Engineering Report

CO2 Storage Technologies Overview

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CO2 Storage Technologies Overview

Summary

CO2 in its supercritical state can be stored in onshore and offshore geological formations comprising abandoned or depleted oil and gas fields, aquifers, and coal mines. Careful consideration of, and a detailed geological assessment of the storage formation and location is essential. Existing hydrocarbon exploration and production wells are particularly appropriate for assessment due to the availability of existing infrastructure.

Current and planned commercial CO2 geological storage projects tend to be associated with major gas production facilities such as Sleipner in the North Sea, Snøhvit in the Barents Sea, In-Salah in Algeria and Gorgon in Australia. CO2 injection for Enhanced Oil Recovery was first demonstrated in the early 1970’s in Texas – USA.

A number of global and regional environmental treaties exist, which can be interpreted as being relevant to the applicability and permissibility of CO2 storage. These treaties were not drafted to facilitate the geological storage of CO2, but to prohibit marine dumping.

The costs involved in the geological storage of CO2 will be site specific, and can lead to a high degree of variability. For onshore locations, the costs depend upon the location and terrain. Offshore costs tend to be higher which reflects the requirements of platforms or sub-sea facilities and higher operating costs.

Greece’s primary sources of CO2 emissions are onshore in the regions of the lignite power stations in Kozani (Ptolemais area) with 22.5Mt/yr CO2 and Peloponnesus (5Mt/yr CO2). In the big cities regions of Athens and Thesaloniki, the annual CO2 emissions are approximated at 5Mt/yr and 1.6Mt/yr respectively.
Greece’s Tertiary coal basins are very well developed. The existing lignite and peat deposits are large, the main lignite coal deposits are onshore and at a shallow depth of <800m with severely faulted seams. Existing data indicate to very low CO₂ storage potential in these rock formations. Lack of comprehensive and sufficiently reliable data for the offshore tertiary rock formations does not permit a reliable assessment of the CO₂ storage potential in these geological formations to be conducted.

Prinos oil and South Kavala reservoirs are >2000m below sea level and are suitable for the storage of CO₂ at supercritical conditions. Both fields have existing infrastructure of pipelines, wells and platforms necessary for CO₂ transportation and injection and are located within 30-40km of the coast. The Prinos oil field can be suitable for CO₂ injection for Enhanced Oil Recovery.

The Prinos basin and W. Thessaloniki aquifers have satisfactory geology: porosity, permeability, depth, fair mineralogy and a very good top seal which can cap and seal CO₂ after injection.
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**Introduction**

The Regulatory Authority for Energy (RAE) of the Hellenic Republic has contracted RWE Power International to produce a ‘CO₂ Storage Technologies Overview’. This report is submitted in fulfilment of the requirements of Task 2.

This report comprises the assembly and evaluation of information on CO₂ storage options at facility level, expected performance and description of pilot/test installations.

This report consists of two parts. Chapters 2 – 6 provide a general and generic overview of the geology of rock formations suitable for the storage of CO₂, existing and planned CO₂ storage projects - both pilot and commercial. Chapter 4 is a brief discussion of CO₂ storage options including, depleted oil and gas fields, enhanced oil recovery (EOR), enhanced gas recovery (EGR) storage in saline formations and enhanced coal bed methane (ECBM). Chapter 5 is a discussion of the legal conventions that might be applicable to CO₂ storage and chapter 6 outlines some basic generic costs.

Chapter 7 focuses in particular on the potential for geological storage of CO₂ in Greece. Potential storage options discussed are abandoned coal mines, storage in hydrocarbon deposits and storage in aquifers.

**1. Facility Level Capture and Transportation to Storage Sites**

At atmospheric pressure CO₂ exists in a gaseous state. At atmospheric pressure, lowering the temperature will change the CO₂ from its gaseous state to a solid ‘dry-ice’ state. Liquid CO₂ is only achievable with the combination of low temperature and high pressure conditions. This necessitates the requirements of large-scale facilities to convert CO₂ into a medium suitable for transportation to the storage site. The principal methods of transporting CO₂ are:

1. High pressure pipelines
2. Ship transportation of liquefied CO₂
3. Transportation be rail and road tankers

The transportation of CO₂ in high pressure pipelines is well established and technically proven in the EOR industry. In the Permian Basin of West Texas, a network of high pressure CO₂ pipelines totalling 2500km transport approximately 50 Mt CO₂/yr from the man-made and naturally occurring McElmo Dome to mature oil fields around West Texas. Kinder Morgan is considered to be amongst the industry leaders in the development and application of CO₂ pipeline technology (IEA GHG R&D 2006). Pipeline transportation is considered the only cost-effective option for the continuous CO₂ Carbon Capture and Storage process.

Marine transportation of CO₂ offers a more flexible alternative, especially for batch CCS processes, but also necessitates intermediate storage facilities at the power station site and port location to handle the loading and reloading of CO₂. This necessitates an increase in the logistical requirements. The experience and skills available in the global Liquified Petroleum Gas (LPG) and Liquified Natural Gas (LNG) industries can be utilised for the establishment of a large-scale CO₂ marine transport infrastructure. The transportation of liquefied CO₂ in rail and road tankers is an unattractive option for large-scale carbon dioxide capture and storage projects.
Of critical significance in the transportation of CO$_2$ is water removal. In the presence of water CO$_2$ is corrosive to mild steel; this therefore requires the CO$_2$ to be in a dry state. Furthermore as a liquid, CO$_2$ exhibits the properties of a solvent and can penetrate rubber seals. It is recommended that a minimum specification for ‘pipeline quality’ CO$_2$ be established.

The current lack of demonstrable power station CO$_2$ CCS projects constrains the accuracy of any economic evaluations. Infrastructure development requirements are based on existing CO$_2$ CCS feasibility studies and therefore must be considered as evaluations predicated on what the assumed infrastructure necessitates. This should be sufficient for an initial ‘first look back-of-the-envelope’ consideration. More accurate information will be available via a sanctioned ‘FEED’ Front End Engineering Design study.

