POTENTIAL IMPLICATIONS ON GAS PRODUCTION FROM SHALES AND COALS FOR GEOLOGICAL STORAGE OF CO_2

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Advanced Resources International

The principal researchers were:

- Mike Godec, ARI

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- John Gale, IEAGHG
- Stefan Bachu, Alberta Innovates – Technology Futures

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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

POTENTIAL IMPLICATIONS OF GAS PRODUCTION FROM SHALES AND COAL FOR CO_2 GEOLOGICAL STORAGE

Key Messages

- Exploitation of gas from both shale and coal will leave the formations with increased permeability and injectivity and therefore with increased potential to store CO_2.
- Large scale demonstration has yet to take place to confirm CO_2 storage capability and capacity for both shale and coal. Though demonstration projects are more advanced for coal with several small scale projects injecting CO_2 into wet coal seams (where there have been some injectivity problems related to coal swelling) and one project into an already dewatered coal seam.
- Overlap between potential shale gas exploration and potential storage reservoirs in deep saline formations may be considerable geographically, but much less so in 3D. Therefore use of both resources should be possible if well managed, though this will need considered on a case by case basis.
- There are still some uncertainties regarding CO_2 storage in shale and coal, and knowledge gaps where further research is needed have been identified as part of this study.

Background to the Study

Production of natural gas from both shale formations and coal deposits is rapidly developing as a major energy supply option in regions including North America, Europe and Australasia. Significant exploitation of these resources could affect CO_2 geological storage potential.

Coal deposits have long been regarded as a potential CO_2 storage option, in association with coal bed methane (CBM) production. Coal deposits used for enhanced coalbed methane (ECBM) are typically those that are too deep or too thin to be currently economically mined.

All coal deposits have varying amounts of methane adsorbed onto the pore surfaces. The methane may initially be recovered through dewatering and depressurisation i.e. as coal bed methane (CBM). Additional recovery and/or storage can then take place by injection of CO_2 into the formation. The CO_2 can be preferentially adsorbed onto the surface of the coal, thereby trapping the CO_2 in the coal deposit or trapped in the coals cleat system. As it is now likely that additional recovery/storage operations using CO_2 will take place after the initial dewatering and depressurisation, the integrity of the coal seam will need to be considered and whether it is still a receptor for CO_2. This approach to coal seam CO_2 storage may also overcome the injectivity problems encountered with the pilot CO_2-ECBM projects. The cost of storage of CO_2 may be offset by the production of methane. However this approach to coal seam storage is new and it is not known whether the CBM production process leaves behind a reservoir that is suitable for CO_2 storage.

Shale formations constitute the most common, low-permeability caprocks that could prevent migration of buoyant CO_2 from underlying storage units, particularly deep saline aquifers.

Organic-rich shales may also form potential storage units for CO_2 based on trapping through adsorption on organic material (similar to coals), although this has not been demonstrated on a field scale. Lately, oil and gas companies combined horizontal drilling and rock fracturing technologies to produce oil and gas from shales, particularly in North America. Whilst these technologies open up the possibility of using shale formations as actual storage media for CO_2 by increasing permeability and injectivity, the same technology may compromise the integrity of shale caprocks in some basins.

Advanced Resources International (ARI), a company based in the USA was commissioned by IEAGHG to undertake this study.

Scope of Work

The main aims of the study are to assess the global potential for geological storage of CO_2 in shale and coal formations and the impact of gas production from shales on CO_2 storage capacity in underlying deep saline aquifers by compromising caprock integrity. The study would comprise a comprehensive literature review to provide guidance on the following issues:

- Global status of hydrocarbon production from shales and CBM and potential effects on CO_2 storage both in the producing shales/ coals themselves and underlying hydrocarbon reservoirs and/or deep saline formations. The focus should be on gas production, but with reference to oil production from shales;
- Current status of research into geological storage of CO_2 in shales and coals;
- Potential nature and rate of trapping processes; mechanisms of storing CO_2.
- CO_2 injectivity into shales and coals, with reference to fracturing practices employed by industry;
- Containment issues arising from shale fracturing, both for shales as a storage medium per se, and in terms of caprock integrity for underlying storage units, particularly deep saline aquifers;
- Methods for assessing storage capacities for CO_2 storage in shales and coals;
- High level mapping and assessment of theoretical/effective capacities;
- Potential economic implications of CO_2 storage in shales and coals.

The contractor was asked to refer to the following recent and ongoing 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:

- Brine Displacement and Pressurisation (Permedia, Report 2010/15)
- Caprocks for Geological Storage (CO2CRC, 2011/01)
- Injection Strategies for CO_2 Storage Sites (CO2CRC, Report 2010/04)
- Impacts on Groundwater Resources (CO_2GeoNet, 2011/11)
- Resource Interactions for CO_2 Storage (CO2CRC, 2013/08)

Findings of the Study

CO_2 Storage in Shale and Coal

Coal seams often contain gases such as methane, held in pores on the surface of the coal and in fractures in the seams. Conventional coal bed methane (CBM) extraction is achieved by dewatering and reducing the pressure in the coal seam, such that adsorbed methane is released from the porous coal surface. However, conventional CBM extraction may leave up to 50% of the methane in the seam after development and production operations have been completed. As much as another 20% could potentially be recovered through the application of CO_2-ECBM. The fact that some CBM is high in CO_2 content shows that, at least in some instances, CO_2 can safely remain stored in coal for geologically significant time periods

Gas shales can also adsorb CO_2, possibly also making shale formations significant targets for CO_2 storage. The process of enhancing the recovery of methane and the storage of CO_2 in shales could occur by the same basic mechanism as that for coal, and the organic matter in gas shales has large surface areas similar to that found in coal. These shales may also form potential storage units for CO_2 based on trapping through adsorption on organic material, as well as with the natural fractures within the shales.

Both shale and coal therefore can theoretically geologically trap CO_2 securely, though the extent of its effectiveness is still being assessed. Finally, deep coal seams and gas shales are widespread and, especially in the case of coal seams, exist in many of the same areas as large, coal-fired, electric power generation facilities.

The same advances that are allowing the potential of shale gas resources to be economically developed -- horizontal drilling and hydraulic fracturing -- open up the possibility of using shale and coal formations as actual storage media for CO_2 by increasing permeability and injectivity.

Methane Production from Coal and Shale

In coal seams, methane desorbs from the micropores of the coal matrix when the hydrostatic pressure is reduced, such as from the drilling of a well, and flows through the cleats to a wellbore. Coal seams are often shallow, and sometimes coexist with surface aquifers, while shale and tight gas are more often found at greater depths.

Coal bed methane reservoirs generally have a higher concentration of gas than shale reservoirs, generally because the organic content of coals is typically higher than that of shales. Shale reservoirs nearly always need to be hydraulically fractured, while perhaps only half of coal seam gas reservoirs require such fracture stimulation.

There are three main methods which can induce methane release from coal formations:

- Reduce the overall pressure, usually by dewatering the formation, generally through pumping

- Reduce the partial pressure of the methane by injecting another inert gas into the formation
- Replace the methane on the surface of the organic material with another gas, such as CO_2.

Dewatering and reservoir pressure depletion is a simple but relatively inefficient process, recovering less than 50% of the gas in place. Lowering the hydrostatic pressure in the coal seam accelerates the desorption process. Once dewatering has taken place and the pressure has been reduced, the released methane can be produced. CBM wells initially primarily produce water; then gas production eventually increases, while water production declines. Some wells do not produce any water and begin producing gas immediately, depending on the nature of the fracture system. Once the gas is released, it is usually free of impurities; and can be easily prepared for pipeline delivery. Some coals may never produce methane if the hydrostatic pressure cannot be efficiently lowered.

Hydraulic fracturing or other permeability enhancement methods are used to assist recovery but, even so, because permeability is normally low, many wells at relatively close spacing must be drilled to achieve an economic gas flow.

Coal bed methane production potential is determined by a number of factors that vary from basin to basin, and include: fracture permeability, development history, gas migration, coal maturation, coal distribution, geological structure, well completion options, hydrostatic pressure, and produced water management. In most areas, naturally developed fracture networks are the most sought after areas for CBM development. Areas where geological structures and localised faulting have occurred tend to induce natural fracturing, which increases production pathways within the coal seam.

As part of the general process for development and producing methane from coal seams, a steel-encased hole is drilled into the coal seam, anywhere from 100 to 1,500 meters below the surface, and sometimes even deeper. Methane from unmined coal seams is recovered through drainage systems constructed by drilling a series of such vertical or horizontal wells directly into the seam. Then the gas is sent to a compressor station and into natural gas pipelines. The produced water is separated and reinjected into isolated formations, treated and released into streams, used for irrigation, or sent to evaporation ponds. Once water is produced from the coal seam, it does not usually tend to refill with water (which becomes relevant if CO_2 is later injected into the coal seam to enhance recovery and be permanently stored). The choice of vertical or horizontal wells is dependent on the geology of the coal seam, in particular, the type of coal in the basin and fluid content. Each type of coal (sub-bituminous to bituminous) offers production options that are different due to the inherent natural fracturing and competency of the coal seams. The sub-bituminous coals are softer and less competent than the higher rank, low-volatile bituminous coals, and therefore are typically completed and produced using more conventional vertical well bores. The more competent higher rank coals lend themselves to completions using horizontal or vertical wells.

Production from shale gas proceeds in a similar fashion; though, with few exceptions, shales do not have to be dewatered to allow gas desorption to occur. Also, in general, shale formations are often too deep and of such low permeability to facilitate economic production using just vertical, simple fractured wells.

Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) increases in natural gas prices. Although known for decades, what "changed the game" was the recognition that one could "create a permeable reservoir" by using intensively stimulated horizontal wells.

Experience to date has shown that each gas shale basin is different and each has a unique set of development criteria and operational challenges. Because of these differences, the most effective development approaches and well drilling and completion strategies for a particular basin tend to evolve over time.

Injectivity Issues

During primary methane production, reservoir compaction due to pressure depletion will occur, which causes an increase in the effective horizontal stress as the reservoir is confined laterally. Gas desorption from the coal matrix will also occur resulting in coal matrix shrinkage, and thus a reduction in the horizontal stress and an increase in cleat permeability.

During ECBM/CO_2 storage in coal, adsorption of CO_2, which has a greater sorption capacity than methane, causes matrix swelling and in contrast to gas desorption, could potentially have a detrimental impact on cleat permeability of coal. Swelling of coal in the presence of CO_2 can reduce the permeability of coal seams, thus affecting the viability of ECBM or CO_2 storage operations.

Early research suggested that matrix shrinkage/swelling was proportional to the volume of gas desorbed/adsorbed, rather than change in sorption pressure. Laboratory studies and field tests on the impact of matrix swelling on coal permeability have confirmed these results. However, such results were not consistently the case. Other factors that could affect the CO_2 injectivity in coal bed reservoirs are thermal effect of CO_2 injection, wellbore effects and precipitate formation.

To alleviate the impact of matrix swelling on injectivity, horizontal well configurations can be used. Numerical simulations have shown increased capacity for Northern Appalachian coals. Horizontal wells can also be designed to take advantage of the orientation of natural fractures in the rock. Well injectivity could also be increased using a CO_2-alternating-N_2 injection strategy. The optimum gas mixtures depend on whether CO_2 storage or methane recovery is the primary objective, operational constraints and economics associated with gas treatment.

Similar issues are expected regarding CO_2 injection in shale's; however research to date is not sufficiently advanced to confirm this.

CO_2 Storage Integrity

The practice of testing seal integrity is not routinely performed as part of CBM production projects, but will be critical in determining the viability of a coal seam as a CO_2 storage site. A recent study considering processes leading to risks of developing leakage pathways include insufficient CO_2-Coal contact volume due to coal bed heterogeneity; injectivity loss due to coal swelling; leakage through pre-existing faults/ discontinuities and outcrops; CO_2/methane desorption due to potential future water extraction. General conclusions with regard to storage in coal seams are:

- There is a higher risk of leakage for open cavity well completions than cased well completions.
- Coal properties and available technology should minimise the risk that hydraulic fractures, used as part of well completion, will grow beyond the coal layer; though techniques to monitor fracture height need further development and demonstration.
- The processes of depressurisation during dewatering and methane production, followed by repressurisation during CO_2 injection, lead to risks of leakage path formation by failure of the coal and slip and discontinuities in the coal and overburden.
- The most likely mechanism for leakage path formation is slip on pre-existing discontinuities which cut across the coal seam. Sensitivity studies need to be performed to better evaluate this risk.
- Relationships between the amount of slip and the increase in flow (if any) along a discontinuity need to be developed.

Generally higher permeability shales are more suitable for gas production and this has been the current focus in the industry; these would also be potentially suitable for CO_2 storage. Whereas lower permeability shales are not commercial for gas production, but would be good candidates as potential caprocks for CO_2 storage.

It is possible that the production of hydrocarbons from shales may affect seal integrity and hence the potential use for CO_2 storage of formations directly underlying the shale formation may be compromised, however it will not affect other deeper saline formations or hydrocarbon reservoirs at other levels in the sedimentary succession. If a shale formation was thought to be producible for gas after already being used as a caprock for CO_2 storage, it is possible that part of the formation may be produced without affecting the stored CO_2; particularly in laterally extensive formations, though this would have to be evaluated on a site specific basis.

Shale formations are geographically and geologically extensive and most basins in the world containing shale gas resources cover large areas. If overlap does occur between formations targeted for shale gas development and production and formations targeted for CO_2 storage, there will likely still be substantial storage capacity available where overlap does not occur to provide decades of storage capacity at current rates of emissions.

Once a shale formation has been fractured for hydrocarbon production, there remains the possibility of utilising the formation for CO_2 storage. There is also the possibility of using CO_2 to facilitate fracturing, though this may only be possible in certain geological settings. An example is a low pressure reservoir where fracturing liquids can become trapped because the pressure differential is not sufficient to push the liquids back to the wellbore. In some cases, the use of CO_2 for hydraulic fracturing is advantageous because it can be pumped as a liquid and then vaporises to a gas and flows from the reservoir leaving no liquid or chemical damage. The process is best applied in tighter (less permeable), low pressure, dry gas reservoirs where stimulation liquids are foreign to the formation and would reduce its permeability to gas, and also in higher permeability reservoirs where near wellbore formation damage can be removed with this non-damaging process.

RD&D Status of CO_2 Storage in Shale and Coal

As indicated previously the process for CBM extraction is likely to proceed first by conventional means and then secondly by CO_2 injection or CO_2-ECBM to produce additional methane. Research on direct injection of CO_2 into wet coal seams has been undertaken but pilot projects have suffered injectivity problems due to coal swelling around the injection well.

To date there has been only one pilot test of CO_2 injection into an already dewatered coal seam, the CONSOL Marshall County project in the USA. This project is supported under the USDOE's Carbon Storage Programme it commenced in April 2001 and will end in December 2014. A recent status report from the USDOE (May 2013) is included as Annex 1 to the main report of May 2013, approximately 3,265 metric tons of CO_2 have been injected at pressures of up to 6.4 MPa into two thin coal seams (considered to be unmineable because of their depth and thickness) which lie at depths of 375 to 500m. The current injection rate is 5 tons per day and there are plans to increase the injection rate to try and attain an injection rate of 17 tons per day. No breakthrough of CO_2 has been observed in any of the production wells, indicating that CO_2 remains stored in the coal seam. Indications are that the production wells may be showing signs of increased methane production as a result of increased sustained CO_2 injection rates. Clearly this is an important project with regard to the feasibility of CBM production followed by CO_2 Storage. It is also worth noting that unlike other geological storage tests, the target reservoirs are shallow (only 375 to 500m). CO_2 will therefore not be injected as a supercritical fluid. Previous estimates by IEAGHG on the storage potential in coal seams set a limit of 800m as the upper level where CO_2 injection should be considered.

Based on a review of past and ongoing R&D related to CO_2 storage in coals and updated for this study, five key knowledge gaps and technical barriers were identified:

1. A lack of globally disaggregate information on the available storage capacity in deep, unmineable coals
2. A lack of guidelines for establishing location-specific criteria for defining "unmineable coals"

3. A lack of sufficient, widely available geological and reservoir data for defining the favourable settings for injecting and storing CO_2 in coals, particularly the lack of data on deep coal depositional settings and reservoir properties
4. Insufficient understanding of near-term and longer-term interactions between CO_2 and coals and between N_2 and coals, particularly being able to develop site/location specific models of coal swelling (reduction of permeability) in the presence of CO_2 and N_2, coal shrinkage with release of methane (increase in permeability), and the physics of CO_2/methane exchange under actual reservoir conditions of pressure and confinement.
5. Need for formulating and testing alternative reliable, high volume CO_2 and/or N_2 injection strategies and well designs, in multiple reservoir settings. This would help reduce the number of wells required for storing significant volumes of CO_2 from power plants and other industrial sources of CO_2 (and N_2)

Research on the potential for recovering methane and storing CO_2 in gas shales is significantly less advanced than that for coal seams. Reservoir characterisation and reservoir simulation work demonstrate that shales can store CO_2 based on trapping through adsorption on organic material as well as in natural fractures within the shales. Sufficient testing of this concept with site-specific geological and reservoir data and detailed reservoir simulation, verified by field tests, in a variety of gas shale settings is needed.

The key knowledge gaps and technical barriers identified for shales are:

1. Lack of information on available storage capacity in shales in all but a few, targeted settings.
2. Lack of geological and reservoir data for defining favourable settings for injecting and storing CO_2 in shales, particularly lack of data on shale depositional settings and reservoir properties. This is true for assessing both the production of methane and CO_2 storage potential in shales.
3. Understanding near-term and longer-term interactions between CO_2 and shales, particularly the mechanisms of swelling in the presence of CO_2, shrinkage with release of methane, and the physics of CO_2/methane exchange under reservoir conditions.
4. Formulating/testing alternative reliable, high volume CO_2 injection strategies and well design.
5. Integrating CO_2 storage and enhanced recovery of methane in shales.

Global Gas Reserves and CO_2 Storage Potential

Global potential for hydrocarbon production and CO_2 storage in coals and shales were assessed with estimated recoverable resources estimated at 23.5 Tcm (trillion cubic metres) of recoverable coalbed methane resource and 188 Tcm of recoverable shale gas. World CO_2 storage potential in coalbeds was estimated to be 488Gt. A breakdown by country can be seen in the main report as well as a discussion on why these estimates are higher than those previously assessed in earlier IEAGHG studies on CO_2-ECBM potential. .

There have been regional estimates, but no previous work on global CO_2 storage potential in shales. In this study to estimate the resource, the US Energy Information Administration

(EIA) was used as a base. The methodology includes; conducting preliminary geological and reservoir characterisation of shale basins and formation(s); establishing the areal extent of the major shale gas formations; defining the prospective area for each shale gas formation; estimating the risked shale gas in-place and calculating the technically recoverable shale gas resource. Risked CO_2 storage potential was calculated as 740Gt. The breakdown by region is shown in the main report. It should be noted that data was not obtainable for all basins, so a number of potentially significant shale gas resources were not included in the assessment.

Expert Review Comments

Comments were received from 8 reviewers representing industry and academia and were overall positive. Changes made from the reviewers' comments include restructuring the report, further discussion of implications of gas extraction on the reservoir, explanation of methods for calculation of storage capacity and additional references.

Conclusions

Exploitation of gas from both shale and coal leaves the formations with increased permeability and injectivity and therefore with increased potential to store CO_2. Both shale and coal appear to preferentially adsorb CO_2, allowing CO_2 to be both adsorbed and stored in the newly opened fractures. In the case of gas production from coal, the coal seam is usually dewatered by pumping, though methane can also be produced by pumping through an inert gas or by replacement with another gas, such as CO_2. To produce gas from shale, which is usually a tighter formation than coal, a combination of horizontal drilling and hydraulic fracturing is needed, whereas with coal vertical drilling may be sufficient depending on the geology.

With both shales and coal there has been a lack of large scale testing to prove storage capability and potential capacity. However, demonstration projects of storage in coal seams are still significantly more advanced than shale.

Reservoir characterisation and reservoir simulation work demonstrate that shales can store CO_2 based on trapping through adsorption on organic material as well as in natural fractures within the shales. Sufficient testing of this concept with site-specific geological and reservoir data and detailed reservoir simulation, verified by field tests, in a variety of gas shale settings is needed.

Research on direct injection of CO_2 into wet coal seams has been undertaken but pilot projects have suffered injectivity problems due to coal swelling around the injection well. The CONSOL project in the USA is the only one to test injection into an already dewatered coal seam, where approximately 3,265 metric tons of CO_2 have been injected at pressures of up to 930 psi into two thin coal seams at depths of 375 to 500m. The current injection rate is 5 tons per day and there are plans to increase the injection to try and attain an injection rate of 17 tons per day. No breakthrough of CO_2 has been observed in any of the production wells, indicating that CO_2 remains stored in the coal seam.

Based on a comprehensive review of the status of research into geological storage of CO_2 in shales and coals, the key knowledge gaps and technical barriers identified that could impact the achievement of this potential include a lack of critical formation-specific information on the available storage capacity in coal seams and gas shales; lack of geological and reservoir data for defining the favourable settings for injecting and storing CO_2 in coals and shales; understanding the nearer- and longer-term interactions between CO_2 and coals and shales; formulating and testing alternative reliable, high volume CO_2 injection strategies and well designs; and developing integrated, cost-effective strategies for enhanced recovery of methane and CO_2 storage in both coals and shales. Therefore, additional work in further addressing these key knowledge gaps and technical barriers is recommended.

