INTERACTION OF CO_2 STORAGE WITH SUBSURFACE RESOURCES

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This report describes research sponsored by IEAGHG. This report was prepared by:

CO2CRC

The principal researchers were:

- Brad Field, GNS Science
- Stefan Bachu, Albert Innovates – Technology Futures
- Mark Bunch, University of Adelaide
- Rob Funnell, GNS Science
- Sam Holloway, British Geological Survey
- Rick Richardson, CanZealand Geoscience Ltd

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The IEAGHG manager for this report was:

Millie Basava-Reddi

The expert reviewers for this report were:

- Bill Koppe, GCCSI
- Bjorn Berger, Statoil
- Karl-Josef Wolf, RWE
- Steve Whittaker, GCCSI
- Mike Godec, ARI
- Martin Streibel, GFZ
- Arthur Lee, Chevron
- Jim Underschultz, Australian Low Emissions Coal R&D
- Dave Ryan, NRCan

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Further information or copies of the report can be obtained by contacting IEAGHG at:

IEAGHG, Orchard Business Centre,
Stoke Orchard, Cheltenham,
GLOS., GL52 7RZ, UK
Tel: +44(0) 1242 680753 Fax: +44 (0)1242 680758
E-mail: mail@ieaghg.org
Internet: www.ieaghg.org

INTERACTION OF CO_2 STORAGE WITH SUBSURFACE RESOURCES

Key Messages

- Other subsurface resources may exist at similar depths and localities and therefore interact with CO_2 Storage. These include oil and gas, coal, natural gas storage, saline aquifer minerals, geothermal energy, potable groundwater and waste water disposal.
- Interaction of CO_2 storage with other resources can be positive or negative depending on the geology, existing resources, economic potential and the regulatory environment.
- CO_2 storage operations may be feasible, both adjacent to other resource uses or at different stratigraphic levels in the same locality, particularly if there is no detrimental pressure connection.
- Resource use interactions can occur at the same time or sequentially.
- Regulatory agencies should consider the following stages when evaluating resource development in relation to geological storage of carbon dioxide:
    - Identify all resources within region/ basin, map their distribution and assess their quality.
    - Establish priority of use between the various resources and CO_2 storage.
    - Assess proposed CO_2 storage project - site characterisation, MMV plans, contingency and mitigation planning.
    - Review injection plans and achievability; assess if they might lead to conflict
    - Review abandonment plan, longer term MMV, liability transfer arrangements.
- Delays in establishing CO_2 storage regulations could not only inhibit CO_2 storage project development, they could lead to future, detrimental resource interactions.

Background to the Study

Sedimentary basins that provide most of the world's CO_2 storage potential also host fossil fuel, groundwater and geothermal energy resources, as well as providing options for gas storage and permanent disposal of waste fluids.

There is a need to define key factors that affect interaction of such resources with CO_2 storage, to provide policy makers and regulators with guidance on the allocation of pore space and resource interaction management, and to clarify the potential impact of interaction on storage capacity and availability.

Storage could affect resource exploitation through fluid displacement and pressure effects beyond the extent of the CO_2 plume, as well as through direct interaction of the plume and its reaction products. Interactions could have beneficial effects, for instance by reservoir re-pressurisation, or negative effects by sterilising resources through contamination with CO_2 or its reaction by-products. This dual potential could be the case in regards to groundwater, where an increased pressure footprint caused by CO_2 injection could beneficially increase the recovery of groundwater resources, or conversely if CO_2 or the associated brine migrates out of the storage formation, there could be an adverse potential for it to reach adjacent potable groundwater resource and cause contamination, either directly or through any substances that may have been mobilised by CO_2.

The exploitation of resources, such as hydrocarbon production, may enhance CO_2 storage by de-pressurising reservoirs/aquifers and by providing re-usable boreholes and infrastructure as well as sub-surface data. This enhanced potential for storage may be durable in some cases, but temporary in others - such as circumstances where offshore oil and gas infrastructure has to be de-commissioned on completion of production, thereby limiting availability. Storage potential could also be negatively impacted, e.g. in locations where seal integrity has been compromised by poor well completions or by the fracturing of seals during shale gas production.

There may also be direct competition for the use of pore space by the proponents of other forms of sub-surface storage or disposal.

When considering locations of overlap, it is important to consider whether the overlap is geographical or whether the actual pore space is in competition. For example, in a recent IEAGHG study on potential impacts on groundwater (2011/11), regional maps showing areas of geographical overlap of potential CO_2 storage locations and potable groundwater resources have been produced. However, in some areas where there is overlap, it is known that there are impermeable layers separating the two potential resources.

Similarly for locations of geothermal resources and potential CO_2 storage resources, there may be some areas of pore space conflict, but if looking at purely geographical overlap, there is the possibility for misinterpretation as geothermal energy for power production usually takes place at much greater depths than the optimum for CO_2 storage. For district heating generation projects, they are more likely to take place at similar depths, though this may not necessarily cause a conflict as the 2 technologies still have different requirements, such as CCS projects needing a caprock, which is not the case for geothermal projects.

In areas of geographical overlap, but no conflict of pore space, it may be potentially possible to have more than one activity, though this may need to be considered on a site specific basis and any planning and monitoring programme would need to take this into account.

It may also be possible, in some circumstances, for two activities to work in synergy with each other, such as CO_2 storage with hydrocarbon production, such as in enhanced oil and gas recovery or with geothermal energy.

CO2CRC, a consortium based in Australia and New Zealand, was commissioned by IEAGHG to undertake a study considering what subsurface resources may interact with CO_2 storage and how this can be managed.

Scope of Work

The objectives of the study were to:

1. Provide a comprehensive literature-based review of sub-surface exploitation activities that may affect storage operations, focussing in regions where large scale CCS development is currently focussed.

2. Provide a qualitative assessment of potential interactions and impacts using case-study sedimentary basins.

3. Provide policy makers, regulators and developers with a checklist of potential sub-surface resource interactions together with a preliminary explanation of possible impacts and management options

4. Where possible, provide case study examples of resource interaction issues have been successfully managed to enable multiple resource use.

CO2CRC were asked to refer to the following recent IEAGHG reports relevant to this study, to avoid obvious duplication of effort and to ensure that the reports issued by the programme provide a reasonably coherent output:

- Global Storage Resources Gap Analysis for Policy Makers (2011/10)
- Potential Impacts on Groundwater Resources of Geological Storage (2011/11)

In addition, the following active IEAGHG projects have strong links to this study and IEAGHG encouraged contact between contractors to avoid duplication of effort or unnecessary discrepancies in findings:

- Potential Implications of Gas Production from Shales and Coal for CO_2 Geological Storage (ARI, draft report)

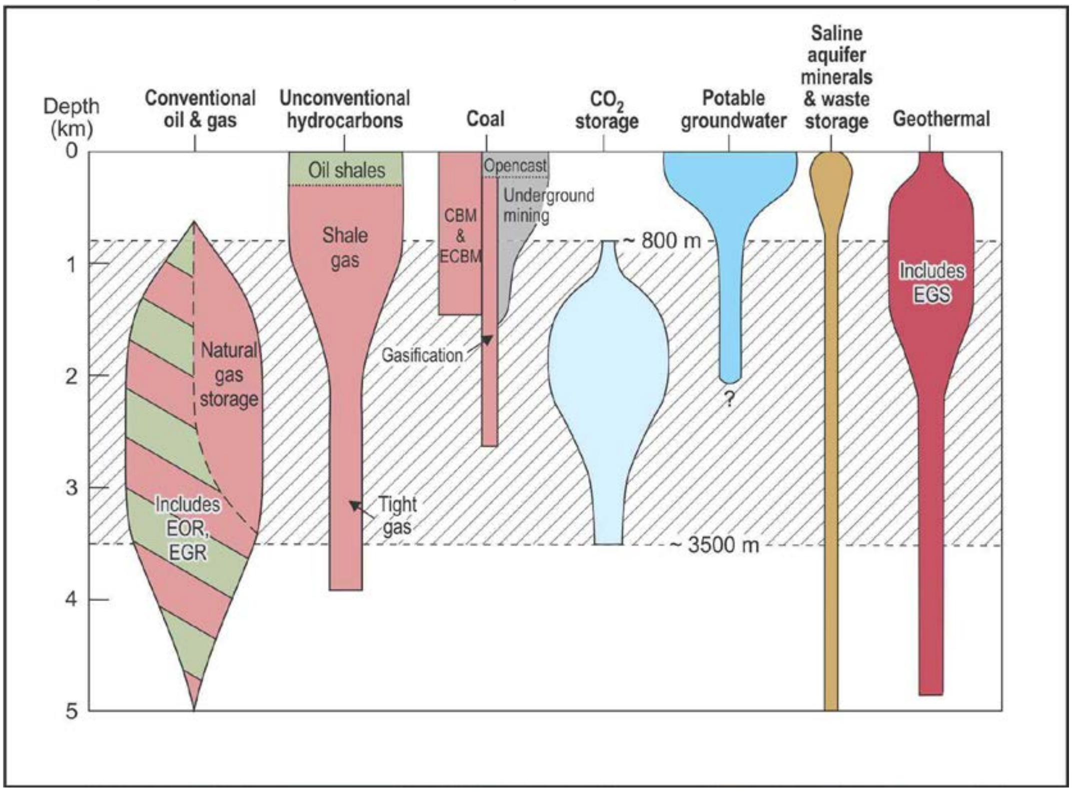
Findings of the Study

This study summarised subsurface resources that could potentially interact with CO_2 geological storage, and presented relevant case studies that looked at how subsurface resource interaction has been managed previously. This is all brought together in a final chapter which considered how potential subsurface resource interaction with CO_2 storage can be dealt with and managed.

Subsurface Resources

Potential resources considered that may interact with CO_2 Storage are conventional oil and gas, shale gas and oil, coal (including natural gas extraction and underground coal gasification), gas hydrates, natural gas storage, minerals in the formation brine and sediments, geothermal energy, potable groundwater and the disposal of waste water. These could all potentially exist at the same depth that CO_2 storage is expected to take place at, Figure. 1.

Figure 1. Schematic diagram of the typical depth ranges over which subsurface resources occur, including the use of pore space for CO_2 storage.



Most producing or prospective hydrocarbon fields occur within the 800-4000 m window desirable for CO_2 storage, and may therefore be affected by changes in pressure or fluid interactions caused by CO_2 injection. Interaction can be positive if it helps flush out residual hydrocarbons. Potential negative interactions could occur if pressure fronts or leaked CO_2 interfere with hydrocarbon production or CO_2 could exacerbate corrosion of pipes and degradation of cements used in exploration and development wells. Negative effects may be avoided by adequate seal and containment of injected CO_2 and anticipated pressure front effects. If a new oil or gas resource is discovered beneath an existing CO_2 storage site; corrosion-resistant well completion materials would need to be used, and pressure interference would need to be pre-assessed and mitigated. Pressure interference has occurred between nearby oilfields and a case study cited is the Zama oilfield, Canada. Water injection in one field caused a pressure increase at a site of acid gas injection, which limited the amount that could be injected. Therefore pressure effects of injection projects near potential CO_2 storage sites, as well as potential effects of the storage site on other injection projects should be assessed and monitored carefully.

Natural gas storage sites have the potential to conflict with potential CO_2 storage sites, but it is not likely at a commercial scale as natural gas storage sites are generally much lower capacity than ideal CO_2 storage sites. This is to reduce the amount of cushion gas (that which is irretrievable once injected) and allows the gas pressure increases quickly during injection, which facilitates rapid gas withdrawal. The optimum volumes of natural gas to be stored are much smaller than the mass of CO_2 to be captured during the lifetime of a power/ industrial plant. However, as with oil and gas fields there may be pressure interference if the sites are close by.

Shale gas and oil have the potential to affect storage security if the formation from which the shale gas is produced is the same as the caprock immediately above the storage formation. However, the if shale gas formation is not integral to storage security, then even if the storage formation and shale gas horizon are in the same geographical area, then potentially both resources can be exploited, if the site is well managed and monitored. This would need to be assessed on a site by site basis.

CO_2 can be stored in ‘unmineable’ coal seams, whereby the CO_2 displaces methane on the coal surfaces due to preferential adsorption. The coal will then not be able to be used at a later date for another purpose, including underground coal gasification (UGC), without releasing the stored CO_2; therefore the various potential uses need to be considered prior to use of the resource. UGC by itself produces large quantities of CO_2 and will likely need to be done in conjunction with CCS.

Subsurface storage of waste fluids, or produced water from mining operations has the potential to influence CO_2 storage by competition for pore space, mixing by leakage and pressure perturbation. An example of waste water disposal is the Surat basin in Queensland, Australia, where production of natural gas from coal seams requires large scale extraction of water, for which the most practical disposal option is into the surrounding subsurface formations. The Surat basin contains a series of reservoir and seal layers with the potential for multiple uses including CO_2 storage and possibly geothermal extraction. This will require extensive monitoring of injected and extracted volumes and pressure perturbations.

Potentially valuable minerals, as well as hydrocarbons may also exist within the formation waters of deep saline formations, such as lead, zinc, potash and rare earth elements as well as many other dissolved minerals. Which minerals exist will be site specific and will depend on a range of factors including source rock, tectonic history, basement rocks and hydrogeological and geothermal history. The potential for extraction of such minerals will also need to be assessed on a site by site basis. There is also the potential to combine mineral extraction and CO_2 storage with technologies such as bioextraction, or in the co-production of brine minerals.

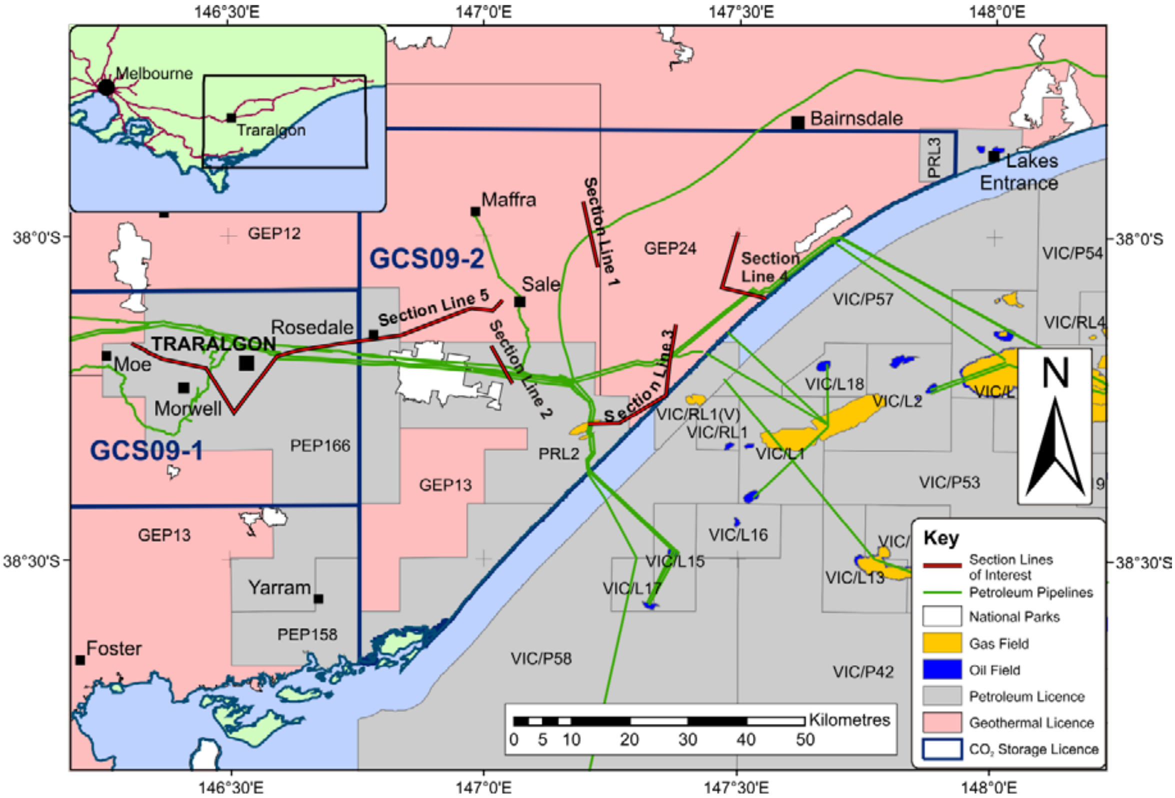
When considering geothermal energy, many resources will not be in competition, such as high enthalpy systems and hot dry rock technologies. However, low enthalpy systems, which can be used for direct heating, have the potential to interact with CO_2 storage. This is likely to be limited to onshore areas as low enthalpy geothermal energy is not economical offshore. Options for synergies include using formation water extracted from CO_2 storage sites for pressure management for geothermal energy and CO_2-plume geothermal system (CPG), which uses CO_2 to extract heat. An example of where this could occur is in the Paris basin in France, which is currently used to supply heating to several districts in Paris. The geothermal resource could be adversely affected by CO_2 storage due to direct competition of pore space and remote pressure fronts. However, dense phase CO_2 can be used as a thermal transfer medium to enhance geothermal resource use or direct competition could be resolved by development of geothermal resource in areas of higher heat flow and CO_2 storage in areas of lower heat flow. Pressure effects will need to be taken into account in this case. It should also be noted that the requirements for CO_2 storage require the presence of a structural trap, whereas geothermal projects do not, which would mean the areas of interest for CO_2 storage could form a minor subset of the areas that are of interest to geothermal projects. Information sharing and co-operation between the 2 industries will be necessary for the exploration phase and beyond.

The majority of potable groundwater is found at depths much shallower than CO_2 storage would take place and will therefore have little direct interaction. However, if shallow groundwater is in the vicinity of a storage site it will need to be considered in the monitoring programme. It can also be affected by pressure perturbations caused by injection of CO_2. This topic was covered in detail in a previous IEAGHG report on the potential effects of groundwater on CO_2 storage (2011/11). A case study considered was the Cassem project, UK, which used a hydrogeological model in conjunction with dynamic flow simulation modelling of CO_2 injection to determine the likely effects of CO_2 injection on potable groundwater. The findings showed a degree of impact to be highly sensitive to vertical permeability of the caprock. Recession of groundwater heads in the shallow unconfined aquifer occurs relatively slowly and lateral movements of the water interface are more strongly influenced by ongoing surface extraction than by CO_2 injection and migration.

A case study of management of the interaction between two subsurface resources is gas over bitumen in north-eastern Alberta, Canada. Bitumen can be extracted using steam assisted gravity drainage, whereby steam is injected to lower the viscosity of the bitumen by increasing the temperature. If the gas cap over a bitumen deposit is produced prior to the completion of bitumen production, the decrease in gas pressure may lead to a temperature drop negatively affecting the bitumen viscosity and making it impossible or uneconomical to produce. The outcome was the decision that bitumen must be produced before the gas can be produced. The significance of this example to CO_2 storage is that injection of CO_2 into reservoirs overlying a subsurface resource has the potential to increase the pressure in the underlying reservoir and potentially improve the production of the resource.

The Gippsland basin in Victoria, Australia is an example where several uses of the subsurface are expected, including oil and gas exploration, coal production, geothermal energy, potable groundwater extraction and CO_2 storage. Figure 2 shows licence boundaries for oil and gas production as well as the newer licences for CO_2 storage and geothermal energy production.

Figure 2 Map showing the coverage of state petroleum and geothermal licence areas across the onshore Gippsland Basin



The broad geographical demarcation between the newer industries and existing oil and gas operations only partially considers distribution and potential for resources as currently understood and shows wariness to impinge on current profitable operations. The large blocks given to CO_2 storage and geothermal energy overlap geographically and it will be important to understand the likely 3D footprint of future operations to understand potential interaction and maximise socio-economic benefit of the exploration mix as well as protect environmentally sensitive areas. In order to help balance exploration priorities and assess the effects of large scale CO_2 injection, a 3D model incorporating existing data (seismic, well data, known hydrocarbon fields and groundwater zones) has been produced allowing regional assessment of potential CO_2 storage areas with minimal risk of resource interaction.

Resource Interaction Issues and their Resolution

The case studies considered in this report illustrate that CO_2 storage can potentially have an influence on other subsurface resources, which in turn may influence the extent and timing of CO_2 storage projects. Influences can be positive or negative and some resources may overlap geographically, but have minimal effect on each other, especially if not in pressure communication. Potential influences are shown in Table 1.

Table 1 Positive and negative aspects of the interaction of CO_2 storage operations on other pore-space resources

Pore space resource	**Positive**	**Negative**
Oil	Might increase sweep efficiency hence more effective resource use; EOR can offset cost of storage, but not always usable; creates demand for CO_2 and hence improvement of capture technology; similar industries and service and supply needs; possible pressure enhancement	Pressure interference with existing operations; contamination of oil; infrastructure conflict; timing delays to CO_2 storage if EOR not feasible or wanted
Gas	EGR possible in some reservoirs (though rarely done); possible pressure enhancement	High cost of separating CO_2 from the produced gas if they mix; pressure interference with existing operations
Coal	CO_2 can flush out methane, creating valuable by-product	CO_2 would sterilize coal for mining or underground gasification
Groundwater	Could re-pressure low-productivity aquifers; pressure-relief wells used to increase CO_2 injection rates might produce useable water	Could acidify or contaminate potable water, or change hydraulic heads through pressure interference
Dissolved minerals	CO_2 could flush or displace saline water, enhancing water, and hence mineral extraction	CO_2 might react with some dissolved mineral salts, plugging pores
Geothermal	Better heat transfer medium than water; possible pressure enhancement	High temperatures might increase risk of corrosion; possible pressure interference with existing operations
Natural gas storage	Nil	Pore space unavailable for CO_2 storage for life of gas storage facility; pressure interference with existing operations
Waste disposal	Nil	Pressure effects or the presence of CO_2 may affect waste storage

If there is likely to be interaction between resources, decisions need to be made on how to go forward. Some regulations may distinguish priority of use, or assign different resources to different stratigraphic levels. The timings of potential resource interactions are relevant and can be classified as pre-implementation, during injection and post-injection. Pre-implementation considers options before the start of injection, such as which resource may have a higher priority, or at what point one resource should be exploited in regards to another resource, e.g. when should EOR be implemented in an injection project. During injection refers to any unexpected behaviour, such as unexpected plume migration or pressure development that may influence other resources. Post-injection refers to unexpected resource interaction after injection has ceased.

Risk assessment is necessary to deal with uncertainties by using past experience and analogues. They will allow regulatory agencies to assess the likelihood of affecting other subsurface resources and whether tying an area up under a permit is likely to lead to a successful outcome. A comprehensive risk model should support any CO_2 storage project and will be updated as more data becomes available.

Levels of certainty of storage capacity will be increased throughout the project as more is known. The initial capacity assessments will be based on the characteristics of the rock, inherited from its depositional environment and prediction of pressure and temperature conditions. As more information is known and if the capacity is less than expected, this may affect the plume size and potentially interaction with other resources.

Potential improved recovery of resources should be considered. Examples of this could be improvements to potable groundwater resources from increased pressure head; EOR, where CO_2 decreases the viscosity of oil, improving flow and production; or extraction of formation waters to mine dissolved minerals. Injection of CO_2 may also limit the use of other resources, such as storing CO_2 in coal which prevents its later use for UCG.

The rate of CO_2 injection needs to be economically viable without rupturing the seal and it is possible that the rate of injection may be less than initially predicted. If so, then solutions may include pressure relief wells and reinjection into shallower/ deeper levels, which may in turn affect other subsurface resources.

Seal integrity issues should be considered. Each storage site selected is expected to be secure, however mitigation plans will always be put in place for the unlikely case of failed seal integrity and other resources that may be affected by this need to be taken into account.

The pressure footprint of a CO_2 storage site will be much larger than the CO_2 plume itself and it will need to be determined if another resource is in pressure communication. Ground surface deformation should also be taken into account, as even though this is unlikely to be sufficient to affect other subsurface resources, it should be assessed on a case by case basis.

Any impurities in the CO_2 should be considered in terms of corrosion or potential contamination. The composition of the stream can affect storage capacity and CO_2 may react with minerals in the rock mobilising other substances, which should be taken into account.

Current infrastructure, such as old abandoned wells, can be a factor as the casing and cement could potentially be corroded by CO_2. It may also be possible to share pipeline infrastructure with oil or gas networks.

Monitoring and verification is an important aspect during all stages of a CO_2 project. There are many different monitoring methods and approaches and the best options may be site specific.

Regulatory conflict or overlap will need to be considered as resource use conflict can occur due to the wording of existing regulations or creation of new ones.

These potential influences to regulatory decisions are summarised in Table 2.

Table 2 Checklist of some of the major factors likely to be involved in regulatory decisions

Factor	Stage	Scale	Resource use effects (main types)	Examples	References
Priority of use	Licensing round design	Basin	All	Gippsland	O'Brien 2011
Timing of interaction	Licensing, permitting, operation and post-closure	Basin and prospect	Hydrocarbons, EOR, gas or waste storage	Gippsland	Varma & Michael 2012
Risk assessment	Permitting, financing, public acceptance; on-going	Prospect	All	In Salah	Bowden & Rigg 2004; Mander et al., 2011; Oldenburg et al., 2011
Storage capacity	Permitting and injection	Prospect	All	Gorgon	Flett et al., 2008
Improved recovery	Permitting and injection	Prospect	Oil, gas, gas hydrates, geothermal; extra resource extraction offsets cost	Weyburn-Midale	Buscheck et al., 2012; EGEC 2009; IEAGHG 2010/4; Nago & Nieto 2011; Regan 2007
Resource sterilisation	Permitting	Prospect	Coal, shale gas, groundwater, saline minerals, natural gas storage	Various, USA	Elliot & Celia 2012
Injectivity	Permitting and injection	Prospect	Variable; possible water production from relief wells	Gorgon	Flett et al., 2008
Seal integrity	Permitting and injection	Prospect	Groundwater, hydrocarbons	Gorgon	Flett et al., 2008
Pressure fronts	Permitting and injection	Prospect and up to ~200 km distance	Groundwater, hydrocarbons, geothermal, waste disposal	Lussagnet/ Izaute, Zama field	IEA 2010/15; IEA 2011/11; Pooladi-Darvish et al., 2011
Surface deformation	Permitting and injection	Prospect (central)	Infrastructure, Geothermal	In Salah	Oldenburg et al., 2011
Composition of gas injected (e.g., CO2+H2S)	Permitting and injection	Source/ prospect/ migration path	Groundwater, geothermal	Laboratory /Canada	Bachu & Bennion 2009; IEA 2011/4&11
Mobilisation of minerals and other substances	Operation and post-closure	Source/ prospect/ migration path	Groundwater, geothermal	Chimayo, Weyburn	Apps et al., 2010; Emberley et al., 2005; IEAGHG 2011/08; Keating et al., 2010
Infrastructure	Permitting through to post-closure	Prospect	Variable	Gorgon	Flett et al., 2008
Monitoring and verification	Permitting through to post-closure; important for public	Prospect and surrounds	All	Otway, Gorgon	Sharma et al., 2009

	acceptance and carbon credits				
Regulatory conflict or overlap	Licensing, permitting, operation	Potentially all scales	Variable	None known	None known

Expert Review Comments

Comments were received from 9 reviewers representing industry and academia and were overall highly positive. Reviewers noted that some aspects of the case studies were not up to date and that there should be more information regarding waste water disposal. This was all addressed in the final report and the Surat Basin case study was added.

Conclusions

The interaction of CO_2 storage with other resources can be positive or negative depending on the geology, existing resources, economic potential and the regulatory environment. CO_2 storage operations may be feasible, both adjacent to other resource uses or at different stratigraphic levels in the same locality, particularly if there is no detrimental pressure connection between sites. On the other hand, if pressures associated with CO_2 storage are not confined then resource uses many kilometres distant from a storage site might be affected (beneficially or detrimentally). Resource use interactions can occur contemporaneously or sequentially. In particular, existing permits might preclude CO_2 storage and CO_2 storage might preclude future use of other resources.

Regulatory agencies should consider the following stages when evaluating resource development in relation to geological storage of carbon dioxide:

1. Identify all resources within the basin or region of interest, including “vacant” pore space, then map their distribution and assess their quality. It is important to do this, even using subjective criteria or estimates if there are few hard data. This will allow an assessment of the resources likely to be affected and the range of likely interactions. The Gippsland Basin study by the Victoria State Government is a good example of this type of assessment.
2. Establish priority of use between the various resources and CO_2 storage.
3. Assess the proposed CO_2 storage project, its site characterisation, monitoring and verification plans, contingency and mitigation planning (e.g., how to cope with possible leakage, fault reactivation, loss of well integrity).
4. Review the injection plans and the likelihood that they will be achievable, and assess whether they might lead to cases of resource conflict (by seal rupture, pressure-front propagation or CO_2 plume migration into regions other than predicted or licensed to the storage operation).
5. Review the abandonment plans, longer term monitoring and verification planning and liability transfer arrangements.

Delays in establishing CO_2 storage regulations could not only inhibit CO_2 storage project development, they could lead to future, detrimental resource interactions. Nevertheless, time is needed to ensure regulations are clear and take into account potential resource prioritisation and interaction, as these issues are essential to the planning, costing, safety and surety of CO_2 storage projects. Assessments of potential resource uses in a region, and of possible usage interactions, should enable effective prioritising of opportunities in a region and efficient allocation and use of known or anticipated resources, and their potential effects on estimates of CO_2 storage capacity and injection scenarios.

Recommendations

There are several examples where interaction with other resources could potentially occur, but by looking at examples, including those from other industries, this may be able to be managed. In some cases this may not be the case and one resource may need to be prioritised over another depending on the priorities and regulations of the particular country.

This is a topic that will likely have more attention as there are more commercial sized CO_2 storage projects and it is recommended that IEAGHG continue to follow this topic and any updates, through future storage network meetings, namely the risk assessment network and by the study programme.

Interaction of CO_2 storage with subsurface resources

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[1,3]Field, B, [2]Bachu, S, [3,4]Bunch, M, [1]Funnell, R, [5]Holloway, S, and [6]Richardson, R

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[1]GNS Science; [2]Alberta Innovates – Technology Futures; [3]Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), [4]Australian School of Petroleum, University of Adelaide, [5]British Geological Survey, [6]CanZealand Geoscience Ltd

CO2CRC
Technologies

CO2CRC Technologies Pty Limited

PO Box 1130, Bentley, Western Australia 6102
Phone: +61 8 6436 8655
Fax: +61 8 6436 8555
Email: dhilditch@co2crc.com.au
Web: www.co2tech.com.au

Members involved in this study

AITF	Alberta Innovates Technology Futures	Alberta Innovates – Technology Futures, Canada
ASP	ASP Australian School of Petroleum	Australian School of Petroleum, University of Adelaide, Australia
BGS	BGS 1835	British Geological Survey, United Kingdom
CanZealand Geoscience	**CanZealand Geoscience**	CanZealand Geoscience Ltd., Canada and New Zealand
CO2CRC	CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies, Australia (CO2CRC)
GNS	GNS SCIENCE TE PŪ AO	GNS Science, New Zealand

Study carried out as part of contract IEAGHG- IEA/CON/11/198

Coordination: Brad Field (GNS)

The principal researchers for this report were:

- S. Bachu — Alberta Innovates – Technology Futures
- M. Bunch — CO2CRC at Australian School of Petroleum, University of Adelaide
- B. Field — GNS Science and CO2CRC
- R. Funnell — GNS Science
- S. Holloway — British Geological Survey
- R. Richardson — CanZealand Geoscience

The report was reviewed internally by Malcolm Arnot and Karen Higgs (GNS Science).

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Executive Summary

This report discusses likely interactions between underground CO_2 storage and other uses of sub-surface resources such as hydrocarbon and groundwater production. Its intended readership is mainly regulatory agencies and policy-makers. With this in mind it contains brief descriptions of the practicalities of CO_2 storage and of the occurrence of various sub-surface resources, with the aim of helping to bridge a potential gap between expertise in the technical aspects of resource use and expertise in policy formulation. The report describes the types of interactions which might occur, discusses case studies where such interactions are likely, and provides a checklist of issues which should be assessed in this context.

Early planning by both companies and regulatory agencies for underground carbon storage requires an assessment of the interaction of CO_2 storage operations with other subsurface resources, so that the economics, impacts and risks associated with the geological storage of CO_2 can be properly assessed. An early analysis of likely interactions may help to balance potentially conflicting resource use prior to licence allocation and reduce the risk of later litigation. An awareness of likely interactions is needed during the lifetime of projects, and continues even after projects have been completed through the design of monitoring and verification systems. Future uses of subsurface resources in the same basin might also be affected by early assessments and decisions made regarding resource interactions. The subsurface depth window most likely to be used for CO_2 storage overlaps to varying degrees with other subsurface resources (Figure i), so CO_2 injection might affect, or be affected by, several different subsurface operations.

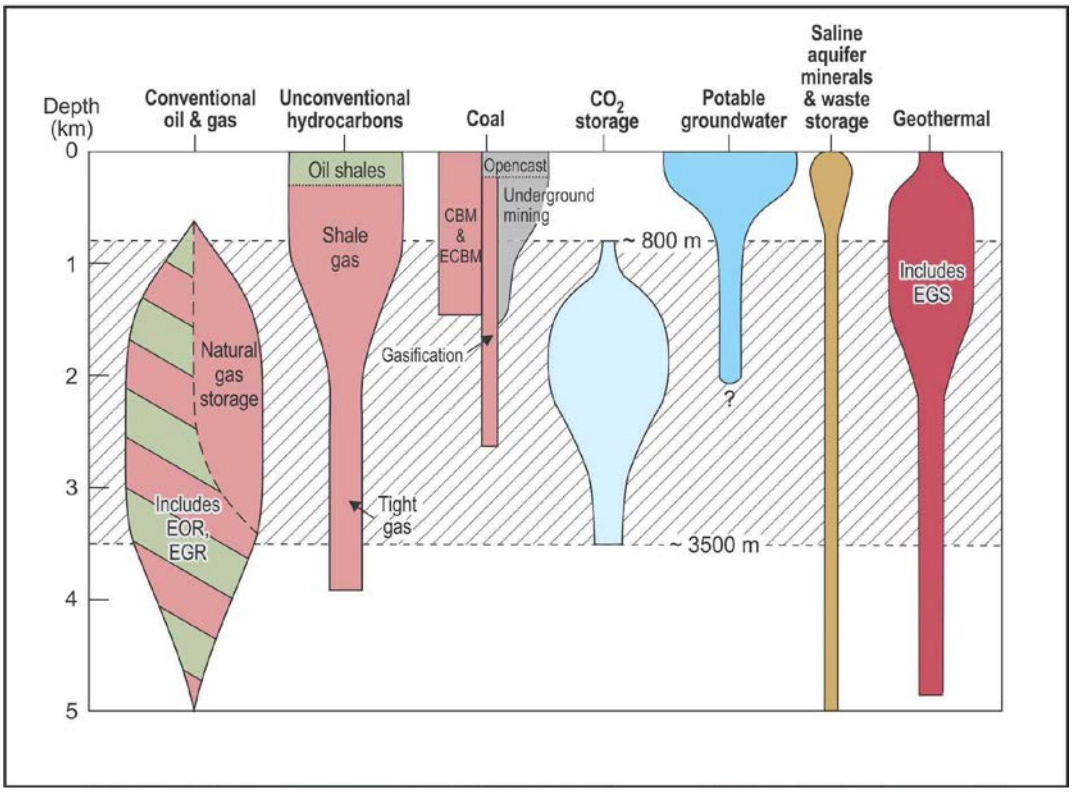

Figure i: Schematic diagram of the typical depth ranges over which sub-surface resources occur, including the use of pore space for CO_2 storage. Variations in the widths of the polygons are conceptually in proportion to the most common depths for the activities.