Figure 1 outlines the required processes to condition CO$_2$ for transportation by ship and pipeline.

**Figure 1: Process Requirements for CO$_2$ Transportation by Ship and Pipeline**

1.1. CO$_2$ Transportation by Ship

Process requirements for the marine transportation of CO$_2$ include:

1. CO$_2$ liquefaction plant
2. Intermediate storage and port loading facilities
3. Ship transportation

1.1.1. Liquefaction plant

CO$_2$ liquefaction is established technology using dehydration or refrigeration processes.
Assuming post-combustion amine absorption CO₂ capture technology, the CO₂ is delivered to the liquefaction process at atmospheric pressure. CO₂ entering the liquefaction plant will be saturated with moisture. The dehydration process will prevent freezing and hydrate generation. The water is condensed by compression and removed in multiple steps. This is followed by the molecular sieve drying process using an adsorbent. The CO₂ is liquefied by refrigeration and further cooled with the heat of vaporisation from the CO₂ decompression process. Consumables include cooling water, electricity and fuel for the drying process.

1.1.2. Intermediate Storage and Port Loading Facilities

For the storage of pressurised liquid CO₂ a spherical tank with skirt support is recommended. The maximum typical tank size for storing CO₂ at 7 bar is 20,000m³, which constitutes an inner tank diameter of 34m and 50-60mm wall thickness. Material of construction is high tensile steel with internal thermal insulation to minimise heat transfer from the ambient.

CO₂ can be loaded onto suitable transportation vessels typically using loading arms and the port site pumps. Unloading would depend upon the receiving facilities at the storage site and the ship based cargo tank pumps.

1.1.3. Ship Transportation

The largest CO₂ carrier in operation is the ‘Coral Carbonic’ with a single cylindrical cargo tank of 1,265m³ capacity. To maintain CO₂ in a liquid state requires a combination of low temperature and elevated pressure. A CO₂ cargo tank must therefore be of ‘pressure type’ or ‘semi-ref’ design. Generally, pressure type carriers tend to be smaller than 5,000m³ and semi-ref range between 5,000 – 20,000m³.

1.2. CO₂ Transportation by Pipeline

The construction of the first CO₂ pipeline was completed in 1972; the 354km Canyon Reef Carriers pipeline to the SACROC oilfield in Texas. Currently the largest existing pipeline is the 808km Cortez pipeline from Cortez – Colorado to Denver City – Texas which commenced operation in 1984. Other examples of CO₂ pipelines include the 330km Weyburn, 6487km Sheep Mountain and the 338km Bravo pipeline. These pipelines have been constructed for supercritical CO₂ transport.

1.2.1. CO₂ Pipeline Pressure and Compression

If the CO₂ is to be used for EOR then the miscibility pressure of CO₂ in oil is an important factor to consider which is typically in excess of 83bar and can often be as high as 160 – 200bar. Pipelines suffer from pressure drops. Recompression stations are necessary along the pipeline route; the compressibility and density of CO₂ demonstrate strong, non-linear temperature and pressure dependence which increases the difficulty in predicting the flow characteristics. Above the CO₂ critical pressure of 74bar, a small change in temperature and pressure yield large changes in density, the hydraulic characteristics of the pipeline warrant careful consideration (Svensson et al). Depending upon the pipe diameter, mass and flowrate, the pipe frictional losses for CO₂ range from 0.04 – 0.5bar per km. Recompression or booster stations should be positioned 100-150km along the pipeline run but the will ultimately be determined by topography (Wong).

Typically 3 - 4 compression stages are required before the optimal CO₂ transportation pressure is achieved. During each compression stage their will be a considerable rise in gas temperature, aerial coolers are generally used to cool the process CO₂ stream to the appropriate suction temperature between stages. The line and intercooler—
pressure losses at each stage should also be factored.

1.2.2. Operational Issues

A glycol dehydrator is often installed upstream of the CO₂ compression unit to control the water content to acceptable levels. CO₂ dissolves in water to form carbonic acid which is corrosive. It is preferable to use stainless steel; H₂S reacts with carbon steel to form a thin film of iron sulphide. Careful consideration must be given to sealing and gasket material. Some petroleum based and synthetic lubricants in the presence of CO₂ become brittle and ineffective.

2. CO₂ Storage Formations, Capacity and Geology

CO₂ can be stored onshore or offshore in sedimentary formations comprising depleted oil and gas fields, coal seams and saline formations. Other proposed storage options include storage in caverns, basalt and organic-rich shales. Basins suitable for CO₂ storage require thick accumulation of sediments, permeable rock formations saturated with saline water, extensive cover of low porosity rocks which act as a cap and structural simplicity. Basins which are shallow or dominated by rocks with low permeability and poor defining characteristics are unsuitable.

To geologically store CO₂, it must first be compressed to its supercritical state. The density of CO₂ increases rapidly until it reaches its supercritical state at ~800m. At depths below 1.5km the density and specific volume of CO₂ becomes nearly constant.

The suitability of sedimentary basins for the storage of CO₂ depends in part upon their location on the continental plate. The structure and stability of basins formed in mid-continent locations or near the edge of stable continental plates are ideal for the long-term storage of CO₂. Basins located in the tectonically active areas of northern Mediterranean are less suited and should be carefully selected because of the potential for CO₂ leakage. Basins located on the edges of plates or between active mountain ranges are likely to be strongly folded and faulted and therefore provide limited storage capacity.

Other critical criteria are porosity, thickness and permeability. Porosity decreases with depth because of compaction and cementation and reduces the storage capacity and efficiency. All storage formations should be capped by an extensive confining unit to ensure the CO₂ does not escape into any overlying, faulted or fractured sedimentary basins. This is particularly important in seismically active areas.

Existing hydrocarbon exploration and production wells should be particularly considered for CO₂ due to the available use of existing infrastructure and the availability of extensive geological data. Though the presence of wells penetrating the subsurface in mature sedimentary basins can create potential CO₂ leakage paths that may compromise the storage site integrity, no measurable leakage of CO₂ has occurred after 4 years of CO₂ injection at the Weyburn site despite the presence of hundreds of existing wells.