The other issue to consider with shale gas exploitation is the potential overlap of formations suitable for shale gas exploitation and those suitable for use as a caprock above deep saline formations that have the potential to store CO_2. Studies show considerable geographical overlap of deep saline formations in the United States with potential shale gas production regions; however the potential storage reservoir and overlying caprock may be separated vertically by several layers from the potential shale gas horizon and may have minimal interaction. Storage project developers and regulators overseeing these projects will need to pay close attention to the interplay of shale gas and CO_2 storage development activities. Subsurface activities such as CO_2 storage and shale gas operations require geological review, ongoing monitoring, and regulatory oversight to avoid conflicts. With sensible safeguards, CO_2 storage reservoirs can, in most areas, coexist in the same space with conventional and unconventional oil and gas operations, including shale gas production and hydraulic fracturing.

Recommendations

CO_2 storage in coals and shales remain a possibility, though further research and demonstration is still needed, particularly regarding larger scale testing of CO_2 storage in both shales and coals following gas exploitation. It is therefore recommended that IEAGHG continue to follow the progress of these demonstration projects, particularly the US CONSOL project, which is the most advanced demonstration project looking into CO_2. IEAGHG could also include progress of work in this area within the research networks.

FINAL REPORT

POTENTIAL OF INCREMENTAL GAS PRODUCTION FROM AND GEOLOGICAL CO_2 STORAGE IN GAS SHALES AND COAL SEAMS

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Prepared by:
Advanced Resources International, Inc.
4501 Fairfax Drive, Suite 910
Arlington, VA 22203 USA

Prepared for:
IEA Greenhouse Gas R&D Programme (IEAGHG)
The Orchard Business Centre
Stoke Orchard
Cheltenham, Gloucestershire UK
GL52 7RZ

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EXECUTIVE SUMMARY

Building upon combined developments in horizontal drilling and hydraulic fracturing technologies, production of natural gas from organic-rich gas shale formations and unmineable coal seams is rapidly developing as a major hydrocarbon supply option in North America, with opportunities for development being assessed in other regions of the world. However, shale formations constitute the most common, low-permeability cap rocks that could prevent buoyant carbon dioxide (CO_2) injected for geologic storage from migrating from underlying storage units, particularly deep saline aquifers. Some are concerned that the application of horizontal drilling and hydraulic fracturing technology may potentially compromise the integrity of shale cap rocks in certain settings that may be targeted for CO_2 storage. Finally, gas shales and coal seams may also form potential storage units for CO_2 based on trapping through adsorption on organic material within the formation, although this has only been demonstrated in a few tests in coal, and has not been demonstrated at all in shales. Nonetheless, the same technologies – horizontal drilling and hydraulic fracturing – that have contributed to the recent rapid development of shale gas production may also open up the possibility of using shale formations and coal seams as actual storage media for CO_2 by increasing permeability and injectivity, allowing storage to potentially be cost effective.

This study's main objectives are to assess the global potential for geological storage of CO_2 in shale and coal formations and the impact of gas production from shales on CO_2 storage capacity in underlying deep saline aquifers due to potentially compromising cap rock integrity.

Research on recovering methane and storing CO_2 in gas shales is significantly less advanced than that for coal seams. Ongoing reservoir characterization and reservoir simulation work in shales is demonstrating that shales can store CO_2 based on trapping through adsorption on organic material (similar to coals), as well as with the natural and induced fractures within the shales. Still lacking, however, is sufficient testing of this concept with site-specific geologic and reservoir data and detailed reservoir simulation, verified by field tests.

Research to date demonstrates that there may be cases where enhanced recovery in coal seams and shales via the injection of CO_2 can be technically and economically successful. However, much about the mechanisms and potential for storing CO_2 and enhancing methane recovery in shales and coal seams remain unknown. At field scale, only a few projects of any appreciable scale have been performed in coal seams, and none have yet been pursued in shales. The key knowledge gaps and technical barriers identified that could impact the achievement of this potential include:

1. A lack of critical formation-specific information on the available storage capacity in coal seams and gas shales in all but a few, targeted settings.
2. A sparseness of geological and production performance data for defining the most favorable settings for injecting and storing CO_2 in coals and shales; this is also true for assessing methane production potential.
3. Understanding the near- and long-term interactions between CO_2 and coals and shales, particularly the mechanisms of swelling in the presence of CO_2, shrinkage with release of methane, and the physics of CO_2/methane exchange under reservoir conditions.
4. Formulating and testing alternative CO_2 injection strategies and well designs.
5. Developing integrated, cost-effective strategies for both enhancing recovery of methane and facilitating storage via the injection of CO_2 in both coals and shales.

The technical recovery potential for methane from the world's coal seams is estimated to be 79 trillion cubic meters (Tcm) globally, 29 Tcm from conventional CBM recovery, and 50 Tcm from the application of enhanced coal bed methane (ECBM) recovery through the injection of CO_2. This could facilitate the potential storage of nearly 488 billion metric tons, or Gigatonnes (Gt), of CO_2 in unmineable coal seams. This potential for coal seams is summarized by country in **Table ES.1**.

Similarly, it is estimated that 188 Tcm of shale gas resources are potentially technically recoverable globally (not including consideration of the potential enhanced gas recovery (EGR) realized as a result of CO_2 injection in shales). This could facilitate the potential storage of 740 Gt of CO_2 in gas shales. Estimates for technically recoverable shale gas resources and potential CO_2 storage capacity in gas shales are summarized by country in **Table ES.2**.

Table ES.1: CO_2 Storage and Methane Production Potential of the Some of the Major Coal Basins in the World

	Estimated Methane Recovery (Tcm)			CO_2 Storage	CO_2 Storage
COUNTRY	**PRIMARY**	**ECBM**	**TOTAL**	**Tcm**	**Gt**
UNITED STATES	4.82	7.54	12.4	52.82	86.16
CANADA	5.21	4.35	9.6	17.85	29.11
MEXICO	0.04	0.09	0.1	0.34	0.55
Total North America	**10.06**	**11.99**	**22.1**	**71.01**	**115.82**
BRAZIL	0.15	0.00	0.2	0.57	0.93
COLOMBIA	0.10	0.22	0.3	1.29	2.11
VENEZUALA	0.07	0.30	0.4	3.57	5.83
Total S. & Cent. America	**0.32**	**0.52**	**0.85**	**5.44**	**8.87**
CZECH REPUBLIC	0.06	0.00	0.1	0.00	0.00
GERMANY	0.45	0.00	0.5	0.62	1.01
HUNGARY	0.02	0.04	0.1	0.10	0.17
KAZAKHSTAN	0.28	0.00	0.3	0.50	0.82
POLAND	0.14	0.94	1.1	4.07	6.63
RUSSIAN FEDERATION	5.66	12.61	18.3	35.20	57.41
TURKEY	0.28	0.00	0.3	0.58	0.94
UKRAINE	0.71	1.72	2.4	4.54	7.41
UNITED KINGDOM	0.43	1.03	1.5	2.73	4.46
Total Europe & Eurasia	**8.04**	**16.35**	**24.39**	**48.34**	**78.84**
				0.00	0.00
Botswana	0.45	1.06	1.5	9.18	14.97
Mozambique	0.37	0.89	1.3	1.84	3.01
Namibia	0.44	1.05	1.5	2.18	3.56
South Africa	0.25	0.61	0.9	1.26	2.05
Zimbabwe	0.25	0.61	0.9	3.44	5.62
Total Middle East & Africa	**1.77**	**4.22**	**5.99**	**17.90**	**29.20**
AUSTRALIA	0.95	0.67	1.62	9.01	14.70
CHINA	5.52	7.13	12.64	47.83	78.01
INDIA	0.57	0.63	1.2	4.04	6.60
INDONESIA	1.93	8.05	9.97	95.40	155.60
Total Asia Pacific	8.96	16.47	25.43	156.28	254.91
Total World	29.15	49.55	78.7	298.97	487.64

Table ES.2: Summary of Technically Recoverable Gas Resources and CO_2 Storage Potential of the World's Gas Shale Basins, for the Countries Considered in the Assessment

Region	Country	Risked Gas In-Place (Tcm)	Risked Technically Recoverable (Tcm)	Risked CO_2 Storage Potential (Gt)
North America	United States	93	24	134
	I. Canada	42	11	43
	II. Mexico	67	19	72
	Sub-Total	*202*	*55*	*249*
South America	III. Northern South America	3	1	3
	IV. Southern South America	126	34	119
	Sub-Total	*129*	*35*	*122*
Europe	V. Poland	22	5	19
	VI. Eastern Europe	8	2	7
	VII. Western Europe	43	11	47
	Sub-Total	*73*	*18*	*72*
Africa	VIII. Central North Africa	53	14	55
	IX. Morocco	8	2	6
	X. South Africa	52	14	52
	Sub-Total	*112*	*30*	*113*
Asia	XI. China	145	36	132
	XII. India/Pakistan	14	3	11
	XIII. Turkey	2	0	2
	Sub-Total	*160*	*40*	*144*
Oceania	XIV. Australia	39	11	39
Grand Total		**717**	**188**	**740**

Note: Risked resources account for two specific judgmentally established success/risk factors. A "Play Success Probability Factor" captures the likelihood that at least some significant portion of the shale gas formation will produce gas at attractive flow rates and become developed. (Shale gas formations already under development would have a play probability factor of 100%.) A "Prospective Area Success (Risk) Factor" addresses a series of concerns that could relegate a portion of the prospective area to be unsuccessful or unproductive for gas production.

Geological storage requires a deep permeable geological formation into which captured CO_2 can be injected, and an overlying impermeable formation, called a cap rock, that keeps the buoyant CO_2 within the formation targeted for storage. Shale formations typically have very low permeability. Such shale formations are believed to be able to effectively prevent buoyant CO_2 injected for geologic storage from migrating from underlying formations targeted for storage, particularly deep saline aquifers. Production of natural gas from shale and other tight formations involves fracturing the reservoir. Some are concerned that the application of horizontal drilling and hydraulic fracturing may potentially compromise the integrity of shale cap rocks in certain settings that may be targeted for both gas development and CO_2 storage. Shale gas production could be considered in direct conflict with the use of shale formations as a cap rock barrier to CO_2 migration. Some have concluded that considerable overlap exists between deep saline aquifers in the United States and potential shale gas production regions and, therefore conclude that the use of these saline aquifers as storage targets could be adversely affected by shale gas production.

However, such a conclusion overlooks the critical third dimension – depth. Sedimentary basins do not consist of just two simple layers, i.e., the CO_2 storage reservoir and the cap rock/shale layer. Instead, most sedimentary sequences typically consist of hundreds to thousands of meters of rock, with multiple layers of shale, sandstones, limestones, etc. (most of which are largely impermeable). If one layer above the storage zone is fractured; additional layers of impermeable rock overlying the fractured area could block migration of the CO_2.

In most settings, multiple layers of shale formations exist that could serve as cap rocks, with generally only a few conceivable targets for commercial shale gas development and production. Other, non-shale low permeability formations could also serve as cap rocks. Experience to date with regard to pursuing methane resource development in both coals and shales has focused on the higher quality, higher permeability settings. Obviously, those settings with good productivity should also be better candidates for CO_2 storage. Likewise, the lower quality, lower permeability settings are not good candidates for development, and would therefore not be good candidate formations for storage. However, these low quality and low permeability formations could be very good candidates for cap rocks overlying the potential formations targeted for storage. Those formations are not commercial because of their very low permeability, and are therefore the most attractive as a cap rocks.

Even if the cap rock seal in one area or formation was impacted by hydraulic fracturing, other layers of impermeable rock that overlie the fractured area could block migration of the CO_2. In many cases, shale formations are very thick, and the likelihood that a induced fracture would extend throughout the vertical extent of the formation is remote.

In fact, in the unlikely event that a potential cap rock is fractured, it would be unlikely to warrant approval as a storage location for CO_2 in the first place. The Class VI injection well program for a CO_2 storage site under U.S. federal law, for example, requires storage site developers to do thorough seismic measurements of the subsurface and ensure a stable overhead rock before obtaining a permit to inject CO_2 underground. It also requires continual monitoring of underground plumes of gas. An already-fractured cap rock is not going to win approval for CO_2 injection and storage.

Storage project developers and regulators overseeing these projects will need to pay close attention to the interplay of shale gas and CO_2 storage development activities. Subsurface activities such as geologic storage and shale gas operations require geologic review, ongoing monitoring, and regulatory oversight to avoid conflicts. Good records and monitoring of impacts associated with both shale gas production and CO_2 storage will be essential. Moreover, comprehensive geologic knowledge and understanding of the characteristics of the multiple geologic layers will be critical. Nonetheless, with sensible safeguards, CO_2 storage reservoirs can, in most areas, coexist in the same space with conventional and unconventional oil and gas operations, including shale gas production and hydraulic fracturing.

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1. INTRODUCTION AND STUDY OBJECTIVES

Building upon combined developments in horizontal drilling and hydraulic fracturing technologies, production of natural gas from organic-rich gas shale formations and unmineable coal deposits is rapidly developing as a major hydrocarbon energy supply option in North America, Europe, Asia, and Australia, with opportunities for development being assessed in other regions of the world. However, shale formations constitute the most common, low-permeability cap rocks that could prevent buoyant carbon dioxide (CO_2) injected for geologic storage from migrating from underlying storage units, particularly deep saline aquifers. Some are concerned that the application of horizontal drilling and hydraulic fracturing technology may potentially compromise the integrity of shale cap rocks in certain settings that may be targeted for CO_2 storage.

At the same time, gas shales and coal seams may also form potential storage units for CO_2 based on trapping through adsorption on organic material within the formation, although this has only been demonstrated in a few tests in coal, and has not been demonstrated in shales. Nonetheless, the same technologies – horizontal drilling and hydraulic fracturing – that have contributed to the recent rapid development of shale gas production may also open up the possibility of using shale formations and coal seams as actual storage media for CO_2 by increasing permeability and injectivity, allowing storage to potentially be cost effective.

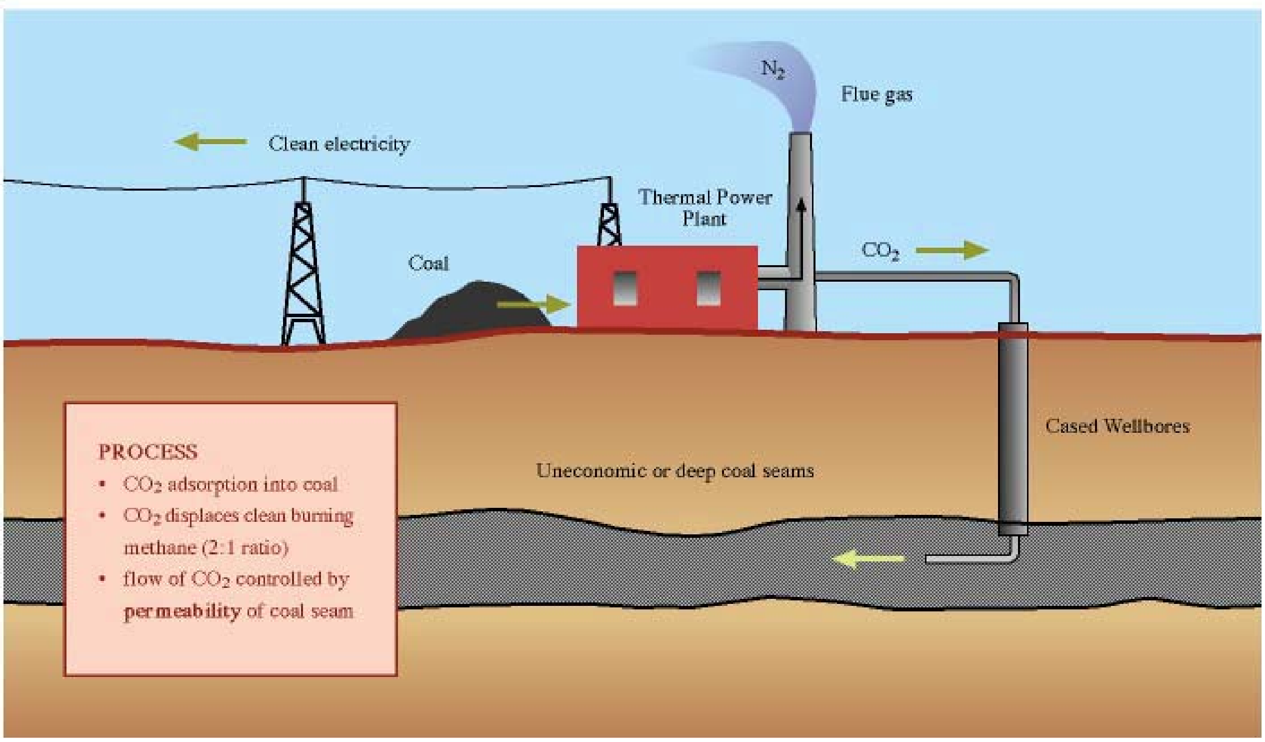
1.1 Methane Production From and CO_2 Storage in Coal Seams

Coal seams often contain gases such as methane, held in pores on the surface of the coal and in fractures in the seams. Conventional coal bed methane (CBM) extraction is achieved by dewatering and reducing the pressure in the coal seam, such that adsorbed methane is released from the porous coal surface. However, conventional CBM extraction may leave up to 50% of the methane in the seam after development and production operations have been completed.

In the early 1990s, Puri and Lee[1] and MacDonald,[2] separately, proposed the concept of enhanced coalbed methane (ECBM) recovery involving injection of nitrogen (N_2) or CO_2 to increase recovery of methane without excessively lowering reservoir pressure. The concept of ECBM using CO_2 predates this; in 1972, Every and Dell'osso found that methane was effectively removed from crushed coal by flowing a stream of CO_2 through it at ambient temperature.[3]

Thus coal deposits have long been regarded as a potential CO_2 storage option, particularly in association with ECBM production. The process of ECBM and storage of CO_2 in deep coal seams, as depicted in the schematic of **Figure 1.1**, involves capturing the CO_2 from a flue gas stream, compressing it to high pressures for transport to an injection site, followed by injection into the coal seam. The CO_2 moves through the coal seam along its natural fractures (the cleat system), and from there diffuses to the coal micro-pores where it is preferentially adsorbed. In coal and shale settings, CO_2 has a higher affinity to become adsorbed onto the reservoir rock surfaces than the methane that is naturally found within them. Upon injection, the CO_2 displaces methane from some of the adsorption sites. The ratio of CO_2 to methane varies from basin to basin, but has been linked to the maturity of the organic matter in the coal.

Figure 1.1: ECBM and CO_2 Storage in Coal Seams



Source: Massarotto, P Rudolph, V Golding S, "Technical and economic factors in applying the enhanced coal bed methane recovery process," Paper, University of Queensland, 2005

As much as another 20% could potentially be recovered through the application of CO_2-ECBM.[4] The fact that some CBM is high in CO_2 content shows that, at least in some instances, CO_2 can safely remain stored in coal for geologically significant time periods.

1.2 Methane Production from and CO_2 Storage in Gas Shales

Gas shales can also adsorb CO_2, possibly also making shale formations significant targets for CO_2 storage. The process of enhancing the recovery of methane and the storage of CO_2 in shales could occur by the same basic mechanism as that for coal, and the organic matter in gas shales has large surface areas similar to that found in coal. These shales may also form potential storage units for CO_2 based on trapping through adsorption on organic material, as well as with the natural fractures within the shales.

The most critical factors in determining shale storage capacity and injectivity of CO_2 are the extent of natural fracturing within the shale formation, the volume of gas contained within the natural fracture network, the volume and rate that methane can be desorbed and then produced from the shales, the volume and rate that the CO_2 can be injected and stored within the fracture matrix, and the volume and rate that CO_2 can be adsorbed and stored on the shales.

Injecting CO_2 to enhance recovery and store CO_2 in liquids-rich (in contrast to gas-rich) shale reservoirs may also be conceivable. Some reservoir simulation work on enhancing or improving recovery in liquids-rich shales has been performed to date on the Bakken Formation in the Williston Basin in the U.S.[5] and plays in Western Canada.[6] These efforts have used "typical" rock and fluid properties with numerical simulation models, not calibrated to historical well performance, resulting in recommended theoretical methods to improve recovery performance in liquid-rich shales. A sound basis for the evaluation of CO_2 injection for enhanced recovery and potential CO_2 storage in actual reservoir settings in emerging liquids-rich shale basins has yet to be established. For this reason, this study is focusing on issues associated with CO_2 storage and enhanced gas recovery in gas shales only.

1.3 Study Objectives

Of the various options for CO_2 storage, storing CO_2 in both coals and shales has particular advantages. Relative to storage in saline aquifers, CO_2 injection can enhance methane production, the revenues from which can help offset the costs of storage. Both shales and coals can theoretically geologically trap CO_2 securely, though the extent of its effectiveness is still being assessed. Finally, deep coal seams and gas shales are widespread and, especially in the case of coal seams, exist in many of the same areas as large, coal-fired, electric power generation facilities.

The same advances that are allowing the potential of shale gas resources to be economically developed -- horizontal drilling and hydraulic fracturing -- open up the possibility of using shale and coal formations as actual storage media for CO_2 by increasing permeability and injectivity. On the other hand, shales constitute the most common, low-permeability cap rocks that could prevent migration of buoyant CO_2 from underlying storage units, particularly deep saline aquifers. The deployment of fracturing technology, some fear, may compromise the integrity of shale cap rocks in some basins.

The main objectives of this study are to: (1) assess the global potential for geological storage of CO_2 in shale and coal formations; and (2) assess the impact of gas production from shales on CO_2 storage capacity in underlying deep saline aquifers due to potentially compromising cap rock integrity. This includes consideration of the following, as specified in the original scope of work for this project:

- Global status of hydrocarbon production from shales and CBM and potential effects on CO_2 storage both in the producing shales/coals themselves and underlying hydrocarbon reservoirs and/or deep saline formations.
- Current status of research into geological storage of CO_2 in gas shales and coals.
- Potential nature and rate of trapping processes; mechanisms of storing CO_2.
- CO_2 injectivity into gas shales and coals, with reference to industry fracturing practices.
- Containment issues arising from shale fracturing, both for gas shales as a storage medium, and in terms of cap rock integrity for underlying storage units, particularly deep saline aquifers.
- Methods for assessing storage capacities for CO_2 storage in gas shales and coals.
- High level mapping and assessment of theoretical/effective capacities.
- Potential economic and social acceptance implications of CO_2 storage in gas shales and coals.