Interaction between CO_2 storage operations and the use of other subsurface resources can be mutually beneficial or undesirable. Beneficial interaction includes the use of CO_2 for enhanced oil or gas recovery (EOR, EGR), as a thermal transfer medium in geothermal fields or in the production of deep water from pressure reduction wells during CO_2 injection. Beneficial interactions may help to offset the cost of CO_2 storage. Water produced from pressure reduction wells might be potable or potentially treatable economically (e.g., in Gippsland Basin, South Australia) and thus increase groundwater production, or might contain valuable salts such as lithium or iodine. The use of CO_2 as a thermal transfer medium in geothermal fields has been proposed and may be more favourable than the current use of water, but this is yet to be tested at pilot and full scale.

Alternatively, interaction might be undesirable, such as if injected CO_2 were to contaminate or affect the production of oil or natural gas from a hydrocarbon field, prevent the exploitation by underground gasification of deeply buried coal or mix with potable groundwater or saline aquifer mineral reserves. Solving one problem might lead to new problems in other areas. For example, disposal of saline water produced from pressure-reduction or coal seam methane wells at shallow depths has the potential to affect other subsurface resources, such as groundwater, by the creation of new pressure fronts or mixing.

In some cases, previous resource use might affect planned CO_2 storage. Old petroleum wells (for example in depleted fields) are likely to have been completed using steel and cement that might be corroded by the stored CO_2 and create a containment risk, thus increasing the cost of CO_2 storage. Other earlier resource uses, for example hydraulic fracturing (also known as “fracking”) as part of exploration for coal seam gas, shale gas or oil production could potentially have damaged the seal caprock and reduced the site suitability for CO_2 storage. In addition, existing resource use might be incompatible with CO_2 storage because of existing permit conditions and regulations, and new, CO_2-related regulations might need to be compatible with existing uses. In some cases overlapping uses may be feasible in a given geographic area at different stratigraphic levels, particularly if they are separated by intervening competent seals.

Comprehensive reviews of proposals for underground carbon storage should consider both immediate and potential long-term interactions. Consideration of many factors is desirable when assessing CO_2 storage sites and allocating licences as this will help ensure efficient use of natural resources, anticipate any beneficial or detrimental interactions and help avoid litigation between companies or between companies and regulators, thus protecting the public interest.

Regulators should consider the following stages when evaluating resource development in relation to carbon storage:

1. Identify the resources within the basin or region of interest, including “vacant” pore space, map their distribution and assess their quality. It is important to do this, even using subjective criteria or estimates if there are few hard data. This will allow an assessment of the resources likely to be affected and the range of likely interactions. The Gippsland Basin study by the Victoria State Government is a good example of this type of assessment (e.g., O’Brien et al., 2011).

2. Establish the priority of use between the various resources and CO_2 storage.

3. Assess the proposed CO_2 storage project, its site characterization, monitoring and verification plans, contingency and mitigation planning (e.g., how to cope with possible leakage, fault reactivation, loss of well integrity). The Gorgon Project has addressed these issues (e.g., Flett et al., 2009; Gunter et al., 2009) and approaches are discussed in IEAGHG (2011/11). The composition of gas being injected will also be important, as any toxic compounds from flue gas contaminants could affect other subsurface resources adversely if they were to mix.

4. Review the injection plans and the likelihood they will be achievable, and assess whether they might lead to cases of resource conflict (e.g., by seal rupture, pressure-front propagation or CO_2 plume migration into regions other than predicted or licensed to the storage operation). The timings of potential resource interactions are relevant (e.g., during injection, post-injection company monitoring, or after permanent hand-over to government agencies) as these might determine who will be responsible for any detrimental interactions.

5. Review the abandonment plans and longer term monitoring and verification planning, and liability transfer arrangements.

Delays in establishing CO_2 storage regulations could not only inhibit CO_2 storage project development, they could lead to future, detrimental resource interactions. Nevertheless, time is needed to ensure regulations are clear and take into account potential resource prioritization and interaction, as these issues are essential to the planning, costing and surety of CO_2 storage projects. Assessments of potential resource uses in a region, and of possible usage interactions, should enable effective prioritizing of opportunities in a region and efficient husbandry of known or anticipated resources, and their potential effects on estimates of CO_2 storage capacity and injection scenarios.

Introduction

Carbon capture and storage (CCS) is a process involving the capture and separation of CO_2 from large stationary emission sources, and the transportation of the CO_2 to a geological storage location, where it is safely stored underground for long-term isolation from the atmosphere. The storage of CO_2 in underground formations is an attractive mitigation option because it offers the opportunity to achieve large reductions in atmospheric greenhouse gas emissions, when used in conjunction with other options such as energy efficiency, energy conservation and renewable energy. The technology for CO_2 storage in geological media 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 could play an important role in reducing anthropogenic CO_2 emissions into the atmosphere in the first part of this century and beyond (IEA, 2004, 2006a,b, 2008). Unfortunately, it seems likely that current rates of implementation of CCS will not be able to meet targets set to limit global warming to only 2°C, due in part to the lead times required and in part to levels of investment. The storage of anthropogenic CO_2 can be facilitated by appropriate regulations (IPCC 2005, IEA 2011/10). This report aims to assist policy makers to develop comprehensive regulations that help resolve issues of conflicting or enhanced uses of subsurface resources in relation to CO_2 storage. Its aim is to draw possible interactions between CO_2 and other subsurface resources to the attention of policy and decision makers, and regulators, to help them consider and balance potential interactions in the context of their specific geological and regulatory environments. The report is not intended to be an exhaustive list of cases of resource interaction globally, and the examples given are for illustrative purposes only.

Three storage media have been identified that have the potential to store CO_2: coal beds, oil and gas reservoirs, and deep saline formations (IEA, 2004; IPCC, 2005). Of these, deep saline formations and hydrocarbon reservoirs offer the best opportunity for near-term large-scale implementation of CO_2 capture and storage. CO_2 storage in economically un-mineable coal beds has been identified as: 1) being an immature technology, and b) globally having the smallest storage potential (IPCC, 2005). For the same volume of rock, an oil reservoir possesses, at depletion, a smaller storage capacity than a gas reservoir because of its lower recovery factor, though the cost of CO_2 storage might be offset by the ability of CO_2 to flush out additional oil. However, it is believed that deep saline formations possess the largest CO_2 storage capacity, besides having the advantage that they are present also 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.

These storage media for CO_2 are found in sedimentary basins, where other resources of economic interest are found, such as oil and gas, coal, mineral deposits and minerals such as lithium and boron dissolved in formation water. In addition, due to the increase of temperature with depth, most formation waters in sedimentary basins in the depth range considered for CO_2 storage represent a potential source of low- to medium-grade geothermal energy which can be exploited, such as in the Paris Basin in France. Given the existence, to various degrees, of resources of economic interest in sedimentary basins, large-scale implementation of CO_2 storage may lead to interaction between the current or future production of these resources and CO_2 storage.

Report Structure

This report is subdivided into six main sections. This first section introduces the scope, background and objectives of the project and the following section describes how CO_2 is stored and the effects of storage. The third section provides an overview of subsurface resources and how the use of these might be affected beneficially or detrimentally by CO_2 storage, and the fourth provides case studies of actual or potential resource interactions. Because currently there are very few CCS operations in the world, no well-documented actual cases of interactions between CO_2 storage and other resources have been identified. The last sections discuss specific aspects of resource interaction and provide conclusions for the study.

Project Scope and Objectives

Regulators need a better understanding of the geology of a basin for a carbon storage project than they do for a hydrocarbon licencing round, as relatively passive extraction is more straightforward than the storage of gas, be it CO_2 or natural gas. The injection of fluids has the potential to cause rupture of seal rocks, with consequent migration of injected fluids in other regions than predicted and/or licensed, and the propagation of pressure fronts into adjacent formations; both of these can affect other subsurface resources. There may also be the potential for injected fluids, including CO_2, to migrate outside of licensed areas and mix with other resources directly. Regulators, as stewards of subsurface pore space, should be aware of potential uses for the various types of rocks in each basin so they can build policies based on the most effective uses of available pore space at multiple levels as well as laterally within a basin. This should include the avoidance of undesired interactions during resource use and ensure transparently prioritised allocation of licences to use pore space as a resource, thus mitigating the risk of subsequent litigation. Timing is of particular importance, as one use might preclude or compromise another, or restrict use of the pore space to a single use for many years. These issues mean that regulatory agencies need access to a wide range of expertise and should use a holistic approach to determining licencing criteria.

This report provides a basic primer on most subsurface resource uses and describes the main ways in which subsurface storage of CO_2 is likely to affect other uses of pore space, and *vice versa*. It should be noted that CO_2 storage is not yet widespread, so there are few cases of intensely studied resource interaction that can be used as examples. So far there have been no major conflicts or negative interactions over resource use associated with CO_2 storage, though there has been beneficial interaction through a large number of enhanced oil recovery projects worldwide.

Geological Storage of CO_2

Relevant CO_2 properties and its subsurface behaviour

Storage or disposal of gas underground is not new. Not only has CO_2 been injected into the ground to enhance oil production and as a means of disposing of waste gases (CO_2 and H_2S) from oil production, but natural gas has been injected underground into storage reservoirs for the last 100 years to help smooth price variations, and air has been injected underground for use as compressed gas for electricity generation. The storage of CO_2 in underground formations is an attractive mitigation option because it offers the opportunity to achieve large reductions in atmospheric greenhouse gas emissions, when used in conjunction with other options such as energy efficiency, energy conservation and renewable energy (IEA 2006b). The underground storage of CO_2 should be an integral part of the carbon capture and storage system (Figure 1). The main options for geological sequestration for large scale disposal of CO_2, as shown in Figure 2 are:

- Disposal in deep saline formations[1];
- Disposal in depleted or near-depleted gas and oil reservoirs, and
- Disposal in coal seams.

The requirements for geological storage are a safe and secure underground disposal site which effectively stores CO_2 for hundreds to thousands of years without adversely affecting other important natural resources such as potable groundwater, coal or petroleum. Key-note reports on CCS may be found in the IPCC Special Report on Carbon Dioxide Capture and Storage (IPCC, 2005), publications from the International Energy Agency Greenhouse Gas (IEAGHG) Research and Development Programme (http://www.ieagreen.org.uk/publications.htm), books by Wilson and Gerard (2007), Thomas and Benson (2005) and Cook (2012), Best Practice Manual by Chadwick *et al*., (2008), proceedings of various Greenhouse Gas Control Technologies Conferences (e.g., GHGT 2010 and preceding meetings) and the International Journal of Greenhouse Gas Control (e.g., Michael *et al*., 2010). Test sites, such as at Otway in Australia (e.g,, Sharma *et al*., 2011 and Jenkins *et al*., 2012) and Ketzin in Germany (e.g., Ouellet *et al*., 2011, CO2Sink, 2012, Martens *et al.*, 2012), offer invaluable data from intensely-studied subsurface experiments.

For efficiency of storage and other reasons, CO_2 storage in hydrocarbon reservoirs or deep saline formations is preferably achieved at depths greater than 800 m, where the ambient temperatures and pressures will usually result in CO_2 being in a dense-phase, or supercritical state (Figure 3) characterized by high CO_2 density in the 400 – 800 kg/m^3 range (Bachu, 2003). Efficient storage of CO_2 is achieved under these conditions, however the density of CO_2 will still range from 25% to 70% of the density of formation water, so a good cap rock seal above the reservoir formation is required to trap the buoyant CO_2.

[1] In this report we refer to saline formations as those in which the resident water contains sufficient dissolved salts or other chemicals to be considered non-drinkable, as distinct from fresh, potable, groundwater resources.

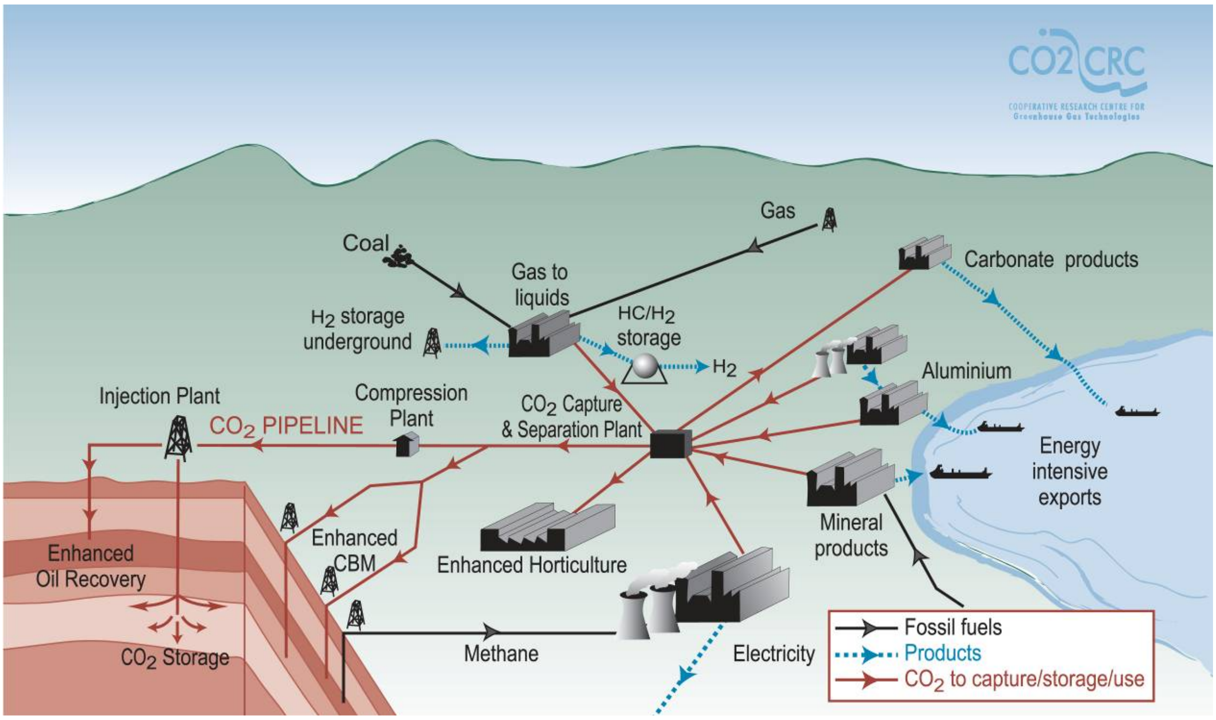

Figure 1: Potential sources and uses of CO_2. CO_2 storage, enhanced recovery and enhanced coal bed methane (CBM) are all subsurface operations with the potential for interaction with other subsurface resources.

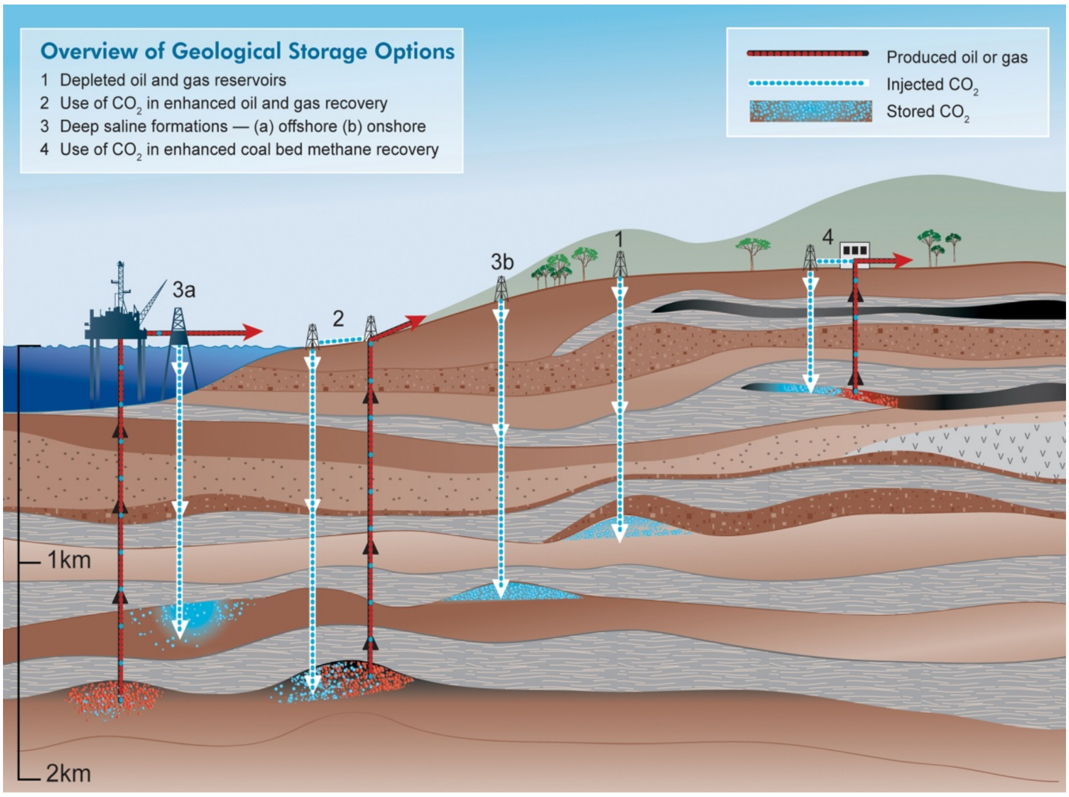

Figure 2: Schematic diagram showing options for geological storage of CO_2 (adapted from Kaldi and Gibson-Poole, 2008).

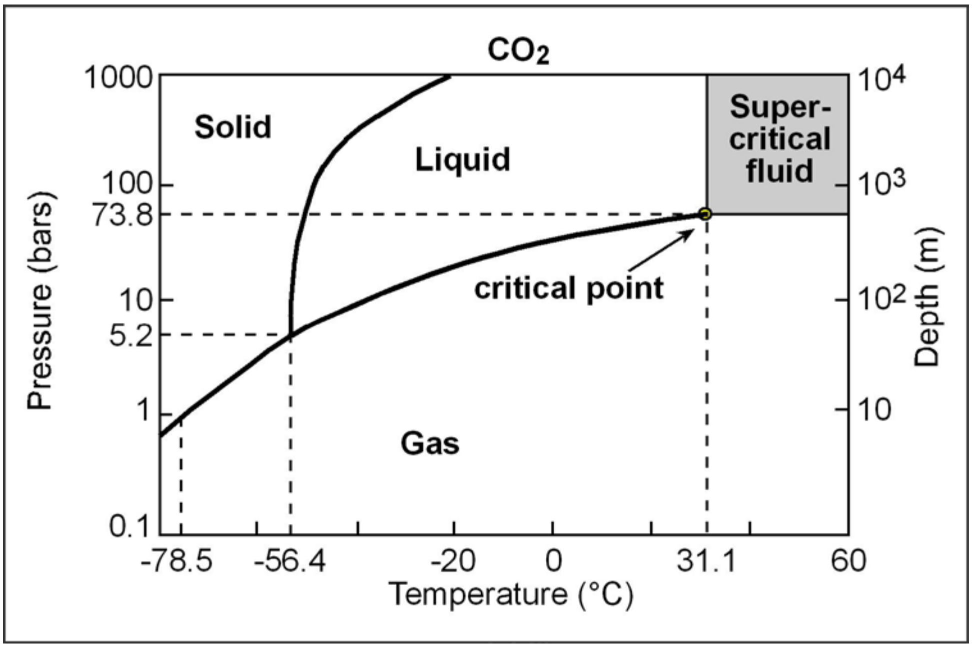

Figure 3: Phase diagram for CO_2. Adapted from Oldenburg and Benson (2002).

Depleted hydrocarbon reservoirs are especially promising for the long-term storage of CO_2. Reservoirs producing oil and gas are proven traps with adequate reservoir and seal intervals capable of trapping hydrocarbons over periods of geological time – millions of years. The geological structure and petrophysical properties of such reservoir and seal rocks have generally been extensively characterised in the search for hydrocarbons. The availability of well and seismic data reduces the cost of implementing sequestration projects and, commonly, sophisticated numerical models of reservoir characteristics and behaviour have already been developed by petroleum reservoir engineers. Often much of the necessary infrastructure for injecting and storing CO_2 exists at oil/gas fields, such that regulatory, compliance, permitting and public acceptance aspects of initiating a CO_2 storage project should be more easily achieved. The use of depleted hydrocarbon fields for storage projects should prove to be less costly and quicker than developing new “greenfield” sites associated with the generally larger-capacity deep saline formations.

Deep saline formations are laterally extensive geological units saturated with brackish water or brine that have good porosity and permeability. In most cases they contain structural or stratigraphic closures or traps, but with the pore space filled with saline water rather than hydrocarbons. These formations are ideal for CO_2 storage. In essence, the CO_2 plume would migrate laterally, and some lateral spread might continue after injection stopped, due to buoyancy migration). The workflows and probabilities of success for CO_2 storage in depleted hydrocarbon fields and deep saline formations are described in IEAGHG (2011/10). Various strategies for optimal CO_2 injection have been evaluated (IEAGHG 2010/4).

Under suitable geological conditions, CO_2 may be injected into oil (or gas) reservoirs to significantly enhance the volumes of oil (or gas) recovered. Typically in enhanced oil recovery (EOR) projects the storage capacity for CO_2 is only a small proportion of the oil reservoir (~ 10%), however EOR may provide the early opportunities for commercialisation of CCS and the first step in developing a value chain for CO_2 storage. That is, CO_2-EOR projects may be important in developing the necessary infrastructure, policy, experience and public acceptance for longer term storage projects on nearby sites. Current CO_2-EOR operations inevitably focus on maximising oil recovery, but future opportunities may lie in optimizing CO_2-EOR projects to maximize CO_2 storage rather than oil production, or in finding the optimum operating conditions depending on the oil price and value of the stored CO_2. Not all fields are suitable for EOR operations using CO_2 (IEAGHG 2011/10, p47).

Coal is also considered a storage option since CO_2 is preferentially adsorbed onto the internal surfaces within the micropores found in the solid coal matrix, and also onto the cleat surfaces, replacing gases such as methane, and will remain trapped as long as temperatures and pressures within the coal seam remain stable. Storage might be considered in deep un-mineable coal seams as well as in association with coal-bed methane production (enhanced coal-bed methane recovery or ECBM). A number of international investigations are underway to research coal storage (e.g., coal-sequestration; http://www.coal-seq.com), but practical storage at industrial scales is yet to be fully demonstrated. Storage volumes are predicted to be relatively small in comparison to deep saline formations and depleted oil/gas fields (IPCC, 2005).

Other options also exist for the storage of CO_2, e.g., as a solid compound in hydrates or as a mineral such as magnesium carbonate, in salt caverns, in organic-rich shales and in basalts (IPCC, 2005; McGrail *et al.,* 2006). Storage as stable carbonate minerals through reacting CO_2 with readily available Ca- or Mg-silicate minerals can store CO_2 safely for millions of years (Seifritz 1990; Gerdemann *et al.,* 2002). Carbonate precipitated from such a calcium-magnesium-silicate rock structure such as serpentinite, is described by the following reaction:

$$Mg_3SiO_3(OH)_4 + 3CO_2 \rightarrow 3MgCO_3 + 2SiO_2 + H_2O$$

While such reactions are very slow in nature, reaction rates may be accelerated by increasing the surface area of the silicates and making use of reactive minerals such as olivine or serpentine (Kohlmann et al., 2002). However, large-scale sequestration as carbonates ("mineral carbonation") would require large amounts of magnesium or calcium silicate minerals and is predicted to be more expensive than sequestration in deep saline formations and depleted oil and/or gas fields (IPCC 2005).

Disposal of CO_2 in large cavities such as salt caverns is another sequestration option. However, gas pressures would need to be maintained lower than the hydrostatic pressure of overlying sediments in order to avoid explosive blowouts. Unless caverns were deeper than about 750 m, any CO_2 sequestered would be stored relatively inefficiently as a gas.

Shale-rich formations with high organic carbon contents are expected to store CO_2 in much the same manner as coal formations, with CO_2 displacing methane that is adsorbed onto surfaces within organically rich shale (NETL website; http://www.netl.doe.gov). While the geological opportunities for this method of sequestration are widespread, the concept of using organic-rich shales to store CO_2 has not yet been tested. Some small projects studying the potential for sequestration in organic-rich shales, such as the Devonian Black Shale project in Kentucky, USA (website, http://www.uky.edu/KGS/emsweb/devsh/devshseq.html), are currently underway.

Basaltic rocks contain reactive minerals and glass, and are also being considered as potential CO_2 storage formations. The reactivity of basalt is expected to potentially convert injected CO_2 to calcite and hence permanently isolate it from the atmosphere (McGrail *et al*., 2006). Large flood basalts are present in Siberia, Deccan plateau of western India, Columbia River basalt in north-western United States, volcanic islands like Hawaii and Iceland and in oceanic ridges. A research project is underway in Iceland to investigate the potential for CO_2 storage in basalts, but in this project CO_2 is mixed with water at the surface prior to injection (http://www.lmtg.obs-mip.fr/co2/hellisheidi.htm). The Pacific

Northwest National Laboratory in the USA is presently conducting tests on the storage potential of Columbia River basalts (www.netl.doe.gov/publications/factsheets/project/Proj277.pdf).

Trapping mechanisms

Carbon dioxide can be trapped by a number of different mechanisms in geological media depending on the rock formation and reservoir type. The most typical traps are:

- Structural (anticline or fault juxtaposition) or stratigraphic (pinchout of reservoir rock against non-reservoir rock), typical of those trapping hydrocarbon accumulations (e.g., Biddle and Wielchowsky 1994);
- Hydrodynamic traps, where CO_2 is entrained in groundwater flow and is constrained above and below by impermeable sealing lithologies (Bachu *et al*., 1994);
- Residual gas trapping, where the CO_2 becomes trapped in reservoir pore spaces by capillary pressure forces (Ennis-King and Paterson 2002; Holtz 2002; Flett *et al*., 2005);
- Solubility trapping, where the CO_2 dissolves in the formation water (Koide *et al*., 1992);
- Mineral trapping, where the CO_2 precipitates as new carbonate minerals (Gunter *et al*., 1993) and
- Adsorption trapping, where the CO_2 adsorbs onto the surface of coal (Gunter *et al.,* 1993).

In the case of CO_2 storage in depleted hydrocarbon reservoirs and deep saline formations, the effectiveness of these trapping mechanisms and the security or permanence of CO_2 immobilised increase with increasing time of residence of the injected CO_2 in the reservoir, and greater contact with the formation water (Figure 4).

An additional form of CO_2 trapping has been proposed, namely as a solid hydrate in shallow ocean sediments or in sub-Arctic and Arctic regions. In the presence of water, and at specific pressures, CO_2 forms hydrates at temperatures below 9 ºC. While this phenomenon is undesirable in CO_2 injection through wells because the hydrates may plug pipelines and wells, it has been suggested that, at the low temperatures found in shallow marine sediments in the deep ocean and also in sub-Arctic and Arctic regions, CO_2 may form hydrates that will immobilize CO_2 in the pore space of these sediments (Koide *et al.*, 1997; Kvamme *et al*., 2007; House *et al*., 2006; Schrag, 2007; Cote and Wright 2010; Qanbari *et al*., 2011). Furthermore, given the solid nature of the CO_2 hydrates, their formation in the pore space will impede CO_2 flow and leakage to the surface or to the sea floor. Furthermore, Zatsepina and Pooladi-Dravish (2012) have proposed CO_2 storage as a hydrate in shallow depleted gas reservoirs in the northern regions of Canada. In addition, because CO_2 hydrates are more stable than methane hydrates, CO_2 could replace methane (CH_4 in existing gas hydrates, thus storing CO_2 while freeing a huge untapped energy resource (Kvamme *et al*., 2007).

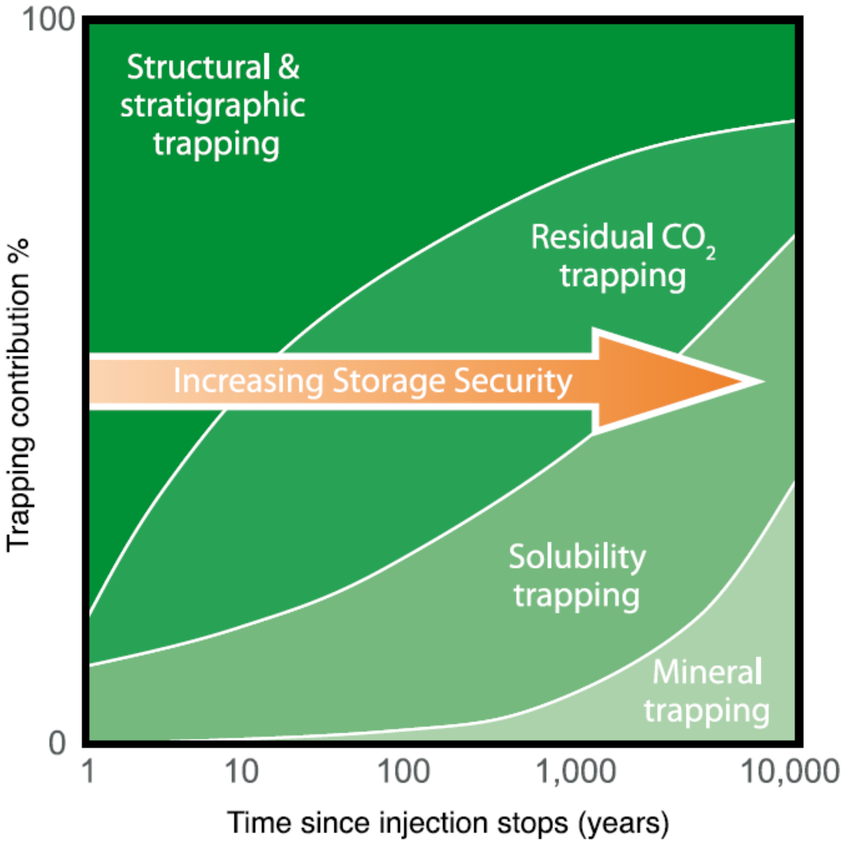

Figure 4: Diagram showing the relative contribution over geological time of the main types of CO_2 trapping mechanisms within underground reservoirs (IPCC 2005). Recent work suggests mineral trapping might in some cases be greater than depicted schematically above (Tenthorey et al., 2011a).

Structural and stratigraphic trapping

Free-phase (immiscible), undissolved, gaseous or supercritical CO_2 is less dense than formation water and will rise buoyantly until it encounters a permeability barrier or seal at the top of the reservoir (Holloway 2001; IPCC 2005). The CO_2 will then either spread out and form a plume, or migrate (flow) up-dip within the reservoir layer and beneath the barrier. The greater the viscosity and density contrasts between the CO_2 and formation water, the faster any undissolved CO_2 will flow up-dip within a reservoir, so a trap is required to ensure the CO_2 does not reach the surface (IPCC 2005). The most common traps are structural and stratigraphic, similar to those in most oil and gas fields.

Structural traps are the easiest to define and map in the subsurface, and usually involve folding or tilting of rock layers (or both), with or without accompanying faulting. The simplest structural trap is an anticline, namely a structure in which the reservoir and seal rock layers have been folded to form a dome. Another common structural trap is a tilted fault block, in which buoyant fluids are trapped in inclined strata by an impermeable or low-permeability fault. Over geological time scales, hydrocarbons migrate to the crestal parts of these structures where they are trapped by overlying seals and/or lateral fault seals.

Stratigraphic traps require some form of up-dip heterogeneity or discontinuity within the permeable rock layers. The most common examples are lateral variations in the sediment type and lithology, or lateral disappearance of permeable layers due to depositional thinning and pinch-out or erosional truncation.

Hydrodynamic trapping

Supercritical CO_2, whilst still retaining some buoyancy, is generally relatively dense (500-700 kg/m^3). It therefore migrates in response to the natural flow of formation water, which may have velocities of between 0.1 and 0.5 m/year. In areas with horizontal or gently-dipping strata the CO_2 will migrate only relatively short distances over long periods of geological time (Bachu *et al.,* 1994). This type of situation, in which the CO_2 effectively resides in situ without the need for structural and stratigraphic trapping, is called hydrodynamic trapping (or Migration Assisted Storage; Spencer *et al*., 2010).

Residual CO_2 trapping

Because CO_2 is a non-wetting fluid (i.e., it does not dissolve quickly or mix well with water), when CO_2 is injected into a rock it will displace some of the original formation water (this drains the water and is called the drainage cycle), whilst the rest of the water will be left in the pore spaces, adhered to rock particles by surface tension. The portion of water that remains in the pore space and that cannot flow due to capillary forces holding it in place is termed “residual” or “irreducible” water saturation. The amount of residual water depends on the surface tension between the rock minerals and the formation fluids, as well as the size of the pore spaces.

Some of the injected CO_2 will dissolve in the residual water until that water becomes saturated. As the CO_2 migrates through the saline formation rock, water invades back and small droplets of supercritical CO_2 will become trapped within pore spaces due to the surface tension between the formation water and the CO_2. This mechanism of residual trapping is well understood in the petroleum industry and is a critical control on ultimate recovery from oil and gas fields. The amount of CO_2 captured by residual trapping is a function of the physical properties of the rock, (i.e., relative permeability and residual CO_2 saturation), the interfacial tension between the formation water and CO_2, in-situ conditions of temperature, pressure and water salinity, rock heterogeneity, and the injected CO_2 (IPCC 2005; Bachu and Bennion 2008).

Residual CO_2 trapping is probably the main trapping mechanism for the first several thousand years after injection. In the longer term it is thought that CO_2 trapped by residual trapping will be dissolved by unsaturated formation water migrating past the trapped CO_2 as a result of convection initiated by solubility trapping (see next section).

Solubility trapping

Solubility trapping involves the dissolution of CO_2 into reservoir fluids. Pore spaces, in their natural state, contain water that is commonly saline and may contain some hydrocarbons. This water is called “formation water”. The migration of CO_2, under either the pressure of injection (hydrodynamic forces) or buoyancy forces during and following injection, will bring injected CO_2 into contact with formation water, enabling the CO_2 to dissolve until the water becomes saturated with CO_2. Additional CO_2 will continue to migrate and dissolve as it comes into contact with unsaturated formation water elsewhere. CO_2-saturated water is about 1% denser than unsaturated water, and therefore has a tendency to very slowly sink through the rock, beneath the CO_2 plume. Vertical convective flow within the reservoir may be established depending mainly on aquifer permeability, in which case the denser CO_2-saturated formation water sinks and displaces unsaturated formation water upwards to upper parts of the formation. This rising unsaturated formation water comes in contact with the CO_2 plume and is capable of dissolving more of the remaining injected CO_2. This convection and dissolution process spans thousands to hundreds of thousands of years after injection (IPCC 2005, Chevron Australia 2005).

Mineralogical trapping

Mineralogical trapping is the most stable mechanism for long-term trapping of CO_2. As injected CO_2 dissolves in formation water, it produces a weak acid (carbonic acid) which can chemically react with minerals in the host reservoir rock. Some of these reactions can result in the precipitation of new minerals and solid compounds in the formation pore space, effectively trapping the injected CO_2 (IPCC 2005; Chevron Australia 2005).

The geochemistry of CO_2 in the subsurface is still an area of on-going research. Initial indications are that kinetics of reactions with carbonates may be fast, while kinetics of silicate interactions appears to be very slow, requiring tens to perhaps hundreds of years for substantial reaction progress. It is generally accepted that the overall slow rates of chemical reactions means that time spans of several thousand years are required to sequester significant volumes of CO_2 in this manner (IPCC 2005).

Adsorption trapping

Adsorption trapping is the storage of CO_2 on the internal surfaces of micropores and fractures in the solid coal matrix. CO_2 has a higher affinity to become adsorbed onto coal surfaces than the methane that is naturally found adsorbed onto coal in unmined coal seams. Therefore if CO_2 is injected into a coal seam, methane will be displaced from some of the adsorption sites in the coal seam. Two types of adsorption are believed to occur between the gaseous phase (either CO_2 or CH_4) and the solid (coal) phase, these being physical and chemical adsorption (chemisorption; Ma 2004). Both types of adsorption are exothermic processes (Starzewski and Grillet, 1989) and will provide a heat source, at least during the active injection phase of sequestration. A process that occurs during CO_2 injection in coals is “coal swelling”, and this has a significant effect of reducing coal permeability and hence CO_2 injectivity.