2.1. Geological Parameters for CO₂ Storage

1. Permeability (admitting the passage of a fluid): reservoir rocks have to be permeable to allow CO₂ migration away from the injection point

2. Porosity (able to absorb air or fluids): reservoirs must be porous enough to allow storage of large volumes of CO₂
3. Volume: thickness and area of the reservoir have to be sufficient to generate large storage volumes
4. Depth: CO\(_2\) should be stored as a supercritical fluid (a fluid possessing the characteristics of both liquid and gas, i.e. being compressible and exhibiting fluid-like densities). This state is achieved at depths >800m below the surface. At increasing depths the rock permeability gradually decreases which necessitates increases in injection pressure and decreased storage capacity. For the GESTCO Greece assessment, aquifers and oil reservoirs with depths ranging 800 – 3000m were considered.
5. Seal (cap rock): the quality of the cap rock is very important in order to prevent CO\(_2\) leakage to the surface.
6. Tectonic activity (earthquake activity): storage areas should be tectonically stable with no significant earthquake activity.
7. Mineralogy: reservoirs and cap rocks should not contain minerals that can deteriorate the reservoir quality and influence the quality of seal resulting from chemical interactions with the sequestered CO\(_2\).

2.2. Physical Condition of CO\(_2\) for Geological Storage

In many sedimentary basins below the ground surface, the average temperature increases by approximately 25 -30°C/km due to the heat flow from inside to the Earth’s other surface. Globally these geothermal gradients can exhibit considerable variations. With increasing depth the pressure also increases. In the pore spaces of sedimentary rocks the pressure is commonly close to hydrostatic pressure (the pressure generated by a column of water of equal height to the depth of the pore space. This is because the pore space is commonly filled with water and is tortuously connected to the groundwater). Under conditions where the pore space is not connected to, or not in equilibrium with the surface, the pressure may be greater than hydrostatic and is referred to as overpressure. Conversely, under-pressure may also exist owning to natural circumstances or as a result of fluid (oil, gas and water) abstraction from the reservoir.

When CO\(_2\) is stored underground, there is a sharp increase in the density of CO\(_2\) and a corresponding decrease in the volume at depths between 600 – 1000m; this is associated with the CO\(_2\) phase change from a gas to a dense supercritical fluid. (The actual characteristics will be dependent on the precise geothermal and pressure conditions of the geological formation in question). In its supercritical state, one tonne of CO\(_2\) with a density of 700kg/m\(^3\) occupies a volume of 1.43m\(^3\). At atmospheric pressure and 0°C, one tonne of CO\(_2\) will occupy approximately 509m\(^3\).

Under the pressure-temperature conditions commonly found in the subsurface, supercritical CO\(_2\) is less dense than, and only slightly miscible with the water or brine solution that is most commonly found within the void spaces in sedimentary rocks. CO\(_2\) is fully miscible with and denser than natural gas and the CO\(_2\) is also fully miscible in oil.

3. Existing and Planned CO\(_2\) Storage Projects

Current and planned CO\(_2\) geological storage projects are listed in Table 1 (IPCC 2005). Commercial CO\(_2\) storage projects tend to be associated with major gas production facilities such as Sleipner in the North Sea, Snøhvit in the Barents Sea, In-Salah in Algeria and Gorgon in Australia as well as the acid gas injection projects in Canada.
and the United States. CO₂ injection for Enhanced Oil Recovery was first demonstrated in the early 1970's in Texas – USA.
Table 1. Current and planned geological storage projects

