CCS SITE CHARACTERISATION CRITERIA

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CCS SITE SELECTION AND CHARACTERISATION CRITERIA

Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) has recently commissioned the Alberta Research Council in Canada to conduct a review of storage site selection criteria and site characterisation methods in order to produce a synthesis report. Among the various elements of the CO_2 capture and storage (CCS) chain, the stage of storage site selection and characterisation is of critical importance because any storage site must demonstrate that it satisfies three fundamental requirements:

1. capacity to store the intended volume of CO_2 over the lifetime of the operation,
2. injectivity, to accept/take CO_2 at the rate that it is supplied from the emitter(s),
3. containment, to ensure that CO_2 will not migrate and/or leak out of the storage unit (safety and security of storage).

This report reviews the literature on the subject on site selection and characterisation since the publication of the IPCC Special Report on CCS, and provides a synthesis and classification of criteria.

This study is intended by IEA GHG as a significant contribution into a wider project being lead by DNV on "Selection and Qualification of sites and projects for subsurface geological storage of CO_2 - CO2QUALSTORE", in which IEA GHG is a partner (IEA GHG 2008/153). The primary objective of this industry-consortium project is to develop a risk-based qualification procedure (guideline) to identify and select storage sites. This study provides criteria information into this qualitative process for site qualification.

Classification of Selection Criteria

The report considers that there is a two stage process for the site screening, so that sites unsuited to geological storage are discounted. The first stage of this is an elimination process, whereby sites are eliminated from consideration completely. The second stage then looks at additional selection criteria, which assesses the sites that passed the elimination stage and screens them against a set of parameters to determine the more favourable sites for further investigation. The study concludes that classification must result in selection of reservoirs with:

- sufficient porosity and thickness to create the storage capacity necessary,
- sufficient permeability to allow injection,
- and the presence of at least one (but preferably multiple) confining stratum to prevent escape and migration of the injected CO_2.

The study then performs an in-depth review of previous work and research on site selection, in particular analysing the work and results in the relevant sections of the IPCC Special Report on Carbon Dioxide Capture and Storage, work by CO2CRC, and the 2008 EU manual on Best Practice for the Storage of CO_2 in Saline Aquifers. The conclusions on key geological indicators for storage in aquifers are reproduced from the latter here overleaf in Table 1.

	Positive Indicators	Cautionary Indicators
Storage Capacity		
Total storage capacity	Total capacity estimated to be much larger than the total amount produced from the CO_2 source	Total capacity estimated to be similar to or less than the total amount produced from the CO_2 source
Reservoir Properties		
Depth	Between 1000 and 2500 m	< 800 m or > 2500 m
Reservoir thickness	> 50 m	< 20 m
Porosity	> 20%	< 10%
Permeability	> 300 mD	< 10-100 mD
Salinity	> 100,000 mg/l (ppm)	< 30,000 mg/l (ppm)
Caprock Properties		
Lateral continuity	Unfaulted	Lateral variations, faulted
Thickness	> 100 m	< 20 m
Capillary entry pressure	Much greater than buoyancy force of maximum predicted height of CO_2 column	Similar to the buoyancy force of maximum predicted height of CO_2 column

Table 1: Key geological indicators for storage site suitability in saline aquifers (from Chadwick et al., Best Practice for the Storage of CO_2 in Saline Quifers, 2008)

From analysis of this and other work, the study provides a synthesis and classification of criteria for site selection and characterisation.

Summary of Findings and Discussion

The report determines that for a site to be deemed suitable for geological storage of CO_2, it must meet a range of criteria, and that these criteria can be grouped into a set of categories;

- Safety and security,
- Capacity and injectivity,
- Legal and regulatory issues,
- Economics,
- Public acceptance.

This forms the basis for the classification of screening criteria as either eliminatory, or selection based. Eliminatory criteria effectively rule out a site for selection if the criteria are not met, whereas selection criteria quantify a site's suitability for storage compared to other sites.

Considering site selection criteria only from the point of view of storage safety and security, particularly during the injection period, the following qualifiers and threshold values can then suggested as set out in Table 2 overleaf.

Criterion Level	No	Criterion	Eliminatory or unfavourable	Preferred or Favourable
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)
	2	Pressure regime	Overpressured: pressure gradients greater than 14 kPa/m	Pressure gradients less than 12 kPa/m
	3	Monitoring potential	Absent	Present
	4	Affecting protected groundwater quality	Yes	No
Essential	5	Seismicity	High	Moderate and less
	6	Faulting and fracturing intensity	Extensive	Limited to moderate
	7	Hydrogeology	Short flow systems, or compaction flow; Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow
Desirable	8	Depth	< 750-800 m	>800 m
	9	Located within fold belts	Yes	No
	10	Adverse diagenesis[+]	Significant	Low to moderate
	11	Geothermal regime	Gradients ≥ 35 ºC/km and/or high surface temperature	Gradients < 35 ºC/km and low surface temperature
	12	Temperature	< 35 ºC	≥ 35 ºC
	13	Pressure	< 7.5 MPa	≥ 7.5 MPa
	14	Thickness	< 20 m	≥ 20 m
	15	Porosity	< 10%	≥ 10%
	16	Permeability	< 20 mD	≥ 20 mD
	17	Caprock thickness	< 10 m	≥ 10 m
	18	Well density	High	Low to moderate

Table 2. Site selection criteria for ensuring the safety and security of CO_2 storage

Oil reservoirs suitable for miscible CO_2 flooding, hence CO_2 storage in CO_2-EOR operations, should meet the following additional criteria as set out in Table 3.

Reservoir Parameter	Miscible CO_2-EOR
Size (ROIP in MMstb; or $MtCO_2$)	≥1 (whichever condition is met first)
Depth (ft/m)	>1500 (>450)
Temperature (ºF/ºC)	82 to 250 (28 to 121)
Pressure	> MMP and < P_f
Porosity (%)	≥3
Permeability (mD)	≥5
Oil Gravity (API)	27 to 45
Oil Viscosity (cP/mPa·s)	≤6
Remaining Oil Fraction in the Reservoir	≥0.30

Table 3: Characteristics of oil reservoirs suitable for miscible CO_2-EOR (metric values are given in brackets)

These qualifiers and threshold values represent the expert opinion of the authors and they should be considered only as a starting point in a broader debate and consultation process whose results should then inform regulatory agencies in establishing requirements for permitting CO_2 storage sites. These criteria and threshold values should be used only as guidance and should be applied by experienced experts to the conditions specific to the geological, geographic, jurisdictional and societal settings of the CO_2 storage site under consideration.

Expert Review Comments

Comments were received from 6 external reviewers on the initial draft report supplied by ARC, with very positive overall feedback. Key points emphasised by the reviewers included the following:

- An onshore location should not always be regarded as a 'favourable' criteria, shallow offshore locations may be suitable or even preferable in some regions;
- The use of depth as an 'eliminatory' criterion may need to be reviewed in some cases;
- The tables in the summary section were received very positively;
- Section 6.1.2 described the Sleipner CO_2 plume breaching a shale layer; one reviewer cautioned that there are several explanations for this development, emphasising that the shale layer is within the storage formation and is not the designated caprock.
- Reviewers emphasised that guidance recommended by the report should always be applied by experienced experts;
- Many of the reviewers cautioned against an over-emphasis of seismic monitoring as the main storage monitoring technique, and that unsuitability for seismic surveying does not necessarily equate to unsuitability for monitoring.

Conclusions

Sites selected for CO_2 storage should be properly characterised. Site characterisation is a continuous and iterative process that starts usually with existing data, particularly at the basin and/or regional scale, and proceeds with the acquisition of new data and information during all the stages of a CCS project relating to the site, namely: selection, evaluation, permitting, design and construction, operation, closure and post-closure. However, the major effort and expenditure of resources occur in the early stages of site selection and permitting. The initial characterisation will be subsequently updated with data and information produced by new well drilling and from monitoring programmes.

Sites should be characterised in terms of geology, rock properties, hydrogeology and geothermics, fault and fracture characteristics - if present, in-situ conditions, composition and phase behaviour of the native fluids and the injected CO_2 stream, reservoir history in the case of hydrocarbon reservoirs, history of wells and their condition, and land features.

Performance assessment is an integral part of site characterisation and is based on numerical modelling of multi-phase, non-isothermal, reactive flow that takes into account hydrodynamic, thermal, geochemical, geomechanical and geophysical effects of CO_2 injection and storage under various scenarios, taking into account also the uncertainties introduced by data availability, distributions, resolution, accuracy and quality, and also the necessary assumptions, simplifications and resolution of the modelling process.

Recommendations

Proper criteria for site selection and proper site characterisation should be part of any process for site qualification and permitting, and this report attempts to review and synthesise the knowledge and experience to date in regard to criteria for site selection. However, the information presented here, particularly as summarised in tables 1-3, should not be used in isolation as a general recipe for project evaluation or site comparison and selection. Local conditions should be taken into account and experienced experts should apply this information to actual site selection and qualification processes. The information presented in this report can serve as guidance only and should be tailored to specific conditions and needs.

CCS SITE SELECTION AND CHARACTERISATION CRITERIA

- REVIEW AND SYNTHESIS -

Submitted to
International Energy Agency – Greenhouse Gas R&D Programme

by
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Disclaimer: The opinions expressed in this report are solely those of the authors, and they do not represent the opinion and/or position of their employers or of the International Energy Agency Greenhouse Gas R&D Programme which commissioned the report.

EXECUTIVE SUMMARY

Along the various elements of the CO_2 capture and storage (CCS) chain, the stage of site selection and characterisation is of critical importance because any storage site must demonstrate that it satisfies three fundamental requirements: 1) capacity to store the intended volume of CO_2 over the lifetime of the operation, 2) injectivity, to accept/take CO_2 at the rate that it is supplied from the emitter(s), and 3) containment, to ensure that CO_2 will not migrate and/or leak out of the storage unit (safety and security of storage). In addition, sites must be legally and physically accessible and available, must meet with public acceptance, and must be viable from an economic and financial point of view. This report reviews the literature on the subject on site selection and characterisation since the publication of the IPCC Special Report on CCS, and provides a synthesis and classification of criteria for site selection and characterisation.

Site screening and selection criteria are classified as: 1) eliminatory criteria, on which basis sites are eliminated from further consideration; and 2) selection criteria, on which basis sites that passed the eliminatory screening are selected on the basis of having most favourable characteristics. Sites may still be rejected if too many unfavourable conditions exist. The eliminatory criteria fall into two categories: a) critical – these criteria have to be met without exception; and b) essential – these criteria should also be met, but some exceptions may occur/be granted, depending on circumstances. Site selection should normally proceed along a scale continuum from basin or regional scale to local or site-specific scale. The following table presents basin-scale site selection criteria.

Characteristics of sedimentary basins or parts thereof suitable and favourable for CO_2 storage

	Criterion Type	Criterion	Not Suitable/ Unfavourable	Suitable/Desirable
1	Critical	Depth	Less than 1000 m	Greater than 1000 m, with storage units deeper than 800 m.
2		Reservoir-seal pairs and stratigraphic sequences	Poor (few, discontinuous, faulted and/or breached)	Intermediate and excellent At least one major extensive, regional-scale competent seal
3		Pressure Regime	Over-pressured	Hydrostatic or sub-hydrostatic
4		“Legal” Accessibility	Forbidden	Possible
5	Essential	Seismicity (basin tectonic setting)	High and very high (subduction zones; syn-rift and strike-slip basins)	Very low to moderate (foreland, passive margin and cratonic basins)
6		Faulting and Fracturing Intensity	Extensive	Limited to Moderate
7		Hydrogeology	Shallow, short flow systems, or compaction flow	Intermediate and regional-scale flow systems; topography and erosional-rebound flow
8		Surface Areal Extent	Less than 2500 km^2	Greater than 2500 km^2

9	Selection	Within fold belts	Yes	No
10		Significant diagenesis	Present	Absent
11		Geothermal Regime	Warm basin (Gradients > 40°C/km and/or high surface temperature)	Cold and moderate basins (Gradients < 40°C/km and low surface temperature)
12		Evaporites (salt)	Absent	Domes and beds
13		Hydrocarbon potential	Absent or small	Medium to giant
14		Industry Maturity	Immature	Mature
15		Coal seams	Absent, very shallow or very deep (< 400 m or > 800 m depth)	At intermediate depth (400 to 800 m)
16		Coal rank	Lignite or Anthracite	Sub-bituminous and/or bituminous
17		Coal value	Economic	Uneconomic
18		On/off shore	Deep offshore	Shallow offshore and/or onshore
19		Climate	Harsh	Moderate
20		Accessibility	Inaccessible or difficult	Good
21		Infrastructure	Absent or rudimentary	Developed
22		CO_2 Sources within economic distance	Absent	Present

At the local scale, the following are eliminatory criteria. Sites located in sedimentary basins or parts thereof that have been evaluated as suitable for CO_2 storage must be: legally available and accessible (i.e., located outside protected or reserved areas, and with right of access), available time-wise (e.g., producing hydrocarbon reservoirs may not be available), and must not adversely affect, directly or indirectly, other resources, including groundwater. In addition the storage site must not be located in overpressured strata and/or in an area of high seismicity; must posses at least one major barrier to the upward migration of CO_2; and it should posses monitoring potential. Favourable or desirable criteria for site selection are: sufficient capacity and injectivity, adequate depth, sufficient thickness, low temperature, favourable hydrodynamic regime, low number of penetrating wells, and the presence of secondary containment and attenuation potential in case of CO_2 leakage. In addition, a storage site should have favourable economics for transportation and delivery at the site (e.g., distance, terrain, right of access, transportation corridors, infrastructure) and for storage (e.g., site facilities, compression, operational monitoring), and should be located, as much as possible, away from high-density population areas. Oil reservoirs suitable for CO_2 miscible flooding must meet a set of specific additional criteria.

Considering site selection criteria only from the point of view of storage safety and security, particularly during the injection period, the following qualifiers and threshold values are being suggested.

Site selection criteria for ensuring the safety and security of CO_2 storage

Criterion Level	No	Criterion	Eliminatory or unfavourable	Preferred or Favourable
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)
	2	Pressure regime	Overpressured: pressure gradients greater than 14 kPa/m	Pressure gradients less than 12 kPa/m
	3	Monitoring potential	Absent	Present
	4	Affecting protected groundwater quality	Yes	No
Essential	5	Seismicity	High	Moderate and less
	6	Faulting and fracturing intensity	Extensive	Limited to moderate
	7	Hydrogeology	Short flow systems, or compaction flow; Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow
Desirable	8	Depth	< 750-800 m	>800 m
	9	Located within fold belts	Yes	No
	10	Adverse diagenesis[+]	Significant	Low to moderate
	11	Geothermal regime	Gradients ≥ 35 ºC/km and/or high surface temperature	Gradients < 35 ºC/km and low surface temperature
	12	Temperature	< 35 ºC	≥ 35 ºC
	13	Pressure	< 7.5 MPa	≥ 7.5 MPa
	14	Thickness	< 20 m	≥ 20 m
	15	Porosity	< 10%	≥ 10%
	16	Permeability	< 20 mD	≥ 20 mD
	17	Caprock thickness	< 10 m	≥ 10 m
	18	Well density	High	Low to moderate

Sites selected for CO_2 storage should be properly characterised. Site characterisation is a continuous and iterative process that starts usually with existing data, particularly at the basin and/or regional scale, and proceeds with the acquisition of new data and information during all the stages of a CCS project relating to the site, namely : selection, evaluation, permitting, design and construction, operation, closure and post-closure. However, the major effort and expenditure of resources occur in the early stages of site selection and permitting. The initial characterisation will be subsequently updated with data and information produced by new well drilling and from monitoring programmes. Sites should be characterised in terms of geology, rock properties, hydrogeology and geothermics, fault and fracture characteristics - if present, in-situ conditions, composition and phase behaviour of the native fluids and the injected CO_2 stream, reservoir history in the case of hydrocarbon reservoirs, history of wells and their condition, and land features. Performance assessment is an integral part of site characterisation and is based on numerical modelling of multi-phase, non-isothermal, reactive flow that takes into account hydrodynamic, thermal, geochemical, geomechanical and geophysical effects of CO_2 injection and storage under various scenarios, taking into account also the uncertainties introduced by data availability, distributions, resolution, accuracy and quality, and also the necessary assumptions, simplifications and resolution of the modelling process.

Proper criteria for site selection and proper site characterisation should be part of any process for site qualification and permitting, and this report attempts to review and synthesise the knowledge and experience to date in regard to criteria for site selection. However, the information presented here, particularly as summarised in tables, should not be used in isolation as a general recipe for project evaluation or site comparison and selection. Local conditions should be taken into account and experienced experts should apply this information to actual site selection and qualification processes. The information presented in this report can serve as guidance only and should be tailored to specific conditions and needs.

The report is organized as follows. After the introduction, previous work on the subject is reviewed by presenting the main findings and/or recommendations (Chapters 2, 3 and 4). Additional specific considerations are discussed in Chapter 5. Two analogue operations relevant to the subject, natural gas storage and acid gas disposal, are reviewed in Chapter 6. The synthesis of all previous material and authors' opinions and recommendations, including explanations, on the subject of criteria for site selection and characterisation for CO_2 storage in deep saline aquifers and hydrocarbon reservoirs is presented in Chapter 7. Section 7.5 at the end of Chapter 7 presents in tabular form suggested threshold values for various criteria to be used in the qualification of prospective CO_2 storage sites from a safety, security and environmental acceptability point of view. Chapter 8 represents a short summary of Chapter 7 to be used as a quick reference guide.

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1. INTRODUCTION

The CO_2 emissions gap created by the forecasted increase in population, global standards of living and carbon intensity of the energy system on one side, and the increase in energy efficiency and conservation on the other side, can be partially covered by artificially increasing the capacity and uptake rate of CO_2 sinks. This involves either the diffuse removal of CO_2 from the atmosphere, after its release, through terrestrial and marine photosynthesis, with subsequent storage of the carbon-rich biomass (natural sinks), or the capture of CO_2 emissions prior to their potential release and their storage in deep oceans or geological media, or through surface mineral carbonation (known collectively as carbon capture and storage, or CCS) (IPCC, 2005). Surface mineral carbonation is not, for the time being, a viable option (economic or otherwise) for reducing atmospheric CO_2 emissions, while ocean CO_2 storage would result in a measurable change in ocean chemistry, with corresponding consequences for marine life (IPCC, 2005), notwithstanding issues of ocean circulation, storage efficiency, technology, cost, technical feasibility, international limitations regarding dumping at sea, and strong public opposition. On the other hand, geological storage of CO_2 currently represents the best and likely only short-to-medium term option for significantly enhancing CO_2 sinks. The technology exists today and can be applied immediately, being based on the experience to date from the oil and gas industry and from the deep disposal of liquid wastes (IPCC, 2005). Forecasts are that CO_2 storage in geological media will play an important role in reducing anthropogenic CO_2 emissions into the atmosphere in the first part of this century and beyond (IEA, 2004, 2006, 2008). The storage of CO_2 in geological media shares many similar features with oil and gas accumulations in hydrocarbon reservoirs and methane in coal beds; whilst the capture, transportation, injection and monitoring of CO_2 in the subsurface has been already practised for a few decades in enhanced oil recovery, acid gas disposal and natural gas storage (IPCC, 2005). Lately the meaning of the term CCS has narrowed down to cover only CO_2 capture, transportation and geological storage, and it will be used in this report only with this connotation.

Three storage media have been identified that have the potential to store CO_2: coal beds, oil and gas reservoirs, and deep saline aquifers (IEA, 2004; IPCC, 2005). Of these, CO_2 storage in uneconomic coal beds has been identified as: 1) being an immature technology, and b) having the smallest storage potential (IPCC, 2005), notwithstanding that there are no clear and accepted definitions of uneconomic coal beds. Globally, oil reservoirs possess, at depletion, smaller storage capacity than gas reservoirs or deep saline aquifers; however they present the advantage that, if suitable for CO_2-EOR (enhanced oil recovery), their storage capacity will increase and the cost of storage will decrease by producing additional oil. Gas reservoirs have significant CO_2 storage capacity because of their very large recovery factor (between 80 and 90%) and large size. However, it is believed that, globally, deep saline aquifers possess the largest CO_2 storage capacity and have the advantage that they are present in regions where there are no oil and gas reservoirs or where oil and gas reservoirs are still in production and are not yet available for CO_2 storage. For these reasons deep saline aquifers and hydrocarbon reservoirs offer the best opportunity for near-term large-scale implementation of CO_2 capture and storage. However, there is a significant difference between hydrocarbon reservoirs and deep saline aquifers, namely in the amount, resolution and confidence in existing data for site selection and characterisation, as indicated also in the IPCC report (2005). Hydrocarbon reservoirs have more and better data as a result of exploration and production, than deep saline aquifers, and this difference will impact the characterisation, approaches and costs of site selection and qualification.

Along the various elements of the CCS chain, the stage of site selection and characterisation is of critical importance because any storage site must demonstrate that it satisfies three fundamental requirements: 1) capacity to store the intended volume of CO_2 over the lifetime of the operation, 2) injectivity, to accept/take CO_2 at the rate that it is supplied from the emitter(s), and 3) containment, to ensure that CO_2 won't migrate and/or leak out of the storage unit. As identified in the IPCC Special Report on CCS (IPCC, 2005), for sites that are properly selected, designed and operated, the expectation is that there will be no leakage or that, if there is leakage, it will be below an acceptable level from both the point of view of atmospheric greenhouse gas emissions and from a health, safety and environmental (HSE) point of view. Regulatory agencies, which will permit CO_2 storage in geological media, and the public, which has to accept and support CCS as a climate-change mitigation strategy, both need to be convinced that proposed CO_2 storage sites meet these requirements, and this can be achieved only through a proper and transparent process of site selection and characterisation. Thus, site screening is the process by which the potential for CO_2 storage in a selected region, defined either by geology (e.g., sedimentary basin), jurisdiction (e.g., country, province or state) or any other criteria, is evaluated by assessing and comparing possible candidate storage sites. The aim is to identify the sites that meet CO_2 storage requirements. Ranking of these sites according to various criteria allows identification of the best sites in respect to that set of criteria, enabling investment decisions into further site characterisation. The final selection of an individual CO_2 storage site will likely be the result of a process that will include other criteria besides those discussed in this report.

Site characterisation is basically the process by which data, information and knowledge are acquired and processed to provide satisfactory answers to the question: does the site meet the site selection criteria? A more detailed definition, as provided by Cook (2006), is: "the collection, analysis and interpretation of subsurface, surface and atmospheric data (geoscientific, spatial, engineering, social, economic, environmental) and application of that knowledge to judge, with a degree of confidence, if an identified site will geologically store a specific amount of CO_2 for a defined period of time and meet all required health, safety, environmental and regulatory standards". However, due to the large variability in geological environments, and investigative methods and techniques to characterise a site, more specific questions need to be answered regarding site selection and characterisation. Furthermore, site characterisation is an iterative process because some basic characteristics of the site need to be known and compared against screening criteria and against other potential storage sites. Initial site characterisation is usually based on existing data and knowledge. If information is insufficient, some additional data may be collected, but usually limited effort and resources are spent in the initial stages of site characterisation for preliminary selection. The above definition of site characterisation is incomplete in that it covers only the site selection stage of CCS operations. After selection, sites need to be characterised further for permitting, design, construction and operational purposes, including monitoring. In the case of site characterisation for these purposes, additional data are collected, requiring well drilling, and/or laboratory analyses and/or running of geophysical surveys.

Sites for CO_2 storage vary around the globe in their quality and characteristics, and there will be instances where sites of poorer quality will be used for storage just because no other sites are available or because potentially better sites are too far away and/or much more costly to develop and operate. However, use of poorer-quality storage sites means that additional measures may have to be taken, particularly in regard to ensuring their safety, in order to obtain regulatory approval. For this reason it is important to be able to judge the quality of a storage site based on an established and accepted set of criteria. If the characteristics of a site fall outside of the recommended criteria it may mean that the safety and security of the storage site will have to be demonstrated and monitored more rigorously.

Various basin-scale criteria have been developed in the past for assessing the suitability of a sedimentary basin or parts thereof for CO_2 storage (e.g., Bachu, 2000, 2001, 2002, 2003). The implication, by default, is that these broad criteria will be applicable to the specific storage media contained therein. Based on the experience at Sleipner in the North Sea, and on site selection and characterisation at four other places in Europe, mostly offshore, the CO2STORE project recently produced a report on “Best Practice for the Storage of CO_2 in Saline Aquifers” (Chadwick et al., 2008). Also in 2008, the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) in Australia published a report on “Storage Capacity Estimation, Site Selection and Characterisation for CO_2 Storage Projects” (Kaldi and Gibson-Poole, 2008). The criteria presented in the CO2CRC report have then been cited in a report to the International Energy Agency greenhouse Gas R&D Programme (IEAGHG) by CO2CRC (Michael et al., 2008). However, neither the European nor the Australian experience is representative for the different geological and operating environments encountered in onshore sedimentary basins like those in North America between the Appalachian and Rocky Mountains which have been in production for more than a century and are penetrated by hundreds of thousands of wells. Also, no specific criteria have been developed for the selection and characterisation of depleted oil and gas reservoirs for CO_2 storage, although the criteria for determining if an oil reservoir is suitable for CO_2-EOR have been reviewed and applied to western Canada (Shaw and Bachu, 2002). Geomechanical factors affecting CO_2 storage in oil and gas reservoirs have also been examined (Hawkes et al., 2005).

Currently there is very little experience worldwide with the selection and characterisation of sites for the injection/disposal of buoyant fluids. There is a wealth of information and experience, both regulatory and in the industry, regarding the disposal of aqueous fluid wastes, but these are at least as dense (heavy) as the water in the deep aquifers into which they are injected, and no issues of buoyancy-driven flow and possibly leakage arise. However, from a safety point of view, mainly leakage, there is significant experience in the oil and gas industry in regard to cross-formational flow of fluids (oil, gas or brine) and with gas migration and seepage, particularly along wells. The only full analogues to CO_2 storage in deep saline aquifers and depleted hydrocarbon reservoirs are natural gas storage and acid gas disposal operations. In the case of the former, the operator has a vested interest in avoiding leakage because this means a loss of capital/revenue. In the case of underground disposal of CO_2 and H_2S (acid gas) separated at gas plants from produced sour gas before the natural gas is sent to markets, the requirements for site selection and characterisation are somewhat more stringent given the permanency of disposal and the toxic nature of the injected H_2S component in the injected acid gas. (In this respect the operations at Sleipner in the North Sea and at In Salah in Algeria are basically acid gas disposal operations because

CO_2 in the produced natural gas is removed to meet pipeline and market specifications, and then it is injected deep into a confined aquifer, similarly to many acid gas disposal operations in North America.) However, the scale of the existing acid gas disposal operations is one to three orders of magnitude smaller than the scale of the CO_2 storage operations needed to achieve significant reductions in atmospheric emissions of anthropogenic CO_2. Nevertheless, since the first acid gas disposal operation in the world was implemented in 1990 near Edmonton, Alberta, Canada, regulatory agencies in western Canada (Alberta and British Columbia) have acquired a wealth of data, information and knowledge about nearly 50 such disposal operations which are currently active, of which close to 60% inject acid gas into deep saline aquifers and the rest inject it into depleted hydrocarbon reservoirs. This knowledge can be used for the benefit of future CO_2 storage operations.

This report represents an attempt to review in greater detail and advance the status of knowledge on criteria for site selection and characterisation developed since the publication of the IPCC Special Report on CO_2 Capture and Storage (IPCC, 2005), which summarised and reviewed the status of knowledge up to and including the first half of 2005. The review, analysis and synthesis are focused only on deep saline aquifers and hydrocarbon reservoirs. Coal beds are not considered in this report due to their limited capacity and immature stage of development as a potential CO_2 storage medium. Since the publication of the IPCC Special Report on CO_2 Capture and Storage (IPCC, 2005), the only comprehensive publications in regard to site selection and characterisation have been those by Kaldi and Gibson-Poole (2008) and Chadwick et al. (2008) reporting on the Australian and European experience, respectively. Also in 2008, the June issue of Environmental Geology published a series of papers selected from papers presented at the International Symposium on Site Characterisation for CO_2 Geological Storage (CO2SC) held in March 2006 at the Lawrence Berkeley National Laboratory in Berkeley, CA, USA. Various relevant papers have been published also in the International Journal of Greenhouse Gas Control. This report builds on these and other relevant publications and on authors' personal experience and knowledge.

The CO2CRC and EU reports are reviewed first, followed by journal publications and conference proceedings. Hydrocarbon reservoirs are treated separately because of certain specific aspects and because little literature is available specifically on the subject of CO_2 storage in oil and gas reservoirs. The general literature on oil and gas reservoirs is extremely rich and could provide much learning for CO_2 storage; however this is beyond the scope of this study. Specific geophysical, geochemical and geomechanical considerations are then presented. Analogue operations, such as natural gas storage and the Canadian experience in acid gas disposal (in both aquifers and oil and gas reservoirs) are reviewed at the end. The review of previous work focuses only on papers, proceedings and reports published previously. The Synthesis chapter presents the views and recommendations of the authors based on the reviewed literature and on their own experience. The Summary chapter at the end of this report attempts to summarise the Synthesis chapter in a short form to be used by decision and policy makers as a reference guide.

2. REVIEW REPORTS

Fundamentally, all site selection criteria reduce to ensuring prior to application, permitting and construction that a site meets the following three criteria:

1) Capacity, to accept the intended volume of CO_2 during the period of active injection.
2) Injectivity, to accept the CO_2 at the rate at which it is supplied from the emitter(s).
3) Confinement, to ensure that the injected and stored CO_2 is contained within the storage unit for the desired period of time, currently estimated to be at least in the order of centuries to millennia.

Besides these three fundamental criteria for site selection, there are also other site selection criteria that can be grouped into three broad categories: economic, legal-regulatory and societal. Existence or cost of infrastructure would fall into the first category, existence or absence of particular legislation and/or regulations that allow or interdict CO_2 storage would fall into the second category, and public attitude and support (or opposition) would fall into the third category.

In this chapter, the IPCC findings (IPCC, 2005) will be briefly summarized as a starting point, then the CO2CRC and EU reports will be reviewed.

2.1 IPCC Special Report on CCS

The IPCC Special Report on CO_2 Capture and Storage (IPCC, 2005) reviewed the status of knowledge up to and including 2005 publications on storage mechanisms and security, site selection criteria and the worldwide distribution of storage formations, site characterisation and performance prediction, injection and monitoring technology, risk assessment and remediation, legal issues associated with CO_2 storage, and costs. This review will be briefly summarized in the following sections. Because the IPCC review had to be brief, it may be necessary in some instances to go back to the original publications in order to provide appropriate detail. The site selection criteria reviewed in the IPCC Special Report on CCS are general, applying to all sites regardless of their specific nature, and also specific to oil and gas reservoirs, deep saline aquifers, and coal seams.

2.1.1 Site Selection

All storage sites need to have sufficient porosity and thickness (for capacity) and permeability (for injectivity), and to be confined by at least one, preferably more, impervious or low permeability overlying stratum that will impede upward CO_2 movement (leakage). In addition, other mineral, energy and groundwater resources need to be protected against possible contamination by CO_2. Ideally sites should be located in a stable geological environment thus avoiding potential compromising of the site in the future, but it is recognized that the fundamental storage criteria may be met also by sites in a less stable tectonic environment such as in California, Japan or around the Mediterranean Sea (e.g., Italy and Greece). Additional site characteristics, such as hydrogeological and geothermal regimes, basin maturity, surface infrastructure and number of penetrating wells, are important in defining the quality of a storage site, but do not necessarily have a site-rejection character. Thus, these characteristics impart a gradational quality to a storage site. Poor storage potential has been identified for sedimentary basins that (1) are thin (less than 1000 m), (2) have poor reservoir-seal relationships, (3) are highly faulted and fractured, (4) are within fold belts, (5) have strongly discordant sequences, (6) have undergone significant diagenesis, or (7) have overpressured reservoirs (IPCC, 2005). Most of the characteristics described previously for sedimentary basins suitable for CO_2 storage, and by implication and extension to sites within these basins, apply to confinement criteria.

It has been recognized that hydrocarbon reservoirs are prime candidates for CO_2 storage because (1) their confining characteristics, integrity and safety have been demonstrated by the trapping and accumulation of oil and/or gas, (2) their characteristics are well known as a result of exploration, production and modelling, and (3) infrastructure is generally in place (e.g., roads, right of way, wells and pipelines) (IPCC, 2005). The storage capacity of depleted hydrocarbon reservoirs may be limited by the need to avoid exceeding pressures that may jeopardize caprock integrity, which may be weakened as a result of production (depletion) and subsequent injection. Use of CO_2 in enhanced oil recovery (EOR) offers economic gains that will partially or totally offset the cost of CO_2 storage. Additional criteria that are considered when screening for CO_2 storage in CO_2-EOR operations are: (1) depth greater than 600 m, (2) oil gravity between 12 and 25 API for immiscible EOR, (3) oil gravity between 25 and 48 API for miscible EOR, (4) pressure higher than the minimum miscibility pressure (MMP) for miscible EOR, (5) reservoirs less than 20 m in thickness, (6) absence of aquifer support, (7) low vertical permeability to achieve better reservoir sweep, (8) reservoir homogeneity, although it has been recognized that in some cases heterogeneity may actually improve the reservoir sweep (IPCC, 2005). In regard to CO_2 enhanced gas recovery (EGR), it was recognized as a possibility for storing CO_2 while producing additional gas, but it has not been implemented anywhere in the world at the time of report writing, hence there was no experience with EGR[1]; some previous authors expressed doubts about its potential because of possible lower recovery factors than straight gas production. No additional specific site selection criteria were identified in the IPCC Special Report on CCS for CO_2 storage in deep saline aquifers.

The authors of the chapter on CO_2 geological storage in the IPCC Special Report on CCS have recognized that impurities in the injection stream would affect CO_2 storage by: (1) taking space that otherwise would have been taken by CO_2; (2) affecting the compressibility and mobility of the injected gas; (3) affecting gas solubility and mineral reactions with formation fluids and rocks; and (4) affecting miscibility in the case of CO_2 EOR. In addition, depending on the impurity and its toxicity or environmental effects (e.g., H_2S versus N_2), surface facilities and safety measures will be affected. However, the IPCC Special Report on CCS (IPCC, 2005) did not identify any site selection criteria that are specific to the type and/or amount of impurities, nor any modifications in the site selection criteria described previously.