Assessment of storage sites

The successful identification and assessment of potential storage sites for storage or disposal of CO_2 is based on five key criteria: adequate storage capacity, secure containment, suitable injectivity, good economics and protection of existing resources. Below we briefly discuss storage capacity, injectivity and containment, with potential interaction of existing resources addressed in the following section.

Storage capacity

The volume of CO_2 that may be stored depends on the volume of the available pore space that the CO_2 can occupy, assuming effective trapping and containment exists. In practice, storage capacity is quoted in millions of tonnes of CO_2, derived from the estimated storage volume and the inferred density of the CO_2 (which depends on the temperature and pressure of the specific storage reservoir).

At its most basic level, the volume of potential usable pore space is derived by calculating the volume of rock in the storage system and applying a value for the average porosity of the rock. Rock volumes are typically estimated using seismic data (preferably in combination with well data) and are the product of area and height of the storage unit, often with an additional factor to account for the geometry of the reservoir. In detailed assessments, reservoir simulations based on multiple well intersections, and sometimes production history, are used to estimate the volume of reservoir pore space accessible to injected CO_2.

The key publications summarising a methodology for the estimation of regional-scale storage capacity of CO_2 in geological formations are:

- Storage Capacity Estimation, Site Selection and Characterisation for CO_2 Storage Projects (Kaldi and Gibson-Poole 2008);

- Summary of the Methodology for Development of Geological Storage Estimates for Carbon Dioxide prepared for the Carbon Sequestration Program of the National Energy Technology Laboratory, U.S. Department of Energy (DOE) in September 2010 (USDOE 2010); and

- Comparison between Methodologies Recommended for Estimation of CO_2 Storage Capacity in Geological Media by the CSLF Task Force on CO_2 Storage Capacity Estimation and the USDOE Capacity and Fairways Subgroup of the Regional Carbon Sequestration Partnerships Program - Phase III Report - Prepared for: Technical Group (TG) Carbon Sequestration Leadership Forum (CSLF) by Bachu (2008).

These summary documents are based on previous publications by U.S. Department of Energy (USDOE 2007) and CSLF (2007). Some useful earlier references discussing storage capacity include: Van der Meer (1995), Bachu & Adams (2003), Bachu et al. (2007), and Bradshaw et al. (2007).

The CO2CRC CO_2 storage capacity system, which is an update of the techno-economic pyramid defined by Bachu *et al.,* (2007), provides a means of classifying storage capacity based on knowledge and certainty. A brief description of the classification is provided here because it is useful for regulatory agencies when assessing levels of certainty, or confidence, when deciding licence boundaries, approving projects or assessing the likelihood of resource interactions.

Storage capacity classification

The storage capacity classification presented here (Figure 5) follows Kaldi and Gibson-Poole (2008). The Total Pore Volume (TPV; Figure 5) is defined as the entire volume which is estimated to exist in sedimentary basins. It is typically calculated by multiplying the area of a reservoir by its thickness and porosity. Prospective Storage Capacity is defined as that quantity of pore space into which it is estimated that CO_2 will be technically and economically potentially injectable into as yet undiscovered storage sites. The Contingent Storage Capacity is defined as that quantity of pore space which is estimated to be potentially technically and economically feasible for CO_2 injection into known storage sites based on anticipated future techno-economic conditions. Operational Storage Capacity is defined as an estimate of that volume of pore space which will be technically and commercially available for injecting CO_2 into known storage sites. The Prospective Storage Capacity defined by Kaldi and Gibson-Poole (2008) is equivalent to the Effective CO_2 Storage Capacity defined by Bachu *et al*. (2007) and to the CO_2 Storage Resource used in the United States (Gorecki *et al*., 2009; Goodman *et al*., 2011). The relationship between the Total Pore Volume (TPV) and the Prospective Storage Capacity (PSC) is given by:

$$PSC = E \times TPV$$

where E is a storage efficiency coefficient (denoted by C by Bachu *et al*., 2007). Work by Gorecki *et al*. (2009) and Goodman *et al*. (2011) has shown that the storage efficiency E at the formation scale depends on lithology and depositional environment, and has values that vary between 1.41% for limestone saline formations and 6% for sandstone saline formations; for coal seams, the efficiency factor E varies between 21% and 48% (Goodman *et al*., 2009).

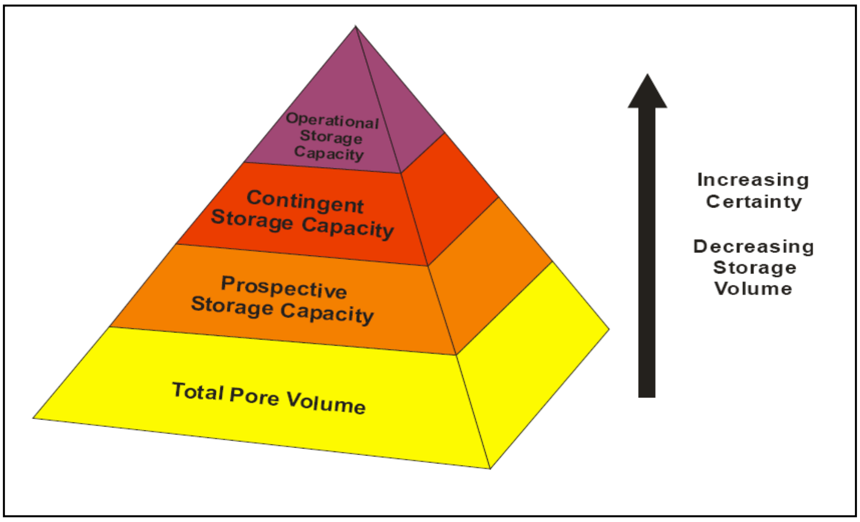

Figure 5: **CO_2 storage capacity pyramid (Kaldi and Gibson-Poole, 2008).**

Storage in depleted oil and gas fields

Storage in oil or gas fields when most of the hydrocarbons have been produced is attractive because the reservoir rocks are comparatively well understood and because it can be assumed that there was an effective seal rock overlying the hydrocarbon reservoir, allowing re-pressurising of the reservoir during injection of CO_2. Depleted oil fields might respond well to CO_2 injection, allowing the production of additional oil by flushing and hence helping to offset the cost of CO_2 injection. The same can apply to gas fields though the technique is less common, more complex and should be started at an earlier stage of reservoir depletion than for oil reservoirs.

Issues that need to be considered include whether:

- the injection of CO_2 would detrimentally affect continued oil or gas extraction;
- the geomechanical integrity of the reservoir, and particularly the caprock, are affected by the pressure depletion during hydrocarbon production and pressure build-up during CO_2 injection;
- the reservoir is subject to strong water-drive, reducing the potential pore space able to be replaced by CO_2;
- the CO_2 would corrode existing cement or hole casings;
- the seal is rate-limited rather than a perfect barrier
- whether there are higher, additional seal units that could act as back-up seals above the storage reservoir, or only one unit;
- the minerals in the reservoir rock would react with injected CO_2 and decrease the permeability of the reservoir and hence lower injection rates.

The simplest approach to estimating storage capacity in a depleted field is to convert the original producible oil or gas volumes into equivalent CO_2 at the appropriate reservoir temperature and pressure.

Storage in saline formations

The term "deep saline formation" is a shorthand term used in the CCS literature to describe porous and permeable reservoir rocks in which the pore-space is filled with saline water, unsuitable for human consumption or agricultural use. They have been identified as one of the best potential options for geological storage of large volumes of CO_2 (IPCC 2005). These deep formations are generally not as well characterized as those targeted by petroleum exploration companies, but are widely distributed in sedimentary basins across the globe (e.g., see discussion by Michael *et al*., 2010). Storage in saline formations can be available at sites not associated with oil or gas fields, down-dip of oil or gas fields, or at other levels within oil or gas fields (e.g., at Ketzin, CO2Sink, 2012). CO_2 can be stored via a range of trapping mechanisms (see earlier section) although typically injected in a dense fluid state at depths greater than 800 m.

Injected CO_2 is typically buoyant and will rise though the subsurface interconnected pore spaces until it reaches the barrier formed by the seal rock; this can be modeled (e.g., Yang 2007). The rate at which the plume of supercritical CO_2 rises depends on how permeable the reservoir rock is, whether there are any fractures or faults that could act as conduits to flow, and whether there are any impermeable obstacles (termed baffles) such as hard concretionary layers or discontinuous mudstone beds (e.g., Boait *et al*., 2011) which the CO_2 would need to flow around as it rises. The CO_2 will tend to follow any highly permeable layers and may by-pass significant parts of the reservoir, thus potentially reducing the useable storage capacity.

Sleipner in the North Sea is the best studied and longest term injection project to date. Over a period of 10 years, the CO_2 plume has spread out over an area of about 5 by 2 km (Figure 6). Migration of a plume however, will depend on several factors, including the permeability of the rocks. At Sleipner, laboratory measurements indicated permeabilities of 2-8 Darcy, but models fit the observed migration rate better if direction-dependent permeabilities of 10 Darcy N-S and 3 Darcy E-W are used (Chadwick *et al*., 2010; see also Durucan *et al*., 2011). Detailed seismic surveys in 3D can be repeated (as depicted in Figure 6) to produce "4-D" surveys, so-named to acknowledge the time dimension. Other

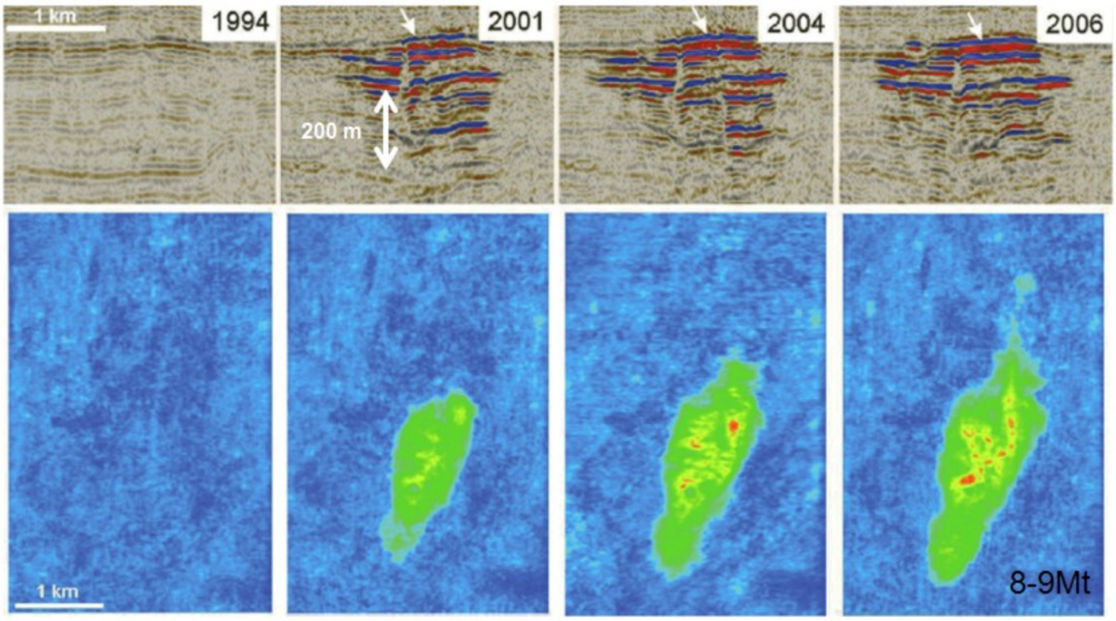

Figure 6: Plume migration at Sleipner (Chadwick *et al*., 2010). The top panels are seismic cross sections and the bottom panels are map views. Injection started in 1996 so the panels track migration over 10 years during the injection of 8.4 Mt of CO_2.

methods may also be useful in monitoring injected CO_2 movement (e.g., in coal beds, Kieke *et al*., 2009; also Fabriol *et al.*, 2011).

As the plume migrates, some CO_2 is stored permanently through dissolution in formation waters in the reservoir pore space (dissolution or solubility trapping), and when no more can be dissolved (i.e., at irreducible gas saturation) some is stored permanently as small globules left behind as the plume moves on. This is called residual trapping. A long migration path, with slow migration, enhances solubility trapping and makes more pore space available for residual trapping. It is therefore possible to store CO_2 via migration trapping without the need for a structural closure, or to use it to store CO_2 along a migration pathway that eventually culminates in a closure (such as depleted oil or gas field).

As some of the injected CO_2 is dissolved in the natural formation waters the density of the water is increased and this causes it to sink. Thus the solubility trapped CO_2 does not all stay in the vicinity of the plume pathway, below the seal rock. As it dissolves and sinks the upward buoyancy pressure of the injected CO_2 plume will therefore decrease with time.

Injectivity

Injectivity is the rate at which CO_2 can be injected into the reservoir and is governed by the permeability of the rock to CO_2 and the thickness of the injection interval, as well as the viscosity of the injected CO_2. When determining the rate of injection it is essential to maintain migration of the CO_2 plume away from the well without inducing micro-fracturing of the formation. Hence the rock properties are critical in defining injectivity.

A number of near-field effects, close to the injection well, that can influence injectivity include reservoir heterogeneity, diagenesis and chemical alteration induced by the injected CO_2, salinity of formation fluids, and presence of nearby faults or migration baffles.

In addition, there are a number of far-field effects that require consideration, especially the effect the injected CO_2 has on increasing the reservoir pressure. The lateral extent of the increase in pressure is greater than the extent of the plume itself, and can reach over 100 km from the injection site (IEAGHG 2011/11). The pressure front might therefore affect other subsurface resources at distance from the storage site and affect the extraction of oil, gas and groundwater, which are influenced by subsurface pressure regimes. Modeling of the Illinois Basin (IEAGHG 2011/11) suggests pressure perturbation of 0.5 MPa could extend at least 150-200 km, and modeling of the Sherwood Sandstone Formation (in the UK) indicated an increase of 10 m in the groundwater hydraulic head could be expected at distance of 50 km up-dip of an injection site, within this unit, after 20 years (IEAGHG 2011/11). However, storage of CO_2 in units at stratigraphic levels not in direct pressure communication with other resources such as groundwater is likely to have minimal effects (IEAGHG 2011/11). Permeability of the reservoir nearby is clearly key (e.g., Schäfer *et al*., 2011) but far-field permeability may also be important to the rate of pressure propagation (Birkholzer et al., 2011). The thickness and permeability of the seal are also key determinants of the local footprint of pressure change (IEA 2010/15).

One potential issue with fluid production (e.g. oil and gas) or injected CO_2 is there may be slight subsidence or uplift respectively, of the land surface. At In Salah (Algeria), these changes have been measured using satellite data and surface surveys. Extraction of natural gas has caused subsidence of a few millimetres per year, and injection of 3 Mt of CO_2 at a depth of 1800 m has caused surface deformation (uplift) with a crestal height, at the injector wellsites, of 5 mm per year (Vasco *et al*., 2010). While these effects are unlikely to be noticeable at an offshore or remote land-based site, they might be significant in an area where infrastructure is present. The effects of this on any subsurface resources, for example at shallow stratigraphic levels above an injection site, are unknown.

Containment

Certainty of containment of injected CO_2 is a major factor in the identification, assessment and economic viability of a storage site, as well as in obtaining permits to store CO_2, and in gaining public acceptance of storage projects. Any significant leakage would probably mean loss of carbon credits, costly remediation operations and possibly liabilities associated with damages and with resource interaction.

Containment of injected CO_2 typically relies on a seal rock, which is commonly mudstone or an evaporite. The seal rock must be sufficiently thick to give confidence that it will not rupture and it might be a few metres to hundreds of metres thick. Ideally there will also be secondary seal rocks above the main seal. Containment is usually described as comprising three elements: seal capacity (the ability of the seal to not leak through interconnected pore spaces, or permeability); seal integrity (the ability of the seal to not rupture); and seal continuity (whether it extends laterally far enough to prevent vertical migration in the area reached by the injected CO_2).

Seal capacity is usually measured by the injection of mercury into a rock sample under pressure (mercury injection capillary pressure, MICP), with corrections estimated for the difference between the mercury-air interfacial tension at laboratory conditions vs the predicted or measured interfacial tension between CO_2 and the saline formation water (e.g., Daniel & Kaldi, 2008). Mercury has conventionally been used by the oil industry for these laboratory tests since it behaves more like oil than water, as it is non-wetting. The pressure at which mercury starts to move through the seal rock is known as the displacement pressure. Mudstones tend to have very low permeabilities and generally allow only small, insignificant amounts of CO_2 to migrate through them over timescales of thousands of years even when the displacement pressure is exceeded.

If the seal has a high displacement pressure then seal integrity is perhaps more significant than seal permeability. Seal integrity can be assessed by performing geomechanical rock strength tests, though this requires good quality core material through the seal rock. Coring is expensive, hence petroleum exploration companies do not often take cores of the seal as they are more interested in the reservoir underneath. Furthermore, given the commonly shaly nature of the caprock (seal), the core has to be preserved under special conditions that would prevent desiccation; otherwise the geomechanical properties measured in the laboratory are not truly representative for in-situ conditions. Therefore, very few geomechanical rock strength test data are available on seal rocks, even in areas that have been well-drilled in the search for petroleum.

Some fractures and faults act as barriers to fluid flow and others act as conduits, reducing seal integrity. Where they act as conduits, fluid flow through them can be rapid. Seal rocks should therefore not contain fracture networks that act as conduits, or conduit faults which cut the entire seal rock. Seal rocks may contain fractures and faults which do not compromise seal integrity, though integrity must be maintained under any increase of pressure caused by CO_2 injection (e.g., van Ruth 2006; van Ruth et al., 2007; Vidal-Gilbert, 2008; Smith et al., 2009). One attraction of using depleted oil and gas fields is that the initial pressure of the reservoir is generally known and this is regarded as the maximum safe pressure that might be reached during CO_2 injection. However, one must be careful because the interfacial tension between CO_2 and water is less than that between hydrocarbons and water (e.g., it is approximately 60% of that between natural gas and water), and in some cases the reservoir original pressure may be higher than the displacement pressure for CO_2. In practice a lower pressure threshold is used, to provide a safety margin. Large faults can be detected using seismic reflection data, but small faults and fracture networks are hard to detect and have the potential to cause unexpected rates and pathways of plume migration.

Seal continuity may be inferred from seismic reflection data and by analogue facies data. For example, if the characteristics or facies of the seal rock are known then examples from other fields or outcrop studies can be used to infer whether the seal is likely to be of only local extent (such as a mudstone lining a local channel) or is likely to be a regional, widespread unit (such as a mudstone deposited in an open, deep marine setting). In a large petroleum province comprising several fields, the combined well data might reveal if there is a regional seal covering very large areas.

Recent scientific debate has focused on the efficiency of pore space use and how pressure is dissipated in response to CO_2 injection, and it has become apparent that the monitoring and verification (M & V) of injection sites is providing useful data on plume behavior; the value of M & V is not just in leak detection (Eiken *et al.,* 2011).

Risking

Geological units such as reservoir and seal rocks are generally not homogeneous materials, and have variable lateral extents. Predicting variations in their depths, thicknesses and material properties is therefore not a precise science, particularly considering that these units lie many hundreds of metres below the ground surface. Faults too are difficult to characterize without real, “hard” data. Seismic surveys provide useful data but are limited in what they can tell us. Even wells, which can provide samples and precise depths, provide limited information, which decreases in certainty away from the well’s location.

To cope with these uncertainties, geologists use models based on past experience and analogues to make predictions. These conceptual models can be built digitally so that computer simulations can be run to test, for example, hydrocarbon extraction rates or CO_2 storage potential. Uncertainties associated with every element in the models can be estimated and combined to provide overall assessments of risk of, for example, flow rates, seal failure, resource interaction or financial success, (e.g., Det Norske Veritas, 2011 and Jacquemet *et al*., 2011).

Risking allows a company to assess whether it should proceed with a costly “next step”, such as committing to drill a well. For example, a seal rock might be realistically assigned a low level of risk of failure, prior to sampling it by expensive drilling, even without hard data. This is important, because a company or regulatory agency needs to be able to anticipate the results of a proposed development programme before committing to, or permitting it, respectively. Risk assessment also allows regulatory agencies to assess the likelihood of affecting other subsurface resources, and whether tying an area up under a permit is likely to lead to a successful outcome. Risk models are updated as different stages of a project develop and more hard data are acquired (e.g., Dodds *et al.*, 2011; Oldenburg *et al.*, 2011).

There are many methods of estimating risks (appendix 2 of NETL, 2011, and the Bayesian Belief Network approach, e.g., Yang et al., 2012), and general standards for risking (not specific to CCS) have been developed (IEC/ISO 2009 and ISO 2009).

Subsurface Geological Resources and Potential Interaction with CO_2 Storage

Conventional oil and gas

Oil and or gas are generated when a rock containing organic material is buried deeply enough for this material to be converted into hydrocarbons. Enough hydrocarbons must be formed to enable them to be expelled from the source rock into adjoining rocks where they can migrate (usually upwards or up-dip, driven by buoyancy) and become concentrated enough (accumulate) to become economic to extract. Hydrocarbons can migrate through interconnected pore spaces or fractures until they reach a seal barrier that traps them, thus forming petroleum fields. If hydrocarbons are not trapped, they will continue to migrate upwards and reach the surface where they may form noticeable seeps on the land surface or seabed. Typically, hydrocarbons are trapped in the pore spaces and fractures within sandstone or carbonate beds and the overlying seal is a mudstone unit several metres to thousands of metres thick. The reservoir sandstone or carbonate must be sealed around the sides as well, commonly in a dome-like structure caused by folding and perhaps 5-50 km across, or through depositional geometries (e.g., reefal build-up). The height, area and shape of the structure determine the trap's volume and the porosity of the reservoir rock helps determine how much oil or gas it can contain. Reservoir sandstones tend to lose some of their porosity as they are buried, due to the weight of rock above them, and good quality reservoir sandstones commonly occur at depths shallower than 4000 m, in the zone of interest for CO_2 injection. Shallower reservoirs are generally more attractive because the drilling costs are usually lower. Balanced against this, however, a mudstone seal that has not been buried deeply might not have been compacted sufficiently to be an effective seal.

Seal rocks can withhold hydrocarbons or leak at a slower rate than incoming, migrating hydrocarbons (in which case they are called "rate seals"). Rate seals would not necessarily be suitable for CO_2 storage. The rate of any significant leakage through a seal in a CO_2 storage system should be on a timeframe of thousands or millions of years.

Most producing or prospective hydrocarbon fields occur within the 800-4000 m window desirable for CO_2 storage, and would therefore be affected by changes in pressure or fluid interactions caused by CO_2 injection. Interaction can be positive if it helps flush out residual hydrocarbons (enhanced recovery of oil or gas, EOR and EGR, e.g., Regan 2007), although negative interaction is the more commonly considered interaction. For example, pressure fronts or leaked CO_2 could potentially interfere with hydrocarbon production or CO_2 could exacerbate the corrosion of pipes and degradation of cements used in exploration and development wells. However, there are as yet no known cases of these negative interactions having occurred. Provided adequate seal and containment of injected CO_2 is present, and pressure front effects are anticipated, they should be avoidable. The converse also applies, for example in the case where a new resource such as oil or gas is discovered beneath an existing CO_2 storage site; corrosion-resistant well completion materials would need to be used, and pressure interference would need to be pre-assessed and mitigated.

Shale gas and oil

The combination of two technologies in drilling has opened up new and vast oil and gas resources, namely production of oil and/or gas from shales. These technologies are horizontal well drilling and hydraulic fracturing for increasing fracture permeability in tight oil and gas reservoirs (which has been practised for more than 30 years). The technology consists of drilling wells that are vertical until they reach the target shale formation, and then steering them into horizontal wells several kilometres in length through the shale formation. By injecting water at suitable pressures above the rock fracturing threshold, the shale formation is fractured, thus increasing its permeability. After pressure release through extraction of the injected water, the fractures are kept open by fine sand grains or proppant that are injected together with the fracturing water. The enhanced permeability through fracturing of shales containing oil or gas has led to significant gas production in North America of gas from shales such as the Marcellus shale in Pennsylvania, Barnett shale in Texas, Montney shale in Canada, and of oil from the Bakken shale in North Dakota. As a result of shale gas and oil production, the United States recoverable reserves and production have increased in the last year, and it is predicted that the United States will become self-sufficient in natural gas and in oil within a decade. Extensive shales containing gas exist in other places where shale gas production has been restricted or even forbidden for the time being, such as the shales in upstate New York and in Quebec, or in France. Restrictions are due mainly to public concerns regarding gas leakage and/or pollution of shallow groundwater resources as a result of hydraulic fracturing (fracking), although these concerns sometimes do not have a factual basis (see King, 2012).

From a CO_2 storage point of view, however, extensive production of shale gas and oil may have a significant impact on CO_2 storage in depleted oil and gas reservoirs and deep saline formations because shales constitute the caprock of these storage media. The height of fracture growth in the horizontal wells is usually several hundred feet (between 100 and 200 m) (King, 2012). Gas and oil production from shales using extensive hydraulic fracturing damages the physical integrity of the shale as a caprock and may negatively impact the potential for CO_2 storage in underlying hydrocarbon reservoirs or deep saline formations. As such, shale oil and gas production can be in direct conflict with CO_2 storage (Elliot and Celia, 2012). In the United States, geographically there is up to 80% overlap between the shale formations with potential for oil and gas production, and sedimentary basins with significant capacity for CO_2 storage (Elliot and Celia, 2012). Similarly, about two thirds of large CO_2 sources are located in areas where shale formations with potential for oil and gas production are found (Elliot and Celia, 2012). However, as Elliot and Celia (2012) recognized themselves, this assessment was a two-dimensional view of the three-dimensional geological space whereby the result was obtained by overlapping areas identified as suitable for CO_2 storage in the United States with areas with ongoing or prospective shale gas and shale oil development. This preliminary assessment did not take into account that in a sedimentary basin there is a succession of deep saline aquifers and intervening shale formations (caprocks), and only one or very few of the latter would be hydraulically fractured for gas or oil production, while the others will not, thus retaining their containment properties and hence the ability of the underlying saline aquifers to store CO_2. Thus, although the geographical overlap between areas suitable for CO_2 storage and shale gas or oil prospects is extensive, and the production of shale oil and gas may affect the seal integrity, and hence the potential use for CO_2 storage of the aquifer immediately underlying the shale formation, it will not affect other deep saline formations or hydrocarbon reservoirs at other levels in the sedimentary succession. Nevertheless, shale oil and gas production has the potential of significantly reducing the CO_2 storage potential in the formations that immediately underlie them to the point of even making them unusable for CO_2 storage.

Coal

Coal seams represent an energy source by themselves, used mainly for power generation and for heating in industrial processes and of homes. In these cases, coal is mined either in open-pit mines if sufficiently close to the land surface, or through shaft and gallery mining in underground mines. In addition, coal seams can be reservoirs for gases, mainly methane.

Coal seams have been considered as a suitable option for the storage of CO_2 normally at depths, or within seams, that would currently be considered as un-minable. Subsurface workings have however, exceeded depths of 1000 m below the ground surface, e.g. in the UK, although in global terms this is uncommon and conventional underground mining would typically be to depths of 300-400 m. Underground coal mining is ultimately limited to depths of around 1500 m because of severe floor heave issues (Younger *et al.*, 2010). Thus there is considerable potential for interactions between coal mining and CO_2 storage in coal seams because coal seams at depths of less than 1500 m may be economic to mine now or at some time in the future. “Un-minable” coal, e.g. thin or dirty seams of coal that cannot be mined economically, could be used for CO_2 storage (Carbon Sequestration Leadership Forum 2012). However, this is a poorly defined category of coal resources at present.

Injection of CO_2 into coal seams in, or close to, areas of underground mining could result in leakage into active or abandoned mine workings. Because mine workings gradually fill with water when abandoned, this gas would eventually be forced to the surface. Leakage into mine workings could also occur from CO_2 injected into conventional sandstone reservoirs within sequences of coal measures.

Some of the energy value of coal that cannot be mined economically may be recoverable by underground coal gasification (UCG). This could preclude the use of such seams for CO_2 storage (see below).

Natural gas within coal

Coal contains a natural system of orthogonal fractures known as cleats, which impart some permeability to it, and although the solid coal between the cleats does not contain significant conventional porosity it contains micropores in which a natural gas known as coalbed methane (CBM) can occur. This usually consists of >90% methane plus small amounts of higher hydrocarbons, CO_2 and N_2. The gas molecules are adsorbed onto the surfaces of the micropores. CO_2 has a greater affinity to be adsorbed onto coal than methane. Thus, if CO_2 is injected into a coal seam, it may be stored by becoming adsorbed onto the coal, and displace methane from the adsorption sites (methane is commonly present, though the level of saturation of the micropores and cleats with methane varies greatly depending on factors including burial history, depth, moisture content and content of inorganic material, known also as ash).

Any methane recovered from coal could have an economic value and offset some of the costs of CO_2 sequestration. Experimental injection of over 100,000 tonnes CO_2 into the Fruitland coal seams in the San Juan Basin, USA, has enhanced coalbed methane production (Reeves *et al.,* 2004). However, economic coalbed methane production (and probably CO_2 injection) can only be established in a minority of coalfields in which the seams have relatively high permeability. Moreover, the methane in coal represents only a small proportion of the energy value of the coal, and the remaining energy would be sterilized if the coal were used as a CO_2 storage reservoir, i.e., the coal could not be mined or gasified underground without releasing the CO_2.

Underground coal gasification

There are vast and widely distributed deposits of coal in sedimentary basins around the world, but much of the coal is too deep to be mined by conventional surface and underground methods. Also, some coal seams are thin or have too many partings or the coal contains high levels of ash or is of low rank making them uneconomic to mine. Coal that cannot be mined economically can, under favorable circumstances, be oxidized underground by the injection of air or steam, producing CO_2, H_2, CO and CH_4 (and other gases such as sulphur gases) in a process known as underground coal gasification (UCG). This gas mixture can then be used for heat production or thermal power generation. The process can be used on seams 100 to 1400 m deep and depends on numerous factors including coal quality. The in-situ technique of Underground Coal Gasification (UCG) used to produce a syngas (synthetic gas) can use much of the coal resource available for power generation, chemicals and gas-to-liquid fuels. The process also results in large quantities of CO_2 being produced. However the CO_2 from UCG is cheaper and easier to capture than that produced by a power plant, resulting in a more cost-effective CO_2 stream for CO_2-EOR or Enhanced Coal Bed Methane (ECBM). Other advantages are that UCG with CCS involves a smaller footprint, lower environmental impact and less capital costs. Where there is no identifiable commercial use for the CO_2 and at locations where the coal to be gasified is deeper than 800 m there is the option to store the CO_2 in the collapsed gasification chamber and adjacent fractured coal and sedimentary strata (Roddy and Younger, 2010).

Although UCG can produce CO_2 from coals which are suitable for ECBM, CO_2 will not be welcomed in UCG projects. UCG companies will find it easier to develop coals that have not been used for ECBM production, as water content, additional CO_2, loss of methane and fractured coals are factors that will likely produce a less predictable gasification process. As UCG produces at least 20 times more energy per tonne of coal than ECBM, in areas in which ECBM and UCG are both possible, UCG should be favored. In particular deep (800+ m), thick coal seams should be retained for UCG. However the coal bed methane industry (CBM; i.e., without using CO_2 for enhanced recovery, as distinct from ECBM) is more established than the UCG industry and governments in most jurisdictions have not addressed the priority between UCG, CBM and even CCS in policies or regulations. Another issue between the three technologies is that CBM/ECBM and carbon storage in what has previously been called ‘un-minable coal seams’ needs to be qualified as “un-minable by conventional means”, as UCG can be viewed as in-situ mining of coals and can occur at depths from the shallow sub-surface to currently at least 1400 m, as is planned in Alberta, Canada.

The UCG industry in most parts of the world has accepted that UCG must be combined with CCS. In north-central Alberta in Canada, the Swan Hill Synfuels UCG project (Figure 7) plans to spend about $1.5 billion to drill 20 pairs of injection and production wells in one area, build a gas processing plant to collect 1.3 million tonnes of CO_2 each year and install a pipeline to take the syngas to a new 300 megawatt power plant. The intent is to sell the CO_2 for use for EOR in local mature oil fields (Swan Hills Synfuels, 2012).

Roddy and Younger (2010) describe a UCG–CCS case study in northeastern England where a wide range of options are possible including both pre and post combustion capture of CO_2 and either saline formation storage and/or coal seam void storage. Another research project is the ‘UCG&CO2 STORAGE’ implemented under the Research Program of the Research Fund for Coal and Steel of the European Commission (EC). The test site is in Bulgaria where the respective coal is more than 1200 m deep. The project is led and coordinated by the Bulgarian company Overgas Inc. in collaboration with nine partners from five European countries (European Commission, 2012). A German project, CO_2 Storage in in-situ Converted Coal Seams (CO2SINUS), is also looking at UCG-CCS issues (CO2SINUS, 2008). An overview of the project and results are discussed in Kempka *et al.,* (2009) where the authors conclude that UCG with combined cycle power plant (CCPP) and CCS (UCG-CCPP-CCS) technology could replace Germany’s current primary fuel requirements for a period of up to 570 years, thereby creating a potential bridging technology for new energy production concepts. The total process is capable of competing economically with any energy production technology currently used for base-load supply on the European market, while substantially lower power generation costs can be expected for an equivalent level of CO_2 emissions".

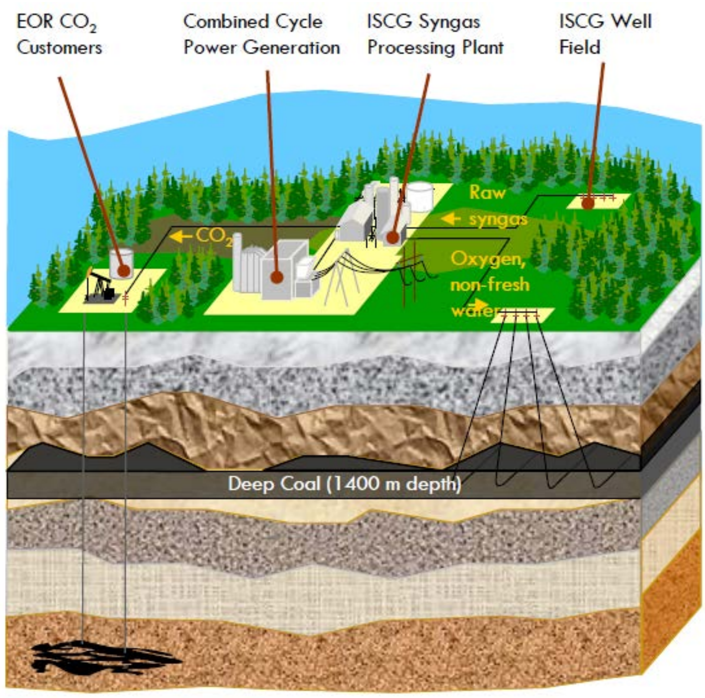

Figure 7: Swan Hills "A" Phase ISCG-Power (In-Situ Coal Gasification) Commercial Development (Swan Hills Synfuels, 2012). Oxygen is injected into coal at 1400 m (too deep to mine conventionally) to feed the underground gasification process, and the syngas thus produced at the ISCG well field is processed, with CH_4 going to a thermal power station and the separated and captured CO_2 being used for enhanced oil recovery.