<table>
<thead>
<tr>
<th>Project</th>
<th>Country</th>
<th>Project Type</th>
<th>Lead Organisation</th>
<th>Injection start date</th>
<th>Average daily injection rate (t/day)</th>
<th>Total storage (tonnes)</th>
<th>Storage type</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Existing – Operational Projects</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sleipner</td>
<td>Norway</td>
<td>Commercial</td>
<td>Statoil, IEA</td>
<td>1996</td>
<td>3000</td>
<td>Planned 20Mt</td>
<td>Aquifer</td>
</tr>
<tr>
<td>Weyburn</td>
<td>Canada</td>
<td>Commercial</td>
<td>EnCana, IEA</td>
<td>May 2000</td>
<td>3000 - 5000</td>
<td>Planned 20Mt</td>
<td>CO₂ – EOR</td>
</tr>
<tr>
<td>Minami-Nagoaka</td>
<td>Japan</td>
<td>Demo</td>
<td>Research Institute of Innovative Technology for the Earth</td>
<td>2002</td>
<td>Max 40</td>
<td>Planned 10kt</td>
<td>Aquifer</td>
</tr>
<tr>
<td>Yubari</td>
<td>Japan</td>
<td>Demo</td>
<td>Japanese Ministry of Economy, Trade and Industry</td>
<td>2004</td>
<td>10</td>
<td>Planned 200</td>
<td>CO₂ – ECBM</td>
</tr>
<tr>
<td>In-Salah</td>
<td>Algeria</td>
<td>Commercial</td>
<td>Sonatrach, BP, Statoil</td>
<td>2004</td>
<td>3000 – 4000</td>
<td>Planned 17Mt</td>
<td>Depleted hydrocarbon reservoirs</td>
</tr>
<tr>
<td>Frio</td>
<td>USA</td>
<td>Pilot</td>
<td>Bureau of Economic Geology of the University of Texas</td>
<td>4 – 13 Oct 2004</td>
<td>~177t/d for 9 days</td>
<td>1600t</td>
<td>Saline formation</td>
</tr>
<tr>
<td>K12-B</td>
<td>Netherlands</td>
<td>Demo</td>
<td>GDF</td>
<td>2004</td>
<td>100 – 1000</td>
<td>~ 8 Mt</td>
<td>EGR</td>
</tr>
<tr>
<td>Fenn Big Valley</td>
<td>Canada</td>
<td>Pilot</td>
<td>Alberta Research Council</td>
<td>1998</td>
<td>50</td>
<td>200</td>
<td>CO₂ – ECBM</td>
</tr>
<tr>
<td>Recopol</td>
<td>Poland</td>
<td>Pilot</td>
<td>TNO – NITG (Netherlands)</td>
<td>2003</td>
<td>1</td>
<td>10</td>
<td>CO₂ – ECBM</td>
</tr>
<tr>
<td>Project</td>
<td>Country</td>
<td>Project Type</td>
<td>Lead Organisation</td>
<td>Injection start date</td>
<td>Average daily injection rate (t/day)</td>
<td>Total storage (tonnes)</td>
<td>Storage type</td>
</tr>
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<tr>
<td>Qinshui Basin</td>
<td>China</td>
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<td>Alberta Research Council</td>
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<td>Salt Creek</td>
<td>USA</td>
<td>Commercial</td>
<td>Anadarko</td>
<td>2004</td>
<td>5000 – 6000</td>
<td>27Mt</td>
<td>CO₂ – EOR</td>
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<tr>
<td>Projects Planned From 2005 Onwards</td>
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<td></td>
</tr>
<tr>
<td>Snøhvit</td>
<td>Norway</td>
<td>Commercial</td>
<td>Statoil</td>
<td>2006</td>
<td>2000</td>
<td>-</td>
<td>Saline formation</td>
</tr>
<tr>
<td>Gorgon</td>
<td>Australia</td>
<td>Planned Commercial</td>
<td>Chevron</td>
<td>Planned 2009</td>
<td>~ 10,000</td>
<td>-</td>
<td>Saline formation</td>
</tr>
<tr>
<td>Ketzin (RWE a participant)</td>
<td>Germany</td>
<td>Demo</td>
<td>GFZ Potsdam (RWE a participant)</td>
<td>2006</td>
<td>100</td>
<td>60kt</td>
<td>Saline formation</td>
</tr>
<tr>
<td>Otway</td>
<td>Australia</td>
<td>Pilot</td>
<td>CO₂CRC</td>
<td>Planned late 2005</td>
<td>160 t/d for 2 years</td>
<td>100kt</td>
<td>Saline formation and depleted gas field</td>
</tr>
<tr>
<td>Teapot Dome</td>
<td>USA</td>
<td>Proposed Demo</td>
<td>RMOTC</td>
<td>Proposed 2006</td>
<td>170 t/d for 3 months</td>
<td>10kt</td>
<td>Saline formation for CO₂ – EOR</td>
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<tr>
<td>CSEMP</td>
<td>Canada</td>
<td>Pilot</td>
<td>Suncor Energy</td>
<td>2005</td>
<td>50</td>
<td>10kt</td>
<td>CO₂ – ECBM</td>
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<tr>
<td>Pembina</td>
<td>Canada</td>
<td>Pilot</td>
<td>Penn West</td>
<td>2005</td>
<td>50</td>
<td>50kt</td>
<td>CO₂ - EOR</td>
</tr>
</tbody>
</table>
4. CO₂ Storage Options

4.1. Abandoned Oil and Gas Fields
Depleted oil and gas fields have demonstrated containment integrity characteristics and should be primarily considered for the storage of CO₂. The geological structure and physical properties of most oil and gas fields tend to be extensively characterised and studied. Depleted fields should not be adversely affected by the storage of CO₂ and might in certain circumstances increase the production of oil and gas through enhanced oil recovery (EOR). The storage capacity of reservoirs will be limited by the need to avoid excessive pressures that can damage the caprock. Storage at depths less than 800m may be both technically and economically feasible, but the low storage capacity of shallow reservoirs where CO₂ is in its gaseous state could be problematic.

4.1.1. In-Salah CO₂ Storage Project – Algeria
The In-Salah project is the world’s first large-scale project for the storage of CO₂ in a gas reservoir. Situated in Algeria’s central Saharan region, it is a joint venture between Sonatrach, BP and Statoil. The Krechba Field at In-Salah produces up to 10% CO₂ in natural gas stream from several geological reservoirs. This project comprises the re-injecting of CO₂ into a sandstone reservoir at a depth of 1800m, with an annual 1.2Mt/yr CO₂ storage capacity. The injection of CO₂ commenced in April 2004 and the total estimated storage capacity is 17MtCO₂. The project consists of 4 production and 3 injection wells.

The Krechba Field is a relatively simple anticline. CO₂ injection occurs down-dip from the gas/water contact in the gas-bearing reservoir. After depletion of the gas zone, the injected CO₂ is expected to eventually migrate into the area of the current gas field. Preliminary risk assessments of the CO₂ storage and integrity have been performed and baseline data acquired. Processes that can lead to CO₂ migration have been quantified and a monitoring programme planned. This involves noble gas tracers, pressure surveys, tomography, gravity baseline studies, microbiological studies, four-dimensional seismic and geomechanical monitoring.

4.2. Enhanced Oil Recovery (EOR)
EOR provides the potential to increase the oil production from existing wells. Though not designed for CO₂ storage, CO₂ – EOR projects can demonstrate associated storage of CO₂. Typically 5–40% of the contents of an oil deposit are recovered through conventional primary production methods, and 10–20% can be recovered by secondary recovery methods using water flooding. CO₂ injection can be used for tertiary or enhanced oil recovery to give an incremental increase of 7-23% in oil production.

The recovery of oil by injection of CO₂ relies on the phase behaviour of CO₂ and crude oil mixtures, which are strongly dependent on reservoir temperature, pressure and crude oil composition. Mechanisms include oil swelling and viscosity reduction for injection of miscible fluids at low pressure and, complete miscible displacement in high-pressure applications. 50–67% of the injected CO₂ is recovered with the oil, which after separation is usually re-injected to minimise operating costs. The remaining 40% is trapped in the oil reservoir.