Finally, matching of CO_2 sources with potential sinks has been identified as a criterion for site selection, since potential sinks that are too far from CO_2 sources may stranded and will not likely be utilized due to the high cost of transportation. Among the criteria

[1] Subsequent to the time of writing the IPCC report (2005), Gas de France is re-injecting CO_2 into a mostly depleted natural gas reservoir offshore Netherlands (K12-B) with apparent success in terms of increasing natural gas recovery.

that affect site selection in the source-sink matching (SSM) process are: volume, purity and rate of the CO_2 stream (since these affect CO_2 transport, not just injectivity and capacity), proximity, diversity of potential sinks, injection and production strategies in the case of CO_2 enhanced hydrocarbon recovery, right of access and population centres, and costs and economics. It is recognized that once a potential sink has been identified on the basis of geological and engineering criteria, other legal, regulatory, economic, safety and environmental criteria may affect the final choice of a CO_2 sink.

2.1.2 Site Characterisation

Once a site has been selected, a more detailed characterisation should follow, combined with performance predictions. Site characterisation both predates and follows site selection. Possible sites should be sufficiently characterised initially to be able to judge them on the basis of site selection criteria, and, once selected, further characterisation is needed to demonstrate site performance. Site characterisation uses geological, geophysical, hydrogeological, geochemical and geomechanical data of the storage unit, the sealing caprock, and all the sedimentary succession above. Performance predictions are based on numerical simulations of injection and of the various processes that take place in the storage unit. The performance modelling also relies on data used for site selection, but needs additional data and of increased resolution and detail. Sites need to be characterised in terms of their geology; pressure, temperature, porosity and permeability distributions; rock mineralogy and chemistry of formation waters; geomechanics (rock properties and stresses); faults, fractures and wells (i.e., possible leakage pathways); caprock integrity (geomechanical, geochemical and displacement effects). Effects of fluid replacement (e.g. CO_2 for brine) on the rock matrix, and subsequent changes in petrophysical properties and geophysical parameters, should also be assessed at this stage. This site characterisation, directly linked with site selection and permitting, usually covers the storage unit and the confining caprock.

Another category of site characterisation activities consists of characterisation of risk at the storage site, and this characterisation usually focuses on the overlying strata and their structure and geology, other resources, shallow groundwater, vegetation, animal life and population, marine (if offshore) and atmospheric conditions, etc.

Finally, additional site characterisation may be performed for capturing the baseline conditions at the site prior to the start of CO_2 injection on which basis a monitoring, measurement and verification (MMV) program can be designed and implemented. However, the objective of this characterisation is monitoring and verification, not site selection (i.e., this characterisation occurs generally after the site has been selected).

2.2 CO2CRC Report and Previous Relevant Work

2.2.1 Site Selection

In a series of papers (Bachu and Gunter, 1999; Bachu, 2000, 2001, 2002, 2003), Bachu successively introduced and expanded on 15 criteria for assessing and ranking sedimentary basins in terms of their suitability for CO_2 storage that can be broadly divided into the following categories:

1) basin characteristics (size and depth);
2) tectonic and geological, regarding tectonic setting and basin geology;
3) hydrogeological and geothermal; regarding pressure, flow and geothermal regimes;

4) basin resources and maturity, i.e., the presence or absence of various media suitable for CO_2 storage (oil and gas reservoirs, coal beds, salt domes and/or beds) and the degree of exploration and production associated with hydrocarbon resources;
5) CO_2 sources, accessibility and infrastructure, including climatic conditions;
6) economics, political and societal factors.

Between 3 and 5 classes of qualifiers were devised for each criterion, with each class indicating the level of suitability within the respective criterion (increasing in numerical order from the least to the most suitable) (Bachu, 2003). The assessment criteria and classes introduced by Bachu (2003) are reproduced here (Table 1) because they have been used in various applications and also used as a starting point or example by others in subsequent work.

	Criterion	**Classes**				
		1	2	3	4	5
1	Tectonic setting	Convergent oceanic	Convergent intramontane	Divergent continental shelf	Divergent foredeep	Divergent cratonic
2	Size	Small	Medium	Large	Giant	
3	Depth	Shallow (<1500 m)	Intermediate (1500-3500 m)	Deep (>3500 m)		
4	Geology	Extensively faulted and fractured	Moderately faulted and fractured	Limited faulting and fracturing, extensive caprock		
5	Hydrogeology	Shallow, short flow systems, or compaction flow	Intermediate flow systems	Regional, long-range flow systems; topography or erosional flow		
6	Geothermal	Warm basin	Moderate	Cold basin		
7	Hydrocarbon resources	None	Small	Medium	Large	Giant
8	Maturity	Unexplored	Exploration	Developing	Mature	Over mature
9	Coal and CBM	None	Deep (>800 m)	Shallow (200-800 m)		
10	Salt beds, domes	None	Domes	Beds		
11	On/off shore	Deep offshore	Shallow offshore	Onshore		
12	Climate	Arctic	Sub-Arctic	Desert	Tropical	Temperate
13	Accessibility	Inaccessible	Difficult	Acceptable	Easy	
14	Infrastructure	None	Minor	Moderate	Extensive	
15	CO_2 sources	None	Few	Moderate	Major	

Table 1: Criteria for assessing sedimentary basins for CO_2 geological storage (from Bachu, 2003).

In addition to these basin-scale criteria, Bachu (2003) introduced local-scale selection criteria such as: caprock integrity including well penetration, in-situ conditions, fate of the injected CO_2, long-term site integrity and safety, and local public acceptance and even support. Many of these criteria apply also to individual site selection and have been included in the criteria listed in the IPCC Special Report (IPCC, 2005).

In order to rank sedimentary basins, parts thereof, or sites in terms of their suitability for CO_2 storage, Bachu (2003) introduced a normalized parametric optimization algorithm for mapping these characteristics into a numerical system, with weights attached according to their importance, which generates individual and cumulative scores that allow comparisons and ranking. The use of normalized parameters allows the mathematical manipulation of various variables, some quantitative and some qualitative, of different units. The weighting, based on expert opinion, allows flexible allocation of importance to the various screening criteria, depending on the particular circumstances and conditions of the case(s) being examined.

In 2008, the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) in Australia produced a report on methodologies for estimation of CO_2 storage capacity, and storage site selection and characterisation (Kaldi and Gibson-Poole, 2008). The methodology for CO_2 storage capacity estimation follows previous work by the Task Force on CO_2 Storage Capacity Estimation of the Carbon Sequestration Leadership Forum (CSLF) (CSLF, 2007; Bachu et al., 2007) and the US Department of Energy (USDOE, 2006, 2007). A CO_2 storage capacity pyramid similar to that developed by CSLF is proposed by CO2CRC whereby the theoretical, effective, practical and matched capacities introduced by CSLF (Figure 1 below) are re-labelled respectively: total pore volume, prospective storage capacity, contingent storage capacity and operational storage capacity.

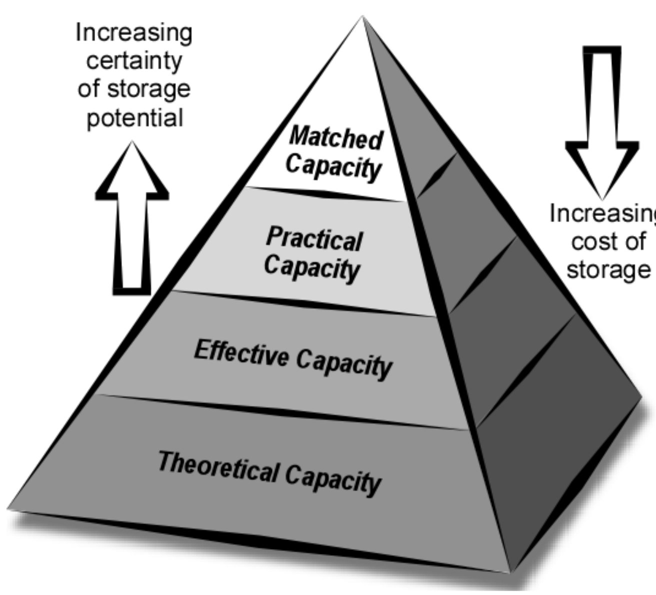

Figure 1. Techno-Economic Resource-Reserve pyramid for CO_2 storage capacity in geological media within a jurisdiction or geographic region (CSLF, 2007; Bachu et al., 2007). The pyramid shows the relationship between Theoretical, Effective, Practical and Matched capacities.

In regard to site selection and characterisation, CO2CRC builds on the previous work by Bachu (2003) and CSLF (CSLF, 2007; Bachu et al., 2007) to define identification, ranking and screening of sedimentary basins at the country and/or state scale, and then successively progressing to more and more detailed scales down to site selection and characterisation (Kaldi and Gibson-Poole, 2008). Furthermore, a correlation is drawn between the various levels of capacity estimates in the pyramid of storage capacity and levels of assessment: country/state, basin, site and deployment. The criteria for country/state scale assessment are reproduced in Table 2.

	Criterion	**Classes**				
		1	2	3	4	5
1	Seismicity (basin tectonic setting)	Very high (e.g., subduction zones)	High (e.g., syn-rift,.strike-slip)	Intermediate (e.g., foreland)	Low (e.g., passive margin)	Very low (e.g., cratonic)
2	Size	Very small (< 1000 km^2)	Small (1000 – 5000 km^2)	Medium (5000 – 25,000 km^2)	Large (25,000 – 50,000 km^2)	Very Large (>50,000 km^2)
3	Depth	Very shallow (<300 m)	Shallow (300-800 m)		Deep (>3500 m)	Intermediate (800-3500 m)
4	Faulting Intensity	Extensive		Moderate		Limited
5	Hydrogeology	Shallow, short flow systems, or compaction flow		Intermediate flow systems		Regional, long-range flow systems; topography or erosional flow
6	Geothermal	Warm basin (>40°C/km)		Moderate (30-40°C/km)		Cold basin (<30°C/km)
7	Reservoir-seal pairs	Poor		Intermediate		Excellent
8	Coal seams	None	Very Shallow (<300 m)		Deep (>800 m)	Shallow (300-800 m)
9	Coal rank	Anthracite	Lignite		Sub-bituminous	Bituminous
10	Evaporites	None		Domes		Beds
11	Hydrocarbon potential	None	Small	Medium	Large	Giant
12	Maturity	Unexplored	Exploration	Developing	Mature	Super mature
13	On/off shore	Deep offshore		Shallow offshore		Onshore
14	Climate	Arctic	Sub-Arctic	Desert	Tropical	Temperate
15	Accessibility	Inaccessible	Difficult		Acceptable	Easy
16	Infrastructure	None	Minor		Moderate	Extensive

Table 2: Criteria for assessing sedimentary basins for CO_2 geological storage at the country and/or state scale (from Kaldi and Gibson-Poole, 2008).

Comparison of tables 1 and 2 indicates that there are no significant differences between the criteria for basin-scale assessment in terms of suitability for CO_2 storage developed by Bachu (2003) and CO2CRC (Kaldi and Gibson-Poole, 2008). In some cases the criteria and classes are unchanged (e.g., Hydrocarbon potential, Maturity, On/off shore storage). In other cases the criteria and number of classes are the same, but the classes are spread out between 1 and 5 in CO2CRC's table instead of 1 to 3 or 1 to 4 as originally listed by Bachu (2003) (e.g., Geology or Faulting intensity, Hydrogeology, Geothermal, Evaporites, Climate, Accessibility, Infrastructure). Only in the following cases CO2CRC introduced some changes (Table 2), listed below:

1. In the "Tectonic setting" (Seismicity) category, the position of foreland and passive margin basins is reversed (classes 3 and 4);
2. The "Very small" class was added to the "Size" category;
3. The "Very shallow" class was added to the "Depth" category;
4. The "Very shallow" class was added to the "Coal seams" category;

Some numerical values were modified, refined or added by CO2CRC (Table 2) for basin size, depth, geothermal regime and coal seam depth. The only significant differences between Bachu (2003) and CO2CRC (Kaldi and Gibson-Poole, 2008) are that Bachu (2003) has a category regarding "CO_2 sources" (no. 15 in Table 1) which is absent from CO2CRC's list (Table 2) (although mentioned in the CO2CRC report), while CO2CRC has added two additional criteria: "Reservoir-seal pairs" which refers to geological barriers to upward CO_2 flow, and "Coal rank", which refers to the type and quality of coal for CO_2 storage in coal seams (no. 7 and 9 in Table 2, respectively). The category on CO_2 sources is important for source-sink matching. The absence of CO_2 sources within or nearby a sedimentary basin will significantly decrease its suitability for CO_2 storage in the near and medium terms. On the other hand, adding the two categories on reservoir-seal pairs and coal rank refines the criteria for assessing basin suitability for CO_2 storage.

Based on earlier work by Bradshaw et al. (2002), CO2CRC (Kaldi and Gibson-Poole, 2008) recommends identification of prospective sites within the selected basin(s) (basin-scale assessment) based on the following criteria:

- Site location and logistics: on/offshore, distance from CO_2 source(s), depth to top of storage unit, technological and economic feasibility;
- Storage capacity, based on pore volume, area, thickness and CO_2 density;
- Injectivity, based on permeability and thickness;
- Containment, based on stratigraphy and reservoir-seal pairs, seal capacity and thickness, and CO_2 migration distance;
- Existence of natural resources that need to be protected: petroleum system(s), coal, groundwater, national parks;
- Location of population centres.

CO2CRC proposes a ranking scheme (Table 3) based on these five fundamental factors (Kaldi and Gibson-Poole, 2008).

For depth, CO2CRC recommends that the minimum depth is based on CO_2 properties, i.e., CO_2 should be in dense supercritical phase (~800 m), and that the maximum depth is based on injectivity, i.e., when permeability is too low to allow viable injection rates (assumed to be at ~3500-4000 m depth). Sites can be qualitatively ranked and selected based on the above set of criteria. Generally, CO2CRC defines the selection of a suitable site for CO_2 storage as being based mainly on a geoscience evaluation at progressively more and more detailed scales. This process progressively reduces uncertainty at an increasing cost, time and resources, as already illustrated by CSLF (Figure 1; CSLF 2007; Bachu et al., 2007).

Criterion	**Meets Criterion**	**Considerations**
Storage capacity	Will meet the volume requirements of identified CO_2 sources	Temperature, pressure, area, pore volume
Injectivity potential	Reservoir conditions viable for injection	Porosity, permeability, thickness
Site logistics	Site is economically and technically viable	Distance from CO_2 source(s), sea depth for offshore storage, overpressure
Containment	Seal and trap will work for containing CO_2	Seal capacity and thickness, trap, faults
Existing natural resources	No viable natural resources at the site that may be compromised	Proven or potential petroleum system, groundwater, coal or other resource (e.g., National Park)

Table 3: Ranking criteria for deep saline aquifers and hydrocarbon reservoirs as prospective CO_2 storage sites (from Kaldi and Gibson-Poole, 2008).

2.2.2 Site Characterisation

Once a site is selected, CO2CRC proposes a detailed site characterisation that is based on (Kaldi and Gibson-Poole, 2008):

- Geosience: structure and geology, geometry, seal characteristics, hydrodynamics of natural water flow, geochemistry (rocks and fluids) and geomechanics;
- Engineering: injection rate, sweep efficiency, wells, long term CO_2 migration, coupled processes (fluid flow, reactive transport, geomechanical), trapping mechanisms (free phase, residual, dissolved and precipitated);
- Socio-economic aspects: capital and operating costs for compression, transport and injection, performance and risk assessment, and monitoring and verification.

Finally, after some discussion of the various elements of site characterisation, CO2CRC compiled a table of data needs (required and desirable) at the various levels of site selection and characterisation: country/state, basin and site (Table 4 below, adapted with slight modifications from Table 9 in Kaldi and Gibson-Poole, 2008).

Data needs		Country/state Scale	Basin Scale	Site Characterisation	Site Deployment
Maps	Regional geology	R	R	D	
	Detailed geology		D	R	R
	Structure		D	R	R
	Reservoir geometry		D	R	R
	Reservoir quality		D	R	R
	Fault	D	D	R	R
	Seismicity	D	D	R	R
	Water salinity	D	D	R	R

	Surface infrastructure	D	D	R	R
	Topography	D	D	R	R
Seismic	2D	D	R	R	R
	3D		D	R	R
Well logs	Gamma ray		D	R	R
	Porosity		D	R	R
	Sonic			R	R
	Density			R	R
	Image			R	R
Core analyses	Porosity	D	R	R	R
	Permeability	D	R	R	R
	Anisotropy			R	R
	Relative permeability			R	R
	Capillary pressure		D	R	R
	Mineralogy		D	R	R
	Rock strength		D	R	R
Hydraulic Tests	Repeat formation tests (RFT), drillstem tests (DST)		D	R	R
	Leak-off tests (LOT); formation integrity tests		D	R	R
Reservoir characterisation	Tectonic model	R	R	D	
	Sequence stratigraphy	D	D	R	R
	Biostratigraphy	D	D	R	R
	Regional stress regime	D	R	D	
	Analogues		D	R	R
	Fluid properties		D	R	R
	Production history		D	R	R
	Static model			R	R
	Dynamic model			R	R
Economics				R	R
Regulatory framework				R	R

D: desirable; R: required

Table 4: Summary of main data needs for reservoir characterisation (modified from Kaldi and Gibson-Poole, 2008).

The country/state and basin-scale assessments are generally based on existing data, while the site characterisation and site deployment scale assessments require collection of new data, which is expensive both in terms of acquisition, and processing and interpretation. This is the main reason why the cost of site characterisation increases as the assessment scale decreases and the resolution and certainty increase.

2.3 EU Best Practice Manual

Also in 2008, the European Union produced a Best Practice Manual for Storage of CO_2 in Saline Aquifers (Chadwick et al., 2008, based on a 2007 report by the same authors), building on the European experience gained between 1998 and 2006 through the SACS, SACS2 and CO2STORE projects. The SACS and SACS2 projects focused on offshore CO_2 storage at Sleipner in the North Sea, whereas CO2STORE widened its scope to a range of geological settings by expanding its coverage to offshore Mid-Norway, Kalundborg in Denmark (onshore/offshore), Schwarze Pumpe in Germany (onshore) and Valleys, offshore South Wales in UK. Site screening, ranking and selection, and site characterisation are respectively steps 2 and 3 in a recommended 7-stage template for site development from inception to closure. The authors recognize that the experience based on the three cases is relatively limited and that the Earth is an extremely variable natural system with site specific properties, such that the applicability of their findings and recommendations to other sites has to be assessed carefully.

2.3.1 Site Selection

The authors of the report compiled a table, reproduced below as Table 5, of positive (favourable) and cautionary (less favourable) qualitative indicators regarding reservoir and caprock properties to be used in the assessment of prospective CO_2 storage sites.

The efficacy of the top seal (caprock) is a prerequisite, and in the case of dipping aquifers, the nature of the lateral sealing features is also important. The authors recognize that small reservoirs with perfectly-sealed non-elastic boundaries have very little capacity since the only storage space available will be that generated by compression of aquifer water and rock. Significant storage is possible only where significant displacement of the native pore fluid can be achieved during the injection period. The effects of aquifer compartmentalization by faults also have to be taken into account. The authors correctly identify that mineral trapping will contribute very little in creating additional storage space during CO_2 injection, and hence they conclude that the estimation of storage capacity needs to consider only structural and stratigraphic trapping, residual saturation trapping, and dissolution, ***and*** the boundary constraints of the site (authors' emphasis). In addition, the authors rightfully point out the issue of availability of the storage site, which may be a significant issue in the case of oil and gas reservoirs although these are not considered in their review. Limiting events that may occur during injection may be: 1) unforeseen unacceptable rise in reservoir pressure approaching caprock capillary entry and/or fracturing pressure, and 2) migration of injected and/or displaced native fluids, including entrained substances, to parts of the geosphere and/or biosphere where they are not acceptable (oceans, atmosphere, potable water, etc.).

	Positive Indicators	**Cautionary Indicators**
Storage Capacity		
Total storage capacity	Total capacity estimated to be much larger than the total amount produced from the CO_2 source	Total capacity estimated to be similar to or less than the total amount produced from the CO_2 source
Reservoir Properties		
Depth	Between 1000 and 2500 m	< 800 m or > 2500 m
Reservoir thickness	> 50 m	< 20 m
Porosity	> 20%	< 10%
Permeability	> 300 mD	< 10-100 mD
Salinity	> 100,000 mg/l (ppm)	< 30,000 mg/l (ppm)
Caprock Properties		
Lateral continuity	Unfaulted	Lateral variations, faulted
Thickness	> 100 m	< 20 m
Capillary entry pressure	Much greater than buoyancy force of maximum predicted height of CO_2 column	Similar to the buoyancy force of maximum predicted height of CO_2 column

Table 5: Key geological indicators for storage site suitability (from Chadwick et al., 2008)

The reason provided for recommending a thick storage aquifer is to minimize the lateral spread, hence the areal footprint of the CO_2 plume. The authors also discuss the difficulties encountered in estimating/calculating the storage capacity of a prospective site because of the lack of data, poor data resolution, difficulty in assessing the role and share of the different storage mechanisms, etc. (see also Bradshaw et al., 2007, Bachu et al., 2007), and recognize in particular the important role and effects of pressure and geothermal gradients, and of impurities in the CO_2 stream in regard to storage efficacy. Finally, the authors point out that refined estimates of storage capacity, including simulation of various injection strategies, will be carried out only after a site has been already selected and likely additional data collected. In conclusion, it seems that estimating the storage capacity of a prospective site brings in the greatest uncertainty in regard to site characteristics and this may considerably affect site selection. Uncertainty assessment is thus critical in preliminary site characterisation and selection.

In the case of the five sites examined in the SACS and CO2STORE projects, various screening/selection criteria were used, such as size (capacity), injectivity, depth, structural enclosure, aquifer thickness, porosity, caprock quality, distance from the CO_2 source, potential conflict with other industries (mainly hydrocarbon production) and land use, right of access and population density (for onshore sites). It is worth noting here that all five storage sites described/analysed in the report (Chadwick et al., 2008) are in high-porosity sandstone aquifers (none of them is in carbonate rocks), and that possible storage in coal seams was rejected in the case of the Valleys site because of coal's low permeability and possible use for underground coal gasification in the future.

Flow simulations were used in the case of the three prospective Mid-Norway sites as a site screening tool, but the authors recognized that the simulations:

- are resource and time intensive, which may not always be available;
- are unnecessary when other screening criteria may differentiate between various prospective storage sites;
- may not always be used;
- are useful when lack of robust geological control leads to the need for developing a set of flow scenarios to examine the effects of geological uncertainty, as in the case of the Mid-Norway sites.

Flow simulations are particularly useful in identifying possible CO_2 migration and leakage pathways, and unacceptable pressure buildups that may limit the CO_2 injection rate, thus basically limiting/reducing the storage capacity.

Societal risks associated with CO_2 storage were also examined and used as a screening tool in relation to the five SACS and CO2STORE sites. These include health, safety and environmental (HSE) risks, economic risks, and risks related to public perception and trust. In regard to risks, the authors differentiate between onshore and offshore CO_2 storage, whereby onshore densely populated areas and environmentally sensitive/protected locations and parks should be avoided. Geomechanical risks associated with CO_2 storage should be considered, such as microseismicity (e.g., earthquakes of magnitudes 2.6 to 2.8 associated with natural gas storage were recorded in Germany, and up to 3.5 in The Netherlands), ground deformation which may damage buildings, and fault opening. Leakage of CO_2 into very shallow groundwater may affect building foundations. Active neotectonic and/or volcanic areas should be avoided.

Conflicts of land and underground use constitute another set of screening criteria for the selection of CO_2 storage sites. Basically any geological sites where other resources are present, with current or potential future economic value, should be avoided. This includes deep saline aquifer water that can be used as a source of base material for the chemical industry, for metal extraction (such as lead, zinc, lithium, etc.), or for geothermal energy. Sites that can be used for natural gas storage should also be avoided. In Europe, particularly Germany, brines and mineral waters used in health spas are protected, including whole protection zones around them. And, of course, hydrocarbon resources and licensed areas for exploration and production should be avoided. In regard to land use conflicts, urban, military, industrial and natural reserve areas should be avoided.

It is interesting to note that in final analysis no other options than the Utsira aquifer were available or feasible for CO_2 storage at Sleipner in the North Sea because of: 1) mismatch between CO_2 supply and demand rates for use in CO_2 EOR, and 2) potential contamination of gas reservoirs if CO_2 were to have been injected into gas reservoirs or aquifers in contact with gas reservoirs. At Kalundborg, other structures were not considered because of their potential use for natural gas storage, and because of monitoring difficulties in protected areas.

2.3.2 Site Characterisation

The authors of the Best Practice for Storage of CO_2 in Saline Aquifers (Chadwick et al., 2008) devote a significant portion of their report to site characterisation, based on the five sites but also on general knowledge. Although not explicitly listed as below, the aims of site characterisation are:

1) Refine storage capacity estimates, therefore confirming capacity requirements;
2) Predict the extent of the plume of injected CO_2 and the effects of CO_2 in free phase or dissolved in aquifer water in reservoir and seal rocks;
3) Ascertain that, as far as it can be discerned prior to injection, the site will perform effectively and safely;
4) Establish the baseline conditions for the design and implementation of a monitoring program;
5) Assess the risk associated with the storage operation and remediation strategies in case of site non-performance;
6) Complete the material necessary for application and permitting of the site.

To achieve the aims of site characterisation, the authors recommend the following:

- geological characterisation
- characterisation of reservoir rock properties
- characterisation of caprock properties
- predictive flow modelling
- geochemical assessment
- geomechanical assessment
- risk assessment
- design of monitoring programme
- evaluation of transportation options, including costs

In each case the authors discuss characterisation needs in a generic fashion and then provide examples of application from the five SACS and CO2STORE sites, although in quite a number of cases not much was specifically done at some or all the sites.

Geological Characterisation Geological characterisation is a pre-requisite for predictive fluid flow and geochemical simulations, risk assessment and design of a monitoring programme. The geological characterisation of the storage reservoir and its overburden aims to describe the geometry and lithology or the sedimentary succession comprising the storage aquifer, the immediately confining caprock, and the overburden above. Pressure and temperature distributions are essential in establishing the in-situ properties of CO_2 such as density and viscosity, which affect storage capacity, injectivity and sweep efficiency. Aquifer top structure, thickness and compartmentalisation by faults and/or depositional and/or diagenetic processes (i.e., lateral extent) are the minimum information that should be produced using geophysical and well data. In the case of laterally-constrained traps (structural, stratigraphic, depositional, diagenetic) migration is tightly constrained and of limited areal extent, which is beneficial, but the CO_2-water contact area is limited, thereby restricting CO_2 dissolution processes. In the case of an open aquifer (unconstrained laterally) the footprint of the plume will be large, requiring examination of possible leakage pathways and risks over a larger area, but, at the same time, the CO_2-water contact area will be correspondingly larger, accelerating CO_2 dissolution. Properly mapping the aquifer top is critical in the case of open aquifers because it is essential for establishing plume evolution and migration pathways along the top of the aquifer (since CO_2 is buoyancy driven).

Reservoir Properties These properties are derived from well logs, core and cuttings, and analysis of geophysical data. The main rock properties are aquifer porosity and permeability, facies type an distribution (which control in turn porosity and permeability), shale fraction and geometry of shale bodies, net-to-gross thickness, and mineralogy, which is critical for geochemical evaluations of the effects and fate of the injected CO_2.

Analysis of reservoir core should attempt to meet the needs of predictive flow, geochemical and geophysical modelling, and most likely will include:

- Sedimentology (optical and scanning electron microscopy)
- Mineralogy (X-ray diffraction, particle size analysis)
- Petrophysical properties (porosity, permeability, relative permeability)
- Mechanical and thermal properties
- Acoustic and elastic properties
- Pore water chemistry.

Porosity at Sleipner is in the 35-40% range, with permeability in the 1-3 Darcy range. At Kalundborg porosity is approximately 22%, and permeability is around 500 mD. Porosity in the 25-30% range and permeability in the 500-1000 mD range characterise Mid-Norway aquifers.

Caprock and Overburden Properties The evaluation of the caprock is key in establishing the long-term safety and integrity of the storage site. The presence of additional aquifers and sealing units is of considerable interest as it provides the possibility of early warnings in case of CO_2 leakage via seismically-imaged anomalies, changes in groundwater chemistry or even changes in microgravity values. Because caprock is comprised of distal sediments, it is usually quite homogeneous, allowing data extrapolation for large distances. The capillary entry pressure is critical because it is a limiting factor in regard to the height (thickness) of the underlying CO_2 plume that it can sustain. A laboratory programme is necessary to test the capillary entry and breakthrough pressure, mineralogy and geochemical composition of the caprock. Using the simplification of Lindeberg (1997), it is possible to evaluate the pressure difference Δp (kPa) for CO_2 to enter a water-wet shale pore of radius r (m):

$$\Delta p = \frac{2\sigma}{r} \qquad (1)$$

where σ (mN/m) is the interfacial tension between CO_2 and aquifer water (assumed to be around 20 mN/m.

Caprock core analysis should include:

- Sedimentology (optical and scanning electron microscopy)
- Mineralogy (X-ray diffraction, particle size analysis, cation exchange capacity – CEC, total organic carbon - TOC)
- Petrophysical properties (capillary entry pressure, permeability, porosity)
- Mechanical and thermal properties (Young modulus, Poisson's ratio, Mohr-Coulomb failure criterion, drained bulk modulus, time-dependent creep, dehydration)
- Acoustic and dynamic elastic properties
- Pore water chemistry

High porosity (in the 32-38% range) and low permeability (in the $4\text{-}15 \times 10^{-4}$ mD range) have been measured for the shale caprock at Sleipner, with capillary entry pressure in the 3-3.5 MPa range for gaseous CO_2 and ~1.7 MPa for supercritical CO_2.

Predictive Flow Modelling This is a key element in site characterisation because it helps in refining storage capacity estimates and provides a means to evaluate the pressure build-up and likely lateral spread of CO_2 during injection and in the future (plume footprint), which are essential in identifying possible leakage scenarios, design of a monitoring programme, and application and permitting. Key modelling parameters include:

- Reservoir characteristics: geometry, temperature, pressure, porosity, permeability, relative permeability and capillary pressure
- Caprock characteristics: thickness, permeability, capillary entry pressures
- Fluids: water salinity, CO_2 composition (type and amount of impurities), phase behaviour

Predictive flow modelling was carried out at Sleipner first using a modified black oil simulator to predict injectivity, identify the potential for induced overpressures, and find out if CO_2 may reach production wells. At Kalundborg, preliminary simulations were carried out using the commercial black-oil simulator Eclipse 100. At Schwarze Pumpe, two different flow simulations were carried out, one to model CO_2 behaviour during 40 years of injection, and another one to simulate long-term CO_2 migration and dissolution in the aquifer over a 1000 years period. At Valleys, two models were run using the SIMED reservoir flow simulator, one assuming a layer-cake succession consisting of 13 layers of alternating sheet sand and mudstone (this was considered the best-case scenario for ease of injection and storage capacity, and the worst for rapid migration), and the second one assuming a stochastic distribution of fluvial sandstone bodies within the aquifer, constrained to fit sandstone occurrences in the two available exploration wells.

A key observation is that predictive flow modelling at the site characterisation stage is likely to be rather rudimentary (or with a high degree of uncertainty) since key controlling parameters on the scale of the CO_2 plume become constrained only after monitoring data are acquired.

Geochemical Assessment Once dissolved in aquifer water, CO_2 forms a weak carbonic acid which may potentially attack and alter rocks, cements and well casings that come in contact with it. The assessment of geochemical impact is thus essential in assessing the safety of a CO_2 storage site. The degree of reactivity between CO_2, pore water and rock minerals will influence the long-term storage potential and safety of the reservoir. The authors of the EU Best Practice report recommend a four-step process in the geochemical assessment of a prospective storage site:

1) Geochemical characterisation of the aquifer, caprock and fracture filling material; characterisation of aquifer water and CO_2 injection stream; and in-situ pressure and temperature conditions;
2) Assessment of the initial geochemical status and acquisition of missing data;
3) Modelling of short-term geochemical reactions, based on the initial characterisation of the system and constrained by laboratory experiments used to calibrate the predictive geochemical modelling;
4) Long-term predictive modelling to assess the geochemical impact of the injected CO_2 over hundreds to thousands of years.

Modelling results are crucially dependent on which reactions are taken into account and their underpinning chemical data (i.e., the simulations cannot predict phases or reactions that are not included within the model database, or the results will be unreliable if data for the specific in-situ conditions are not available). The output will depend also on the chosen conceptual model. Because the supply of CO_2 in the aquifer is large as a result of injection and flow, the reactivity of dissolved CO_2 will act as an open system from a geochemical point of view. On the other hand, assuming that at a properly selected site

CO_2 will not penetrate the caprock (i.e., pressures will remain below the capillary entry pressure), chemical reactions in the caprock will be limited by the amount of available CO_2, which is controlled by diffusion (a very slow and the only process for CO_2 penetration into the caprock). Thus, CO_2 will likely be consumed entirely due to geochemical interactions in a geochemically closed system, further retarding the advancement of the diffusion front.

Geomechanical Assessment Little geomechanical assessment has been carried out at the SACS and CO2STORE projects, and the report authors devote only a few lines to the subject, particularly noting that geomechanical processes were unlikely to be an issue because of the relatively small pressure changes as a result of the high porosity and permeability at these sites.

Risk Assessment This type of characterisation is important for assessing the potential risks to the environment and life posed by the CO_2 storage project. Within the CO2STORE project, the Features, Events and Processes (FEP) and Scenario methodology was used for risk assessment, which consists of the following steps:

1) Establishment of the risk assessment criteria;
2) Description of the system by investigating and screening of all FEP (FEP analysis);
3) Scenario selection and analysis;
4) System model development;
5) Qualitative and quantitative consequence analysis.

In the evaluation of consequences versus environmental criteria, the latter must correspond to amounts or concentrations that are measurable, and acceptable levels and limit values must be determined. To determine site-specific criteria, it is necessary to know the baseline conditions, such as groundwater chemistry and ecosystem composition.

It is important to note that authorities are responsible for setting requirements, environmental criteria and limit values, but input from industry, the public and other stakeholders is important in the development and determination of acceptable levels and limits. The authors note also that currently there are no established risk criteria for CO_2 storage. More important, there is no agreement on the timeframe for risk assessment evaluation (e.g., time frames of 1000 years and 10,000 years have been both proposed and/or used). Furthermore, the authors point out that worst-case events and processes tend to be emphasized regardless of how (un)likely they are to actually occur. Thus "leakage scenarios tend to be highlighted and qualifying uncertainties and assumptions ignored". The authors of the Best Practice report recommend care in presenting risk assessment results to an external audience.

Design of Monitoring Programme The design of a monitoring programme is not strictly part of site characterisation per se, but builds strongly on site characteristics, and also affects site characterisation because of the need to plan and execute appropriate baseline surveys, prior to commencing CO_2 injection. The main objectives of a monitoring programme are:

- Imaging of the CO_2 in the reservoir (aquifer);
- Detection of CO_2 migration from the primary storage unit;
- Detection of CO_2 leakage through the overburden to shallower depths;
- Detection and/or measurement of CO_2 in groundwater, soil and/or atmosphere.