UCG and CCS have a number of challenges for their successful implementation but also share a number of characteristics that when combined may improve their chance of adoption. There is potential for interaction between UCG and CO_2 storage in coal seams because using a coal seam for CO_2 storage would result in enhanced CO_2 production if the seam was subsequently gasified. Vice-versa, if a coal seam is used for underground coal gasification, then it is rendered unusable for CO_2 storage unless one considers the underground cavity formed as a result of the gasification process and only if that cavity is deeper than 800 m.

Gas hydrates

Gas hydrates found widely in marine and permafrost environments (Figure 8) constitute a huge potential energy resource and, while many of the national programs are in the phase of resource identification and characterization, two long-term production tests of methane hydrates will likely start in 2012 in the Alaskan North Slope permafrost, and offshore Japan (Koh *et al*., 2012). The Alaskan test by Conoco the US-DOE and Japan Oil, Gas and Metals National Corporation (DOE/NETL 2012, web page 1) is particularly interesting as CO_2 will be used in the extraction of methane and storing CO_2 as a hydrate. A review of the technique is provided by Nago and Nieto (2011). They point out that "CO_2 hydrates are more stable than CH_4 hydrates, and exposing CH_4 hydrates to carbon dioxide has resulted in the release of methane, while carbon dioxide remained trapped." The viability of the technology is currently (as of Feb. 2012) being tested with injection of 22 tonnes of liquid CO_2 (DOE/NETL 2012, web page 2). A significant challenge to the economics of producing gas from hydrates is the remoteness of gas hydrates in the arctic regions and marine environments. Small scale commercial production for gas hydrates in the Arctic is not expected until around 2030 (Figure 9, and Ruppel, 2011). However, no resource competition is perceived between gas hydrates and CO_2 storage as CO_2 will be used to recover the gas hydrates.

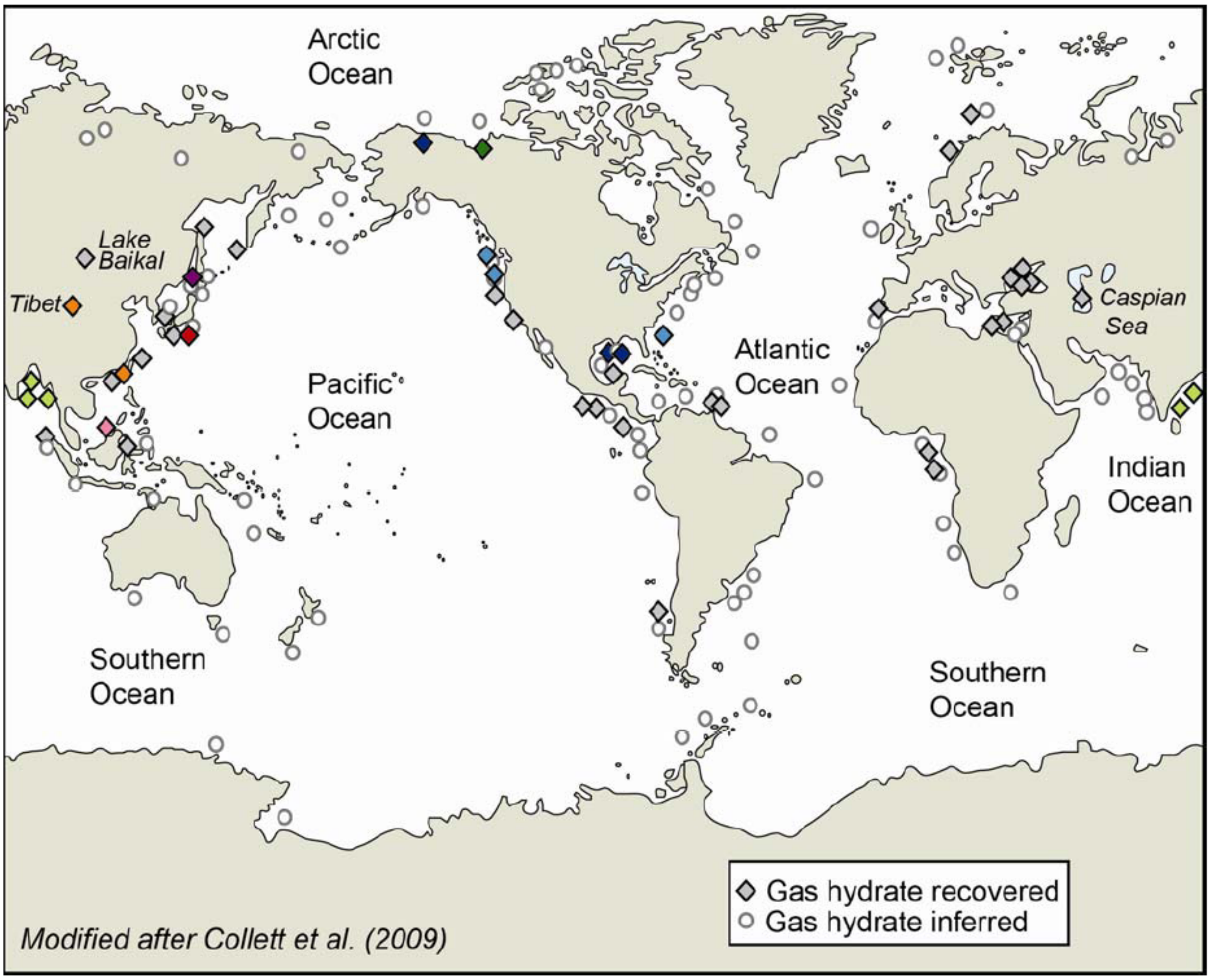

Figure 8: **Global map of recovered and inferred gas hydrates.**

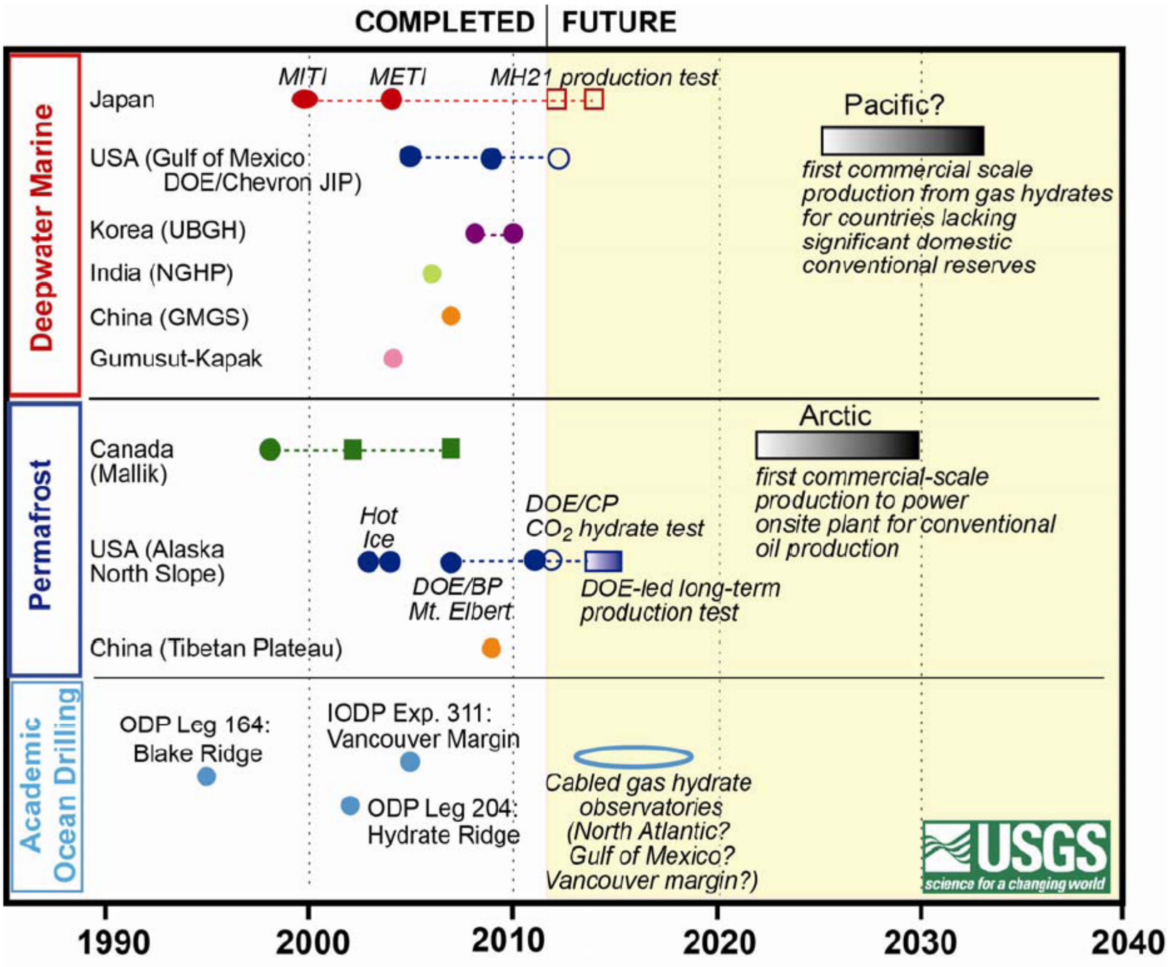

Figure 9: Global view of gas hydrate use, modified from Collett et al., (2009). For full discussion see Ruppel et al., (2011).

Natural gas storage

Storage of natural gas is commonly undertaken to provide a buffer to help to deal with seasonal changes in natural gas demand. It is a profitable industry, exploiting the price differences between natural gas supplied in summer and winter. In summer there is commonly oversupply of natural gas and so gas can be purchased cheaply and stored. In winter, when there is commonly pressure on gas supplies, this gas can then be produced from the store and sold at a higher price. Natural gas is commonly stored underground, in depleted gas or oil fields, closed structures in deep saline aquifers or engineered salt caverns.

Storage in engineered salt caverns is not likely to interact in any way with CO_2 storage because engineered caverns are not large enough to store significant amounts of CO_2.

When natural gas is stored in depleted natural gas reservoirs, oil reservoirs or structural traps in aquifers, a significant fraction of the gas in the structure is irretrievable. This fraction of the gas is called cushion gas. The remainder is known as the working gas. Typically, depleted fields or aquifer structures used to store natural gas are much smaller in size than those that will likely be used to store CO_2, as:

- smaller reservoirs need smaller volumes of cushion gas,
- the gas pressure increases quickly during injection which facilitates rapid gas withdrawal, and
- The optimum amounts of natural gas stored in an individual natural gas storage complex are much smaller than the amounts of CO_2 likely to be sent for storage during the lifetime of a large industrial plant such as a fossil fuel-fired power plant

The largest natural gas storage site in the world is Severostavroposlkoe in Russia (IEA 2006). It contains 37 Bm^3 (billion cubic metres) cushion gas and has approximately 24 Bm^3 capacity for working gas. A crude estimate suggests that the working gas could be replaced with approximately 60 Mt CO_2. This is only approximately 6 years of emissions from a 2 GW coal-fired power plant, so even the largest natural gas storage site in the world might not be a first choice for CO_2 storage. Severostavroposlkoe is considered very much an exception: only 47 out of 607 natural gas storage sites worldwide (8% of sites), can hold more than 3 Bm^3 of natural gas, a capacity that can store approximately 7.5 Mt CO_2 (less than a year's output of CO_2 from a single 2 GW coal-fired power station).

Thus the economies of scale achievable by using very large sinks when storing CO_2 makes it unlikely that there will be a great deal of direct competition for depleted hydrocarbon fields or deep saline aquifers between storing natural gas and storing CO_2 if CCS is deployed at a commercial scale (IEAGHG 2009/01). However, there is the possibility that interactions could occur between hydraulically connected natural gas storage schemes and CO_2 storage schemes, for example where these sites occur in nearby parts of the same aquifer. Regional pressure increase in the aquifer could occur as a result of CO_2 injection and this could affect the pressure in any hydraulically connected natural gas storage sites. Such potential interactions would have to be considered on a case-by-case basis. Pressure perturbations associated with two natural gas storage operations in France (Lussagnet and Izaute) were described by IEAGHG (2011/11), along with local conflicts with thermal water use.

Depleted natural gas fields have been proposed as CO_2 storage sites in demonstration projects. For example, the Goldeneye depleted gas/condensate field, in the North Sea, was originally proposed as the storage reservoir for the Scottish Power/ National Grid/ Shell Longannet CCS demonstration project, and is now being considered as a possible CO_2 storage reservoir for the CO_2 emissions from Peterhead gas-fired power plant, near Aberdeen (CO2 DeepStore 2012).

The anticline containing the Ketzin depleted gas field in Germany is currently a pilot CO_2 storage site, although a different reservoir is used from the one that was formerly used in the natural gas storage scheme (CO2Sink 2012).

In oil and gas-bearing sedimentary basins, many fields use shared facilities such as common gas- or oil-gathering pipelines and common export pipelines. Gathering points tend to be at the larger fields. Thus some of the infrastructure at a large gas field may be needed to service one small field, or a series of smaller fields that are either still producing or which could be used for natural gas storage. Thus the availability of common infrastructure could potentially affect the availability of large oil and gas fields for CO_2 storage. Experience gained in gas storage projects can be useful in CO_2 storage projects (Tenthorey *et al*., 2011b).

Saline aquifer minerals and sediment hosted minerals

In addition to hydrocarbons (oil and gas), sedimentary basins may hold many other valuable energy (uranium, coal), metallic (lead, zinc, gold, platinum among a few examples), gems (diamonds) and industrial mineral (salt, potash, cement) deposits, as well as dissolved minerals and elements in formation waters (brines). There are many different types of sedimentary basins and their mineral potential is highly variable, depending on a range of factors such as source rock, tectonic history, basement rocks, hydrogeological and geothermal history.

The Michigan Basin was the birthplace (through Dow Chemical Co.) of industrial mineral and chemical production from formation brines (attributed to Schaetzl, 2001, in Rostron *et al*., 2002). However, all sedimentary basins contain brines and dissolved minerals at various concentrations. Dissolved minerals are arguably the most at-risk resource from CO_2 storage operations as deep saline formations have been identified as excellent storage sites because of their widespread extent and large capacity.

As an example, the deep saline formations of the Alberta Basin have been proposed as good candidates for CO_2 storage but also contain valuable elements such as calcium (Ca), magnesium (Mg), potassium (K), lithium (Li), iodine (I) and bromine (Br) (Hitchon *et al*.,1993; Underschultz *et al*., 1994; Bachu *et al*., 1995). Lithium enrichment of oil-field brines and saline formation waters is known to occur worldwide in sedimentary basins of various ages (Eccles and Berhane, 2011). Recently, because of building demand for lithium used in the production of lithium-Ion batteries, there has been a number of mineral leases taken out in the Alberta Basin and, during 2009 and 2010, at least three exploration companies reported high levels of lithium (up to 112 mg/L) from brine-sampling programs as well as other valuable elements such as elevated boron (223 mg/L), potassium (5870 mg/L) and bromine (412 mg/L) (Eccles and Berhane, 2011). The areas with elevated values are large (Figure 10) but still localized within the basin and apply for only some of the deep saline formations in the basin. Nevertheless, this example demonstrates the importance of identifying potential resources before a decision is made regarding storing CO_2 in deep saline formations.

Rare elements like lithium are not the only valuable brine minerals; calcium, magnesium and potassium are the most abundant elements in brines and are economically recovered from a number of basins worldwide. For example, extraction of sodium chloride in large volumes of up to 2,000 liquid tonnes daily from saline aquifers has been ongoing in the Alberta Basin for over 25 years (Tiger Calcium Services Inc., 2012). Areas where major components of brines can be economically recovered should be identified in any proposed CO_2 aquifer storage project and the potential for sterilization of these resources or the possible co-production with storage should be evaluated.

Uranium roll-front and flat (sheet) deposits form in sedimentary basins and currently 41% of the world's uranium production is in-situ leach-mined in sedimentary basins (World Nuclear Association, 2012). Most in-situ uranium mining is at relatively shallow depths but one pilot test in Crownpoint, New Mexico in 1979 was at 610 m. In addition, a project in south central Kazakhstan is targeting uranium deposits at 650 to 700 m depth in the Kharassan-2 sandstone (Silk Road Economy & Business Report, 2011). Where the uranium bearing sedimentary host rocks also contain carbonate minerals, CO_2 is used in the leachate. At the Crownpoint pilot, for example, a hydrogen peroxide/alkaline bicarbonate leachate was used. Although CO_2 storage in a deep saline aquifer is unlikely to leach uranium without an oxidant being present, it highlights an area of geochemistry that might be further researched. An accompanying issue is the disposal of wastewater from in-situ uranium operations in deep saline aquifers which might also have potential for CO_2 storage. This situation should also be considered as a potential conflict between resource uses.

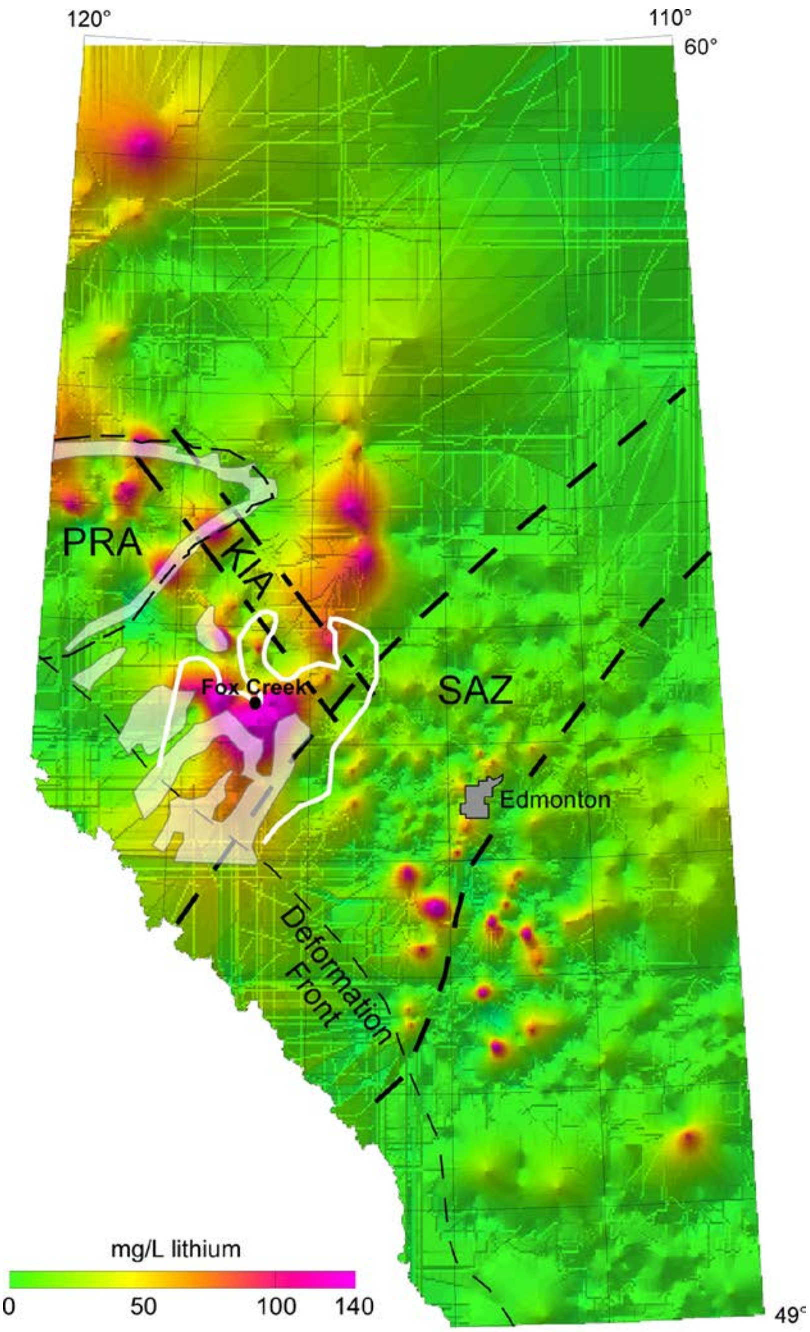

Figure 10: Shaded contour map of lithium-bearing formation waters in west-central Alberta (Eccles and Berhane, 2011). The Fox Creek anomaly is about 100 km across (each degree of latitude is 111 km).

The other minerals within sedimentary basins currently mined by in-situ solution methods are water-soluble salts such as potash (sylvite), rock salt (halite, sodium chloride), and sodium sulfate. These salt deposits are common to many sedimentary basins and can be extensive in area and very thick. Often large caverns are left after in-situ solution mining of salt in salt beds or domes. Caverns have been suggested as potential CO_2 storage sites (Fradley, 2012) where a valuable mineral can be produced at the same time (Dusseault *et al*., 2001). However the cost and capacity of the caverns suggest that they will only be useful in niche areas where other CO_2 storage options are limited or as buffers (temporary storage) in CO_2 transportation systems (Bachu and Rothenburg, 2003).

Sediment-hosted ore deposits of gold, lead-zinc-silver and copper are found in many sedimentary basins. Most are surface mined and some are underground mined. The depth of mining is usually no more than a few hundred meters, but in some basins, such as the Witwatersrand Basin in South Africa, gold mines have reached 4 kilometers in depth. With metals becoming more scarce and mining technology advancing, deeper mines may become an issue for CO_2 storage in some sedimentary basins. In addition if the mineral industry is able to develop in-situ methods for traditional sediment-hosted ore deposits at great depths, conflict with CO_2 storage could become an issue.

One important type of sediment hosted lead zinc deposit called Mississippi Valley-Type (MVT) is found in many basins worldwide but is best developed in North America. This type of deposit "is hosted mainly by dolostone and limestone in platform carbonate sequences and usually located at flanks of basins, orogenic forelands, or foreland thrust belts inboard of the clastic rock-dominated passive margin sequences" (Leach *et al*., 2010) and are at depths and locations that are too shallow and distal from any potential CO_2 storage sites.

Polymetallic black shales, some with elevated levels of Rare Earth Elements (REE), are one type of sedimentary deposit which is found around the world (Lüning 2012) and which is being evaluated for mining potential in a number of sedimentary basins. However, the mining of these unconventional deposits is currently at a development stage and only surface minable polymetallic black shales are being explored. Metal rich organic rich shales can be extensive in area and are found at depth within many basins. To date only one polymetallic black shale, a metamorphosed schist deposit located in eastern Finland, is being mined (Talvivaara Mining Company Plc., 2012).

In Alberta, the company DNI Metals Inc. (DNI Metals, see web-page) is exploring the shallow up-dip erosional edge of the Cretaceous Second White Speckled Shale Formation (Second White Specks Shale) which is present at depth over a large portion of the Alberta Basin. Recoverable grades for Molybdenum trioxide (MoO_3), nickel (Ni), triuranium octoxide (U_3O_8), vanadium pentoxide (V_2O_5), zinc (Zn), copper (Cu), cobalt (Co) and lithium carbonate (Li_2CO_3) have been estimated (Inferred Mineral Resource) and testing of acid heap leaching and bioextraction methods has been undertaken (Dufresne *et al*., 2011). A further report identified rare earth elements (REE), yttrium (Y), scandium (Sc) and thorium (Th) as co-products (Dufresne *et al*., 2012). Mining of shales for production of these minerals will affect caprock integrity for the underlying aquifer, rendering CO_2 storage in this aquifer questionable.

It is possible that in-situ methods could be developed at depths similar to and in the same shales that are currently being developed for shale gas or shale oil. It has been suggested that the hydraulically fractured gas shales could be mined for minerals using bioextraction methods (GEOTEK, 2011). Those gas shales may also be future candidates for CO_2 storage (DOE/NETL Project Factsheet, 2011; Pestrusak, 2011) or as enhanced shale gas or enhanced shale oil projects. However, CO_2 storage should only happen after in-situ acid-leach extraction as the CO_2 would make acid extraction impossible. It may be possible to store CO_2 in conjunction with and by enhancing bioextraction methods.

To date only the interaction of CO_2 in relation to conventional oil and gas resources and unconventional Coal Bed Methane (CBM), as part of storage in coal, has been considered to any degree. However, the value of sedimentary-basin hosted minerals is very significant and, as world demand for mineral resources grows and extraction technology improves, the mineral industry is looking at minerals deeper within sedimentary basins and at lower levels of concentration. Without a good understanding of the minerals present and processes used in their extraction, the unplanned negative effects of CO_2 storage (chemical, temperature, pressure, porosity etc.) could sterilize or make uneconomic a host of minerals that will be needed by future generations. Alternately, there is potential for some mineral extraction synergies, such as combining mineral extraction and CO_2 storage along with technologies such as bioextraction or in the co-production of brine minerals.

Geothermal energy

Geothermal energy production has been around for over 100 years but its development has been uneven as technological breakthroughs have been slow and the volatile nature of energy prices, particularly low oil and gas prices, have had a negative influence on the growth of this form of energy production. More recently high energy prices, the predictions of 'peak oil' and concerns over climate change have stimulated renewed interest and support for what is a very large renewable resource.

Potential interactions and synergies between CO_2 storage and geothermal energy production are described in IEAGHG (2010/TR3). There are four principal types of systems that extract geothermal energy: ground source heat pumps, low enthalpy systems, high heat flow systems and enhanced geothermal systems.

Types of systems for geothermal energy extraction

Ground source heat pumps (GSHPs). The most common GSHPs extract heat by passing piped water (or a water-antifreeze mix) through the ground at shallow depths. These types of GSHPs are known as closed loop systems. They absorb heat from the ground in winter (typically at temperatures of 10-12°C) and this is extracted, typically for space heating in houses, using a heat exchanger. They can draw water from as deep as 200 m and could perturb groundwater flow at even greater depths. Nevertheless, ground source heat pump systems are not expected to interact in any significant way with CO_2 storage, which is most likely to take place at depths of 800 m or more.

Low enthalpy geothermal systems. These systems mine heat from warm or hot water in underground aquifers. Typically they provide space heating or district heating as, for example, in the Paris Basin, France (Bonijoly *et al.,* 2003). Low enthalpy geothermal systems are more economically viable in relatively warm-to-hot aquifers (in areas where there is relatively high heat flow from the interior of the earth towards its surface, with corresponding high geothermal gradients) whereas, all other things being equal, CO_2 storage is more efficient in cooler reservoirs as the density of the stored CO_2 is likely to be higher (Bachu, 2003). Nevertheless, there is certainly potential for competition for pore space between such low enthalpy geothermal systems and CO_2 storage because both use reservoirs with similar properties at similar depths.

High heat geothermal systems. Typically these are found in areas of very high heat flow such as volcanic regions and tectonically active regions. They extract very hot water or steam from the subsurface through boreholes. Steam may be used directly to generate power. Alternatively, steam or hot water may be used to generate power via a binary system or passed through a heat exchanger. There is not expected to be any significant competition between high heat geothermal systems and CO_2 storage because CO_2 storage is unlikely to take place in the typically tectonically unstable and volcanic areas where high heat geothermal energy is produced (Bachu, 2003).

Enhanced Geothermal Systems (EGS) from aquifers with temperatures from greater than 80°C to hot dry rock environments up to 500°C are now also being proposed. In these systems, alternate methods are used or proposed for use to mine underground heat. The latter can involve fracturing of a low permeability rock to increase fluid flow, as in a Hot Dry Rock system. Recently it has been proposed that using CO_2 as a heat transfer fluid could improve the efficiency of such systems (e.g., Pruess 2006) and could also result in CO_2 sequestration. Thus there appear to be opportunities for significant synergies between CO_2 sequestration and enhanced geothermal systems in the future.

Most of the past development of geothermal energy has been concentrated on high-temperature geothermal resources (conventional hydrothermal 120°C – 300°C) for electric energy production (power generation) in places with high geothermal gradients located in tectonically active areas such as California, Iceland and New Zealand. Direct use for heating (district heating, greenhouses, bathing etc.) of low-to-medium temperature (20°C - 150°C) geothermal energy has generally not received the same attention as geothermal electrical power generation and often has been considered 'low tech' and has involved lower levels of investment. As a result, it generally has had a lower profile and until the last 15 years it hasn't been as well documented or tracked by geothermal energy professionals. An overview of direct use geothermal by Lund *et al.,* (2010) documents the growth in usage from 1995. Much of the increase is from the introduction of very low temperature <20°C geothermal heat pumps GHGPs) in a number of countries in North American, Europe and China. Lund *et al.,* (2010) report that the five countries with the largest installed direct use capacity are: USA, China, Sweden, Norway and Germany accounting for 60% of the world capacity, and the five countries with the largest annual energy use are: China, USA, Sweden, Turkey, and Japan, accounting for 55% of the world use. The Paris basin, exploited since the 1970s for geothermal district heating purposes, is an early example where low-to-medium temperature brines now supply heat to 150,000 dwellings. The carbonate reservoir depths and formation temperatures range from 1400 to 2000 m (depths suitable for CCS) and 56 to 80°C respectively (Ungemach *et al*., 2005). Today France is still one of the leaders in district heating but is joined by 24 other countries, the top five being Iceland, China, Turkey, France and Russia (Lund *et al*., 2010). Because low-to-medium temperature direct-use geothermal resources are available almost anywhere, this type of resource will receive greater prominence in the future.

In the past, 20°C - 150°C water could only be used for direct heat applications which restricted its use. Improved technology for binary type electrical power plants using 70°C to 150°C brines, typical of temperatures for co-produced brines from many sedimentary basins, has recently stimulated much interest in the development of low-enthalpy geothermal systems. These are often the same aquifers that are also being considered for CO_2 storage.

Competition between low enthalpy geothermal systems and CO_2 storage

Typically, low enthalpy geothermal systems are found in sedimentary basins and they extract heat from aquifers at depths of approximately 500 to 3000 m. Relatively low aquifer temperatures of the order of 50°C to 150°C are compensated for by the high transmissivity (permeability) of the geothermal reservoir. The economics of the technology are improved if suitable end users for the extracted heat are available in the immediate area around the water production wells. Typical large schemes provide heating for individual buildings or district heating schemes (as in the Paris Basin). Smaller schemes provide space heating, e.g. for greenhouses, or water heating.

It seems possible that the demand for low enthalpy geothermal energy might increase in future decades as fossil fuels become more expensive and there is also increased demand for low carbon energy sources. Indeed van Wees *et al.,* (2010) detect a boom in the uptake low enthalpy geothermal energy in NW Europe. They also point out that low enthalpy geothermal energy is well received in urban areas whereas the same may not always be true for CO_2 storage.

Because CO_2 storage involves the essentially permanent storage of CO_2, it may have the potential to prohibit, or reduce the economic efficiency of the development of low enthalpy geothermal resources in the future. Low enthalpy geothermal heating is not economic offshore at present and it is difficult to foresee this situation changing in the near future. Therefore, in the near term at least, it seems likely that any competition will be limited to onshore areas.

There is concern however that CO_2 storage in aquifers may hinder the development or even prevent the development of geothermal energy resources in some sedimentary basins. In 2009 the European Geothermal Energy Council (EGEC) published a position paper on CCS where it stated "*There is obviously conflicting potential as a result of the competition between CO_2 disposal and geothermal energy projects because they may target the same deep aquifers or the same areas within sedimentary basins*". The EGEC also recommended to the EU member states that "*zones of dual use capability should be clearly identified and priority should be given to their use for geothermal energy over their use as a carbon storage site*" and concludes "*The increase of a renewable energy source* (geothermal)*, a long term solution, must not be hampered by a technology, CCS, that has the potential only to serve as a temporary, interim GHG mitigation measure* (EGEC, 2009).

The current policy and legal situation with regard to CCS in the EU is outlined in a presentation *CCS Directive transposition into national laws in the Baltic Sea Region: progress and problems by the end of 2011* by Shogenova (2012), who comments that "*Geothermal applications might constitute conflict with the use of saline aquifers onshore. However the joint use of geothermal exploitation and CCS in the same place have been already proposed by number of authors.* "

Indeed, In February 2010 a conference was held at Potsdam, Germany on *Geothermal Energy and CO_2 Storage: Synergy or Competition?* (Helmholtz Centre Potsdam - GFZ German Research Centre for Geosciences, 2010). The conference's objective was to explore the synergies and conflicts where geothermal energy may be produced at the same sites where carbon dioxide can be stored in the underground. Haszeldine (2010) felt that there was little overlap between Enhanced Geothermal Systems (EGS) and CCS as the optimal temperature of 150°C for EGS would occur in basins with a normal geothermal gradient at about 4 km depth while most CCS sites would be between 1 km and < 3 km deep. He also pointed out that EGS has a smaller footprint than CCS and that in Europe offshore development of large scale CCS may also diminish any conflicts with EGS, as mentioned previously. A case study where geothermal energy and CCS could synergistically co-exist was outlined by Christensen (2010). He outlined how a sandstone formation in northern Denmark at 2 km depth could be developed first for geothermal energy and then be used later for both CCS and geothermal energy production. As part of the plan, produced and then cooled water would be re-injected at a distant site, providing more storage space for the CO_2.

The Delft Geothermal Project in the Netherlands is conducting a feasibility study on capturing CO_2 and co-injecting it with the cooled-down-return water of the geothermal system. In this case the CO_2 is not used as a working fluid, but simply stored simultaneously with hot-water extraction. The paper outlines a Negative Saturation (NegSat) approach for compositional flow simulations of mixed CO_2-water injection into the aquifer under Delft (Salimi *et al*., 2011). Their results showed "*that as long as the injected CO_2 remains completely dissolved in the aqueous phase for the entire process, as the overall injected-CO_2 mole fraction increases, the useful energy extraction decreases slightly, but the maximum stored CO_2 increases accordingly.*"

In North America, over the last decade there has been research on the geothermal potential of co-produced fluids from oil and gas wells that have a high water cut and temperature (McKenna *et al*., 2005). A hybrid two-stage energy-recovery approach to sequester CO_2 was proposed by Buscheck *et al.,* (2012) where, in stage one, formation brine, which is extracted to provide pressure relief for CO_2 injection, is the working fluid for energy recovery. The "*produced brine is applied to a consumptive beneficial use: feedstock for fresh water production through desalination, saline cooling water, or* *make-up water to be injected into a neighbouring reservoir operation, such as in Enhanced Geothermal Systems (EGS)."* In stage two "*which begins as CO_2 reaches the production wells; coproduced brine and CO_2 are the working fluids*" (Buscheck *et al.,* 2012).

A number of co-production projects have now been initiated outside the United States, including China (Xin *et al*., 2011) and Canada (Borealis Geopower, 2010). Recently, a new CCS-geothermal technology called CO_2-plume geothermal (CPG) system (Figure 11) has been proposed (Randolph and Saar, 2011). The technology can be employed in both aquifers that have oil and gas as part of enhanced oil/hydrocarbon recovery (EOR) and in those that do not. More research and testing will be needed, but a new company based on the technology has been created (Heat Mining Company, 2012).

A further refinement would see that in addition to CCS and geothermal energy production, the extraction of valuable minerals takes place. The opportunity to integrate energy production from geothermal, reducing CO_2 emissions from CCS and producing valuable mineral components from brine at the surface may result in enhanced commercial attractiveness of all three processes.