The USA has approximately 73 CO₂ - EOR operations that inject up to 30MtCO₂/yr. The SACROC project in Texas was the first large-scale commercial CO₂ – EOR project in the world. EnCan has established a CO₂ - EOR project at the Weyburn Oil Field in Southern Saskatchewan, Canada.
4.2.1. Weyburn CO2 - EOR Project (Canada)
The Weyburn CO2 – EOR project commenced operation in late 2000 and is located in the Williston Basin. This is a geological structure extending from south-central Canada into North-central USA. The CO2 source is the Dakota Gasification Company facility located ~325km south of Weyburn in Beulah, North Dakota. Coal is gasified at the plant to make synthesis gas (methane). The high purity CO2 by-product is dehydrated, compressed and piped to Weyburn which takes delivery of 3000 – 5000 t/d CO2 from the pipeline for 15 years.

The Weyburn field covers an area of 180km² and is expected to store 20Mt CO2. The oilfield layout and operation is relatively conventional and currently produces 1600m³/day of incremental oil from the field. Approximately 100 tCO2/d is recycled, captured, recompressed and re-injected into the production zone. Current estimates indicate 20Mt CO2 will eventually be stored in the field. Potential leakages are monitored using high-resolution seismic surveys and surface monitoring. These include the sampling and analysis of potable groundwater and soil gas sampling. No indication of CO2 leakage to the surface and near-surface environment has been detected.

4.2.2. Rangely CO2 – EOR Project. Colorado (USA)
Operated by Chevron, the Rangely CO2 – EOR project is located in Colorado (USA). CO2 from Exxon-Mobil’s LaBarge natural gas processing facility in Wyoming is transported 283 km by pipelines to the Rangely field. Additional spurs transport CO2 to the Lost Soldier and Wertz fields in central Wyoming and end at the Salt Creek field in eastern Wyoming.

Since 1986, CO2 has been used to flood the sandstone reservoir at Rangely field by the Alternative Water Gas (WAG) process. This should yield an additional 21million m³ of oil (6.8% of original oil). Approximately 3MtCO2 were injected in 2003 which facilitate 13,913 barrels/day additional oil recovery. The total cumulative CO2 stored is 22.2 MtCO2.

Compliance is maintained with the appropriate regulations which govern production, injection, protection of potable water formations, surface use, flaring and venting. Surface release from the storage reservoir is below the detection limit of 170 t/yr (<0.00076% of total stored CO2). The estimated annual methane leakage rate of 400t/yr could be associated with the increased CO2 injection pressure which is above the original reservoir pressure. Water chemistry studies have indicated that the injected CO2 is dissolving in the water and may be responsible for dissolution of ferroan calcite and dolomite.

CO2 - EOR is also under consideration for the North Sea, though there is little operational experience of offshore CO2 - EOR. In addition to commercial storage EOR projects, a number of pilot storage projects are under way or planned. The Frio Brine Project in Texas – USA involves the injection and storage of 1900 tCO2 in a highly permeable formation with a regionally extensive shale seal. Pilot projects are also proposed for Ketzin (Germany), Otway Basin (SE Australia) and Teapot Dome (Wyoming – USA). A small-scale CO2 injection and monitoring project is being carried out by RITE at Nagasaki (Japan) and the proposed FutureGen project in the USA is a geological storage project linked to coal-fired electricity generation.

4.3. Enhanced Gas Recovery (EGR)
The technical and economic advantages of enhanced gas recovery have not been commercially demonstrated; the only project being implemented on a pilot scale. The
additional recovered gas will be limited as up to 90% of the original gas can be extracted through conventional methods.

4.4. Aquifers and Saline formations
Saline formations are widespread and comprise deep sedimentary rocks saturated with very large formation of waters or brines with high concentrations of dissolved salts that are unsuitable for agriculture or human consumption. The Sleipner project in the North Sea is the best example of CO₂ storage in a saline formation. In the Sleipner project, CO₂ is injected into poorly cemented sands at 800 – 1000m below the sea floor. The sandstone contains secondary thin shale and clay layers which influence the internal movement of the injected CO₂. The overlying primary seal is composed of an extensive thick shale or clay layer.

4.4.1. Sleipner Project – North Sea
The Sleipner project is the world’s first commercial-scale project to geologically store CO₂ in a saline formation. Operated by Statoil in the North Sea and located 250km off the Norwegian coast, it commenced operation in 1996 as a research project to monitor and research the storage of CO₂. The gas stream from the Sleipner West Gas Field contains approximately 9% CO₂ which is separated and injected into a large deep saline formation sited 800m below the seabed in the North Sea. 1 MtCO₂ is sequestered annually which equates to ~2700t/day. The total storage capacity over the project duration is estimated at 20Mt CO₂.

Seismic time-lapse surveys have been used to determine the status and transport of the CO₂ plume within the storage formation. These surveys have shown the caprock to be an effective sealant preventing the CO₂ migration out of the storage formation. Reservoir studies and computer simulations have determined that the CO₂ will eventually dissolve in the pore water, which will become heavier and sink - thereby minimise the risk of long-term leakage.

4.5. CO₂ - ECBM: Enhanced Coal Bed Methane
CO₂ can be injected into coal seams to enhance the recovery of methane gas from 50% using conventional reservoir-pressure depletion technique to 90% with CO₂ injection. Besides the Allison Unit CO₂ – ECBM pilot project in New Mexico, no commercial projects are currently in operation.

4.5.1. Allison Unit CO₂ – ECBM Pilot Project
The Allison Unit CO₂ – ECBM pilot project is sited in the San Juan Basin - New Mexico. Owned and operated by Burlington Resources, production from the Allison field commenced in July 1989. The injection of CO₂ for ECBM recovery commenced in April 1995, and the project was suspended in August 2001 to evaluate the results of the pilot.

McElmo Dome in Colorado provides the CO₂ which is delivered to site through the Kinder-Morgan (formally Shell) pipeline. 181 million m³ of CO₂ has been injected into the reservoir over a six year period. This pilot project consists of 16 methane production wells, 4 CO₂ injection wells and 1 pressure observation well.