The monitoring programme should be designed to provide sufficient information to enable site remediation in case of unforeseen events, and also to enable a satisfactory site closure strategy.

A three-step process is recommended for the design of an effective site monitoring programme:

1) Review of all available proven and available monitoring technologies and techniques;
2) Selection of the particular techniques that will likely work at the site and are required to achieve the necessary objectives;
3) Design appropriate field deployment to achieve effective monitoring.

Selection of monitoring tools depends on site specific factors including surface conditions (e.g., onshore/offshore, rural/urban, desert/agricultural/forested land, flat/mountainous) and site characteristics (e.g., depth, type, intervening strata, etc.). Generally monitoring tools can be split broadly into "deep" focussed techniques and "shallow" techniques, but also into "imaging and remote sensing" techniques (e.g., seismic, radar satellite interferometry), and "sampling" techniques (e.g., water, air, soil).

The potential for monitoring may affect site selection as well. Since monitoring is likely a requirement for all CCS projects, then feasibility of the monitoring program might also contribute to a decision on a site, e.g., two sites may be identical in other criteria but if one has severe topography and heavy forest cover and the other is open pasture on flat ground, then the latter might be selected. This is similar to the transportation arguments below, and has been covered by Bachu (2003) in the criterion of accessibility, albeit not as explicitly. Furthermore, the ability to monitor may cover cases when surface conditions are similar, but subsurface conditions may make monitoring in one case more difficult and/or expensive (e.g., the presence of an overlying salt bed), in which case the other site will most likely be chosen.

Transportation This affects site selection, and by extension site characterisation, because the ways and means for accessing a site may play an important role in site selection. Transportation of up to 100,000 t CO_2/yr by trucks, railway and ship is found in the food and brewery industry. Pipelines are the best means for transporting large quantities of CO_2 onshore (currently, except for one pipeline operation in The Netherlands, onshore CO_2 pipelines are in operation only in North America). The only existing offshore pipeline is operated by Statoil Hydro at the Snøhvit site in the Norwegian Sea offshore northern Norway. Pipeline routing (including right of way), size and costs are the main factors affecting transportation. Within the CO2STORE project, only the Schwarze Pumpe site is on land and required application of routing analysis.

The current European CASTOR project has a goal of improving this Best Practice manual through the addition of four new CO_2 storage case studies from Europe: an abandoned oil reservoir (the Casablanca field in Spain), the Snøhvit aquifer in the North Sea where StatoilHydro started injection in the spring of 2008, and two depleted gas reservoirs, one offshore The Netherlands in the North Sea and another one in Austria.

In closing, CO2CRC has produced recently another review report on development issues in aquifer storage (Michael et al., 2008) in which, among other subjects, reviews both the earlier CO2CRC report on site selection and characterisation (Kaldi and

Gibson-Poole, 2008) and the EU best practice manual (Chadwick et al., 2008), and in regard to this subject, conclude with the following recommendations:

1) Add a broadly representative range of case studies to the Best Practice manual;
2) Expand the case study representation outside the narrow European focus;
3) Combine/synthesize Best Practice and Site Characterisation manuals produced in various parts of the world;
4) Summarise the Best Practice manual into a summary document of generic findings to serve as a reference guide that can be cross-referenced against regulatory requirements (i.e., the voluminous EU Best Practice Manual at 270 pages gives extensive examples from the 5 cases studies, but is difficult to use);
5) Develop Best Practice Manuals for other CO_2 storage options besides deep saline aquifers (e.g., depleted oil and gas reservoirs, CO_2-EOR and/or coal seams).

Since this second CO2CRC report (Michael et al., 2008) is a review report, no new material or knowledge has been generated in respect to the subject of site selection and characterisation, but its recommendations are very appropriate.

3. JOURNAL PUBLICATIONS AND CONFERENCE PROCEEDINGS

Various papers have been published since 2005 on the subject of site characterisation, mainly describing site-specific cases of application. The subject of site selection has not been addressed specifically in a generic way in any of these publications, but, nevertheless, elements of site selection are present in each case. In 2006 an International Symposium on Site Characterisation for CO_2 Geological Storage (CO2SC) was held at the Lawrence Berkeley National Laboratory in Berkeley, CA, USA, and selected papers from that symposium have been published in the June 2008 issue of Environmental Geology. Also in 2006, Environmental Geosciences, the journal of the Division of Environmental Geology (DEG) of the American Association of Petroleum Geologists (AAPG), published two special issues devoted to the subject of characterisation of sites for CO_2 storage. In 2007 the International Journal of Greenhouse Gas Control was launched, and a number of papers on site characterisation have been published in that journal since then. Finally, the 8th and 9th International Conferences on Greenhouse Gas Technologies (GHGT-8 and GHGT-9) were held in 2006 in Trondheim, Norway, and in 2008 in Washington, D.C., USA, respectively, with sessions devoted to site selection and characterisation. Relevant papers published in these journals and presented at these conferences are reviewed in the following sections.

3.1 Special Issue of Environmental Geology - CO2SC

Eleven selected papers from the International Symposium on Site Characterisation for CO_2 Geological Storage (CO2SC) were published in Environmental Geology. One of the papers deals with site selection and characterisation (Meyer et al., 2008), and another one deals specifically with screening and ranking of CO_2 storage sites on the basis of health, safety and environmental risk (Oldenburg, 2008). Three papers deal with the general characterisation of specific sites (Gibson-Poole at al., 2008; Doughty et al., 2008; Daley et al., 2008a) and the fourth deals with geomechanical characterisation of the Teapot Dome site in Wyoming (Chiaramonte et al., 2008). The latter paper will be discussed in Section 5.3 on Geomechanical Characterisation. One paper deals with identification of CO_2 EOR storage sites (Núñez-López et al., 2008); this paper will be discussed in Section 4.1. Finally, three papers deal with generic, non-site specific, issues that, nevertheless, affect site characterisation (Ambrose et al., 2008; Bachu and Bennion, 2008; and Tsang et al., 2008).

The paper by Meyer et al. (2008) describes the regional screening, site selection and characterisation of the Schweinrich structure in northeastern Germany that has been selected as the Schwarze Pumpe case study within the CO2STORE project, described in detail in the EU Best Practices Manual (Chadwick et al., 2008). The objective of the study was to identify an anticline capable of storing the CO_2 emitted by the Schwarze Pumpe coal-fired power plant. The conclusion of previous studies indicated that the most promising options for storing CO_2 in Germany are deep saline aquifers and depleted gas reservoirs (oil reservoirs and coal seams were assessed as lacking the necessary capacity). The investigation area covered about 40,000 km^2 in an area where the North German basin exceeds 1000 m in thickness. Inclusive criteria for site selection were: depth between 1000 and 4000 m, presence of extensive caprock of good quality, aquifer thickness greater than 20 m, water salinity higher than the salinity of drinking water (it is interesting to note, however, that in Germany all groundwater is protected, not just the potable water, and brines are considered a mineral resource), aquifer porosity greater than 20%, and the number of wells penetrating the caprock. Exclusive criteria, on which basis a prospective site would be excluded, were: insufficient storage capacity, tectonically strongly disturbed sites (safety issues), large transport distance (greater than 300 km), and conflict with other resources: hydrocarbon production and/or storage, geothermal energy, disposal of liquid wastes. Additional land-based selection criteria were: existence of surface infrastructure (right of access corridors), presence and kind of protected areas (either inaccessible, or where compensation will be due), natural scenery (where public acceptance is expected to be low), population density (relating to safety, cost and acceptance). Mineral, dissolution and residual gas trapping were not considered in storage capacity estimations as these processes contribute little during the injection period. Once selected, the Schweinrich structure was characterised based on geological and seismic data, log and core data, mineralogy and geochemistry applied both to the reservoir and caprock, and confining strata in the overlying sedimentary succession. Subsequent reservoir simulations have confirmed site capacity.

Oldenburg (2008) presents a screening and ranking framework based on the potential for and effects of leakage from a CO_2 storage site. In this framework, three main characteristics are evaluated: 1) the potential for primary containment of the CO_2 within the target unit; 2) the potential for secondary containment between the target unit and the shallow subsurface in case CO_2 containment in the primary storage unit fails; and 3) the potential for attenuation of the leaked CO_2 in the shallow subsurface and at surface, in case CO_2 leaks past secondary containment. For each characteristic, a series of representative attributes are considered that basically are a proxy for the desired characteristic. For example, thickness and lithology of the caprock above the storage aquifer or hydrocarbon reservoir are properties that characterise the primary seal in the assessment of the potential for primary containment. The attributes for the primary containment are caprock properties, depth and reservoir/aquifer characteristics, and they are basically defined by all the properties identified by previous authors such as permeability, porosity, etc. The attribute for secondary containment in case of leakage is basically the existence of secondary and multiple seals between the caprock of the storage reservoir/aquifer and the shallow subsurface, defined generally by the depth of the potable groundwater zone. These seals are characterised by their thickness, lithology, depth and lateral continuity. Attenuation potential is defined by the following four attributes: 1) groundwater hydrology, 2) surface characteristics, 3) existing wells, and 4) faults that reach the surface. These attributes are then defined by the following properties:

- For groundwater: flow system, pressure, salinity geochemistry;
- For surface: topography, wind, climate, land use, population, surface waters;
- For wells: depth and status (abandoned, suspended, producing or injecting);
- For faults: type (thrust, normal or stike-slip) and permeability

Numerical values, weighting factors and confidence indicators are assigned by the user to each property, allowing thus for assigning greater or lower importance to various properties on a case-by-case basis, and also indicating the level of confidence in the qualifiers. The attributes are then summed by the three characteristics and evaluated and ranked. This simple algorithm, similar to the one devised by Bachu (2003) for the ranking of sedimentary basins, allows for the ranking of sites that are being considered for CO_2 storage to identify the best one(s). The system enables application early on in the process of site selection and characterisation when only usually limited data are usually available, and is designed to avoid complex simulations, probabilistic evaluations and alike, for which there are no data available or are too complex and/or resource consuming.

The paper by Gibson-Poole et al. (2008) describes the site characterisation effort of the offshore rift Gippsland Basin, a premier hydrocarbon province in southeastern Australia, with focus on the Kingfish oil field that is anticipated that will be depleted sometimes after 2015. Site characterisation comprised geology, seismic interpretation, stratigraphic architecture, identification of faults and fractures and assessment of their stability, reservoir and seal units, rock mineralogy/petrology, porosity and permeability distributions, hydrogeological and geothermal regimes, and geochemistry of formation waters and rocks. Capillary pressure measurements to determine seal capacity (defined as the height of the CO_2 column that can be sustained before CO_2 overcomes seal's capillary entry pressure) and evaluation of the in-situ stress regime and of geomechanical rock properties were used to determine the maximum pressure that could be sustained before the mechanical integrity of the caprock is damaged (fracturing or fault-reactivation pressure) or CO_2 penetrates the caprock (displacement, or capillary entry pressure). Reservoir flow simulations and geochemical modelling were employed to assess the fate and effects of the injected CO_2 under various scenarios of CO_2 injection in a sandstone aquifer downdip from several oil and gas fields. These simulations have shown that the storage capacity is increased in the case of downdip injection as a result of residual gas trapping and CO_2 dissolution along the CO_2 migration pathway. Basically the authors have used the site characterisation approach described in the CO2CRC report (Kaldi and Gibson-Poole, 2008).

Two papers present the site characterisation program that was conducted at the Frio CO_2 injection pilot in Texas, United States. The first paper (Doughty et al., 2008) focuses on the geological characterisation, and the second (Daley et al., 2008a) presents the seismic monitoring program. Traditional characterisation techniques were initially used at the Frio site, such as geological mapping, geophysical imaging, well logging, core analyses (including capillary pressures), hydraulic well testing, and water sampling and analysis. In addition, formation compressibility was determined through interference well tests, and single-phase dispersivity was determined through aqueous-phase tracer tests. The hydraulic well tests helped in assessing the nature of aquifer boundaries and caprock. The authors make the point that additional, non-traditional techniques can be used after the start of CO_2 injection to improve site understanding and characterisation, and predictions regarding the fate of the injected CO_2. Such techniques include pressure transient analysis in injection and observation wells, two-phase tracer tests, and seismic monitoring (Daley et al., 2008a). Numerical modelling was valuable in integrating and interpreting the field observations. The information gleaned from CO_2 injection and monitoring helps in improving not only the site-specific model, but also characteristic-curve parameters, such as relative permeability, that then can be applied to other sites.

Ambrose et al. (2008) analyzed geological heterogeneity factors that control CO_2 storage capacity and permanence in clastic reservoirs based on beach and barrier-island reservoirs, and fluvial reservoirs from the Texas Gulf Coast in the United States. Structural heterogeneity factors include faults, folds and fracture intensity. Stratigraphic heterogeneity is controlled by depositional facies and sandbody continuity, which both affect permeability distributions, which in turn affects injectivity, migration pathways, and storage capacity and effectiveness (storage effectiveness is defined as the amount of

CO_2 stored per unit volume of rock mass). The paper makes the case for good understanding of aquifer or reservoir origin, depositional environment and internal architecture/heterogeneity.

Tsang et al. (2008) compare hydrogeological issues and technical approaches in deep disposal of liquid wastes and CO_2 storage in the following areas: injection well integrity and well abandonment, buoyancy and multi-phase flow effects, heterogeneity and channelling, multilayer isolation, caprock effectiveness and hydromechanics, site characterisation and monitoring, and effect of CO_2 storage on groundwater resources. The authors conclude that there are many similarities between the two processes, but also significant differences due mainly to the buoyant and non-wetting character of CO_2 combined with phase-change effects of CO_2 as it moves to shallower strata in case of leakage. An important observation is the multi-layer isolation effect of sites that are overlain by several pairs of reservoir/caprock, or aquifer/aquitard pairs. This effect has been identified and quantified in the case of simulation of leakage along wells from a deep storage aquifer by Nordbotten et al. (2004, 2005, 2008) who have shown that the amount of CO_2 that would leak to the shallow subsurface is greater in the case of a single aquifer/aquitard (reservoir/caprock) pair than in the case of multiple pairs even if the overall aquifer/aquitard thickness ratio is the same. This is because leaking CO_2 will flow and disperse into intervening aquifers, with less CO_2 continuing its upwards leakage along defects in the overlying aquitard (e.g., leaky wells). This phenomenon has been labelled "elevator effect" by Nordbotten et al. (2004) by analogy with the fact that in a tall building people taking the elevator will get off at various levels and only a few, if any, will reach the top floor, as opposed to an observation tower where all the people in the elevator will reach the top. This multilayer or "elevator" effect is synonymous in site characterisation with the potential for secondary containment introduced by Oldenburg (2008). Furthermore, a case of application to assess the potential for CO_2 leakage in the Wabamun Lake area in Alberta, Canada (Celia et al., 2008), has shown that the number of wells that penetrate a storage unit, in this case a deep aquifer, affects the amount of potentially leaking CO_2. In this case deeper aquifers are preferable for CO_2 storage to aquifers located at intermediate depth because of both the usually smaller number of wells that penetrate them and of the increased number of intervening aquifers between them and the shallow subsurface (multilayer or "elevator" effect). The reduced risk for CO_2 leakage should compensate for the increased cost of drilling and CO_2 compression to reach greater depths.

Finally, Bachu and Bennion (2008) show preliminary results of laboratory experiments for interfacial tension (IFT) between CO_2 and brine, and for relative permeability of various sandstone and carbonate rocks from the Alberta basin, Canada, to show that IFT is affected by in-situ conditions of pressure, temperature and water salinity, affecting in turn relative permeability, hence the displacement and trapping character of CO_2 in deep saline aquifers. Final results of this series of laboratory experiments are presented by Bennion and Bachu (2008) and Bachu and Bennion (2009). Basically IFT decreases with increasing pressure, and increases with increasing temperature and water salinity, with the latter two having a stronger effect than pressure at the depth of interest for CO_2 storage. In this regard, deeper aquifers that are at higher temperature and usually have higher water salinity than aquifers at intermediate depths are preferable for CO_2 storage because of increased IFT, hence lower relative permeability (Bennion and Bachu, 2006) and lower migration velocity of the CO_2 plume. From a characterisation point of view, the experimental work of Bennion and Bachu (2008) shows also that there is extensive variability in the displacement character (relative permeability) of deep consolidated sediments; therefore it is critical to measure it on core samples taken from the storage unit in order to make reasonably accurate predictions about the fate, trapping and migration of the injected CO_2.

3.2 Special Issues of Environmental Geosciences

Environmental Geosciences published in 2006 two special issues on "Characterisation of Demonstration Projects of CO_2 Geological Sequestration" (storage). Among the eight papers, the contribution by Lucier et al. (2006) deals with geomechanical aspects of CO_2 sequestration in a deep saline aquifer in the Ohio Valley in the United States (this paper will be reviewed in Section 5.3 on Geomechanical Characterisation), three papers deal with site characterisation for CO_2 storage in aquifers (Hovorka et al., 2006; Sayers et al., 2006; and Förster et al., 2006) and two deal with CO_2 storage in oil reservoirs (Pawar et al., 2006; and Friedmann and Stamp, 2006). The other two papers deal with storage capacity assessment in the UK sector of the North Sea, and with the field experiment of enhanced coalbed methane recovery in Poland.

Hovorka et al. (2006) describe the monitoring of 1600 t of CO_2 injected at the Frio site in Texas, U.S.A. The Frio site was selected after a national evaluation of deep saline aquifers in the United States, based on capacity (high) and multilayer containment (overlying pairs of aquifer-aquitard), proximity to large CO_2 sources along the Gulf Coast, and potential for stacked storage in oil reservoirs and aquifers in the sedimentary succession. Another site selection criterion, besides the ability to carry out the pilot experiment, was risk minimisation (damage to humans, animal life, property and/or ecosystems). The site was characterised using well logs, geology, core analyses, mineralogy and petrography, temperature and pressure data, analyses of formation fluids, but also hydraulic testing, cross-well seismic tomography, vertical seismic profiling, fluid sampling and analysis, tracers and modelling during the CO_2 injection phase (see paper by Doughty et al., 2008, discussed in the preceding section).

A site in the onshore Bowden basin in Queensland, Australia, was selected and evaluated using regional geology and basin resources (coal, oil and gas, water) (Sayers et al., 2006). The site was selected based on storage capacity, injectivity, containment (seal integrity), existing natural resources and site specifics, including depth (>800 m). Containment was assessed based on aquifer geometry and continuity and potential seal breaching through facies changes, erosion, faulting and well penetrations. Mercury injection capillary pressure (MICP) analyses have shown that the seal can sustain a CO_2 column in excess of 490 m. The site was characterised using commonly-accepted methods (petrography, core analyses, geology and facies interpretation, etc., including also numerical simulations to predict the fate of the injected CO_2).

Förster et al. (2006) present the pre-drilling characterisation of the Ketzin site in Germany part of the CO2SINK European project, which included geology and facies modelling, 2-D and 3-D seismic, stratigraphy and lithology, well logs, well tests and core analyses (porosity and permeability), mineralogy and petrography, hydrogeology, geophysical properties of CO_2-saturated rock, fluid analyses of shallow and deep waters, caprock mineralogy, and CO_2 flux at surface. Additional characterisation during the drilling phase (completed since then) of one injection and two observation wells included fluid chemistry, lithology, porosity, permeability, pressure and temperature, seismic velocity, electrical resistivity. Post-drilling but pre-injection characterisation includes baseline cross-hole seismic structure, cross-hole electrical resistivity (ERT), temperature profiling (DTS), vertical seismic profiling (VSP) and moving-source seismic profiling (MSP). The site was selected for testing onshore CO_2 geological storage in Europe based on favorable geological conditions (the anticline trap), industrial land and infrastructure, and the permit obtained by the operator from the state mining authority.

The West Pearl Queen oil reservoir in New Mexico, U.S.A., was selected for testing the injection of 2090 t CO_2 with the aim of assessing the science and technology necessary for safe and efficient storage of CO_2 in depleted oil reservoirs (Pawar et al., 2006). The project combined a small-scale CO_2 injection experiment with geophysical monitoring, numerical simulations and laboratory experiments. The reservoir was chosen for reasons having to do more with the ability to carry out the test rather than general site selection for storage of large amounts of CO_2. Phase I of the project consisted of pre-injection activities, including site characterisation. The reservoir was characterised based on existing data (well logs and core analyses), new field data (geophysical surveys such as dipole sonic logs, cross-well surveys) and laboratory data (mineralogical analyses, geochemical experiments combined with geochemical modelling, flow-through experiments for permeability and relative permeability). Outcrop data were used to better understand the reservoir. However, the response of the reservoir during the field experiment was significantly different than what was expected based on pre-injection characterisation and modelling, which was attributed to reservoir heterogeneity not captured by the characterisation data.

The Teapot Dome oil field in eastern Wyoming is the last federally owned and operated oil field in the United States, and this provided the opportunity for a detailed characterisation of the entire sedimentary succession at depths where CO_2 would be in the supercritical phase because of the wealth of data available in the public domain (Friedman and Stamp, 2006). Geophysical data include 3-D seismic and vertical seismic profiles. Reservoir data include wire-line logs and stratigraphic, sedimentological, petrologic, petrographic, porosity and permeability data. Geochemical data include soil gas, noble gas, brine composition and hydrocarbon organic geochemistry. In regard to the hydrocarbon character of the reservoir, data include basic sets, such as API gravity, original oil-water contact and initial gas saturation, and detailed analyses, such as whole gas chromatography, source rock kerogen characterisation and fluid inclusions. These data support interpretations regarding reservoir compartmentalisation and communication, and leakage potential. Geomechanical data include fractures and in-situ stress regime (see also Chiaramonte et al., 2008, discussed in Section 5.3). Cores, well logs and pressures, borehole breakouts, leak-off tests, field outcrops helped develop an understanding of the distribution and geometry of fractures (Friedman and Stamp, 2006).

In addition to these two special issues of Environmental Geosciences, the American Association of Petroleum Geologists (AAPG) is in the process of publishing a special volume on site characterisation for CO_2 storage (AAPG Studies #59: Carbon Dioxide Sequestration in Geological Media – State of the Art).

3.3 International Journal of Greenhouse Gas Control and GHGT Conferences

The series of International Conferences on Greenhouse Gas Control (GHGT) continued after GHGT-7, which was held in 2004 and whose relevant papers were reviewed in the IPCC Special Report on CCS (IPCC, 2005), with GHGT-8, held in June 2006 in Trondheim, Norway, and GHGT-9, held in November 2008 in Washington, D.C., U.S.A.

Both GHGT conferences had sessions devoted specifically to the subject of site selection and characterisation. Papers presented at these two conferences were published only in electronic form on CD. In parallel, Elsevier launched in 2007 a new journal, the International Journal of Greenhouse Gas Control (IJGGC), with the aim of publishing papers covering the entire CCS chain, from capture to storage, and including economic, legal, regulatory and public attitude aspects. Consequently, a series of relevant papers where published in this journal. Relevant papers from both the 8th and 9th GHGT conferences and from IJGGC will be briefly reviewed here.

Ramírez et al. (2008) present a system for screening storage options in The Netherlands that was developed based on the opinion of a large group of international experts. The experts were asked first to comment on an initial set of screening criteria and indicators which were then subsequently modified to reflect experts' feedback. In the second round, the experts were asked to provide scores and weights to these criteria and indicators. More than 500 oil and gas fields and deep saline aquifers were screened based on the following 10 criteria arrived at based on expert opinions (Table 6). Four oil fields, 139 gas fields and 34 deep saline aquifers passed the screening.

Parameter	**Selection Threshold**
Storage capacity	4 Mt CO_2 for oil & gas reservoirs, 2 Mt CO_2 for deep saline aquifers
Lithology	Sandstone for aquifers; sandstone, dolostone, limestone and siltstone for oil and gas reservoirs
Depth to top	≥ 800 m
Thickness	> 10 m
Porosity	> 10%
Permeability	> 200 mD
Pressure	Overpressured aquifers are excluded
Caprock lithology	Salt, anhydrite, shale or claystone
Caprock thickness	≥ 10 m
Salt domes	Traps located alongside/near salt domes/walls have been excluded because of high risk of salt cementation

Table 6: Screening criteria for storage in deep saline aquifers and hydrocarbon reservoirs in The Netherlands (from Ramírez et al., 2008)

Further screening of the 177 potential sites was based on potential storage capacity, cost, and effort needed to manage risk. For aquifers, only structural traps were considered (anticlines, compartments, etc.) up to their respective spill point. Storage capacity was calculated based on ultimate recovery for hydrocarbon reservoirs, and applying a 2% storage coefficient to aquifer (trap) volume. Costs were calculated for four classes: hydrocarbon reservoirs and aquifers, onshore and offshore, for the following categories: drilling of new wells, site development, surface facilities, monitoring, and O, M & M costs. For risk management, proxies were used resulting in 5 categories with 12 indicators (Table 7).

Ranking of the potential storage sites is based on numerical scores. Storage capacity and costs intrinsically have numerical values, whereas the effort for managing risk, as represented by Table 7, has qualitative and quantitative indicators. These were translated into scores through a process of values and weighting factors that assign importance, based on experts' opinions.

Category	Indicators	Meaning
Faults	1) Number of faults 2) Fault displacement	Risk of leakage along faults, particularly those reaching shallow strata.
Seismicity	3) Type	Stable, slightly unstable and unstable tectonic zones.
Wells	4) Drilled before 1967 5) Drilled between 1967 and1976 6) Drilled after 1976 7) Status 8) Accessibility	Regulatory changes in 1967 and 1976 in well drilling, completion and abandonment are indicators for leakage potential along wells. Well accessibility refers to the possibility to locate, reach and fix the well in case of leakage.
Caprock	9) Thickness 10) Composition 11) Proven sealing	The caprock of gas reservoirs has proven that it can retain buoyant gases, and the caprock of oil reservoirs has proven that it can retain buoyant viscous liquids. Aquifer caprock has not demonstrated sealing capacity.
Depth	12) Depth	Considered as a proxy for the existence of secondary seals (multilayer barriers to leakage)

Table 7: Risk-based screening criteria for storage in deep saline aquifers and hydrocarbon reservoirs in The Netherlands (from Ramírez et al., 2008)

Of noteworthy interest is that a huge gas field with an estimated storage capacity of 7 Gt CO_2 (compared with the rest of the Netherlands estimated at 3.2 Gt) was not included because it will not become available before 2060. Preliminary results show that ~50% of storage capacity is found in relatively small sites, aquifers have an average risk (mainly because of lack of detailed information and because seal capacity is not proven), and that aquifers entail a higher cost than hydrocarbon reservoirs because of lack of infrastructure. The analysis shows that, at least in the case of the Netherlands, gas reservoirs are the best option for CO_2 storage.

In regard to the use of wells as an indicator of potential risk for CO_2 leakage by Ramírez et al. (2008), it is worth mentioning here that Watson and Bachu (2007, 2008) have similarly shown through the analysis of ~320,000 wells in Alberta, Canada, that various well attributes, including date of drilling, completion and abandonment in relation to regulatory changes, are indeed a good indicator for the potential of a well to leak.

Wilkinson et al. (2008) introduce three key priorities for storage site selection, design, construction and operations, which expand in a way on the three fundamental criteria for site selection (capacity, injectivity and confinement). The three key priorities are:

- **Safety, Health and Environment (SHE)**, which involves protection of personnel and the environment. The definition introduced by Wilkinson et al. (2008) actually includes both capacity and confinement as defined previously because they define explicitly having the capacity to store CO_2 under confinement (no leakage) conditions (in the subsurface and well equipment);

- **Efficiency**, which is defined by storing the greatest amount of CO_2 in the minimum amount of pore space at the lowest unit cost. The first two parts of this definition (greatest amount of CO_2 in the minimum amount of pore space) was defined previously as **efficacy** of storage. By adding an element of economics (lowest cost), efficacy becomes efficiency;
- **Reliability**, which is an operational concept and refers to maximizing uptime and minimizing downtime of the storage operation when CO_2 storage will have to cease, which in some instance may result in unscheduled venting (i.e., emissions into the atmosphere). Reliability actually applies to the whole CCS chain, from capture to storage.

Using real examples from a depleted oil and gas field, a weak aquifer adjacent to a producing gas field, and a regional aquifer with producing oil fields in the basin, Wilkinson et al. (2008) show the impact of uncertainties in measured CO_2-brine relative permeability on displacement and sweep, sensitivity to internal heterogeneity of the storage unit, effects of well placement and injection strategies, and aquifer pressure gradients and hydrodynamics.

In a generic study of CO_2 storage in compartmentalized structures, Zhou et al. (2008) show that in some cases pressure build-up may be a storage-capacity limiting factor that would reduce the initial estimate of storage capacity by volumetric methods ("static" capacity) as a result of the significant and rapid pressure build-up that, nevertheless, has to be maintained at all times safely below the smaller of the caprock fracturing pressure and the brine-displacement pressure in the caprock. The same point is demonstrated by a paper by Ghaderi et al. (2008), who show that, in the case storage of high volumes of CO_2 at high supply/injection rates, storage capacity should be evaluated not on the basis of available pore volume, but by the ability to inject CO_2 without exceeding the rock fracturing pressure, which may have a limiting effect on injectivity and storage capacity. Aquifer permeability and thickness exert a primary control on injectivity, but rock compressibility also affects pressure build-up, although with a smaller effect than the other two characteristics.

In a simulation study of the amount and timing of residual-gas trapping, Taku Ide et al. (2007) show, in a generic way, the importance of vertical permeability (medium anisotropy), relative permeability, capillary pressure and CO_2 mobility in regard to the evolution of a plume of injected CO_2 and the amount of trapped CO_2. The importance of relative permeability determinations and their effect on CO_2 injectivity were demonstrated also by the study of Burton et al. (2008), who have shown, using relative permeability curves from Bennion and Bachu (2008), a four-fold variation in injectivity. Since absolute permeability and aquifer thickness are easy to determine once a well is drilled, uncertainty in relative permeability will have a large contribution to the uncertainty regarding achievable injection rates in CO_2 storage projects (Burton et al., 2008). The same relative permeability measurements by Bennion and Bachu (2008) show CO_2 and brine irreducible saturations varying within a factor of 3 to 4, and this variability affects not only the efficiency of residual-gas trapping, but also the sweep of the aquifer and the spread of the CO_2 plume (Hesse et al., 2008; Szulczewski and Juanes, 2008).

In a series of two papers Kopp et al. (2009a, b) examined through dimensional analysis and numerical simulations the effect of parameters such as depth, temperature, absolute and relative permeability, and capillary pressure, on storage capacity in aquifers. Their analysis is based on the relevant characteristics of 2540 oil reservoirs in the United States and on the relative permeability data published by Bennion and Bachu (2008).

Considering median properties as a reference case (depth of 1524 m, porosity of 20%, permeability of 123 mD, geothermal gradient of 30 ºC and dip of 4 º), the analysis of Kopp et al. (2009a, b) shows that high storage capacity is obtained for strong viscous and capillary forces compared to gravitational forces, i.e., deep, cold and/or low-permeability reservoirs are more favourable from a storage-capacity and plume evolution point of view than shallow, warm and/or high-permeability reservoirs, confirming the qualitative analysis of Bachu (2003). Relative permeability exerts a great influence on storage capacity through both irreducible CO_2 and brine saturations and the shape of the relative permeability curves, comparable with the entire range of reservoir properties such as depth and geothermal gradient. Another important result evidenced by the analysis of Kopp et al. (2009a, b) is that storage capacity and injectivity are not completely independent of each other because both depend on permeability and mobility (i.e., CO_2 and brine viscosity, which in turn depend on in-situ conditions of pressure, temperature and water salinity). Basically, higher storage capacity is achieved for lower injectivity. This counter-intuitive result is due to the fact that, in a homogeneous environment, poorer sweep efficiency is attained for higher permeability/injectivity, hence less pore space will be reached, and less residual gas trapping and less dissolution will occur.

4. HYDROCARBON RESERVOIRS

Oil and gas reservoirs have long been considered to be likely the most advantageous sites for CO_2 storage because they have demonstrated confinement (sealing) properties in regard to buoyant fluids, they are well known and characterised, and in most cases access infrastructure is already in place. Carbon dioxide can be stored in hydrocarbon reservoirs after abandonment (at depletion), or can be stored while hydrocarbons are still being produced,during enhanced recovery operations. The latter option provides the advantage that some of the CCS costs will be offset, or, most likely, an economic profit will be realized as a result of incremental oil production. Although 800 m is considered as the minimum depth for CO_2 storage because of the high density of supercritical CO_2, shallower hydrocarbon reservoirs should not be rejected a priori, particularly if they meet the requirements of capacity and confinement (injectivity has been demonstrated by producing the oil and/or gas).

The typically high recovery factor (of more than 70%) by natural depletion in gas reservoirs has traditionally left little incentive for the development of enhanced gas recovery (EGR). Interest in enhanced gas recovery has primarily risen since depleted gas pools have been considered as potential sites for CO_2 storage. The limited existing literature on the subject is reviewed in Section 4.3. The situation is different for oil reservoirs, which most often have much lower recovery factors (less than 40%) and for which the value of the incremental oil produced justifies the additional costs of enhanced recovery (including CO_2 separation). However, CO_2-EOR has not yet found wide application except for the Permian basin in west Texas and other locations in the United States where CO_2 is produced on a large scale and at a very affordable cost from several natural CO_2 reservoirs and a few gas processing, ammonia and fertilizer plants, and a coal gasification plant that pipelines its CO_2 to the Weyburn oil field in Canada. The high cost of CO_2, along with cyclic oil prices tend to keep most areas from implementing CO_2-EOR (e.g., in Alberta, Canada, there are close to 70 enhanced oil operations that use natural gas or solvents, but only one that uses CO_2 from a nearby ethylene plant). With the supply of CO_2 increasing as a result of capture operations, and with a likely decline in the price of CO_2, more CO_2-EOR operations will be implemented and, hopefully, sooner than the coming abandonment of very mature oil reservoirs. While depleted oil reservoirs can be considered a target for CO_2 storage, acting before complete depletion could provide opportunities for increasing both recovery and storage (Winter and Bergman 1993).

4.1 Enhanced Oil Recovery

On average, 40-50% of the total volume of injected CO_2 is trapped (stored) in CO_2-EOR operations (Hadlow, 1992). Not all oil reservoirs are suitable for CO_2-EOR, thus additional criteria must be applied for the identification and selection of oil reservoirs for CO_2 flooding, notwithstanding the economics of such operations. This is because most CO_2-EOR operations are based on the miscibility between oil and CO_2 and their phase behaviour. Based on the experience with CO_2-EOR in the United States, a series of authors have identified several criteria for the identification of oil reservoirs technically suitable for miscible CO_2-EOR; these criteria are summarized in Table 8.

