is to provide an overall damage assessment but this assessment is not part of a cost-benefit analysis.

- **Damages on Human Health:**

For damages on human health, IEC (2012) use as a starting point compensations that would be awarded to plaintiffs by Texas juries in case of both personal injury and wrongful death cases. According to this analysis, the health damages may include: (1) medical costs, (2) productivity losses, and (3) non-economic losses:

- “Medical costs include the past and future medical expenses incurred due to the injury or death;
- Productivity losses include past and future diminished earning capacity, including the value of lost fringe benefits; plus value of lost household services; less earnings and services the victim would have consumed but for his/her injury or death;
- Non-economic losses include compensation for physical pain and impairment, mental anguish, disfigurement, loss of consortium, loss of advice and counsel, and similar losses.”

They then use various references presenting past decisions in the US in order to retrieve some statistics for compensations awarded for fatalities, hospital case and non-hospital case (i.e. minor injuries that did not necessitate an intervention in hospital). With respect to the method, they typically use a revealed preferences method based on past compensation mechanisms. Their results are shown in the figures below.

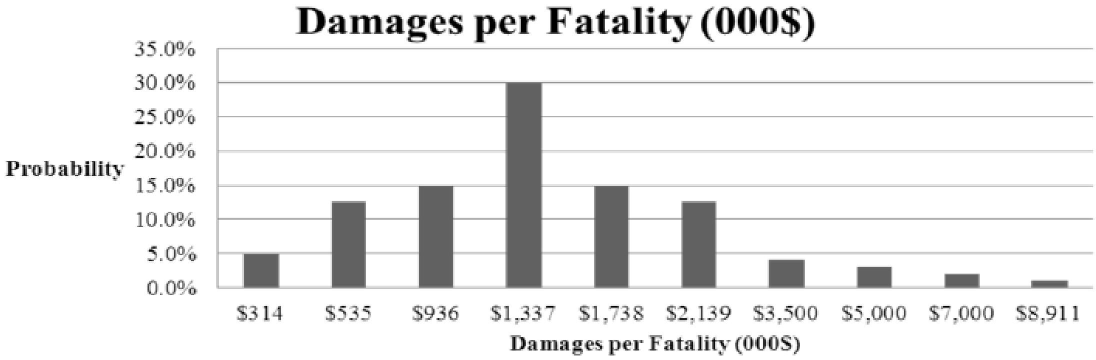

Figure 34 – Range of damages per fatality used in IEC (2012).

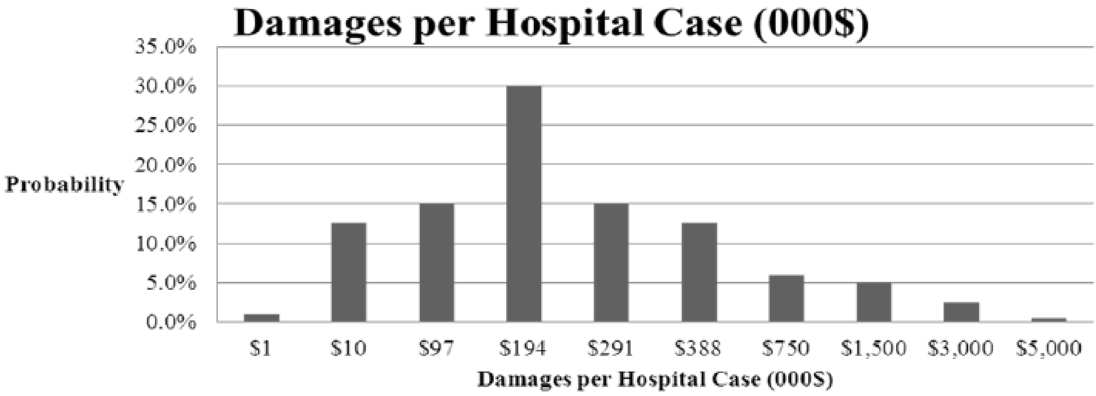

Figure 35 – Range of damages per hospital case used in IEC (2012).

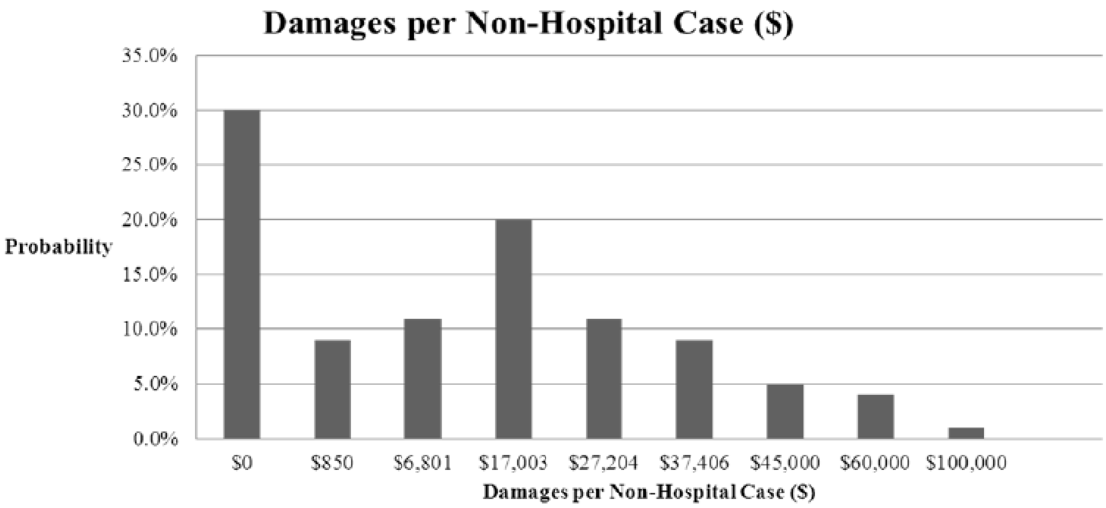

Figure 36 – Range of damages per non-hospital case used in IEC (2012).

- **Damages on groundwater:**

In addition to damages on human health, they also estimate potential damages for groundwater. They start by listing the various methods for groundwater valuation:

Table 13 – Methods for groundwater valuation (from IEC, 2012).