2. PRODUCING METHANE FROM COALS AND SHALES

2.1 Natural Gas Development and Production from Coals and Gas Shales

Characteristics of Unconventional Natural Gas Resources

Conventional gas reservoirs are created when natural gas migrates from an organic-rich source formation into permeable reservoir rock, where it is trapped by an overlying layer of impermeable rock. In contrast, coal seam and shale gas resources form within the organic-rich source rock (coal or shale). The lower permeability of the shale or coal greatly inhibits the gas from migrating to more permeable reservoir rocks.

Shale gas is the most pervasive of the unconventional gas resources, consisting of gas that is trapped in its source rock, so that the source rock is also the reservoir. Gas shales typically have low permeability due to their laminated nature. Shales are organically-rich sedimentary rocks, very fine grained, and composed of many thin layers.

Gas within shale can be stored in three ways: 1) adsorbed onto insoluble organic matter that forms a molecular or atomic film; 2) absorbed in the pore spaces; and 3) confined in the fractures in the rock. Gas shales may contain little or very low amounts of organic material; it is the shales with relative high levels of organic material contained within them that have adsorption ability, and thus methane production (and CO_2 storage) potential.

Tight gas is gas that is held in low permeability and low porosity sandstones and limestones. The natural gas is sourced (formed) outside the reservoir and migrates into the reservoir over millions of years. The lack of permeability generally does not allow the gas to be produced without some sort of stimulation – such as hydraulic fracturing. Most tight gas wells are drilled horizontally and are hydraulically fractured to enhance production.

Finally, coal seam gas is gas that is present within coal seams. Like shales, coal seams are also both the source rock and the reservoir. The methane is stored in the matrix of the coal, both in the micropores and adsorbed onto organic matter, as well as the fracture spaces of the rock (cleats), held there by water pressure. Generally, coalbed methane (CBM) is produced from formations too deep to mine.

Producing Coalbed Methane Resources

In coal seams, methane desorbs from the micropores of the coal matrix when the hydrostatic pressure is reduced, such as from the drilling of a well, and flows through the cleats to a well bore. Coal seams are often shallow, and sometimes coexist with surface aquifers, while shale and tight gas are more often found at greater depths.

Coalbed methane reservoirs generally have a higher concentration of gas than shale reservoirs, generally because the organic content of coals is typically higher than that of shales. Shale reservoirs nearly always need to be hydraulically fractured, while perhaps only half of coal seam gas reservoirs require such fracture stimulation.

There are three main methods which can induce methane release from coal formations:

- Reduce the overall pressure, usually by dewatering the formation, generally through pumping
- Reduce the partial pressure of the methane by injecting another inert gas into the formation
- Replace the methane on the surface with another gas, such as CO_2.

Dewatering and reservoir pressure depletion is a simple but relatively inefficient process, recovering less than 50% of the gas in place. Lowering the hydrostatic pressure in the coal seam accelerates the desorption process. Once dewatering has taken place and the pressure has been reduced, the released methane can be produced. CBM wells initially primarily produce water; then gas production eventually increases, while water production declines. Some wells do not produce any water and begin producing gas immediately, depending on the nature of the fracture system. Once the gas is released, it is usually free of impurities; and can be easily prepared for pipeline delivery. Some coals may never produce methane if the hydrostatic pressure cannot be efficiently lowered.

Hydraulic fracturing or other completion enhancement methods are used to assist recovery but, even so, because permeability is normally low, many wells at relatively close spacing must be drilled to achieve economic gas flow.

Coalbed methane production potential is determined by a number of factors that vary from basin to basin, and include: fracture permeability, development history, gas migration, coal maturation, coal distribution, geologic structure, well completion options, hydrostatic pressure, and produced water management. In most areas, naturally developed fracture networks are the most sought after areas for CBM development. Areas where geologic structures and localized faulting have occurred tend to induce natural fracturing, which increases the production pathways within the coal seam.

As part of the general process for development and producing methane from coal seams, a steel-encased hole is drilled into the coal seam, anywhere from 100 to 1,500 meters below the surface, and sometimes even deeper. Methane from unmined coal seams is recovered through drainage systems constructed by drilling a series of such vertical or horizontal wells directly into the seam. Then the gas is sent to a compressor station and into natural gas pipelines. The produced water is separated and reinjected into isolated formations, treated and released into streams, used for irrigation, or sent to evaporation ponds. Once water is produced from the coal seam, it does not usually tend to refill with water (which becomes relevant if CO_2 is later injected into the coal seam to enhance recovery and be permanently stored). The produced water may contain dissolved solids such as sodium bicarbonate and chloride.

The choice of vertical or horizontal wells is dependent on the geology of the coal seam, in particular, the type of coal in the basin and fluid content. Each type of coal (sub-bituminous to bituminous) offers production options that are different due to the inherent natural fracturing and competency of the coal seams. The sub-bituminous coals are softer and less competent than the higher rank, low-volatile bituminous coals, and therefore are typically completed and produced using more conventional vertical well bores. The more competent higher rank coals lend themselves to completions using horizontal or vertical wells.

The process of bringing a well to completion is generally short-lived, taking only 70 to 100 days for a single well, after which the well can be on production for 20 to 40 years. The process for a single horizontal well typically includes four to eight weeks to prepare the site for drilling, four or five weeks of rig work, including casing and cementing and moving all associated auxiliary equipment off the well site before fracturing operations commence, and two to five days for the entire multi-stage fracturing operation.

Producing Shale Gas Resources

Production from shale gas proceeds in a similar fashion; though, with few exceptions, shales do not have to be dewatered to allow gas desorption to occur. For example, the Antrim and New Albany Shales in the U.S. are shallower shales that produce significant volumes of formation water, unlike most of the other gas shales. Also, in general, shale formations are often too deep and of such low permeability to facilitate economic production using just vertical, simple fractured wells.

In fact, essentially three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) increases in natural gas prices. Although known for decades, what “changed the game” was the recognition that one could “create a permeable reservoir” by using intensively stimulated horizontal wells.

Despite the recent surge in shale gas development activity, the concept for developing natural gas from shales has been around a long time. In the mid-1970s, a partnership of private operators, the U.S. Department of Energy (USDOE), and the Gas Research Institute (GRI) endeavored to develop technologies for the production of natural gas from the relatively shallow Devonian (Huron) shale in the Eastern United States. Other research efforts focused on the role fracturing techniques could play in coal seams and low permeability sandstone (tight gas) formations. This partnership helped foster technologies that eventually became crucial to producing natural gas from shales, including horizontal wells, multi-stage fracturing, and slick-water fracturing.[7,8]

Practical application of horizontal drilling began in the early 1980s, facilitated by improved downhole drilling motors and other necessary supporting equipment, materials, and technologies, particularly downhole telemetry equipment.[9] Large-scale shale gas development and production began with experimentation by Mitchell Energy during the 1980s and 1990s, leading to deep shale gas production becoming a commercial reality in the Barnett Shale in North-Central Texas. As a result of Mitchell’s success, other companies entered the Barnett by 2005, where production reached almost 14 billion cubic meters (Bcm) (0.5 trillion cubic feet (Tcf)) per year). This led producers to try applying the same techniques in the Fayetteville Shale in North Arkansas, and then in other shale formations including the Haynesville, Marcellus, Woodford, Eagle Ford and other shales in the United States.

Each of these gas shale basins is different and each has a unique set of development criteria and operational challenges. Because of these differences, the most effective development approaches and well drilling and completion strategies for a particular basin tend to evolve over time.

Key Technologies for Producing Unconventional Gas Resources

Modern CBM and shale gas development is a technologically driven process. Presently, the drilling and completion of shale gas and CBM wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. Emerging shale gas basins are expected to follow a trend similar to the more established plays, with increasing numbers of horizontal wells as the plays mature. Horizontal drilling provides more exposure to a formation than does a vertical well, which creates a number of advantages over vertical wells drilling. In particular, six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as 16 vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas and CBM is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the formation to the well in economic quantities. Ground water is protected during fracturing process by a combination of the casing and cement that is installed when the well is drilled and, generally in the case of shale gas in particular, the thousands of meters of rock between the fracture zone and any fresh or treatable aquifers. Fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up 99% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

2.2 Global Production from Coals and Gas Shales

Production of natural gas from shale formations and coal seams is rapidly increasing, and new potential productive horizons are continuously being identified. Major expansions in natural gas supplies from these sources, particularly shale formations, are occurring in a number of regions, including North America, Europe, Asia and Australia.

The proliferation of activity into new shale plays has increased annual shale gas production from 11 Bcm (0.39 Tcf) in 2000 to 141 Bcm (5.0 Tcf) in 2010, 23% of U.S. dry gas production. The market has moved from tight gas supplies with huge price spikes during cold weather to low and stable prices, just because of the new supplies of shale gas. Moreover, wet shale gas reserves (those shale gas reserves also containing liquid hydrocarbons) have increased to over 1.7 trillion cubic meters (Tcm) (60 Tcf) by year-end 2009 (on a natural gas equivalent basis), 21% of overall U.S. natural gas reserves, the highest level since 1971. And production of CBM in the United States has grown from 39 Bcm (1.3 Tcf) in 2000 to over 54 Bcm (1.9 Tcf) per year in 2010.

Production of shale gas in the United States is expected to continue to increase, and constitute 49% of U.S. total natural gas supply in 2035, as projected in the U.S. Energy Information Administration’s (EIA's) Annual Energy Outlook 2012 (Early Release).[10]

The International Energy Agency (IEA) estimates that global unconventional natural gas production was nearly 470 Bcm (16.3 Tcf) in 2010.[11] Of this, nearly 148 Bcm (5.2 Tcf) was from shale gas, and 80 Bcm (2.8 Tcf) was from CBM production (**Table 2.1**).

Production of unconventional gas is still overwhelmingly from North America; with 76% of global unconventional gas output coming from the United States (360 Bcm) and 13% from Canada (60 Bcm). Outside North America, the largest contribution to unconventional gas production came from China and Australia, mostly from CBM production.

The economic and political significance of these unconventional resources as an energy supply source depends not only on their size, but also in their wide geographical distribution, which is in marked contrast to the concentration of conventional resources.

Table 2.1: Estimates of Global Unconventional Natural Gas Production

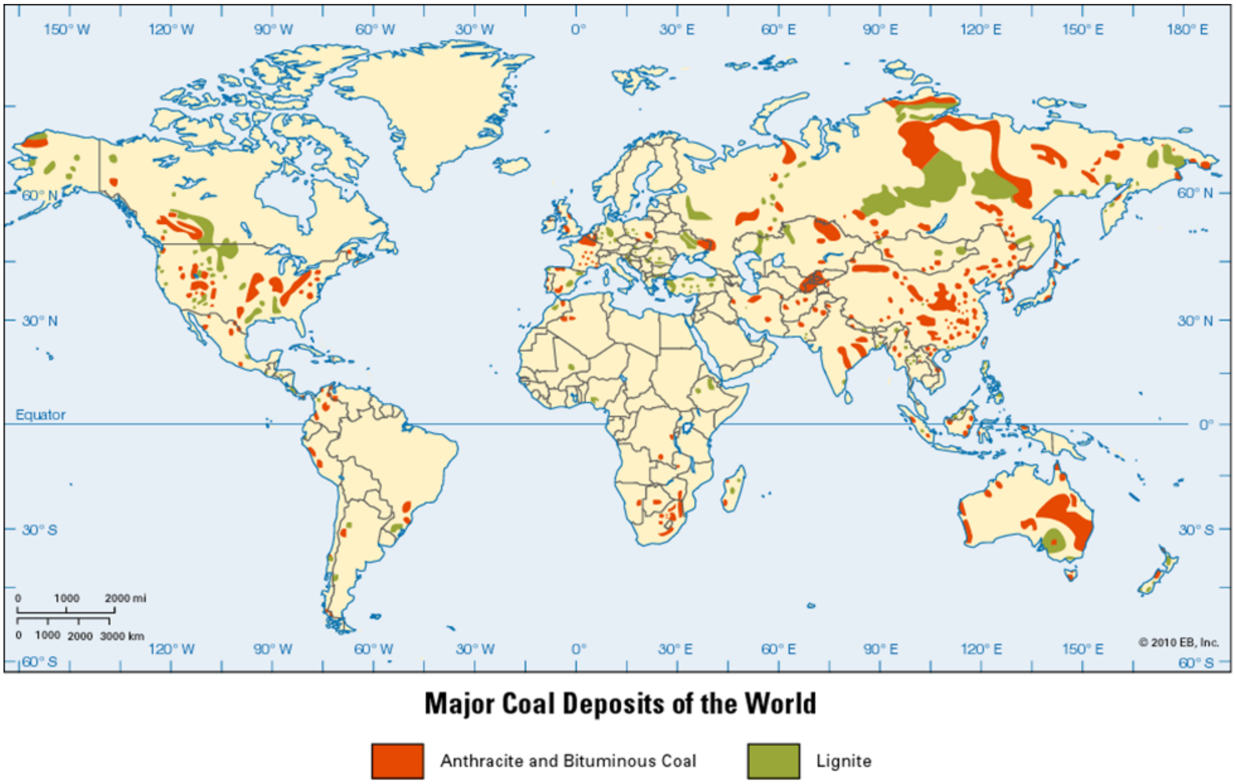
	Annual Unconventional Gas Production in 2010 (Billion Cubic Meters, Bcm)					Annual Unconventional Gas Production in 2010 (Billion Cubic Feet, Bcf)			
	Shale Gas	Tight Gas	CBM	Total		Shale Gas	Tight Gas	CBM	Total
United States	141.0	161.0	56.0	**358.0**		4,976	5,681	1,976	**12,633**
Canada	3.0	50.0	8.0	**61.0**		106	1,764	282	**2,153**
Mexico	0.0	1.5		**1.5**		1	53	0	**54**
China		2.0	10.0	**12.0**		0	71	353	**423**
India			1.0	**1.0**		0	0	36	**36**
Indonesia				**0.0**		0	0	0	**0**
Russia		19.1		**19.1**		0	674	0	**674**
Poland			0.4	**0.4**		0	0	13	**13**
Australia			5.0	**5.0**		0	0	176	**176**
Algeria				**0.0**		0	0	0	**0**
Argentina	3.8			**3.8**		133	0	0	**133**
All Other				**8.0**					
TOTAL	**147.8**	**233.6**	**80.4**	**469.8**		**5,216**	**8,244**	**2,836**	**16,296**

Source: International Energy Agency, Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report on Unconventional Gas, OECD/IEA, May 29, 2012

2.2 Global Coalbed Methane Potential

Coalbed methane, which once enjoyed the spotlight and enthusiasm as the gas shales of today, is now one of the “other” unconventional gas resources, being surpassed by shale gas. The major coal deposits in the world are shown in **Figure 2.1**. In 2009, Advanced Resources’ country-by-country assessment of CBM resources in place was 100 to 216 trillion cubic meters (Tcm) (3,540 to 7,630 trillion cubic feet (Tcf)), with an estimated 24 Tcm (830 Tcf) recoverable (**Table 2.2**), with the largest CBM resources anticipated to exist in the former Soviet Union, Canada, China, Australia and the United States.[12] An update to this assessment will be presented later in this report.

Figure 2.1: World Coal Deposits



Source: http://www.britannica.com/EBchecked/topic/122863/coal/50690/World-distribution-of-coal

Table 2.2: World Coalbed Methane Resources

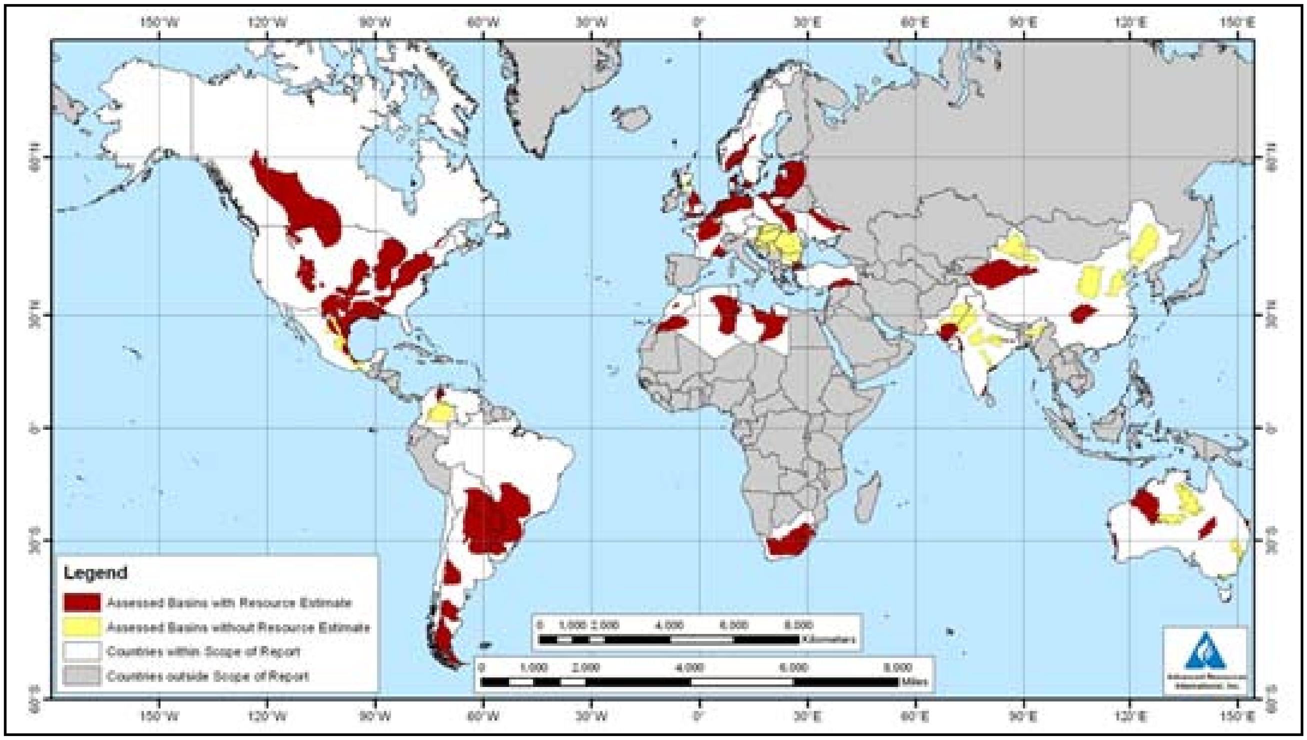
Country/Region	CBM Resource In-Place (Tcm)		CBM Resource In-Place (Tcf)		CBM Recoverable	
	Low	High	Low	High	(Tcm)	(Tcf)
Russia	12.8	56.7	450	2,000	5.7	200
China	19.8	36.0	700	1,270	2.8	100
United States	14.2	42.5	500	1,500	4.0	140
Australia/New Zealand	14.2	28.3	500	1,000	3.4	120
Canada	10.2	13.0	360	460	2.6	90
Indonesia	9.6	12.8	340	450	1.4	50
Southern Africa (incl. Carbonaceous Shales)	2.6	6.2	90	220	0.9	30
Western Europe	5.7	5.7	200	200	0.6	20
Ukraine	4.8	4.8	170	170	0.7	25
Turkey	1.4	3.1	50	110	0.3	10
India	2.0	2.6	70	90	0.6	20
Kazakhstan	1.1	1.7	40	60	0.3	10
South American/Mexico	1.4	1.4	50	50	0.3	10
Poland	0.6	1.4	20	50	0.1	5
TOTAL (Tcf)	100.3	216.2	3,540	7,630	23.5	830

Source: Kuuskraa V.A. and Stevens S.H., "World Gas Shales and Unconventional Gas: A Status Report", presented at United Nations Climate Change Conference, Copenhagen, December 2009

2.3 Global Shale Gas Potential

A recent report sponsored by EIA and prepared by Advanced Resources assessed the resource potential of 48 shale gas basins in 32 countries, containing almost 70 shale gas formations.[13] The report only examined the most prospective shale gas basins in a select group of countries that demonstrate some level of relatively near-term promise, and for which a sufficient amount of geologic data exists for preliminary resource characterization (**Figure 2.2**). The report concludes that an estimated 163 Tcm (5,760 Tcf) of shale gas resources exists in these 32 countries, which exclude the United States. By adding EIA's 2010 U.S. estimate of technically recoverable shale gas resources for the U.S. of 24 Tcm (862 Tcf),[14] the total global shale resource base is estimated to be 188 Tcm (6,622 Tcf).

Figure 2.2. Regions Considered in EIA's World Shale Gas Resources Assessment



Source: Advanced Resources International (ARI): *World Shale Gas Resources: An Initial Assessment of 14 Regions outside the United States*, prepared for the U.S. Energy Information Administration (EIA), April, 2011

These results are summarized by country in **Table 2.3.** Much of this shale gas resource exists in countries with limited conventional gas supplies or where the conventional gas resource has largely been depleted, such as in China, South Africa and Europe.

Also important to note is that Russia and Central Asia, the Middle East, South East Asia, and Central Africa were not addressed by this report. This was primarily because there were either significant quantities of conventional natural gas reserves noted to be in place (i.e., Russia and the Middle East), which would presumably be developed first, or because there was a general lack of information to carry out even an initial shale gas resource assessment.