Reservoir Parameter	Geffen (1973)	Lewin and Assoc. (1976)	NPC (1976)	McRee (1977)	Iyoho (1978)	OTA (1978)	Taber and Martin (1983)	Taber et al. (1997)
Depth (ft)		>3000	>2300	>2000	>2500	>7200 >5500 >2500	>2000	>4000 >3300 >2800 >2500
Temperature (ºF)			<250					
Initial Pressure (psia)	>1,100	>1500						
Permeability (mD)				>5	>10			
Oil Gravity (API)	>30	>30	>27	>35	30 to 45	<27 27-30 >30	>26	22-28 28-32 32-40 >40
Oil Viscosity (cP)	<3	<12	<10	<5	<10	<12	<15	<10
Remaining Oil Fraction	>0.25	>0.25		>0.25	>0.25		>0.30	>0.20

Table 8: Screening criteria for the identification of oil reservoir suitable for miscible CO_2 enhanced oil recovery[2]. In the case of OTA (1978) and Taber et al. (1997), each oil gravity value corresponds to the depth value in the same position in the table cell.

To these criteria one should add that reservoir pressure should be above the minimum miscibility pressure (MMP), i.e., the pressure at which CO_2 and oil become miscible. The MMP depends on oil gravity and a few other characteristics, and usually is determined in the laboratory on a case-by-case basis, but it is always above the CO_2 critical pressure. In the absence of specific laboratory data, particularly when screening a large number of oil reservoirs, the following empirical relationship, based on earlier work, can be applied to estimate MMP on the basis of the molecular weight (MW) of the C_{5+} components in reservoir oil and reservoir temperature T (Núñez-López et al., 2008):

$$MMP = -329.558 + (7.727 \times 1.005^{T} - 4.377) \times MW \quad (2)$$

where MMP is in psi, T is in º F and MW is dimensionless (kg/kg). Rivas et al. (1994) actually recommend that reservoir pressure should be at least 200 psi (1.38 MPa) above MMP.

At the end of 2007 there were 95 CO_2 miscible EOR projects in the United States and 5 immiscible ones, the oldest being in operation since January 1972 (Moritis, 2008). Several new operations started in 2008. Previous production in these operations was either primary or waterflooding (secondary), and in one case there was no prior

[2] Values are provided in imperial units, as per the original publications. Conversion factors are: m = 3.28084 ft; kPa = 0.145 psi; °C = (ºF -32) × 5/9, mPa·s = cP; oil density (kg/m^3) = 1000 × 141.5/(131.5 + ºAPI).

production. In Canada there are three commercial-scale miscible CO_2-EOR operations. Reservoir lithology is both carbonate and sandstone. Table 9 presents the main characteristics of these CO_2-EOR operations.

Reservoir Parameter	Miscible CO_2-EOR	Immiscible CO_2-EOR
Depth (ft)	1500 to 11,950	1150 to 8500
Temperature (ºF)	82 to 250	82 to 198
Initial Pressure (psia)	na	na
Porosity (%)	3 to 26	17 to 27
Permeability (mD)	3 to 4000	30 to 1000
Oil Gravity (API)	28 to 45	11 to 35
Oil Viscosity (cP)	0.35 to 6	0.6 to 45
Remaining Oil Fraction in the Reservoir	0.35 to 0.89	0.32 to 0.75

Table 9: Characteristics of CO_2-EOR operations in the United States (Moritis, 2008) and Canada[3].

4.2 EOR and CO_2 Storage

The primary objective in an EOR process is maximizing oil recovery while minimizing CO_2 usage. This is because traditionally there is a cost associated with the purchase of CO_2, and minimizing CO_2 usage while maximizing recovery would lead to maximum profit. Any produced CO_2 is re-injected to minimize the cost of the CO_2 purchase. For CO_2 storage, however, one will be interested in maximizing CO_2 retention in the reservoir, while minimizing costs. A number of investigators have considered opportunities for increasing oil recovery while storing CO_2 (e.g., Kovscek 2002; Trivedi and Babadagli, 2005; Patil et al., 2008; Ghomian 2008). It can be expected that an optimized EOR project would not necessarily be optimized with respect to CO_2 storage. Furthermore, the optimum conditions will depend on a number of parameters, including oil price and the cost of CO_2. Interestingly, however, Ghomian et al. (2008) found, through a set of simulation studies, that, for typical CO_2 EOR projects, CO_2 storage may be optimized without a significant reduction in profits.

When the question is shifted from co-optimization of a particular project to selection of a suitable reservoir among a number of reservoirs, then, in the opinion of the authors, the miscible vs. immiscible categorization used in CO_2-EOR projects is also useful for assessing suitability for CO_2 storage too. In general terms, oil recovery is higher when the CO_2 displacement is performed under miscible conditions. Such conditions are likely to be more favourable for maximizing CO_2 storage. This is because miscibility between CO_2 and hydrocarbon liquids occurs when CO_2 is in the dense phase. Under these conditions, the mass of CO_2 stored per unit volume of pore space will be larger. Furthermore, when compared with an immiscible displacement, the miscible displacement of hydrocarbons leads to better displacement efficiency and delayed breakthrough of the injected CO_2, once again favouring CO_2 storage.

Kovscek (2002) introduced a formula for estimating the mass C of CO_2 per unit volume of rock that may be stored both in free phase and dissolved in reservoir water, given by:

$$C = \rho_{CO2}\left(1 - S_{or} - S_{wir}\right)\phi + S_{wir}\phi C_S \quad (3)$$

where ρ_{CO2} is CO_2 density, S_{or} is residual oil saturation, S_{wir} is the irreducible water saturation, C_S is the solubility of CO_2 in water and ϕ is porosity. This equation may be used for estimation of C in the swept region of a petroleum reservoir. However, during a CO_2 displacement process, only a small fraction of the reservoir is swept.

Shaw and Bachu (2002) applied screening criteria based on the miscibility criterion in addition to those presented in Table 8 to approximately 10,300 oil reservoirs in western Canada and identified that less than 5000 would be suitable for CO_2-EOR (Bachu and Shaw, 2005). In addition, they have developed an analytical method to estimate the incremental oil recovery from these reservoirs and the amount of CO_2 that would be stored through CO_2-EOR. A normalized parameter-ranking algorithm was developed for ranking the oil reservoirs suitable for CO_2-EOR in terms of optimum reservoir parameters (technical ranking) and performance (incremental oil production and CO_2 storage capacity) that allows identification of prime candidates for CO_2-EOR and CO_2 storage (Shaw and Bachu, 2002). Most of the oil reservoirs in western Canada that are suitable for CO_2-EOR are quite small, with an average CO_2 storage capacity of ~135 kt CO_2, yielding a total capacity of only ~640 Mt CO_2. If the requirement that the CO_2 storage capacity should be greater than 1 Mt CO_2 is added as a screening criterion, then only 81 oil reservoirs would qualify (Bachu and Shaw, 2005), but their cumulative storage capacity of 450 Mt CO_2 and corresponding incremental oil recovery would justify the costs of implementation and operation of CO_2-EOR.

Núñez-López et al. (2008) have developed similar methodology, based on the same principles, for screening of oil reservoirs suitable for CO_2-EOR and estimating their incremental oil recovery and corresponding CO_2 storage capacity, and have applied it to oil reservoirs along the US Gulf Coast. Their methodology comprises four stages: 1) identification of oil reservoirs suitable for CO_2-EOR, 2) quick estimate of incremental oil production and CO_2 storage capacity, 3) improvement of previous estimates of oil production and CO_2 storage for a selected set of oil reservoirs by using rock and fluid properties, and 4) refinement of results by applying numerical simulations to selected reservoirs considering reservoir internal architecture and fluid distributions. This staged approach allows not only the broad identification of reservoirs suitable for CO_2-EOR, but also identification of the best ones for further analysis and consideration for field development.

Unlike Shaw and Bachu (2002), who calculated CO_2 storage capacity first and then screened out oil reservoirs with CO_2 storage capacity less than 1 Mt CO_2, Núñez-López et al. (2008) start from reservoir size as the first screening criterion and consider only reservoirs with a cumulative production greater than 1 million standard barrels (Mmstb). This approach eliminates small reservoirs from consideration right from the start while avoiding using estimates of CO_2 storage capacity, which are uncertain, as a screening criterion. Furthermore, Núñez-López et al. (2008) consider only reservoirs that are at least 6000 ft (1828 m) deep and that have already been water flooded (secondary recovery) or that have a strong water-drive mechanism because only these reservoirs would be at the stage in their production life where CO_2-EOR would be suitable (i.e., most of the mobile oil would have been produced and the remaining oil is residual oil that cannot be produced without EOR). Previous waterflooding is not applied as a screening criterion for large, deep reservoirs where vaporizing gas-drive miscibility can be achieved and where CO_2-EOR can be applied directly after primary production. Finally, Núñez-López et al. (2008) apply a geological ranking based on structural regime, structural style, stratigraphic heterogeneity and depositional system (see also Ambrose et al., 2008), where complexity is categorized as high, intermediate and low. Economic ranking of the reservoirs is based on parameters that reflect reservoir size and activity, such as cumulative and previous-year production, and on distance from a large CO_2 source.

In Stage 2 of their screening process, Núñez-López et al. (2008) apply simple spreadsheet calculations to estimate the volume of incremental oil that would be produced through CO_2-EOR as 15% of OOIP (original oil in place) (this recovery factor is subsequently adjusted in Stage 3) and the amount of CO_2 that would be stored. In Stage 3, Núñez-López et al. (2008) consider fluid and rock properties for each reservoir, but not reservoir geometry, through 10 dimensionless groups (Wood et al., 2006): effective aspect ratio, dip angle, mobility ratio (water), mobility ratio (CO_2), buoyancy number, injection pressure with respect to MMP, producing pressure with respect to MMP, initial oil saturation, residual oil saturation to water, and residual oil saturation to gas (CO_2). Applying this multi-stage approach, Núñez-López et al. (2008) found that 1068 oil reservoirs out of 3700 reservoirs in the US Gulf Coast would be suitable for CO_2-EOR and CO_2 storage. Stage 4 of their approach involves detailed numerical simulations.

The methodologies developed by Shaw and Bachu (2002) and Núñez-López et al. (2008) for screening oil reservoirs suitable for CO_2-EOR and estimating their incremental oil recovery and CO_2 storage capacity are very similar. In terms of screening, the only major difference is that Núñez-López et al. (2008) screened reservoirs based on cumulative oil production to date (substitute for size) and on waterflooding or aquifer support. While these criteria are suitable for Gulf Coast reservoirs in the US that have been in production for a long time, they are not suitable for other producing regions in the world because they would eliminate from consideration reservoirs that are in an initial stage of production or that are not yet at the stage of immediate CO_2-EOR application but which may be amenable to CO_2-EOR at some time in the future. Instead of cumulative oil production, a more suitable criterion indicative of reservoir size would be the recoverable oil in place (ROIP), which is given by the product of recovery factor (R_f) and original oil in place (OOIP). In regard to timing of availability, this should be based on reservoir analysis and considered broadly in the interplay between CO_2 storage in deep saline aquifers and hydrocarbon reservoirs (e.g., Dahowski and Bachu, 2006).

One of the overlooked opportunities for CO_2-EOR relates to expanded targets (intervals). Most oilfields have an interval beneath the oil/water contact that has residual oil in the pore space. These are often referred to as “transition” zones that produce only water with a “skim” of oil upon primary or secondary production, and represent targets for CO_2-EOR because much of the respective interval will have residual oil saturations above minimums for successful EOR flooding. Some oilfields have extensive zones beneath the oil/water contact and a more general term is used (“residual oil zones” or ROZ). These can be shown to be up to 200-300 ft (60 to 90 m) thick in some oilfields (Melzer et al., 2006) and represent huge targets for CO_2-EOR and CO_2 storage. These zones would increase the storage capacity of oil reservoirs through enhanced oil recovery. Except for a few projects in the Permian basin region of West Texas and New Mexico, not enough is yet known about these ROZ intervals since they have not been targets for oil production in the past.

4.3 Enhanced Gas Recovery

As mentioned earlier, and in contrast with enhanced-oil recovery (EOR), enhanced gas recovery (EGR) is a more recent consideration. Interest in EGR has arisen in light of the large storage capacity of depleted gas pools. Considering that any additional gas recovered as a result of CO_2 injection might offset the cost of CO_2 storage, a number of experimental and simulation studies have been undertaken to examine displacement efficiency of reservoir gas by CO_2. Mamora and Seo (2002) and Seo and Mamora (2003) conducted experiments of 1-D natural gas displacement with CO_2, and showed that mixing between the injected and in-situ gas was small, and high recoveries (in excess of 70%) could be obtained before CO_2 breakthrough. Similarly, Sim et al. (2008) have shown using a 1-D experimental apparatus that natural gas displacement could lead to high displacement efficiency. Field experience is however very limited and suggest that premature breakthrough may adversely affect gas production, unless used late in the life of the gas reservoir.

Van der Meer et al. (2006) reported on a project involving CO_2 injection into the nearly depleted K12-B reservoir offshore from the Netherlands. Starting with an initial pressure of nearly 40 MPa, CO_2 injection was initiated when the reservoir pressure had reduced to nearly 5 MPa. After about a year of injection, production continued without significant breakthrough. The authors have indicated that based on the analysis of the data, no clear evidence of measurable improvement in the gas production performance was observed. Pooladi-Darvish et al. (2008a) reported on the experience of concurrent gas production with CO_2 injection (disposal) in a nearly depleted gas pool in Alberta. Breakthrough was observed 1 to 3 years after the start of gas injection in all three producing wells, leading to their abandonment. The simulation studies indicated that some additional gas was recovered as a result of CO_2 injection. Furthermore, comparison between the model and field data indicated that the geological characterisation obtained during the development and primary depletion of the reservoir was not sufficient to accurately predict the breakthrough time. The authors have suggested that the length scale of heterogeneity characterised during primary production was larger than the length scale of heterogeneity that affected displacement of the natural gas by CO_2, leading to unexpected breakthrough of the injected gas. Pooladi-Darvish et al. (2008b) arrived at a similar conclusion in a study of acid gas disposal in another depleted gas pool, where premature gas breakthrough had been observed.

The existing field experiences reported above suggest that there could be additional gas recovery associated with CO_2 injection, particularly when injection is considered late in the life of the reservoir. However, early use of CO_2 injection for enhanced gas recovery purposes should be evaluated carefully, as premature breakthrough may be observed. Unexpected breakthrough of injected fluids is also experienced in oil reservoirs. However, the larger well spacing used in development of gas reservoirs compared to that in oil reservoirs limits the ability of characterising heterogeneities that would affect gas-gas displacement. In the opinion of the authors of this report, this factor, along with the high recovery factor associated with natural depletion in gas reservoirs, reduces the incentive for early implementation of EGR. This is not meant to indicate that special opportunities for EGR do not exist. For example, in Alberta, production of gas overlying bitumen is not permitted because of the adverse effect that pressure reduction might have on future development of the underlying bitumen resource. In this case, EGR is being seriously evaluated where injection of CO_2 or flue gas could allow production of the natural gas without reducing bitumen pressure. It should be noted that under current conditions in Alberta, penalties for CO_2 release are not large, and CO_2 storage is considered as a by-product. In a situation like this, and while enhanced gas recovery and storage may be complementary, they have different criteria and the chances of success as well as the primary intent should be stated clearly. While there may be opportunities for co-optimization (as reviewed under EOR) it is advantageous to clarify the primary and secondary objectives; any secondary benefits should be clearly "secondary" and should not be allowed to derail the primary objective.

4.4 Depleted Oil and Gas Reservoirs

For the purposes of CO_2 storage, depleted hydrocarbon reservoirs have a number of favourable factors over aquifers (IPCC, 2005): (1) their confining characteristics have been demonstrated by the trapping and accumulation of oil and/or gas, (2) their characteristics are well known as a result of exploration, production and modelling, and (3) infrastructure is generally in place. However, just having a depleted hydrocarbon reservoir doesn't necessarily make that reservoir a good candidate for CO_2 storage. It is expected that in many cases, most aspects of containment, capacity and injectivity need to be re-evaluated for the purpose of CO_2 storage. The availability of significant static and dynamic information for a depleted oil and gas reservoir makes the assessment of its suitability more reliable as compared to an (undeveloped) aquifer.

Some of the reasons that make re-evaluation of a depleted hydrocarbon reservoir for storage purposes necessary are listed below. The discussion concentrates primarily on depleted gas reservoirs; however most of the considerations are applicable to oil reservoirs too.

Containment

1. While primary depletion of a reservoir is often accompanied by pressure reduction, storage of CO_2 leads to an increase in pressure. Sealing properties of the caprock, particularly when it includes faults that have acted as sealing faults during natural depletion, will need re-examination. This is especially necessary when reservoir pressure (even on local basis) exceeds the initial reservoir pressure.
2. The practices and protocols used in abandonment of producing wells, need re-examination to ensure containment against CO_2 leakage at storage pressure and over the time-frame when CO_2 might exist as a buoyant phase.
3. Because of practical reasons, it is expected that the injected CO_2 stream would carry some fraction of other contaminants. Depending on the source of CO_2, the contaminant may be more toxic or corrosive than the CO_2 itself (for example, CO_2 obtained from gas sweetening operations is often contaminated by H_2S). In such cases, the potential for leakage (through cap rock and/or wells) will need to consider the contaminant too.
4. Knowledge of flow paths in a reservoir gained during depletion, are often less reliable than those observed when injection occurs. This is because the information collected during primary production (rates and pressures) is not very sensitive to displacement paths. Experience exists (e.g., in a reservoir at Marlowe in northern Alberta, Canada) where breakthrough of injected acid gas occurred in an oil reservoir in a fault-block that was thought to be isolated from the depleted oil reservoir into which acid gas was injected in an adjacent fault block. Similarly, many cases exist where natural gas storage operations have indicated passage of gas from one pool to a nearby one, where the experience from primary production

suggested isolation. In such cases the evaluation of containment characteristics of the storage site may need to include a wider area. Yet, other cases exist where, despite successful depletion of a gas reservoir, conversion to a gas storage site led to upward migration of gas into shallower horizons (Katz and Coats 1968).

Capacity

The following relation may be used to estimate the total mass of CO_2 that can be stored in a depleted oil reservoir is (Shaw and Bachu, 2002; Bachu et al., 2007):

$$M_{CO2} = C_{ef} \times R_f \times OOIP \times B_o \times \rho_{CO2} \quad (4)$$

where M_{CO2} is the mass of CO_2 that can be stored, R_f is recovery factor, *OOIP* is the original oil in place, B_o is the formation volume factor and C_{ef} is the storage efficiency coefficient. This provides only an approximate estimate of the CO_2 storage capacity in the oil column, as it ignores solubility in the water and the oil, and it assumes that the oil volume produced from the reservoir may be replaced by CO_2.

Storage capacity is discussed in two parts (1) volumetric reservoirs, and (2) reservoir in contact with an aquifer.

1. In depleted volumetric reservoirs, the estimation of capacity is relatively simple. For a depleted gas reservoir, the volume of CO_2[3] at reservoir conditions that may be expected to be storable into the reservoir is directly related to the reservoir volume of gas produced from the reservoir. (The volume of CO_2 at standard conditions that can be injected is equal to volume of gas at standard conditions that was produced, multiplied by ratio of density of CO_2 to natural gas at reservoir conditions; Bachu et al., 2007). This calculation will be somewhat conservative as it will ignore the solubility of CO_2 in the formation brine. On the other hand, and more importantly, if the time-scale of re-pressurization is significantly shorter than that of production, then the above estimation could be grossly over-estimated. This is because, during natural depletion, if done over a long period of time, gas would not only be produced from higher permeability portions/layers of the reservoir but also from the lower permeability ones. During storage, if done over a shorter period of time, the tight portions/layers of the reservoir may not be pressurized as quickly, resulting in a smaller effective capacity. Cases exist where a dry gas reservoir exhibits a capacity for gas storage that is as much as 30 – 40% less than the capacity exhibited during production. This occurs when the storage reservoir is cycled between initial and depleted pressure over a few months, while the same reservoir was depleted over a period of many years.
2. In the presence of an aquifer, a couple of considerations need to be taken into account. First, the same time-scale issue that was explained for the effect of tight layers in a volumetric dry gas reservoir needs to be extended to the water-bearing section of the reservoir. For example, if a reservoir with an aquifer was produced over a long period of time such that the aquifer moved in slowly and provided significant pressure support, during storage, if it occurs over a much shorter time, the aquifer may not be able to withdraw as fast, leading to quick re-pressurization

[3] If the injected gas is impure CO_2, then storage calculations should take into account the effect of impurity in occupying part of the pore space.

and smaller effective capacity. Hysteresis effects could augment this. Second, when CO_2 injection volumes are so large that in addition to the hydrocarbon reservoir its associated aquifer volume is also a target of storage, considerations similar to those related to storage in aquifers need to be taken into account, as there is little information about the properties of the aquifer (and its caprock) there. Storage in aquifers was discussed previously and will be discussed later on (In the context of natural gas storage in Section 6.1.2).

The difference in storage capacity between volumetric reservoirs and reservoirs in contact with an aquifer is in the storage efficiency coefficient C_{eff}, which for hydrocarbon reservoirs in western Canada was found to be 0.4 and 0.72 for oil and gas reservoirs with strong aquifer support, respectively, as opposed to reservoirs with no aquifer support, for which C_{eff}=1 (Bachu and Shaw, 2003).

Injectivity

This criterion for screening of storage reservoirs is introduced to ensure that CO_2 could be injected at the desired rates. Often the rate of injection can be increased by either changing completion techniques (e.g. fracturing, or use of horizontal wells), or by increasing the number of wells. On the other hand, often the reservoir itself has a limit at which CO_2 may be injected into it. To address both issues, wellbore injectivity is separated from reservoir injectivity.

1. Wellbore injectivity: The evaluation of wellbore injectivity, and whether it satisfies the required injection rates, is often dealt with when economic feasibility is being studied (as opposed to at the technical feasibility). This is because, when injectivity is low at a wellbore level, it could be overcome by modifying completion techniques or increasing number of injectors, both of which would affect the economics of the project. Regardless, the injectivity at or nearby the producing wells can often be estimated to a reasonable level of accuracy, as it is in direct relation to the productivity of the producing wellbore there. Injectivity (and productivity) of a wellbore is the ratio of injection (or production) rate per unit of pressure difference between the injection/production pressure and reservoir pressure (this is usually referred to as the Productivity/Injectivity Index $q/\Delta P$). The change in injection rate as a reservoir is depleted or pressurized is taken into account by the difference between the reservoir and wellbore pressure that is changing with time. Late in the life of a reservoir, the difference between reservoir and wellbore pressure is small (leading to low production rates). In the injection mode, however, wellbore pressure will be significantly larger than the reservoir pressure leading to much higher injection rates (as compared to final production rate). In addition, there is a number of other factors that could affect the injectivity of a well by up to one order of magnitude. Some of these factors improve injectivity while others deteriorate injectivity. They include: (i) stimulation vs. damage, (ii) the difference between viscosity of the injecting fluid and the in-situ fluid, (iii) relative permeability effects as a results of two-phase or multi-phase flow, and (iv) stress dependency of permeability.
2. Reservoir Injectivity: The rate at which CO_2 may be injected into a reservoir can not simply be increased by increasing the number of injectors. A limit to the rate at which a reservoir can accept CO_2 is reached when reservoir fluids are not being displaced fast enough to allow more injection. In other words, the high pressure area created by injection, which can be orders of magnitude larger than the area covered by the CO_2 plume itself, could restrict further injection. In these cases an

increase in reservoir pressure (in the region influenced by the wellbore) restricts further injection. In such cases a change in injectivity does NOT occur, as the potential injection rate per unit of pressure difference between the wellbore and the reservoir does not reduce, but the difference between the wellbore pressure and the reservoir pressure decreases. Dereniewsky et al. (1982) have given examples from natural gas storage sites, where as a result of pressure interference between wells reservoir deliverability is less than half of the summation of the deliverability of the individual wells. As such injectivity may not be an appropriate term for characterising this effect. Regardless, this effect could lead to a reduction in the reservoir capacity to accept CO_2. It is expected that permeability-thickness values at large distances from the CO_2 plume (as opposed to the near wellbore region) would influence reservoir injectivity. However, we have not seen sufficient treatment of this aspect in the literature.

In North America, the low productivity of many (tight) formations does not foster their individual development. A significant amount of gas production in North America is comingled. The challenges in the evaluation of the potential of these hydrocarbon reservoirs for storage include: (i) availability of limited data on an individual reservoir level, making it difficult to estimate storage capacity and injectivity; (ii) time of depletion, in that some reservoirs may/will deplete before others; (iii) different pressure and temperature conditions between the comingled reservoirs.

In a recent report to IEA-GHG R&D Programme, Poÿry elementenergy (Poÿry) and the British Geological Survey (BGS) estimated the worldwide CO_2 storage capacity in gas reservoirs and applied two criteria (filters) for selecting gas fields for CO_2 storage (Poÿry and BGS, 2008):

1. *Reservoir type*. Only gas reservoirs in gas fields were considered (i.e., gas associated – dissolved and/or free - with oil reservoirs was not considered);

2. *Size*. Gas fields considered too small to be suitable for CO_2 storage in the next 50 years were not accounted in the estimates. Two cutoffs were considered, depending on reservoir location: 50 Mt CO_2 storage capacity for onshore reservoirs, and 100 Mt CO_2 storage capacity for offshore reservoirs. In estimating capacity, it was assumed that the reservoirs will be re-pressured only to the initial reservoir pressure. The cutoff values were chosen based on proxy economics, based on the estimate that CO_2 emissions from a coal-fired power plant will fill a 50 Mt capacity reservoir in approximately 20 years, and that offshore reservoirs need to be larger to justify the higher cost of storage.

It should be noted here that the selection and estimates by Poÿry and BGS (2008) are at the field level and not at the reservoir level. This means that actual reservoirs in a gas field may have smaller individual CO_2 storage capacity. Other assumptions were made by the authors in regard to calculating storage capacity on a global basis, but these are not relevant to this study. The authors make the point that gas reservoirs suitable for CO_2 storage will not compete with gas reservoirs used for natural gas storage, as the latter are much smaller in size and operate on different premises.

While it is correct to discard gas in solution associated with oil reservoirs (solution gas), it is debatable whether or not to discard the gas contained in the gas cap of an oil reservoir (true “associated” gas) because this may provide a significant volume that can be used for CO_2 storage after production and abandonment of both oil and gas. Also, the choice of the threshold (cutoff) values may be debated, but most likely will vary from one jurisdiction to another depending on circumstances and availability. For example, Bachu and Shaw (2005) have used a cutoff value of 1 Mt CO_2 when evaluating the storage capacity in oil and gas reservoirs in western Canada, but the gas production and gathering infrastructure is more amenable to reaching these reservoirs.

5. SPECIFIC CONSIDERATIONS

In addition to the general consideration in site selection and characterisation, there are some additional discipline-specific considerations discussed below.

5.1 Geophysical Considerations

Geophysical data are important for all aspects of site selection and site characterisation for CCS. Nearly all sites discussed in the CO2CRC report (Kaldi and Gibson-Poole, 2008) and the EU manual for Best Practice for the Storage of CO_2 in Saline Aquifers (Chadwick et al., 2008) and in subsequent publications in the literature use existing geophysical data that had been acquired previously for hydrocarbon exploration and development. However, as CCS operations expand there will be sites selected and characterised for which existing geophysical data may be minimal or absent.

In this section, specific geophysical aspects of site selection and site characterisation are presented first (Sections 5.1.1 and 5.1.2, respectively), followed by a discussion about resolution from geophysical data (Section 5.1.3). to reinforce the importance of this topic in both site selection and site characterisation using geophysical data. The CO_2 storage operation at Sleipner is often held as the benchmark for these technologies in CCS as the seismic monitoring program implemented at Sleipner has been very successful in mapping the CO_2 plume. The Utsira Sand reservoir at Sleipner is thick (~ 200 m), with porosity up to 35% (Kaldi and Gibson-Poole, 2008), so that the geophysical signature of the CO_2 plume is unequivocal. However, the properties of the Utsira Sand are not typical of storage formations at other CCS sites and the results from Sleipner should not necessarily be used to illustrate what to expect from geophysical site characterisation and monitoring programs elsewhere. This is particularly true in basins with consolidated strata and thin target reservoirs which may have low porosity; e.g. the Otway Project in Australia (Urosevic, et al., 2008), the Ohio River Valley Project in the U.S.A (Lucier et al., 2006) and the Pembina Cardium Project in Canada (Lawton et al., 2008). In geological situations like these, a broader range of site characterization and monitoring technologies are required.

5.1.1 Site Selection

At a basin scale, defined in Table 2 (Kaldi and Gibson-Poole, 2008) as ranging from small (< 1,000 km^2) to very large (> 50,000 km^2), there are 4 main types of geophysical data that can be used to define general basin architecture. These are:

1. Regional seismicity data
2. 2D reflection seismic or long-offset refraction seismic refraction data.
3. Gravity data
4. Magnetic data

The scope of the seismicity analysis necessary for CCS projects will be determined from the geological setting of the basin. Seismicity criteria discussed by Bachu (2003) and Kaldi and Gibson-Poole (2008) are similar, with high seismicity expected in basins near active margins (subduction zones) and very low seismicity in cratonic basins. Seismicity is expected in regions of active tectonics and hypocentres will often be located close to faults. The purpose of seismicity assessment is to provide an input into risk analysis of possible tectonic-driven leakage along active faults occurring over the life cycle of a particular storage project.

The expense of seismic data acquisition precludes the use of 3D seismic surveys for basin evaluation at a large scale. However it is common that regional 2D seismic lines (refraction or reflection) may have been collected by government or industry as part of regional mapping or exploration programs (land or marine). Long-offset refraction seismic data are typically used to map seismic velocity structure in the upper crust and may identify basin-bounding faults. Regional 2D reflection seismic sections can be interpreted to map structural and stratigraphic interpretations along the seismic lines, identify faults that cross them, and generate horizon picks that can be correlated to stratigraphic tops through synthetic seismograms, if well data are available. A grid of 2D seismic lines can provide information on the 3D geometry of the basin, but often the line spacing in regional surveys is too large (> 10 km) to yield reliable 3D maps with unaliased structures. Reflection seismic data are traditionally processed in two-way traveltime and are depth-converted using spatially variant velocity-time functions determined from the processing of the data, constrained from sonic logs or vertical seismic profiles (VSPs) run in well(s) in the basin. Increasingly, reflection seismic data are now depth-imaged. Depth structure maps can be generated directly from interpretations of the sections, without the concern for apparent structure often seen in time-processed sections, caused by lateral velocity variations. Of all the geophysical methods, reflection seismic data provide the highest resolution of the subsurface geology but even that may be insufficient to accurately map the internal geometry of a target reservoir (Section 5.1.3).

Gravity and magnetic data are perhaps the most appropriate data-type for structural mapping at a basin scale, because these datasets can be acquired relatively cheaply using airborne surveys for land basins and shipborne surveys for marine basins. Magnetic data on land have routinely been acquired using airborne surveys for many decades and the data have generally been used to determine depth to magnetic basement and to elucidate basement structure. However, recent advances in data processing and the ability to collect high-resolution airborne magnetic (HRAM) data have lead to more detailed interpretations of the basin fill, such as locating intrasedimentary faults and mapping subtle lithologic contacts (e.g. Nabighian et al., 2005a; Goussev et al., 2004; Hassan et al., 2003). Gravity surveys have traditionally been ground-based on land, but within the last decade airborne gravity surveys have become more common with sufficient precision to map basin structure (e.g. Nabighian et al., 2005b). Shipboard magnetic and gravity surveys are routine in marine settings. CCS projects discussed in the literature that have reported using gravity and magnetic data to assist in regional basin analysis and CCS site characterisation are Weyburn (Canada) and Valleys (UK). At Weyburn, site HRAM data were used in conjunction with regional seismic data to map a 3D fault network that may be susceptible to subsurface fluid flow (Whittaker et al., 2004). At the Valley's site, Bouguer gravity data were combined with seismic data to investigate the St. George's Channel Basin, the Bristol Channel Basin and the South Celtic Basin (Chadwick et al., 2008).

5.1.2 Site characterisation

Seismic surveys are identified as providing important datasets for CCS site characterisation (Kaldi and Gibson-Poole, 2008; Chadwick et al., 2008), although it should be recognized that they may not be applicable or feasible in all situations (e.g., either the seismic signal cannot be detected or seismic surveys cannot be run because of land access restrictions). HRAM and gravity surveys may also be used, in conjunction with seismic surveys, to assist in mapping faults that may be present at a site. The main objectives of a seismic (or geophysical) survey in site characterisation are:

1. To delineate subsurface geological structure (faults, folds) from the target storage reservoir to shallow depths.
2. To map subsurface stratigraphy, not only the target storage reservoir and caprock, but also shallow reflectors associated with aquitards or aquifers.
3. To map, if possible, the thickness of the reservoir and lateral variations in lithology (facies) within it.
4. To map the caprock and identify potential leakage paths through it into overlying strata.

Chadwick et al., (2008) recommend that key datasets for robust characterisation of a reservoir (and to meet the objectives outlined above) are:

1. A regular grid of 2D seismic data
2. A high-quality 3D seismic volume at the injection site and the adjacent area, with the survey designed if possible to resolve the reservoir and the overburden.
3. Adequate number of wells to characterise the petrophysical properties of the reservoir and the overburden.

Although 2D seismic surveys can provide useful information for site characterisation, 3D seismic surveys are far superior for mapping the structure and stratigraphy of the site, particularly between wells. At the Ohio River Valley Mountaineer Power Plant in West Virginia, site characterisation was restricted to using 2D seismic data due to cultural features and industrial facilities (Gupta et al., 2004). In Germany, saline aquifer storage is being investigated at the anticlinal structure Schweinrich (Schwarze Pumpe), where mapping the geological structure of the reservoir was undertaken from 1970's vintage seismic data and from wells drilled during an earlier hydrocarbon exploration phase (Meyer et al., 2008; Kreft et al., 2007). However, delineation of faults in the structure was uncertain due to the poor resolution of the seismic data and only faults with a displacement of >50 m could be mapped with confidence (Chadwick et al., 2008). A new 3D seismic survey is recommended by Meyer et al. (2008) for a further feasibility study. At the Valley's site in the UK, basins in the outer Bristol Channel and St. George's Channel were investigated using about 5500 line-km of 2D seismic data combined with gravity data and well data. The Bristol Channel Basin was interpreted to be formed from a faulted syncline, and was considered to be less suitable for CO_2 storage than the inshore St. George's Basin, which exhibited better structural closure (Chadwick et al., 2008).