The reservoir thickness is 13m and located at a depth of 950m, the original reservoir pressure was 115bar. Significant reductions in coal permeability have been experienced as a result of CO₂ injection, the estimated methane recovery has increased from 77 to 95%. The CO₂ injection to methane recovery ratio of 3:1 has contributed to proving this project uneconomical.
Besides Allison Unit, a further 59 CO₂ - ECBM opportunities have been identified worldwide. The majority are in China with projects under further consideration in Canada, Italy and Poland.

5. The Legality of Geological CO₂ Storage

General principles of international law allow States to engage in onshore and offshore CO₂ storage activities in regions within their jurisdiction and where they exercise sovereignty.

A number of global and regional environmental treaties exist which can be interpreted as being relevant to the applicability and permissibility of CO₂ storage, particularly offshore geological storage. These are summarised in Table 2 (IPCC 2005).

<table>
<thead>
<tr>
<th>Treaty</th>
<th>Adoption (Signature)</th>
<th>Entry Date</th>
<th>No. of Parties/Ratification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Convention on Climate Change</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kyoto Protocol</td>
<td>1997</td>
<td>2005</td>
<td>132</td>
</tr>
<tr>
<td>the Law of the Sea</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>London Convention</td>
<td>1972</td>
<td>1975</td>
<td>80</td>
</tr>
<tr>
<td>London Protocol</td>
<td>1996</td>
<td>-</td>
<td>20</td>
</tr>
<tr>
<td>of the Marine Environment of the</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North-East Atlantic</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

These treaties were not drafted to facilitate the geological storage of CO₂, but to prohibit marine dumping. When interpreting these treaties it is important to consider:

- Whether storage of CO₂ is considered ‘dumping’ if it is for purposes other than the ‘mere disposal of’
- Is CO₂ storage exempt from wastes arising from the normal operations of offshore installations, their discharges and emissions
- Is CO₂ storage in the seabed explicitly covered in the treaties
- Is CO₂ an ‘industrial waste’ or ‘hazardous waste’ and does the CO₂ storage process constitute ‘pollution’
- Is the CO₂ transportation and storage infrastructure considered to be a disposal site

6. Economics of CO₂ Storage

The costs involved in the geological storage of CO₂ will be site specific, which can lead to a high degree of variability. Costs are dependent on:

- storage option selected
- location (on or offshore),
• depth and characteristics of the storage reservoir formation
• economic benefits from the upside recovery of additional hydrocarbon resources.

For onshore locations, the costs depend upon the location and terrain. Offshore costs tend to be higher which reflects the requirements of platforms or sub-sea facilities and higher operating costs.

Table 3 (IPCC 2005) summarises the CO\(_2\) storage cost estimates for the United States, Australia and Europe. These estimates include capital, operating and site characterisation costs. Monitoring, remediation and other additional costs required to address long-term liabilities have been omitted. The CO\(_2\) storage costs for the Sleipner and Snøhvit projects are illustrated in Table 4 (IPCC 2005).

<table>
<thead>
<tr>
<th>Options</th>
<th>Storage Type</th>
<th>Location</th>
<th>Low</th>
<th>Mid</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Saline formation Onshore</td>
<td>Australia</td>
<td>0.2</td>
<td>0.4</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Saline formation Onshore</td>
<td>Europe</td>
<td>1.5</td>
<td>2.2</td>
<td>4.9</td>
<td></td>
</tr>
<tr>
<td>Saline formation Onshore</td>
<td>USA</td>
<td>0.3</td>
<td>0.4</td>
<td>3.5</td>
<td></td>
</tr>
<tr>
<td>Saline formation Offshore</td>
<td>Australia</td>
<td>0.4</td>
<td>2.7</td>
<td>23.7</td>
<td></td>
</tr>
<tr>
<td>Saline formation Offshore</td>
<td>N. Sea</td>
<td>3.7</td>
<td>6.0</td>
<td>9.4</td>
<td></td>
</tr>
<tr>
<td>Depleted oil field Onshore</td>
<td>USA</td>
<td>0.4</td>
<td>1.0</td>
<td>3.1</td>
<td></td>
</tr>
<tr>
<td>Depleted gas field Onshore</td>
<td>USA</td>
<td>0.4</td>
<td>1.9</td>
<td>9.6</td>
<td></td>
</tr>
<tr>
<td>Disused oil or gas field Onshore</td>
<td>Europe</td>
<td>0.9</td>
<td>1.3</td>
<td>3.0</td>
<td></td>
</tr>
<tr>
<td>Disused oil or gas field Offshore</td>
<td>N. Sea</td>
<td>3.0</td>
<td>4.7</td>
<td>6.4</td>
<td></td>
</tr>
</tbody>
</table>

Table 4. Investment costs for Sleipner and Snøhvit projects

<table>
<thead>
<tr>
<th>Project Variable</th>
<th>Units</th>
<th>Sleipner</th>
<th>Snøhvit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Country</td>
<td></td>
<td>Norway</td>
<td>Norway</td>
</tr>
<tr>
<td>Commencement Year</td>
<td>Year</td>
<td>1996</td>
<td>2006</td>
</tr>
<tr>
<td>Storage Type</td>
<td></td>
<td>Aquifer</td>
<td>Aquifer</td>
</tr>
<tr>
<td>Annual CO(_2) Injection Rate</td>
<td>MtCO(_2)/yr</td>
<td>1</td>
<td>0.7</td>
</tr>
<tr>
<td>Location</td>
<td></td>
<td>Offshore</td>
<td>Offshore</td>
</tr>
<tr>
<td>Number of wells</td>
<td></td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Pipeline length</td>
<td>km</td>
<td>0</td>
<td>160</td>
</tr>
<tr>
<td>Capital Cost</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capture and Transportation</td>
<td>€m</td>
<td>61.9</td>
<td>112.1</td>
</tr>
<tr>
<td>Compression and Dehydration</td>
<td>€m</td>
<td>61.9</td>
<td>54.9</td>
</tr>
<tr>
<td>Pipeline</td>
<td>€m</td>
<td>0</td>
<td>57.2</td>
</tr>
<tr>
<td>Storage</td>
<td>€m</td>
<td>11.7</td>
<td>37.6</td>
</tr>
<tr>
<td>Drilling and well completion</td>
<td>€m</td>
<td>11.7</td>
<td>19.6</td>
</tr>
<tr>
<td>Facilities</td>
<td>€m</td>
<td>-</td>
<td>9.4</td>
</tr>
<tr>
<td>Other</td>
<td>€m</td>
<td>-</td>
<td>8.6</td>
</tr>
</tbody>
</table>