Approach	Application
Treatment cost	The cost of treatment either *in-situ* or at wellhead/point of use
Added cost	Contamination can impose added costs on current and future water users (e.g. cost of treatment or access to a substitute source of water)
Market price	The application of observed prices in competitive markets. Limited to locations with active water markets.
Hedonic property analysis	Econometric analysis of patterns in residential property prices to reveal environmental amenity/disamenity
Benefits transfer	Application of existing valuation literature in a new setting. Values based on the methods listed above
Replacement cost	Damages based on cost to restore, replace or acquire the equivalent of the injured resource, such as cost to protect an aquifer of equivalent yield and quality
Stated Preference	Values derived through surveys of the public

The six first methods presented in this table are revealed preferences methods. In addition to the common hedonic property analysis approach (called hedonic price method in the present report), they also list other methods (such as treatment cost and added cost) that can bring information to this particular case.

For this study though, IEC (2012) only use a combination of treatment cost and added costs: "[…] damages are assumed to include the costs necessary to stop the release, and costs necessary to address the impacts of the release to groundwater and groundwater services." By assuming that CO_2 releases in the aquifer is only related to wells (in operation or abandoned), they then used a mix of references and consultation of industry experts in order to provide well work-over costs. The damages they use as inputs for their calculation are summarized in Table 14.

Table 14 – Groundwater damages used in IEC (2012)

Source of damage	Dollar estimate	Incidence
Operating wells	\$50,000 – 300,000	90%
Abandoned wells	\$2M – 3.65M	10%

In the framework of a global (i.e. from society's viewpoint) cost-benefit analysis supporting the decision for the best mitigation or remediation method, the treatment cost method should not be used since the benefits (equivalent to avoided damages) are only evaluated by the cost of the treatment method. At no time does this analysis consider the actual benefit for the environment (or the asset) and the only criterion that will be taken into account will be the cost necessary for the remediation of the impact (as stated in the introduction of this section, the objective of this IEC study is to provide an overall potential damages assessment, and not to perform a cost-benefit analysis). One should always favour methods that estimate a cost for the considered good that reflects the actual value for society (whatever 'value' means). A similar impact, whatever the cause, should lead to a similar damage.

2.2.3. Uncertainty Management and inclusion of monitoring methods

The most straightforward way to perform a cost-benefit analysis is to use expected or deterministic values. The uncertainties associated with the evaluation of damages on the environment are usually very large though. It is important to bear in mind that a cost-benefit analysis is merely a decision-making *support* tool, which means that the result of a CBA should not be taken for granted, but should help discussions and thinking in order to find the best decision possible. Performing the analysis is thus more important than the result itself, and best practices of CBA should always include a sensitivity analysis on the main input parameters and hypothesis.

The other drawback of using expected values only is that they do not reflect the risk aversion of the decision-maker. If a decision-maker is risk averse, then he will prefer a sure gain to a gamble, even if the expected payoff of the gamble is the same as the sure gain. For example in a game of heads or tails, a gambler can choose between two configurations. In the first one, if he loses he has to give 2 €, but if he wins then he receives 2 €. In the other configuration, if he loses, he has to give 100 € but if he wins, he receives 200 €. The coin used is unflawed, meaning that the probability of hitting head or tail is 50% for both. The expected result of the second configuration is better (0.5*-100 + 0.5*200 = +50 € compared to 0.5*-2 + 0.5*2 = 0) but it is easy to see that a risk averse gambler will prefer the first configuration, with a low gain/low risk bet. He does not want to risk to lose 100 € even if the potential reward is higher.

In order to take into account risk aversion in the analysis, a first method consists in using a utility function (Figure 37). The utility is a function of the benefits that reflects the set of weights that the decision maker attaches to the outcome. In the figure below, it can be seen that the decision maker is risk averse as his utility rises quickly at low levels of benefits but at a declining rate for higher benefits.

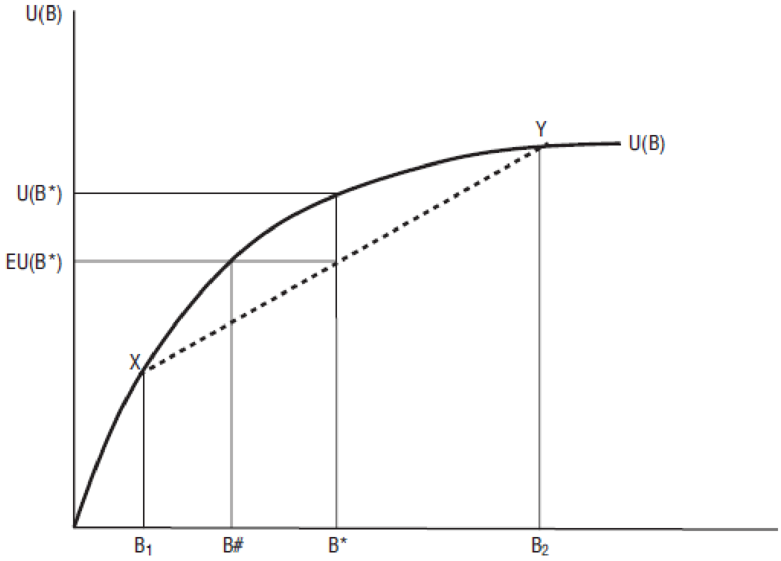

Figure 37 – Example of an expected utility function (from Pearce et al.*, 2006).*

Risk aversion can also be dealt with by taking cautious values as inputs and hypothesis. The sensitivity analysis can also help the decision maker to see whether he is pessimistic or optimistic about the risks.

Option value or cost of information

A possible solution in the case of decision-making under uncertainty is to wait before making the decision and gather more information in order to reduce the uncertainty. There is an existing decision theory, named option value that can help to determine what would be the value of additional information (See Pearce *et al.,* 2006 or Schultz *et al.*, 2010 for more information on option value and value of information). In the case of remediation of impacts from geological storage, this theory can be used in order to determine if additional monitoring is required before taking the decision and how much resource should be put into additional monitoring.

How better monitoring can improve the mitigation/remediation action?

In practice, the amount of uncertainty may be the main driver for the final decision: operators (who are risk averse) will favour measures that have certain acceptable outcomes more than measures that have potentially better outcomes but with more uncertainties. Here, uncertainties stem from two different sources:

- Uncertainties related to the irregularity: what exactly happened, what will be the impact?
- Uncertainties related to the intervention: will this measure work?

The first source of uncertainties depends on the level of accuracy of the characterization of the (unwanted) event, which is different than merely detecting that there is an irregularity. Hence, if the irregularity is well characterized and understood, using the monitoring system in place, the decision regarding the best mitigation or remediation action will be improved. Prior knowledge on the physical processes related to migration of CO_2 can also help to improve this characterization.