In Australia, the eastern flank of the Queensland Bowen Basin was assessed for CO_2 storage potential (Sayers et al., 2006), using wells and 2D seismic data on a coarse grid (2 – 5 km line spacing). Although the line spacing was too large to enable stratigraphic traps to be mapped, the data indicated a lack of faults penetrating the reservoir. A similar approach was used for the CO_2SINK Project near Ketzin in the North German Basin (Förster et al., 2006, 2008). The Ketzin anticline was initially characterised using 36 wells and vintage 2D seismic lines from earlier exploration activities (Förster et al., 2008), although these data were unable to resolve small faults or internal facies variations within the target Stuttgart Formation. In 2005, a 12 km^2 3D seismic survey was undertaken (Juhlin et al., 2007). They report that the top 1000 m of the structure were well-imaged with a central graben mapped across the top of the structure, and bounding faults delineated with throws of about 30 m. Of note at this site was that it was previously used for gas storage until the year 2000 (Juhlin et al., 2007). They interpret amplitude anomalies within two aquifers near the top of the structure as being generated by residual gas.

At Weyburn, Canada, initial site selection was driven by enhanced-oil-recovery operations, but site characterisation was regional in extent, initially covering an area of 40,000 km^2 (Whittaker et al., 2004). This work included the reprocessing and interpretation of 2000 line km of seismic data as a precursor to more localized multicomponent seismic surveys around the injection pads that served as baseline surveys for subsequent seismic monitoring during the CO_2 flood. Similarly, at Sleipner, Norway, existing 2D seismic data and well information were used for the initial regional interpretation (Chadwick et al., 2008). The authors report that 3D seismic data were used to map the Utsira Formation, initially a domal structure north-northwest of the Sleipner platform, but later at a preferred site northeast of the platform.

Other CCS projects used 3D seismic surveys from the outset to characterise the injection site. At the Pembina Cardium CO_2 EOR project in Alberta, Canada, two east-west parallel 2D seismic lines and an orthogonal north-south 2D seismic line were all live for all shots in the seismic survey (Lawton et al., 2008). This approach generated high-fold data along each of the 2D lines as well as low-fold 3D coverage of the pilot site. For the Otway project in Australia, 3D seismic data were available from existing hydrocarbon exploration and production from the Naylor field (Urosevic et al., 2008) and high-resolution 3D vertical seismic profile (VSP) data were also used to characterise the Waarre Formation because the reservoir is deep (~1500 m) and thin (< 25 m) and the added resolution from VSP data was helpful. Other examples of CO_2 storage projects for which 3D seismic surveys were available at the start of the program are the British Petroleum In Salah CO_2 Sequestration Project in Algeria (Raikes et al., 2008), and the West Pearl Queen Field, USA (Benson and Davis, 2006).

5.1.3 Resolution

Of all geophysical methods, seismic reflection imaging has the greatest potential for providing the greatest detail about subsurface structure. An important criterion in assessing the efficacy, hence applicability, of seismic surveys for site characterisation is *resolution*, which is the ability to identify reflections from the top and base of the horizon of interest. Seismic resolution is a function of the interval seismic velocity at the target level, the frequency bandwidth of the seismic data and the dominant frequency of the reflection wavelet. The resolvable thickness is generally defined to be $\lambda/4$ where λ is the dominant wavelength of the seismic data (Widess, 1973).

Resolution differs from *detection*, which is the ability to record a reflection from a very thin horizon ($\lambda/20$), but carries inherent uncertainty in terms of amplitude or other seismic attribute analysis. Thin beds and resolution were important considerations for uncertainties in site characterisation using reflection seismic data at Weyburn (Whittaker et al., 2004), Otway (Urosevic et al., 2008) and Pembina Cardium (Lawton et al., 2008). Ideally, the CO_2 storage formation should be greater than the resolvable thickness determined by the seismic data, as is the case at Sleipner (Chadwick et al., 2008). This reduces the interpretation uncertainty and may allow lateral facies variations within the reservoir to be mapped.

5.2 Geochemical Considerations

The objective of this study is to review site selection and characterisation criteria for CO_2 storage in deep saline aquifers and hydrocarbon reservoirs in sedimentary basins. However, there is growing interest in geochemically more reactive formations (those containing high proportions of mafic minerals, e.g., ultramafic rocks, serpentines, peridotites, ophiolite sequences, basic volcanic sequences, etc.) that sometimes are found at the edges of sedimentary basins. Use of these rocks for CO_2 storage can result in a higher proportion of carbon dioxide being sequestered as a carbonate mineral (see Kelemen and Matter, 2008). In addition, many of the mineral reactions encountered in these formations are relative quick. Geochemical modelling supports the reactivity of these formations, but issues of safety and security of storage, and injectivity, particularly with respect to solid volume changes, need to be addressed before they can be selected as suitable sequestration sites, and they will not be discussed any further in the following.

Geochemical processes can affect carbon storage site selection criteria through the modification of:

- Site capacity through the dissolution of solid material in the injection formation, thus increasing permeability and porosity, and through the precipitation of carbonate minerals, thus providing a denser form of carbon storage;
- Site injectivity through the precipitation or dissolution of phases in the near well region, resulting in an increased or decreased skin effect.
- Site containment though the dissolution of caprock and/or fault sealing minerals, thus decreasing security;

There is growing debate as to the importance of geochemical reactions in the context of trapping mechanisms, especially in predominately sandstone reservoirs, because the reaction rates are very, very slow. However, geochemical reactions can be important in the context of dissolution of some minerals in certain types of caprock, and of wellbore cement. And in the context of the geomechanical response of the caprock (see Section 5.3), microfractures filled with a soluble mineral can be opened through the coupled action of dissolution and pressure increase (and change of stress field) in the storage unit, thereby becoming flow pathways, thus practically bypassing the capillary barrier of the undisturbed caprock. Thus, geochemical reactions may have a significant effect on storage containment, but much less so on storage capacity and injectivity.

Ample evidence exists that injected carbon dioxide can, and does react with the fluids and solids in the subsurface. This includes changes in the formation mineralogy observed at paleo- and active natural analogues, and changes in produced fluid compositions from CCS pilot programs and CO_2-EOR operations. These observations are consistent with predictions and interpretations made using various geochemical modelling programs, which are based on thermodynamic data.

Evaluation of the potential geochemical effects on site capacity, containment and injectivity can be done by field observations, experiments and geochemical modelling. Experiments are limited in time and scope. Field observations of existing CO_2 storage and EOR sites are limited in observation time and the scope is fixed. Only geochemical modelling can be used for long term evaluations and it has the advantage of relatively easy modification of the input parameters. All of the existing CO_2 storage pilots and EOR field application are in either silica (quartz sand with generally small, but varying amounts of feldspars and clays) or carbonate (varying percentages of calcite and dolomite, with significant amounts of anhydrite, minor quartz and clays) reservoirs, which are typical of large sedimentary basins. Most of the experiments have been undertaken with these compositions, using material from either a real or potential site or by making a representative sample using material from other locations. Specific sites have been chosen for geochemical modelling, thus representative fluid and mineralogical compositions have been chosen. Only very few studies have compared different mineralogies (e.g., Gunter et al., 1993), and these have concluded that the availability of divalent cations and an assemblage that buffers fluid pH are critical in maximizing mineralogical carbon captures. All of the modelling and experimental studies implicitly select a representative formation water composition for a particular location. Obviously, if the formation water has a low pH with a high dissolved inorganic carbon component, solubility trapping of CO_2 will be lower as the water has less capacity to dissolve more CO_2. Correspondingly, formation water with low dissolved inorganic carbon component has the potential to dissolve more CO_2. The other chemical components in the formation water may also affect CO_2 solubility, either directly through complexing or chelation, indirectly through "salting out", or by changing/limiting the reactions between the water, the CO_2 and the formation mineralogy.

Standard engineering practice can and does take into account the effect of an impure CO_2 stream on facilities design, as the PVT (pressure, volume and temperature) properties of gas mixtures can be easily calculated. The geochemical effects of the injection of impure CO_2 streams have not been studied to the same degree. As part of a study on acid gas injection, Gunter et al (2004) concluded that there may be a benefit to the injection of H_2S along with CO_2. Knauss et al (2005) evaluated the geochemical effects of H_2S and SO_2 on a CO_2 injection at Frio in Texas, and concluded that H_2S would not adversely impact injectivity but that SO_2 had the potential to change the mineralogical reactions (as compared to the CO_2 only and CO_2-H_2S cases), resulting in changes to the fluid chemistry and reservoir properties. Their modelling results also show that each of the components of the injected fluid dissolved at a different rate, leading to a spatial variation in fluid composition. More work is needed to address the issues of the presence of impurities in the injected CO_2 stream.

5.2.1 Field Observations at CO_2 Storage and EOR sites

Detailed fluid sampling programs have been undertaken at CO_2 storage pilots, notably Frio (Kharaka et al., 2006, Doughty et al., 2008) and Frio II (Daley et al., 2008b) and the Otway Basin Pilot (Stalker et al., 2009), and at several CO_2 EOR projects, notably the IEA GHG Weyburn Monitoring Program (White et al., 2004, Emberley et al., 2005, Raistrick et al., 2006) and the Penn West Monitoring Program (Shevalier et al., 2008). More restricted sampling programs have taken place elsewhere. All have yielded valuable insight into the subsurface chemical processes at different time and process scales. The Frio pilot projects had hourly based sampling over a period of days, the Otway pilot sampled primarily bi-weekly over (currently) a year, the Penn West program sampled monthly over four years and the Weyburn program sampled three times yearly over four years. The Frio and Otway pilots were smaller in extent with only a single monitoring well, the Penn West program monitored two injection wells and eight surrounding production wells, while the Weyburn program monitored a set of 60+ wells (approximately 50 sampled each trip). Changes in the monitored fluid composition, including pH, total dissolved inorganic carbon, cation concentrations, isotopes and injected tracers have been observed at these sites. The changes at each site are different and depend on the specific formation mineralogy and composition of the formation fluids, temperature and pressure and injection stream chemical and isotopic composition. For the case of Enhanced Oil Recovery, injected water composition (both current and historical) are critical in determining the current fluid composition.

Core samples from reservoirs which have were exposed to injected carbon dioxide are restricted to very few cases, all of which are from reservoirs actively undergoing CO_2 EOR. The most extensive study to date was undertaken as part of the Penn West Monitoring Program, where Nightingale et al. (2008) analyzed core from each of the three sandstone units in the Cardium reservoir. Samples encompassed three distinct time periods: pre-water flood (before 1955), pre- CO_2 flood (between 1955 and 2005), and during the CO_2 flood in 2007. The results of whole rock analysis (XRF, ICP, and XRD), and microscopy (polarizing and scanning electron microscope) suggest the three separate sandstone units are both texturally and compositionally similar regardless of when the core was recovered. Thus the effects of the injected CO_2 could not be distinguished from the effects of preceding water flooding. This could be due to the loss of reactive mineral sites due to reactions during the water flood or the similarity of the reactions.

Although each potential site is unique, comparison of a potential site to existing sites give direction into critical issues and confidence that they are understood.

5.2.2 Experimental Activity

There are two basic types of experiments which are generally designated as autoclave (closed system) and core floods (open system). Both are usually limited by the availability of formation samples, thus either proxy samples or mineral mixtures are often used. Synthetic formation water is usually used in these experiments which may be charged prior to the experiment with CO_2.

The solids used in autoclave experiments are usually ground into a powder in order to increase reaction rates but, as this disturbs the relative reaction rates for the phases, it can perturb the results. The ratio of solids to fluids can be varied for each experiment. Experiments often run for months; changes in the fluid chemistry can be clearly seen but it is difficult to observe changes in mineralogy.

The charged synthetic formation water used in core floods is not in equilibrium with the mineral core, thus the primary reaction observed is mineral dissolution. Particularly for carbonate cores, the dissolution can be significant, principally at the injection port. Fluid velocities in core floods are low but limited core length results in short transit times. The effects of mineral dissolution can be clearly seen in the fluids sampled from the core floods.

Both autoclave and core floods can used for and yield insight into reactions in the injection horizon. Their application is much more limited when the reactions are diffusion limited, such as could be found in a cap rock. Because of their restricted nature, the primary uses of experiments are for fundamental understanding of rapid (less than a year) chemical reactions and to provide verification for modelling programs.

5.2.3 Modelling

Based on the scope of the modelling software, geochemical modelling can be divided into three categories, equilibrium, mass transfer (closed system kinetic reactions), and coupled reaction transport (essentially reservoirs flow models coupled to chemical reactions). Each of these are necessary and have applications in site selection.

Equilibrium models are primarily used to evaluate reported water chemistries, to undertake simple modifications of the chemistry, and to determine the potential for minerals to dissolve into or precipitate from the fluid. They have been applied to the produced water chemistries from all of the CO_2 storage and EOR sites where fluid monitoring programs exist. They are used to prepare the initial fluid composition for the more detailed models.

Mass transfer models calculate the change in fluid composition, mineralogy and gas composition as the system moves toward an equilibrium state from an initial disequilibrium state. They are for closed system, which may have limited transfer into / out of it. The reaction rates are based on kinetic parameters for each phase. These models can model quite sophisticated processes in detail and can be used to evaluate the effects of differing fluid compositions and mineralogies. The long term chemical effects of storage can be estimated using theses, allowing estimates of solubility, ionic and mineralogical trapping to be made. Once the chemical processes are understood, then they are simplified for inclusion into the coupled reaction transport models.

Reaction transport models calculate the flow within the injection (and associated hydrological zones) horizons and the geochemical reactions that occur. Based on their complexity and size, the geological data, the reservoir data (permeability and porosity), fluid chemistries and mineralogies often have to be simplified in order to reduce the simulation to a manageable level. They are particularly useful in evaluating fluid movement when there are multiple injection points which may have differing compositions, when aquifer support or drive is significant and when density driven flow needs to be included.

Reservoir fluid chemistry and reservoir mineralogies are critical inputs for all of these programs. Fluid samples can be taken by downhole pressurized sampling vessels, dedicated sampling systems such as a U-tube (Freifeld et al., 2005) or by surface sampling. Particularly for surface sampling, a number of analyses (ph, density, eH, iron, alkalinity) must be made immediately upon sampling and then re-determined analytically in the laboratory. Regardless of the sampling method, the sample must be representative, no drilling fluids or kill fluids should be present, and the sample should correspond to a single zone. The analysis should be complete and pass all culling criteria. If possible, both temporal and spatial reservoir fluid composition should be evaluated. Reservoir and cap rock mineralogy should be evaluated for each of the potential units within and adjacent to the injection horizon. If possible, core from a number of wells should be used to establish if any regional variations in mineralogy exist. Within each potential unit, a number of samples should be taken. Each sample should undergo XRF, XRD, SEM, thin section and microprobe analysis. Estimates of grain size and surface area should be made as part of this process. Each of these measurements yields a different scale of information, and the results for each of the potential units should be consolidated to yield the “most appropriate” mineralogy using software like LPNORM (de Caritat et al., 1994).

The most critical and difficult to evaluate input parameter for mass transfer models and for reaction transport models is the kinetic term for each of the existing and potential minerals and for CO_2 dissolution. For the minerals, the rate constant, power dependence and activation energy data are available from a number of sources or can be approximated by comparison with similar minerals. The surface area can be estimated based on the average grain size for each mineral (White, 1995) and an estimated roughness factor. The reactive surface area is not easily determined and is typically estimated to be 1 to 3 orders of magnitude lower than the surface area. When modelling the entire lifetime of a storage site, the "fast mineralogical reactions" (the salts, carbonates and sulphates) and "typical mineralogical reactions" are still relevant. The "slow mineralogical reactions" (quartz is perhaps the most extreme) are not relevant, they are simply too slow. The rate of CO_2 dissolution in the formation waters appears to be primarily dependent on fluid mixing in the injection unit and can not be predicted from fundamental principles. Observations from the Frio, Penn West and Weyburn operations suggest that this mixing occurs very rapidly, on the order of 10's of hours to months.

5.2.4 Expected Geochemical Reactions

Based on the fluid sampling programs, experiments and geochemical modelling, a summary of geochemical reactions that could occur would include (in approximate order of appearance):

Rapid reactions and less rapid reactions:

- Dissolution of the injected gas in the fluids (oil, water and gas) present in the injection horizon, resulting in an increased carbonic acid concentration in the aqueous phase.
- Disassociation of the carbonic acid to form bicarbonate, carbonate and associated aqueous species and complexes.
- The resulting increase in pH will cause:
  - changes in the distribution of mass among the various species and complexes in solution;
  - release and absorption of material on the surfaces of clays.
- Dissolution of the minerals with rapid reactions kinetics, primarily the carbonate minerals, amorphous iron oxides and similar phases;
- Increased dissolution of CO_2 through neutralization and the formation of increased amounts of bicarbonate and carbonate ions and complexes.

The following reactions are slower and have not been observed in the field sampling programs.

Slower Reactions

- Dissolution of complex minerals, predominately silicates, which result in increased cation and anionic loading;
- Precipitation of carbonate minerals and other minerals.

Each of these processes can and do modify the others. However, the complete suite of reactions can only be recognized in natural analogues or through geochemical modelling.

Direct comparison of produced fluid chemistry and predicted fluid chemistry through geochemical modelling has been limited to only a few CO_2-EOR sites and several storage pilots. The results given by Talman et al. (2008) for the Penn West CO_2-EOR site illustrate that that the primary mineralogical and physical controls can be appropriately modelling, but that there are issues with adequate representation of the reservoir and with the availability of detailed reservoir/injection data prior to CO_2 injection.

Geochemical experiments and observations of existing storage and EOR sites are limited in scope; they can and do address short term issues such as injectivity but can not address long term issues such as containment and capacity modification. Long term issues can only be examined through geochemical modelling. Geochemical modelling has the additional benefit of allowing parametric studies which can establish what the critical information gaps are and what the impact would be.

5.3 Geomechanical Considerations

The changes in pore fluid pressure associated with CO_2 injection have the potential to induce new fractures in a storage unit's bounding seal, and/or re-open or induce slip on existing fractures or faults. These processes can create new leakage pathways or enhance existing ones, hence impacting a site's confinement (or containment) effectiveness.

Geomechanical considerations for the site selection process are adequately covered in the existing site selection criteria, summarized earlier in this report. Key concepts include the afore-noted preference to select sites that are in geologically stable settings (Tables 1 and 2). Although this does not necessarily preclude the feasibility of CO_2 storage in less stable settings (e.g., convergent basins, subduction zones), it does point to the need for a heightened level of vigilance at the site characterisation stage, in order to assess the injection pressure at which containment would be breached, so that the injectivity and storage capacity can be assessed within the limits imposed by geomechanics.

Other significant geomechanical considerations which were duly noted in the IPCC Special Report on CO_2 Capture and Storage (IPCC, 2005) (see summary in section 2.1.1 of this report) include (1) the lower storage potential of basins that are highly fractured and faulted; and (2) the need to recognize that the bounding seal of a depleted hydrocarbon reservoir, under consideration as a storage unit, may have been weakened as a result of pore pressure changes during the reservoir's exploitation history. The first point is especially important to assess for saline aquifers, for which little may be known about the hydraulic properties of these fractures and faults. In such cases, analyses of stresses on the fractures and faults can provide insights into whether or not they are likely to be sealing or conductive.

5.3.1 Site Characterisation and Geomechanical Parameters Affecting Storage Containment

The procedures for geomechanical performance assessment of a candidate site at which pore fluids will be produced and/or injected are at a relatively mature state of development (see Grasso, 1992, for a review). In essence, the geomechanical performance of a storage unit and its bounding seal is largely driven by the mechanical stresses acting within these rocks, and the response of the rocks to these stresses. If shear stresses within zones of intact rock exceed the shear strength of these rocks, shear fractures will develop. Similarly, if shear stresses on existing fault or fracture surfaces exceed the shear strengths of these features, they will be reactivated (i.e., slip will occur). If the pore pressure at a point exceeds the minimum in-situ stress (plus any tensile strength that the rock may possess… typically very little in sedimentary rocks), a tensile fracture will develop. Similarly, if the pore pressure on an existing fault or fracture plane exceeds the compressive stress component oriented normal to this plane, the fracture or fault will open. In all of these scenarios, it is presumed that the newly created or recently reactivated or reopened discontinuity surface will serve as a conduit for fluid flow. Depending on the location, orientation and extent of these conduits, they may provide a leakage pathway that allows CO_2 to escape from the storage unit. As such, geomechanical site characterisation really amounts to identifying pre-existing features and the pore fluid pressure at which any critically-located, oriented and connected conduits would develop, so as to identify the limiting value for pressure during storage operations.

The main challenge at the site characterisation stage is the difficulty in obtaining the input data required for confident geomechanical performance prediction. These data are as follows:

- In-situ stresses;
- Rock strength (especially compressive shear strength; the tensile strength is typically assumed to be small);
- Rock deformation properties (e.g., elastic constants);
- Rock thermal properties (especially thermal expansion coefficient)
- Presence, location, extent, orientation and strength of existing discontinuities such as faults or fractures;
- Initial pore fluid pressure and temperature distributions;
- Changes in pore fluid pressure and temperature during storage unit operation.

Most of the above are self-explanatory; however, in-situ stresses are somewhat more complex and merit further discussion.

In sedimentary basins with relatively flat-lying rock strata and limited ground surface relief, it is reasonable to assume that the vertical stress at any point within these strata is due simply to the weight of the overburden. Further, there are no shear stresses acting in the vertical direction in such a setting, hence the vertical stress is a principal stress component. Due to the orthogonal nature of principal stresses, the other two principal stresses lie in the horizontal plane, and are oriented at right angles to one another. As such, the in-situ stress state at any point may be fully defined by specifying the magnitudes of the vertical stress (σ_V), the maximum horizontal stress (σ_{Hmax}) and the minimum horizontal stress (σ_{Hmin}), as well as the orientation of either one of the horizontal stresses. One of the benefits of selecting sites in basins that have not been tectonically disturbed is the fact that the aforementioned conditions generally hold true, hence simplifying the characterisation of in-situ stresses. This does not preclude the feasibility of geological storage in tectonically disturbed settings – it just points to a greater degree of difficulty in characterising the stress state in these settings.

5.3.2 Literature Review

Following is a summary of papers on geomechanical characterisation and analysis for CO_2 storage that have been published from 2005 to 2008. For the purpose of this report, these papers have been lumped together into three groups, based on the affiliations and/or locations of the principal authors.

Stanford University (Mark Zoback et al.):

A comprehensive treatment of the geomechanical analysis of reservoirs, including data types and methods for interpreting in-situ stresses, rock mechanical properties, and pore pressures, is given in a textbook by Zoback (2007). Chiaramonte et al. (2008) present a recent example of the typical workflow developed by Zoback and his collaborators; in this case, applied to the Teapot Dome CO_2 EOR/storage pilot project in Wyoming, USA. The interpretation of in-situ stress regime was based on:

- Analysis of borehole image log data, acquired in three vertical wells, to estimate horizontal stress orientations. Drilling-induced tensile (hydraulic) fractures, which were observed in these logs, are aligned parallel to the maximum horizontal stress (σ_{Hmax}) orientation; borehole breakouts, which would normally develop perpendicular to σ_{Hmax}, were not found at this site.
- Calculation of the vertical stress magnitude from bulk density logs.
- Estimates of rock strength parameters for the storage unit and surrounding rocks from empirical correlations based on geophysical log properties; this approach was necessary because laboratory measurements on core samples were not available.
- The magnitudes of the maximum and minimum horizontal stresses (σ_{Hmax} and σ_{Hmin}, respectively) in the storage unit and surrounding rocks were constrained using an elastic model for stresses on the borehole wall, rock strength estimates, and the observed presence of drilling-induced tensile fractures and absence of borehole breakouts. One measurement of the σ_{Hmin} magnitude, obtained from a minifrac test run near the project site, provided a value that fell within the range inferred using the aforementioned method.

Chiaramonte et al. (2008) used two criteria for identifying the critical (i.e., maximum allowable) pressure in the storage unit:

1. The pressure required to reactivate a specific high-angle fault, which had been identified in a seismic reflection survey, and was shown to transect the storage unit and the overlying/underlying rocks. They generated a contour plot showing the critical pressure at all points on the fault surface, for two different modeling scenarios; one in which it was assumed that the in-situ stresses would not change as pore pressure increased, and another in which a simple poroelastic model (based on the uniaxial strain concept) was used to predict the magnitude of stress change. Notable is the fact that they implemented their fault reactivation analyses within a probabilistic framework; more specifically, they ran Monto-Carlo simulations that accounted for uncertainties in fault orientation and in-situ stress magnitudes. For the fault under consideration at this site, they concluded that reactivation was unlikely for all scenarios considered.

2. The pressure required to induce tensile (hydraulic) fractures in the storage unit or, more critically, the bounding seal. This upper limit is simply given by the magnitude of the minimum in-situ stress (σ_{Hmin} at this site) in either the storage unit or the bounding seal (depending on considerations discussed below in the summary of Lucier et al., 2008).

Chiaramonte et al. (2008) concluded that the upper limit on pore pressure within the storage unit should be dictated by the lesser of the critical pressures identified using these two criteria.

Lucier et al. (2008) used a similar approach to analyze geomechanical constraints on CO_2 storage in the Rose Run sandstone aquifer in the Eastern Ohio River Valley, USA. Notable differences to the work presented by Chiaramonte et al. (2008) include:

- The use of a multi-phase reservoir simulator, using rock property distributions generated using geostatistical methods, to predict the pore pressure distribution to be used in their geomechanical analyses.
- Consideration of different criteria for identifying the upper limit on pore pressure increase, in which a less conservative limit may be used in order to achieve higher injectivity. More specifically, they termed the "safe" injection pressure as one that remained below the minimum in-situ stress of the storage unit, so as to avoid tensile (hydraulic) fracturing within it. Further, they analyzed the potential increases in injectivity if an injection pressure was used that was sufficiently high to induce tensile fracturing of the storage unit, and/or reactivation of natural fractures within it; both of these being processes that should increase its bulk permeability. In fact, it was concluded in their paper that injectivity at this site would be unfeasibly low unless this type of stimulation was used. They argued that it should be possible to conduct injection at a pressure sufficiently high to stimulate the storage unit, as long as the minimum in-situ stress of the caprock is not exceeded, and any reactivated fractures within the storage unit are relatively small (i.e., the reactivation of large fractures or faults that extend into the bounding seal should be avoided).

Laurence Berkeley National Laboratory (Jonny Rutqvist et al.):

The focus of work presented by Zhou et al. (2008) is mostly on the development of a simple methodology for assessing CO_2 storage capacity in closed or semi-closed aquifers; however, they do refer to the role of geomechanical processes in constraining the upper limit on pore pressure within the injection zone. More specifically, they draw on the regulatory practice of the US Environmental Protection Agency for liquid waste injection, which specifies the fracture closure pressure (i.e., minimum in-situ stress) measured in a hydraulic fracture (e.g., minifrac) test as the upper limit on injection pressure. [Note: This is also consistent with the licensing requirements for acid gas injection operations in Alberta, Canada, as noted in section 6.2 of this report.] Although Zhou et al. (2008) use this criterion solely in their work, they do refer readers to other references (e.g., Rutqvist et al., 2007) for a discussion of alternate criteria.

While the focus of Rutqvist et al. (2007) is largely on the assessment of critical pressure for fault reactivation, they also note that the pressure required to induce tensile fracturing of the bounding seal may serve as the upper limit on pore pressure in some cases. More specifically, they note that tensile fracturing of the bounding seal is more likely to be the limiting factor in settings with unfractured and unfaulted caprock, and an in-situ stress regime in which the differences between all three principal stress components are relatively small. Notable in this paper is a discussion of the coupled implementation of a numerical geomechanical model (FLAC3D) with a multi-phase reservoir simulator (TOUGH2) to assess poroelastic injection-induced stress changes, and consequent fault reactivation potential. This type of modeling may be required in some projects when progressing to more advanced stages of site characterisation, especially when site conditions are relatively complex (e.g., highly non-uniform pore pressure distributions, non-idealized storage unit / bounding seal geometry, non-continuum deformation response near fault surfaces or fault zones). Additionally, although not explored in this paper, numerical modeling tools of the type used by Rutqvist et al. (2007) have the potential to analyze the thermo-elastic effects and non-linear material constitutive behaviour on fault reactivation or induced fracturing risks.

Rutqvist et al. (2008) used the above-noted coupled numerical modeling approach to assess ground uplift over horizontal CO_2 injection wells at the In Salah Gas Project site in Algeria. Their approach is identified as a means of supplementing monitoring data acquired after CO_2 injection has started, which could help in the characterisation of leakage paths - should they develop. In settings where ground surface movement is particularly critical (although this is expected to be relatively rare), this modeling approach could be used to assess the limits on injection pressure to avoid consequent problems.

<u>Australian Group:</u>

Gibson-Poole et al. (2008) presented a site characterisation study of a basin-scale CO_2 geological storage system in the Gippsland Basin, offshore southeast Australia. Limited details were given on the interpretation of in-situ stresses and fault strength parameters, as these had been treated in more detail in earlier papers. Notable is the fact that a highly anisotropic stress state was interpreted for this setting; i.e., the maximum horizontal stress was interpreted to be roughly twice the magnitude of the minimum horizontal stress. They first investigated the pore pressure required to induce compressive shear fractures: (a) within the storage unit; then (b) in the bounding seal. The latter was found to be the limiting factor in this setting. They subsequently analyzed the critical pressure required to reactivate faults which had been mapped in the area, de-emphasizing the leakage potential for faults that were not located close to anticipated CO_2 plumes, and/or did not transect the bounding seal.

Earlier work presented by Streit and Hillis (2004) was similar to that presented by Gibson-Poole et al. (2008), with the notable difference being the fact that the former authors also analysed the effects of pressure depletion in hydrocarbon reservoirs which may later be used for CO_2 storage. They used a simple poroelastic model (based on uniaxial strain) to assess the depletion-induced stress changes, and analyzed how these changes may have affected the integrity of the bounding seal.

The lack of European papers in this summary is worthy of note. As mentioned in Section 2.3.2 of this report, geomechanics was not identified as a critical component in the EU "Best Practices" Report (Chadwick et al., 2008). This is largely a consequence of the fact that, in the major European projects which informed the development of their report, permeability at the storage units is high. As such, high injection rates were achievable with relatively small injection pressures, hence the likelihood for induced fracturing or fault reactivation or reopening was small.

Key points illustrated in the reviewed literature are as follows: (1-a) At sites with intact caprock and stress regimes that approach an isotropic condition, injection-induced tensile (hydraulic) fracturing can create leakage pathways; a conservative approach is to limit pressure based on the minimum in-situ stress in the storage unit, so as to mitigate the likelihood of hydraulic fracturing within it; (1-b) A less conservative approach at such sites is to use the minimum in-situ stress of the caprock as the upper limit on pore pressure in the storage unit; (2) At sites where the stress regime is highly anisotropic, the upper limit on reservoir pressure is more likely to be dictated by the potential to induce new shear fractures and – if the bounding seal is fractured or faulted - slip on fractures or faults; (3) In some cases, avoidance of induced seismicity and ground movement may impose limits on reservoir pressure.

Under-represented in the literature are potential thermo-elastic effects; i.e., the injection of relatively cool fluids can facilitate tensile fracturing. These effects were demonstrated for CO_2 injection using a numerical geomechanical model by Jimenez et al. (2004). Similarly, these effects were demonstrated for water injection using field data from sandstone reservoirs in the North Sea by Santarelli et al. (2008). Careful consideration of thermo-elastic effects is probably more critical in cases where tensile fracturing of the storage unit is being used as the limiting criterion for containment, although more study will be needed to confirm this.

Although the effects of faults on containment have been considered in the geomechancial literature reviewed above, the context has largely been restricted to the effects of shear and tensile stresses on permeability; i.e., if a fault is critically stressed, it is presumed to pose an increased leakage risk, although this provides no information on the leakage potential of faults that are not critically stressed. Although other aspects of fault behaviour have been studied extensively (e.g., Jones et al., 1998; Koestler and Andreas, 2002), it is the authors' view that the hydraulic properties of faults, and the factors that control them, are not understood well enough to allow for a simple and reliable means of classifying their leakage potential. Following are a number of factors which may be useful for preliminary assessment of fault seal behaviour, while bearing in mind that integrated studies involving datasets of varied scale and type (e.g., seismic reflection surveys, core data, logging data, well test data) are required to develop a reliable understanding of the hydraulic properties of faults:

- Faults that extend from the reservoir through to (or near) the ground surface likely pose a bigger leakage risk than faults that do not.
- Assuming that a fault is not critically stressed, and all other factors being equal, a large in-situ stress component acting normal to the fault should reduce its aperture, hence reducing its permeability.
- Faults that have offset clay-rich lithologies (e.g., shales, mudrocks) should pose a reduced leakage risk, presuming that a substantial amount of clay will have been smeared along the fault in such cases, effectively in-filling it with low-permeability material.
- Faults that transect caprocks in settings where there are known to be hydrocarbon accumulations, and an observed absence of gas chimneys, are presumed to have low permeability, and should be likely retain this low permeability unless they are reactivated, re-opened or otherwise disturbed by fluid extraction or injection activities.
- Faults that transect aquitards in which the underlying and overlying aquifer pore waters possess distinct pressure regimes and /or chemical compositions are presumed to have low permeability, and should be likely retain this low permeability unless they are reactivated, re-opened or otherwise disturbed by fluid extraction or injection activities.

6. ANALOGUE OPERATIONS

As identified in the Special Report on CCS (IPCC, 2005), there are three industrial (engineered) analogues to CO_2 geological storage: enhanced oil recovery since 1972, natural gas storage for more than 90 years, and acid gas disposal since 1990. The worldwide experience of all these three industrial analogues demonstrates that the technology of bringing CO_2 to a storage site and injecting it deep into the ground exists today and can be easily applied. There are some major differences between CO_2 storage and these industrial analogues, namely:

- CO_2 is injected in EOR operations to increase oil production, and some of it is produced together with oil at the pump; also, CO_2 being a commodity and representing an operating cost, the operators generally try to minimise the amount of CO_2 left in the reservoir;
- Natural gas is seasonally and cyclically injected into and produced from deep saline aquifers and depleted gas reservoirs, hence permanence of storage is not being sought, only minimisation of leaks;
- Acid gas disposal is the closest to CO_2 storage because the acid gas (CO_2 and H_2S) is injected for permanent retention and leak avoidance, the main difference being only in the scale of these operations.

However, there are also significant similarities in terms of site selection and characterisation, and these will be discussed in the following sections for natural gas storage and acid gas disposal. Enhanced oil recovery will be discussed in the next chapter as a means by itself of storing CO_2.

6.1 Natural Gas Storage

A wide range of media has been considered for storage of natural gas. These include natural media such as depleted gas, condensate and oil pools, aquifer, and man made media such as salt caverns, pipeline and steel containers. The emphasis of this section will be natural gas storage in depleted hydrocarbon reservoirs and aquifers.