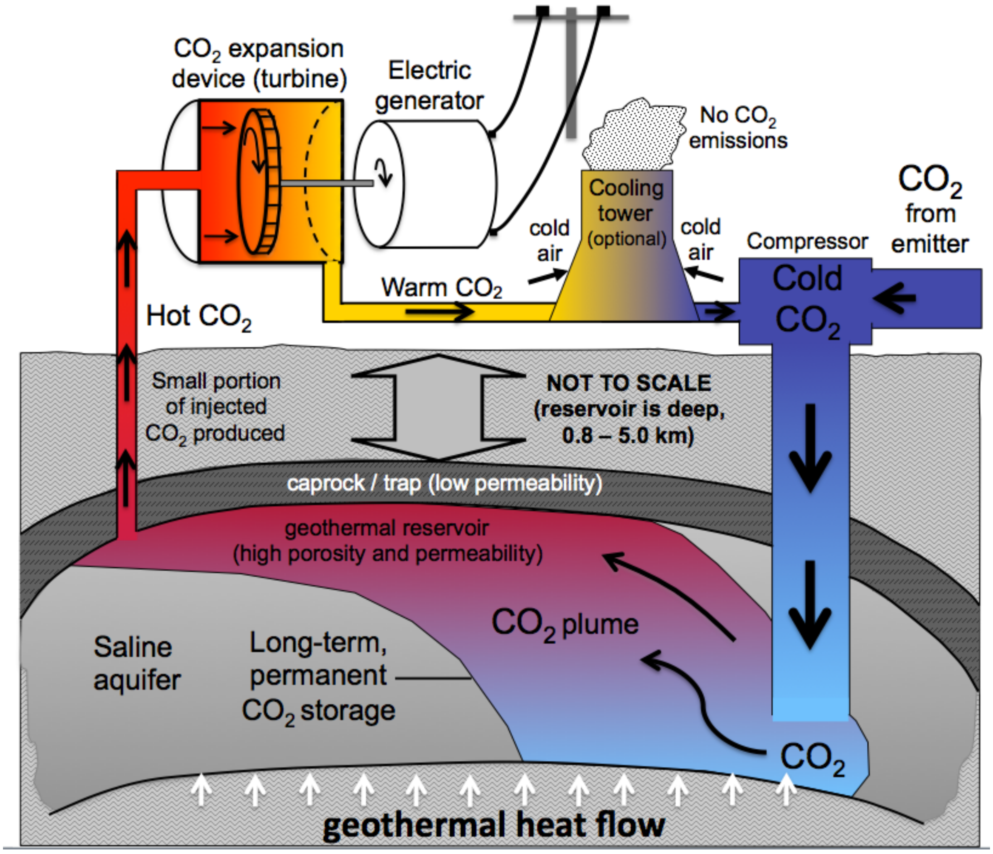

Figure 11: Simplified schematic of one possible implementation of a CO_2-plume geothermal (CPG) system, established in a deep saline aquifer or as a component of enhanced oil/hydrocarbon recovery (EOR) operations (Randolph and Saar, 2011).

Groundwater

Groundwater typically occurs in gravels, sands and fractured rocks (aquifers) at depths of up to a few hundred metres below ground and is usually rain and melt water that has percolated into the aquifer over periods of up to thousands of years (Figure 12). Shallow aquifers might be exposed to the ground surface but they can be capped by an impervious layer called an aquiclude. A large groundwater system might consist of several interlayered aquifers and aquicludes, with little or no pressure or fluid connection between each aquifer; each can be exploited separately and each might have particular characteristics (e.g., purity or rate of recharge). Because most groundwater occurs at shallow depths there is likely to be little interaction with CO_2 storage sites (which are typically deeper than 800 m), particularly where CO_2 storage is occurring offshore, provided there are good seal rocks between the CO_2 storage reservoir and the groundwater aquifer and that there is no deleterious pressure interaction. Some groundwater systems extend offshore under the seabed and, if in fluid connection with sea water, can be affected by salt-water intrusion.

CO_2 storage reservoir rocks that are not within geometric closures are sometimes called "saline aquifers" to differentiate them from freshwater, potable aquifers. Saline aquifers, by definition, contain water too salty for direct use for industrial or agricultural or drinking purposes, though low-salinity saline waters might be made usable after desalination.

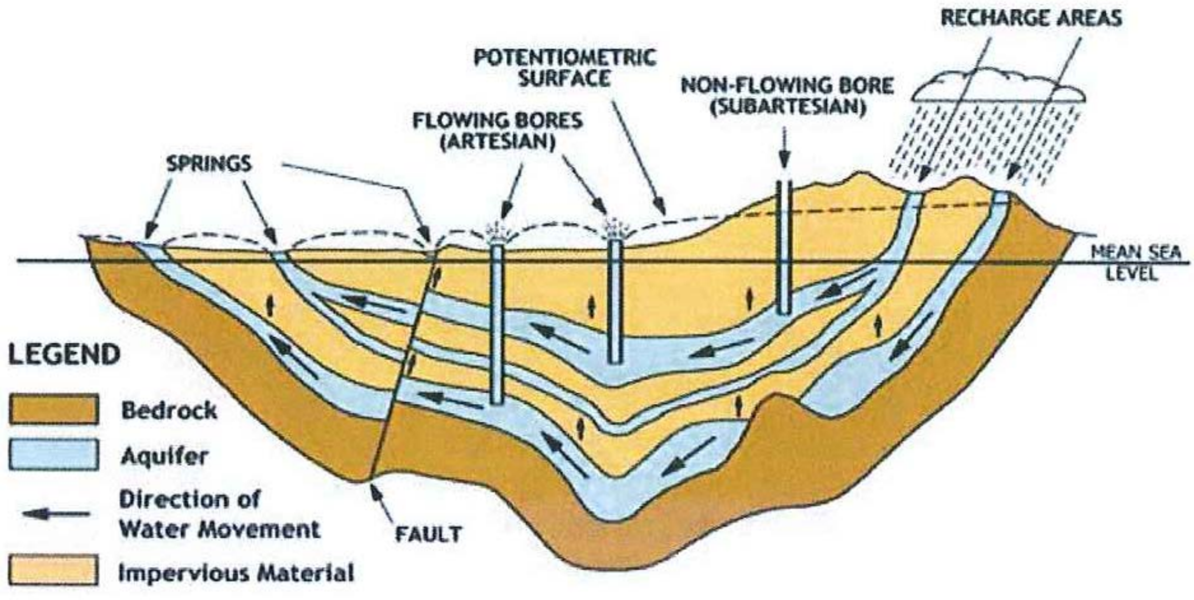

Figure 12: Generalized cross section of the Great Artesian Basin in Australia (Queensland Department of Environment and Resource Management). The basin is 1.7 million square kilometres in area and up to 3000 m deep (average depth of bores is 500 m, maximum ~2000 m) and the oldest groundwater is two million years old; most groundwater systems are shallower and younger than this.

In cases where the interaction of CO_2 with potable groundwater is possible (by pressure contact or direct contact), the interaction can be positive or negative (IEAGHG 2011/11). Positive effects could include pressurisation and brine displacement that could support or improve groundwater abstraction rates in aquifers that have previously been over-exploited or affected by drought. Pressure relief wells associated with CO_2 storage projects could provide saline water fit for desalination in areas currently lacking potable groundwater. Negative impacts could be caused by:

- Leakage of buoyant, free-phase CO_2 from the storage site into potable aquifers, causing acidification or mobilization of dissolvable substances;

- Displacement of high salinity water from deeper storage formations into potable groundwater;

- Disruption of aquifer flow systems and groundwater discharge pattern by pressure perturbations caused by storage (IEAGHG 2010/15 and IEAGHG 2011/11).

The injection of CO_2 down dip of pore space that contains potable water has the potential to mix with potable water, alter groundwater flow patterns, change discharge regimes or alter the level of the water table (Nicot 2008, Birkholzer *et al.,* 2009, Yamamoto *et al.,* 2009). Detrimental effects could occur as a direct result of CO_2 mixing with the potable water or as a result of entrained substances such as metal ions entering the potable water supply (IEAGHG 2011/11). It is important to ascertain the range of potential ways in which interaction of CO_2 and groundwater might occur; these might be specific to each project (Figure 13). Numerical models at the wellbore scale (e.g., Nicot et al., 2009) and at basin scales including both potential CO_2 storage reservoirs and groundwater reservoirs can be used to predict any likely interactions (IEAGHG 2011/11); this publication also discusses the status of CCS regulations with respect to groundwater and ways of mitigating any unexpected interactions of CO_2 storage with groundwater resources.

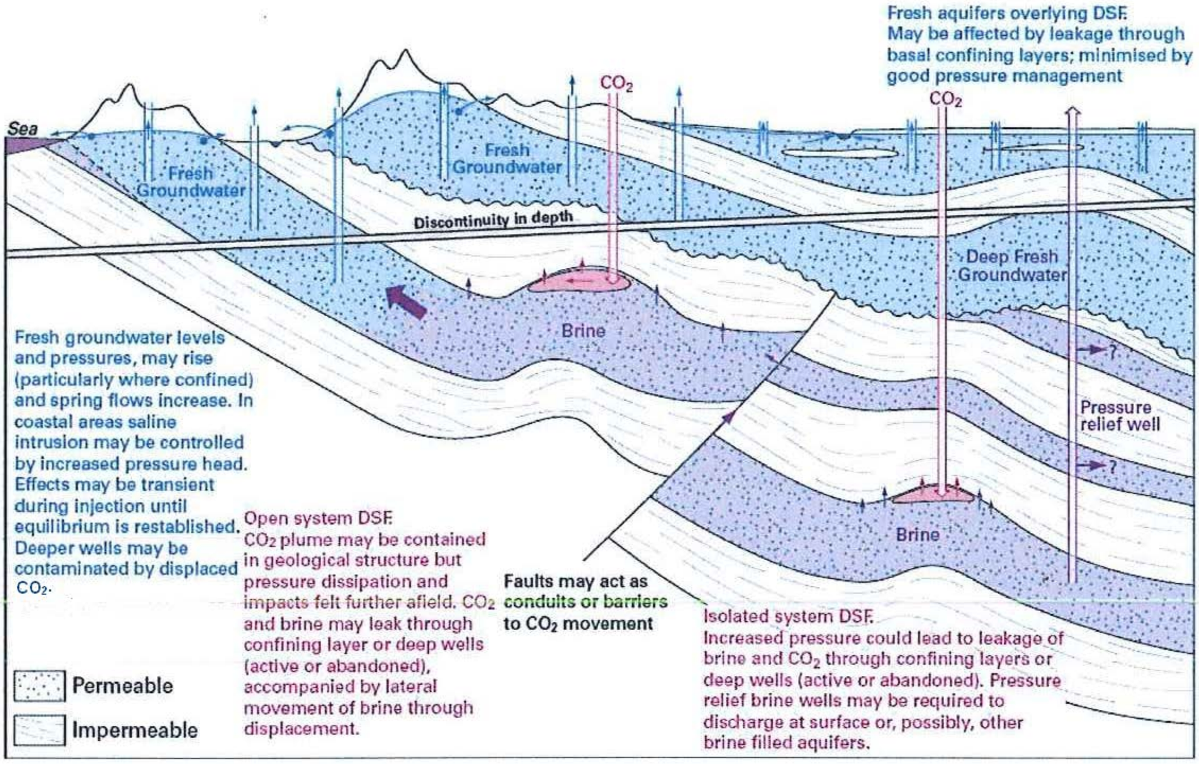

Figure 13: Potential leakage mechanisms and impacts of CO_2 storage on groundwater (figure 3 of IEAGHG 2011/11). Not to scale.

Other uses of geological pore space

Subsurface storage of waste fluids has the potential to influence CO_2 storage by competition for pore space, mixing by leakage, and pressure perturbation. One of the key elements of a safety case at underground nuclear waste repositories is an understanding of the local groundwater flow, which, albeit very slow, potentially could have an effect on the distribution of radionucleides should these leak from the repository, e.g., Heathcote & Michie (2004). Also, large-scale CO_2 injection has the potential to perturb groundwater flow rates and directions in reservoir rocks and thus has the potential to affect the safety of any nuclear waste repositories sited in connected groundwater systems in the same sedimentary basin. However, there are major differences between CO_2 storage and nuclear waste disposal (Bachu and McEwen, 2011), and the disposal of nuclear waste is typically done in hard rock (e.g., Finland and Sweden), where there is no competition with CO_2 storage.

The disposal of saline waste water at Werra, Germany, was discussed by IEA (2011/11) as an analogue for CO_2 storage, with the conclusion that diffuse leakage could affect groundwater resources and that vertical leakage could be enhanced by pressure reduction in the overlying groundwater system as water is extracted. Disposal of waste water, or produced water, is discussed further in the next chapter under several of the case studies.

Case Studies of Resource Interactions

Europe, UK

Groundwater: Cassem Project

Although the UK regulatory regime for CO_2 storage does not cover onshore areas, a study of the potential for CO_2 storage in the Bunter Sandstone beneath the East Midlands, UK, was undertaken as part of the Cassem project (Smith *et al.,* 2011). The part of the Bunter Sandstone targeted as a potential reservoir for CO_2 storage is close to the east coast of the UK and is the down-dip extension of a major potable water aquifer (Figure 14). As the aquifer is traced up-dip and westwards from the east coast of the UK it is used extensively for water abstraction. Two further groundwater supply aquifers overlie the Bunter Sandstone, though these are separated from it by thick and extensive mudstone-dominated formations.

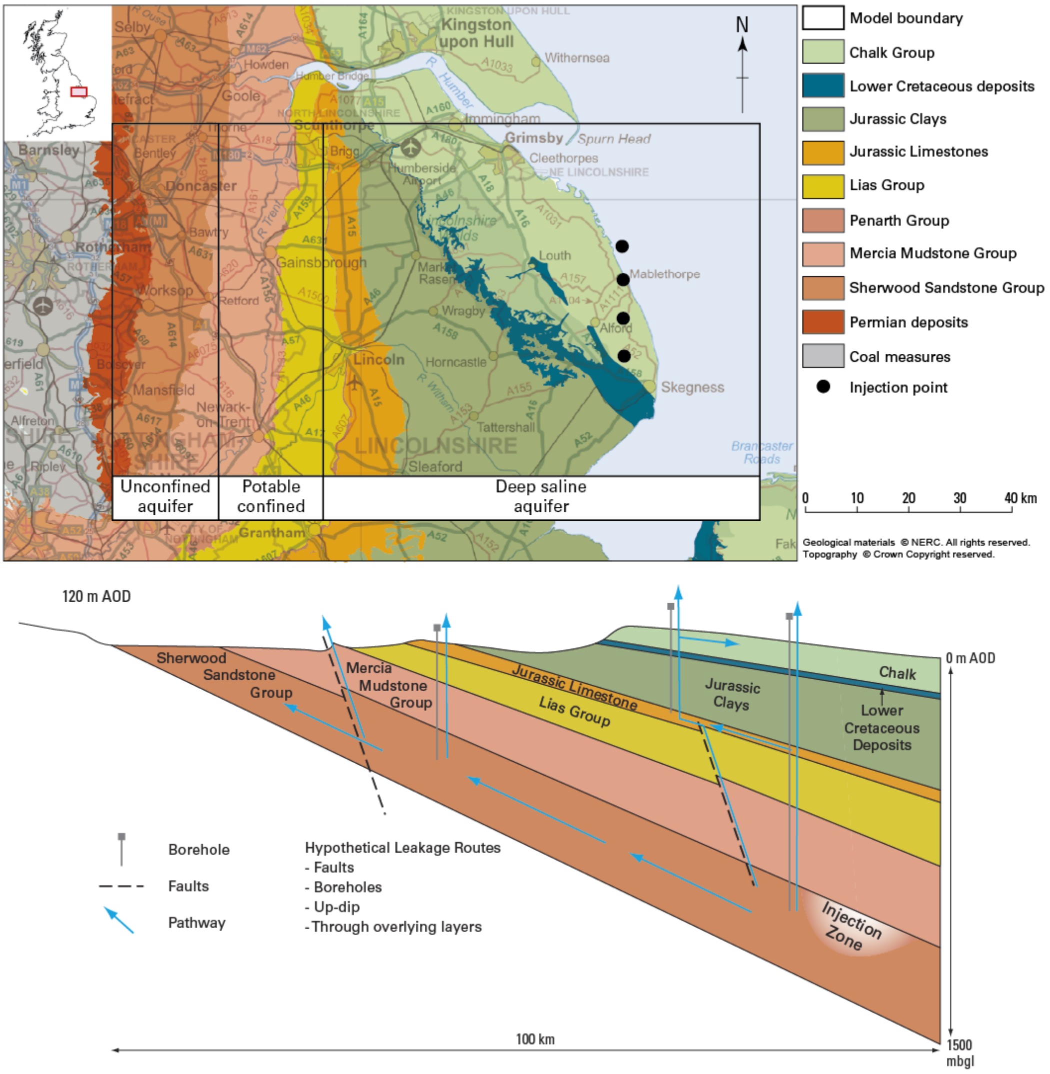

Figure 14: Location of the study of CO_2 injection into the Bunter Sandstone in Lincolnshire on the east coast of the UK undertaken in the Cassem project.

A hydrogeological model of the whole area between the coast and the outcrop of the Bunter Sandstone to the west was produced (Bricker *et al.,* 2010) and integrated with dynamic flow simulation modelling of CO_2 injection to determine the likely effects of CO_2 injection on potable water supply. The injection of 15 Mt CO_2 per year for 20 years, distributed across 8 injection wells, was simulated. Key findings of the study were:

- The degree of impact on shallow groundwater systems is highly sensitive to the vertical leakage assigned to the cap rock. Reducing the vertical conductivity of the cap rock by one order of magnitude to 10^{-17} m^2/day has the effect of increasing groundwater head in the shallow confined aquifer by 0.1 – 50 m (depending on location) and increasing river flows on the unconfined aquifer by approximately 9%.

- Recession of groundwater heads in the shallow confined aquifer occurs relatively slowly, with groundwater heads still elevated by up to 1 m ten years after injection ceases.

- At the interface between the deep and shallow confined aquifer, particle tracking shows a small movement (c. 6m) of water over a 20-year injection period. Lateral movements of the water interface are more strongly influenced by ongoing surface abstraction than by CO_2 injection and migration, assuming intergranular flow.

Natural Gas Storage: Hewett gas field

The Hewett gas field complex in the UK sector of the Southern North Sea consists of the giant Hewett gas field and six smaller satellite fields (Big Dotty, Little Dotty, Deborah, Delilah, Della and Dawn). The Hewett field was proposed as the CO_2 storage site for Eon's Kingsnorth CCS demonstration project. In the FEED studies for the CO_2 storage project (Department of Energy and Climate Change, 2012), no conflicts are reported with the field licensee (ENI)'s plans to convert the Deborah field into a natural gas storage project (ENI, 2012). However, the CO_2 storage project was withdrawn in October 2010, so the possibility that conflicts may have occurred later had the development of both the CO_2 storage project and the natural gas storage project matured cannot be ruled out.

Geothermal field: Delft

Delft University has applied for the geothermal exploration license under and around its campus grounds (Wolf *et al*., 2009).

The first phase of exploration is focusing on the construction of a normal low-enthalpy geothermal system in which water at a temperature of about 75°C from a depth of about 2300 m will be extracted from and re-injected into the Delft and Rijswijk Sandstone Members of the Upper Delfland Formation of Upper Jurassic age at rates of about 150 m^3 per hour. This will contribute to the reduction of emissions from the university site because there will be less demand for the on-site 79 MW power plant, which has two cogeneration units for base-load and three gas boilers for peak demand.

In the second phase of the project, a research programme for CO_2 capture and storage will be realized. Capture techniques for removing the CO_2 from the power plants' flue gas are being studied. One of the options is adding CO_2 at low pressure (about 20 bar) to the re-injected water volume. CO_2 will diffuse into the water, which will be undersaturated with CO_2 when it reaches the target storage reservoir (which comprises the same sandstone members as the geothermal reservoir). An anticlinal structure is present beneath the proposed injection site, and the injected water will be heavier than the original water and thus will migrate downward within the storage formation; it is planned that about 5 ktons CO_2 will be stored annually. The studies show sufficient storage volume at subsurface pressure and temperature conditions. About 2 km of favourable overburden rock will prevent upward migration of the stored CO_2.

Waste disposal: Sellafield

A site in basement rocks of the Borrowdale Volcanic series was being investigated to determine its potential to host an intermediate-level nuclear waste repository at Sellafield in Cumbria, on the west coast of the UK mainland (Chaplow 1996). The proposed location was close to the nuclear power station at Sellafield and, geologically, lies on the eastern margin of the East Irish Sea Basin (Michie 1996). The overlying Permo-Triassic sandstones (the St Bees Sandstone and Ormskirk Sandstone formations) have CO_2 storage potential in the deeper parts of this basin. It seems conceivable that perturbations of groundwater flow induced by large-scale CO_2 injection into the Permo-Triassic sandstones offshore could affect the groundwater flow at the proposed Sellafield repository site and thus require that groundwater modelling in the repository safety case be reconsidered. To avoid such an interaction, flow modelling would have to be undertaken to scope the areas in which CO_2 injection could affect groundwater flow at the repository.

Petroleum exploration and production: North Sea

The location of the North Sea relative to the UK and the European mainland and the division of the North Sea in country sectors are shown in Figure 15.

CO_2 storage is not likely to take place in the near future in the onshore parts of the five countries that surround the North Sea, for a variety of reasons:

- There are no suitable storage reservoirs onshore in Norway.
- In the UK: “Currently the UK Government’s view is that the most appropriate sites for carbon dioxide storage in UK territory are offshore .... and therefore we would not anticipate implementing the [EU Storage] Directive onshore in the first instance. Any change in this position will be subject to consultation.” (BERR, 2008, paragraph 5.6).
- In the Netherlands, CO_2 storage onshore has been put on hold: “According to the Minister of Economic Affairs, Agriculture and Innovations, there is not sufficient societal support for onshore CCS. Therefore the national Government only allows and supports offshore initiatives.” (Feenstra, 2012).
- In Germany, legislation transposing the EU CO_2 Storage Directive has been passed. However, it seems likely that considerable discretion will be given to the regions (Lander) on whether to allow CO_2 storage. Moreover, only demonstration projects are likely to be allowed onshore until 2017 (Krämer, 2011 and Armeni, 2012).
- In Denmark, the existing Danish Subsoil act addresses the use of the subsoil for storage purposes. The new [storage] Directive was implemented into Danish legislation on May 24, 2011 by an amendment of the Danish Subsoil act, among other statutory provisions. The amendment includes the possibility of CO_2 geological storage. However, the Danish Parliament has put onshore storage on hold until 2020.

Consequently, storage in the North Sea itself is the most promising option for these countries at present, and indeed for many other nearby European countries.

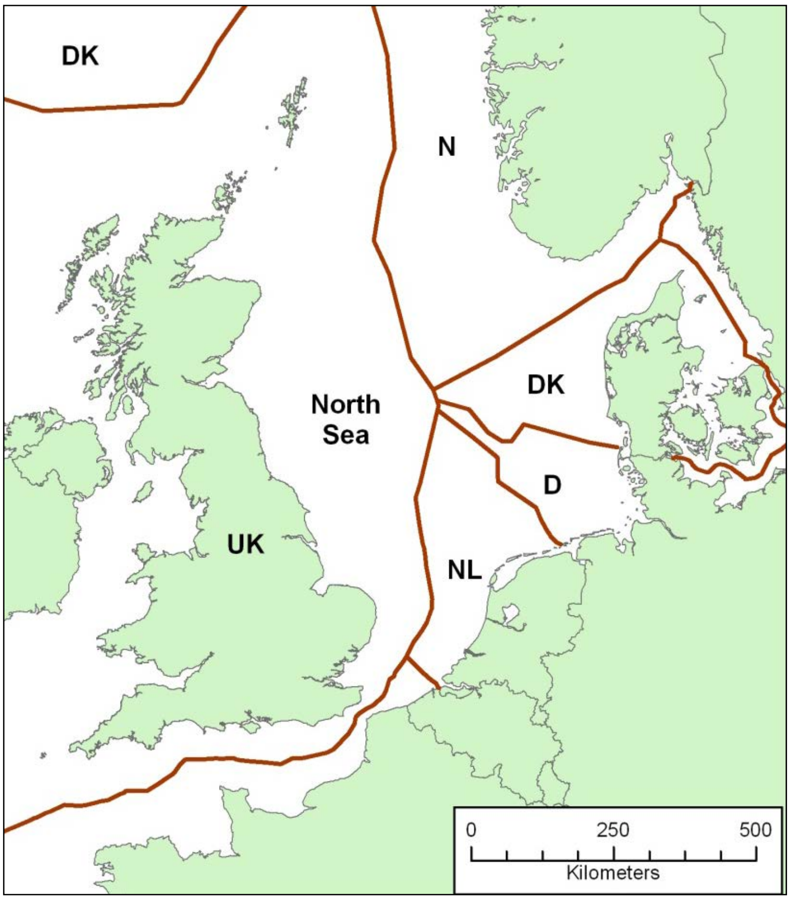

Figure 15: Location of the North Sea showing the United Kingdom (UK), Norway (N), Denmark (DK), Germany (D) and Netherlands (NL) sectors and respective onshore areas.

In Norway the main conflict of use for potential CO_2 storage reservoirs is with oil and gas exploration and production. Consequently, those deep saline formations and parts thereof that occur in the area in which significant hydrocarbon migration is interpreted to have taken place in the Norwegian North Sea have not been included in the Norwegian North Sea CO_2 Storage Atlas (NPD 2012) because they are considered to be unlikely to become available for CO_2 storage for many years to come. The approximate limits of this area are shown in Figure 16 (redrawn from NPD 2012). However, it should be borne in mind that potentially major saline formations occur *above* the hydrocarbon reservoirs that are in the petroleum systems in this area, namely the Utsira Formation (which reservoirs the Sleipner CO_2 storage project) and the Skade Formation. The parts of these formations considered suitable for CO_2 storage have been assigned a combined prospective storage capacity of approximately 16 Gt. An indication of the potential storage capacities of the hydrocarbon fields is also presented in the Atlas, because these may become available for storage sooner than the saline formations in which they occur, i.e., when they are depleted, which may be while exploration and further field developments are still continuing.

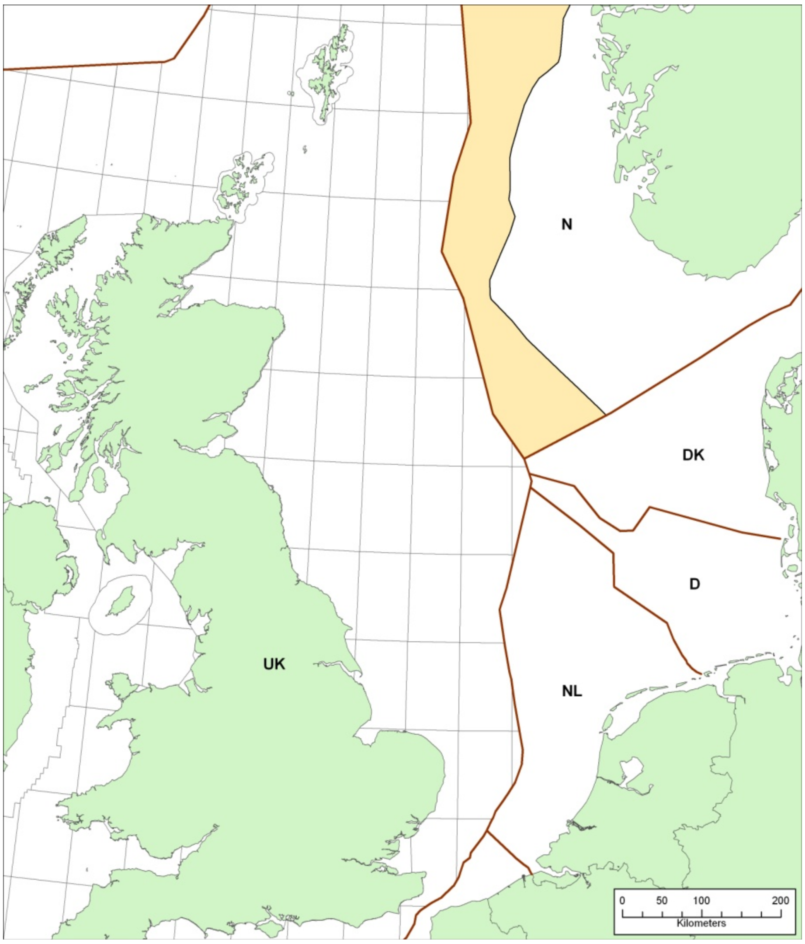

Figure 16: Approximate area of the Norwegian sector of the North Sea in which saline aquifers are excluded from the analysis of CO_2 storage capacity in the "CO_2 Storage Atlas of the Norwegian North Sea" because of potential conflicts of use with hydrocarbon exploration and production.

In the UK, in order to try and pre-empt any negative interactions with other uses of the marine area, seabed and subsurface, developers are advised to discuss their CO_2 storage proposals with both The Crown Estate (TCE)[2] and DECC Energy Development Unit to identify issues and ways forward before applying for a CO_2 Storage Licence and Lease. Initial approaches may be made to either, as may be convenient; TCE and DECC will jointly discuss cases and maintain a joined-up approach.

Section 1.10 of DECC's guidance for obtaining a CO_2 storage permit indicates that consideration needs to be given to any potential interaction of CO_2 storage activities with oil and gas operations, or other CO_2 storage sites in the same hydraulic unit. In the case of the latter, it must be demonstrated that the potential pressure interactions between the sites will not prevent either from meeting the requirements of the Storage Directive. This will inevitably require co-operation between the respective licensees of the sites. It is likely that the same consideration would need to be given to any potential interaction of CO_2 storage activities with natural gas storage facilities in the same hydraulic unit (e.g., the existing Rough gas storage facility, or the proposed Deborah natural gas storage facility, both in the Leman Sandstone reservoir in the UK Southern North Sea).

[2] The Crown Estate's role in CO_2 storage can be most simply understood as the landlord that can lease out the seabed and subsurface in the UK territorial sea and the GISZ. A lease (from TCE) and a licence (from DECC or Scottish Ministers) are required in order to store CO_2 in the UK offshore area.

If DECC considers the interaction of a CO_2 storage operation "poses a significant threat to the overall security and integrity of any other activity in the vicinity or neighbouring area" then the proposed plan will be rejected (see section 1.10 at http://og.decc.gov.uk/en/olgs/cms/licences/carbon_storage/carbon_storage.aspx).

Coal mining has occurred in the nearshore area of the North Sea adjacent to the UK coast (e.g. Younger *et al.,* 2010). However, this is unlikely to constrain CO_2 storage because the overlying aquifers such as the Rotliegend sandstones and Bunter Sandstone are too shallow for CO_2 storage above the mined area.

In Denmark there could potentially be a conflict of interest between use of the seabed for wind farms and some of the structures for possible near shore (offshore) storage. On the positive side for CCS, the Danish Parliament expects that Mærsk Oil will start enhanced hydrocarbon recovery (EHR) in some of the hydrocarbon fields in the Danish part of the North Sea around 2015. Research is being carried out on EHR for the Danish Chalk oilfields under the High Technology funding grants in Denmark (e.g. Olsen 2011).

The most prospective storage option in the offshore Netherlands is in depleted gas fields. Conflicts of interest with hydrocarbon production are to be found where producing reservoirs or reservoir blocks are juxtaposed against depleted reservoirs or reservoir blocks. Several offshore wind farms are present in the Netherlands offshore, which will potentially hamper the development of CO_2 storage activities in these areas. Dedicated shipping corridors to Rotterdam port are excluded from CO_2 storage exploitation. Particular consideration should also be given to protected marine reserves (Natura 2000 areas).

No specific information is available about possible conflicts of use of potential CO_2 storage reservoirs offshore in Germany. However, the main potential conflicts are likely to be between CO_2 storage and oil and gas exploration and production or natural gas storage.

Electricity generation from offshore wind energy is a fast-developing technology which is rapidly being deployed in the shallower parts of the North Sea, offshore from the UK, the Netherlands, Germany and Denmark. Wind farms could interfere with the installation of any part of the infrastructure necessary for CO_2 storage, which could potentially include pipelines, platforms and subsea developments. It is also conceivable that any uplift of the seabed as a result of CO_2 storage (see page 15) could adversely affect wind farms.

Energy technologies that could potentially become economically important in the North Sea in the more distant future could include low enthalpy geothermal energy production, underground coal gasification and radioactive waste disposal. Of these, only low enthalpy geothermal energy production would likely use the same reservoirs as CO_2 storage.

Geothermal heat: Paris Basin

The Paris basin is a large, nearly circular, intra-cratonic sedimentary basin some 110,000 km^2 in size located in northern France. At its deepest, the basin reaches 3000 m depth (Figure 17). Geothermal development in the Paris basin started in the early 1970s, the main target being the Dogger aquifer. The Dogger aquifer is recharged at outcrop along the eastern border of the basin and discharges on the seafloor in the English Channel. The salinity of formation water varies between 0.5 g/L in the outcrop area in the southeast, and 35 g/L in the deepest area of the Dogger Formation (Lopez *et al*., 2010). The potential interaction of CO_2 storage with groundwater use was discussed by IEA (2011).

We discuss, below, the deeper, geothermal resource of the basin and the potential for interaction with the storage of CO_2.

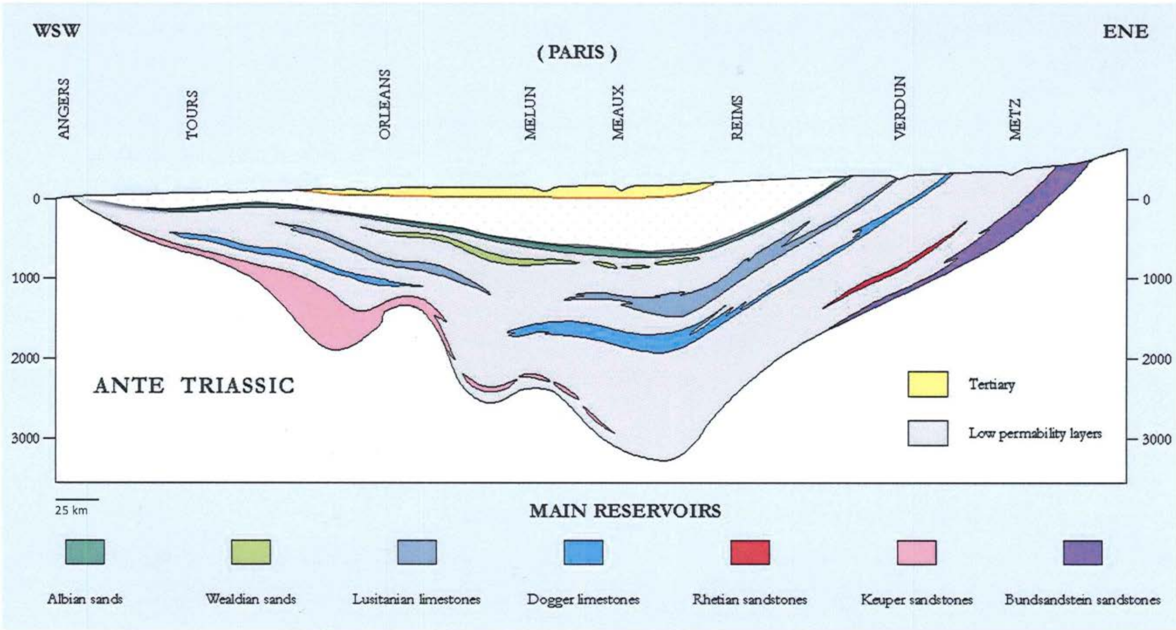

Figure 17: Schematic cross section of the Paris Basin (figure 2.11 of IEAGHG 2011, modified from Bonijoly *et al*., 2003). Fresh water occurs above the Albian sands; strata below contain saline water. Main potential CO_2 reservoir units are the Dogger, Keuper and Bundsandstein.

Nearly all geothermal operations use the doublet technology consisting of a closed loop with one production well and one injection well. Of 55 doublet systems that have been implemented over the years, 34 were still active in 2010 (Lopez *et al*., 2010). The geothermal reservoir in exploitation stretches over 15,000 km^2, underlying a large part of the Paris metropolitan area and its western suburbs, where it lies at depth of 1500 to 2000 m. The productive layers in the reservoir, which vary in number between 3 and 20, have an average cumulative thickness of 20 m, and represent only 10% of the total formation thickness. These productive layers are characterized by very high permeability of 2 to 20 Darcies (Lopez *et al*., 2010). Formation temperatures at the top of the productive layers vary generally between 55°C and 80°C (Lopez *et al*., 2010). The mean temperature gradient between the surface and the producing saline formation is 35°C/km, ranging between 27.5°C/km in the Saint Denis area northeast of Paris and 41 ºC/km in an area southeast of Paris.