Both shale gas and CBM looks promising in China and Russia, although appraisal is still at a very early stage. While currently not producing shale gas, both have similar geological conditions to the U.S.[15,16]

Table 2.3: Risked Gas In-Place and Technically Recoverable Shale Gas Resources in 33 Countries

Region	Country	Risked Gas In-Place (Tcf)	Risked Technically Recoverable (Tcf)	Risked Gas In-Place (Tcm)	Risked Technically Recoverable (Tcm)
North America	United States	3,284	862	93	24
	I. Canada	1,490	388	42	11
	II. Mexico	2,366	681	67	19
	Sub-Total	*7,140*	*1,931*	*202*	*55*
South America	III. Northern South America	120	30	3	1
	IV. Southern South America	4,449	1,195	126	34
	Sub-Total	*4,569*	*1,225*	*129*	*35*
Europe	V. Poland	792	187	22	5
	VI. Eastern Europe	290	65	8	2
	VII. Western Europe	1,505	372	43	11
	Sub-Total	*2,587*	*624*	*73*	*18*
Africa	VIII. Central North Africa	1,861	504	53	14
	IX. Morocco	267	53	8	2
	X. South Africa	1,834	485	52	14
	Sub-Total	*3,962*	*1,042*	*112*	*30*
Asia	XI. China	5,101	1,275	145	36
	XII. India/Pakistan	496	114	14	3
	XIII. Turkey	64	15	2	0
	Sub-Total	*5,661*	*1,404*	*160*	*40*
Oceania	XIV. Australia	1,381	396	39	11
Grand Total		**25,300**	**6,622**	**717**	**188**

Source: Advanced Resources International (ARI): *World Shale Gas Resources: An Initial Assessment of 14 Regions outside the United States*, prepared for the U.S. Energy Information Administration (EIA), April, 2011

Shale gas exploration in Europe is in its infancy; as a consequence, little is known about Europe's ultimate potential. There are some potentially major regional shale gas plays in Europe, plus a number of others with smaller potential. Most promising are the Baltic Depression (mainly in Poland, but also in Lithuania), Lower Saxon basin (Northwest Germany) and several areas in the UK, Netherlands, Sweden and Austria. European governments, particularly in Eastern Europe (Poland, Ukraine) see an opportunity to reduce dependence on Russian gas imports through the development of shale gas resources.

Poland is seen as the most promising country for shale gas development in Europe, thanks to favorable geological and regulatory environments, and it may lead the way to shale gas development in Europe. However, in July 2012, ExxonMobil announced the company had ended its exploration efforts in Poland, after drilling two unsuccessful test wells in the country's Lublin and Podlasie basins. Chevron, however, is still pursuing prospects in Poland.[17]

While the first phase of the EIA–sponsored global shale gas study referenced above covered a large portion of the world, several important regions were outside of the initial scope of work. Specifically, the initial report did not include the resource-rich Middle-East, Southeast Asia, Russia and Central Africa. As shale and coal formations are source rock for most conventional natural gas **and oil**, it is likely that regions with large conventional petroleum deposits also contain significant shale source rocks.

2.4 Global Potential of Liquids-Rich Shales

There are oil shales and there is shale oil, and the two are often confused. Oil shale and shale oil differ by the API gravity and viscosity of the fluids, as well as the method of extraction. Oil shale is an inorganic rock that contains a solid organic compound known as kerogen. Oil shale is a misnomer because kerogen is not a crude oil, and the rock holding the kerogen is often not shale. To generate liquid oil synthetically from oil shale, the kerogen-rich rock is heated to as high as 500 degrees Celsius in the absence of oxygen, in a process known as retorting.

In contrast, shale oil is a liquid, while the kerogen in oil shale is not. Liquids-rich shales, often now referred to a "tight oil" to avoid confusion with oil shale, consists of light crude oil contained in petroleum-bearing formations of relatively low porosity and permeability (generally shales). Developing liquids-rich shale plays uses the same horizontal well and hydraulic fracturing technology used in recent boom in production of shale gas. Liquids-rich shale formations include the Bakken Shale, the Eagle Ford Shale the Niobrara Formation, along with certain areas of the Barnett Shale and the Utica Shale in the United States; the R'Mah Formation in Syria; the Sargelu Formation in the northern Persian Gulf region; the Athel Formation in Oman; the Bazhenov Formation and Achimov Formation in West Siberia; and the Chicontepec Formation in Mexico.[18]

The recent experience in the United States suggests that, due to the high productivity of liquids-rich shale wells, it is today a lower-cost resource than many sources of conventional oil production.

Given this, an effort has been initiated by EIA to complement and expand upon its widely distributed World Shale Gas Resources study. The objectives of this new effort are to prepare a series of resource assessments for U.S. liquids-rich shale basins and plays, including providing presentation-style reports for each basin/play, along with a high level assessment of the potential for international U.S. liquids-rich shale, similar to the shale gas study. The plan for this report is to: (1) set forth the methodology for assessing U.S. liquids-rich shale technically recoverable resources (TRR); (2) provide estimates of the TRR; (3) define the productivity of these basins and plays; and (4) provide representative production decline curves.

In addition, a number of gas shale plays not included in the initial assessment will also be included in an update. The current plan is for publication of this report in 2013.

Since no global assessment of U.S. liquids-rich shale potential has yet been developed, along with the other reasons noted in Section 1.3, this study by IEAGHG is focusing on issues associated with CO_2 storage and enhanced gas recovery in *gas shales only*.

2.5 Achieving the Production Potential of Unconventional Resources

Technology advances – particularly horizontal drilling and hydraulic fracturing technologies -- have facilitated a surge in the production of unconventional gas in North America. Based on the North American experience and with evidence of a large and widely dispersed shale gas and CBM resource base, there has been a surge of interest from countries all around the world in improving their security of supply and gaining economic benefits from exploitation of these resources. However, the pace of development of these gas resources in other areas of the world, many believe, will be slower than that which has occurred in the United States.[19]

A recent report by the IEA forecasts that if industry develops and implements sound environmental practices for unconventional gas, particularly shale gas, development (their so-called "Golden Rules"), which ensures public acceptance that allows development to aggressively proceed, then unconventional gas production, primarily shale gas, can more than triple to 1.6 Tcm, or 56 Tcf, by 2035. Unconventional resources can account for nearly two-thirds of the cumulative incremental gas supply over the period to 2035, and the share of unconventional gas in total gas output in the world rises from 14% today to 32% in 2035. The largest producers of unconventional gas over the period are projected to be the United States, which moves ahead of Russia as the world's largest global natural gas producer, and China, whose large unconventional resource base can allow for very rapid growth in unconventional production starting around 2020. There are also large increases in production forecast in Australia, India, Canada and Indonesia. Unconventional gas production in the European Union, led by Poland, is sufficient after 2020 to offset the continued decline in conventional output.[20]

Yet a bright future for shale gas and CBM is far from assured. Developing and producing shale gas and CBM is an intensive industrial process. Compared to conventional gas development, more wells are often needed, drilled at considerably tighter well spacing. Moreover, hydraulic fracturing, along with expensive horizontal drilling, is usually required for sufficient gas production to ensure economic viability. The technological and operational wherewithal to develop shale gas and CBM resources using this technology is beyond the capability of many operators in the world today, requiring the use of global service companies, the services of which are currently in tight supply.

Moreover, a myriad of environmental concerns are also threatening to slow down or stop shale gas development in a number of regions of the world. These restrictions are due mainly to public concerns regarding gas leakage and/or pollution of shallow ground water resources as a result of hydraulic fracturing, although it is claimed by many regulators and industry that these concerns lack a factual basis.[21] Nonetheless, the scale of shale gas development can have major implications for local communities, land use, and water resources, if improperly managed. In addition, this development raises concerns about the potential for air pollution, greenhouse gas emissions, and contamination of surface and ground water. In France, environmentalists have been campaigning against shale gas development after a few shale drilling licenses were awarded in the south of France and around Paris. In July 2011, France approved a ban of the use of hydraulic fracturing techniques because of these concerns.[22] In the United Kingdom, in April 2012, the government backed the exploration of shale gas, nearly one year after it also temporarily banned the drilling method.[23] In Bulgaria, a similar ban was invoked,[24] but has also since been eased somewhat by allowing exploration, but not development.[25]

Politically contentious bans on shale gas development also currently exist in Quebec, Canada,[26] the state of New York in the United States,[27] and in several other states in the U.S. like Vermont and New Jersey (though these states are not expected to have much shale gas development potential).[28]

3. MECHANISMS FOR PRODUCING INCREMENTAL METHANE FROM AND STORING CO_2 IN COALS AND SHALES

In geologic settings such as deep saline aquifers and depleted conventional oil and gas reservoirs, CO_2 can be trapped by a number of different mechanisms, depending on the rock formation and reservoir type and its inherent properties. The most typical trapping mechanisms for CO_2 are:

- Structural (anticline or fault juxtaposition) or stratigraphic trapping (pinch-out of reservoir rock against non-reservoir rock), typical of the mechanism that often traps hydrocarbon accumulations.
- Hydrodynamic trapping, where CO_2 is entrained in formation water flow and is constrained above and below by impermeable sealing lithologies.
- Residual gas trapping, where the CO_2 becomes trapped in reservoir pore spaces by capillary pressure forces.
- Solubility trapping, where the CO_2 dissolves in the formation water.
- Mineral trapping, where the CO_2 precipitates as new carbonate minerals.

While all these mechanisms may also come into play in coal seams and gas shales, the principal and unique mechanism for CO_2 trapping in these settings is by adsorption. Adsorption trapping is the storage of CO_2 on the internal surfaces of micro-pores and fractures in the solid coal or shale matrix. The methane is stored in the matrix, both in the micropores and adsorbed onto organic matter. Adsorption is a chemical process in which the gas molecules form a layer upon the surface area of the organic matter within the pore space of the coal or shale. While porosity in coals and shales can be low, the micro-porous nature creates large amounts of surface area, and therefore vast amounts of gas storage potential.

In coal and shale settings, CO_2 has a higher affinity to become adsorbed onto the reservoir rock surfaces than the methane that is naturally found within them. Upon injection, the CO_2 displaces methane from some of the adsorption sites. The ratio of CO_2 to methane varies from basin to basin, but has been linked to the maturity of the organic matter in the coal or shale.

Two types of adsorption are believed to occur between the gases (either CO_2 or methane) and the reservoir rock. The first, physical adsorption, involves intermolecular forces (van der Waals forces) between the gas molecules and rock, and is believed to occur nearly instantaneously, with equilibrium quickly established. The second, chemical adsorption, involves the sharing or transfer of electrons. These two types of adsorption have been proven in coals, and it appears that these same two processes also occur in shales, but more research is needed.

The adsorption rate of coal varies based on the pressure in the reservoir. This is important as the pressure within the system needs to be lowered, through dewatering and CBM production, before injectivity of CO_2 can begin.

Sorption isotherms relate the gas storage capacity of a coal or shale as a function of pressure. The data obtained from sorption isotherms can be used to predict the maximum volume of gas that can be stored in the reservoir rock during injection, or the amount that can be produced from the rock when the pressure is depleted. Different sorption isotherms are characteristic of different gases.

Adsorption isotherms are measured through laboratory analysis of cuttings and core samples and are presented on a curve as a volume of gas per unit of coal or shale mass, at various pressures.

In both shales and coals, injected CO_2 will occupy the natural fracture system as either a free gas or a supercritical fluid, depending on reservoir pressure and temperature conditions. Standard volumetric methods can be used to estimate this capacity. A generally larger volume of CO_2 can be stored by the mechanism of adsorption of gas onto organic matter and clay minerals in the shale matrix. It does not matter whether or not the CO_2 is in a supercritical or dense phase for this mechanism to occur, though under supercritical conditions, coal can hold more gas than predicted by the Langmuir isotherm theory,[29] yet the mobility and reactivity of supercritical fluids in coal seams and shales is still not well understood.[30]

3.1 Coal Seams

Coal seams are naturally fractured, low-pressure, water-saturated reservoirs, where most of the gas is retained in the micro-pore structure of the coal by physical adsorption. CO_2 injected into coal seams is trapped by the combination of sorption on the coal surface and by physical trapping in the cleats within coal. A reservoir is that portion of the coal seam that contains gas and water as a connected system. Consequently, coal serves as a both the reservoir and the source rock. However, CO_2 can be transported away from a coal bed by becoming dissolved in formation water.[31]

Detailed understanding about what happens to CO_2 when it is injected into a coal seam is still evolving. The theory and understanding of the physical, chemical, and thermodynamic processes involved is complex, and numerous hypotheses have been formulated. White, et al.,[32] provided a good discussion of these hypotheses. The same processes dictate what takes place with regard to both methane production from and CO_2 storage in coal seams.

Shi and Durucan[33] report the following factors as playing a key role on coal seam capacity for CO_2 storage and potential ECBM production:

- ***Pressure, temperature, moisture content and coal rank:*** In general, the gas content in a coal seam increases with coal rank, depth, and reservoir pressure. Moisture content may affect the adsorption capacity, adsorption phase-density, and mixture adsorption behavior. Temperature-pressure conditions have a strong influence on the CO_2 storage in CBM reservoirs, as CO_2 becomes a supercritical above a temperature of 31.1^oC and a pressure of 7.4 MPa.

- ***Local hydrology:*** Often, coal seams are under-saturated with gas and need significant dewatering before methane can be produced. Hydrological constraints are considered one of the main factors for ECBM production and effective CO_2 storage.

- ***Inherent permeability:*** Permeability of coal is considered as the main factor that controls CBM production during primary and ECBM recovery. Theoretical and experimental studies investigating the effects of stress on coal permeability have been reported and indicate that coal permeability declines exponentially with depth. Shallow reservoirs tend to be low in reservoir pressure and gas content, whereas deep reservoirs suffer from diminished permeability. Seams deeper than 1,500 meters are generally considered not suitable for CBM extraction due to the excessive overburden weight.

Massarotto et al.[34] report a number of technical factors related to the reservoir-holding or reservoir-transport properties of coal seams. These include stressed and competitive sorption, geostructural and hydrogeological issues, geochemical reactions, counter-diffusion, effective and relative 4-D coal permeability, and methane recovery levels.

In general, most researchers conclude that coal rank is the primary selection criterion for CO_2 storage, with lower rank coals generally exhibiting higher sorption affinity for CO_2. In addition to the rank, variability in coal fracture properties (fracture porosity, permeability, and water saturation) and coal matrix properties (equilibrium sorption, diffusion, and gas saturation) also affect CO_2 storage.

For CO_2 storage and ECBM to be successful, storage targets should include coals with high permeability, thick coals with minimum faulting and folding, low water saturation, and high methane saturation. Coal cleats (small fractures in the coal seams) provide porosity and permeability in the coal seams and increase the capacity for CO_2 storage.

A good cap rock should overlay the target coal seam so that injected CO_2 remains in place and does not travel upwards. Favorable areas for successful CO_2-ECBM application would have coal seams that are laterally continuous and vertically isolated from the surrounding strata. This will ensure containment of the CO_2 within the reservoir as well as efficient lateral sweep through the reservoir. If not eventually mined, the CO_2 stored should, in theory, remain permanently within the coal deposits. Gunter et al. estimated that the retention time for CO_2 injection in deep unmined coal seams is on the order of 100,000 to 1,000,000 years.[35]

Trapping/Storage Mechanisms in Coal Seams

Gas stored by sorption in the coal matrix accounts for most of the gas in the coal seam, with the remaining gas stored in the natural fractures, or cleats, either free or dissolved in water. The proportion stored by each mechanism varies based on the characteristics of the coal. Most of the gas flows by diffusing through the coal matrix into the cleat system, which is then produced through desorption from the cleat surfaces. Thus, gas that is produced from coal is the result of desorption <u>and</u> diffusion.

The same mechanisms apply for CO_2 storage, though essentially in reverse.

Gas adsorption takes place primarily in the micro-pores of the coal matrix, and a significant proportion of the open pore volume is located in micro-pores, which represent the potentially available sites for adsorption. The surface area of the coal on which the methane is adsorbed is large, from 20 to 200 square meters per gram (m^2/g) and, if saturated, coal seams can have five times the volume of gas contained in a conventional gas reservoir of comparable size.

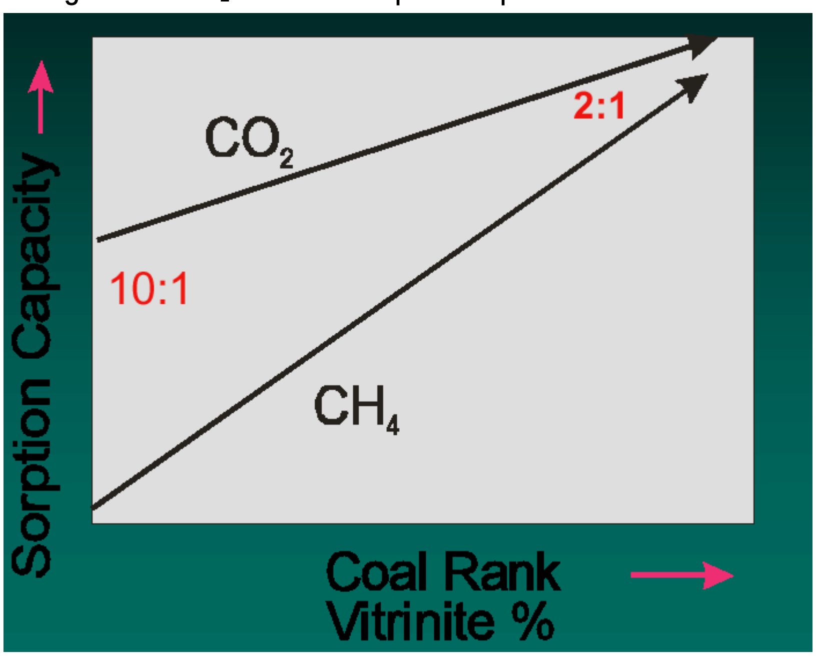
The chemical reactions and physical processes that occur during CO_2 injection into coal seams and their impact on the integrity of the coal seams are not well understood. Important coal properties that affect the capacity and rate of CO_2 up-take and methane desorption are coal rank, maceral content, and moisture content. Moreover, the CO_2 retention capacity of a coal is related not only to the properties of the coal itself, but also to *in situ* pressure and temperature.

Published values for the ratio of molar sorption capacity for coals vary from 2:1 to 10:1 or more.[36] For high volatile bituminous coals at low to medium pressures, the storage ratio is approximately 2:1. For lower quality coals at the same pressure, the storage ratio increases to approximately 8:1, and can be as high as 13:1 for lignite.[37]

This variation can relate to some extent to the fact that the ratios are often determined at pressures below saturation, and CO_2 is adsorbed more strongly than methane, which would increase the ratio especially at very low pressures. However, of more fundamental interest is the maximum adsorption capacity of the two gases, which has not been so intensively investigated.

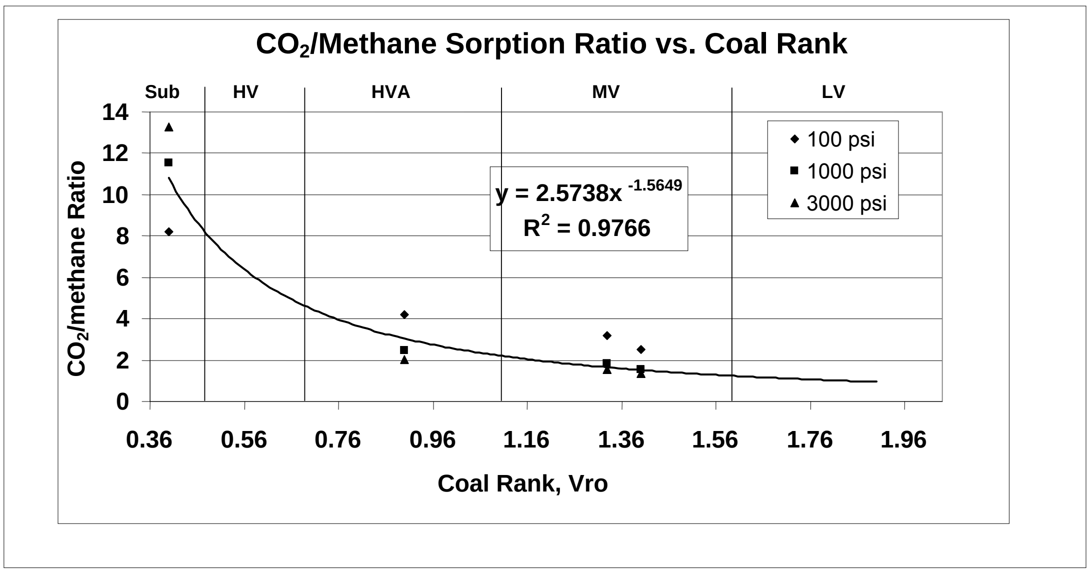
A technical consideration in selecting coal seams for ECBM/CO_2 storage process is the base methane adsorption capacity or gas content of the seam. Gas content varies with rank and reservoir pressure.[38] Bustin[39] conceptually presented sorption capacities for CO_2 and methane as a function of coal rank. This relationship, shown schematically for illustration purposes in **Figure 3.**1 (without units), suggests the replacement ratio of CO_2-to-methane is highest for low rank coals, and decreases with increasing coal rank. At higher ranks, the sorption curve at low pressures is steeper than at lower rank coals.

Figure 3.1: CO_2/Methane Sorption Capacities vs. Coal Rank



Reeves, et al.[40] analyzed selected data to provide a foundation upon which such a relationship could be established and used for developing basin-level assessments of the CO_2 storage capacity in coal seams. This was one of the first "quantitative" representations of its type. That relationship is presented in **Figure 3.2**. CO_2/methane replacement ratios decrease with increasing coal rank. The ratios are in the range of 10:1 for sub-bituminous coals, decreasing to 1:1 for low-volatile coal. A ratio of 10:1 means that 10 times the volume of CO_2 can be adsorbed relative to methane. CO_2 stored in the cleats can be either gas or supercritical, depending on temperature and pressure.