A number of classical textbooks and papers by Katz and his co-workers (1959, 1963, 1968, 1971, 1981), and other textbooks by Tek (1987) and Ikoku (1992) deal with natural gas storage. Furthermore, the Society of Petroleum Engineers designated its 50th Reprint Series to a selection of previous papers on natural gas storage (Valerie et al., 1999). More recently, Bennion et al. (2000) have proposed a protocol for screening and selection of gas storage reservoirs. This literature covers a wide range of topics from characterisation, to engineering and optimization. Significant attention is also given to inventory verification and monitoring. Natural gas storage is a mature technology, and many of the concepts have been developed to the point of maturity, and are repeated is various sources. This literature along with other selected papers on natural gas storage has been reviewed. Since the majority of this literature relies on the experience in North America, such a bias may remain.

One of the main motivations for development of underground natural gas storage facilities is creating a balance between the variable market for natural gas particularly for heating in large centers of population, and the relatively steady supply from pipelines. In Northern climates and on a cold day more than half of the gas sold could be storage gas (Katz and Tek 1981). As such most gas storage facilities are close to large cities. Nevertheless, Ikuko (992) suggest that sites at a distance of 150 to 300 km from the market are now used effectively.

Among others, Katz and Tek (1981) review the evolution of the underground natural gas storage since it was first implemented in 1915 in Ontario Canada, and shortly after in 1916 in Buffalo, NY. The industry experienced a remarkable growth in the 1950's and afterwards resulting in nearly 212×10^9 m^3 (7.5 Tcf) of storage by 1979. Storage capacity has remained steady since then (Knepper 1997). Natural gas storage capacity in Canada is roughly 7% of that in the United States. Over the past century, underground gas storage has developed into a mature technology with hundreds of pools in use.

As formalized by Katz and his co-workers (1968, 1981), design and operation of a storage reservoir has three objectives, (i) accessing the desired the capacity, (ii) retention against migration, and (iii) developing and maintaining desired deliverability.

Figure 2 is a reproduction of the flow diagram given by Tek (1987), which identifies the tasks involved in selecting a prospect for aquifer storage. After the need for storage is identified along with quantity of storage and market location, two screening phases follow. Screening for physical possibility examines the three requirements of containment, capacity and deliverability; where as screening for economic feasibility involves more detailed evaluations. In the following, and starting with depleted hydrocarbon reservoirs, considerations given to each of these aspects for the purpose of natural gas storage are discussed.

6.1.1 Natural Gas Storage in Depleted Hydrocarbon Reservoirs

A typical natural gas storage site is a depleted dry and sweet (without H_2S) gas reservoir of high permeability. While Bennion et al. (2000) suggest that typical permeability is above 1 Darcy, many examples exist of storage reservoirs of permeability in the range of 0.1 to 1 Darcy. Katz and Coats (1968) give examples of successful gas storage sites with a few milli-Darcy in permeability. Typically these zones do not contain mobile oil, water or an aquifer. While depleted oil reservoirs, and particularly gas cap of depleted oil pools and gas condensate reservoirs, have been used for storage (generally when suitable depleted dry gas pools were not available), liquids in the reservoir result in added complications. These complications are a result of possible liquids in the wellbore, possible enrichment of gas and condensate formation in the pipelines. These factors could interfere with wellbore deliverability, and require significant dew point control operations as part of the surface facilities. Furthermore, it has been reported that dissolution of natural gas in oil has led to complications in inventory estimations. Therefore, in site selection, depleted dry gas reservoirs are favored over depleted oil and condensate reservoirs. When depleted oil pools or gas condensate reservoir have been considered, production of oil, recovery of additional liquids in surface facilities or an increase in heating value of the gas have played some positive role. In addition to the above considerations, containment, capacity and deliverability need to be ensured. In the following we review these criteria. In some cases, the existing information might allow a judgment regarding suitability of the site in meeting the specific requirement, while in other cases further characterisation is needed before a site may be selected.

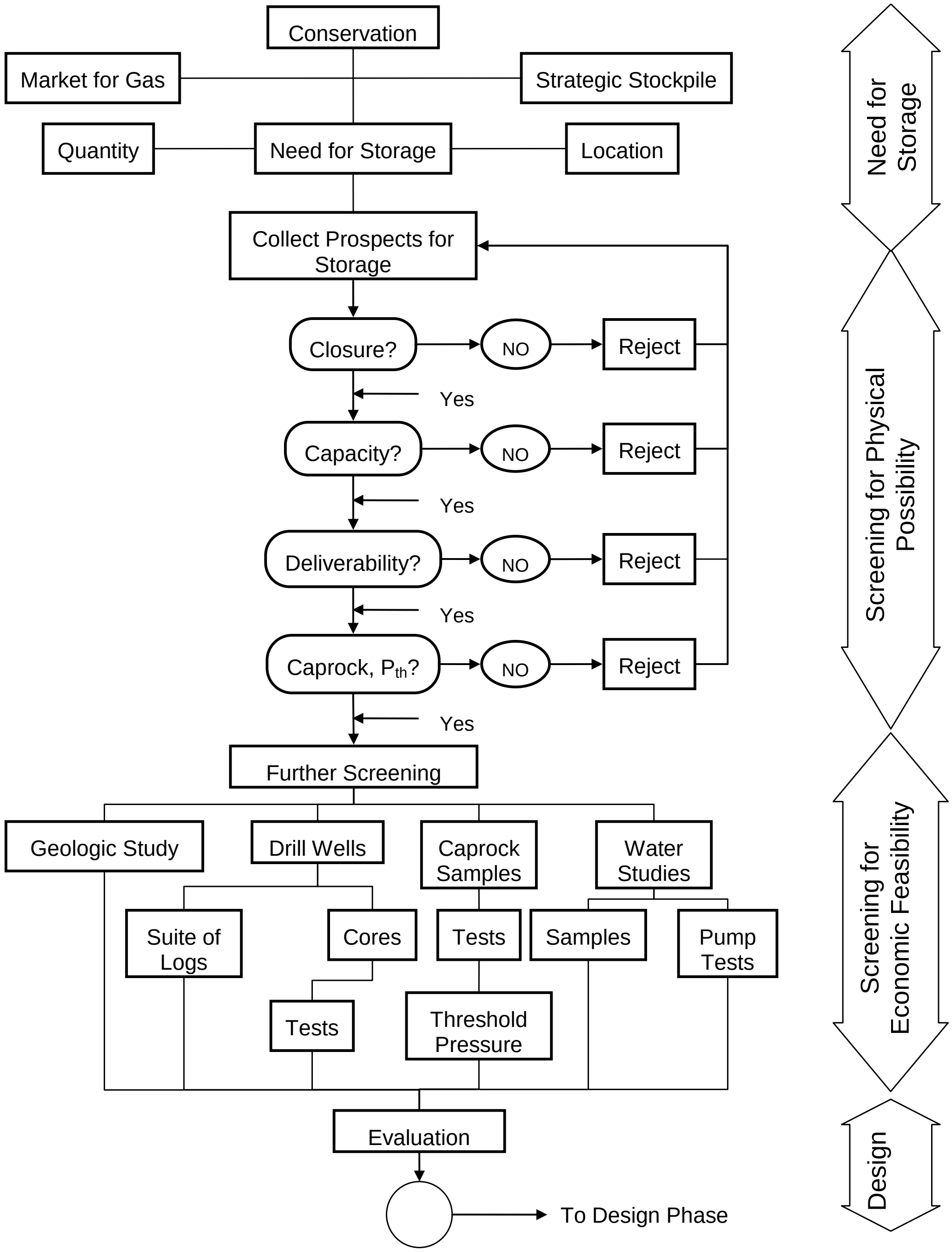

Figure 2: Task involved in selecting prospects for natural gas storage in aquifers (from Tek, 1987)

Containment. Study of containment can be broken up into a number of categories including caprock threshold pressure, fault and/or fractures in the caprock, and leakage through wells. Existence of a hydrocarbon reservoir itself is a reflection of a presence of a sealing caprock such that over geological times the caprock has contained the hydrocarbons at their discovery pressure. In natural gas storage operations however, the storage pressure may be raised to a value above the discovery pressure. This is called delta pressure. In these cases, the pressure differential across the caprock under storage conditions would be more than that at discovery, and the existence of the hydrocarbon reservoir does not provide a guarantee that the caprock would contain the stored gas at such design pressures[4]. This is discussed in more detail, when gas storage in aquifers is dealt with. In the case of gas storage in aquifers, pressure has to be raised above the initial aquifer (to displace the water and create space of storage).

Screening for confinement, also requires investigation of abandoned wells, especially the casing and the associated cement at the casing shoe, across the caprock and at casing joints[5]. This is to ensure that none of the wells penetrating the reservoir are either creating a connection from the reservoir to the overlying strata, or have been damaged to a point that would affect the ability of the caprock to contain the fluids. Knepper (1997) suggest that wells can be reworked to improve their mechanical integrity. However, wells that may have blown out or had other serious problems need to be evaluated carefully.

Capacity. In depleted hydrocarbon reservoirs, capacity is known to a high degree of reliability. This was previously discussed under Hydrocarbon Reservoirs and will not be repeated here. One consideration for natural gas storage is that typically a base volume of gas (known as cushion gas) is always kept in the reservoir, and the working capacity refers to the storage volume associated with raising the reservoir pressure from the base state to the maximum design pressure. As mentioned earlier, the optimum design pressure can be (and often is) more than the initial discovery pressure. This could provide additional capacity[6].

Deliverability. In gas storage operation, the ability to meet market demand at peak times is a very important consideration, and provides the main motivation for building a storage facility. Therefore, deliverability is very important. In depleted hydrocarbon reservoirs a good knowledge of wellbore deliverability exists from the historical information. Wellbore deliverability was previously discussed under Hydrocarbon Reservoirs and will not be repeated here. Of importance is that reservoir deliverability in a natural gas storage site is generally considered to be a design parameter. The number of wells required is designed to attain the desired deliverability (Katz et al. 1959, Tek 1987).

Bennion et al. (2000), propose guidelines and considerations that could control the loss of deliverability that occurs with time. Once the cause of the loss deliverability is known (e.g. formation damage, accumulation of compressor oil, etc) remedial actions can be planned.

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[4] A similar situation may arise if the density of the stored fluid is less than the initial reservoir fluid (e.g. for example when depleted oil reservoirs are turned into gas storage). In this case and once turned into gas storage, the capillary pressure threshold that the caprock faces with will be more than what it experienced when it contained a heavier fluid (oil). Once again, existence of the hydrocarbon reservoir does not provide a guarantee that the caprock would contain the stored gas.

[5] Katz (1978) suggests that there are three possible sources for gas loss in cased wells: 1) casing collar thread leaks, 2) corroded or imperfect piping, and (3) through imperfect cement behind the casing shoe at the caprock.

[6] This needs to be balanced against additional compression costs.

After basic characterisation and evaluation of potential storage site and selection of one, a detailed engineering design will ensue. Among other factors, optimum base-gas pressure, number of wells, gathering/injection pipeline and compression facilities will be designed.

6.1.2 Natural Gas Storage in Aquifers

For a number of decades, depleted hydrocarbon reservoirs were considered to be the only option for underground natural gas storage. Starting in 1950's however, natural gas injection in aquifer was implemented. Generally, aquifers are chosen if depleted gas pools of sufficient size and deliverability are not available. Availability of less data, lack of knowledge about caprock integrity, and necessity for drilling many wells for characterisation development and monitoring are among the factors influencing this choice. The preliminary step in searching for an aquifer storage field is very similar to steps that an exploration geologist would take for finding a hydrocarbon reservoir. As will be reviewed below, selection and characterisation of an aquifer for natural gas storage requires significant attention to caprock quality for containment and to water movement for capacity and lateral containment.

Containment. As in the case of storage in depleted hydrocarbons, the sources of leakage could be caprock (small threshold pressure or presence fault or fractures) and leakage through wells. As compared with depleted hydrocarbon reservoirs, aquifers are often drilled through with a lesser number of wells. Therefore, risk of leakage through existing wells is considered to be lower. Nevertheless, the existing wells need to be investigated in a similar manner to those in depleted hydrocarbon reservoirs. Quite importantly however, is examining the sealing capacity of the caprocks of a candidate aquifer.

Aquifers are generally found at discovery pressure gradients of close to hydrostatic pressure (8 to 12 kPa/m). Creation of a storage site, requires driving the water away, i.e. creating delta pressure. Katz and Tek (1981) and Ikoku (1992) report that delta pressure of 2 to 3 MPa is common place with values of as high as 6 MPa reported. The corresponding gradients are 14.5 kPa/m and as high as 17 kPa/m. Therefore, it is important to examine the sealing capability of the caprock. Among others, Tek (1987) suggests that examination of water level and chemistry in layers above and below the caprock of interest could in case of similarity indicate communication across the caprock. Nevertheless, Katz and Coats (1968) and Bays (1964) recognize that there is possibility of difference in head and chemistry across (partially) communicating caprocks. Alternatively, similarity of head and/or chemistry is not a guarantee for communication.

More specifically, tests commonly suggested for examining the sealing capability of aquifer caprocks are capillary threshold pressure (or gas intrusion) tests and absolute permeability tests. Bennion et al. (2000) recommend that absolute permeability of an effective caprock should be no more than 1 nano-Darcy (1×10^{-6} mD). Katz and Coats (1968) suggest that values as high as 100 nano-Darcy can be acceptable.

Another important measure of the sealing capability of a caprock is its capillary intrusion pressure. This is particularly true for shale and carbonates, where some permeability can be measured. In these cases, the low permeability would slow flow but will not halt it. However, a capillary phenomenon known as gas intrusion pressure could resist flow of gas into the pores of the caprock. In a water-gas system in the presence of caprock material, gas is the non-wetting phase. Therefore, it has to overcome a capillary pressure before it can enter the caprock. The smaller the pore radii of the caprock and the higher the gas-water interfacial tension at reservoir pressure and temperature, the higher would be the gas intrusion pressure. Caprocks can be tested for their gas intrusion pressure. Alternatively, an empirical relation between threshold pressure and permeability has been reported. However, knowledge of gas intrusion pressure is not sufficient, as that needs to be balanced with design conditions. More specifically, the required gas intrusion pressure depends on the overpressure (pressure in the stored gas minus the initial pressure) and the vertical distance between the caprock and the gas-water contact. Both of these parameters need to be evaluated on a case-by-case basis. Katz (1978) suggests that in aquifers, caprocks are evaluated at some twice or more the delta pressure planned for the project.

One practical consideration resulting from gas intrusion pressure is that overpressure should be carefully managed. In early phases of injection, when the water is being displaced, injection pressures should be controlled carefully (to overpressure values less than 1 MPa) to avoid any pressure fluctuations that would get directly imposed onto the caprock. Once storage is full, gas can be withdrawn and injected rather quickly.

Another factor that could significantly influence the sealing capability of a caprock is its continuity. Bennion et al. (2000) suggest that dense shale layers of more than 3 to 4 meter thickness could act as impermeable barrier. Tek (1987) suggests that, while a thin layer of shale of 1.5 m thickness could retain gas, discussion of caprock thickness often has more to do with continuity of the caprock. The seismic monitoring at Sleipner shows the CO_2 plume migrating upwards through the Utsira Formation, including through what was thought to be a continuous 5-7 m thick shale layer, despite relatively low injection pressures (Chadwick et al., 2008). No clear explanation has been put forward in the literature, but the most likely explanation is vertical movement of CO_2 around stratigraphic breaks and depositional discontinuities in the shales, rather than CO_2 "breaching" through the shale layer as a result pressure increase due to injection. This particular case shows that typical methods used for the characterisation of extensive shale layers (caprock) (e.g., seismic, well logs and core samples) lack the resolution and/or the length scale necessary to identify discontinuities that will allow flow. Long-term flow tests and pressure measurements in the overlying strata may identify such discontinuities, as used in natural gas storage.

In addition to use of geological, geophysical and core analysis methods, presence of discontinuities in the caprock (e.g. because of presence of faults or fractures) is often tested using long water pump tests. In these tests, water is either withdrawn or is injected into the target formation, and pressure (or water level) is monitored in the formation (aquifer) above the caprock. Katz and Coats (1968) give a number of examples, where long test of up to 80 days have been reported. Similarly, Crow et al. (2008) have shown the use of pressure testing in an overlying aquifer to detect leakage and estimate permeability in a leaky well.

One important realization about containment of natural gas in aquifers is that there are many reports of some gas loss. Katz and Coats (1968) and Tek (1987) report of storage sites with significant leakage that have been used successfully for years. In more than one case, gas accumulated below sealing rocks at shallower horizons was collected and returned back to the storage site, when there was no market for it (Katz and Coats 1968, Araktingi et al. 1984). Goeber (1965) suggests that there are very few storage sites that exhibit some form of vertical gas leakage.

Among others, Knepper and Cuthbert (1979) suggest that leakage problems may be identified through a combination of observation wells, inventory calculations and logging in the storage formations and those above and below. There is little evidence of use of geophysical methods among the spectrum of monitoring techniques.

Another consideration in evaluation of containment in storage of natural gas in aquifers is related to closure; presence of spill point and/or saddles. In natural gas storage, where the injected gas is to be produced, it is important that the gas does not flow away beyond a spill point. This is evaluated by building structural maps (and all that goes into it). Closure and the reservoir properties at the spill point are also of importance in evaluation of capacity, as discussed below.

Capacity. In natural gas storage in aquifers, the estimation of capacity starts with development of a structure map, and determination of the pore volume within the closure. However, all of this space is not available for storage. Storage space could be created by either compressing the water or displacing it. From the initial studies of Katz and his co-workers it was realized that because of the low compressibility of the water and formation, a large overpressure of the order of 1 MPa, would make approximately 0.1% of the pore space available[7]. Therefore, the boundary conditions of the aquifer beyond the closure play a major role in determining the storage capacity. Extended open aquifers (e.g. blanket sands) would allow significant displacement of the water beyond the geological closure. Katz (1978) suggests that to ensure sufficient flow (e.g. transmissibility), reservoir properties should be evaluated as far as one might expect water movement over a period of years. Katz and his co-workers have developed relations that relate the outward flow of water at the boundary with overpressure and aquifer properties in homogeneous and uniform aquifers. In cases where water displacement is restricted and pressure build-up quickly, active engineering techniques, such as production of water, have been used as a methodology to relieve pressure and provide storage capacity.

In addition, there are a number of other factors that influence the storage capacity. First, the advance of the gas in the aquifer is not uniform; it is controlled by layering and variable permeability and gravity forces. Due to adverse mobility ratio, gas has a tendency to move along the high permeability streaks, especially early in injection. As a practice, gas injection after gas in a particular layer has arrived at the spillpoint is not continued; unless the gas front is given time to withdraw, when water is drained from unswept layers above the high permeability layer where gas has moved along. Second, the microscopic displacement efficiency of water by gas is low. This means that 20 to 40% of the water may remain in areas that gas has passed through. And finally, not all of the injected gas can be produced. In analogy to that in depleted gas reservoirs, a cushion gas volume, which can account for 40% or more of the available pore space, will need to be retained to avoid watering out of the wells (Goeber 1965).

Deliverability. Deliverability in aquifers depends on product of permeability and net-pay thickness. This product may be estimated using flow tests. Alternatively, permeability may be measured on whole core and/or core plugs and thickness may be estimated using logs. While at times flow tests with gas have been performed, water tests are the preferred choice. This is because the former is more difficult to conduct, is more costly, and is more difficult to interpret. A gas injection test however, gives a more direct measure gas injectivity especially in early stages of injection (Wang and Holditch 2005). After estimation of wellbore injectivity, the reservoir potential for fluid acceptance and water displacement away from the storage area will need to be evaluated. This is

[7] Use of water pump tests and measurement of pressure at an observation well within the target formation is used for determination of total compressibility-porosity product.

because pressure interference between wells could lead restrictions on production rate. Dereniewsky et al. (1982) have given examples from natural gas storage sites, where as a result of pressure interference between wells reservoir deliverability is less than half of the summation of the deliverability of the individual wells.

6.1.3 Similarities and Differences between Natural Gas Storage and CO_2 Storage

The following is a summary of similarities and differences between natural gas storage and CO_2 storage.

- Requirements that are associated with a preferred site for natural gas storage are the same as those for CO_2 storage.
- Natural gas storage is close to centres of population; CO_2 storage sites will preferably be far from cities and closer to CO_2 emitters.
- Natural gas storage started in reservoirs close to centres of population. While this still remains a general trend, storage sites at greater distances (150 to 300 km) away from the market have been successfully developed. CO_2 storage might follow a similar path. In time, it is expected that CO_2 storage sites farther from emitters may be necessary, or even favoured.
- Knepper (1997) suggests that storage capacity has remained steady for roughly 20 years through the 80's and 90's at approximately 7.5 Tcf. Assuming an average reservoir pressure 10 to 15 MPa (1500 to 2250 psia) this corresponds to approximately 1Gt CO_2 storage capacity. The needed storage capacity for CO_2 is much larger.
- The majority of this stored natural gas is produced (and re-injected) on a yearly basis. In CO_2 storage, a steady accumulation of CO_2 in the storage site is expected for a period of 10 to 50 years, followed by closure.
- Other differences include the need for production of the injected gas. This means: (i) lateral flow (migration) of gas is not acceptable, (ii) projects with large number of wells are typical.
- There is a difference in the concept of deliverability between production and storage. In production, the number of wells is significantly affected by the size of the reserve whereas in storage, it is the deliverability capacity that is paramount. For example, if the size of a reservoir is 5 Bcf (~ 140×10^6 m^3), to produce it economically one may require 1 well, whereas when the same size reservoir is used as a storage, several wells may be needed to achieve the needed peak deliverability, or injectivity to fill up in one season what took 10 years to deplete with one well. When moving to CO_2 storage a similar difference might arise (in the opposite direction) where CO_2 storage will likely be designed for a steady rate.
- While most gas storage aquifers are pressurized above their discovery pressure, there is compensation during production periods so that often the average pressure against the sealing beds on a year-round basis is essentially that natural to the aquifer (i.e., the annual or multiannual average of pressure increase is null). For a CO_2 storage site where CO_2 is injected at a constant rate, it is expected that pressure would be continuously rising.

- Similar to natural gas storage, in early phases of CO_2 injection, when the water is being displaced, injection pressures should be controlled carefully (to overpressure values less than 1 MPa) to avoid any pressure fluctuations that would get directly imposed onto the caprock.

- Active engineering techniques, such as production of water from natural gas storage sites in aquifers, have been used for pressure control. Similar methods can be used in use of aquifers for gas storage. Hassanzadeh (2006) has demonstrated use of such techniques for increasing solubility trapping.

- While in gas storage the flow of the stored gas beyond the spill point (or a saddle) is not desirable, in CO_2 storage, flow of CO2 beyond the spill point may be OK (and may in fact be desirable, provided integrity of the caprock is ensured

- For gas flow in aquifers, Katz et al. (1963) have developed relations that relate the outward flow of water at the boundary with overpressure and aquifer properties in homogeneous and uniform aquifers. For CO_2 storage volumes are much larger. Therefore the area of pressure plume is much larger (in excess of 100 km by 100 km). As such assumption of homogeneity is invalid. In this context, investigation of the relation between injectivity and dynamic capacity is necessary.

- There is little evidence in the gas storage literature of the application of geophysical methods for monitoring. Instead, there is significant reliance on the use of observation wells for monitoring. It is expected that in heavily developed basins (where a large number of wells may be available, or their drilling may be inexpensive) well-based techniques be used more often, particularly if depth and/or the nature of the overlying formations does not allow geophysical images to be obtained with sufficient resolution. On the other hand, in offshore environments, where the cost of drilling a well is orders of magnitude higher than that onshore and where geophysical measurements may provide better resolution, use of such monitoring techniques may prevail.

- In characterisation of the caprock for natural gas storage, there is significant reference to the use of gas intrusion pressure tests, and use of water pump tests for detecting any communication pathway(s) with overlying strata. Geomechanical techniques for caprock characterisation are rarely used. In CO_2 storage, however, the continuous rise of pressure associated with continuous injection needs to be taken into account and the geomechanical evaluation of the caprock should be part of the site characterisation process.

The presence of H_2S in a dissolved state in aquifer water needs more consideration. It is possible that injection of CO_2 would lead to release of H_2S, which in turn could lead to safety concerns. Some deep saline aquifers may contain dissolved gases such as natural gas and H_2S, as a result of hydrocarbon generation and migration and of thermo-sulphate reduction. This is the case of some deep saline aquifers in foreland basins of the Rocky Mountains in North America. When a plume of injected CO_2 comes in contact with brine containing dissolved gases, including H_2S, thermodynamic equilibrium is achieved between the various gases and brine, as a result of which some dissolved gases, including H_2S, will exsolve from the brine into the CO_2 plume. Consequently, even if the original CO_2 stream did not contain these gases, the subsurface CO_2 plume will. In case of leakage, both CO_2 and the contained impurities will leak, which may increase risks if the contained impurity is H_2S.

6.2 Acid Gas Disposal in Western Canada

Acid gas is a mixture of CO_2 and H_2S obtained by separation of these gases from produced sour natural gas before the latter is sent to markets. Since 1990 acid gas has been injected into deep saline aquifers and depleted hydrocarbon reservoirs in western Canada and the United States. Until the late 1980's and early 1990's sulphur recovery and acid-gas flaring were considered the most economic ways of dealing with sulphur in sour and acid gases. As a result of public concern about flaring, including human and animal health, environment degradation and waste, regulatory agencies in western Canada (Alberta and British Columbia) have not allowed flaring since 1990 and require that operators reduce/eliminate atmospheric emissions. Because desulphurization and sulphur blocking on the ground are both uneconomic and environmentally hazardous to shallow groundwater, operators increasingly are turning to acid gas injection as the most economic means of avoiding atmospheric emissions. The number of sites that were in operation at various times is close to 60, but some sites were rescinded over time either by the operator or by the regulatory agency. Currently there are approximately 50 acid gas disposal operations in western Canada that cumulatively inject approximately 1 Mt acid gas/year, of which approximately half is CO_2 and half is H_2S. To date, approximately 9 Mt of acid gas have been injected into deep saline aquifers and depleted oil and gas reservoirs in western Canada. More than 20 acid gas disposal operations are active in the United States, most of them being located in Texas, Oklahoma and Wyoming. The largest acid-gas disposal operation in the world is operated by ExxonMobil at La Barge in Wyoming, which was designed to inject 1,700,000 m^3/d at ~5410 m (17,750 ft) depth in a carbonate formation of ~9% porosity and <10 mD permeability, and temperature of ~130 °C. The La Barge gas plant actually supplies CO_2 for CO_2-EOR in the nearby Monell and Salt Creek oil fields, and to the Rangely oil field in Colorado. In addition to these operations in North America, acid gas disposal operations are in construction in Iran and in central Asia, and consideration is being given to implementing a few in North Africa.

Acid gas disposal operations constitute the best analogue to CO_2 storage, the only difference between the two being their scale. Otherwise the objective is the same, avoiding emitting these gases into the atmosphere by isolating them in the geosphere. Various aspects of the acid gas disposal operations in western Canada have been presented previously in a series of papers (Bachu and Gunter, 2004, 2005; Bachu and Haug, 2005; Bachu et al., 2005) that reviewed them at the time of writing, not of publishing, such that they present these operations at various times between the end of 2002 (Bachu and Gunter, 2004) and summer of 2005 (Bachu and Gunter, 2005), with the other two at different times within this interval. The brief summary here represents an updated review of these operations as of 2008.

The acid gas is separated from sour gas using amines, and is dehydrated usually using a four- or five-stage compression process during which water drops out of the gas. In Canada the selection of an acid-gas injection site must address considerations that, more than anything else, relate to the safety and security of the operation, such as: proximity to the source of acid gas to minimize transportation distances, confinement of the acid gas in the subsurface, effect of the acid gas on rock matrix, protection of energy, mineral and groundwater resources, equity interests, wellbore integrity and public safety. More specifically, the geological and hydrogeological assessment of the site is designed to evaluate the potential for leakage, and includes:

- size of the disposal zone, to confirm capacity;

- thickness and extent of the overlying confining layer, and any fractures that may affect the ability to contain the injected acid gas;
- location and extent of underlying and/or laterally-bounding formations;
- folding and faulting in the area, and an assessment of neotectonic (seismic) risk;
- rate and direction of the natural flow system, to assess the potential for migration of the acid gas;
- permeability and heterogeneity of the injection zone;
- chemical composition of formation fluids (brine, oil or gas);
- formation temperature and pressure;
- core analyses of the disposal formation and caprock (if available);
- a complete and accurate history of offset wells within the radius of influence of the disposal well, to identify wells and/or zones that may be impacted by the acid-gas disposal operation; and
- composition of the injected acid gas.

To avoid acid gas leakage through the caprock, maximum bottom-hole injection pressure is set by the regulatory agency at a fraction of the rock fracturing threshold (90% in Alberta, 75% in British Columbia), and also below the displacement pressure of brine in the caprock (capillary entry pressure), whichever is less. Table 10 presents the range of relevant characteristics of the acid gas disposal operations in western Canada.

Characteristic	**Minimum Value**	**Maximum Value**
Licensed injection rate (10^3 m^3/d)	10	900
Actual injection rate (10^3 m^3/d)	0.84	500.7
Actual injection rate (kt/year)	0.5	280
Licensed injection volume (10^6 m^3)	6	1876
CO_2 content in acid gas	0.14	0.98
H_2S content in acid gas	0.02	0.83
Injection depth (m)	824	3432
Net pay (m)	4	100
Porosity (%)	3	30
Permeability (mD)	1	4250
Formation pressure (kPa)	5915	35,860
Formation temperature (º C)	26	116
Water salinity (mg/l)	19,740	341,430
Oil gravity (º API)	16	56.6
Gas specific gravity	0.57	1.19
Acid gas density at in-situ conditions (kg/m^3)	204.8	728.3
Acid gas viscosity at in-situ conditions (mPa·s)	0.02	0.09

Table 10: Characteristics of acid-gas disposal operations in western Canada (injection rates and volumes are at standard conditions of 15 °C temperature and 101.3 kPa pressure).

Acid gas is or was disposed in deep saline aquifers at 31 sites, in depleted oil or gas reservoirs at 23 sites, and in the water leg underlying a reservoir at 3 sites. Given the thermodynamic properties of CO_2 and H_2S, the acid gas is injected in liquid phase at most of the sites, although there are a few sites where it is injected in gaseous phase. At 36 sites injection takes place in carbonate rocks and at 21 sites in sandstones. Shales, evaporites, and anhydrites and tight limestones form the caprock.

The minimum stress in the Alberta basin is horizontal ($\sigma_{min} = S_{Hmin}$), oriented parallel to the trend of the Rocky Mountains and with an estimated gradient of roughly 17 kPa/m, and the rock fracturing threshold P_f at the acid gas injection sites has an average gradient of 19 kPa/m. Licensed maximum bottom hole injection pressures are below S_{Hmin}, thus avoiding the potential opening of existing fractures.

There were several cases of unexpected performance issues in the case of six acid-gas disposal operations: acid gas broke through at producing wells in three cases of acid gas disposal into a depleted gas reservoir (Pooladi-Darvish et al., 2008a,b), in these cases gas production ceased; in one case acid gas injected into a depleted reservoir broke through at producing wells in another reservoir believed to be separated from the disposal one by a closed fault, when actually the fault was open(ed); in two cases of disposal in depleted reefal oil reservoirs the pressure increased above the licensed maximum bottom hole pressure as a result of hydrodynamic communication - these operations were rescinded by the regulatory agency.

The experience of acid gas disposal in western Canada is relevant to site selection and characterisation for CO_2 storage because it shows:

- what are the regulatory requirements currently in force for site selection and characterisation;
- the range of characteristic parameters for these operations that are transferable to CO_2 storage operations; and
- the importance of proper site selection and characterisation to avoid malfunctioning of the storage site.

This review of acid gas disposal operations shows that they are absolutely analogous to CO_2 storage, the only difference being in the significantly larger volumetric, spatial and temporal scales of the latter versus the former. However, the difference in scales, and public attitude and perception, may require additional site selection and characterisation criteria.

7. Synthesis

Carbon dioxide capture and storage is a technologically complex process that has three major components: industrial capture of CO_2 from large stationary sources; transportation, most likely by pipeline but also by ship at some point in the future, and storage in geological media at depths where, for efficacy of storage, CO_2 is in a dense-fluid phase (liquid or supercritical). The storage component has itself several successive activity stages:

- Site selection and characterisation, including scenario analysis and performance prediction
- Preliminary design
- Application and permitting
- Facilities design and construction
- Operation
- Closure, and
- Post-closure

It should be noted here that monitoring is a key element in site operation, closure and post-closure (IOGCC, 2005, 2008). In the early stages of deployment of CO_2 storage technology, there will likely be operations that will start with a pilot phase before full-scale implementation. The data and information gathered during this pilot phase will improve the site characterisation.

The security of storage is a common thread throughout all the stages of the storage chain, and it has to be demonstrated when applying for tenure of the storage unit and permit to operate, during operations, and after cessation of operations and site abandonment. In the first stage, the security of storage is demonstrated through a due-diligence process of site selection and characterisation. Storage security is not the only criterion by which a future CCS site is selected, but this criterion is an eliminating one, i.e., sites that are not secure will never be selected and/or permitted. In addition to being safe and secure, storage sites have to be economic, environmentally acceptable, and generally acceptable to the public. While economic conditions and/or societal attitudes may change, such that sites that do not meet these criteria today may meet them at some time in the future (i.e., these are “soft” criteria as defined by Bachu (2003), site safety and security is a “hard” criterion in the sense that it will not change in time (Bachu, 2003). It is not possible to engineer safeguards at the scale necessitated by CO_2 geological storage, as opposed, for example, to nuclear waste disposal where the small radioactive waste volume allows construction of engineered barriers in addition to the natural barriers at the site (Bachu and McEwen, 2009).

Site characterisation is not a single, linear process that starts and ends during this stage. During the selection process, the proponent of the project will likely evaluate the available existing characteristics of a number of sites to rank them, and will perform scenario analysis and performance predictions for these sites in order to select the best available site. If important information is missing, a preliminary characterisation may be required. Subsequent operation, closure and post-closure stages will require site monitoring and updating of predictions of CO_2 fate and effects, and this requires baseline characterisation prior to the start of operations, and also continuous site characterisation as new data and information are acquired as a result of monitoring during these stages, as recommended by the Interstate Oil and Gas Compact Commission (IOGCC, 2005;

2008). During application and permitting, the regulatory agency(ies) may require additional data and information, thus sending the applicant back for more detailed characterisation. Even during the first stage, site characterisation will most likely be an iterative process by which an initial evaluation is conducted on the basis of existing data and information; some additional data then are collected to complement the existing data and cover gaps in knowledge; the number of potential storage sites is narrowed down from a multitude of candidates to a few; more detailed characterisation follows until a site is chosen; followed by very detailed characterisation to meet the requirements of the application and permitting process and the collection of the baseline information needed for future monitoring.