Personnel requirements to operate the CO\(_2\) monitoring, transportation and storage facility will be site specific and must be determined on a project-by-project basis. Factors influence required personnel include:

- Technology selected for the capture of CO\(_2\)
- Quantity of CO\(_2\) captured from the power station
- Operating regime of the power plant: continuous base-load or peaking
- Requirements of intermediate on-site storage facility
- Location of power plant: coastal site or inland. A coastal site might favour transportation by ship, even for distances normally considered uneconomical for ship based transportation and favouring pipeline
- Distribution of responsibilities for power generation and CO₂ transportation
- Selected technology to ‘Condition the CO₂ for transportation’
- Selected method of transportation: pipeline or ship
- End use of CO₂: EOR or immediate storage
- Is the storage site sited on the coast or will their be requirements for intermediate pipeline runs from the off-loading site to the storage site
- Is the storage site an existing operational oil and gas facility

For ship based transportation of CO₂, the transportation vessel operators should be able to transfer the CO₂ from the on-shore storage tanks using their personnel, onboard pumps and transfer lines. Similarly they should be able to supervise the off-loading of CO₂. The supervision of CO₂ storage at the storage site may be performed by the storage facility operators.

7. Assessment of the Potential for Geological Storage of CO₂ in Greece

Greece’s primary sources of CO₂ emissions are onshore in the regions of the lignite power stations in Kozani (Ptolemais area) with 22.5Mt/yr CO₂ and Peloponnnesus (5Mt/yr CO₂). In the big city regions of Athens and Thesaloniki, the annual CO₂ emissions are approximated at 5Mt/yr and 1.6Mt/yr respectively.

The GESTCO project identified the Thessaloniki basin and the Mesohellenic trough as regions potentially suitable for the storage of CO₂. The geological storage types considered in detail in the GESTCO study are:

1. Coal deposits and abandoned mines
2. Oil and gas reserves
3. Saline aquifers

These Tertiary sedimentary rocks formations contain coal deposits, hydrocarbon fields and geothermal fields. The CO₂ storage potential of the following reservoirs was evaluated:

1. The Prinos oil field which will be available for alternative uses following exhaustion
2. The nearly exhausted South Kavala gas fields
3. The Prinos Miocene sedimentary basin deep saline aquifer
4. The deep aquifer in west Thessaloniki molasse type sedimentary rocks
5. Mesohellenic molasses type sediments filling the Mesohellenic basin

Geothermal fields were omitted from this evaluation. Greece’s low enthalpy geothermal fields occur at shallow depths of (<800m) and contain inherent CO₂, which would have to be separated from the geothermal fluid before storage.

Greece’s Tertiary coal basins are very well developed. The existing lignite and peat deposits are large, the main lignite coal deposits are onshore and at a shallow depth of <800m with severely faulted seams. Existing data indicate to very low CO₂ storage potential in these rock formations. Lack of comprehensive and sufficiently reliable data on the thickness, distribution and potential reserves of lignite and hydrocarbon reserves in the offshore tertiary rock formations did not permit GESTCO to conduct a reliable
assessment of the CO₂ storage potential in these geological formations to be conducted.

7.1. Potential for CO₂ Storage in Abandoned Coal Mines

Utilising data obtained from the Ministry of Development of the Public Power Corporation (PPC) and the Greek Institute of Geology and Mineral Exploration (IGME), GESTCO evaluated the potential for CO₂ sequestration in abandoned coal mines. This data identified 27 abandoned underground mines; 25 lignite and 2 ore mines. Most of these mines ceased operation in the 1950s. The Aliverion mine in the Euboea region was operational until the 1980s.

Of the identified 25 lignite mines, except for the Kimi and Aliverion mines, the remaining have insufficient storage capacity and have suffered from roof collapse which has consumed the empty volume. Aliverion is <800m below the surface, its shallow depth render it unsuitable for CO₂ storage. The 2 identified ore mines, the chromite mine in Skoumtsa and the large sulphide deposit in Ermiion were considered unsuitable for CO₂ storage. No salt mines were identified except for a deposit in the Epirus region in western Greece.

7.2. Potential for CO₂ Storage in Hydrocarbon Deposits

Greece has 4 known oil and gas fields as illustrated in Table 5 (IGME 2003), Prinos, South Kavala, Katakolo and Epanomi. As of 1st January 2003, only Prinos was producing significant quantities of oil, the South Kavala gas field is almost exhausted. The combined potential for CO₂ sequestration is estimated at 26.2Mt/CO₂.

<table>
<thead>
<tr>
<th>Field Name</th>
<th>Deposit</th>
<th>Storage Potential CO₂ (M tonnes)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prinos</td>
<td>Oil</td>
<td>17</td>
</tr>
<tr>
<td>S. Kavala</td>
<td>Gas</td>
<td>4</td>
</tr>
<tr>
<td>Katakola</td>
<td>Oil</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Gas</td>
<td>1.2</td>
</tr>
<tr>
<td>Epanomi</td>
<td>Gas</td>
<td>2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>26.2</strong></td>
</tr>
</tbody>
</table>

The Prinos oil and South Kavala gas fields have been operational since the 1980s. The Prinos fields lie approximately 6km northwest of Thassos Island in the North Agean Sea. The South Kavala gas field covers a 5km² area and is sited 25km south of Kavala city. The original reservoir pressure was 320bar and declined to 62bar in 1994. Prinos oil field is still in production but at a declining rate.