The second source of uncertainties depends on the theoretical and practical knowledge that operators have. It can be reduced by performing experiments, pilot tests and sharing experiences coming from real applications of interventions.

2.3. OTHER DECISION-MAKING FRAMEWORKS

For this report, it was decided to present the cost-benefit analysis which is one of the most common decision-making frameworks used in the field of environmental remediation, mainly because it is the method that can best encompass the viewpoint of society as a whole (Pearce *et al*., 2006). Other methodologies are used as well and can be more practical for operators as a decision-making tool, the cost-effectiveness analysis (CEA) and the multicriteria analysis (MCA) being the more relevant in this case. The main difference between CBA and CEA or MCA is that for the former, every action must be converted in monetary terms, whereas for the latters, any indicator can be used. CBA is often criticized for practical and philosophical aspects, needing to put a value on the environment and the human life. Its main advantages with respect to the other framework are the following (Pearce *et al.* 2006):

- CBA can tell if a project is worth financing or not, whereas in the case of CEA and MCA, only ranking of various options is possible; but it is not possible to say that any option will be beneficial for the society in its entirety;
- Within the CBA framework, the time aspect is taken into account in the discounting factor. This aspect can be added to a MCA, but is not necessarily systematic;
- Similarly, in a CBA, an inventory of who pays and who benefits is part of the result, whereas in the other methods, the balance can be lost in the process.

2.3.1. Cost-effectiveness analysis

It its most simple form, a cost-effectiveness analysis consist in comparing an indicator of effectiveness E with the cost of the option C:

$$CER = \frac{E}{C}$$

CER is the Cost-effectiveness ratio.

The CEA can only be used for comparing and ranking several options according to their CER. This type of analysis is very useful when a policy must be followed. In the case CO_2 leakage, a potential indicator would be the variation of the concentration of CO_2 with respect to a baseline. The policy is to allow only a variation of say 10% (arbitrary value, just for illustration). The CEA can then rank all the options that are able to restore the concentration of CO_2 within the fixed target. The CEA does not state if this objective is worth pursuing though; this is only possible if E and C are in the same unit which is the case in a CBA in monetary terms.

Another difference with CBA is that for CEA, values tend to come from experts judgements and not from individual preferences. It is both a drawback – as expert judgement can be biased and less transparent than individual preferences – and an advantage, as retrieving values from experts is quicker and cheaper than doing a complete survey.

If the regulator requires the operator to intervene, then CEA is probably the most convenient tool to use. As for CBA, it is recommended to consider the uncertainties and to at least perform a sensitivity analysis. CEA then allows operators to answer the following question: “how can I best attain my objective?”

2.3.2. Multicriteria analysis

Essentially, multicriteria analysis is similar to CEA but involves multiple indicators of effectiveness. In a MCA, different effectiveness indicators, measured in different units, have to be normalised by converting them to scores and then aggregated via a weighting procedure. The formula for the final score for a project or policy using the simplest form of MCA is:

$$S_i = \sum_j m_j . S_j$$

Where i is the i-th option, j is the j-th criterion, m is the weight, and S is the score.

By allowing focusing on multiple objectives at the same time, MCA is the only approach that is as broad as a CBA. As with CEA, it is better for ranking different options than for stating that a policy is worth following, and values also tend to come from experts judgements.

This method is recommended if several stakeholders need to take part in the final decisions, as it allows each stakeholder to choose one or several indicators. This is a way to enhance participation and acceptation of the final decision. As for CBA and CEA, uncertainty management, at least as a sensitivity analysis, is recommended. MCA answers the following question “What will be the *various* effects of my actions?”

2.4. CONCLUSION

This chapter shows that comparing costs and benefits can be complex. Some tools and numbers from the existing literature were provided in order to give elements of costs and benefits related to mitigation and remediation actions. The framework of cost-benefit analysis was mostly used in this chapter as it best represents the viewpoint of society as a whole. Practice of CBA requires the knowledge of various tools and concepts, particularly for damage assessment, i.e. for monetizing the impacts. This chapter provides an overview of the main aspects of damage assessment and is illustrated by an example in the field of CO_2 storage. For more practical decision-making tools for operators, cost-effectiveness analysis and multicriteria analysis are also briefly presented. Overall, it represents a short introduction to the practice of decision-making related to mitigation and remediation; the method and tools that are presented can be used and adapted for specific projects. The various figures provided here can be used as a reference point for comparison with specific analyses. These figures are mainly derived from the existing literature.

Chapter 3. Mitigation and remediation plan for CO_2 geological storage: review of existing plans and regulatory guidelines

3.1. INTRODUCTION

CO_2 geological storage is now implemented in several places around the world. In such projects, risks management procedures are being set up and integrate mitigation techniques in case of deviation from the expected behaviour of the storage complex. Regulatory requirements are now in place and need to be followed. In Europe, the 2009 Directive on CO_2 geological storage (EC, 2009) requires operators to submit a plan describing measures considered for preventing significant irregularities and to propose a corrective measures plan. Similarly, the U.S. Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration Wells (US EPA, 2010a) requires that the owner or operator submit an emergency and remedial response plan within the permit application. In Australia, the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Australian Government, 2011a) and the associated regulations (Australian Government, 2011b) require well operations management plan, which should include explanations on how the risks can be dealt with. Several guidelines or guidance documents mentioning the mitigation and remediation measures plan have been issued (EC, 2011; IEA, 2010; DNV, 2009 and 2012). A new Canadian Standard (CSA Z741) has been recently issued to establish requirements and recommendations for CO_2 geological storage, including a section on risk treatment (CSA, 2012). In addition, International standards, which are not specific to CO_2 geological storage, also propose generic workflow for risk management and guidelines for the risk treatment stage (ISO 31000:2009).

To date, no comparison has been published between the different intervention strategies elaborated at existing storage sites or storage projects. Despite the above mentioned international and regulatory frameworks, a unified methodology for designing intervention plans for CO_2 geological projects is missing. There is thus a need for gathering the best practices for mitigation of undesired CO_2 migration, based on the scientific literature and on the experience gained in CO_2 storage projects and related industrial experiences.

In this section we propose a review of existing corrective and remediation measures plans (both in the CCS and in some non-CCS related industries) and literature on intervention plan set up.