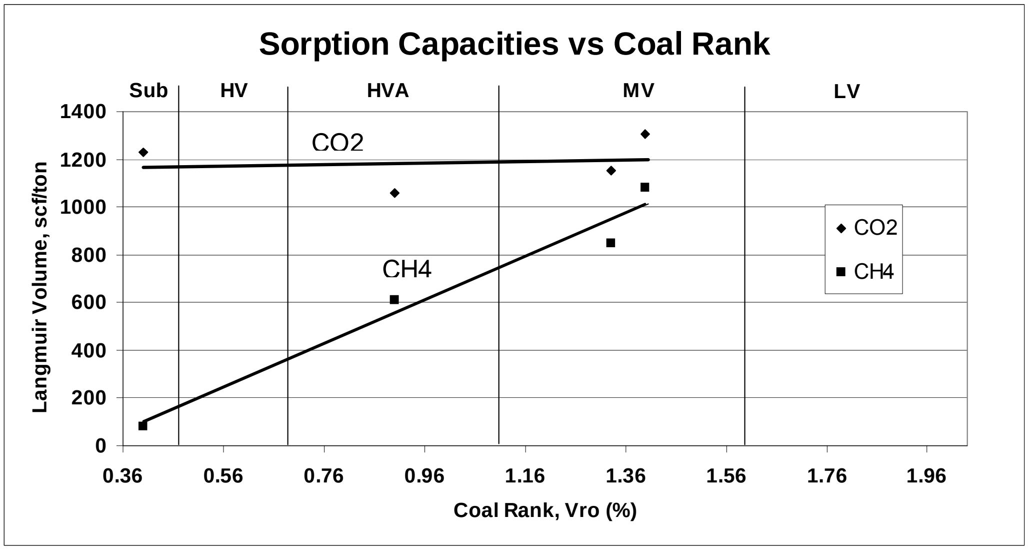
Figure 3.2: CO_2/Methane Replacement Ratios vs. Coal Rank



The ratios were computed at various pressures. The changes in ratio with coal rank are less pronounced at lower pressures. Since "higher" pressures are likely to be the operating range of most storage projects, the power-law curve fit shown is for a pressure of 1,000 psi.

Illustrating the same information in another way, **Figure 3.3** shows the CO_2 and methane sorption capacity, as defined by the Langmuir Volume, as a function of coal rank. This suggests that the changes of CO_2 sorption capacity with coal rank are only very minor, whereas those with methane are significant.

Figure 3.3: CO_2/Methane Sorption Capacities Ratio vs. Coal Rank



Footnote: The terminology used here for coal rank is low-volatile (LV), medium volatile (MV), high volatile A (HVA), high volatile (HV), and sub-bituminous (Sub).

In their more recent assessment of the sorption of CO_2, methane, ethane, and N_2 for a number of coals, Sakurovs et al. found that:[41]

1. There is a good correlation between the maximum sorption capacities of different gases on coals. The maximum sorption capacity of all examined coals for N_2 was found to about half that of their maximum sorption capacity for methane.

2. The differences in sorption capacity for the different gases are not consistent with pore accessibility, swelling variations or specific interactions with certain gases. The sorption capacity for a supercritical gas increases with increasing critical temperature of the gas.

3. The ratio of sorption of CO_2 to methane increases with decreasing carbon content; that is the ratio of maximum sorption capacity of CO_2 to methane decreased linearly with increasing rank. This variation is not due to the low rank coal having a specific interaction with CO_2, since the ethane to methane sorption ratio behaves similarly.

4. The ratio of maximum sorption capacity between CO_2 and methane decreases with increasing carbon content, from a ratio of 2.5 to a ratio of 1.5 over the range investigated, with an average ratio of about 1.8.

From a comparison of high and low pressure sorption behavior of 28 bituminous and subbituminous coals, Sakurovs[42] also found that for CO_2, the sorption capacity calculated at high pressure is always substantially greater than that estimated from low pressure sorption measurements. The difference between maximum sorption capacity from high pressure measurements and that from low pressure measurements increases with decreasing rank.

This difference can be quantitatively explained by swelling of the coal at high pressure that does not occur during low pressure measurements. When expressed as volume percent, the maximum sorption capacity calculated from high pressure measurements was found to equal the sum of the maximum sorption capacity calculated from low pressure measurements and the volumetric swelling the coal undergoes on exposure to high pressure. This relationship implies that the volume occupied by the coal molecules is constant when it swells: the greater apparent coal volume that occurs on swelling in gases is taken up completely by increased pore volume.

Moreover, this relationship provides a natural explanation for the finding that when a coal that is swollen with gas is compressed, the coal releases the gas. If so, low pressure sorption measurements may provide a more direct estimation of coal sorption capacity in constrained coal seams, provided a robust method of predicting maximum sorption capacity from low pressure sorption behavior can be established.

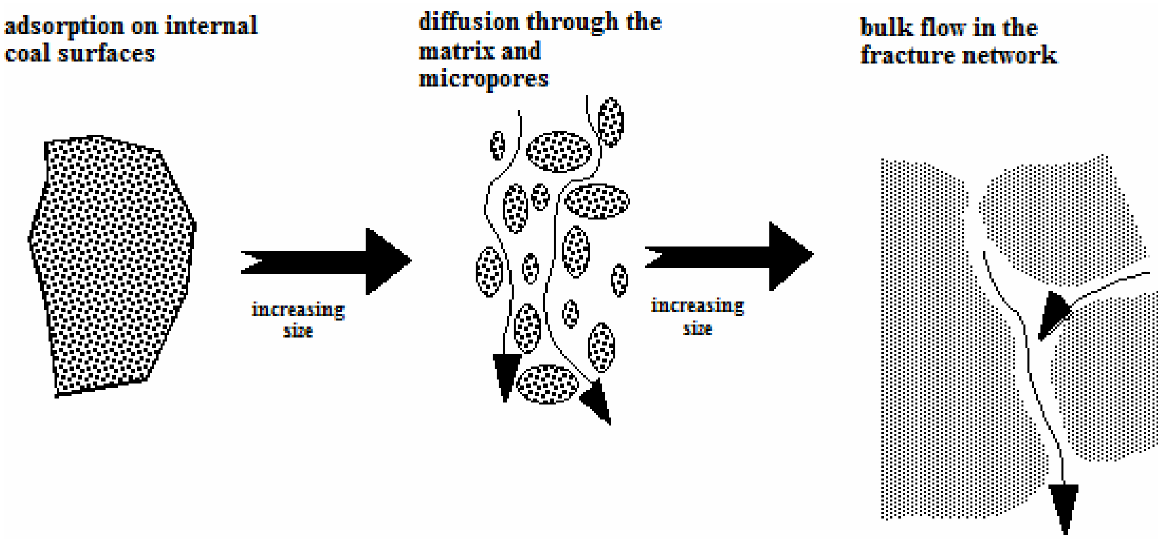
Transport of CO_2 and Methane in Coal Seams

During primary recovery by pressure depletion, methane production is facilitated by dewatering the target seams to allow desorption of the methane, which then migrates through the coal matrix into the cleats, **Figure 3.4**. In the early stages of dewatering, mainly water is produced. As more and more gas desorbs and becomes available for production, a two-phase flow regime develops. Eventually the water production declines and the coal seam behaves almost as a dry gas reservoir.

Therefore, the ability to transport the CO_2 through the coal seam is dependent on both the permeability of the seam itself (Darcian flow) and the intrinsic permeability of the coal matrix (Fickian diffusion). It is generally assumed that flow of gas (and water) through the cleats is laminar and obeys Darcy's Law. On the other hand, gas transport through the porous coal matrix is controlled by diffusion, described by Fick's Law.[43,44]

Three mechanisms have been identified for diffusion of an adsorbing gas in the macro-pores: molecular diffusion, where molecule-molecule collisions dominate; Knudsen diffusion, where molecule-wall collisions dominate; and surface diffusion, characterized by transport through a physically adsorbed layer. Gas diffusion in coals is influenced by coal rank and lithotype, microstructure, and secondary mineralization. As a result, the net effective diffusivity generally appears to include contributions from more than one mechanism.[45]

Figure 3.4: Schematic of the Flow Dynamics in Coal Seams



Again, with regards to injection and/or storage, the pathway for CO_2 and/or N_2 is reversed. During a CO_2 storage/ECBM operation, flow of CO_2 gas in the cleats would initiate a counter-diffusion between methane and CO_2 in the coal matrix, whereby adsorbed methane molecules are displaced by incoming CO_2 molecules, which have a higher adsorption capacity. Although diffusion of methane and other gases in coal has been extensively investigated, research on CO_2-methane counter-diffusion and competitive adsorption and desorption is still in its early stages.

As CO_2 becomes supercritical, it seems that adsorption is gradually replaced by absorption and the CO_2 diffuses or 'dissolves' in coal. Moreover, CO_2 is a 'plasticizer' for coal, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure (coal softening). The transition temperature is dependent on the maturity of the coal, the maceral content, the ash content and the confining stress, and is not easily extrapolated to the field. Coal plasticization or softening, may adversely affect the permeability that would allow CO_2 injection.

3.2 Gas Shales

Trapping/Storage Mechanisms in Gas Shales

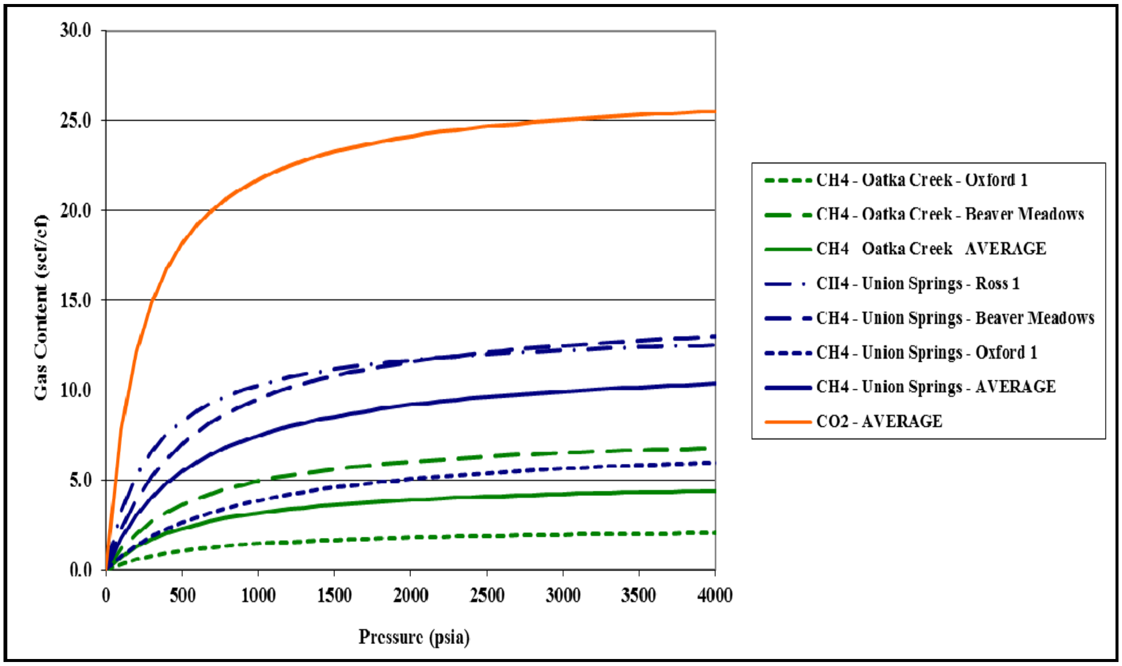
Like coals, gas stored by sorption in shales also accounts for much of the gas in the reservoir rock, with the remaining gas stored in the natural fractures. Bustin et al. concluded that the relative importance of adsorbed versus free gas varies depending on the amount of organic material present, pore size distribution, mineralogy, diagenesis, rock texture, and reservoir pressure and temperature.[46]

Although numerous CO_2 sorption measurements on coals under various conditions have been published, reports on CO_2 sorption isotherms on shales at high pressures are sparse. Nuttall et al.[47] investigated carbonaceous Devonian black gas shales from Kentucky and their CO_2 storage and methane recovery potential. They found a direct positive correlation between CO_2 storage capacity and total organic carbon (TOC), whereas no correlation with the clay mineral content was observed. In addition, drill cuttings from the Kentucky Geological Survey Well Sample and Core Library were sampled to develop CO_2 adsorption isotherms.

Methane and CO_2 adsorption isotherms for the Marcellus shale in the U.S. are available from three New York wells.[48] Methane isotherm data are available from the New York State Museum (NYSM) for the Beaver Meadows #1 and Oxford #1 wells in Chenango County. Methane isotherms for the Marcellus from the Ross #1 well in Otsego County have been made accessible courtesy of Gastem USA, Inc. NYSERDA acquired CO_2 isotherm data for the Marcellus from the Ross #1 well. The Marcellus isotherm data for New York are shown in **Figure 3.5.**

Recent work by Chareonsuppanimit and colleagues reports new primary data and gives a thorough review of previously published isotherm data for methane, CO_2, and N_2 on shales.[49] In this work, adsorption isotherms of methane, CO_2, and N_2 were measured on a New Albany shale sample from the Illinois basin in the U.S. As-received samples were used for measurements at 328.2^o K and pressures to 12.4 MPa. At about 7 MPa pressure, the excess adsorptions on New Albany shale for N_2, methane, CO_2, are in the ratio 1 to 3.2 to 9.3. This N_2:methane ratio was found to be similar to that for gas adsorption on coals and activated carbons, while the adsorption ratios of CO_2:methane and CO_2:N_2 were much higher than those typically seen for coals. Further, the amounts adsorbed on this shale are 10 to 30 times lower than adsorption on coals of varying rank. The authors conclude that the low levels of total organic carbon content (5.5%) and higher ash content of the shale (90%) play a role in reducing the gas adsorption capacity of the shale compared to coal.

Figure 3.5: Marcellus Methane and CO_2 Adsorption Isotherms



Kang, et al.[50] performed experiments on the ability of Barnett shale core samples to store CO_2. They demonstrated that organic shale has the ability to store significant amounts of gas permanently due to adsorption within its finely-dispersed organic matter. They note that CO_2 storage in shale has added advantages because the organic matter acts as molecular sieve allowing CO_2 -- with linear molecular geometry -- to reside in smaller pores that the other naturally-occurring gases cannot access. In addition, the molecular interaction energy between the organics and CO_2 molecules is different, which leads to its enhanced adsorption.

In both the samples they analyzed, the total CO_2 storage capacity is four times larger than the methane storage capacity at a pressure of 17.2 MPa. They also conclude that adsorption is the dominant mechanism for CO_2 storage, which is more pronounced that the case for methane. In one of their samples for the Barnett Shale, at the test pressure of 17.2 MPa, the ratio of absorbed to total CO_2 was 0.93, compared to 0.54 for methane. In the other sample, the ratio of absorbed to total CO_2 was 0.72, compared to 0.46 for methane.

Sidewall core samples were acquired by the Kentucky Geological Survey (KGS) to investigate CO_2 displacement of methane. Average random vitrinite reflectance data ranged from 0.78 to 1.59 (upper oil to wet gas and condensate hydrocarbon maturity range). Total organic content determined from acid washed samples ranged from 0.69% to 4.62%. CO_2 adsorption capacities at 2.8 MPa range from a low of 0.6 cubic meters per metric ton in less organic-rich zones to 2.9 cubic meters per metric ton in the Lower Huron Member of the shale. [51]

In Advanced Resources' (yet to be published) work for the DOE/NETL on the Marcellus shale, it has been determined that CO_2 would be preferentially stored by adsorption compared to methane at a ratio of approximately 3:1. For the Marcellus study area overall, adsorbed CO_2 accounts for 68% of the theoretical maximum CO_2 storage capacity, whereas adsorbed methane gas in-place is estimated to be only 26% of total gas in-place. These ratios of adsorbed-to-total volumes vary across the study area.

Kang, et al. concluded that pore volume estimation is a crucial step in CO_2 storage considerations in gas shale. However, this volume is not important for the free gas, since most of the injected gas (60% to 97% in their estimation) of the injected CO_2 will be stored in the adsorbed state inside the organic pores. They also conclude that gas transport takes place within a framework of dynamic porosity and permeability, and could be dominated by adsorbed-phase transport. [52]

Finally, as discussed above, Busch et al.[53] assessed the CO_2 sorption capacity of the Muderong Shale from Western Australia under conditions relevant for CO_2 storage. They found that CO_2 that migrates from a storage reservoir into the cap rock through the pore network will be largely immobilized, minimizing (slow, diffusion-driven) leakage and providing additional CO_2 storage potential. They conclude that high CO_2 sorption capacities for the Muderong Shale show that the high CO_2 concentration is related to a combination of CO_2 dissolution in water and gas sorption on clay minerals. Changes in specific surface areas before and after the sorption experiments and variations in the CO_2 sorption and diffusion behavior due to repetitive experiments on the same sample were observed, possibly related, they believe, to geochemical alteration of the shale and clay minerals. These could not be quantified and seemed to occur only at high pressures. They further conclude that these results provide a positive view on the sealing integrity of intact shale cap rock formations.

Transport of CO_2 and Methane in Shales

Kang, et al. [54] determined that mass transport paths and the mechanisms of CO_2 uptake in shale are not exactly like coals. Once at the fracture-matrix interface, the injected gas faces a geomechanically strong porous medium with a dual (organic/inorganic) pore system, and therefore has choices of path for its flow and transport into the matrix. Specifically, the CO_2 molecules can dissolve into the organic material and diffuse through a nano-pore network, and can enter the inorganic material and flow through a network of irregularly shaped voids. Using gas permeation experiments and history-matching pressure pulse decay, they show that a large portion of the injected CO_2 reaches the organic pores through the inorganic matrix. More importantly, they conclude that CO_2 transport in the organic pores is not due to flow, but mainly to pore and surface diffusion mechanisms.

Busch et al.[55] performed CO_2 sorption and diffusion measurements in order to assess the molecular transport through and the adsorptive storage behavior of well-defined shale, along with a variety of clay minerals. This was done in a repetitive succession on identical sample material to obtain insight into the changes in diffusion and sorption behavior due to the interaction with CO_2. Their results indicate that geochemical alterations such as dissolution of silicates and precipitation of carbonates may have measurable effects on the porosity, permeability and diffusion properties of shales, with a tendency to enhance the transport properties. But they conclude that even these enhanced transport properties are not likely to create substantial leakage problems through undisturbed massive shale sequences. Indeed, they state that by favoring the access to larger volumes of shale, they could positively contribute to mineral trapping of significant amounts of CO_2.

3.3 Processes/Mechanisms for Enhanced Gas Recovery and CO_2 Storage

No project to date has proceeded throughout the entire enhanced gas recovery (EGR) process for shales, or the ECBM process, through to CO_2 storage. To date, this process is conceptual, or only small scale tests have been performed.

However, at least ideal, it is important to conceptually understand the likely processes, mechanisms, and operational steps required for ECBM and EGR, followed by CO_2 storage. The sequence would likely start with some period of “conventional” primary shale gas or CBM production. In this process, wells (either vertical or horizontal, or both) would be drilled at a well spacing appropriate for the given geological setting. Most likely, these wells would be fractured (especially in the case of gas shales), perhaps in multiple sequences, to facilitate economic methane recovery. For coals and some shales, each well would proceed through a phase of dewatering, followed by gas production, where both free gas (in the fractures and matrix) and desorbed gas would be produced. For both, initial production rates would be high, followed by potentially long periods of production at a lower but steady rate.

After some period of primary production, some existing wells would likely be converted to CO_2 injection wells, and CO_2 injection into the shale gas or coal reservoir would commence. The optimal process for EGR/ECBM, combined with ultimate CO_2 storage, has yet to be determined. As described elsewhere in this report, critical performance factors will depend on reservoir properties (e.g., permeability, porosity, storage capacity) Given these properties, different field development strategies (e.g., well spacing, configuration, additional stimulation) or operating practices (e.g., timing of primary recovery relative to beginning CO_2 injection) could be optimal.

4. STATUS OF RD&D ON CO_2 STORAGE IN COALS

A summary of ongoing research activities related to CO_2 storage in coal seams is provided below. Additional details on the results of this research are sometimes described elsewhere in this report.

4.1 U.S. DOE Regional Carbon Sequestration Partnership Program

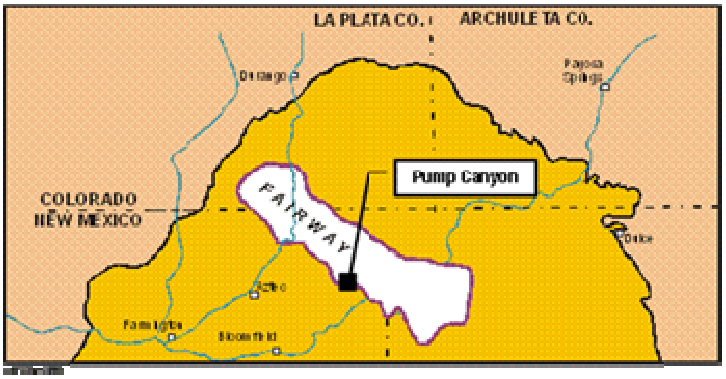
The U.S. federal government support of R&D on CO_2 storage is largely accomplished through the U.S. DOE Regional Carbon Sequestration Partnerships (RCSP) Program.[56] Research under the RCSP is being carried out in three main phases: Phase 1 – Characterization Phase (2003 – 2005), Phase 2 – Validation Phase (2004 – 2009), and Phase 3 – Deployment Phase (2009 – 2017). In Phase I, among a variety of tasks, all of the Partnerships performed a preliminary assessment of the storage potential of unmineable coal seams in their region. These are summarized in the *Carbon Sequestration Atlas of the United States and Canada*,[57] though the methane recovery potential through the application of ECBM has not been assessed.