The objectives of site characterisation during the pre-construction stages are to demonstrate to the proponent(s), the regulatory agency(ies), the financial supporters and insurers, and the public that the proposed storage site is safe, secure and acceptable from equity, environmental, and health and safety points of view. The economics of the site is a matter of interest between the proponent and its financial supporters and insurers, but it is of no interest to the regulatory agency(ies) and the public. The objectives of site characterisation during the operation, closure and post-closure stages are to improve the understanding about the fate and effects of the injected/stored CO_2, to ensure that the operation meets the conditions under which it was permitted or permission for abandonment was granted, to optimize the storage operations, and to allow remedial action in case these conditions are not being met. This report concerns itself with the criteria for site selection and characterisation prior to designing, constructing and operating the storage site.

The suite of site characterisation criteria is a collection of types of data and information needed to reach the necessary understanding and confidence that the proposed storage site is safe and acceptable, and that it can be operated and abandoned in a safe and secure manner. Site selection criteria are the criteria by which a site is judged, assessed, evaluated, and, in the case of multiple potential storage sites, ranked, for final selection. Together they form the basis on which the proponent of a CCS operation proceeds to the next stage, that of application and permitting. Site selection and characterisation depends on the scale of the assessment: basin and/or regional scale, or local and/or site specific (Bachu et al., 2007), and also on the storage medium, in this case deep saline aquifers or hydrocarbon reservoirs. Accordingly, site selection and characterisation criteria will be discussed by these categories. It is important to note that the data requirements and the level of detail (resolution) are in an inverse relationship with the scale of the assessment (Figure 3; Bachu et al., 2007). Much less data and detail are needed for basin and/or regional scale assessments than for local and/or site scale assessments, and this applies to selection and characterisation criteria as well.

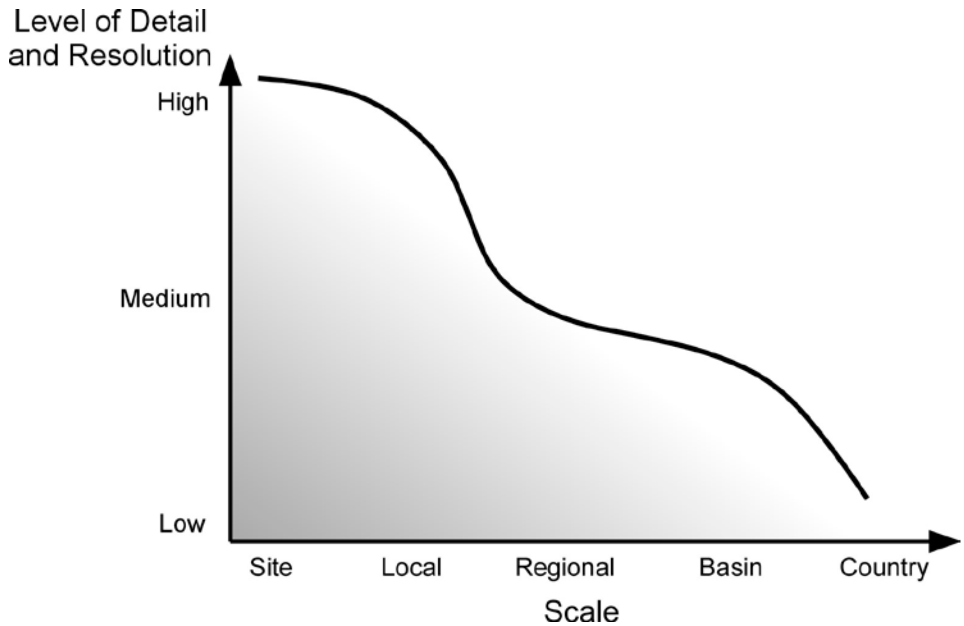

Figure 3. Relationship between level of detail and resolution of a CO_2 storage capacity assessment and its scale (from Bachu et al., 2007).

7.1 Basin and/or Regional Scale Screening

The criteria for basin and regional scale evaluation and ranking developed by Bachu (2003) with improvements by IPCC (2005) and Kaldi and Gibson-Poole (2008) form the basis of site screening at these scales. Table 11 presents a set of **suitability** criteria, i.e., a sedimentary basin or region that does not meet these criteria should not be considered for CO_2 storage. The first three criteria (depth, seals, and pressure regime[8]) are **critical criteria**, in the sense that a basin or part thereof that does not satisfy either one of these criteria should automatically be deemed as not suitable for CO_2 storage because of the high risk of compromising the safety and security of storage. The next four criteria (size, seismicity, faulting and fracturing, and hydrogeology) are **essential criteria** in the sense that there may be special cases that have to be thoroughly documented and justified where if one of these criteria is not being met, but all the others are, such a basin may still be considered for CO_2 storage. An example would be a small intramontane basin with a single large CO_2 source (e.g., a pulp mill) and with no other options for storage, such as in the Canadian Rocky Mountains, or sedimentary basins in California where hydrocarbon reservoirs are present. However, if more than one of the essential suitability criteria is not being met, then that basin or region should not be considered for CO_2 storage. Finally, the last criterion (Legal Accessibility) is also a critical criterion (i.e., it is eliminatory by itself), but unlike the others, it is not a physical characteristic of the basin but rather a designation resulting from a legislative or regulatory act that may change in the future. Examples are certain offshore North American basins were drilling and exploration are not permitted at this time.

[8] In the context of basin/regional scale screening, pressure regime refers to the whole basin or a significant portion thereof, whereby the basin is overpressured (approaching lithostatic), hence presenting a higher risk. This should not be confused with a reservoir that is overpressured in a basin that otherwise is hydrostatic or subhydrostatic, where generally the basin is suitable for CO_2 storage and even the overpressured reservoir might be suitable, albeit with reduced capacity because of the overpressuring.

	Criterion Type	Criterion	Not Suitable	Suitable
1	Critical	Depth	Less than 1000 m	[9]Greater than 1000 m, with storage units deeper than 800 m.
2		Reservoir-seal pairs and stratigraphic sequences	Poor (few, discontinuous, faulted and/or breached)	Intermediate and excellent At least one major extensive, regional-scale competent seal[9]
3		Pressure Regime	Over-pressured	Hydrostatic or sub-hydrostatic
4	Essential	Seismicity (basin tectonic setting)	High and very high (subduction zones; syn-rift and strike-slip basins)	Very low to moderate (foreland, passive margin and cratonic basins)
5		Faulting and Fracturing Intensity	Extensive	Limited to Moderate
6		Hydrogeology	Shallow, short flow systems, or compaction flow	Intermediate and regional-scale flow systems; topography and erosional-rebound flow
7		Surface Areal Extent[10]	Less than 2500 km^2	Greater than 2500 km^2
8	Critical	"Legal" Accessibility	Forbidden	Possible

Table 11: Suitability criteria for assessing sedimentary basins for CO_2 geological storage.

Other suitability criteria for CO_2 storage, listed in Table 12 below, do not fall into either the critical or essential category, but rather they fall in the **desirable** category. The first four criteria (1 to 4) in Table 12 refer to general CO_2 storage characteristics of a basin. Storage sites within fold belts are less desirable because of faulting. However, there may be cases where storage sites may be found in the fold belts of mountain ranges, similarly to the very large gas reservoirs found in the thrust and fold belt of the Canadian Rocky Mountain foothills. Diagenetic processes usually lead to loss of porosity (hence of storage space) and permeability (hence of injectivity). Warm basins have lower storage efficacy and the stored CO_2 is subject to stronger buoyancy forces because of lower CO_2 density. Salt beds have the advantage that they form strong barriers to upward flow (aquicludes or caprock), and both salt domes and beds may offer the opportunity of CO_2 storage in salt caverns. The next five criteria (5 to 9) refer to the potential for storage in specific media. Hydrocarbon potential and industry maturity refer to the potential for CO_2 storage in oil and gas reservoirs, while the presence or absence of coal seams, their rank and their economic value refer to the potential for CO_2 storage in coal beds (not discussed in this report, but included in this table for the sake of completeness). The next four criteria (10 to 13) are proxies for the economics of CO_2 storage. Costs are

[9] This requirement and the one for criterion #3 were recently adopted by the Technical Committee of the National Atlas of CO_2 Storage in Canada (unpublished).
[10] This size threshold was recently adopted by the Technical Committee of the National Atlas of CO_2 Storage in Canada (unpublished). A basin that at surface is 50 by 50 km in areal size (5 x 5 townships in North America) will be smaller at depths greater than 800 m, hence it will be too small for CO_2 storage.

higher deep offshore, in harsh climate conditions (e.g., in the Arctic), in places that are difficult to access (again, Arctic, or intramontane basins, etc.) where infrastructure is lacking and has to be built. The last criterion is also a proxy for economics, but the economic distance may change with developments in pipeline technology and construction, in shipping technology, or with the construction of new CO_2 sources (e.g., compression stations along the planned pipelines that will bring natural gas from Arctic basins in Canada and Alaska to population centres and industries in Canada and the U.S.A.). None of these criteria is eliminatory by itself, and it could be that a basin or region therein may have several unfavourable characteristics but still be considered for CO_2 storage. On the other hand, if too many criteria are unfavourable, then serious consideration should be given to the question whether or not to proceed with CO_2 geological storage in that basin.

	Criterion	**Undesirable**	**Desirable**
1	Within fold belts	Yes	No
2	Significant diagenesis	Present (manifest through reduced porosity and permeability)	Absent
3	Geothermal Regime	Warm basin (Gradients > 35°C/km and/or high surface temperature)	Cold and moderate basins (Gradients < 35°C/km and low surface temperature)
4	Evaporites (salt)	Absent	Domes and beds
5	Hydrocarbon potential	Absent or small	Medium to giant
6	Industry Maturity	Immature	Mature
7	Coal seams	Absent, very shallow or very deep (< 400 m or > 800 m depth)	At intermediate depth (400 to 800 m)
8	Coal rank	Lignite or Anthracite	Sub-bituminous and/or bituminous
9	Coal value	Economic	Uneconomic
10	On/off shore	Deep offshore	Shallow offshore and/or onshore
11	Climate	Harsh	Moderate
12	Accessibility	Inaccessible or difficult	Good
13	Infrastructure	Absent or rudimentary	Developed
14	CO_2 Sources within economic distance	Absent	Present

Table 12: Desirable characteristics of sedimentary basins or parts thereof suitable for CO_2 storage.

In regard to criterion #14, it may or may not be applied depending on local conditions and particularly the stage of development of a particular region or country. For example, in the case of existing large CO_2 sources it is important to identify potential storage sites in basins as close as possible to these sources, while in other cases it may be important to identify and characterise potential geological sinks for CO_2 because their location may affect the economics and decisions regarding the location and/or infrastructure relating to planned or future large stationary CO_2 emitters, particularly if they have to be capture and storage ready.

Generally, Table 12 can be used to asses if a sedimentary basin has poor or good potential for CO_2 storage before proceeding with storage capacity estimations and site selection. A basin or part thereof that meets most of the desirable criteria has good potential, while the reverse is true for basins or regions with poor CO_2 storage potential.

7.2 Local and Site Scale Screening

A storage site must meet the criteria for identification of sedimentary basins suitable for CO_2 storage (Table 11), should posses desirable (or favourable) characteristics (Table 12), and must meet additional screening criteria that are specific and can be applied at these scales, but not at the basin and/or regional scales, such as injectivity and capacity. It should be clarified here that, in this context, "site" means the actual storage unit located in a three-dimensional geo-spatial framework, and not the surface land location of the site. A storage site may exist in the subsurface but may be inaccessible at surface, or multiple stacked sites may exist at a single land location, etc.

Based on the work to date, site selection criteria can be grouped into the following broad categories:

1) Capacity and injectivity, which is similar to capacity and deliverability in natural gas storage;
2) Confinement, including avoidance or minimization of risks to other resources, equity and life, as well as return of CO_2 to the atmosphere;
3) Legal and regulatory restrictions, including access;
4) Economic, including costs, infrastructure, financing, etc.,
5) Societal attitudes.

Although capacity and injectivity were listed as separate criteria for site selection in the past, more recent work, also reviewed in this report, indicates that they are not completely independent of each other, at least not during the active period of injection. Because of the link between the two, they are considered hence as a single criterion. There is a significant difference between the first and the second of the criteria listed above, and these criteria should be met simultaneously. However, if capacity and/or injectivity are less than those initially desired or estimated, operational adjustments can be made (e.g., storing less CO_2 or injecting at a lower rate, with the balance of CO_2 being diverted to another site, or just storing a smaller volume than that emitted). On the other hand, lack of confinement would automatically exclude a site from consideration. A storage site meets the containment requirement if the injected CO_2 does not migrate or leak out of the storage unit as permitted by the regulatory agency(ies). However, as long as CO_2 does not migrate or leak into other hydrocarbon reservoirs, aquifers used for mineral or geothermal resources, shallow aquifers containing potable water, the vadose zone or at the surface, containment still could be acceptable in a multi-layered system (secondary containment; Oldenburg, 2008). Although not desirable, and it might occur by accident, it is possible to have a storage site where CO_2 leaks beyond its immediate caprock, for the leaked CO_2 to be confined by another caprock shallower in the stratigraphic section. Natural gas storage sites with such conditions have been successfully (and economically) used in the past, where the natural gas was collected from beneath the upper caprock and sold or returned into the main storage site. Also, the first criterion applies to the active period of CO_2 injection, which is in the order of decades, while the second one applies to a much longer period, up to three orders of magnitude longer than the injection period. Failure to properly assess site capacity and/or injectivity can and will be identified during the operational (injection) period, and, in the case that either of these is lacking, measures can be taken immediately, such as increasing well injectivity, drilling additional CO_2 injection or water production wells, or moving to another site if there is insufficient capacity. Meeting the second criterion must be demonstrated prior to injection, based on site knowledge and predictions of the fate and effects of the injected CO_2. Lack of confinement, with corresponding CO_2 migration and/or leakage[11], may occur much later (years to centuries) after cessation of injection, in which case different remedial measures have to be taken that no longer affect the selection and operation of the site. Many other detailed site selection criteria derive from these two.

Some of the screening criteria are outright eliminatory, such as unacceptable risk of leakage, or strong public opposition, or lack of access. Some may be applicable at a particular moment in time, but may change in the future, e.g., economics of operation, or regulatory changes, or availability in the case of a hydrocarbon reservoir that is still producing. Below is a detailed list of criteria on which basis prospective CO_2 storage sites should be assessed. Some of these are eliminatory while others are only unfavourable; however, if a prospective storage site has too many unfavourable characteristics then serious consideration should be given to rejecting it.

7.2.1 Eliminatory Screening Criteria

The following are several eliminatory site selection criteria, i.e., sites falling in any of the following categories should generally be eliminated from further consideration and characterisation. In discussing these criteria, the reader should be aware of the three-dimensionality of the problem, the storage unit being located at a certain depth in the subsurface but requiring land access at surface. These criteria can be grouped into three broad categories: a) lack of legal and/or physical access, b) potentially affecting other resources whose production and/or utilisation has primacy over CO_2 storage; and c) lacking security and safety. The criteria are all important, and presenting them in this order does not signify order of decreasing importance. Furthermore, although one may view the safety and security criteria as being more important than those in the other two categories, the authors believe that all site selection criteria are important in guiding the proponents of a CO_2 storage site in selecting a site that will meet all requirements. Thus, the screening criteria are listed in the order in which the site selection process would/should be approached. If sites are not accessible for whatever reason, or storing CO_2 will impact on other resources, then these sites will be eliminated before expending significant time and resources for assessing site suitability based on the last category of criteria.

1) Legally inaccessible. This is the case of potential sites located in protected or reserved areas, such as national parks, protected natural reserves, military areas and regions where drilling and exploration are prohibited (e.g., offshore in certain US and Canadian waters). In some cases exceptions can be made by legislative and/or regulatory bodies, such as in the case of the Gorgon project located on the Barrow island offshore northwestern Australia, but generally this is an eliminatory criterion. Aboriginal reserves in the Americas and Australia may also fall into this category, although there will likely be cases where permission may be granted by the leadership of the reserve.

[11] For clarification, migration in this context is defined as the lateral movement of a plume of injected CO_2 within the same geological unit, e.g., aquifer, but out of the storage site as legally defined through the tenure and permitting process, while leakage is defined as cross-formational flow of CO_2 out of the storage unit into overlying strata and possibly to shallow groundwater, soil and/or the atmosphere.

2) Legally unreachable. This is the case of sites for which right of access cannot be obtained for various reasons (mostly land access). In some jurisdictions there are regulatory bodies that may decide and grant right of access for the greater public good.

3) Legally unavailable. This would be the case of a prospective site, such as a hydrocarbon reservoir, in which there are third party equity interests that make the site unavailable for CO_2 storage. Future legislation may deal with this situation through unitization, like in the case of flooded oil reservoirs. Or it could be the case of a subsurface property owner, like in the case of free holders in Canada, or land owners in the US, who refuse access to, or use of, the subsurface storage site itself.

4) Physically unavailable. This would be the case of a hydrocarbon reservoir still in production, and possibly of an aquifer used for mineral or geothermal energy production, unavailable for CO_2 storage within the time period of interest.

5) Potentially affecting other natural, energy and mineral resources and equity. Sites where CO_2 storage may indirectly adversely affect other resources and/or equity, such as hydrocarbon reservoirs and brines with geothermal or mineral potential, should not be considered for CO_2 storage. This would be the case of CO_2 and/or brine leaking or migrating into other reservoirs or aquifers. There will be cases when the interested parties may reach compensatory agreements, but generally such sites should be considered only as a last resort.

6) Within the depth of protected groundwater. Sites at depths encompassed by the designation of protected groundwater should not be considered for CO_2 storage, regardless of actual physical depth that may in some cases be greater than the accepted 800 m. Protected groundwater is defined as groundwater with salinity less than a certain threshold, which varies between 4000 and 10,000 ppm depending on the jurisdiction. With increasing needs for water and increasing reliance on groundwater, probably groundwater with salinity less than 10,000 ppm should probably be protected for human, agricultural and industrial use.

7) Lacking at least one major, extensive, competent barrier to upward CO_2 migration. This obviously relates to the requirement of security and safety of storage, i.e., containment within the primary storage unit. A highly fractured region, with fractures reaching to the surface will also fall into this category. The caprock should be any combination of salt, anhydrite, shale or claystone, and likely at least 5 m in thickness[12].

8) Located in an area of very high natural or induced seismicity. This also relates to the security and safety of storage.

9) Located in overpressured strata. The risks of leakage and/or well blow-out are higher in overpressured strata (approaching lithostatic) than in normally-pressured and sub-hydrostatic aquifers and/or reservoirs.

[12] Although Ramírez et al. (2008) recommend a minimum thickness of 10 m, there are many documented cases of very competent caprock thinner than 10 m.

10) Lacking monitoring potential. Monitoring can be divided into three categories: (1) operational monitoring, which tracks the plume during the injection phase; (2) containment monitoring, which detects the migration of CO_2 from the primary reservoir, and (3) assurance, or environmental, monitoring, which detects CO_2 in the shallow subsurface, potable aquifers, soils or the atmosphere. Monitoring may be undertaken using a range of geophysical surveys (e.g. seismic, microgravity, electrical, electromagnetic), geochemical methods (water, soil or air sampling and analysis), reservoir surveillance (e.g. formation pressure, well integrity) or measurements of surface deformation (e.g. satellite radar interferometry, tiltmeters, global navigation satellite systems). Since it is assumed that regulatory requirements for site permitting, operation and abandonment will include monitoring of the fate and effects of the injected CO_2, sites where operational and containment monitoring may not be possible will most likely not be approved, and, hence, should be avoided. However, monitoring potential must be assessed for all possible monitoring technologies. In some cases, geophysical surveys may not be suitable for operational monitoring for geological reasons (e.g. thin reservoir, low porosity), but may be adequate for containment monitoring. In other cases, geochemical sampling methods may be deemed adequate. Monitoring potential may also be limited for logistical reasons, for example where wells cannot be drilled for geochemical sampling or pressure monitoring, or where monitoring through geophysics, wells or other techniques will be difficult due to high population density or protected natural environments (e.g., Sørensen et al., 2009).

One may argue that criteria 3 and 4 (site availability) implicitly cover criteria 5 and 6 (affecting other resources or groundwater); however, criteria 3 and 4 are broader, and criteria 5 and 6 need explicit identification. Also, one may question if monitoring potential, which does not fall specifically in any of the three broad categories mentioned initially, should be an eliminatory criterion. In the authors' opinion, lack of monitoring potential may and likely will lead to the rejection of a proposed CO_2 storage site. Currently monitoring is not a requirement for selecting and permitting sites for natural gas storage and for acid gas disposal, but there are significant differences between these and CCS operations that require monitoring of the latter: i) the injected volumes are comparatively much smaller in the former than in the latter; ii) the traps used for natural gas storage are shallower and very well characterised; iii) it is in the interest of the operator to monitor the stored natural gas to avoid losses, and iv) the fill/draw cycle of natural gas storage limits its the spread, which is not the case of CO_2 storage. As a closing comment, perhaps monitoring at natural gas storage and acid gas disposal sites should be a requirement[13], to avoid accidents like the natural gas leak in 2001 at Hutchinson in Kansas. A 2D seismic line recorded about 1 month after the leak showed reflection amplitude dimming that was interpreted to be caused by gas in shallow fracture-prone dolomites (Nissen et al., 2002).

[13] The Energy Resources Conservation Board, which regulates injection of fluids in the subsurface in Alberta, Canada, is currently reviewing the requirements for permitting and operating acid gas disposal sites in light of the implementation in the near term of several commercial-scale CO_2 storage operations in the province as a result of provincial and federal initiatives in CCS.

7.2.2 Site Selection Criteria

While the previous criteria were of an eliminatory nature (i.e., yes/no, a site either passes these criteria or is rejected), the following criteria are only desirable. Failure to meet a particular criterion will not eliminate a potential storage site, it will only reduce its "preferability" or "desirability". Furthermore, in contrast with many of the previous studies, hard numbers are not used in this report to designate an acceptable property. This is primarily because, depending on the size of the operation, the minimum requirements may change. For example, the permeability and thickness of 0.1 Mt/year storage operations would need to be very different from a 10 Mt/year project. Instead, important parameters are identified. These will then need to be incorporated in sometime simple and sometime complex (i.e., simulation) calculations to evaluate the desirability of a selection site.

Criteria that are being automatically met by passing the eliminatory criteria will not be repeated.

1) <u>Sufficient capacity and injectivity</u>. As mentioned previously, it is desirable to have sufficient capacity for storing emissions at the supply rate for the entire period of time, but, depending on economics and the expansion of the pipeline network for CO_2 collection and distribution, smaller-capacity sites may be considered. It is very important to assess not just the "static" storage capacity according to accepted methodology and guidelines and based on ultimately-available pore volume (through displacement of native fluids, compression of the rock matrix and contained fluids, and CO_2 dissolution during the injection period), but also the "dynamic" storage capacity, i.e., the storage capacity that can be achieved during the active lifetime of the project by injecting CO_2 at rates and pressures that meet safety and regulatory requirements. This refers to maintaining maximum bottom hole injection pressure (BHIP) at injection wells, and/or aquifer or reservoir pressure below one of, or some combination of, the following:
    a. Initial reservoir pressure (in the case of storage in hydrocarbon reservoirs),
    b. A percentage of the rock fracturing threshold (usually established by regulation),
    c. Fracture and/or fault opening or reactivation (shearing) pressure (for pre-existing fractures and faults) in the storage unit,
    d. Rock fracturing threshold in the caprock,
    e. Fracture and/or fault opening or reactivation (shearing) pressure (for pre-existing fractures and faults) in the caprock,
    f. Caprock displacement pressure (pressure at which the injected CO_2 intrudes into the caprock, related to capillary pressure and interfacial tension of the CO_2/brine system at in situ conditions). It should be clarified here that, in addition to the height of a CO_2 column, as suggested by some authors, the absolute pressure of the CO_2 phase at the caprock interface is of importance (and will likely play the dominant role).

   The dynamic storage capacity is most likely significantly less than the static storage capacity, and along with injectivity can be better evaluated through numerical modelling (simulation) of injection over an area that could be orders of magnitude larger than the expected CO_2 plume, including various injection strategies such as:

a. Increasing the number of injection wells,
b. Using directional and horizontal wells,
c. Other active engineering techniques[14].

It is important to note that the contribution of mineral trapping is negligible during the active period of CO_2 injection and should not be considered in storage capacity estimations. The contributions of residual-gas trapping and dissolution to storage capacity during the injection period are larger than that of mineral trapping. Their estimation however, requires detailed characterisation that may be unavailable even after the project is initiated. Therefore, it is expected that evaluation of the importance of these mechanisms will be seriously limited by the uncertainty introduced by data variability, distribution and quality. If computer simulations are being used for estimation of capacity and injectivity, as suggested in this document, the importance of solubility and residual trapping could be evaluated using uncertainty assessment and sensitivity studies, provided that data are available.

2) *Located at sufficient depth*. Generally a depth of minimum 800 m has been considered as desirable or even necessary for CO_2 storage to maximize storage efficacy (amount of CO_2 stored per unit of pore volume). Although this is not a "hard" threshold, in the sense that some sites could be at a shallower depth as long as they meet all other criteria, the congruence of this and other criteria such as groundwater protection, and the general acceptance of this threshold depth, makes it generally screening criterion. Shallow hydrocarbon reservoirs may be the exception to this criterion since they have demonstrated confinement of buoyant fluids and there is no groundwater or other resources to be protected in the reservoir itself. Thus, consideration may be given to using them for CO_2 storage, particularly if other options are not available, are poorer or are more expensive.

3) *Sufficient thickness*. Thick aquifers or reservoirs are preferable to thin ones not just because of assumed higher storage capacity, but also because they allow various injection strategies (e.g., injection at the bottom, letting the plume of CO_2 rise), that can be assumed to lead to areally smaller plumes of CO_2, to increase CO_2 dissolution through larger area of contact between CO_2 and aquifer water, to increase CO_2 residual-gas trapping through exposing more pore volume to CO_2, and to increase the potential for monitoring of plume evolution using

[14] Active engineering techniques, such as pumping aquifer water while injecting CO_2, can increase capacity. This strategy will help maintaining lower pressures, but it increases the cost of the operation and it also requires disposal of the produced water in another aquifer, which: i) will increase pressure in that aquifer, and ii) will reduce the storage capacity of that aquifer that may itself be used for CO_2 storage. Unless production of aquifer water can be co-optimized (e.g., production of dissolved minerals), and the water can be disposed of or utilized at surface (e.g., for agricultural or industrial purposes), this option of active aquifer storage engineering is not likely to be pursued. Other active engineering techniques have also been suggested, including water production from the target formation and its reinjection on the CO_2 plume at some distance from the CO_2 injector (Hassanzadeh 2006), or application of water-alternating-gas (CO_2) injection, both of which would improve solubility trapping.

geophysical methods. A minimum thickness of 20 m is recommended, although natural gas storage and acid gas disposal operations have used even thinner aquifers or reservoirs.

4) *Sufficient porosity* for capacity. The experience in Europe and at In Salah in Algeria suggests that porosity should be at least 15% (Chadwick et al., 2008; Ringrose et al., 2009), while international experts consulted on selecting storage sites in The Netherlands recommend at least 10% porosity (Ramírez et al., 2008). However, the North American experience with CO_2-EOR, acid gas disposal and natural gas storage suggests that, depending on the size of the project and other factors, porosity can be as low as 3%.

5) *Adequate permeability* for injectivity. Again, the European studies (Chadwick et al., 2008; Ramírez et al., 2008) recommend permeability to be at least 200-300 mD. However, the experience at In Salah (Ringrose et al., 2009) and in North America indicates that, depending on the required injection rates, permeability in the order of 10-20 mD is also sufficient.

6) *Low temperature* (as defined by low geothermal gradients and/or low surface temperatures). This increases storage efficacy by ensuring higher CO_2 density, yielding higher storage capacity for the same pore volume. It also increases storage security by decreasing the density difference between CO_2 and brine or oil, hence decreasing the buoyancy force that would drive the CO_2 upwards.

7) *Favourable hydrodynamic regime*. Aquifers with long-range, regional-scale flow systems are preferable to those with intermediate or short/restricted systems because the former will allow a much longer travel time during which the injected CO_2 will dissolve and/or be immobilised by residual-gas trapping.

8) *Hydraulically isolated from protected groundwater*. There are instances of deep saline aquifers, which, although part of a deep regional system, are, nevertheless, in hydraulic communication (even contact) and equilibrium with shallow, protected groundwater aquifers. Injection of very large volumes of CO_2 in these aquifers may lead not to CO_2 migration into the protected groundwater zone, but of brine displacement into these aquifers, thus compromising the quality of the shallow protected groundwater (see Nicot, 2008). Storage of CO_2 in such aquifers should be carefully considered.

9) *Low number (density) of wells penetrating the storage area of influence*. The presence of wells increases the potential and risk of leakage. Although studies in Alberta, Canada, and The Netherlands, have shown that various well characteristics, including time of drilling and/or abandonment, affect the potential of wells to leak, generally the larger the number of wells is, the higher is the potential for leakage. The presence of wells constitutes a conundrum for the following reasons. A larger the number of wells leads to a better characterisation of the storage unit, increases confidence and certainty, and increases the potential for monitoring through fluid sampling, pressure monitoring and/or well-based seismic methods (e.g., microseismic surveys or 3D vertical seismic profiles). On the other hand, as stated, the potential for leakage increases with an increasing number of wells. Furthermore, situations may arise, as is the case in Alberta, Canada, where an aquifer is fully penetrated all the way by many

wells producing from a deeper hydrocarbon reservoir. In such case, the hydraulic isolation of the penetrating wells is critical.

It is very important to have a clear and thorough understanding of what constitutes the area of influence. Injecting CO_2 in a reservoir or aquifer has two effects: introduction of an immiscible buoyant fluid that will spread and migrate for a certain distance until immobilisation, and increasing reservoir or aquifer pressure, which will propagate significantly faster and beyond the distance of the CO_2 plume itself. This pressure wave may affect other resources and may induce brine leakage in wells and/or fractures that otherwise will not be reached by CO_2. In this respect, the presence of wells and their potential for leakage should be considered for the area of influence as defined by pressure increase and not by CO_2 plume extent. Within the CO_2 plume area, gasses that were initially dissolved in the formation water may be present, as they may have evolved out of solution because of change in composition. In cases where the initial formation water has high concentration of toxic gases (e.g., H_2S which is found in some deep saline aquifers in western Canada as a result of sulphate thermo-reduction), the risk assessment in the CO_2 plume area should take into account that the buoyant gas may be more toxic than the one that was originally injected.

10) *Presence of a multi-layered overlying system of aquifers/reservoirs and aquitards/caprock*. This increases the safety and security of storage (secondary containment in case of leakage), and is particularly important in the case of sites with a significant number of well penetrations.

11) *Potential for attenuation of leaked CO_2 near and at surface* (in shallow groundwater, soil and in the air). Sites with characteristics more favourable for CO_2 attenuation and dispersion near and at the ground surface as a result of topographic, climatic and/or vegetation conditions should be preferred to sites where CO_2 will have a tendency to stagnate and accumulate[15].

12) *Site accessibility and infrastructure*. This affects the cost/economics of transportation to the storage site. This criterion includes any combination of location (onshore/offshore), terrain and climate difficulty, right of access (e.g., pipeline corridors) and avoidance of populated or reserved areas that have to be bypassed. This can be assessed through an economic analysis of various storage options.

13) *Transportation economics*. This includes distance from CO_2 source, cost of pipelines and/or ships, and cost of compression and delivery on site.

14) *Storage economics*. This includes the cost of site facilities, wells and compression, and operational and environmental monitoring, all of which affect the cost/economics of the entire CO_2 capture and storage operation.

11) *Population density*. Sites located in areas of high population density (basically cities) should not be considered because of very likely public opposition. For example, the sedimentary succession beneath the city of Edmonton, Alberta, with a metropolitan population of slightly over 1 million people and a very large

[15] Such favourable characteristics are found, for example, in open areas with air circulation (wind)

footprint (area), likely contains several good geological storage sites, but these would be inaccessible and unreachable, and the very attempt to permit them will encounter very strong public opposition that will likely force the regulatory agency to turn down any application that would consider such a site. This criterion should be applied carefully and only relative to local conditions and options because population density varies greatly around the world.

The authors wish to draw attention here that not all the criteria listed above are truly independent one of each other. Only the criteria of capacity, injectivity, hydrodynamic regime, low number of penetrating wells, multi-layered system, surface attenuation of CO_2, accessibility and infrastructure, economics, and population density are independent of each other. The other criteria: depth, thickness, porosity, permeability, and temperature are either implicitly included in the previous ones or are inter-related. They have been suggested in the past to be site selection criteria and they are included here for the sake of explicit identification as parameters, for easy use when other criteria are harder to estimate (e.g., capacity and injectivity) and also for consistency with previous studies. However, none of these should be a site selection criterion by itself for the following reasons.

I. Depth is really a proxy for pressure and temperature to reach the supercritical conditions for CO_2, where the efficacy of CO_2 storage (amount of CO_2 stored per unit volume) is higher as a result of higher CO_2 density.
II. Compartmentalized high-permeability aquifers may have less capacity than lower permeability open aquifers.
III. The characteristics of the CO_2-EOR and acid gas disposal operations in North America show that injection of CO_2 is possible in sandstone and carbonate aquifers and reservoirs as thin as 4 m, with porosity as low as 3% and permeability as low as 1 mD, and at depths reaching more than 5000 m. While one may claim that these are comparatively low injection-rate operations, injection of ~1 Mt CO_2/year at In Salah in Algeria occurs in a 20 m thick sandstone of only 10 mD permeability (Ringrose et al., 2008). Thus, the suggested minimum operational values depend more on the size of the CO_2 storage operation than on some artificially-imposed absolute threshold value.
IV. Thickness, porosity and permeability are included indirectly in the criterion of capacity and injectivity. Porosity and thickness are also included in the criterion of monitoring potential. Depth is included indirectly in the criteria of groundwater protection and storage economics. Thus, these parameters should not be double counted, and, as long as the main criteria of capacity, injectivity and monitoring potential are being met, their absolute values should not matter.

Water salinity was also suggested by some to be a selection criterion, but it is implicitly taken into account by the criterion related to groundwater and mineral resource protection.