3.2. METHODOLOGY AND KEY FINDINGS

The present section aims at reviewing the mitigation and remediation plans existing in active or planned projects in case of an abnormal behaviour of a geological storage complex.

This synthesis is based on a qualitative survey. From a list of CO_2 storage sites[8], more than a dozen representative projects have been identified and operators and/or service companies have been contacted in order to gather information on their corrective measures plans. Natural gas storage companies have also been contacted in order to benefit from the longer experience in underground gas storage industry. The cover letter and survey form that have been sent out are presented in appendix 1. Two publicly available corrective measure or risk management plans have also been considered (the Goldeneye project; ScottishPower CCS Consortium, 2011 and the Gorgon project; Chevron, 2005 and 2008), and are referenced when used in the present synthesis.

Among the 14 companies contacted, 8 participated to the survey through a written response or an oral interview, under a strict guarantee of confidentiality of the answers. This synthesis therefore does not name any of the projects. It also refers to some public documents that may not necessarily correspond to the survey responses.

The panel of the answers is presented in Figure 38.

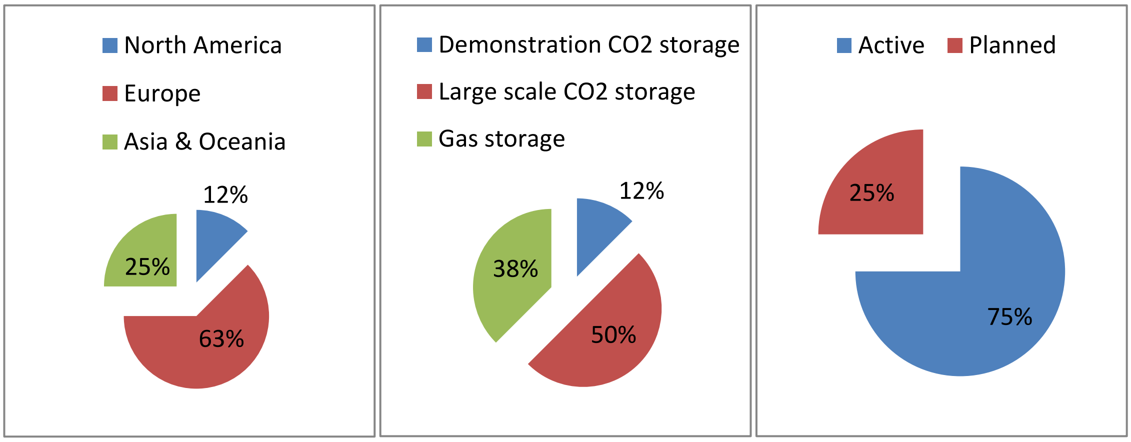

Figure 38 – Breakdown of the answers per geographical origin, per activity type and per status.

For comprehensiveness, in this discussion we also integrate the existing regulatory documents specific to CO_2 geological storage mentioning intervention plans: the European Directive (EC, 2009) and associated guidance document 2 (EC, 2011); the USA Federal Requirements (US EPA, 2010a); the Australian Act (Australian Government, 2011a) and regulations (Australian Government, 2011b). The Carbon Capture and Storage Model regulatory framework document (IEA, 2010), which addresses the regulatory issues associated to CCS and the Canadian Standard on geological storage of CO_2 (CSA, 2011) are also included in this section.

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[8] An up-to-date database of large scale CCS projects is for instance proposed by the GCCSI at http://www.globalccsinstitute.com/projects/browse

The key-messages from the survey are the following:

Site-specific and risk-based corrective measures plan

The mitigation and remediation measures plan should be site-specific and risk-based. The corrective measures plan, containing risk-reduction actions, is included in the risk management process and is closely linked to the risk assessment and monitoring plans. The plan is usually public, has been reviewed by stakeholders, and updated over time as new information becomes available. Formats of corrective measures plans are very diverse. This may be explained by the difference in legislations, which sometimes only give limited and non-detailed guidelines compared to other mature industrial fields.

Corrective measure methods centred on well interventions

In terms of content, the corrective measures and methods proposed in the plans mostly imply actions on wells (intervention on injection wells or abandoned ones) or directly related to operational aspects such as reducing the CO_2 injection rate. Other pressure management techniques, such as drilling of new injection or pressure relief well are generally seen as ultimate measures. The technologies judged not mature enough (breakthrough technologies) are not contemplated for the moment and the development of new remediation measures on impacts is often judged unnecessary given the experience in environmental clean-up field.

Flexible decision protocol and holistic decision making

Despite the importance of the initial plan, the decision protocol should be flexible and seen as a support for decision-making at the time of the irregularity detection. The detailed intervention process cannot be included in the plan submitted during the storage permit application but will rather be decided by the team in place (operator and competent authority) according to the specificities of the irregularity. The contingency plan should, however, help that team to have a holistic view on the issues and to balance the technical feasibility, the benefits (avoided impacts), the economic costs and the potentially negative impacts of the measures implementation.

These findings are further developed in the following sections based on the answers from the survey and on public documents when referenced.

3.3. MITIGATION AND REMEDIATION PLAN ELABORATION

3.3.1. Risk based corrective measure plan

According to the answers received from the CO_2 storage operators, it becomes clear, as it was expected, that the corrective measures plan is specific to the site and based on the risk assessment outcomes. Risk identification has typically been assessed through experts' workshops using e.g. FEPs methodology and/or bow-tie analyses in order to identify relevant risk scenarios. Experts workshops included mostly people experienced in oil and gas industry, and the risks have therefore been assessed relatively to their experience. Classically engineered barriers were considered if, after evaluation, one risk scenario was assessed as pertinent. A barrier in a risk scenario consists of both monitoring and mitigation (or remediation) measures. Even if this study is exclusively focused on mitigation and remediation technologies, the importance of monitoring within the mitigation strategy has been emphasized in many answers.

In some projects, the corrective measures and/or remediation measures are implicitly included as risk reduction measures of the risk management plan, whereas it is presented as a distinct document in other projects. The European Directive (EC, 2009) for instance, requires a specific corrective measure plan for every storage permit application, which should however be linked with the risk assessment and risk monitoring plan. The EC Directive guidance document 2 (EC, 2011) proposes that a section of the corrective measure plan (*N.B.* section 1) should be devoted to this link by including the following elements:

- The identified risk the measure is related to;
- The threshold triggering the corrective measure implementation;
- The monitoring system necessary for monitoring the measure effectiveness.