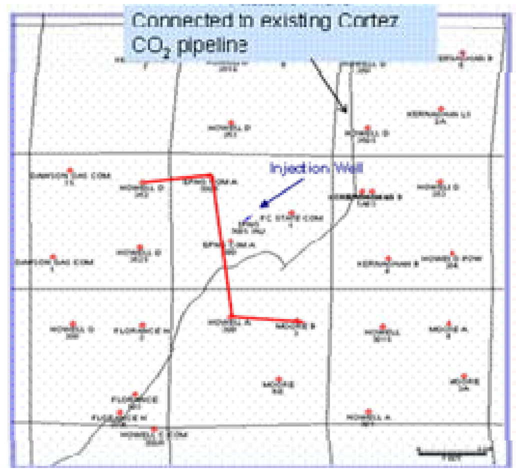
Activities for Phase 2 included five projects in the U.S. assessing the potential for ECBM recovery and CO_2 storage. The five tests injected a combined volume of more than 18,000 metric tons of CO_2 into coal seams to study their storage capability. These tests were conducted for various injection volumes, seam thicknesses, and coal types. The RCSP Validation Phase tests focused on addressing challenges to CO_2 storage in unmineable coal seams to move towards commercialization of this technology. These five tests are summarized below.

SWP Pump Canyon Test (U.S.)

The largest of these tests was the Pump Canyon CO_2-ECBM/storage demonstration in New Mexico, conducted as part of the Southwest Regional Partnership for Carbon Sequestration (SWP). The project was located in the Northern New Mexico portion of the San Juan Basin, **Figure 4.1**. A new CO_2 injection well was drilled into the late-Cretaceous Fruitland coals within an existing pattern of CBM production wells mainly operated by ConocoPhillips. CO_2 injection in the three coal seams was initiated in late July 2008 and stopped in August 2009.

Figure 4.1 : Location of the Pump Canyon Demonstration Site



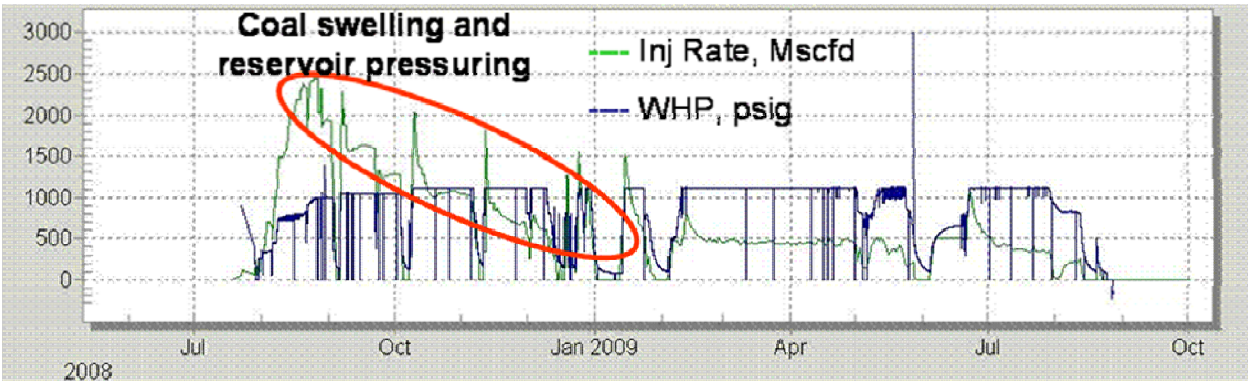


A variety of monitoring, verification and accounting (MVA) methods were employed to track the movement of the CO_2. These included continuous measurement of injection volumes, pressures and temperatures within the injection well, CBM production rates, pressures and compositions at the offset producer wells via CO_2 sensors, tracers in the injected CO_2, time-lapse vertical seismic profiling, and surface tiltmeter arrays.

A detailed study of the overlying Kirtland shale was conducted to investigate the integrity of this cap rock. In addition, detailed geologic characterization and reservoir modeling was implemented in order to reproduce and understand the behavior of the reservoir. No CO_2 breakthrough occurred, classifying the small scale demonstration pilot as a success.[58] Overall, 9 million cubic meters (316 million cubic feet) of CO_2 were injected at rates up to 70 thousand cubic meters per day (2,500 Mcfd). However coal swelling and reservoir pressuring decreased injectivity, with injection rates decreasing to 14 thousand cubic meters per day (500 Mcfd), **Figure 4.2.**

The effectiveness of methane recovery and CO_2 storage was determined to probably be limited due to the small amount of CO_2 injected. CO_2 sensors were shown to be an excellent means of monitoring breakthrough, but also that monitoring N_2 concentration might be as important. The reservoir model developed for this effort adequately predicted production and injection performance.

Figure 4.2: Injection Rate and Wellhead Pressure at the Pump Canyon Demonstration
(July 2008 to August 2009)



MGSC Wabash County Test (U.S.)

The Midwest Geological Sequestration Consortium (MGSC) conducted ECBM tests to determine the ECBM recovery potential and CO_2 injection and storage capability at a site located at the Tanquary field in Wabash County, Illinois. The target formation was the Pennsylvanian Carbondale formation at a depth of 275 meters (900 feet) in a 2 meter (7 foot) thick Springfield Coal. Pre- and post-CO_2 injection coal permeability was estimated with water in a pressure transient test. A CO_2 micro pilot injection test to assess coal swelling and permeability reduction was conducted with three monitoring wells aligned with the natural cleat system (1 face-cleat and 2 butt-cleat) spaced at 15 and 30 meters (50 and 100 feet) from the injector.

Pre-injection site MVA began in February 2007. Four wells were drilled and completed (three monitoring and one injection) by May 2008. CO_2 injection began in the summer of 2008 with a total of 91 metric tons of CO_2 injected. Methane gas production was noted at the face and butt cleat monitoring wells, and CO_2 was observed at all monitoring wells. No reduction in injection rate attributable to CO_2 swelling was observed. MVA activities for the test included baseline, injection, and post-injection monitoring, including continuous in-zone pressure and temperature, gas content of the injection formation, cased-hole logging, shallow groundwater quality surveys, and shallow geophysical surveys.

The preliminary MVA results showed shallow ground water quality was not impacted by CO_2 injection activities, based on water chemistry results. Acquired high-resolution, color-infrared aerial imagery to assess potential stress showed no CO_2 stress and a hydrogeologic flow model was developed that shows ground water flow is generally from the west.[59]

PCOR ECBM Test (U.S.)

The Plains CO_2 Reduction Partnership (PCOR) conducted a coal seam test where approximately 80 metric tons of CO_2 was injected into unmineable lignite seams of the Williston Basin at a drilling depth of approximately 370 meters (1,200 feet) to determine the suitability of these strata for both CO_2 storage and ECBM production. The test was located in Burke County, North Dakota, and attempted to determine whether long-term contact with CO_2 affects the physical stability, hydrodynamic properties, and gas storage capacity properties of a lignite coal seam.

One CO_2 injection well and four monitoring wells were completed in a five-spot pattern during the summer of 2007. A 9 meter (30 foot) core was retrieved (including 6 meters (20 feet) of cap rock) for geophysical and geochemical analysis. Site characterization work revealed the existence of multiple coal seams with sufficient areal extent and low-permeability clay layers above and below the target seam. CO_2 was injected in March 2009, providing 80 metric tons over a 16 day period. Seismic imaging revealed the extent of the CO_2 plume, and enabled estimation of CO_2 migration and occupation within the coal. Down-hole instruments measuring pressure and fluid pH in monitoring wells proved to be a successful in corroborating seismic data and logging results, which enhanced the determination of the fate of the injected CO_2. Indications are that the injected CO_2 migrated within the coal formation and was contained within the expected injection zone.[60]

SECARB Black Warrior Basin Coal Test (U.S.)

One project in the Southeast Regional Carbon Sequestration Partnership (SECARB), the Black Warrior Basin Coal Test, took place in the Blue Creek Coal Degasification Field near Tuscaloosa County, Alabama. An existing CBM well was utilized for injection into the coal seams of the Pennsylvanian-age Pottsville Formation, and three monitoring wells were drilled and instrumented. Three coal seams -- the Black Creek, Mary Lee and Pratt --, whose depths range from 305 to 610 meters (1,000-2,000 feet), were targeted. The plan was to inject about 900 metric tons of CO_2 (approximately 300 metric tons per coal seam). However, based on operator preference and concern over fugitive migration of the CO_2, just over 270 metric tons of CO_2 were injected between June and August of 2010. [61]

SECARB Central Appalachian Basin Coal Test (U.S.)

A second SECARB project, the Central Appalachian Basin Coal Test, validated storage opportunities in the unmineable coal seams of the Central Appalachian Basin. Located in Russell County, Virginia, the project planned to inject 900 metric tons (1,000 tons) of CO_2 into multiple coal seams of the Pocahontas and Lee Formations at depths ranging between 425 and 670 meters (1,400 feet and 2,200 feet).

A detailed regional assessment was completed of the potential Central Appalachian Basin CO_2 storage capacity. A comprehensive suite of production maps for the active CBM wells in the Central Appalachian Basin was developed. Preliminary reservoir modeling on the test site was completed. Site selection was completed on a donated CNX Gas CBM well, along with the initial reservoir modeling, site permitting, and well design for the field test site. Injection occurred from January 15 to February 9, 2009. Post-injection monitoring activities verified the CO_2 has remained in the coal seams, but gas analysis has shown that the injected tracer is present in the offset producing CBM wells. Long term monitoring of the flow back is ongoing.

The Central Appalachia Basin Coal Test under SECARB has two additionally funded follow-on projects. One project, located in an active CBM field in Buchanan County in southwest Virginia, plans to inject 20,000 metric tons of CO_2 into a series of thin, unmineable coal seams. Up to three CBM production wells will be converted for use as injection wells. The goals are to test the injection and storage potential of the coal seams and to assess the potential for ECBM recovery at offset wells. The reservoir consists of approximately 15 coal seams, distributed over 270 meters (900 feet) of section. This reservoir geometry creates an unusual target for CO_2 injection, and is also challenging for many monitoring and imaging techniques.[62]

The second follow-on project in the Appalachian Basin is the evaluation of the potential application of geomechanical models in coal seam reservoir simulation of CO_2 geologic sequestration and ECBM recovery. This work, led by the Virginia Center for Coal and Energy Research at Virginia Tech University, will examine the potential of geomechanical models to better account for the physical processes that occur during CBM production and CO_2 injection and storage. The results of this study could be potentially used for improving modeling of reservoir simulators, which rely on analytical models to describe pressure-permeability relationships.

In summary, the results of these five tests showed adequate CO_2 containment capabilities for the geologic sealing layers located above the injected coal seam formations. Coal swelling was identified as a potential barrier to CO_2 injection into coal seams.

4.2 Review of Major Coal Seam Field Tests – Other U.S. Based Projects

Additional field-level tests on the injection and storage of CO_2 in coals, combined with ECBM, have been or are being conducted in the United States. The most significant of these tests are summarized below.

Allison Unit CO_2-ECBM Pilot (U.S.)

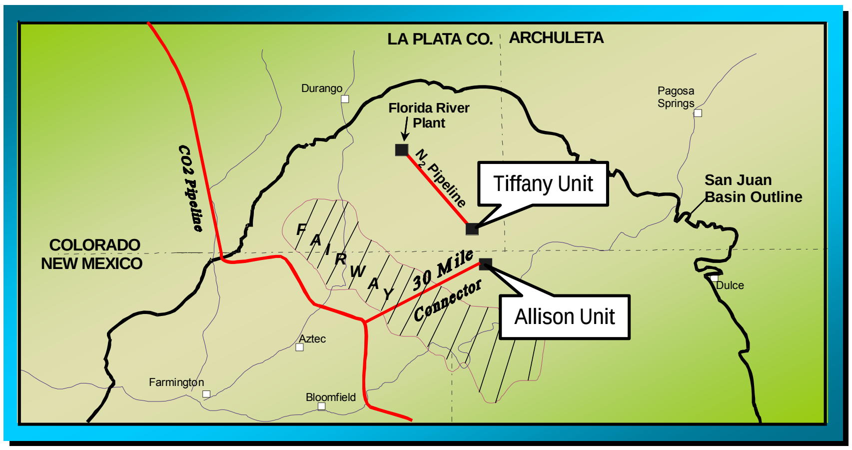
One of the longest-operated ECBM and CO_2 storage field pilots in the U.S. is the Allison Unit CO_2-ECBM pilot in the San Juan Basin, operated by Burlington Resources and evaluated by Advanced Resources. During six years of operation (1995-2001), approximately 335,000 metric tons of CO_2 were injected into the deep, 900 meter (2,950 feet) Fruitland coal seams. The project recovered 45 million cubic meters (1.6 Bcf) of incremental CBM and stored a net 270,000 metric tons of CO_2.

A detailed reservoir study of the pilot, which included performing a full-field characterization, simulation history-matching, and performance forecasting, indicated that CO_2 injection improved CBM recovery in the affected area from 77% to 95% of the original gas in-place, **Figure 4.3**. The production history and reservoir properties for this CO_2 storage and ECBM project are provided on **Figure 4.4**.

During CO_2 injection at the Allison Unit, a reduction in CO_2 injectivity was initially observed, **Figure 4.5**.[63] This was the first documented field evidence confirming the theoretically anticipated phenomena of coal swelling and permeability reduction with CO_2 injection. Studies of this behavior, including well testing, indicated that the coal permeability near the well was reduced by up to an order of magnitude, but that the effects gradually became less severe further from the well, leading to an overall 60% reduction in CO_2 injectivity in the four injection wells.

Figure 4.3: Background on Allison Unit, San Juan Basin

Location of Allison Unit, San Juan Basin



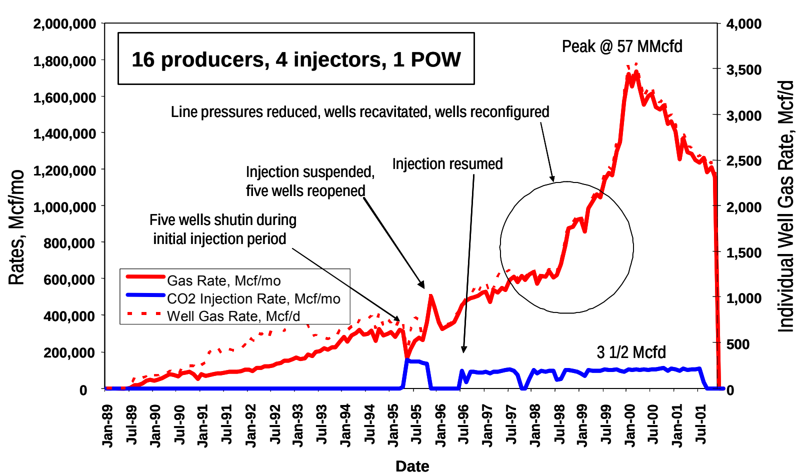
Field History/Status

- **CBM field on primary production since 1989.**
- **CO_2 injection commenced in 1995 (four injection wells, 16 production wells).**
- **Production enhancement (recavitation, line pressure reduction, well workovers) implemented with CO_2 injection.**
- **3 million cfd (6.4 Bcf) of CO_2 injected from 1995 through 2001.**
- **Operator currently evaluating "long-term" effects of ECBM.**

Source: Reeves S.R. and Oudinot, A.: "The Allison Unit CO2-ECBM Pilot – A Reservoir and Economic Analysis", 2005 International Coalbed Methane Symposium, Paper 0523, Tuscaloosa, Alabama, May 16-20, 2005

Figure 4.4: Producing History and Reservoir Properties, Allison Unit CO_2-ECBM Pilot

Producing History

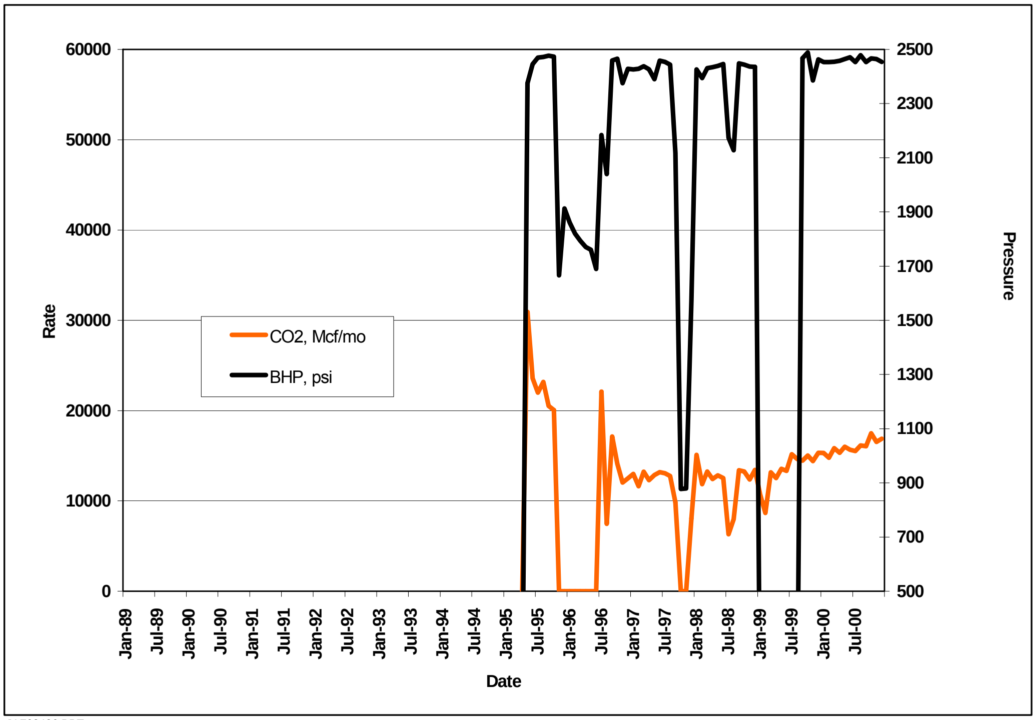


Basic Coal Reservoir Data

Property	Value
Average Depth to Top Coal	3,100 feet
Coal Rank	High Vol, A (Ro 1.3)
Average Total Net Thickness	43 Feet (3 intervals)
	Yellow – 22 ft
	Blue – 10 ft
	Purple – 11 ft
Initial Pressure	1,650 psi
Temperature	120º F

Source: Reeves S.R. and Oudinot, A.: "The Allison Unit CO2-ECBM Pilot – A Reservoir and Economic Analysis", 2005 International Coalbed Methane Symposium, Paper 0523, Tuscaloosa, Alabama, May 16-20, 2005

Figure 4.5: Typical Injection Pressure History, Allison Unit CO_2-ECBM Pilot



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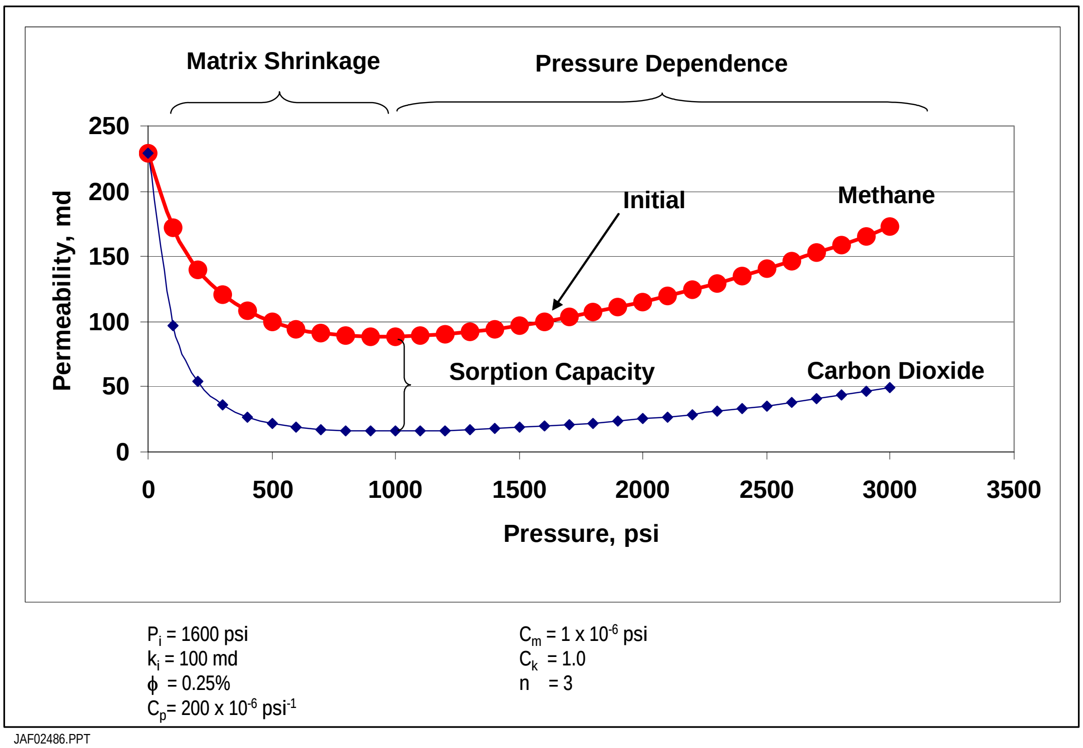
Source: Reeves S.R. and Oudinot, A.: "The Allison Unit CO2-ECBM Pilot – A Reservoir and Economic Analysis", 2005 International Coalbed Methane Symposium, Paper 0523, Tuscaloosa, Alabama, May 16-20, 2005

What was unexpected was the rebound in injectivity following the initial decline, as shown in **Figure 4.6**. Further analysis concluded that this was caused by a continued decrease in overall reservoir pressure with time (methane production volumes from the reservoir were considerably greater than CO_2 injection volumes into it), which enabled the adsorbed CO_2 near the well to desorb and migrate further into the reservoir, causing matrix shrinkage and a permeability increase, similar to that observed during primary methane depletion.