The technical development of geothermal resources in the Paris basin was favored by three main technical and economic factors (Menjoz, 1990).

- Presence of a productive hot reservoir at a reasonable depth, whose characteristics (temperature and flow rate, i.e., permeability) were suitable for the supply of heating networks;
- Existence of an important potential heat market, with densely populated areas, suitable for low-temperature energy production; and
- Public policy incentives and insurance policies that favoured the development of new energy sources.

Nearly all operations were planned and completed in the aftermath of the 1973 and 1979 oil crises, with a boost in activity since the adoption of the Kyoto Protocol in 1998 (Lopez *et al*., 2010). The geothermal wells are completed with an open hole in the producing formation. There were two main reasons for choosing the doublet technology instead of just single production wells. First, processing of the geothermal brines for surface disposal involved prohibitive additional costs, negatively affecting project economics. Second, single-well exploitation would have progressively reduced the reservoir pressure, eventually affecting pumping conditions, limiting the number of wells able to tap the same reservoir and reducing the exploitable fraction of the resource. There are several advantages to full injection of the cooled brine (Lopez *et al*., 2010):

- There are no environmental impacts;
- Production rates in the range of 50 to 600 m^3/h are maintained;
- The exploitation pressures are stabilized (beneficial pressure interference)
- The area impacted by pressure variation is limited and the exploitation domain can be legally defined by regulating authorities, thus allowing for the optimal management of the geothermal resource.

The geothermal plants in the Ile-de-France (Paris) region contribute between 32% and 100% of the heat supply in the respective district where the plant operates, the balance being provided by fossil fuels (gas and heavy fuel oil) (Lopez *et al*., 2010). Most of the geothermal doublets have been exploited for more than 20 years and so far no thermal decline has been observed in any of the operations in the Paris basin, indicating that cold-water breakthrough has not occurred yet. The in-situ conditions of a few production and injection wells was examined after several years of continuous operation, revealing deposition of iron sulfides as a result of the presence of H_2S in formation water, which affected the operating conditions of the wells. The wells were first mechanically cleaned and then preventive measures were taken by injection of corrosion inhibitors. Disequilibrium pressures between the production and injection wells in doublets were observed at some operations, and detailed studies have shown that these were due either to small leaks due to casing corrosion (which were subsequently fixed) or to interference between a few clusters of doublets (Lopez *et al*., 2010).

Currently the steel company ArcelorMittal is developing plans for CO_2 capture from steel mills in the west-Lorraine region in the northeastern part of the Paris basin, and storage locally in the Triassic aquifer (project ULCOS, located at a significant distance from Ile-de-France where geothermal energy is produced). In 2011 this project received support from the French government and it was forwarded to the European Commission for funding under the NER300 program for demonstration projects (http://www.developpement-durable.gouv.fr/spip.php?page=article&id_article=22732), and an exploration permit for an area of 3516 km^2 was granted by the French government in November 2011 (Journal Officiel de la République Française, November 4, 2011).

Development of the Paris Basin geothermal resource could be adversely affected by CO_2 storage through:

- Direct competition for exclusive use of pore space;
- Remote pressure fronts affecting either usage.

However, dense-fluid CO_2 can be used as a thermal transfer medium to enhance geothermal resource use.

Direct competition for pore space might be resolved by the development of the geothermal resource in areas of higher heat flow, and CO_2 storage in areas of lower heat flow. CO_2 storage might increase fluid pressures in adjacent geothermal areas, and while this might enhance the extraction of hot brines, it might add to the cost of re-injecting cool brines in the doublet systems. The use of CO_2 as a thermal transfer medium looks promising but is a relatively new technique that needs further research and would probably require additional community consultation as part of any feasibility study.

North America

Currently there are no cases of interaction between CO_2 storage operations and other subsurface resources in North America. At Weyburn-Midale in Canada oil has been produced since 2000 using CO_2 transported by pipeline from a coal gasification plant in North Dakota, U.S. To avoid CO_2 migration out of the CO_2-EOR pattern into an adjacent oil field operated by another operator, Cenovus, the operator of the Weyburn oil field, is maintaining a hydraulic (or pressure) barrier at the boundary between the CO_2-EOR operation and the neighboring oil field by injecting water along the boundary between the two oil fields, thus avoiding loss of CO_2 from its operations and contamination of the oil produced by another operator (which otherwise would have to install CO_2 separation facilities). Thus, application of this "hydraulic or pressure barrier" technology avoids both CO_2 waste and migration out of the intended storage unit. There are no other operational CO_2 storage projects in Canada. In the United States, similarly there is a CO_2 storage operation associated with an oil reservoir at Cranfield in Mississippi, but there is no interaction with other resources.

Pressure transmission

Oil and gas are produced in western Canada from tens of thousands of oil and gas reservoirs found in the Alberta and Williston basins in Ordovician to Tertiary sedimentary strata. During the Devonian a long string of carbonate reefs (Leduc Formation) formed in the central part of the Alberta basin on the underlying carbonate platform of the Cooking Lake Formation. Oil generated in the Duvernay shales that overlie the Cooking Lake and Leduc formations has accumulated in the Leduc reefs. Significant oil production from these reefs started in 1947. By the mid-1960s it became apparent that oil production in some Leduc reefal reservoirs has affected the pressure in adjacent reservoirs, namely pressure depletion as a result of oil production in one reservoir has led to a decrease in pressure in neighboring oil reservoirs through the underlying Cooking Lake aquifer, thus affecting production from the latter (Hnatiuk and Martinelli, 1967). By analogy, hydrocarbon production from a reservoir in pressure communication with a CO_2 storage project could lead to a reduction in pressure in the CO_2 reservoir. This interaction might improve CO_2 injectivity and thus be beneficial but it might also lead to unexpected changes in migration direction and speed of the CO_2 plume.

A similar case of pressure transmission between two carbonate reefs through the underlying aquifer has been documented and demonstrated in the Zama oil field northwestern Alberta (Pooladi-Darvish *et al*., 2011). After cessation of production in 1970, during which reservoir pressure declined from 15 MPa to 10 MPa, pressure increased to 26 MPa by 1986, and then decreased slightly to 22 MPa by 1995, when the Zama X2X pool started to be used for acid gas disposal (a mixture of 80% CO_2 and 20% H_2S resulting from sweetening of sour natural gas). The provincial regulatory agency has imposed limits on acid gas injection rate and limited the reservoir pressure to the initial pressure of 15 MPa. After several years during which the operator has tried to bring down the reservoir pressure, the regulatory agency first suspended and then rescinded the acid gas disposal operation. Subsequent analysis (Pooladi-Darvish *et al*., 2011) has shown that the pressure build-up above the initial reservoir pressure was due to disposal of more than 1 million m^3 of water in the adjacent Zama YY pool between 1970 and 1988 and again in 1992-93. While no disposed water has actually reached the Zama X2X reservoir, the pressure build-up in the Zama YY reservoir was transmitted through the underlying Lower Keg River aquifer (Figure 18). Injection of any fluids (e.g., waste water or natural gas) can thus cause unanticipated pressure increases in nearby reservoirs to exceed their original levels and hence be at greater risk of seal rupture. The pressure effects of any injection projects near CO_2 storage reservoirs should therefore be assessed and monitored carefully and vice-versa.

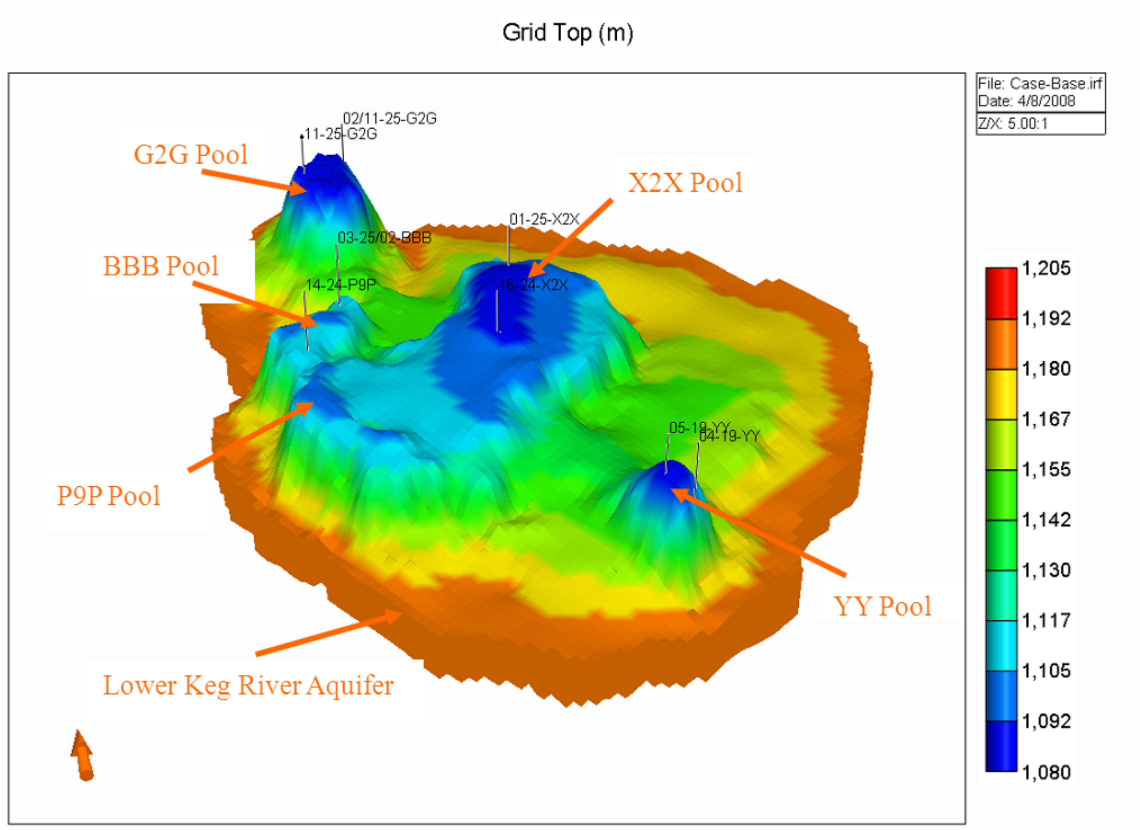

Figure 18: Relationship between various oil pools in the Zama field in northeastern Alberta and the underlying Lower Keg River aquifer. Water disposal in the Zama YY pool led to pressure build-up in all the other pools, ultimately leading to the shut-in and rescinding of the acid gas disposal operation in the X2X pool (from Pooladi-Darvish *et al*., 2011). The model is approximately 2.5 x 2.5 km and the vertical scale is in metres from a common datum close to the ground surface.

Gas over bitumen and gas over oil

An example of conflict between the production of two different resources is the “Gas over Bitumen” issue in northeastern Alberta, Canada. Very large bitumen deposits exist in Cretaceous-age unconsolidated sands in the Athabasca area in northeastern Alberta, with proven reserves of more than 176 Bbbl, which make this the third largest oil reserve in the world, after Saudi Arabia and Venezuela. Only a small portion of these reserves are exploited through open-pit mining in areas where the oil sands are at shallow depths that allow stripping of the overburden and then mining of the oil sands for separation of the bitumen from the host sands using surface steam-based processes.

In the majority of the Athabasca oil sands area, bitumen can be extracted in-situ through a process called Steam Assisted Gravity Drainage (SAGD). In this process, steam at high temperature and pressure is injected through a horizontal well, heating up the bitumen reservoir and creating a “steam chamber” (see Figure 19 - left). The high temperature within this steam chamber leads to a drop in bitumen viscosity by four to six orders of magnitude, such that the oil flows freely, under gravity forces, to a second producing horizontal well located under the steam injection well (Figure 19 - left). As the process continues, the steam chamber expands laterally and upwards until it reaches the top of the bitumen-saturated sands.

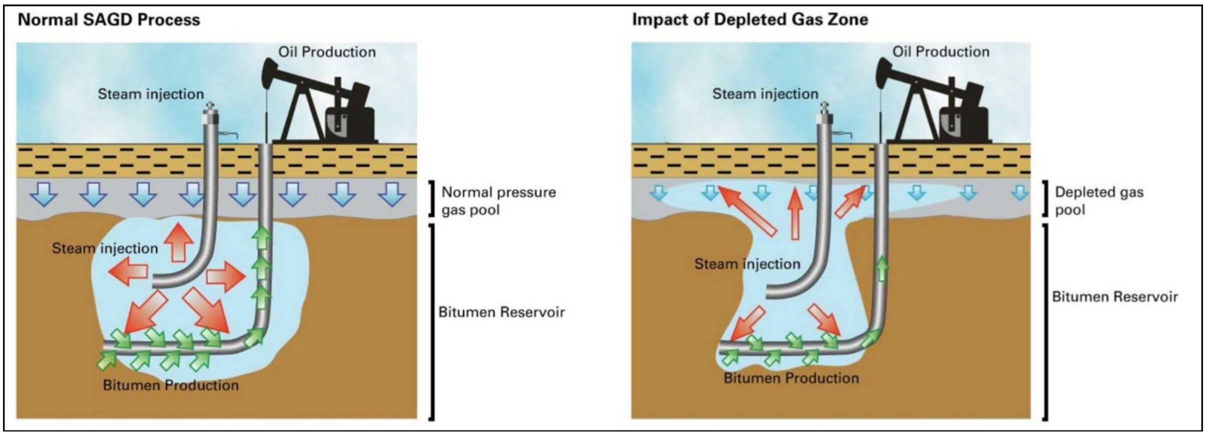

Figure 19: Diagrammatic representation of the steam assisted gravity drainage (SAGD) process used for oil sands production in the Athabasca area of northeastern Alberta, Canada: normal process (left), and process affected by a depleted overlying gas reservoir (right). Figure from Alberta Department of Energy web site.

The oil sands deposits are overlain in many places by gas reservoirs that were producing gas until 2000. As a result of gas production, the pressure in these gas reservoirs dropped significantly below the initial and hydrostatic pressures. When an expanding steam chamber reaches the top of the oil sands reservoir and breaches at the bottom of a depleted gas reservoir (illustrated in Figure 19 on the right), the pressure in the steam chamber drops significantly, leading to a corresponding drop in steam temperature, up to the point of condensation. The drop in temperature leads in turn to a significant reduction in the thermal effect of temperature on bitumen viscosity, to the point that the bitumen ceases to flow freely toward the bottom of the steam chamber where it can be produced. At this stage, the operation has to be abandoned. Even if the temperature drop is not so drastic, the efficiency of the oepration, and hence bitumen production, are negatively affected to the point of making uneconomic in-situ oil sands production using the SAGD process. Thus, clearly gas production from reservoirs overlying bitumen reservoirs has the negative effect of sterilizing the oilsands resource by making it non-producible.

During hearings in front of the Energy Resources Conservation Board (ERCB), which is the oil and gas regulatory agency in the Province of Alberta, great emphasis was given to pressure transmission between producing gas reservoirs through the aquifer overlying the bitumen deposits. The gas producers argued that each producing gas reservoir is isolated and that the pressure decrease as a result of production does not propagate beyond the boundaries of the respective gas reservoir, while the bitumen producers argued that the drop in pressure propagates beyond the boundaries of the various producing gas reservoirs such that bitumen production is or will be affected not only in areas directly underlying producing gas reservoirs, but also in areas farther afield, as proven by the hydrogeology and pressure regime of the respective aquifer (Barson *et al*., 2001).

After several years of hearings involving both gas and oil sands producers with an economic interest in the area, ERCB rendered several successive decisions to shut in production from natural gas wells perforated in gas reservoirs overlying bitumen deposits to protect oil sands production from the negative effects of gas production. In reaching its decision, ERCB applied the precautionary principle according to which continued gas production will affect future bitumen production, while shutting in the natural gas and producing the bitumen first will not jeopardize gas production at some time in the future.

The other principle used by ERCB in reaching its decision regarding gas over bitumen is the principle of judicious and optimal production (conservation) of province's oil and gas resources, according to which production of one resource should not sterilize another resource. This principle is actually the basis of setting up in 1938 of ERCB with the mandate of regulating oil and gas production in the province. This was the result of producing in the 1930's of gas from oil reservoirs with a gas cap before producing the oil, with the result that, due to the corresponding drop in reservoir pressure, the oil couldn't be produced anymore. Since then, producers have to produce first the oil in an oil reservoir with a gas cap, of which there are several thousands in the province, before they can produce the gas.

The significance of this example of resource interaction is that the injection of CO_2 into reservoirs overlying a subsurface resource has the potential to increase the pressure in the underlying reservoir and hence improve production of the resource.

Shale gas and shale oil

By combining two technologies, horizontal well drilling and multistage hydraulic fracturing, it became possible to drill horizontal wells several km long into gas-rich or oil-rich shale formations and produce natural gas (e.g., Barnett shale in Texas and Marcellus shale in the Appalachian basin in New York, Pennsylvania, West Virginia and eastern Ohio, and the Bakken shale in the Williston basin in North Dakota, all in the United States, and the Horn River and Montney shales in western Canada). Fracturing these shales for gas or oil production may jeopardize potential for the CO_2 storage in the immediately underlying aquifer, but will not jeopardize the storage potential in other deep saline aquifers in the sedimentary succession that meet the conditions for storage capacity, injectivity and containment. Figure 20 shows the position of the Marcellus shale in the Apalachian basin in relation to other formations in the sedimentary succession. While CO_2 storage in the Onandaga Limestone may be jeopardized by hydraulic fracturing of the Marcellus shale (Figure 20), CO_2 storage would still be possible in the Oriskany sandstone beneath the Needmore shale, or in the Tully limestone if the latter meets the conditions necessary for CO_2 storage. Similarly, production of oil from the Mississippian Bakken shale in the Williston basin does not jeopardize CO_2 storage in deeper Cambrian to Devonian formation, or in shallower Mississippian to Cretaceous formations, but only in the saline aquifer immediately underlying it. The same holds true for any other shale formation in North America that is hydraulically fractured for shale gas or oil production.

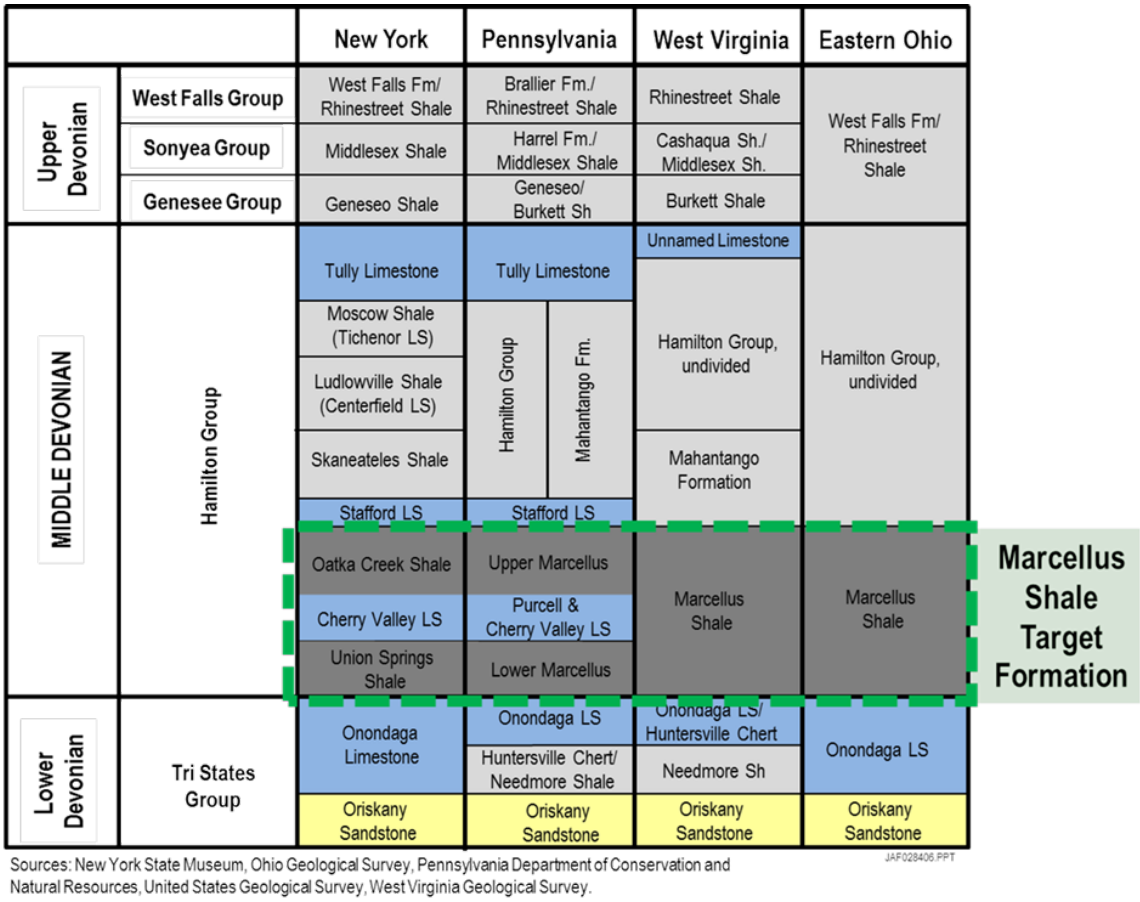

Figure 20: Startigraphic table showing the position of the Marcellus shale in the Appalachian basin, which is used for shale gas production.

Australia

Produced water: Gorgon

Description

Chevron's discovery of 40 trillion cubic feet of natural gas off the northwest coast of Australia has led to the largest project worldwide to store CO_2 underground (Figure 21, Figure 22). The project is large and innovative, and has taken 29 years from concept to operation. Plume migration and containment (and pressure effects) have been assessed and no adverse resource interactions are anticipated. It is included in this report as an example of a large-scale storage project with a significant plume size, involving pressure relief wells, assessments of containment of CO_2, external expert reviews (e.g., Gunter et al., 2009), public comment, and positive interaction and planning between regulatory bodies and operators.

The natural gas in the Gorgon Field contains on average about 14% CO_2 and ~95% of the CO_2, totaling some 120 Mt, will be stripped and pumped into Dupuy Formation sandstones 2.5 km beneath Barrow Island over the life of the field, starting in 2015. The project includes a 145 km sub-sea tie-back pipe in water depths over 1 km (Flett et al. 2009). Injection of CO_2 will cause an increase in pressure in the Dupuy Formation, and this could cause the displacement of natural formation water into any adjacent formations that are in fluid-contact with the Dupuy Formation. A marine mudstone at the base of the overlying Barrow Group is anticipated to act as a seal that will stop vertical migration of displaced formation waters and the CO_2 plume (Figure 23). It is anticipated that 10-20% of the injected CO_2 will be trapped by solution during the injection period, and 35% of the injected CO_2 will dissolve in the formation waters over the first 1000 years; eventually the remaining 65% of it will also be dissolved (Chevron's draft Environmental Impact report of 2005). There will be nine CO_2 injection wells from three drill centres, with pressure management from two drill centres comprising four water production wells (for pressure relief) and two water injection wells (to dispose of the produced water into a saline aquifer in the overlying Barrow Group).

Assessment of environmental and resource interaction issues

The West Australian government funded expert review panels to assess the project, four times, timed to coincide with significant approval steps. The partners spent more than $150M prior to final commitment, with the assessment work including a test well and 4D seismic acquisition (on top of the existing 30 wells and seismic data) as well as extensive modeling (Figure 24, Figure 25). They required certainty regarding licence conditions from regulators before final commitment. Barrow Island is a Class A nature reserve.

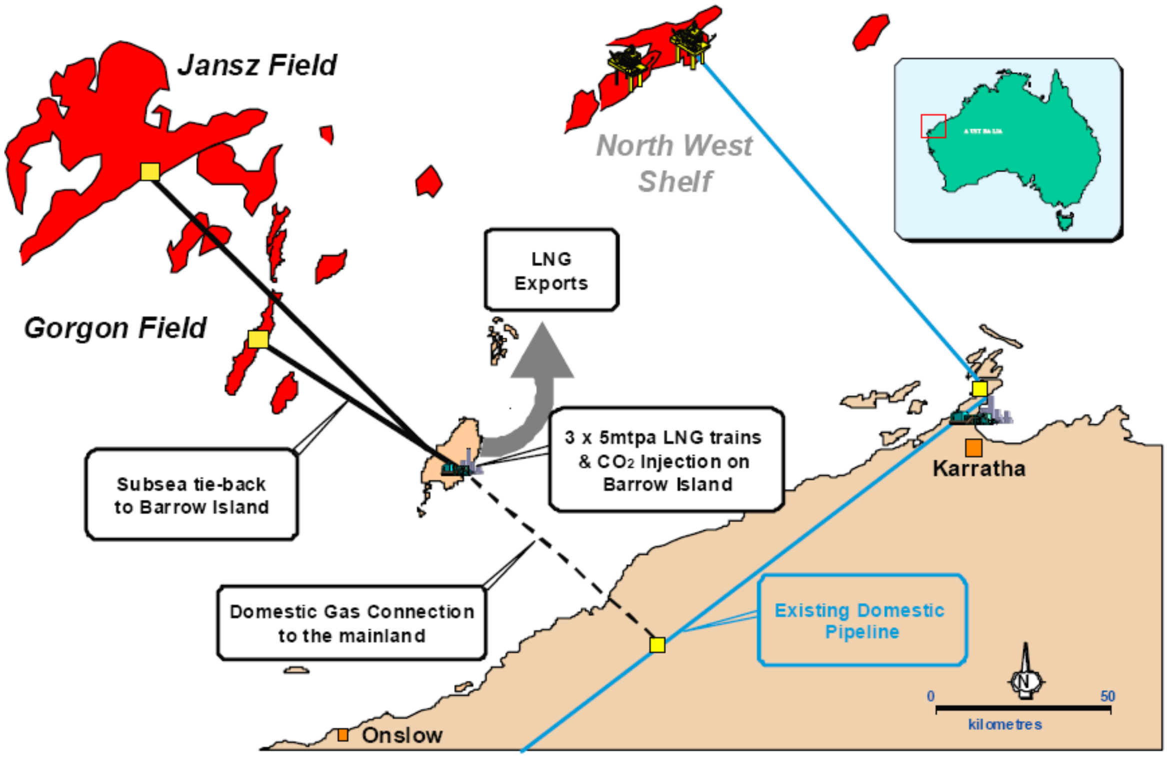

Figure 21: Map of the Gorgon Project area, showing the Gorgon Field and Barrow Island where the injection wells will be drilled. From Flett *et al*., 2008.

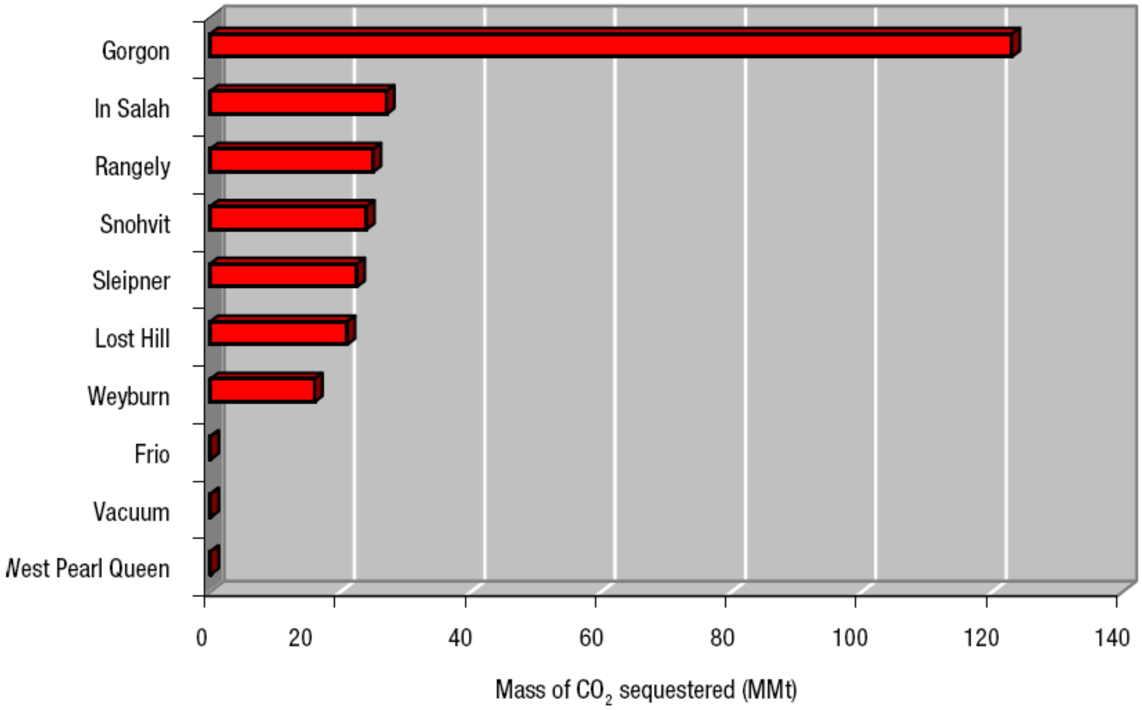

Figure 22: Comparison of the scale of the Gorgon project with other CO_2 storage projects. www.dmp.wa.gov.au/documents/Petroleum_WA_Sep_2009b.pdf

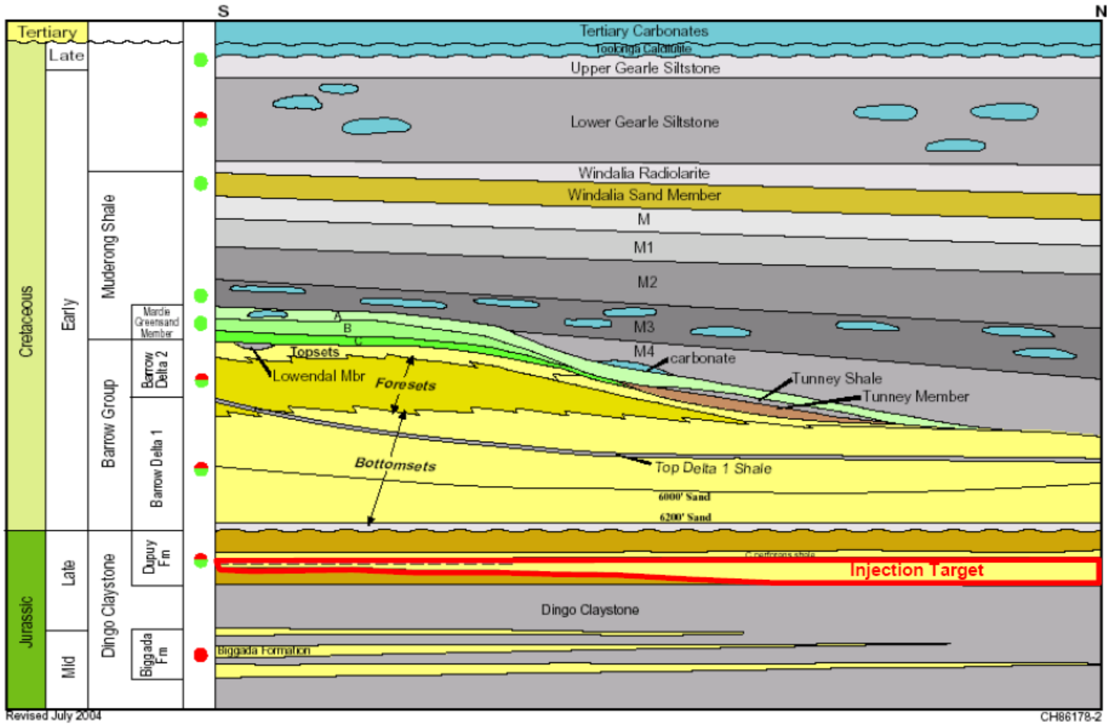

Figure 23: Stratigraphy of the Barrow Island area, showing the injection target in the Dupuy Formation and the seal rocks in the overlying Barrow Group and Muderong Shale. From Flett *et al*., 2008.

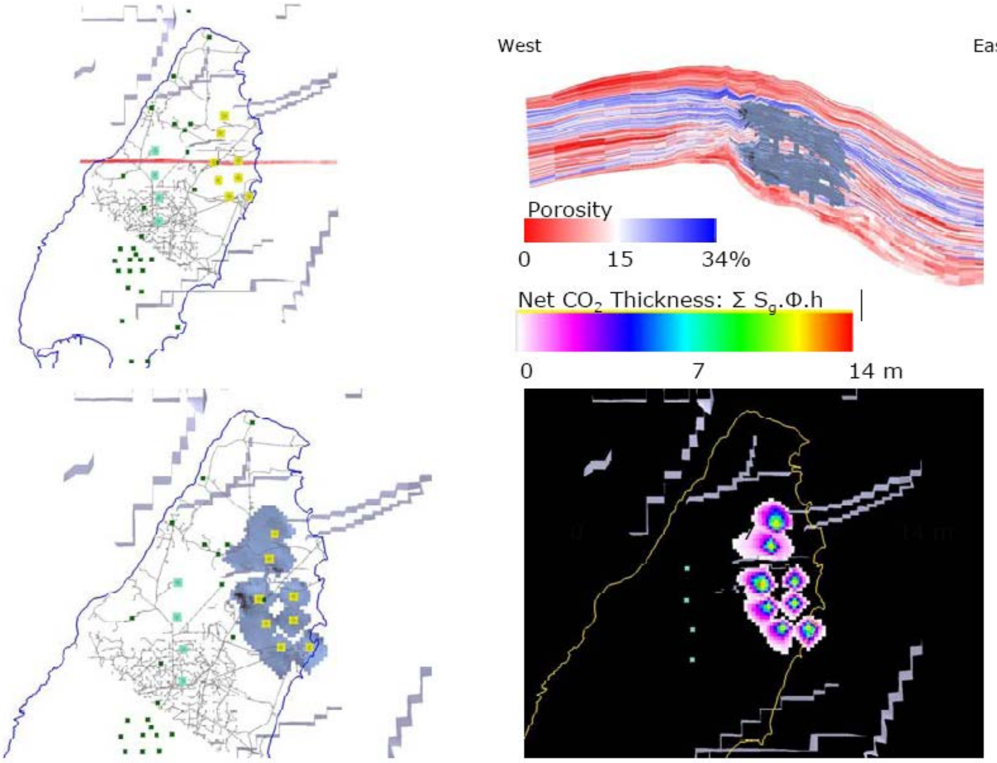

Figure 24: The red line (top left) shows the position of a cross section across Barrow Island, including two injector wells. The cross section (of the model simulation, cropped to the level of CO_2 storage) is shown top right, with the predicted plume shown in grey. Plan views of the expected/modeled plume extent after 10 years of injection are shown bottom left and right. The grey, pixelated lines bottom right show major faults as incorporated in the reservoir simulation model. From Flett *et al*., 2008.