The Canadian Standard on geological storage of CO_2 (CSA, 2012) also recommends a risk treatment plan for each significant risk, with the following elements:

- The objective in terms of target level of risk to be achieved;
- A prioritized list of preferred risk treatment options;
- The analysis to be performed to ensure an acceptable level of risk across time;
- The cyclic assessment of the effect of the implemented risk treatment options and the acceptability of the residual risk level (followed by new risk treatment options if it is assessed as non-tolerable);
- A contingency plan for unexpected circumstances or incidents.

As an example of corrective measures implicitly included in the risk management plan, we can mention the Gorgon project (Chevron, 2005). Mitigation and remediation measures are presented in two steps; first, a CO_2 injection management plan has been set up, applying the practice of reservoir management plans developed in the oil and gas industry. This plan includes a nine-page long table in which each identified "uncertainty" is associated with the monitoring techniques required to identify them and with "management actions". "Uncertainty" corresponds to "possible outcomes that lie at the extreme of the range predicted by the objective analysis", and includes risk of unexpected migration. "Management actions" are strategies and methods proposed in order to mitigate these possibilities. For instance, "modify injection pattern […]" is a management action proposed in response to the uncertainty "unexpected pressure gradient in the formation may alter the CO_2 migration path". Mitigation measures are also recapped in the second phase of the analysis called the potential failure modes assessment that includes the failure modes resulting in the unplanned migration of CO_2. These measures associated to natural safeguards are specified according to the relevant failure mode. Even if the terminology may be different compared to the one used in this study, the intervention measures are presented with close links with the risk assessment and monitoring techniques.

Alternatively, the Goldeneye project (ScottishPower CCS Consortium, 2011) explicitly set up a corrective measures plan as required by the European Commission and for this purpose followed the guidelines provided by the Commission for the plan elaboration (EC, 2011). The risk assessment plan, the MMV plan and the corrective measure plan are three distinct documents, but are clearly linked with each other. The potential subsurface migration paths identified in the risk assessment plan are recalled and serve as a basis for the proposed corrective measures.

We may note that this distinction of explicit or implicit corrective measure plans also corresponds to different geographical areas and legislations.

The corrective measures plans are deduced from the risk assessment which is site-specific, and are therefore necessarily site- and project-specific (considering for instance the completion of the injection well of the CO_2 storage project).

3.3.2. Reviewed and public corrective measures plans

All the answers mentioned that the corrective measures plan had been reviewed. The organizations mentioned for the review were: the stakeholders who had significant exposure in the project, the IEA-GHG, the owner or representatives of the operator, engineering companies, technical teams (incl. experts in the field of geological CO_2 storage), HSE department, fire-fighting brigades in some cases and regulatory authorities. Several answers have also mentioned that the plan has been updated after this review, and/or that it is planned to be regularly updated. Plans are also updated if new information comes up during operations from injection and monitoring and changes the risk profile (e.g. a plume migration different than expected). An example of such update is provided from the Gorgon project in Australia, which adapted the initial failure modes assessment and the associated mitigation measures to the proposed increase in injection rates (Chevron, 2008). Such changes implied notably the modification of the pressure management strategy, including modifications in the injection wells numbers and placement and the extraction of formation water (see below section 3.4.3).

The USA Federal Requirements (US EPA, 2010a) imposes such updates after a minimum fixed frequency (not to exceed five years), following any significant change, or when required by the competent authority. No regular update requirement of the corrective measures plan is mentioned in the EC Directive (EC, 2009); the storage permit review might however impose such updates in case of new information regarding monitoring, site characterisation, risk assessment (new risk emerges or risk becomes irrelevant) or scientific knowledge (including new corrective measures or methods) (EC, 2011). According to the Australian regulations (Australian Government, 2011b), well operations management plan should be modified in case of changes in the understanding about the characteristics of geology, in case of the occurrence of a new risk or of a significant increase in a detrimental risk.

Answers of operators of large scale CO_2 storage sites highlighted the fact that their corrective measure plan or summaries were public, either in reports or academic articles. In addition to public plans or summaries, internal versions contain more specifications especially regarding the cost elements.

One answer insisted on the necessity of obtaining commitment from all diverse and required parties, which might be challenging given their different concerns and drivers.

3.3.3. Comparison with risk and mitigation plans from other close industrial operations

Comparison of answers from CO_2 storage operations to the ones from operators or engineering companies in the field of natural gas storage gives an interesting insight on the existing differences on both the approach and the existing regulations. Since most of the companies having responded to our survey and operating the gas storage sites are mostly operating in France, this country is used for the comparison. This example might however not be sufficient for drawing global conclusions.

Natural gas storage operations in France must submit Risk Prevention Plans to the competent authority and are required to update it every five years. This might be seen as similar to the detailed risk assessment and the corrective measures plans required by the European Directive (EC, 2009) in preparation to the storage permit application for CO_2 storage; the transposition of this Directive in the French Law imposes an update of the corrective measure plan at least every five years (Code de l'environnement, article L229-38).

The French Risk Prevention Direction issued a guidance document determining methods relative to risk reduction for underground gas storage (MEEDDM, 2009, section E.). This document presents a list of 13 to 20 risk reduction measures, depending on the type of storage (mined caverns, salt caverns, aquifers or depleted reservoirs). If these measures are implemented, the risk of gas migration is not anymore considered relevant in the Risk Prevention Plan. These measures mostly consist in design (e.g. “adequate cementation”) and monitoring (e.g. several requirements of pressure monitoring) obligations. In comparison, there is no such technical guidance document for risk management of CO_2 storage projects in France.

The non-French gas storage company stated that the protocol to be followed, from the detection of a risk to the implementation of an appropriate mitigation measure, does exist with the measures normally to be approved by relevant authorities prior to implementation. Reviews and required updates of the mitigation measures plan and procedures are typically conducted annually according to the ISO 9001 Management Review clause.

3.4. MITIGATION AND REMEDIATION METHODS AND TECHNIQUES INCLUDED IN PLANS

As stated in the previous section, corrective measures are site-specific and this synthesis does not intend to present detailed measures, nor does it reproduce an exhaustive list of all proposed corrective measures. It rather aims at comparing the categories of methods available in scientific literature (presented in Chapter 1) with the methods considered in the reviewed CO_2 storage mitigation and remediation plans.