Additional sensitivity studies were performed to evaluate the impact of other parameters on project performance. These studies indicated that deeper, higher rank, and lower permeability coals that have not been previously developed for conventional CBM production may provide the best economics for CO_2 storage. It also showed that, in these cases, near-pure CO_2, rather than a mixture of N_2 and CO_2, provided the best economic results, due to additional capital costs related to N_2 separation and recycling, and the lower CO_2 storage volumes when using N_2 and CO_2 mixtures. The exceptions were in the lowest permeability and highest rank coals, when the inclusion of N_2 appeared to enhance performance sufficient to offset the increased costs. In general, N_2 was shown to still be effective at depths greater than 800 meters. In these settings, miscibility is not a critical factor, and CO_2 would still retain its properties. In fact, at depths shallower than 800 meters, the CO_2 is essentially adsorbed in a supercritical-like state. Nonetheless, understanding these phenomena is still something that future R&D needs to resolve.

Figure 4.6: Permeability Changes with Net Stress, Gas Concentration, and Sorptive Capacity, Allison Unit CO_2-ECBM Pilot



Source: Reeves S.R. and Oudinot, A.: “The Allison Unit CO2-ECBM Pilot – A Reservoir and Economic Analysis”, 2005 International Coalbed Methane Symposium, Paper 0523, Tuscaloosa, Alabama, May 16-20, 2005

The main conclusions drawn from the Allison Unit CO2-ECBM project were:

- *CO_2 injection into coal can significantly improve methane recovery*. At the Allison Unit CO_2-ECBM pilot in the San Juan Basin, methane recovery was improved from 77% (under traditional practices) to 95% (using CO_2 injection) of original gas in place within the central pilot area.
- *Injectivity losses are likely when CO_2 is first introduced into the coal seam*. Initial CO_2 injectivity at the Allison Unit was reduced by 60% (with coal permeability reduced by an

order of magnitude near the wells). However, the loss of CO_2 injectivity was modest and a steady rebound in CO_2 injectivity was noted with time.

- Improvements are required in reservoir simulation models to properly capture the interaction of CO_2 injection, methane release, and the coal reservoir. Existing reservoir simulation models provide a reasonable match of project performance. However, the current mathematical models of multi-component sorption, diffusion and phase behavior may not accurately replicate actual reservoir behavior. Specifically, coal swelling cannot currently be adequately modeled in a dynamic fashion.

- *Advances in well injectivity technology could unlock the massive CO_2 storage potential of CBM resources in deep coals.* A technical/economic sensitivity assessment shows that the most favorable coal conditions for CO2 storage are the deep, high-rank coals with low permeability that have not been previously developed for conventional CBM production. However, this assumes technology is developed to overcome reduced injectivity due to matrix swelling.

Tiffany ECBM Pilot (U.S.)

The potential benefits of using CO_2/N_2 mixtures to possibly overcome the limitations from swelling associated with injecting pure CO_2 were also well documented at the Tiffany ECBM pilot in the San Juan Basin of New Mexico, the first long-term N_2-ECBM pilot conducted.[64,65] BP (formerly Amoco Production Company) began to investigate ECBM techniques in the late 1980s, primarily via laboratory experiments, which involved injecting a gas, or mixture of gases such as N_2, CO_2, or flue gas, to improve CBM recovery. Building on the success of laboratory and pilot tests, it moved forward with the first full scale N_2-ECBM commercial pilot at the Tiffany Unit. After nine years of production, N_2 injection was commenced in January 1998; utilizing ten newly drilled directional N_2 injection wells, and later into two additional converted production wells.

The results showed a steep increase in methane production accompanied by the rapid breakthrough of N_2. This breakthrough resulted from a ten-fold increase in the cleat permeability; increasing from 1 to 10 md with an associated reduction in storage capacity.

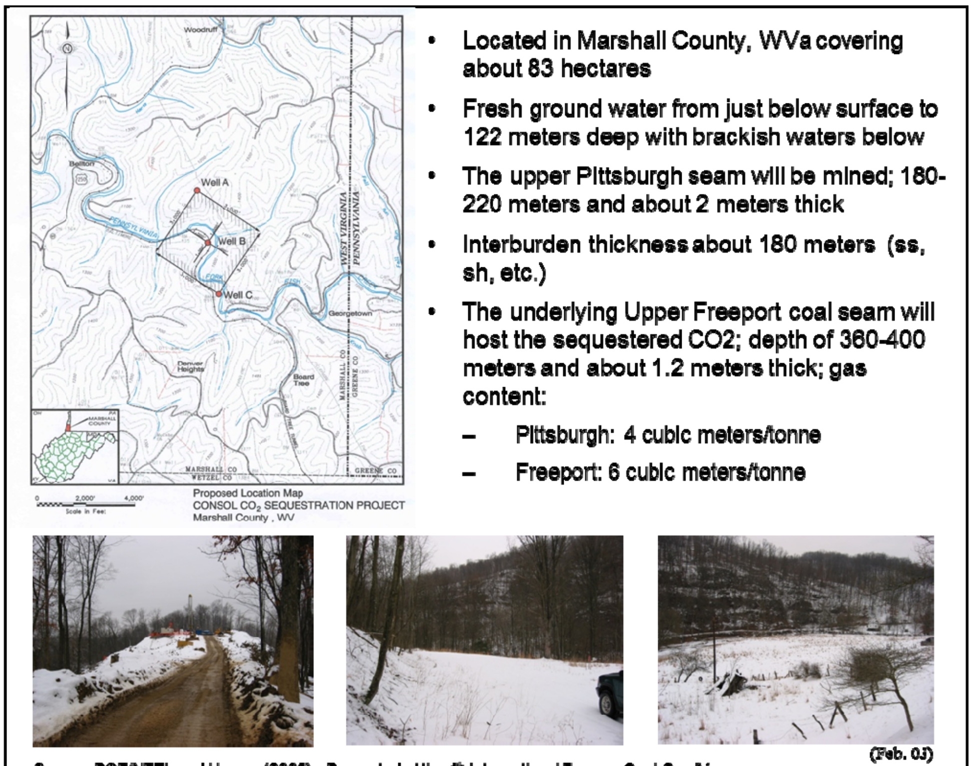
Interestingly, this is the opposite behavior of what happened at the pilot at the nearby Allison Unit. Since the coal swells during the injection of CO_2, permeability decreases. In fact, permeability measurements at the site using pressure transient testing revealed a permeability decrease from 100 to 1 md. As expected, this hundred-fold reduction in permeability resulted in a significant loss of CO_2 injectivity. In addition, the high CO_2 storage capacity of these coals, combined with a declining injection rate due to coals swelling, resulted in no CO_2 breakthrough during the six-year test,[66] although methane production did improve, albeit not as dramatically as at the Tiffany N_2-ECBM test site.

These results indicate that in cases where the rank and permeability are not adequate for ECBM and storage operations, there may be opportunities to look at pulsing and/or mixing N_2 into the injection stream to improve injectivity during storage and ECBM operations.[67]

CONSOL Marshall County Project (U.S.)

DOE/NETL sponsored a major field project with CONSOL Energy to demonstrate the application of novel coal seam well drilling technology to economically recover CBM and store CO_2. The project was located in Marshall County, West Virginia with the deeper Upper Freeport coal seam serving as the proposed host for injection and storage or CO_2, **Figure 4.7**. The field project involved a combination of four vertical wells, six lateral wells, and three vertical monitoring wells, **Figure 4.8**.

Figure 4.7: Site Map and Site Characteristics, CONSOL Project



Source: DOE/NETL and Hyman (2005) – Presented at the 4th International Forum – Coal-Seq IV, Denver, Colorado, November 9-10, 2005.

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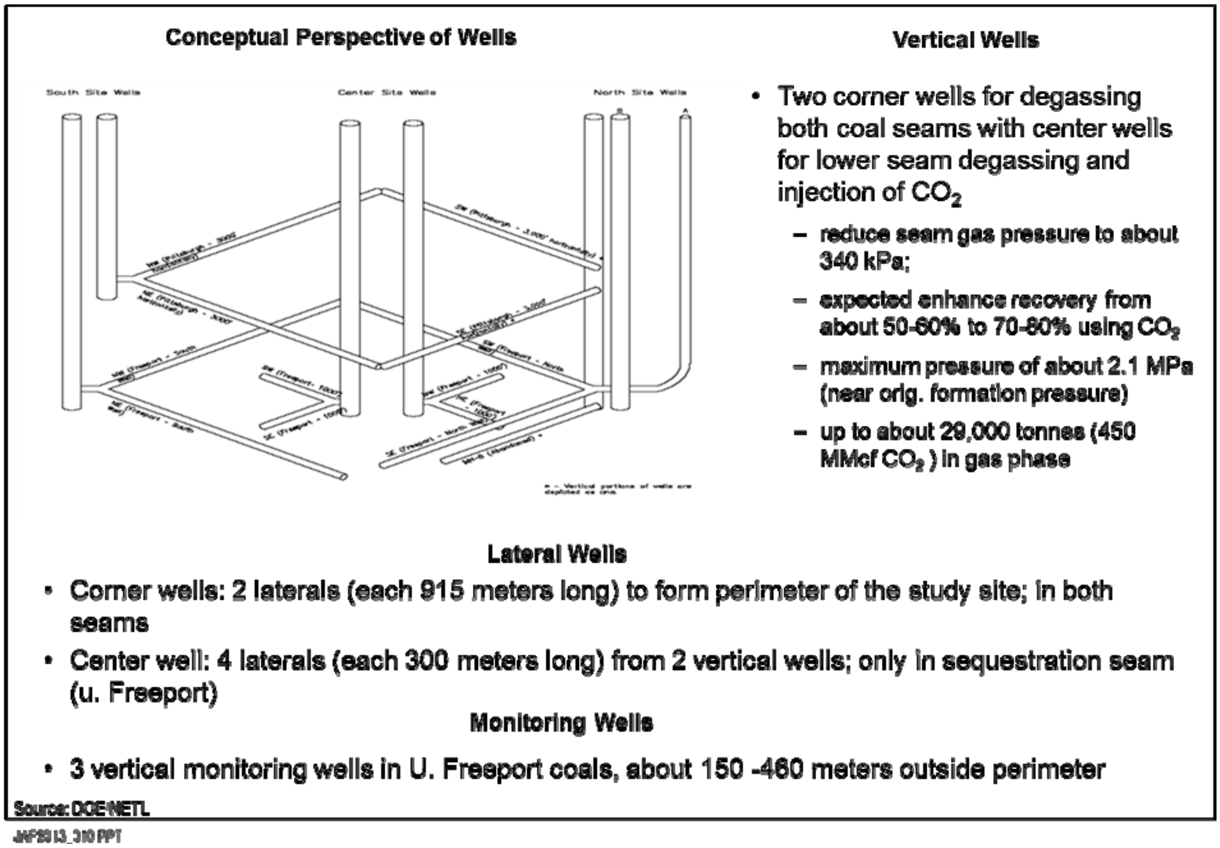
Figure 4.8: Conceptual Perspective Wells, CONSOL Project



Source: Hyman (2005) – Presented to 4th International Forum – Coal-Seq IV, Denver, Colorado, November 9-10, 2005.

The operational objective of this field project was to increase the recovery of CBM from the traditional 50% to 60% of gas in-place to 70% to 80% of gas in-place using CO_2. Injection of CO_2 began in September 2009. Nearly 1,800 metric tons of CO_2, out of the planned 18,000 metric tons, have been injected into the Upper Freeport coal seam. CO_2 injection has been subject to injection pressure limitations and mechanical difficulties. Injection system operation is limited to an injection pressure of 6,400 Mpa (933 psig) by the West Virginia Department of Environmental Protection (WVDEP) Class II underground injection control (UIC) permit. The injection increased to and was maintained just below this pressure for more than a year. After the maximum pressure was achieved, the daily injection rates gradually decreased to a rate of only 5 metric tons per day, far below the 24 metric tons per day target.

West Virginia University, DOE/NETL, and CONSOL Energy are working to expand monitoring and characterization activities at the site. Activities include monitoring for perfluorocarbon tracers injected in the CO_2 stream (NETL), soil gas flux monitoring (NETL), CBM monitoring (CONSOL), ground water monitoring (CONSOL, WVU), surface tilt monitoring (WVU), and seismic monitoring (WVU). Monitoring activities are widely distributed across the site and surrounding area. Monitoring will continue for two years after injection ceases.

As of early August, 2011, over 1,900 metric tons of CO_2 were injected without indication of CO_2 leakage. Injection will continue until CO_2 breakthrough occurs or 18,000 metric tons of CO_2 are injected, whichever is first.[68]

4.3 Review of Major Coal Field Tests -- Non-U.S. Based Projects

Internationally, research focused on ECBM and CO_2 storage in coal seams has been conducted or is currently underway in Canada, Australia, Japan, Poland, Switzerland, UK, Norway, Germany, the Netherlands and China.

Fenn-Big Valley (Alberta, Canada)

One of the earliest and highest profile ECBM research pilot projects took place in Alberta, Canada starting in 1997. The project, funded by the former Alberta Research Council (now part of Alberta Innovates – Technology Futures), consisted of a three-phase program. Phase I consisted of an initial assessment of the feasibility of injecting pure CO_2 into deep Mannville coals in Canada. Phase II consisted of the design and implementation of a micro-pilot test of injection of pure CO_2. Phase III consisted of the assessment of reservoir responses to different compositions of injected flue gases and of the design and implementation of a full-scale pilot project. Phase IIIA focused on: (1) efficient surface facility designs both at commercial and pilot scale (based on economics and net CO_2 stored); (2) testing synthetic flue gas compositions in several micro-pilots both in an existing well and in a new well drilled at Fenn-Big Valley; (3) testing pilot-scale flue-gas generation and injection facilities; and (4) performing additional reservoir characterization.

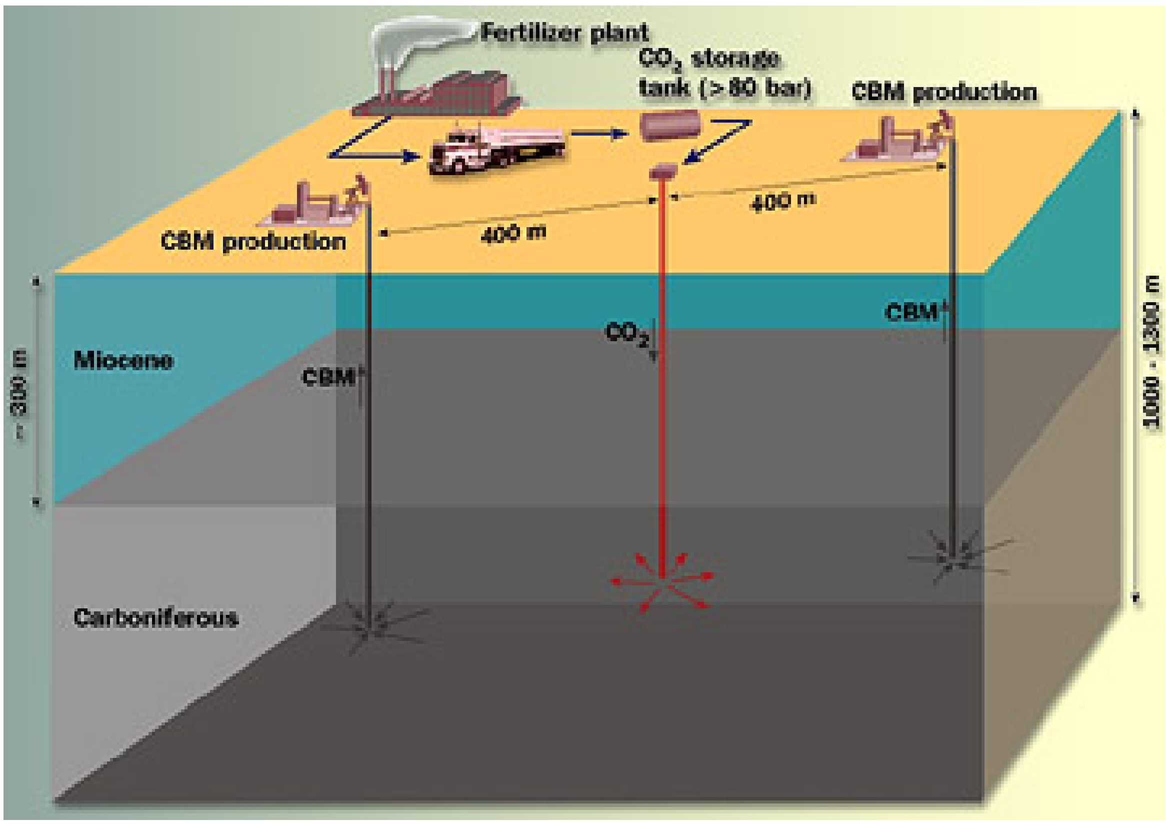
This project showed that even in tight reservoirs, continuous CO_2 injection is possible and that the injected CO_2 remains in the reservoir while increasing sweep efficiency. This project was one of the first to assess using CO_2/N_2 mixtures to possibly overcome the limitations from swelling associated with injecting pure CO_2.[69]

RECOPOL Project (Poland)

The RECOPOL CO_2 injection project involved three wells, one CO_2 injection well and two CO_2 production wells. Two existing CBM production wells (MS-1 and MS-4) were refurbished as the CBM/CO_2 production wells. A new well (MS-3) was drilled 150 meters north (down dip) of the

MS-4 well as the CO_2 injection well, **Figure 4.9**. Three thin coal seams were the target for the CO_2 injection and storage test. Each coal seam was bounded (above and below) by a highly impermeable sandstone layer. There was uncertainty as to whether the coal seams were continuous between the two wells. The target coals were high volatile bituminous in rank, with low to moderate permeability (0.5 to 5 md). The actual permeability measured in the test wells was 1.2 md. The gas content of the coal seams was 95% methane (minimum), with 1 to 3% CO_2 and 0.5 to 3% N_2.

Figure 4.9: Design of Field Experiment, RECOPOL Project

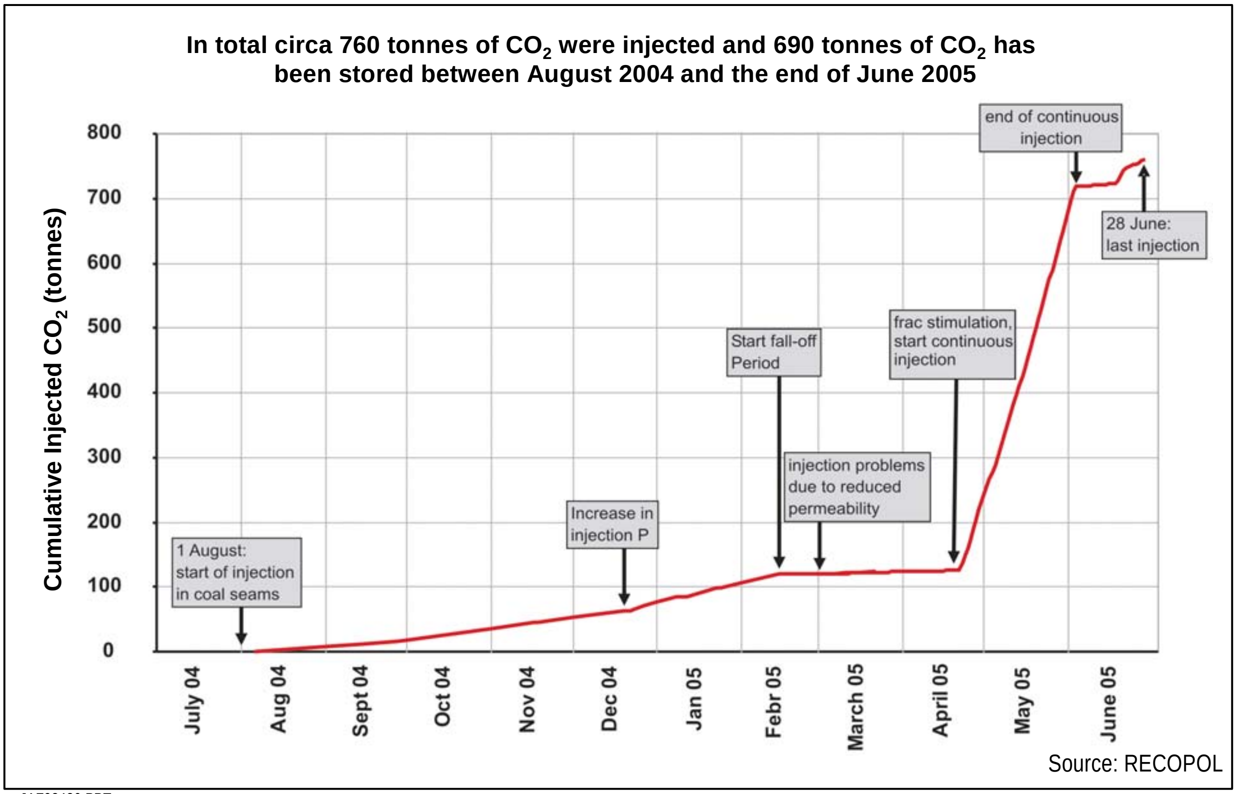


Source: http://recopol.nitg.tno.nl/recopol5a.shtml

A pressure fall-off test conducted after CO_2 injection ended showed that the injection pressure was insufficient either to fracture the coal or to sufficiently open the cleat system in the coal to support CO_2 injection. The CO_2 injection rate reduction was likely due to the effect of coal swelling around the injection well as CO_2 was absorbed by the coal.

During the second phase, a hydraulic stimulation (with proppant) was conducted to provide improved reservoir access and injectivity for the CO_2. Following the stimulation, CO_2 was successfully injected at rates of 15 metric tons per day, close to initial design rates, and a total of 692 metric tons of CO_2 were stored in the coal reservoir, **Figure 4.10**. An increase in the CO_2 content of the produced gas was observed toward the end of the project. Isotopic analyses subsequently confirmed that the increased CO_2 content was from the injected CO_2. A breakthrough of the CO_2 into the production well was predicted by the simulation models.