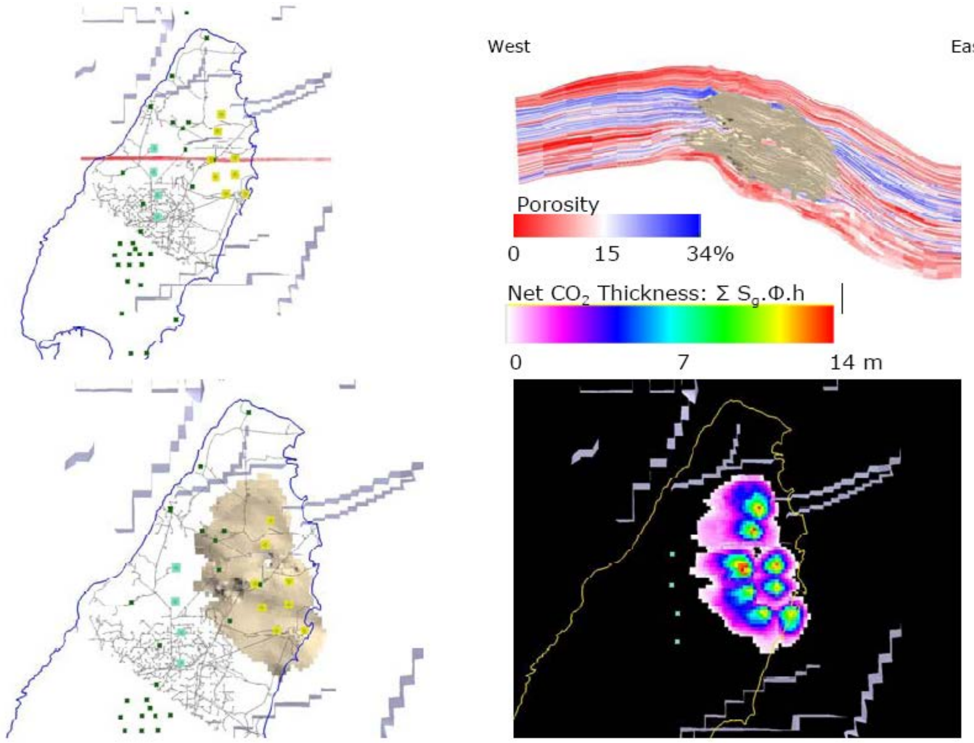

Figure 25: As for Figure 24, but showing the modeled plume extent after 1000 years. From Flett et al., 2008 (see this reference for additional plume maps at intervals of 40 and 100 years).

The Barrow Island Oil Field Joint Venture operates an oil field to the southwest of the CO_2 injection site. Existing wellbores pose the greatest risk for upward migration of the CO_2 plume into this field, and some 27 wells intersect the Dupuy Formation. Chevron have remediation plans in place for the seven wells modeled as being in the path of the plume over the first 1000 years, with further measures in place if unexpected plume migration were to occur (Chevron Australia, 2005).

The Barrow Island oil field has been extracting hydrocarbons for 40 years, mainly from the Windalia Formation, and these reservoir units are likely to have reduced pressures. Any unexpected pressure communication or upward migration of formation fluids or CO_2 would need to pass through the basal seal of the Barrow Group and the Muderong Shale before it could affect the overlying oil resource. Having two seal rock units between the Dupuy and Windalia formations provides additional assurance that direct resource interaction is unlikely.

Increasing pressure due to CO_2 injection within the Dupuy Formation will be managed through four water production wells located to the southwest of the planned injection wells. Pressure management is necessary firstly to avoid propagation of pressure increases too far away from the injection wells, and potentially interacting with other resources, and secondly to ensure the pressure near the injection sites does not exceed allowable pressure limits and potentially affect seal integrity. In the case of Barrow Island, water extraction from the reservoir is expected to make available 46 to 63% of the pore space utilised for CO_2 storage (Gunter *et al*., 2009).

The operators plan to inject the produced water (~10,000 to 12,700 m^3 per day) from the Dupuy Formation into reservoir intervals within the overlying Barrow Group. Little information is available on the probable impact of the injected water, although it is likely that in this case any increase in pressure within the Windalia Formation should have a positive impact on production from oil wells several kilometres to the south.

As part of the Gorgon Project, a comprehensive geomechanics model based on data collected from wells has been used to determine allowable pressure limits to ensure containment of injected CO_2 (Flett et al., 2008). Observation wells will measure pressures in the overlying rock formations and there will be substantial surface monitoring to allow early detection and mitigation (e.g., by pressure management) if any leakage were to occur. After injection ceases it is anticipated that the percentage of mobile CO_2 will decline rapidly, as increasing amounts are dissolved or trapped (Figure 26). This lessens any long term risk.

The Gorgon CCS project is regulated under the Barrow Island Act 2003 (http://www.austlii.edu.au/au/legis/wa/consol_act/bia2003145/notes.html). The assessment and approvals required for this project far exceed those for simple hydrocarbon extraction and are probably more intensive and costly than will be required for other future storage projects, as this is the first large-scale project. The Gorgon Project is exceptional for its scale, because it is the first in Western Australia and because it is in an environmentally sensitive area. The Federal and Western Australian governments have agreed to take on long-term liability for the storage of CO_2 under the Gorgon project, though the project partners are liable for CO_2 during operation and for 15 years after closure. The governments are taking on 80% and 20% of any liability respectively (http://www.bloomberg.com/apps/news?pid=newsarchive&sid=aSZEVpdXI110).

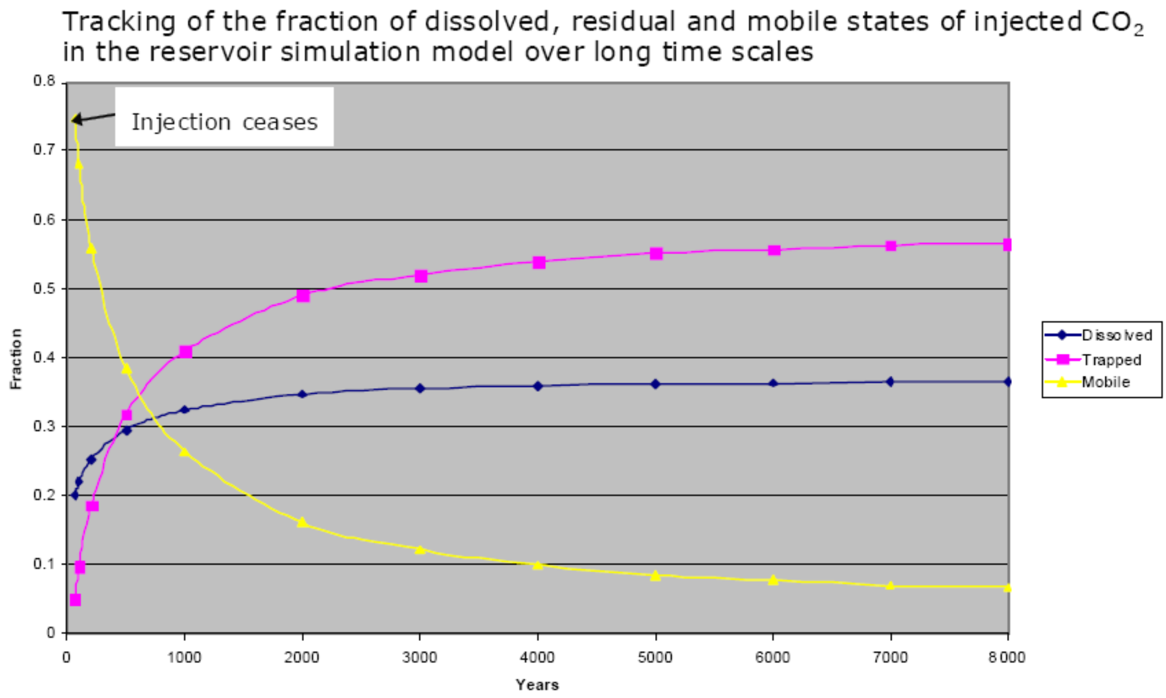

Figure 26: After injection ceases at Gorgon, increasing proportions of the injected CO_2 will dissolve into formation waters, become trapped as isolated globules in pore spaces ("residual gas trapping"); some may also be trapped as newly-formed minerals. From Flett et al., 2008.

In addition to direct interaction of CO_2 with use of other resources, it is possible that water produced from storage projects may also introduce a potential conflict. Past storage capacity estimates have been questioned, especially for closed and semi-closed saline aquifers where pressures are likely to buildup in response to injected fluids (Van der Meer and Egberts 2008; Zhou *et al*., 2008). Bergmo *et al*., (2011) state water production will be necessary to constrain pressure buildup in storage projects to within safe limits, especially in confined systems where more than 1-2% of the available pore-space is to be utilized for CO_2 storage. In more open systems, significant pressure increases may be less of an issue, although it is likely that water production plays a key role in actively controlling pressure in storage projects. Bergmo *et al*. (2011) suggest that for large projects, produced volumes may be of the order of 1 km^3 water for every Gt CO_2 injected.

Water production associated with storage projects may represent an environmental challenge since water is likely to be too saline to be released at the surface, although (as mentioned above: Groundwater) desalination of low saline waters may offer advantages for industrial, or agricultural purposes. In offshore locations, it may be possible to 'release' suitable formation fluids into the sea, but other situations may require disposal into overlying reservoirs, such as is planned for the Gorgon Project in Australia. Injection of produced waters into nearby reservoirs should be subject to the same monitoring and assessment requirements as injected CO_2, since the same issues apply in terms of potential conflict with uses of other resources.

Multiple uses: Gippsland Basin

In Australia, onshore resource exploration approval and licensing to operate fall under state government jurisdiction. The onshore pilot project to store CO_2 within the Naylor gas field in the Otway Basin (the CO2CRC Otway Project; Undershultz *et al*., 2011; Jenkins *et al*., 2012) provides the only analogue for CO_2 geological storage licensing within Victoria. This was achieved through use of existing petroleum production licensing legislation. Since then, the Victoria State Government has drafted CO_2 storage exploration and operations tendering guidelines together with the release of onshore storage assessment permit areas for Geological Carbon Sequestration (VicDPI, 2009).

Two of these assessment permit areas were allotted within the onshore Gippsland Basin (Figure 27, after Bunch *et al*., 2009). Prospective CO_2 storage reservoir systems that fall within these areas also occur within adjacent or coincident onshore petroleum retention leases or petroleum exploration licence areas, and geothermal exploration license areas (Figure 27,). Through these recent CO_2 storage and geothermal exploration licencing rounds the Victorian state government committed to managing the onshore Gippsland Basin as a subsurface resource for operators across multiple energy sectors for decades to come (Varma and Michael, 2012). However, neither of the onshore CO_2 storage assessment permits was taken up when the licensing round closed in 2011. Geothermal exploration activity in the region is to date limited to a desktop study (Greenearth Energy, 2012) though all leases continue to be held by active geothermal energy companies (VicDPI, 2012).

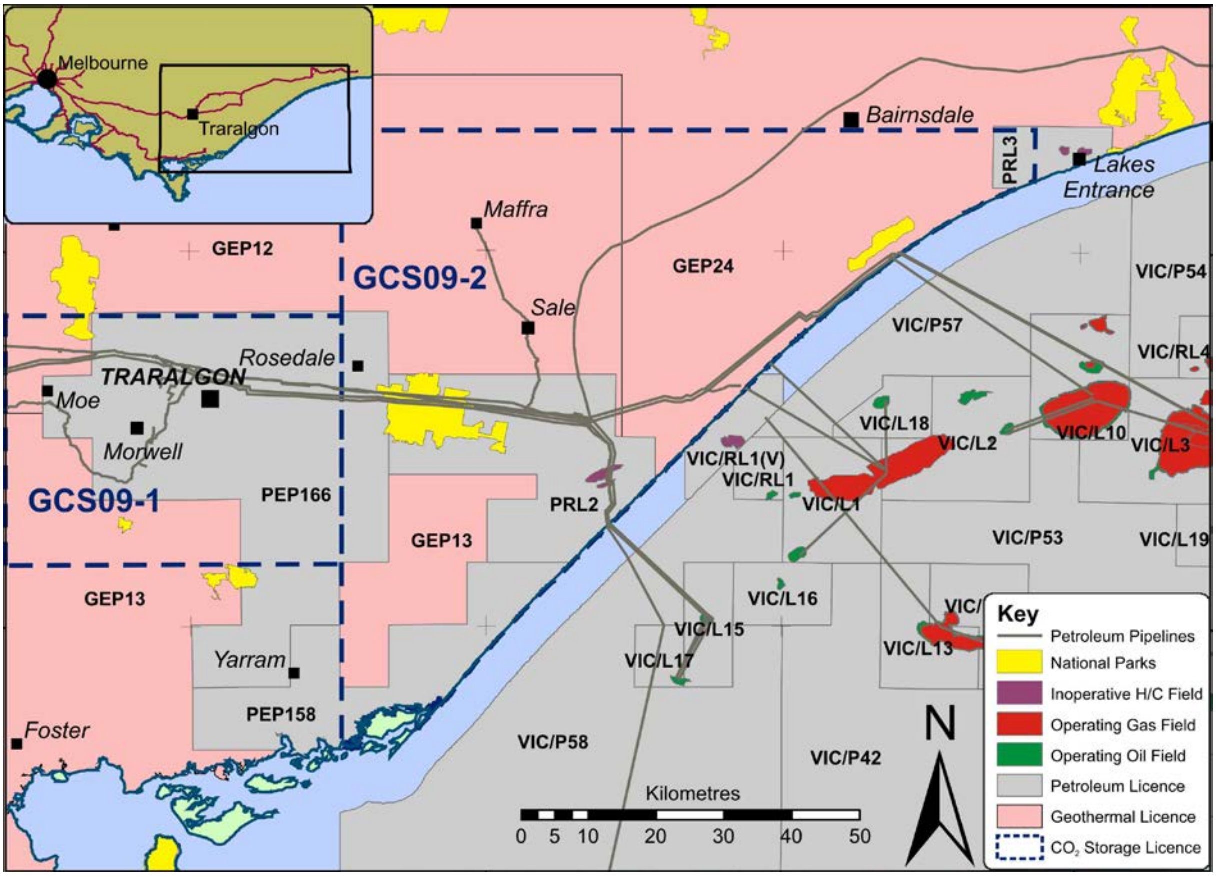

Figure 27: Map showing permit boundaries offered in 2009 for CO_2 storage (blue polygons), and the coverage of state petroleum and geothermal licence areas across the onshore Gippsland Basin.

In March 2009 the Australian Federal Government gazetted three large offshore Green House Gas Assessment blocks, inviting applications by 30th September 2011 (Figure 28; DRET, 2009). GIPP-02 and GIPP-03 leases have since expired without take-up and will not be released again until precompetitive assessments are made of their likely storage potential (GA, 2012). However, GIPP-01 was acquired by the Victoria Department of Primary Industries as VIC-GIP-001 for fast-track assessment and potential development by the CarbonNet federal flagships project.

The CO_2 storage industry and perhaps also the geothermal power industry will therefore join established subsurface oil and gas operations offshore, and subsurface coal extraction and groundwater abstraction operations onshore within the Gippsland Basin. The broad geographic demarcation between exploration licence blocks allocated for these *de facto* new industries - geothermal power and CO_2 storage – and existing oil and gas operations, only partially respects the distribution of potential for resources as currently understood. Non-optimal correlation between resource concentration and licensing reflects wariness to impinge on those commercially profitable operations already exploiting the subsurface. Licence release documents similarly summarize the perceived resource in lesser detail than expressed by petroleum exploration license release documents, which is due in part to the larger repository of relevant, pre-existing exploration and production data available for oil and gas prospect appraisal. However, it is also the case that vague licensing summaries for the new industries can express only a high-level understanding of industry-scale requirements in the absence of proven industry-scale operations.

Given the large geographic scale of the GHG assessment blocks made available (4,000-5,500 km^2) for the new industries and required properties of the subsurface being shared between them, these areas inevitably overlap geographically and in terms of depth. Understanding the likely 3D footprint of future operations will be critical to maximizing the socio-economic benefit of the exploration mix while continuing to protect environmentally sensitive areas at or near land, seabed or water surfaces. Such features along the coastal strip of the Gippsland Basin include (from northeast to southwest) the Lakes Entrance coastal park, Gippsland Lakes, Sale wetlands, Ninety Mile Beach, and Wilson's Promontory.

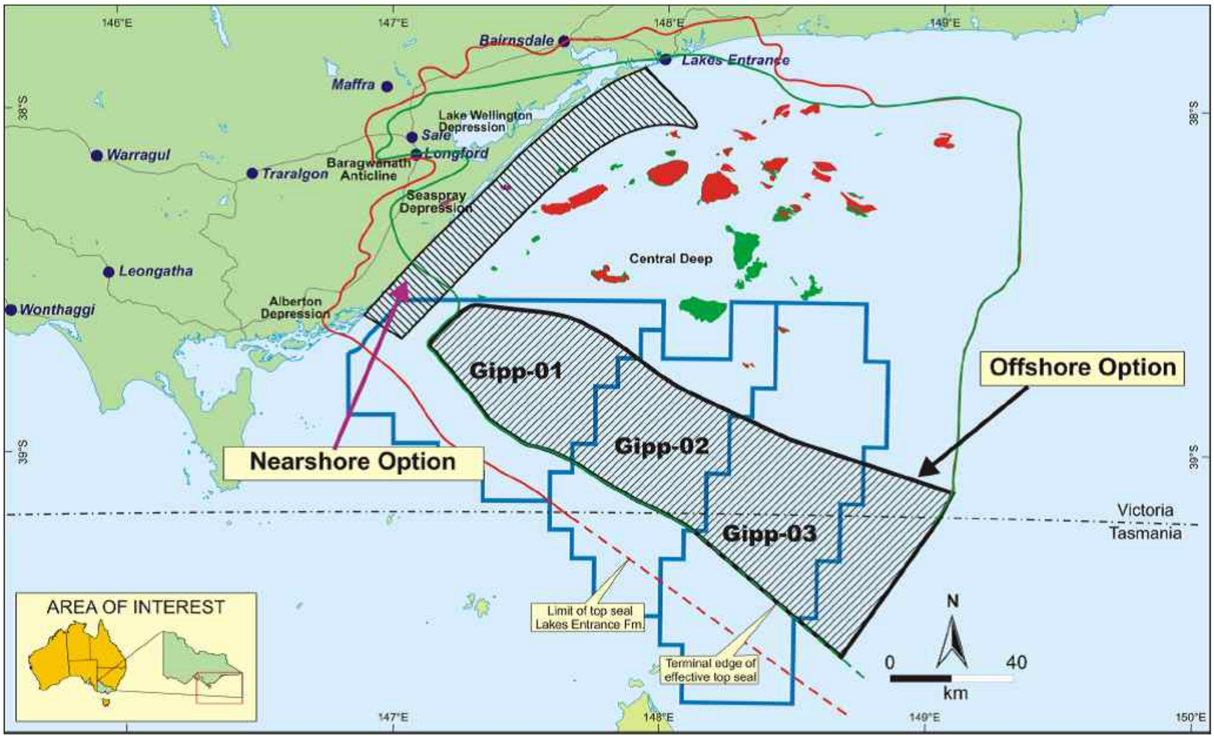

Figure 28: The basin-scale model developed by the Victorian DPI allowed the delineation (in blue) of areas offered for CO_2 storage in 2009 (O'Brien, 2011). GIPP-01 was acquired by the Victoria Department of Primary Industries as VIC-GIP-001 for fast-track assessment and potential development by the CarbonNet federal flagships CCS project.

In general, operational sweet spots can be defined for each explorative or industrial use that are segregated to some extent in depth. Most groundwater abstracted onshore for direct industrial, agricultural or municipal purposes is taken from semi-confined aquifers (e.g., Balook Formation) lying stratigraphically adjacent to the regional sealing horizon (Lakes Entrance Formation) to the main oil and gas play reservoir (Late Cretaceous sandstones of the upper Latrobe Group; SRW, 2010). The top surface of the aquifer interval occurs at an average onshore elevation of 177 m below sea level. Conventional geothermal power operations use in situ formation fluid at 150°C or greater (Driscoll, 2006). Within the Gippsland Basin this temperature occurs within the approximate range 2900-7000 m below land surface or seabed (Driscoll, 2006; Greenearth Energy, 2012). Oil and gas is produced from a similarly large range of depth within the Gippsland Basin (~350-3200 m below sea level). The majority is produced from within two depth windows, – 1050-1600 m and 2000-2500 m below sea level. The deeper of these has been or is produced offshore. Thus, even though optimal ranges of depth for these resources can overlap within the Gippsland Basin, their distributions in three dimensions are exclusive.

Hydrocarbon accumulations are most easily producible when occurring at shallow depths as the costs of drilling and secondary recovery are reduced. The same principle applies for other subsurface operations that involve subsurface engineering to control the dynamics of interstitial pore fluids. This is particularly true for supercritical CO_2 storage given the current absence of an independent market mechanism to fund infrastructure or operations. A critical limit applies to the range of depths viable for CO_2 storage. CO_2 must be injected in a dense fluid/supercritical state in order to maximize the mass per unit volume stored. To sustain CO_2 within the developing plume in this state, the subsurface environment must exceed 31.1°C in temperature and 7.38 MPa of pressure (Bachu, 2003). Under hydrostatic conditions this environment is reached at a minimum depth of 752 metres. Hydrostatic conditions exist above economic basement across the Gippsland Basin (SRW, 2010). This depth criterion is satisfied across the majority of the basin bar for a location near the coast onshore within the Seaspray Depression – the Holey Plains Low Heat Flow Region (Greenearth Energy, 2012) – where vigorous on-to-offshore hydrodynamic flow within the principle reservoir of the upper Latrobe Group (Underschultz and Johnson, 2005) is thought responsible for significant cooling that depresses the critical surface to a depth >1 km (Figure 29; Bunch *et al.*, 2009). This occurs within the (now

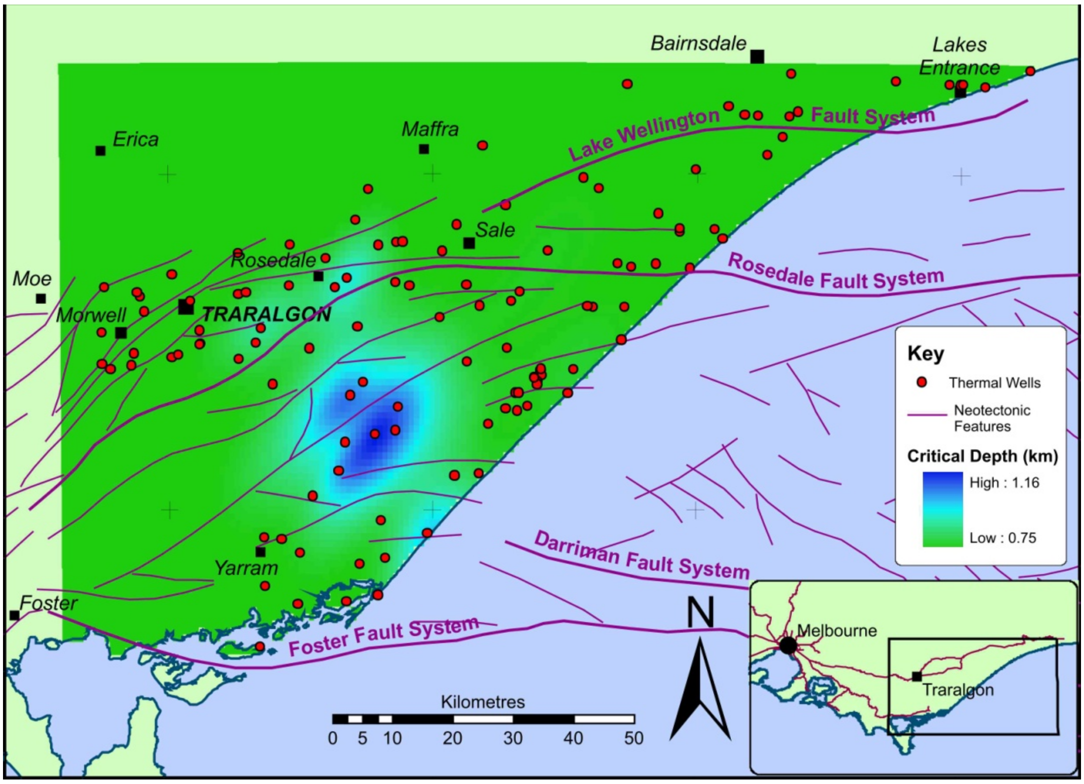

Figure 29: Variation of critical depth (the minimum depth for storage of high density CO_2) in onshore Gippsland Basin.

lapsed) larger CO_2 storage assessment lease GCS09-2 and the geothermal exploration lease area GEP13. The hypothesis to explain low surface heat flow in this location implies that shallowest possible CO_2 storage operations would descend closer to shallowest possible geothermal energy production operations. The reality however remains that at least ~2 km in depth would separate these zones even if this was proven to be the case.

Another more general consideration in the onshore basin is disappearance of the regional seal provided by the Lakes Entrance Formation (O'Brien *et al*., 2011; Hoffman, 2012). CO_2 storage operations onshore would be likely to rely on baffle systems of the floodplain-upper coastal plain facies present within the Latrobe Valley Group (Holdgate *et al*., 2000). Associated intraformational floodplain mudstone units would form a vital part of a CO_2 storage system but their occurrence is associated with extensive brown coals that are responsible for a long-established geothermal blanketing effect that enhances the geothermal prospectivity of underlying strata (Driscoll, 2006). Seal rock strengths were assessed by van Ruth and Nelson (2005).

Recent work by the Victorian DPI CarbonNet team has built on earlier data to show that facies and mineralogy of the topseal is the dominant factor in seal effectiveness and that present-day depth of burial is rather less important. Mineralogy cannot be directly inferred from seismic data but facies can be at least partially mapped, and seal thickness is a directly-mappable and key co-varying parameter in determining seal effectiveness. Hoffman *et al*., (2012; Figure 30) used mercury injection capillary pressure (MICP) and Leak Off Test data acquired in nearshore to basin margin settings, to identify the Lakes Entrance Formation (and underlying seal units interbedded with greensands) as the best sealing lithologies, with a median threshold pressure of 1942 psi (183.3 m CO_2 column). However, intraformational shales within the Latrobe Group have median values of 1466 psi (151.1 m column), as might be expected from the numerous occurrences of hydrocarbons trapped at intra-Latrobe level. This encourages the concept of multi-storey CO_2 storage at several different intra-Latrobe structural levels where circumstances are favourable.

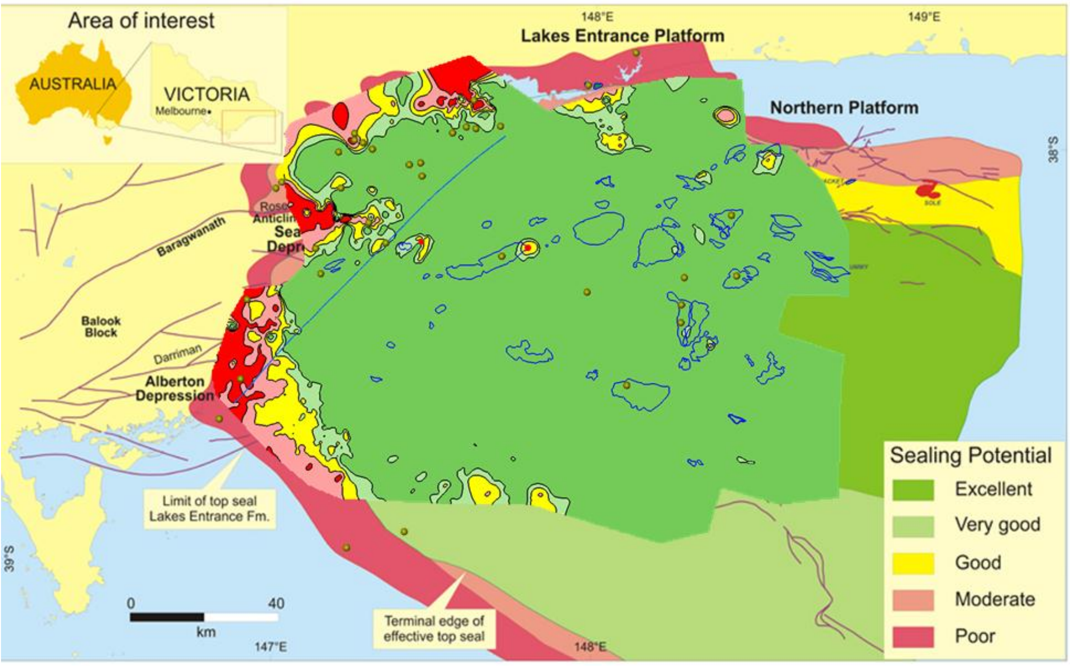

Figure 30: The basin-scale model created by the Victorian DPI assists the assessment of potential interaction of deep groundwater systems with potential CO_2 storage sites associated with oil and gas fields using a regional assessment of seal potential. This can be useful for determining storage licence boundaries. From Hoffman *et al*., (2012).

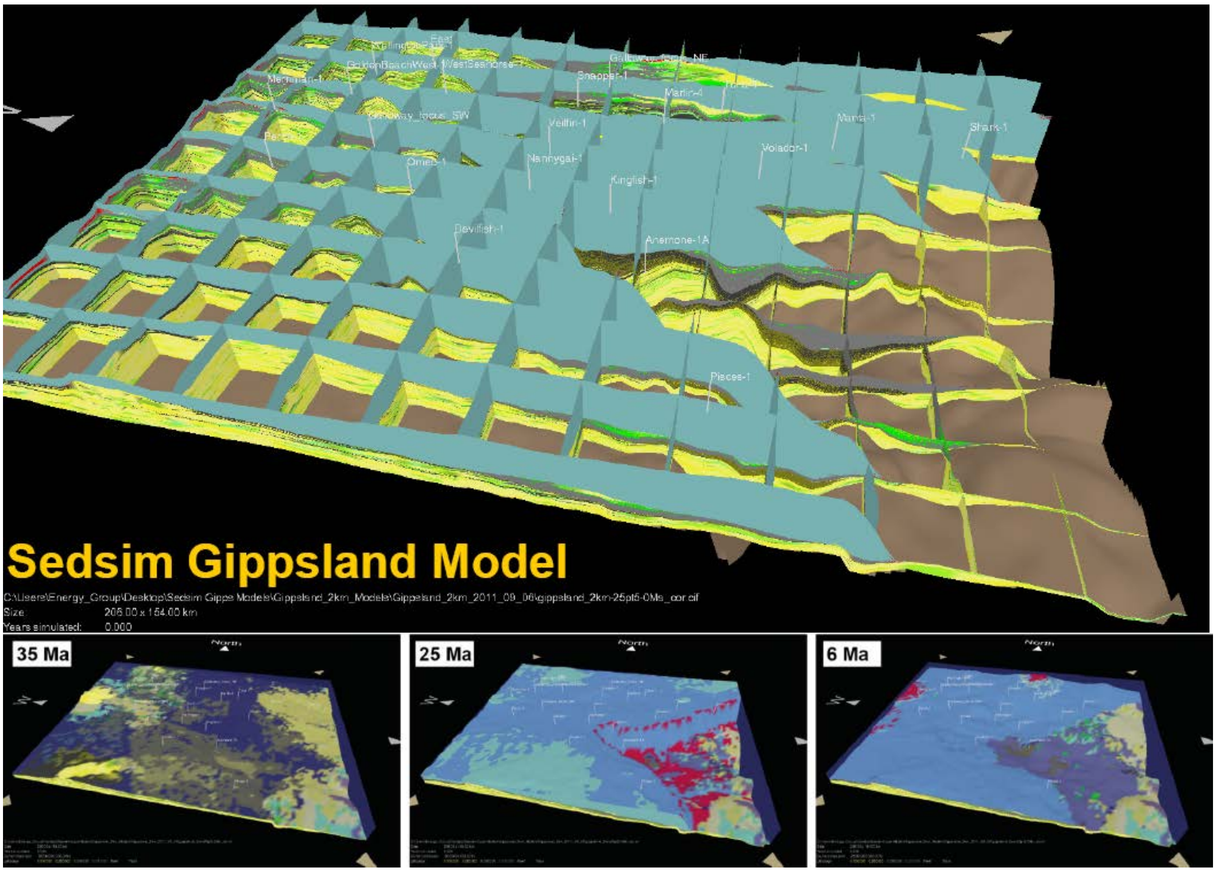

Figure 31: The Victorian State Government's DPI has developed a geological model for the Gippsland Basin that enables it to make informed decisions on potential resource interactions (O'Brien, 2011). This diagram shows a grid of cross sections depicting the layers in the model (top), and maps of the various types of sediments in map view for three times (or layers) in the development of the basin (bottom three panels).

Exploration licensing within the Gippsland Basin reflects the shared attractiveness of subsurface resources to a number of sectors. The state government of Victoria recognized that they could not easily balance exploration priorities or assess the effects of large scale injection of CO_2 in the Gippsland Basin without a basic model of reservoir and seal extents and what the regional pressure connectivities were likely to be. They commissioned a completely revised 3D geological model to be constructed by 3DGeoEO Pty Ltd using all available exploration survey datasets and a variety of modeling workflows. Of these, CSIRO's SedSim software was adopted to provide a forward modeling component that produced a geocellular representation of the Latrobe Group calibrated by existing well data and additional regional seismic surveys covering known hydrocarbon fields, leads, and groundwater zones. This model (Figure 31) corresponds with seismic survey data on a basin scale and, though perhaps not accurate in detail, has allowed a regional assessment of which parts of the basin are prospective for CO_2 storage by identifying areas with likely reservoir rocks where there is minimal risk of resource interaction if exploited (O'Brien, 2011). The potential multiple resource uses of the Gippsland Basin are shown schematically in Figure 32.

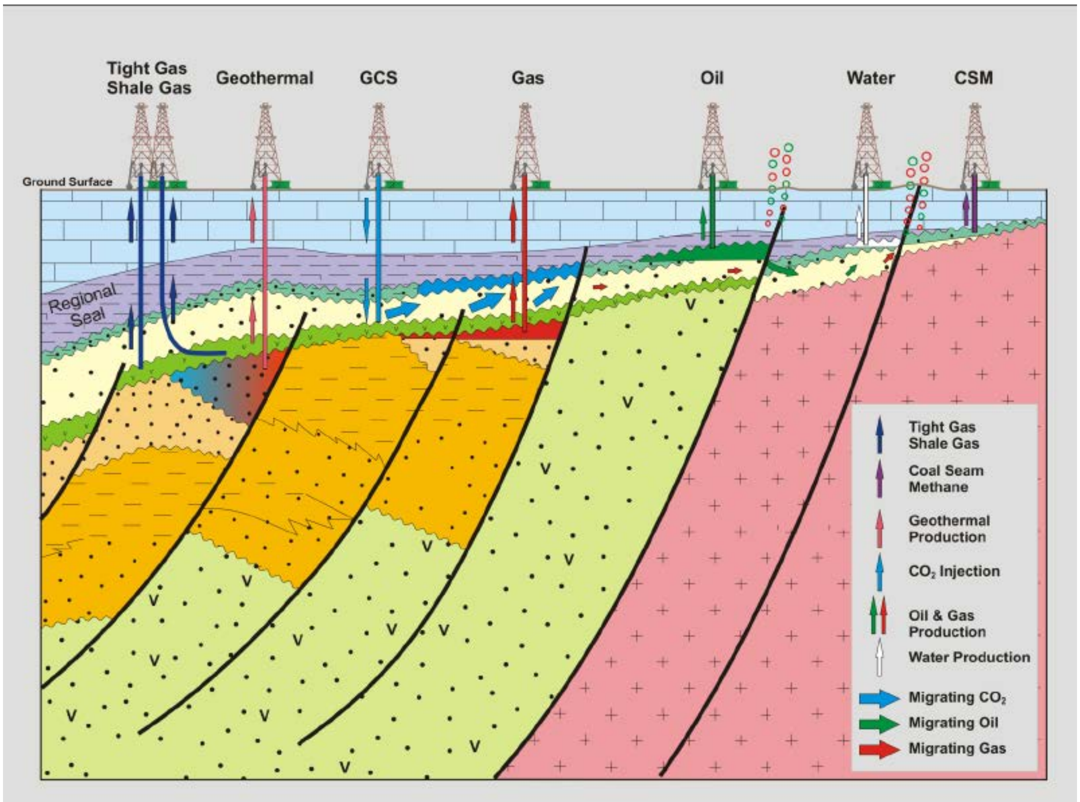

Figure 32: The aim of Victoria DPI's model is to facilitate licensing decisions that allow best multiple use of the basin, minimizing conflict and maximizing effective use. This diagram (from O'Brien, 2011) is a cartoon of the existing and potential uses of the basin in a theoretical cross section, showing schematically how different layers might be used and to help illustrate potential interactions. Neither horizontal scale nor vertical scale is implied. Note the depiction of theoretical leaky faults (marked by bubbles). A similar concept diagram might be a useful tool for regulators to develop when evaluating priorities and interactions in other sedimentary basins.