3.4.1. Distinction of natural and engineered pathways

In the majority of the reviewed corrective measures plans for CO_2 storages, the measures were classified depending on the type of migration pathways: either natural (e.g. fractures, faults) or man-made (i.e. related to wells). This distinction is essential when dealing with risk treatment as the effectiveness is likely to be much more limited for the geological system, as stated by the EC Directive guidance document (EC, 2011).

3.4.2. Action on wells

In all of the risk assessments, leakages through operating or abandoned wells have been identified as potential risks. All CO_2 storage projects are concerned since they have at least one operating well used for injection, and possibly more abandoned or operating wells, usually due to the oil and gas exploration or production.

Intervention on wells is a large part of the corrective measures list considered in all reviewed plans. It is based on the experience of the oil and gas industry and many different techniques are proposed: well killing; injection tubing and packer replacement, repair (scab casing, squeeze cementing, patch or sealant) or plugging and abandonment.

These interventions are specific to each well. The measures potentially applied to the injection well may be detailed: for instance, the remediation plan for Goldeneye project (ScottishPower CCS Consortium, 2011) recalls the injection well completion, the identified potential leakage pathways and proposes corresponding intervention measures. However, the well remediation techniques are not always specified in the plans, especially regarding abandoned wells whose completion is less likely to be precisely known, but such techniques are known to be available and applicable based on oil and gas industry experience.

3.4.3. Fluid and pressure management

Fluid management options are primarily considered in case of geological leakage pathways, unpredicted CO_2 plume migration, or unacceptably high pressure build-up in the near injection well formation.

The measures considered include turning the injection off, reducing the injection flow rate or varying the injection pattern. Most of the large scale CCS projects answered that no pressure relief well was considered, mentioning that it was either not pertinent (e.g. in case of storage in a depressurized depleted reservoir) or extremely expensive especially in offshore locations. Other projects considered the drilling of a new injection or pressure relief well as an ultimate measure.

The increase of the CO_2 injection rate at Gorgon project implied changes in the pressure management strategy: it is now planned that four extraction wells will be drilled and the injection wells locations and rates adjusted. This pressure management strategy is set up to decrease the risks of fracturing and to mitigate the risks of CO_2 leakage through existing wells or faults by influencing the CO_2 plume migration. The extracted water is proposed to be injected in an overlying geologic unit (Chevron, 2008). Modelling studies using these planned injection and extraction wells have been recently achieved (IEA-GHG, 2012) and show that the combination of these wells is beneficial both for pressure management and plume migration control.

One operator has incorporated the drilling of a new well for CO_2 injection into its mitigation plan aiming at minimizing operational risks. Once the new injector is in place, the plans are that the currently existing CO_2 injector will be shut down and used as a backup in case of an operational down-time of the new CO_2 injector.

In addition, extending vertically the overall perforation interval or perforating new reservoir zones for CO_2 injection were two fluid management options cited several times in the responses. No project considered producing back the injected CO_2 from the injection well or locally in the vicinity of an identified leakage. No project considered injecting fresh brine or water for enhancing residual trapping and dissolution, or implementing a hydraulic barrier (which has been considered conceivable but not achievable at an affordable cost).

These answers are in line with the EC Directive guidance document (EC, 2011), which states that whereas some fluid management procedures are quite classical, notably in the oil and gas industry, others are either novel technics never applied *in-situ* or technically feasible but at very high costs.

3.4.4. Breakthrough technologies

Breakthrough technologies such as foams, gels or other low-permeability materials were not explicitly considered in any answer. The main reasons were that some of these technologies are either not mature enough or not tested extensively for the size/type of the problem which may be encountered in CO_2 storage sites. Therefore, since an intervention plan should only include technologies that are feasible at a given time, the breakthrough technologies have not been mentioned in existing plans. If new methods are developed and tested after the establishment of a mitigation measures plan, these methods would be added during the periodic plan update. Moreover, an intervention measure will ultimately be decided at the time of the leakage based on the available technologies, which may include these nowadays-breakthrough technologies.

3.4.5. Remediation on impacts in sensitive aquifers, in the vadose zone or at surface

The risk assessments, which form the basis of the reviewed corrective measures plans, concluded that the risks of impacts in sensitive aquifers, in the vadose zone or at the surface were low either because some natural barriers (e.g. secondary seals) make a CO_2 migration reaching vulnerable assets unlikely or due to the absence of vulnerable assets such as vadose zone or drinking water aquifers (e.g. in offshore sites). The development in advance of customized remediation measures on impacts was often judged unnecessary given this low risk of contaminations associated to the significant experience in the environmental clean-up field, explaining the fact that no remediation method on impacts was presented in the reviewed CCS projects.

3.4.6. Remarks

CO_2 blowout risks was mentioned and one project even mentioned a written blowout contingency plan associated to some CO_2 release modelling based on a major leak at the wellhead.

3.4.7. Conclusions

As a conclusion on this section on the proposed techniques, the statements obtained from the survey responses are corroborated by the EC Directive guidance document (2011) that points out the limited experience in terms of corrective measures in the CCS field and the reliance on existing rules and regulations developed by and established in the oil and gas industry. The methods need to be adapted mostly from oil and gas as well as environmental clean-up industries. The CCS Model regulatory framework document (IEA, 2010) also confirms that best practices already exist in the oil and gas industry regarding mitigation measures such as well-plugging or well-repair techniques. Partial removal of CO_2 from the reservoir, decrease of the pressure and remediation of groundwater in case of impacts are also mentioned.

In addition, one survey pointed out the lack of precise knowledge on the processes occurring during an unexpected CO_2 migration. In parallel to the development of mitigation and remediation techniques, more studies should be focused on the behaviour of leakage over time to be able to choose the most relevant mitigation and remediation strategies.

3.5. FLEXIBLE DECISION PROTOCOL AND HOLISTIC DECISION MAKING

3.5.1. Flexible protocol for measure implementation

Most answers clearly stated that corrective measures plans are submitted by the operator during the storage permit application. It is based on identified leakage scenarios established during the risk assessment process. However, the operator and the competent authority do not know the specific location and the actual process of a significant irregularity or leakage before it is detected. For instance, it is not known *a priori* whether a fault is highly permeable, or which one of the abandoned wells has a low degree of integrity. The best measure design in response to the leakage may not be submitted *a priori* in the plan. Even if it states that plans should be “ready to use”, the EC Directive guidance 2 document (EC, 2011) also acknowledges the fact that the corrective measure plan might be generic, especially at the first stages of the storage site lifecycle.