Prinos oil and South Kavala reservoirs are >2000m below sea level and are suitable for the storage of CO₂ at supercritical conditions. The CO₂ storage potential in the South Kavala gas field is 4Mt; sufficient for the storage of small CO₂ sources for more than 20 years. Prinos has sufficient storage potential (17MtCO₂) for the storage of CO₂ from the Komotini gas fired power station (0.7Mt/yr CO₂) for 25 years. Both these fields have the existing infrastructure of pipelines, wells and platforms necessary for CO₂ transportation and injection and are located within 30-40km of the coast. The Prinos oil field lends itself well for CO₂ injection for Enhanced Oil Recovery. The South Kavala gas field has been thought of as a potential natural gas storage facility by the Public Natural Gas Company (DEPA). Both these sites require seismic studies to evaluate the safety aspects of CO₂ storage and leakage.
The Epanomi gas field is located close to Thessaloniki city. Its low gas reserve and inherent 22.6% CO\textsubscript{2} concentration render this field uneconomical. The reservoir is close to a big CO\textsubscript{2} emission source but the low porosity and low permeability make this field unsuitable for CO\textsubscript{2} storage.

The West Katakolon oil field is located in the Katakolon area (NW Peloponnesus) and is too small for CO\textsubscript{2} sequestration. There are no significant CO\textsubscript{2} emission sources within 100km of this field.

### 7.3. CO\textsubscript{2} Storage in Aquifers

Table 6 (IGME 2003) lists potential aquifers assessed by GESTCO for the suitability of CO\textsubscript{2} storage in Greece. The criteria applied in their identification were:

- Proximity to the major sources of CO\textsubscript{2}
- Availability of data to perform assessment
- Sufficient aquifer depth for the storage of CO\textsubscript{2}
- Reservoir characteristics suitable for CO\textsubscript{2} storage

The identified aquifers are in the North Aegean region and exclude hydrocarbon fields. These are:

1. Offshore Prinos aquifer
2. Thessaloniki onshore aquifer
3. Mesohellenic trough aquifer

#### Table 6. CO\textsubscript{2} storage potential in North Aegean Aquifers

<table>
<thead>
<tr>
<th>Position</th>
<th>Prinos</th>
<th>W. Thessaloniki</th>
<th>W. Thessaloniki Sandstone</th>
<th>Alexandria</th>
<th>Mesohellenic Basin</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth to top Of aquifer (m)</td>
<td>2400</td>
<td>1200 – 2200</td>
<td>2400</td>
<td>900</td>
<td>1000</td>
</tr>
<tr>
<td>Area (km\textsuperscript{2})</td>
<td>800</td>
<td>1700</td>
<td>1700</td>
<td>70</td>
<td>-</td>
</tr>
<tr>
<td>Av. Thickness (m)</td>
<td>260</td>
<td>100</td>
<td>21</td>
<td>180</td>
<td>-</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>18</td>
<td>10</td>
<td>10</td>
<td>8</td>
<td>10</td>
</tr>
<tr>
<td>Pore Volume (km\textsuperscript{3})</td>
<td>29.95</td>
<td>10.20</td>
<td>3.21</td>
<td>0.76</td>
<td>4.8</td>
</tr>
<tr>
<td>Storage Capacity (Mt/CO\textsubscript{2})</td>
<td>1350</td>
<td>460</td>
<td>145</td>
<td>35</td>
<td>210</td>
</tr>
<tr>
<td>Hydrocarbon field in basin</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Top Seal Quality</td>
<td>v. good</td>
<td>v. good</td>
<td>v. good</td>
<td>Good</td>
<td>good</td>
</tr>
<tr>
<td>CO\textsubscript{2} leakage concern</td>
<td>low</td>
<td>low</td>
<td>low</td>
<td>-</td>
<td>Yes</td>
</tr>
<tr>
<td>Mineralogy</td>
<td>fair</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>good</td>
</tr>
</tbody>
</table>

Prinos basin has satisfactory geology: porosity, permeability, depth, fair mineralogy and a very good top seal which can cap and seal CO\textsubscript{2} after injection. The storage capacity of the W. Thessaloniki basin is estimated at 460MtCO\textsubscript{2}. The sandstone reservoir has satisfactory porosity, low permeability, high depth and a very good top seal; it is considered a good CO\textsubscript{2} storage reservoir with remote possibilities of leakage. Similarly, the W. Thessaloniki sandstone basin has an estimated CO\textsubscript{2} storage capacity of 145MtCO\textsubscript{2}. The sandstone has satisfactory porosity, low permeability, high depth and a
very good top seal. It too is considered a good CO\textsubscript{2} storage reservoir with remote possibilities of leakage. Alexandria basin has a CO\textsubscript{2} storage capacity of \(\approx 35\text{MtCO}_2\). The thick overlying clay sedimentary rocks and the green clay should provide a good seal and the basin’s permeability is relatively low.

The Mesohellenic trough is estimated to contain 2 formations suitable for CO\textsubscript{2} storage; the Eptahorion and the Pentalofon formations. Total storage capacity is conservatively estimated at 216MtCO\textsubscript{2}. The quality of storage is fair and may present a danger for CO\textsubscript{2} leakage.

### 7.4. Security of CO\textsubscript{2} Storage

To allay public concerns regarding the storage of CO\textsubscript{2}, selected sites must be demonstrated to be safe from leakage. Greece is known to be one of the most seismically active countries in Europe. The oil and gas reserves of Prinos and S. Kavala and the aquifers of Thessaloniki and Mesohellenic are located in areas with a small number of recorded earth quakes. The Katakolen oil field is in an area of considerable seismic activity and is therefore not considered suitable for CO\textsubscript{2} storage. Other natural and environmental hazards will require a similar evaluation before reaching a final decision on their appropriateness.

### 8. References


Wong, S., ‘CO\textsubscript{2} Compression and Transportation to Storage Reservoir’, Asia-Pacific Economic Cooperation – Building Capacity for CO\textsubscript{2} Capture and Storage in the APEC Region.