Disposal of waste water: Surat Basin

The production of natural gas from coal seams in Queensland, specifically in the Surat, Bowen and Clarence-Moreton basins, requires large-scale extraction of water from coal measures, and the disposal of this water. The most practical way of disposing of the water is injection into aquifers. The Sural Basin alone has an estimated theoretical storage capacity of 3 Gt (Bradshaw *et al*., 2010; Figure 33), This type of estimate does not take into account the use of, and interaction with, other resources such as groundwater and clearly in this case the amount of available theoretical capacity will depend greatly on policy decisions regarding priority usage.

The sedimentary rocks of the Surat basin is also part of the Great Artesian Basin (GAB), which is a hydrological unit rather than a distinct basin (Queensland Water Commission, 2012), so any water extraction or injection will affect the GAB. Water extraction (e.g., as part of coal seam gas operations) and associated waste water injection could affect CO_2 storage operations. The sedimentary fill of the Surat basin contains several aquitards as well as aquifers, so there is scope for multiple uses of the basin provided care is taken over the influence of pressure fronts or of possible direct mixing. Extensive monitoring of extracted and injected volumes and pressures and springs will be required, along with the development of mitigation strategies (Queensland Water Commission, 2012).

In the Surat Basin the typical depth of the Walloon Subgroup coal measures which are the target of coal seam gas operations is 200-800 m (Queensland Water Commission, 2012; Figure 34). Deeper reservoir units include the lower part of the Precipice Sandstone (e.g., Patchett, 2006, and Bradshaw, 2010) and the seal is commonly lacustrine shales of the Evergreen Formation. This formation underlies the Walloon coals and could act as a barrier between CO_2 storage in the Precipice and coal seam gas operations in the Walloon coals. However, the Precipice contains fresh water and is in places shallower than 800 m, which is generally too shallow for CO_2 storage. Use of the Precipice Sandstone for CO_2 storage would therefore be limited to areas where it is more than 800 m deep, the overlying seal is well developed, and the need for deep water reserves was of lesser importance than CO_2 storage.

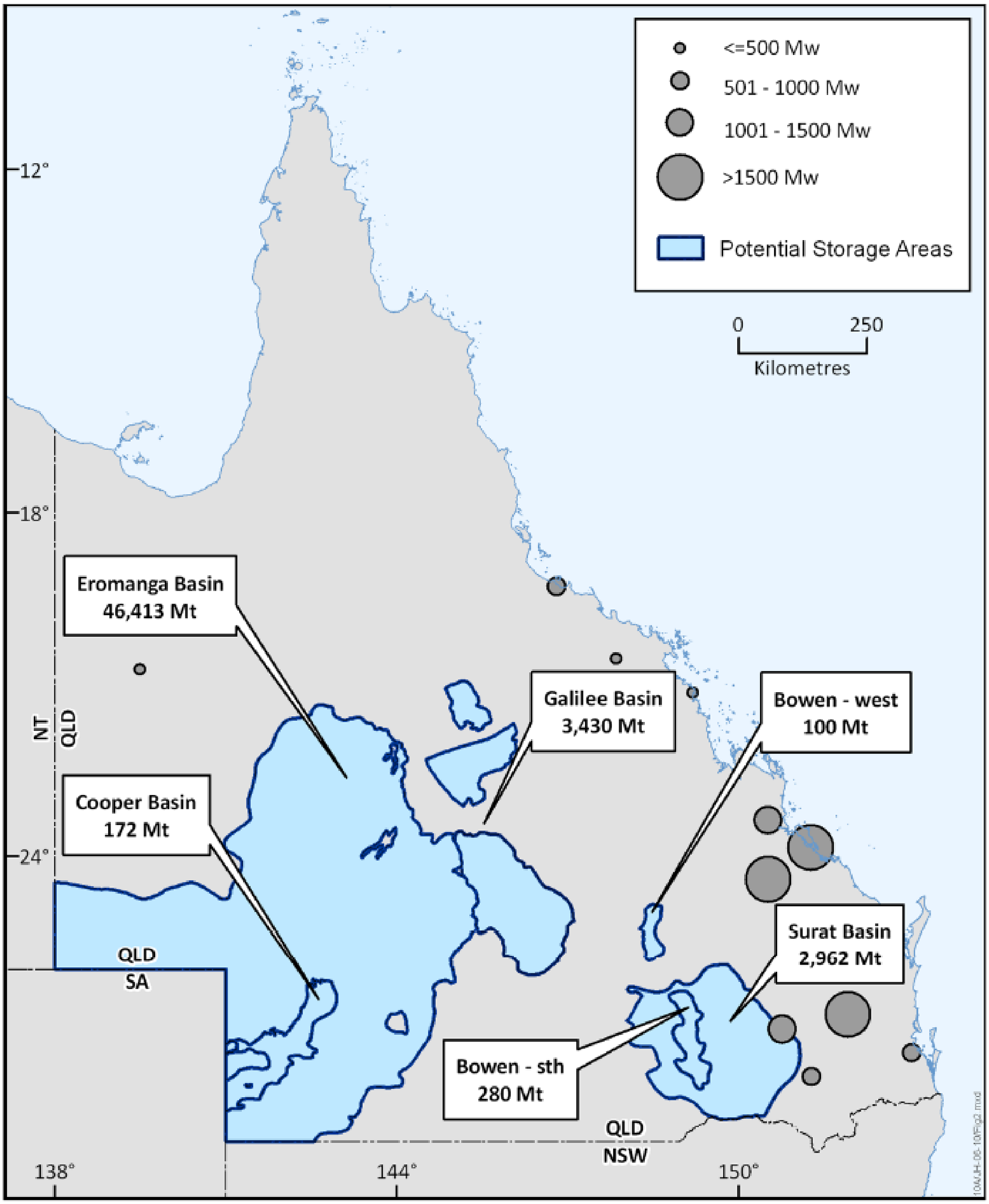

Figure 33: Map of Queensland showing the magnitudes of point source emissions of CO_2 and regions with high potential for CO_2 storage (figure 2 of Bradshaw *et al*., 2010). The most prospective part of the Surat Basin is outlined at lower left.

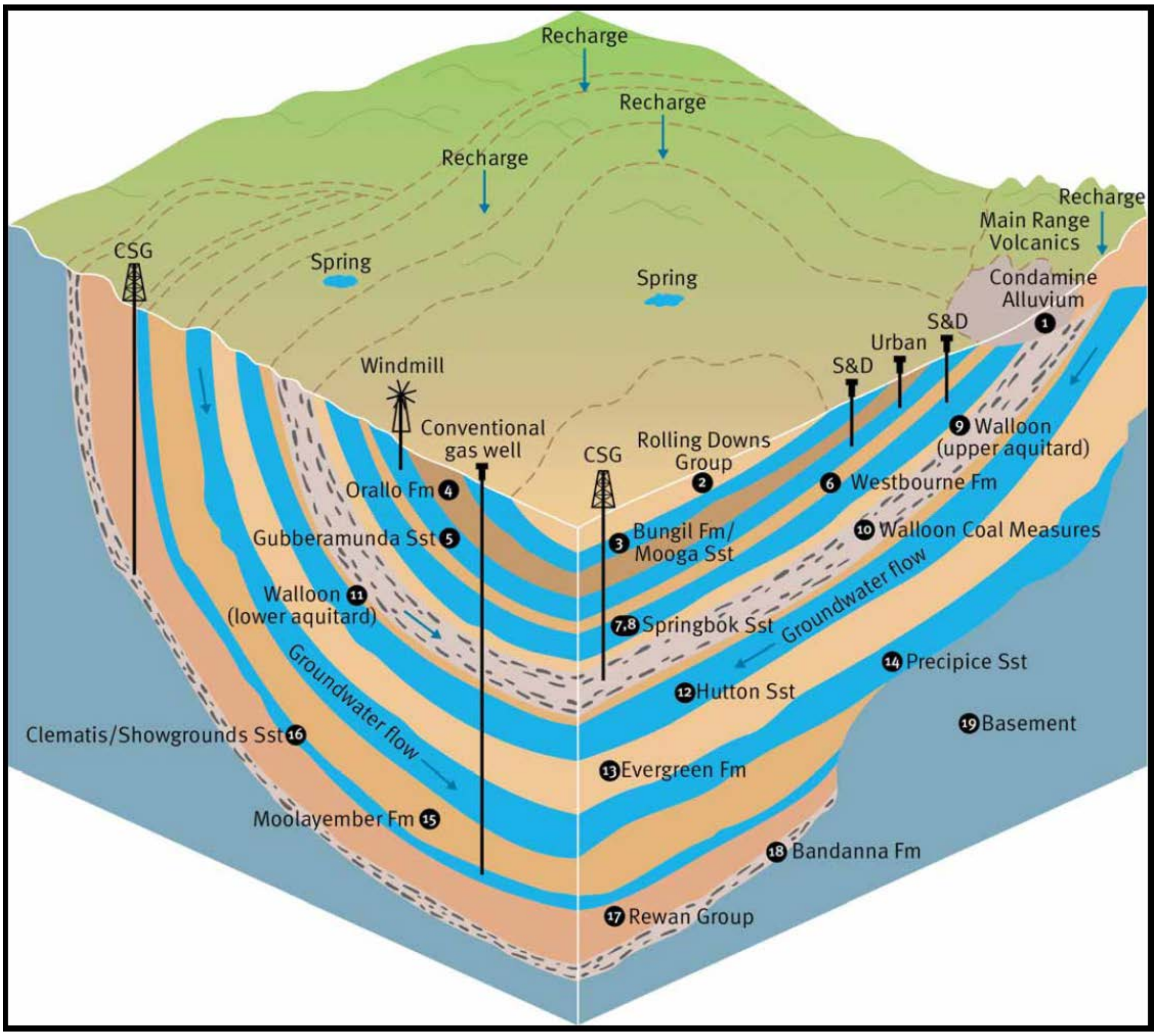

Figure 34: Conceptual model of the groundwater systems of the Surat and nearby basins (figure 6-3 of Queensland Water Commission, 2012). Note the coal seam gas extraction well (CSG, centre, tapping the Walloon Coal Measures), Precipice Sandstone (numbered 14) and the intervening seal (or aquitard) of the Evergreen Formation (numbered 13). Wells for conventional gas in the Showgrounds Sandstone (numbered 16) of the Bowen Basin (which in places underlies the Surat Basin) could pass through the Precipice Sandstone, potentially encountering any CO_2 stored locally in the Precipice Sandstone.

Waste water disposal is one for the greatest issues surrounding coal seam gas production in Queensland (Harris *et al*., 2012). Evaluation of potential sites for waste water injection are underway, with trials planned at four localities, involving three aquifers at depths from less than 100 m to about 1500 m (Morris and Hogan, 2012). Competition for use of this pore space, from disposal of produced water from coal seam gas operations, might be reduced in some areas because of the cost of deep injection, if shallower options suitable for waste water injection are available.

Further complications include that part of the Surat basin is also being assessed for geothermal energy production (Varma *et al*., 2011), that conventional gas reserves occur locally at deeper levels, and that CO_2 could be stored in deep coal seams (though this was considered by Bradshaw *et al*., (2010) as unlikely to be economic unless undertaken as part of enhanced recovery of gas). While there is no CO_2 storage in the Surat Basin at present, there are plans to store CO_2 there in association with a power station at Wandoan (CTSCO, 2011).

Resource Interaction Issues and their Resolution

Introduction

The case studies provided illustrate that CO_2 storage can affect other subsurface resources, or their future use, just as the use of other resources can influence the availability, extent or timing of CO_2 storage. The ability to assess interactions will depend considerably on the level of knowledge available on the geology of the region of interest and information available on past and present resource use operations. The assessment of physical interactions should be made considering the legal constraints and regulations currently applicable to the region, both for CO_2 storage operations and for the use of other resources. If no CO_2 storage regulations have been formulated then useful reference can be made to existing regulations in other countries[3], as well as European Commission Directives (European Commission 2009) and United Nations Framework Convention on Climate Change (UNFCCC) guidelines on underground storage of CO_2 (UNFCCC 2012).

Influences can be positive or negative, as summarized in Table 1 and discussed in more detail earlier in the report. Successful resource uses can overlap geographically, particularly if they are at different depths and are not in pressure communication. Subsurface resources typically occur over certain depth ranges (Figure 35), and in many cases fall outside the typical depth range of CO_2 storage (~800-3500 m). On the other hand, resource uses can clash even if they are many kilometers apart, for example by detrimental pressure fronts or fluid migration. We provide a checklist of some of the major factors likely to be involved in regulatory decisions (Table 2) and provide further discussion below.

Priority of use

An early determinant of potential subsurface resource interaction is the decision on the order of priority of resource use, and this is commonly determined through legislation or by regulatory agencies. For example, the pore space in a depleted gas field might be licensed for natural gas storage, waste water disposal or CO_2 storage and, in these cases, the decision might determine the permanent use of the pore space resource. The enhanced recovery of hydrocarbons might allow multiple uses, for both CO_2 storage and the maximum extraction of additional energy reserves and hence offer optimal management of resources, though life-cycle emissions in EOR projects need to be accounted for (McCoy *et. al.*, 2011).

Different areas of a basin might suit different uses based on the depth of pore space (e.g., > 800 m), competency of seals, presence of deep, potable groundwater (as in the Gippsland Basin), the proximity to CO_2 point sources and other factors. Multiple use of a basin can also occur through

[3] For example, in Australia these include the Federal Offshore Petroleum Amendment (Greenhouse Gas Storage) Act 2008; Queensland's Greenhouse Gas Storage Bill 2008; Victoria's Greenhouse Gas Geological Sequestration Act 2008; Western Australia's Barrow Island Act 2003 and South Australia's Petroleum Act 2000 Amendments. In the USA they include the Environmental Protection Agency's regulations (https://www.federalregister.gov/articles/2010/12/10/2010-29954/federal-requirements-under-the-underground-injection-control-uic-program-for-carbon-dioxide-co2#p-3 and in Alberta, Canada, they include the Carbon Sequestration Tenure Regulation 68/2011.

assigning different uses to different stratigraphic levels, such as shallow levels for groundwater or waste water disposal, intermediate levels for CO_2 storage and deeper levels for hydrocarbon extraction. Figure 35 illustrates the usual range of depths at which various subsurface activities are undertaken.

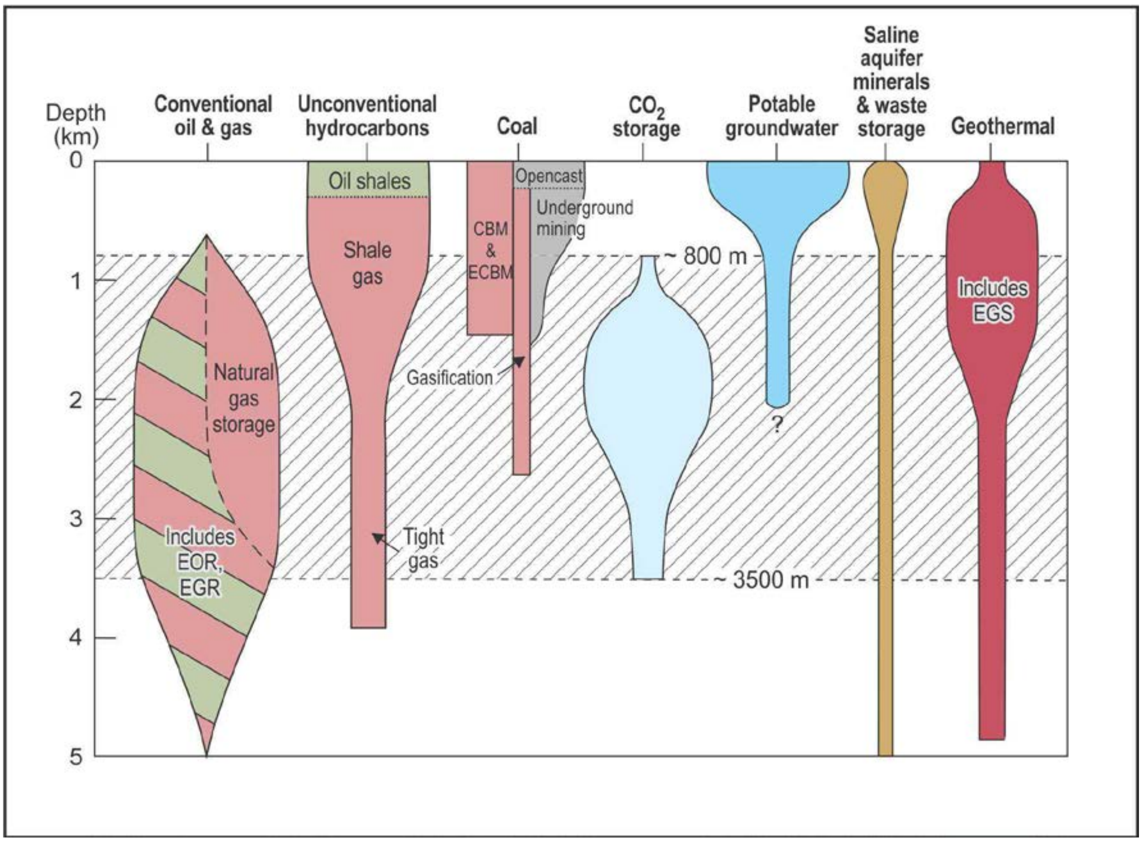

Figure 35: Schematic diagram of the typical depth ranges over which subsurface resources occur, including the use of pore space for CO_2 storage.

Timing of interactions

The timings of potential resource interactions are relevant and can be classified as:

- Pre-implementation, e.g., which resource use has higher priority of use or production and should receive a permit; or planning and economics, for example to determine at what stage of an injection project should EOR be implemented, if at all; or what mix of successive uses will produce the best return, environmentally, economically, or both? In this phase, regulatory agencies have the opportunity to influence effective resource allocation and development in line with their respective government's policies, and companies will be planning any interactions to optimise economic returns and minimise liabilities.

- During injection, e.g., is monitoring showing unexpected plume migration or pressure development that might affect other resources such as hydrocarbons or groundwater; or is injectivity lower than expected, requiring for example pressure relief wells and subsequent disposal of produced water that could harm, or be used to re-pressurize, shallow groundwater resources.

Table 1: Positive and negative aspects of the interaction of CO_2 storage operations on other pore-space resources.

Pore space resource	Positive	Negative
Oil	Might increase sweep efficiency hence more effective resource use; EOR can offset cost of storage, but not always usable; creates demand for CO_2 and hence improvement of capture technology; similar industries and service and supply needs; possible pressure enhancement	Pressure interference with existing operations; contamination of oil; infrastructure conflict; timing delays to CO_2 storage if EOR not feasible or wanted
Gas	EGR possible in some reservoirs (though rarely done); possible pressure enhancement	High cost of separating CO_2 from the produced gas if they mix; pressure interference with existing operations
Coal	CO_2 can flush out methane, creating valuable by-product	CO_2 would sterilize coal for mining or underground gasification; disposal of water produced during coal seam gas extraction could compete with CO_2 storage operations
Groundwater	Could re-pressure low-productivity aquifers; pressure-relief wells used to increase CO_2 injection rates might produce useable water	Could acidify or contaminate potable water, or change hydraulic heads through pressure interference
Dissolved minerals	CO_2 could flush or displace saline water, enhancing water, and hence mineral extraction	CO_2 might react with some dissolved mineral salts, plugging pores
Geothermal	Better heat transfer medium than water; possible pressure enhancement	High temperatures might increase risk of corrosion; possible pressure interference with existing operations
Natural gas storage	Nil	Pore space unavailable for CO_2 storage for life of gas storage facility; pressure interference with existing operations

Table 2: Checklist of some of the major factors likely to be involved in regulatory decisions.

Factor	Stage	Scale	Resource use effects (main types)	Examples	References
Priority of use	Licensing round design	Basin	All	Gippsland	O'Brien 2011
Timing of interaction	Licensing, permitting, operation and post-closure	Basin and prospect	Hydrocarbons, EOR, gas or waste storage	Gippsland	Varma & Michael 2012
Risk assessment	Permitting, financing, public acceptance; on-going	Prospect	All	In Salah	Bowden & Rigg 2004; Mander *et al*., 2011; Oldenburg *et al*., 2011
Storage capacity	Permitting and injection	Prospect	All	Gorgon	Flett *et al*., 2008
Improved recovery	Permitting and injection	Prospect	Oil, gas, gas hydrates, geothermal; extra resource extraction offsets cost	Weyburn-Midale	Buscheck *et al*., 2012; EGEC 2009; IEAGHG 2010/4; Nago & Nieto 2011; Regan 2007
Resource sterilisation	Permitting	Prospect	Coal, shale gas, groundwater, saline minerals, natural gas storage	Various, USA	Elliot & Celia 2012
Injectivity	Permitting and injection	Prospect	Variable; possible water production from relief wells	Gorgon	Flett *et al*., 2008
Seal integrity	Permitting and injection	Prospect	Groundwater, hydrocarbons	Gorgon, Gippsland	Flett *et al*., 2008; Hoffman *et al*., 2012
Pressure fronts	Permitting and injection	Prospect and up to ~200 km distance	Groundwater, hydrocarbons, geothermal, produced water and waste disposal	Lussagnet/Izaute, Zama field, Gorgon, Surat	IEA 2010/15; IEA 2011/11; Pooladi-Darvish *et al*., 2011
Surface deformation	Permitting and injection	Prospect (central)	Infrastructure, geothermal	In Salah	Oldenburg *et al*., 2011
Composition of gas injected (e.g., CO_2+H_2S)	Permitting and injection	Source/prospect/ migration path	Groundwater, geothermal	Laboratory/ Canada	Bachu & Bennion 2009; IEA 2011/4&11
Mobilisation of minerals and other substances	Operation and post-closure	Source/prospect/ migration path	Groundwater, geothermal	Chimayo, Weyburn	Apps *et al*., 2010; Emberley *et al*., 2005; IEAGHG 2011/08; Keating *et al*., 2010
Infrastructure	Permitting to post-closure	Prospect	Variable	Gorgon	Flett *et al*., 2008; Korre 2011
Monitoring and verification	Permitting through to post-closure; important for public acceptance and carbon credits	Prospect and surrounds	All	Otway, Gorgon, Ketzin	Sharma *et al*., 2009; Martens *et al*., 2012
Regulatory conflict, overlap, resolution	Licensing, permitting, operation	Potentially all scales	Variable	Surat	Korre 2011; Queensland Water Commission 2012

- Post-injection company monitoring, matching the record of plume migration as determined by monitoring wells and 4D seismic surveys with the digital model used to predict future plume stability. During this period the operator might be liable for any remedial measures needed or costs relating to damage to other resources. For the Australian Gorgon Project this period lasts 15 years (assuming plume behaviour is as expected). Long term liability legislation in many countries was assessed by Hoversten (2009). Regulations governing site closure might influence what future uses might be feasible in and around a CO_2 storage site (Korre, 2011; CO2Care, 2012).

- After permanent hand-over to government agencies; during this period local or federal governments might be liable for any remedial measures needed or costs relating to damage to other resources.

Risking

Risks should be assessed, at even the basic level of listing the uncertainties surrounding the existence and main parameters of each potential resource. Risking can become more detailed and quantitative in phases, as more data are obtained and as investment decisions progress. A comprehensive risk model, preferably with a dynamic digital model, should support any CO_2 storage project, but it need not (initially) include complete, hard data for that specific site; preliminary estimates by experts have a useful role in balancing initial gaps in hard data with regulatory requirements (e.g., Stenhouse *et al.*, 2009). Expert risk assessment will be important for public acceptance, particularly for onshore sites (e.g., Kuijper 2011; Mander *et al*., 2011).

Storage capacity

A key issue for regulatory agencies is likely to be the feasibility of a proposed use. For example, for CO_2 storage, if the pore space available turns out to be less than was anticipated, perhaps because of high permeability zones causing parts of the reservoir being by-passed by the CO_2 plume, then can the proposed maximum extent of the plume be extended without causing detrimental interactions with other resources? As depicted in Figure 5, there are increasing levels of certainty which improve as more is known about a storage space but it is only during storage ("Operational" or "Matched" Storage Capacity"), or even on completion of storage, that the actual capacity is known with certainty. Key factors in assessing storage capacity include the characteristics of the reservoir rock inherited from its depositional environment (e.g., IEAGHG 2009/13) and the prediction of the temperature and pressure conditions in the storage rock (as this determines the density of the CO_2 and its solubility in the natural formation waters and hence the potential for solution trapping). These factors (and others) need to be taken into account when calculating storage capacity and in the early stages of a project, before wells are drilled, they can only be estimates.

Improved recovery of resources

Improved recovery of subsurface resources can ensue from CO_2 injection by simple pressure transmission, such as if a groundwater resource gains an increased pressure head, or by the miscibility of high-density CO_2, such as in EOR. Pressure relief wells associated with improving CO_2 injectivity will produce water which might not otherwise have been economical to extract, and in some cases could be desalinated for other uses or "mined" for dissolved minerals such as lithium. Improved or enabled recovery might offset some of the cost of CCS, as is currently the case with EOR (e.g., at Weyburn).

Resource sterilization

The injection of CO_2 has the potential to limit the use of other resources, such as when CO_2 is stored in deep coal seams, thus precluding the use of underground gasification of coal. The storage of CO_2 in depleted gas fields would probably stop later use of the reservoir for natural gas or compressed air storage (as produced gas would contain significant CO_2 levels), though the converse would not be true if the reservoir were suitable for EGR operations. The potentially exclusive uses of “clean” underground pore space, or newly-drained pore space in the case of depleted hydrocarbon reservoirs, should be prioritised before assigning usage.

Injectivity

The rates of CO_2 injection must be economically viable without risking seal rupture. If the rate of safe injection turns out to be less than predicted, for example because the permeability is less than expected or through salt plugging, what are the fall-back solutions available to ensure the project does not fail or affect other subsurface resources? Solutions might include drilling of additional pressure relief wells, with disposal of greater volumes of produced water into shallower or deeper levels. An assessment of whether this (as a contingency procedure) might affect the use of groundwater or hydrocarbons in adjacent areas could be made as part of the permitting process. Drilling more wells is not necessarily the best solution, as decreased injectivity can have a variety of causes and solutions (IEAGHG 2010/4 table 8).

Seal integrity

Seal integrity is a key element in gaining public acceptance of CO_2 storage, in ensuring carbon credits are preserved and in predicting any subsurface resource interaction. Geomechanical and original reservoir pressure data from depleted hydrocarbon fields can assist in estimating maximum CO_2 storage pressures, assuming the reservoir-seal system behaves elastically when re-pressurized. The presence of several seal units at various levels above the storage zone can greatly reduce the chance of leakage and can give some assurance against direct pressure communication between the storage zone and other shallower resources. A thorough analysis of the reservoir history should be made, including whether any reservoir enhancement, such as hydraulic fracturing (fracking), might have damaged the seal unit. IEAGHG (2011/01) provides a comprehensive discussion on seal rocks and the roles of faults, and Hoffman *et al*., (2012) provide an example of a basin-wide assessment of seal rock quality in relation to CO_2 storage.

Seismic data for a seal unit should be of sufficient quality that any through-going faults in the seal can be detected, and an assessment can be made as to whether such faults would act as conduits or barriers to plume migration.

If the plume passes through or around a seal unit, there are contingency measures available, such as cessation of injection, the drilling of relief wells or CO_2 extraction wells, or managing the direction of plume migration by altering subsurface pressure regimes using a combination of injection and extraction wells (see IEA 2010/4 table 9 for a range of options).

Pressure fronts

The lateral extent of the increase in pressure during CO_2 injection can reach over 100 km from the injection site (IEAGHG 2011/11) if the injection formation and the saline formation are in pressure communication. However, if the stratigraphic levels are not in direct pressure communication with other resources then pressure effects are likely to be minimal (IEA 2011/11 p96). Assessment of whether there is pressure communication will be straightforward in some cases and difficult to quantify in others; a lot will depend on the clarity and certainty with which the lateral extent, thickness and lithological variation of storage and seal units can be determined using seismic and well data. Permeability also plays an important role in pressure transmission. Depending on the depositional setting and lateral extent under consideration, seals can vary laterally in lithology and hence seal capacity and strength.

The presence of faults, and their ability to act as seals or fluid conduits, may also be significant though pressure transmission between layers via leaky faults might be intermittent, with the fault acting as a valve. It is possible that very thin seal units (e.g., < 10 m thick) could have leaky faults below the resolution of the available seismic data.

Ground surface deformation

It is unlikely that uplift caused by CO_2 injection would be sufficient to affect other subsurface resources, particularly in the subsurface, as such deformation is likely to be quite localized and less than a few centimetres in magnitude. Deformation would affect the leveling of any infrastructure nearby but whether this would be significant would need to be assessed on a case-by-case basis.

Composition of the injected gas

If the composition of the CO_2 stream being injected is known then any effects of corrosion or contamination through leakage can be anticipated. For example, this might require knowledge of the composition of the flue gas and of the captured CO_2 stream, which depends on the composition of the coal being used, on the capture process being used, and how that might vary over the lifetime of plant operations. The effects of leakage of injected gas that is not pure CO_2 on groundwater quality are discussed in IEA (2011/11) and include direct contamination by flue gas chemicals, possible dissolution and transport of minerals, metals and organic compounds in the reservoir rock, and modified microbial activity. Impurities in injected CO_2 can also affect storage capacity (IEA 2011/04; Wang *et al*., 2011).

Mobilization of minerals and other substances

Injected CO_2 changes the acidity of the formation waters and can cause dissolution of minerals in the host rock (e.g., IEA 2011/04 & 11). This can cause the release of new elements and radicals which can cause further reactions and affect injectivity, or contamination if leakage occurs. Injected CO_2 can also displace organic compounds, such as oil, which also have the potential to contaminate if leaked. Impurities in the injected fluids such as sulphur compounds from flue gases (e.g., H_2S or SO_2) also affect the chemistry of the formation waters and can release additional compounds through dissolution of minerals in the reservoir, or seal-rock interface.

Infrastructure

CO_2 or CO_2-rich brines can contact the casing and cement of old wells and potentially corrode them, causing leakage up-well (e.g., Gasda *et al*., 2011). This is particularly an issue when injecting CO_2 into depleted oil or gas fields (for storage or as part of CO_2 EOR operations), particularly if the old wells do not have good records of completion techniques and materials used. New cements resistant to CO_2 can be used to remediate old wells, as planned at the Gorgon Project. Wells outside the expected region of plume migration might also need to be assessed, in case remediation becomes necessary.

CO_2-proof cements should clearly be used in any new injection or monitoring wells to avoid resource interaction, for example through leakage up-well into shallow groundwater resources, and appropriate well abandonment procedures should be in place for the post-injection phases. IEAGHG (2010/03) provide assessments of corrosion risk at all phases of CCS projects (see also IEAGHG 2009/08).

It may be possible to share pipeline infrastructure, for example with oil or gas networks.

Monitoring and verification

The ability to recognise CO_2 interaction with other resources requires knowledge of pre-injection CO_2 levels (so that leaks can be recognised as such) and characterisation of plume migration, and pressure front propagation, with respect to other resources. Thus, baseline studies must be undertaken before injection, the injected plume must be monitored and secure storage must be verified.

Baseline studies are usually carried out at proposed sites, generally for over a year, to determine background or “normal” levels of CO_2, for example at the Otway and Gorgon sites (e.g., Etheridge *et al.*, 2005; Schacht *et al.*, 2010 & 2011, Sharma *et al.*, 2009). Such studies may include monitoring very small, even diurnal, changes in natural CO_2 in soils, regular monitoring of atmospheric CO_2 to determine existing variability from natural and anthropogenic CO_2 emissions, and regular monitoring of natural levels of CO_2 in groundwater (e.g., Hortle *et al*., 2011). An important goal of this monitoring is to establish whether CO_2 leakage can be detected, and this depends on defining the level of CO_2 increase that is regarded as “anomalous”. Monitoring continues during and after injection (e.g., Martens *et al*., 2012). After cessation of injection, the CO_2 plume is likely to be more stable and, if this appears to be the case, it might be appropriate to decrease the frequency of monitoring. There are many different monitoring methods and approaches and choices may best be site-specific (see Beck and Aiken, 2009).

Regulatory conflict or overlap

Resource use conflict can arise through the wording of existing regulations, or the creation of new regulations. Existing regulations might provide unhindered access to hydrocarbon resources and might allow for the injection of saline water or CO_2 for enhanced extraction, but they might not make specific provision for long-term storage of CO_2; for example, new regulations allowing CO_2 injection for storage would need to differentiate between or be compatible with existing regulations allowing for CO_2 use for EOR.

Any new regulations would need to protect the rights of existing users while still allowing multi-level or adjacent resource use. This would ensure that CO_2 storage operations could occur at shallower or deeper levels than those for hydrocarbon production, groundwater extraction or other resource uses, permitting all to continue without conflict.

The absence of regulations governing CO_2 storage can put at risk the development and costing of CO_2 storage projects, avoiding conflict in the short term by, in effect, preventing CO_2 storage from proceeding. The establishment of workable regulations will be an important part of implementing the large number of CCS projects required to mitigate climate change (IEAGHG 2011/10).

Summary and conclusions

The interaction of CO_2 storage with other resource uses can be positive or negative and depends on the geology, existing resources, economic potential and the regulatory environment. CO_2 storage operations may be feasible adjacent to other resource uses, or at different levels in the same locality, particularly if there is no detrimental pressure connection between sites. On the other hand, if pressures associated with CO_2 storage are not confined then resource uses many kilometres distant from a storage site might be affected (beneficially or detrimentally). Resource use interactions can occur contemporaneously or sequentially. In particular, existing permits might preclude CO_2 storage, and CO_2 storage might preclude future use of other resources.

Regulatory agencies should consider the following stages when evaluating resource development in relation to carbon storage:

- Identify all the resources within the basin or region of interest, including “vacant” pore space, map their distribution and assess their quality. It is important to do this, even using subjective criteria or estimates if there are few hard data. This will allow an assessment of the resources likely to be affected and the range of likely interactions. The Gippsland Basin study by the Victoria State Government is a good example of this type of assessment (e.g., O’Brien et al., 2011).

- Establish the priority of use between the various resources, including alternative uses for available pore space, and CO_2 storage.

- Assess the proposed CO_2 storage project, its site characterization, monitoring and verification plans, contingency and mitigation planning (e.g., how to cope with possible leakage, fault reactivation, loss of well integrity). The Gorgon Project has addressed these issues (e.g., Flett et al., 2008 & 2009; Gunter et al., 2009) and approaches are discussed in IEAGHG (2011/11).

- Review the injection plans and the likelihood that they will be achievable, and assess whether they might lead to cases of resource conflict (by seal rupture, pressure-front propagation or CO_2 plume migration into regions other than predicted or licensed to the storage operation).

- Review the abandonment plans and longer term monitoring and verification planning, and liability transfer arrangements (e.g., Korre, 2011).

Delays in establishing CO_2 storage regulations could not only inhibit CO_2 storage project development, they could lead to future, detrimental resource interactions. Nevertheless, time is needed to ensure regulations are clear and take into account potential resource prioritization and interaction, as these issues are essential to the planning, costing, safety and surety of CO_2 storage projects. Assessments of potential resource uses in a region, and of possible usage interactions, should enable effective prioritizing of opportunities in a region and efficient allocation and use of known or anticipated resources, and their potential effects on estimates of CO_2 storage capacity and injection scenarios.

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