The corrective measure plan should therefore allow for flexibility and ultimately, the final decision and measure design will be taken by the operator and the competent authority that will be in place at the time of the leakage. DNV recommended practices (2012) state that the implementation of risk treatment should be done according to the following procedure: 1) *the detection of a circumstance that signals the need to implement risk treatment*; 2) *assessment and selection of an appropriate treatment to address the situation*; 3) *the implementation of the selected risk treatment*. This should be followed by a risk assessment step to assess whether an additional treatment action should be carried out (DNV, 2012). Several plans include this classical decision process for implementing corrective measures. For instance, in one case it is described as follows: monitoring base plan; monitoring contingency plan, risk assessment, and action in conjunction with authorities. The action has been detailed in another plan as: evaluate likely treatment effectiveness, execute treatment, re-evaluate risk level, and repeat if necessary.

The Federal Requirements under the Underground Injection Control Program for CO_2 Geologic Sequestration Wells (US EPA, 2010a) provides a detailed procedure to be followed in case of a potential impact on groundwater: cease injection, identify and characterize any release, notify to the competent authority, implement the emergency and remedial response approved by the competent authority.

In terms of responsibility, the IEA CCS model regulatory framework document (IEA, 2010) explains that the existing regulatory documents tend to give the responsibility of implementing the measures to the operator, while the relevant authority would ultimately decide which measures should be considered and whether this implementation is necessary or not.

3.5.2. Holistic approach during the decision process

One of the responding operators insisted on the fact that, after detecting and analysing the irregularity, the team in charge of deciding and implementing the most appropriate action should have a systematic approach considering all possible corrective measures given the type of risk to mitigate, their economic cost, operational feasibility, and potential environmental impacts with and without implementing the measure. That team should aim at an overall risk reduction; one option may be not to intervene if the abnormal migration does not threaten a sensitive target or if the risks associated with the measure itself are too high compared to its benefits. The decision should be made having a holistic view, balancing the risk of the leakage, and the practically achievable options. According to DNV (2012), risk treatment options should be identified among the methods that are cost effective and do not introduce other significant risks, which outweigh potential benefits of the treatment. In order to allow the comparability between relevant measures, the EC Directive guidance 2 document (EC, 2011) proposes a possible format for the corrective measures plan. This format notably specifies details about the measures likely to be needed for decision making: *estimated timeframe needed for implementation*, *detailed description of the measure* (including activities to be carried out), *rationale for the use of the measure*, *current status of the measure* (proven, commercial, under development).

Conclusions and recommendations

The development of CO_2 capture and geological storage technology is highly dependent on the assurance of the storage process safety, especially with regards to potential leakage out of the target zone. A proper risk management process should be set up for this aim, including assessing the risks specific to a given storage site, monitoring the site to detect any potential loss of confinement, mitigating these potential leakages and remediating possible impacts. This study is dedicated to the last two steps, with the purpose of giving a comprehensive picture of the actual situation regarding the mitigation and remediation of an unwanted CO_2 migration.

The state of knowledge of mitigation and remediation technologies has been presented from a technical point of view. Thus, for different scenarios, the potential actions for avoiding, reducing or correcting impacts caused by an unwanted CO_2 migration have been reviewed. There is a large discrepancy between the different techniques available in literature with respect to their maturity and therefore some measures may not be operationally available at the present time. The operational feasibility of a given measure is dependent on additional criteria especially on the balance between the benefits (impact avoided) and the costs (economic direct costs and potential negative environmental impacts). Elements and generic tools for such analysis have been reviewed in this study; however, any detailed assessment would require to be specific to a site and to a given risk scenario. This technical and operational knowledge is the basis for the intervention strategy to be set up according to the existing regulations. A literature and experience review has been carried out focusing on both the development of mitigation plans and the measure implementation in case of an unwanted CO_2 migration in the subsurface.

As outcomes of the study, some recommendations are proposed. This study has covered several aspects of mitigation and remediation (technical, operational and in terms of implementation of the mitigation and remediation strategy) and therefore these recommendations are of different kinds. Research directions are suggested for filling the existing gaps in terms of technical answers to mitigate unpredicted CO_2 migration. Concerning the implementation perspective, best practices regarding the mitigation plan set up and the intervention in case of unwanted CO_2 leakage are provided.

Technical aspects

Gaps in technologies development

Most of the measures come from the experience in mitigation or remediation of other kinds of risks and impacts (oil and gas industry and environmental clean-up). Even if the analogy might be meaningful, CO_2 geological storage brings new conditions. Therefore, there is a need for research on how the measures could be adapted to the specific conditions of CO_2 geologic storage. For instance, remediation measures originated from the environmental clean-up field are very much referenced but their applicability to CO_2 migration potential impacts have been hardly studied, contrary to technologies from the oil and gas sector, which form the basis of the measures proposed in the literature or submitted in existing remediation plans.

Development of new measures tailored to CO_2 leakage is also needed. Some theoretical concepts have been proposed for instance in terms of pressure management; however, their feasibility has to be proven through experimental tests, in-situ deployment, or experimentations at a scale in between the lab and the field following detailed modelling and simulation studies. Similarly as presented in this study, some breakthrough technologies are being developed; however, their development is at early stages and therefore much effort is needed to integrate them in the portfolio of mitigation and remediation measures.

Operational aspects

Needs for accurate description of conceivable measures

More than a list of measures to be potentially applied in case of unwanted migration of CO_2, the operators or regulators will need a comprehensive description of each measure in order to make a knowledgeable choice. The purpose of the measure, the time needed for implementation, the associated economic costs, the maturity or the environmental impacts of a measure are key elements that need to be assessed. The review performed in this study gives these elements when available. However, there is a lack of such information and therefore an extensive work is needed to fill this gap.

Needs for methods and tools to support decision-making

One of the main challenges related to mitigation and remediation of leakage in the fields of CO_2 storage is to choose the best possible way to intervene, and to do so at a reasonable cost. Moreover, a negotiation may take place between operators and regulators regarding a specific event because they do not share the same objectives. A method, based on multicriteria analysis, (and/or cost-benefit analysis) and adapted to the context of mitigation and remediation of irregularities in CO_2 storage could help to support informed, shareable and more acceptable decisions.