It could be seen that criteria 1 to 6 refer to the efficacy of storage (capacity and injectivity), criteria 5 to 9 refer to the safety and security of storage (criteria 5 and 6 belong in both efficacy and safety categories), and the last three refer, in aggregate, to the cost and economics of storage. In regard to the last category, conditions may change as infrastructure and technology develop, and as regulations and economic conditions change.

7.3 Selection of Oil Reservoirs for CO_2-EOR

Storage of CO_2 in EOR operations represents a special case that requires additional or different selection criteria. Although one may argue that criteria for CO_2-EOR suitability are not necessarily criteria for CO_2 storage, as long as CO_2 storage in CO_2-EOR operations is considered and recognized as a viable option, it is important to be able to identify oil reservoirs that are suitable for CO_2-EOR, hence with CO_2 storage potential. Based on the review of previous literature and on the characteristics of existing CO_2-EOR operations (Section 4.1), the following criteria (Table 13) can be used for identifying oil reservoirs suitable for miscible CO_2-EOR (we have not included the immiscible operations because, as pointed-out in Section 4.2, the storage capacity of immiscible projects is generally lower than that of the miscible ones, and the existing projects are far fewer than the miscible ones, hence limiting our ability to draw conclusions). The condition that reservoir pressure should be greater than the minimum miscibility pressure (MMP) for miscibility, while at the same time it should be less than the fracturing pressure P_f, implicitly introduces a screening criterion that MMP should be less than P_f.

Once an oil reservoir has been identified as suitable for CO_2-EOR, only economic criteria would apply in the decision to pursue CO_2-EOR, hence storing CO_2. All other criteria are either not applicable or are satisfied automatically. It is very likely that CO_2-EOR operations will be selected and permitted under a different set of regulations than CO_2 storage operations; however, for a CO_2-EOR operation to be converted into a CO_2 storage operation it will have to meet the criteria for CO_2 storage. Currently regulatory agencies have not developed specific criteria and regulations for permitting or converting “CO_2-EOR and Storage” operations.

Reservoir Parameter	**Miscible CO_2-EOR**
Size (ROIP in MMstb; or $MtCO_2$)	≥1 (whichever condition is met first)
Depth (ft/m)	>1500 (>450)
Temperature (ºF/ºC)	82 to 250 (28 to 121)
Pressure	> MMP and < P_f
Porosity (%)	≥3
Permeability (mD)	≥5
Oil Gravity (API)	27 to 45
Oil Viscosity (cP/mPa·s)	≤6
Remaining Oil Fraction in the Reservoir	≥0.30

Table 13: Suggested characteristics of oil reservoirs suitable for miscible CO_2-EOR (metric values are given in brackets).

7. 4 Site Characterisation

Site characterisation is not a single, distinct, linear process in the selection and operation of a CO_2 storage site, but rather a continuous and iterative process occurring with various frequency, intensity, focus and detail or resolution during the entire lifetime of the operation, since the very beginning at selection until complete site abandonment. Time-wise, prior to CO_2 injection, sites are characterised for site selection, for permitting and for establishing the baseline conditions for subsequent monitoring. During the operational phase, site characteristics are continuously updated as new data and information are collected, particularly through monitoring, and better understanding of the site is gained. After cessation of injection, as long as a monitoring programme is in place, site characterisation will continue to improve based on the continuous flow of incoming data. Objective-wise, the purpose of site characterisation for selection and permitting is performance prediction. The purpose of site characterisation for monitoring is validation of the predicted performance, and detection of deviations from it. Its objectives and measured parameters and variables are different, depending on the expected behaviour of the injected CO_2 and of the technology used for monitoring. During injection and site closure and abandonment, the feedback from monitoring helps validate and improve the understanding of the storage unit and its internal architecture and characteristics, as well as those of the caprock and overlying strata, and also of the models and predictions regarding the fate and effects of the injected CO_2.

The major effort in site characterisation is at the beginning, during the site selection and permitting process. The aims of the initial site characterisation efforts are:

1) Site selection;
2) Evaluation of site capacity and injectivity;
3) Development of a comprehensive model of the site;
4) Evaluation of the fate and effects of the injected CO_2;
5) Assessment of the risks associated with the proposed storage operation; and
6) Meeting regulatory requirements for site permitting.

Site characterisation may also be used for design of a pilot project and design of monitoring program.

After an initial characterisation and evaluation of several prospective storage sites, usually based on existing data from various sources, and after site selection, further, more detailed characterisation follows for performance prediction and permitting. Evaluation of site capacity and injectivity, of the fate and effects of the injected CO_2, and of possible risks involves numerical modelling of multi-phase, multi-component, non-isothermal flow; geochemical and reactive transport modelling; and geomechanical modelling coupled with flow. Since comprehensive models that allow satisfactory incorporation of all of these phenomena are not readily available, individual studies are conducted where some of the processes are modelled in isolation from the others. This may not only be a reflection of the unavailability of comprehensive models, but also may be desirable because of varying objectives. For example, multi-phase flow modelling is of more importance in estimation of dynamic capacity, while geomechanical modelling is of more importance in evaluation of containment and risk of leakage. This is not to say that interaction between different phenomena should not be considered. For example, in the assessment of possible opening of micro-fractures in caprock because of a combination of dissolution and stress changes, coupling of geochemical, geomechanical and flow modelling may be required. Some additional data may be collected/generated during site characterisation for performance prediction and permitting, mainly lab data based on existing core and fluid samples. New data may be collected only if and when a new well is drilled, either for the specific purpose of additional data collection (at significant additional cost), or for injection or monitoring. New geophysical data may also be collected to improve the understanding of the geometry and petrophysical properties of the storage unit and of the overlying sedimentary succession.

There is a significant difference in the level of available data and understanding between hydrocarbon reservoirs and deep saline aquifers. The former are much better characterised and known as a result of both exploration and production, hence the level of confidence in performance predictions for these is high, while the uncertainty regarding the latter is much higher as a result of data paucity. However, this increased level of confidence in regard to hydrocarbon reservoirs usually comes at a price, namely the higher well density associated with them increases the risk of CO_2 leakage and the costs of remedial action. These factors may some cases may even lead to the rejection of a prospective site that otherwise would qualify for CO_2 storage, as in the case of the De Lier gas field in Netherlands (Hofstee et al., 2008).

Site characterisation involves mainly geosciences and engineering, and encompasses the following disciplines: geology, hydrogeology, geophysics, geochemistry, geomechanics and geotechnical engineering, reservoir engineering, and soil and atmospheric sciences. The objects of study are the rocks and fluids in the storage unit and in the entire sedimentary succession (geosphere) between the storage unit and surface (atmosphere). More specifically, the objects of study should be characterisation of:

- The three-dimensional strata of different lithologies that form the aquifers and reservoirs, and aquitards and caprock;
- Planar discontinuities such as faults and fractures;
- Linear features such as wells;
- In-situ conditions of pressure, temperature and stress; historical, current and predicted;
- Contained water/brine, oil and/or gas, including composition;
- Injected CO_2 and contained impurities (types and amounts);
- The PVT properties and behaviour of all the relevant fluids;
- The flow, mineralogical, chemical and mechanical characteristics of the geological framework, wells, and contained fluids;
- Production history for oil and gas reservoirs.

The detailed enumerations and descriptions provided by the CO2CRC and EU reports (Kaldi and Gibson-Poole, 2008; Chadwick et al., 2008) are descriptive, detailed and exhaustive in certain ways, but differently organized and incomplete in places, and will be only briefly synthesised here to provide a list of variables, properties and features that need characterisation at the selection and permitting stages of a CO_2 storage project. Furthermore, for risk assessment and monitoring purposes, site characterisation should cover not only the storage unit (aquifer or reservoir) and the immediate caprock, but also other, if not all, units in the overlying sedimentary succession, up to the ground surface.

1) *Geology*, based on well and geophysical data, includes: regional and local scale geology, stratigraphy, structure, thickness, facies distribution, lithology, geometry of the storage unit (external and internal architecture, compartmentalisation), location and extent of faults and fractures;

2) *Rock properties*, based on flow testing, core and log data and analyses, for aquifer/reservoir, and aquitard/caprock: porosity, permeability, relative permeability, capillary entry pressure, sedimentology and mineralogy, rock strength, coefficient of thermal expansion, acoustic and elastic properties (static and dynamic), such as Young's Modulus and Poisson's Ratio;

3) *Hydrogeology and geothermics:* flow direction(s) and strength in aquifers, aquitard strength, geothermal gradients;

4) *In situ conditions*, based on well tests and static measurements: pressure, temperature, stress;

5) *Fault and fracture characteristics*, based on core and log data analyses and seismic reflection surveys: orientation, shear strength (most notably friction coefficient), infilling material mineralogy and properties (if present), evidence of sealing or non-sealing attributes.

6) *Fluid properties*, based on laboratory analyses of fluid samples: water salinity, oil and/or gas composition (reservoir gas and CO_2 stream), formation factor (for oil), Z-factor or compressibility (for gas and CO_2 stream to be injected), interfacial tension (IFT) at in-situ conditions between the various fluids;

7) *Phase behaviour* of reservoir/aquifer fluids and CO_2 stream;

8) *Reservoir history* for oil and gas reservoirs: production (and injection) rates, pressure decline (and build-up);

9) *History of wells and their condition*, based on information collected by regulatory agencies and/or archived by oil companies: status (producing, injecting, suspended, abandoned), depth, direction, casing (types and grades), cementing (classes and amounts/levels), perforations, plugging (type, cements, etc.), history (including surface casing vent flow, gas migration, casing failures, leakage, stimulation treatments, workovers and repairs).

10) *Land features*, such as topography, rivers and lakes, land ownership and use, right of access, transportation corridors and roads, railway and/or harbours, population centres, reserved areas.

Performance prediction modelling for site selection and permitting should include:

1) *Modelling of the pressure increase* and distribution in the aquifer/reservoir. The pressure increase defines the area of influence of the storage operation, drives the displacement of aquifer/reservoir fluids, affects dynamic storage capacity (through compression, displacement and limiting thresholds), may open or re-activate pre-existing faults and fractures, may induce well leakage, and affects the geomechanical behaviour and integrity of the aquifer/reservoir and overlying strata. It also affects interfacial tension, hence relative permeability, and geochemical reactions in the aquifer/reservoir.

2) *Modelling of fluid flow and displacement* for predicting storage capacity, the migration and possibly leakage pathways of the injected CO_2, and the migration pathways and possibly leakage of the displaced brine, particularly if it may affect shallow groundwater aquifers. Pressure and fluid flow modelling are not independent, and they are modelled together, but the distinction is made here to underline the importance of pressure effects, not just of fluid flow effects.

3) *Modelling of CO_2 dissolution and geochemical reactions* to assess CO_2 storage capacity dissolved in aquifer and/or reservoir water and/or oil (amount and timing), CO_2 storage through mineral precipitation (amount and timing), effects of CO_2 and/or CO_2-saturated aquifer/reservoir water on caprock and/or well integrity; and effects of CO_2-saturated water on shallow groundwater in case of leakage. Ideally geochemical modelling should provide a feedback loop to flow modelling in regard to expected changes in porosity and permeability as a result of geochemical reactions, but this is a very difficult task that so far has achieved limited success (more successful in predicting porosity changes, less so in predicting permeability changes).

4) *Modelling of thermal effects* of the injected CO_2. This is important when there are significant temperature differences between the injected CO_2 and the aquifer/reservoir rocks and fluids, or in the case of CO_2 leakage when shallower strata are at lower temperatures than the storage unit. Thermal stresses and CO_2 phase change depend strongly on these temperature differences and variations. Thermal modelling is usually coupled with fluid flow modelling and may need to be coupled with geomechanical modelling.

5) *Modelling of geomechanical effects* of injection, particularly in respect to opening or shear reactivation of fractures and/or faults, induced tensile or shear fracturing, wellbore stability, ground heaving and microseismicity.

6) *Modelling changes in the petrophysical properties of the formation in response to the injected CO_2*. This is necessary in order to assess the monitoring potential of the site and to determine which technologies are suitable to track the CO_2 plume.

7) *Modelling of CO_2 spread and production, and incremental hydrocarbon recovery* when stored in enhanced hydrocarbon operations. For CO_2-EOR and CO_2-EGR, assessing the fate of the injected CO_2, the timing of breakthrough at production wells, and the forecasted incremental oil or gas production are essential in deciding whether or not to pursue the proposed operation.

8) *Modelling of engineered options* to optimize the operation and compensate for shortcomings.

9) *Modelling of uncertainties* to better understand the range of possible responses on all of the above.

There is a direct and indirect link between characterisation and modelling because the characterisation needs to satisfy all requirements for performance modelling (and the quality of modelling results depends on the quality of the input), and has to cover the area of influence, defined by the extent of physical changes in the system (i.e., pressure effects). Furthermore, modelling should encompass the short, intermediate and long terms, i.e., the active period of injection (several decades), the closure and post-closure period leading to complete site abandonment (a few decades to possibly a few centuries), and post-abandonment (centuries to millennia).

Based on the comprehensive site characterisation and predictive modelling of the fate and effects of the injected CO_2, a comprehensive risk assessment of the storage site should be performed that should include: a) establishment of the risk assessment criteria and methodology, b) scenario analysis, c) system model development, d) consequence analysis, and e) risk analysis (defined as the product between the probability of an event occurring and the consequences of its occurrence).

Design of a monitoring programme is not part of the site selection and characterisation (assuming that monitoring is possible and feasible, otherwise the site would have been rejected), but is likely part of the permitting process and lays the ground for running a successful monitoring programme once CO_2 injection starts.

7.5 Safety and Security Qualification of CO_2 Storage Sites

The site selection criteria presented in the previous sections represent the criteria that, in the opinion of the authors, should be used, either sequentially or in parallel, for selecting sites for CO_2 storage. As mentioned in Section 7.2, the selection criteria could be grouped into the following five categories:

1) Capacity and injectivity;
2) Confinement, namely; safety, security and environmental acceptability;
3) Legal and regulatory restrictions, which can in turn be subdivided into:
    a. Legally inaccessible, unreachable or unavailable;
    b. Potentially affecting other resources whose production or protection has primacy over CO_2 storage, such as: energy resources (hydrocarbons, coal, geothermal), mineral resources (either as deposits or dissolved in brine), and potable groundwater.
4) Economic, i.e., cost, as expressed by proxies such as: proximity of CO_2 sources, location (onshore, offshore), climate, accessibility and infrastructure, and potential for CO_2-EOR.
5) Societal.

There are a few screening criteria that may fall into more than one category. For example, location in a high-density population area could be considered a “societal criterion” because of likely public opposition, a safety criterion because of the increased risk in case of leakage (for the same probability and amount of leakage, consequences will be much higher in a densely populated area than in a sparsely populated one), and an economic criterion because of the higher costs associated with increased monitoring and protective measures. Also, a producing oil or gas reservoir may fall under the legal category, but also under the economic category.

The site selection and characterisation criteria presented thus far represent the entire set of criteria that should be used by various parties involved in CO_2 storage, particularly regulators and industry proponents. However, the intent of this report, as stated by IEA-GHG, was “to develop a set of site selection criteria that could be used in the development of future guidelines for the safe and environmentally-acceptable storage of CO_2” in geological media. Hence, the focus of the report is on the first two categories, mainly on the second one.

In regard to the site selection criteria that fall into the capacity and injectivity, and confinement categories, the authors initially considered providing classes (or grades, or degrees) of characteristics covering the spectrum of variation within each selection criterion, similarly to Bachu (2003), Kaldi and Gibson-Poole (2008) and Chadwick et al. (2008), and also ranking and assigning weights to the various selection criteria, similarly to Bachu (2003), Oldenburg (2008) and Ramírez et al. (2008). (The criteria in the other three categories have either a binary character – yes/no – or are ultimately an economic/policy/public decision). The intended approach was abandoned during the execution of the study for the following reasons:

- There is a very wide range of variability in natural systems (geological and at surface) that is extremely difficult, if not impossible, to capture;
- There is a very high variability in consequences of leakage, if it will occur, and they cannot be captured, while possible causes and consequences will most likely dictate importance and ranking of various site selection criteria;
- Conditions vary significantly from basin to basin and site to site, hence the applicability of any particular classification or ranking would likely vary;
- Qualification criteria will depend also on the size of the CO_2 operation, namely injection rate and total volume;
- There are many interdependencies between the various parameters, such as depth, temperature, pressure, stress, capacity and injectivity that cannot be separated. Setting a threshold value in one case may indirectly affect another;
- There are regions in the world where potential CO_2 storage sites are marginal or even deficient in certain attributes that will still be approved for lack of better options, albeit with increased safety and monitoring requirements; rigid application of a "qualifying system" will exclude these sites;
- Any system devised by the authors of this report would most likely not fit conditions everywhere;
- Establishment of the importance of various selection criteria rests with regulatory agencies in each jurisdiction (for ensuring public safety and equity protection) and with the companies pursuing CO_2 storage (for the cost and economics of storage);

Thus, the authors strongly believe that at this time it is neither possible nor prudent to assign global threshold values that would qualify prospective CO_2 storage sites based on a simple check list. However, to meet the terms of producing this report, the qualifiers and threshold values presented in Table 14 are being suggested. They are based on the literature review in previous chapters of this report and of authors' expert opinion. The authors make no warranty as to the applicability of these suggested values to each and every potential CO_2 storage site, and are concerned that these values may be misinterpreted, misused or used in a prescriptive way rather than just as guidelines. Only regulatory agencies have the authority to develop and implement qualification criteria within their respective jurisdictions, and it is these that should be used for actual permitting of CCS projects. Furthermore, the authors believe that establishing qualification criteria and threshold values should be the focus of one or several international workshops where they can be discussed, debated and refined[16]. After such

[16] In fact, a more appropriate objective of such a series of workshops and studies is the development of workflows and "best practices" for site selection, qualification and ranking, as opposed prescribing threshold criteria. The workflows and best practices, which may be developed after significant "case studies" are performed, would recommend how one should proceed with evaluating and ranking the suitability of geological sites for CO_2 storage. An analogy that might prove useful is the development of hydrocarbon reservoirs. After more than a century of oil and gas production, there are no threshold values for selection of preferred reservoirs to be developed. Instead, workflows have been developed as to how a company would

a process is completed, the results may serve only to inform regulatory agencies tasked with permitting and compliance-monitoring of CCS operations.

Since the focus here is on safety and security of storage sites, no distinction is made between regional/basin scale criteria and local/site scale criteria, as prospective sites must meet both sets. Similarly, no distinction is made between deep saline aquifers and hydrocarbon reservoirs because both have to meet these criteria. Table 14 presents a synthesis of all the site selection criteria that affect the security, safety and environmental-acceptability of CO_2 storage sites.

Criterion Level	No	Criterion	Eliminatory or unfavourable	Preferred or Favourable
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)
	2	Pressure regime	Overpressured: pressure gradients greater than 14 kPa/m	Pressure gradients less than 12 kPa/m
	3	Monitoring potential	Absent	Present
	4	Affecting protected groundwater quality	Yes	No
Essential	5	Seismicity	High	Moderate and less
	6	Faulting and fracturing intensity	Extensive	Limited to moderate
	7	Hydrogeology	Short flow systems, or compaction flow; Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow
Desirable	8	Depth	< 750-800 m	>800 m
	9	Located within fold belts	Yes	No
	10	Adverse diagenesis[+]	Significant	Low to moderate
	11	Geothermal regime	Gradients ≥ 35 ºC/km and/or high surface temperature	Gradients < 35 ºC/km and low surface temperature
	12	Temperature	< 35 ºC	≥ 35 ºC
	13	Pressure	< 7.5 MPa	≥ 7.5 MPa
	14	Thickness	< 20 m	≥ 20 m
	15	Porosity	< 10%	≥ 10%
	16	Permeability	< 20 mD	≥ 20 mD
	17	Caprock thickness	< 10 m	≥ 10 m
	18	Well density	High	Low to moderate

[+] Adverse diagenesis is that which reduces porosity and permeability

Table 14: Site selection criteria for ensuring the safety and security of CO_2 storage.

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perform the evaluation. In the same manner, the authors of this report are of the opinion that evaluation of suitability and ranking of CO_2 storage sites cannot be performed using just threshold values.

This table should not be used in isolation as a general recipe for project evaluation or site comparison and selection. Local conditions should be taken into account and experienced experts should apply this table to actual site selection and qualification processes. The table can serve as guidance only and should be tailored to specific conditions and needs.

Sites that do not pass the critical criteria 1 to 4 should not be considered for CO_2 storage. Although preservation of groundwater quality (criterion #4) is a resource-protection criterion, it is included here because it is also an environmental criterion. Sites that do not pass the essential criteria 5 to 7 should generally not be considered for CO_2 storage; however exceptions can be made depending on local conditions. It is desirable that storage sites meet as many as possible of the desirable criteria 8 to 18. If too many of these criteria are not favourable, then either serious consideration should be given as to the suitability of the respective site for CO_2 storage, or additional measures for site monitoring and remediation should be undertaken.

Criteria #2 and #7 apply to CO_2 storage in deep saline aquifers and much less so or not at all to hydrocarbon reservoirs. Depth, temperature and pressure (criteria # 8, 12 and 13) are introduced here only to express the desirability to have CO_2 in supercritical state, although it is recognized that it can be liquid or gaseous if storage sites at lower temperature and/or pressure are considered. The thickness and porosity thresholds are based on seismic monitoring potential more than storage capacity. In fact, criteria # 10 to 16 are proxies for capacity and injectivity. High well density provides data and information that reduce uncertainty; however, the potential for leakage increases with increasing number of wells, thus a trade-off between uncertainty and risk should be considered. No consideration is being given as to maximum depth of storage, since this is mainly an economic consideration relating to the cost of well drilling and CO_2 compression. Similarly, no consideration is given to water salinity, assuming that salinity is greater than that of protected groundwater, since water salinity affects CO_2 dissolution, which has a limited effect on storage safety and security. Finally, no consideration is being given to capillary entry pressure in the caprock since it is assumed that maximum bottom hole injection pressure (BHIP) will be by regulation below the lesser of displacement pressure, fracture/fault opening or reactivation pressure, and induced fracturing threshold.

8 Summary

Sites suitable for geological storage of CO_2 must meet a series of criteria that can be broadly grouped into the following categories:

1) Safety and security of storage;
2) Capacity and injectivity for the volume of CO_2 to be stored;
3) Legal access and regulatory permission;
4) Economic; and
5) Public acceptance.

Consequently, site screening and selection criteria could be classified as:

a) Eliminatory criteria, on which basis sites are eliminated from further consideration; these are of two kinds:
   I. Critical – these criteria have to be met without exception, otherwise a site should be rejected;
   II. Essential – these criteria should also be met, but some exceptions may occur/be granted, depending on circumstances
b) Selection criteria, on which basis sites that passed the eliminatory screening are selected on the basis of having most favourable characteristics. Sites may still be rejected if too many unfavourable conditions exist.

Site selection should normally proceed along a scale continuum from basin or regional scale to local or site-specific scale. Table A presents eliminatory (critical and essential) and selection criteria for basin or regional scale assessments. Detailed explanations are provided in Section 7.1.

	Criterion Type	Criterion	Not Suitable/ Unfavourable	Suitable/Desirable
1	Critical	Depth	Less than 1000 m	Greater than 1000 m, with storage units deeper than 800 m.
2		Reservoir-seal pairs and stratigraphic sequences	Poor (few, discontinuous, faulted and/or breached)	Intermediate and excellent At least one major extensive, regional-scale competent seal
3		Pressure Regime	Over-pressured	Hydrostatic or sub-hydrostatic
4		“Legal” Accessibility	Forbidden	Possible
5	Essential	Seismicity (basin tectonic setting)	High and very high (subduction zones; syn-rift and strike-slip basins)	Very low to moderate (foreland, passive margin and cratonic basins)
6		Faulting and Fracturing Intensity	Extensive	Limited to Moderate
7		Hydrogeology	Shallow, short flow systems, or compaction flow	Intermediate and regional-scale flow systems; topography and erosional-rebound flow
8		Surface Areal Extent	Less than 2500 km^2	Greater than 2500 km^2

9	Selection	Within fold belts	Yes	No
10		Significant diagenesis	Present	Absent
11		Geothermal Regime	Warm basin (Gradients > 40°C/km and/or high surface temperature)	Cold and moderate basins (Gradients < 40°C/km and low surface temperature)
12		Evaporites (salt)	Absent	Domes and beds
13		Hydrocarbon potential	Absent or small	Medium to giant
14		Industry Maturity	Immature	Mature
15		Coal seams	Absent, very shallow or very deep (< 400 m or > 800 m depth)	At intermediate depth (400 to 800 m)
16		Coal rank	Lignite or Anthracite	Sub-bituminous and/or bituminous
17		Coal value	Economic	Uneconomic
18		On/off shore	Deep offshore	Shallow offshore and/or onshore
19		Climate	Harsh	Moderate
20		Accessibility	Inaccessible or difficult	Good
21		Infrastructure	Absent or rudimentary	Developed
22		CO_2 Sources within economic distance	Absent	Present

Table A: Characteristics of sedimentary basins or parts thereof suitable and favourable for CO_2 storage[17].

In Table A, criteria 1 to 3 and 5 to 7 refer to the safety and security of storage, criterion 8 refers to capacity, and criterion 4 refers to legal access. Criteria 9 to 12 refer to general basin characteristics that affect, albeit to a lesser extent, the safety, security and efficacy of storage, criteria 13 to 17 refer to the potential for storage in specific geological media, and criteria 18 to 22 are proxies for the economics of storage. Sites suitable for CO_2 storage must be located in sedimentary basins that pass the critical criteria 1 to 8 (although some exceptions to one of the criteria 5 to 8 can be made in certain circumstances) and posses as many as possible of the favourable criteria 9 to 22.

Local and site-specific scale eliminatory criteria can be grouped into three broad categories:

1) Lacking access
   a) Legally inaccessible: located in a protected or reserved area;
   b) Legally unreachable: located in an area with no right of access;
   c) Legally unavailable: a site, such as a hydrocarbon reservoir, with third-party equity interests;
   d) Physically unavailable: a site, such as a hydrocarbon reservoir, still in production;

[17] Table A is a combination of Tables 11 and 12 in Section 7.1.

e) Physically inaccessible: a site located in a high-density population area such as a city.

2) Potentially affecting other resources:
   a) Third-party equity;
   b) Energy and mineral resources: hydrocarbon reservoirs, geothermal, mineral-rich brines;
   c) Protected groundwater
3) Poor safety/security
   a) Lacking at least one major, extensive, competent barrier to upward migration of CO_2;
   b) Located in an area of very high natural, or potential for induced, seismicity;
   c) Located in overpressured strata;
   d) Lacking monitoring potential.

Selection of storage sites among those that have passed the screening process should be based on meeting or possessing the most favourable characteristics in regard to the following selection criteria. These criteria can be grouped into several categories.

1) Sufficient capacity and injectivity:
   a) Static capacity based on volumetric pore volume
   b) Dynamic capacity based on maintaining injection and aquifer/reservoir pressure during the operational period below one, or the smaller, of:
      i) Percentage of rock fracturing pressure (established by regulatory agencies) for aquifer/reservoir and/or caprock,
      ii) Fracture and/or fault opening or reactivation pressure for aquifer/reservoir and/or caprock;
      iii) Displacement pressure in the caprock (pressure at which CO_2 will displace the brine in the caprock);
      iv) Initial pressure for hydrocarbon reservoirs[18].
2) Higher storage efficacy:
   a) At sufficient depth (greater than 750-800 m)
   b) Thick aquifers or reservoirs;
   c) Low temperature/geothermal gradients;
   d) Long-range, regional-scale flow systems.
3) Higher safety and security of storage:
   a) Low number of wells penetrating the area of influence, which should be defined based on the pressure perturbation as a result of injection rather than the extent and reach of the injected CO_2.
   b) Presence of a multi-layered system of aquifers and aquitards for secondary containment in case of leakage;
   c) Potential of attenuation of leaked CO_2 near and at surface;
4) Accessibility, infrastructure
   a) Location: onshore or offshore;
   b) Terrain and climate difficulty;
   c) Right of access and avoidance of populated and/or reserved areas;
   d) Transportation corridors;
   e) Roads on land, harbours and marine platforms offshore.

[18] Normally, if criteria i. through iii. are met, there should be no issue with injecting CO_2 at pressures greater than the initial reservoir pressure. However, because of the possible negative effect on the reservoir caprock of reservoir depressuring during production and pressuring back during CO_2 storage, regulatory agencies are taking the view that the reservoir pressure should not pass the initial pressure. This is the case with acid gas disposal in Alberta, Canada.

5) Transportation economics
   a) Distance;
   b) Cost of pipelines and/or ships;
   c) Cost of compression and delivery on site;
6) Storage economics
   a) Cost of site facilities;
   b) Cost of wells;
   c) Cost of compression;
   d) Cost of operational monitoring
   e) Cost and difficulty of environmental monitoring.

Oil reservoirs suitable for miscible CO_2 flooding, hence CO_2 storage in CO_2-EOR operations, should meet the following additional criteria.

Reservoir Parameter	Miscible CO_2-EOR
Size (ROIP in MMstb; or $MtCO_2$)	≥1 (whichever condition is met first)
Depth (ft/m)	>1500 (>450)
Temperature (ºF/ºC)	82 to 250 (28 to 121)
Pressure	> MMP and < P_f
Porosity (%)	≥3
Permeability (mD)	≥5
Oil Gravity (API)	27 to 45
Oil Viscosity (cP/mPa·s)	≤6
Remaining Oil Fraction in the Reservoir	≥0.30

Table B: Characteristics of oil reservoirs suitable for miscible CO_2-EOR (metric values are given in brackets)[19].

In the above table MMP is minimum miscible pressure, and P_f is fracturing pressure. It is very likely that CO_2-EOR operations will be selected and permitted under a different set of regulations than CO_2 storage operations; however, for a CO_2-EOR operation to be converted into a CO_2 storage operation it will have to meet the criteria for CO_2 storage. Currently regulatory agencies have not developed specific criteria and regulations for permitting or converting "CO_2-EOR and Storage" operations.

Considering site selection criteria only from the point of view of storage safety and security, particularly during the injection period, the following qualifiers and threshold values are being suggested (Table C). These represent the expert opinion of the authors and they should be considered only as a starting point in a broader debate and consultation process whose results should then inform regulatory agencies in establishing requirements for permitting CO_2 storage sites. These criteria and threshold values should be used only as guidance and should be applied by experienced experts to the conditions specific to the geological, geographic, jurisdictional and societal settings of the CO_2 storage site under consideration.

[19] Table B is a reproduction of Table 13 in Section 7.2.3.

Criterion Level	No	Criterion	Eliminatory or unfavourable	Preferred or Favourable
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)
	2	Pressure regime	Overpressured: pressure gradients greater than 14 kPa/m	Pressure gradients less than 12 kPa/m
	3	Monitoring potential	Absent	Present
	4	Affecting protected groundwater quality	Yes	No
Essential	5	Seismicity	High	Moderate and less
	6	Faulting and fracturing intensity	Extensive	Limited to moderate
	7	Hydrogeology	Short flow systems, or compaction flow; Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow
Desirable	8	Depth	< 750-800 m	>800 m
	9	Located within fold belts	Yes	No
	10	Adverse diagenesis[+]	Significant	Low to moderate
	11	Geothermal regime	Gradients ≥ 35 ºC/km and/or high surface temperature	Gradients < 35 ºC/km and low surface temperature
	12	Temperature	< 35 ºC	≥ 35 ºC
	13	Pressure	< 7.5 MPa	≥ 7.5 MPa
	14	Thickness	< 20 m	≥ 20 m
	15	Porosity	< 10%	≥ 10%
	16	Permeability	< 20 mD	≥ 20 mD
	17	Caprock thickness	< 10 m	≥ 10 m
	18	Well density	High	Low to moderate

[+] Adverse diagenesis is that which reduces porosity and permeability

Table C: Site selection criteria for ensuring the safety and security of CO_2 storage[20].

Once selected, sites for CO_2 storage must be properly characterised. Site characterisation is actually a continuous and iterative process that should be implemented and carried out at all stages of a CO_2 storage operation: site selection, application and permitting, site development, operation, monitoring, closure and post-closure. Site selection is based mostly on existing data initially, but, as options are being narrowed down and the confidence in the suitability of the proposed site increases, some additional data may be collected. The site characterisation should be updated as new data and information become available during various stages of a CO_2 storage operation. The aims of the initial site characterisation (pre-design phase) are:

1) Site selection;
2) Evaluation of site capacity and injectivity;

[20] Table C is a reproduction of Table 14 in Section 7.5

3) Development of a comprehensive model of the site;
4) Evaluation of the fate and effects of the injected CO_2;
5) Assessment of the risks associated with the proposed storage operation; and
6) Meeting regulatory requirements for site permitting.

The objectives of characterisation should be to gather knowledge about:

- The three-dimensional strata of different lithologies that form the aquifers and reservoirs, and aquitards and caprock;
- Planar discontinuities such as faults and fractures;
- Linear features such as wells;
- In-situ conditions of pressure, temperature and stress; historical, current and predicted;
- Contained water/brine, oil and/or gas, including composition;
- Injected CO_2 and contained impurities (types and amounts);
- The PVT properties and behaviour of all the relevant fluids;
- The flow, mineralogical, chemical and mechanical characteristics of the geological framework, wells, and contained fluids;
- Production history for oil and gas reservoirs.

Broadly, the characterisation should cover in detail:

1) The geology of the storage unit and overlying sedimentary succession;
2) Rock properties of the storage unit and immediate caprock;
3) Hydrogeology and geothermics;
4) Fault and fracture characteristics, if present;
5) In situ conditions of pressure, temperature and stress;
6) Composition, properties and phase behaviour of reservoir or aquifer fluids and of the injected CO_2;
7) Reservoir history for oil and gas reservoirs;
8) History and condition of wells penetrating the storage unit;
9) Land features.

Based on site characteristics and projected CO_2 volume and injection strategies, performance prediction should be based on numerical modelling of the following processes, which is also part of characterisation for site selection and permitting:

1) Fluid flow, pressure changes and migration of CO_2 and native fluids (brine, oil, gas);
2) Thermal effects associated with CO_2 injection, migration and possible leakage;
3) Geomechanical effects associated with pressure increases and stress changes as a result of CO_2 injection;
4) CO_2 dissolution, and geochemical reactions and changes in regions where CO_2 and CO_2-saturated brine are present, including wells;
5) Changes in elastic moduli with CO_2 saturation;
6) CO_2 spread in hydrocarbon reservoirs, incremental hydrocarbon recovery and CO_2 production in enhanced recovery operations.

In addition, modelling of engineered options for CO_2 storage (e.g., to increase storage capacity or to improve injectivity), and modelling of uncertainties are necessary as part of site characterisation. Modelling should encompass the short term (injection period), medium term (site closure and abandonment) and long term (post-abandonment).

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