In addition, the development of such methods might require the creation of specific tools for assessing *a priori* the effectiveness of a measure, or for damage assessments. In particular, numerical simulation tools combined with meta-models could be used for computing effectiveness of measures for a number of pre-defined scenarios. For damage assessment, data and figures used in future analyses could be shared for building best practices and improve robustness of future analyses.

Knowledge gap about migration in the geological media and leakage consequences

In practice, the success of an intervention will be highly dependent on the knowledge of what happened. This implies knowing the risks or impacts to be treated: up to now the leakage phenomenon are not well understood (e.g. the mechanisms underlying the migration of CO_2 across several geological formations), and therefore the potential impacts cannot be well characterized. A deeper understanding of the mechanisms related to migration of CO_2 can also improve interpretation of monitoring data. This gap is also due to lack of experience and feedback in the new field of CCS. Research on migration processes should then be pursued.

Implementation of the mitigation and remediation strategy

Mitigation plan based on the existing state of knowledge

The intervention plan should, at a given date, mention the technologies available according to the state of knowledge. The measure selection criteria needed for a knowledgeable choice should be also part of this plan. The plan should be reviewed and updated to allow the integration of any new measures or any new information that may change the ranking list of measures or the associated information.

Mitigation plan integrated in the global risk management process

The mitigation and remedial actions should be linked with the risk scenario selected during the risk assessment process and each measure should be related to the irregularities it mitigates; in addition the methods described in the monitoring plan should be mentioned in the mitigation plan. It will allow identifying the monitoring techniques available for detection and characterization of irregularities, that would trigger the intervention, and the monitoring techniques able to assess the efficiency of this intervention.

Flexible mitigation plan

The choice and design of the measure is dependent on the situation. The plan should be somewhat generic proposing adapted measures to a potential situation. However, it should be able to help as much as possible the decision-making if a deficiency occurs. Therefore, the tools or processes leading to the design of the most relevant mitigation and remediation strategy could be specified in such a plan. The final decision will be ultimately made when a migration occurs taking into account the specificity of the situation and the considerations of both the operators and regulators. This has to be done according to specific decision-making tools that need to be developed.

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Appendix 1
Survey sent to operators

The European Network of Excellence on Geological Storage of CO_2
Association

Ref.: 12-021_Pres/IC

Orléans, June 6th 2012

Subject: Survey of mitigation plans

Dear Sir or Madam,

CO_2GeoNet association, represented by BRGM and IRIS, is currently carrying out a study assessing the methodologies and technologies for mitigation of undesired CO_2 migration in the subsurface in the context of CO_2 geological storage. This work is overseen by the IEA Greenhouse Gas R&D Programme (IEAGHG). In this frame, a survey is carried out with the purpose of gathering the existing experience in terms of mitigation plans from field operations in the oil & gas industries, and in gas or CO_2 storages.

Your site was identified for this survey and the project team would be very glad if you accept to fill in the attached form. Participation is strictly voluntary. If you choose to participate in this survey, please answer the attached form and return the completed questionnaire to the email addresses indicated at the end of the form before the 2nd of July. If a telephone interview is more convenient for you, please contact us by email for fixing a date or call directly one of the numbers listed at the end of the survey form.

The project team guarantees the confidentiality of the information. Only aggregated data from the survey participants will be included in the final public outcomes of the study; no references to your project will be given. A version of the synthesis will be returned to the participants before the final publication in order to take into account any potential required changes. Additional confidentiality agreements can be signed under request.

On behalf of the CO_2GeoNet association, thank you for taking the time to provide this very useful information. If you have any questions related to the survey, please do not hesitate to contact us.

Sincerely,

Isabelle Czernichowski, President of CO_2GeoNet

CO_2GeoNet - 3 avenue Claude Guillemin, B.P. 36009, 45060 Orléans, France – Tel: +33 238 644655
Secretariat - Borgo Grotta Gigante, 42/C, 34016 Sgonico (TS), Italy - Tel: +39 040 2140229 – **info@co2geonet.com**

Survey Form

Project information:

Status:

- □ Ended
- □ On-going
- □ Future

Type:

- □ Gas storage
- □ Oil and gas industry
- □ EOR
- □ CO_2 storage
  - o Depleted oil or gas field
  - o Deep saline aquifer
  - o Coal seems

Location:

- □ Onshore
- □ Offshore

Establishment of Mitigation Plan:

Process

Explanation of the process followed to set-up the mitigation plan (please outline the various steps considered). In particular, please mention the links with the risk assessment and MMV plan.

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Which one of the following methods or means has been used to design the mitigation measures plan? Please provide short comments related to the selected methodologies.

- □ Experts workshops
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- □ Experience regarding mitigation plans from other sectors
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- □ Guidelines (e.g. for CO_2 sequestration guidelines for the Implementation of the European Directive 2009/31/EC on the Geological Storage of Carbon Dioxide)
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- □ Others (Please specify)
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Content
Which types of measures are mentioned (some of the above-mentioned types of measure only concern CO_2 geological storage)?

- □ Well remediation techniques
- □ Pressure management techniques
- □ Breakthrough technologies (use of foams, gels, nanoparticles, biofilms to enhance the CO_2 trapping and reduce risks of unwanted migration)
- □ Remediation measures on the potential impacts of unwanted CO_2 migration on sensitive aquifers, within the vadoze zone and even at the surface
- □ Others:
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Please provide a brief explanation on the type of information given for each proposed measure (e.g. purpose according to a specific risk, timeframe for implementation, cost, status of the technology, impacts of the mitigation measure implementation)

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Are there, in the plan you developed, any guidelines or recommendations about choosing the most suitable measure according to the characteristics of the detected risk?

- □ Yes
- □ No

If yes, please explain briefly the principles of these recommendations.

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Is there a protocol to be followed from the detection of a risk to the implementation of an appropriate mitigation measure?

- □ Yes
- □ No

If yes, please explain briefly this protocol.

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Review, verification and update

Have there been any reviews and/or verifications of the mitigation measures plan?

- □ Yes
- □ No

If yes, please specify the stakeholders that have been involved in this review/verification.

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Are there any updates of the initial mitigation measure plan according to new information originated from the monitoring, characterization, modeling, etc. processes?

- □ Yes
- □ No

If yes, please explain briefly how often this update is taking place.

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Given your experience, what are the most significant difficulties when setting up a mitigation measures plan?

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Plan availability
Is the plan/a summary of it public/available for consultation?

Public: □ Plan □ Summary

Available for consultation: □ Plan □ Summary

Confidential: □ Plan □ Summary

Any additional comments:

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