Figure 4.10: CO_2 Injection, RECOPOL Project



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CO_2 injection into the coal seam at RECOPOL helped identify the many challenges faced for this geological storage option. Some of the challenges are attributable to establishing proper equipment design. Equally challenging was to understand and decide how to address the decrease in permeability around the well bore. RECOPOL considered two alternatives for increasing the permeability around the well bore - - coal fracturing and horizontal drilling. RECOPOL chose to use the lower cost coal fracturing option, given the considerable depth of the coals and the presence of competent cap rocks and seals that would contain the upward growth of the fracture.

CSEMP CO_2 Sequestration and Enhanced Methane Production (Alberta, Canada)

The Carbon Storage & Enhanced Methane Production (CSEMP) project was led by Suncor Energy, with the research program under the leadership of the former Alberta Research Council. The site was located in the Pembina field in Alberta. The zone of interest was the Lower Ardley coal. The overall scientific/technical objective of the project was to develop an extended pilot to test coal seam response to CO_2 injection, determine CO_2 storage parameters, evaluate ECBM production potential and establish storage, monitoring and verification parameters, and evaluate the impact on ground water quality and production.

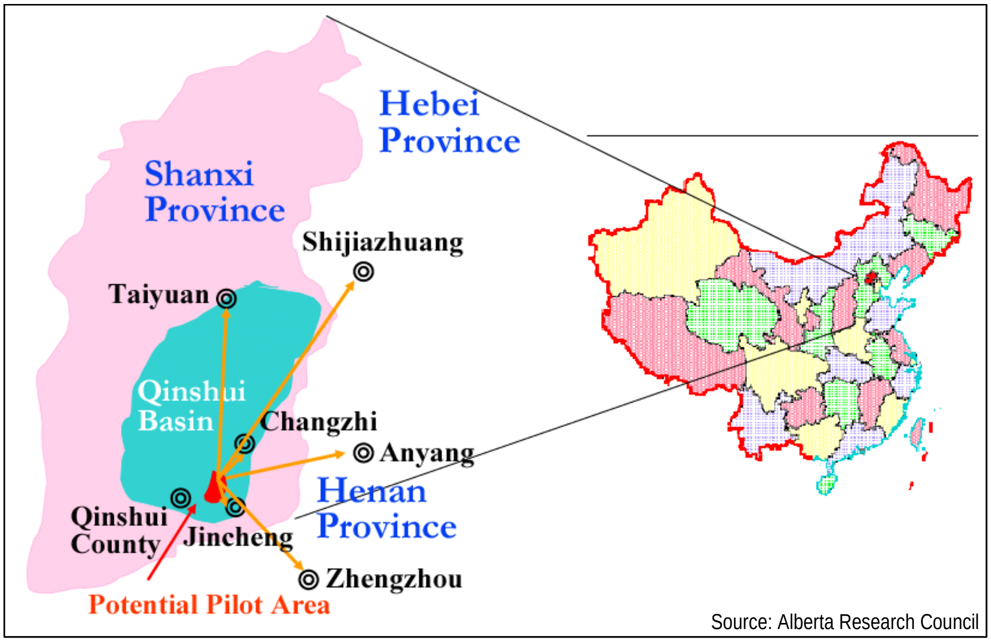
This pilot test was successfully completed and met all technical objectives. A total of 192 metric tons of CO_2 was injected, with a coal seam soak of 30 days. Injectivity decreased during injection, but permeability rebounded after an extended production period of one month. Production took place for 60 days, with measurement of gas composition, pressures and flow rates. History matching indicated a significant methane production enhancement compared to primary production, and demonstrated that substantial CO_2 storage in the coal seam is feasible in a multi-well project.[70]

Qinshui Basin Project (China)

The former Alberta Research Council also conducted a joint project with the Canadian International Development Agency (CIDA) and the China Coal Bed Methane Clearing House (CUCBM) in the south Qinshui Basin of Shanxi Province in North China, **Figure 4.11**. In the initial (completed) phase of the project, 192 metric tons of CO_2 were injected into a single coal seam in 13 injection cycles, soaked, and produced back.

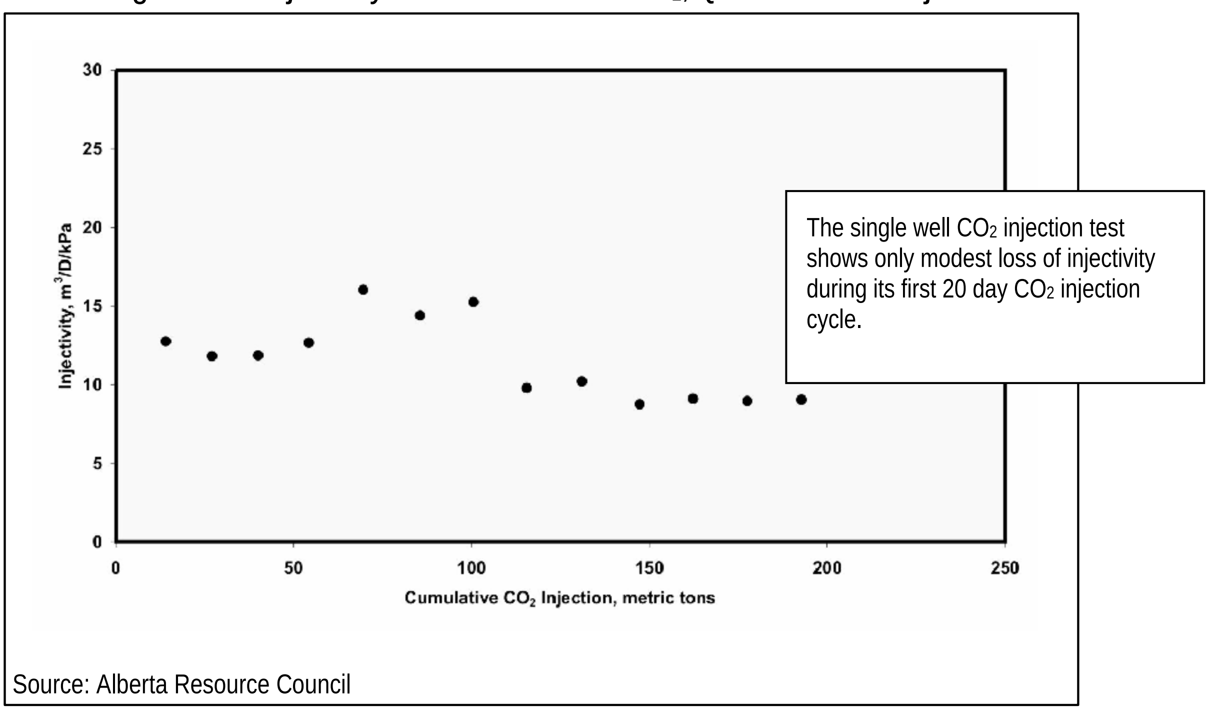
In an initial, single well, “huff and puff” test conducted from October 2003 to August 2004, it was reported that some 200 metric tons of CO_2 had been injected over a 22 day period at an injection rate of about 10 metric tons per day, **Figure 4.12**. The target coal was anthracite and has a measured permeability from the well pressure test of 1 to 3 md.

Figure 4.11 : Demonstration Site Location, Qinshui Basin Project



Source: http://gcep.stanford.edu/pdfs/wR5MezrJ2SJ6NfFI5sb5Jg/15_china_gunter.pdf

Figure 4.12: Injectivity versus Cumulative CO_2, Qinshui Basin Project



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Source: http://gcep.stanford.edu/pdfs/wR5MezrJ2SJ6NfFI5sb5Jg/15_china_gunter.pdf

The injectivity stayed relatively constant while the estimated permeability reduced substantially during injection. The single well micro-pilot test well has been completed successfully and met all technical objectives. Successful history matching of the dataset from the micro-pilot and use of the calibrated numerical simulator to predict the multi-well pilot performance established the level of production enhancement compared to primary production, and demonstrated that CO_2 storage in the coal seam is feasible.[71]

Hokkaido Project (Ishikari Coal Field, Japan)

The potential for ECBM and CO_2 storage was assessed at a project near Yubari on the island of Hokkaido in northern Japan. The target coal seam was a 5 to 6 meter thick Yubari coal seam located at a depth of 900 meters. A small test with a single well and several multi-well CO_2 injection tests involving injection and production wells were carried out in the period between May 2004 and October 2007. A variety of tests were conducted, including an initial water injection fall-off test and a series of CO_2 injection and fall-off tests. Although the gas production rate was shown to be obviously enhanced by CO_2 injection, the water production rate was not clearly affected by CO_2 injection. Several tests suggested that injectivity of CO_2 into the coal seam saturated with water was eventually increased as the water saturation near the injector was decreased by the injected CO_2. Low injectivity of CO_2 was believed to be caused by the reduction in permeability induced by coal swelling.[72]

A N_2 flooding test was performed in 2006 to evaluate the effectiveness of N_2 injection on improving well injectivity. The test showed that the daily CO_2 injection rate was boosted, but only temporarily. Moreover, the permeability did not return to the initial value after CO_2 and N_2 were repeatedly injected. It was also indicated that coal matrix swelling might create a high stress zone near to the injection well.

CSIRO/CUCBMC Shanxi Province Project (Australia, China)

In 2010, the Australia Commonwealth Scientific and Industrial Research Organisation (CSIRO) announced a CO_2-ECBM demonstration project in China partnering with China United Coal Bed Methane Corporation Ltd (CUCBMC) and supported by JCOAL, Japan. The project is in the Liulin Gas Block, Shanxi Province, at a depth of approximately 500 meters. The plan is to investigate the effect of horizontal drilling through the coal seams, with the aim to store 2,000 metric tons of CO_2 underground and extract methane for use as an energy source.

4.4 Other Research on the Storage of CO_2 in Coals

Coal-Seq Consortium (U.S.)

The U.S. DOE-sponsored Coal-Seq Consortium has also been underway for some time with the purpose of advancing the science of CO_2 storage in unmineable coal seams and gas shale reservoirs.[73] The initial Coal-Seq Project, which ran from 2000 – 2004, was solely DOE funded. Subsequent Phases II (2005 – 2008) and III (2009 – present) are joint DOE/industry funded. The Coal-Seq Consortium is a consortium of government, academia, and industry charged with developing and producing models for permeability and injectivity of CO_2 in coal and shale.

Phase I of Coal-Seq performed detailed studies of two ECBM pilots in San Juan basin (Allison Unit & Tiffany Unit, described above), created a field Best Practices Manual, created the first publically-available database of isotherms for U.S. CBM basins, evaluated isotherm models to multi-component gaseous systems, assessed the CO_2 storage and ECBM recovery potential for U.S. coal basins, developed a screening model for CO_2-CBM storage, performed pilot design modeling for Poland's RECOPOL project (described above), developed an improved permeability model to incorporate differential swelling, evaluated geochemical effects of CO_2 injection in coal, and facilitated technology transfer via the Coal-Seq website (www.coal-seq.com) and annual fora.

Phase II of Coal-Seq built upon these initial efforts to build an improved model and the computational algorithms to estimate single and multi-component sorption capacity for coal bed gases based solely on readily accessible coal characterization parameters; a theory-based adsorption modeling capability, including further development of the simplified local-density framework for describing CBM adsorption equilibrium of pure fluids and mixtures, and a generalized, matrix-calibrated model to provide accurate predictions within three times the experimental uncertainties; a significantly expanded CBM adsorption database, which includes valuable data for pure-gas adsorption on six wet coal matrices and activated carbon; and the experimental setup and procedure design for development of a new equation-of-state (EOS) for methane-CO_2-N_2 gaseous systems. Phase II efforts also included the measurement of incremental swelling of coal when CO_2 is injected, identification and analysis of coal mechanical weakening when exposed to CO_2, a comparative study of geo-mechanical models for CBM operations, continued reservoir analyses for the RECOPOL (Poland) and Yubari (Japan) CO_2 storage pilots, the incorporation of various reservoir theories developed into flow modeling software, assessment of “best” reservoir environments and development strategies for CO_2-ECBM and storage projects, and the continued facilitation of global technology exchange and networking via the website and annual fora.

The primary project goal of the current Coal-Seq III Consortium is to develop a set of robust mathematical modules to accurately predict how coal and shale permeability and injectivity change with CO_2 injection. This is to include improved capabilities in three key areas: (1) changes in coal mechanical strength properties and thus permeability in the presence of high pressure CO_2; (2) changes in cleat and matrix swelling and shrinkage of coals and thus permeability due to injection of CO_2 under field replicated conditions, and (3) rigorous modeling of CO_2 and other gas adsorption behavior in wet coals, with water as a separate adsorption component.

In terms of continued validation, Coal-Seq III endeavors to validate the theoretical and experimental results with data from large-scale field projects; explore the feasibility of storing CO_2 in gas shale reservoirs; using the newly generated simulation modules; assess the CO_2 storage potential of the San Juan Basin’s Fruitland Coal as well as the Marcellus and Utica shales of the Appalachian Basin; disseminate the project findings to industry, regional sequestration partnership working groups, and the scientific/ engineering communities via publications and presentations; and foster continued international collaboration on CO_2 storage in coal seams and shale reservoirs via the website and fora. This work is still underway, with most of the work not yet published.

Pennsylvania State University (U.S.)

The EMS Energy Institute at Penn State University is comparing high-pressure CO_2 sorption isotherms of eastern and western U.S. coals. The role of mineral components in coals, coal swelling, the effects of temperature and moisture, and the error propagation has been analyzed. Changes in void volume due to dewatering and other factors such as temporary caging of CO_2 molecules in coal matrix were identified among the main factors affecting accuracy of the CO_2 sorption isotherms. Additional work includes the investigation of the permeability of propped and non-propped artificial cleats in bituminous coal and the quantification of the proppant embedment. The goals of the research are to ultimately provide guidelines for drilling of new CBM production wells and enable field engineers to determine if cases of poor CO_2 storage and/or low methane productivity can be attributed to non-ideal coalbed temperatures, depths, or other factors.[74]

Oklahoma State University (U.S.)

Oklahoma State University is leading an effort to develop, test and investigate the ability of injected CO_2 to enhance CBM production. The research is investigating competitive adsorption behaviour of methane, CO_2 and N_2 on the surface of a variety of coals to determine how much is needed to displace the methane. The project objectives are to investigate the ability of injected CO_2 to enhance methane production, investigate competitive adsorption behaviour of methane, CO_2 and N_2 on coal surfaces, and to determine the level of CO_2/N_2 required to displace methane from coal.[75]

CARBOLAB Research Project (European Commission Research Fund for Coal)

The CARBOLAB research project (funded by the European Commission Research Fund for Coal and Steel) aims to improve knowledge of carbon storage and CBM production by “in situ” underground tests. The CARBOLAB project intends to advance this knowledge by performing underground tests of CO_2 injection and CBM production in a specially conditioned panel of a coal mine in Spain. The tests will be performed from underground, in order to save costs and to improve the experiment control by reducing the size of the test dimension. It is expected that data obtained in this way will be of higher quality and density than in other tests carried out from the surface, and in combination with the planned laboratory tests, will enable to observe with detail the behaviour of the injected gases and the methane initially contained in the coal bed, and to obtain understandable parameters of the different processes involved. All this information will be used to produce models of these phenomena that will help to better understand the process of ECBM and the long term safety of CO_2 storage.[76]

Commonwealth Scientific and Industrial Research Organisation (CSIRO) (Australia)

In Australia, CSIRO is conducting an integrated program of research to assess the viability of the long-term storage of CO_2 in coal seams. This work is part of a research program conducted by CSIRO through the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC). The project aims to develop an understanding of the geological and geochemical behaviour of injected into coal seams by taking accurate measurements to determine the adsorption/desorption properties of CO_2 in coal, undertake analogue (equivalent/likeness) studies of naturally occurring CO_2 in coal, and develop reservoir simulations to predict the long-term behaviour of coal-injected CO_2. CSIRO researchers have developed methods to characterize Australian coal seams at the high temperature and pressure conditions that are indicative of the deep coal seams targeted for CO_2 storage. Results indicate increased adsorption at high pressures over what would be predicted for low pressures, and studies of natural analogues in the Sydney coal basin have shown that coal seams can hold CO_2 within their structure for many millions of years.[77] CSIRO's work is indicating that complicating effects such as site accessibility, swelling, confining stress and mineral matter of coal along with new observations and experimental approaches are leading to questions whether these traditional adsorption experiments can be used to accurately predict the methane-CO_2 gas exchange expected in the coal seams.

Bengal Engineering and Science University (India)

In India, a research project had been initiated, entitled "Methane and Carbon Dioxide Pure and Competitive Sorption Behavior of a Set of Indian Coals for Enhanced Methane Recovery and Carbon Sequestration," with the objective to understand the pure and competitive sorption behavior for the CO_2-methane system in coal. The complete sorption isotherm characteristics of a few Indian coal samples of varying maceral composition and vitrinite reflectance between 0.64% and 1.30% were first studied separately with methane and CO_2.[78]

CO2SINUS (Germany)

Work is underway in Germany to evaluate the potential for a low emission power plant based on utilization of synthetic gas from in-situ coal conversion, or underground coal gasification (UCG), with emphasis on free-gas and adsorptive CO_2 storage in the resulting gasified coal seams. Within this evaluation, the economic and environmental aspects of CO_2 storage in gasified coal seams will be considered with regard to operational costs, environmental protection, and CO_2 storage security. Project goals for this effort are as follows:[79]

- Implementation of an innovative concept for CO_2 storage in in-situ converted coal seams
- Evaluation of environmental impacts with regard to ground water protection and technical approaches based on operating experience of former and current international UCG projects
- Investigation of economics of UCG and combined CO_2 storage
- Estimation of CO_2 storage potential based on laboratory gasification, permeability tests, and sorption experiments
- Evaluation of CO_2 storage security in gasified coal seams by numerical modelling using input parameters from experimental studies conducted on coal seams and cap rocks

- Preparatory scientific work for implementation of a large-scale field test.

4.5 Summary

The process and technology of ECBM and CO_2 storage is still in the development phase. In 2006, in support of a USDOE "Carbon Sequestration Technology Roadmap and Program Plan," Advanced Resources developed data and an information intensive "Technology Design and Implementation Plan" for CO_2 storage in deep, unmineable coal seams.[80] At the time, it provided a baseline of ongoing research and field tests in the area of CO_2 storage in coals. As part of the effort, information and opinions were gathered from a group of ten experts from industry, academia, and government via questionnaires. Based on a review of past and ongoing R&D related to CO_2 storage in coals, a review of major field projects at that time, and the input of the interviewed experts, key knowledge gaps and technical barriers were identified. These are presented below (in somewhat modified form reflecting new information and the specific requirements of this assessment):

1. A lack of globally disaggregate information on the available storage capacity in deep, unmineable coals
2. A lack of guidelines for establishing location-specific criteria for defining "unmineable coals"
3. A lack of sufficient, widely available geological and reservoir data for defining the favorable settings for injecting and storing CO_2 in coals, particularly the lack of data on deep coal depositional settings and reservoir properties
4. Insufficient understanding the near-term and longer-term interactions between CO_2 and coals, and between N_2 and coals, particularly being able to develop site/location specific models of coal swelling (reduction of permeability) in the presence of CO_2 and N_2, coal shrinkage with release of methane (increase in permeability), and the physics of CO_2/methane exchange under actual reservoir conditions of pressure and confinement
5. Need for formulating and testing alternative reliable, high volume CO_2 and/or N_2 injection strategies and well designs, in multiple reservoir settings. This would help reduce the number of wells required for storing the significant volumes of CO_2 from power plants and other industrial sources of CO_2 (and N_2)
6. Integrating CO_2 storage and enhanced recovery of coalbed methane.

Based on the identified technical, economic and environmental barriers, a set of R&D needs and supporting tasks were considered to be of high priority for improving the understanding and technology of CO_2 storage in coals. Note that this set of high priority R&D needs and supporting tasks was specific, at the time, to USDOE. Nonetheless, while significant progress has been made concerning the key knowledge gaps and technical barriers identified, and some of the R&D needs and supporting tasks have been pursued, these knowledge gaps and technical barriers, along with the high priority R&D needs, still exist. These are presented in **Table 4.1** (in somewhat modified form reflecting new information and the specific requirements of this assessment).

Table 4.1: R&D Needs and Supporting Tasks for CO_2 Storage in Coals

R&D Needs	Supporting Tasks
1. Conduct an increased number of integrated field pilots.	• Ensure that all field tests contain supporting laboratory work on coal properties and extensive use of reservoir simulation. • Develop an accessible, in depth database of coal properties and injection/storage capacity for each major coal basin. • Ensure field tests and new laboratory and reservoir simulation development are closely coordinated.
2. Improve predictive modeling capability for N_2 and CO_2 injection in coals, including: • Improved representation of bi-directional diffusion • Appropriate incorporation of hysteresis during adsorption and desorption • Rigorous representation of multi-component gas adsorption.	• Define "unmineable coal seams." • Develop methods for sampling deep coals. • Gather data on coal properties from a range of potential formations – especially for deep seams on absolute permeability, permeability anisotropy, Young's modulus. • Conduct sustained CO_2/N_2 injection field tests over a range of coal ranks and depths with significant pre- and post-injection sampling and modeling support. • Develop scientific and applied reservoir models of CO_2/N_2 flow and recovery in concert with field tests and laboratory studies.
3. Demonstrate well stimulation and other field practices that provide viable CO_2/N_2 injection rates.	• Exercise CO_2 flow models to identify CO_2 well and pattern design practices that will enhance CO_2/N_2 injectivity. • Conduct field tests of CO_2 injection into coal seams using horizontal wells.
4. Develop a better fundamental understanding of coal properties and their changes with injection of CO_2 and sorption under reservoir conditions.	• Address limitations of current experimental data/methods: o Effects on confining pressure on absorption and desorption of $CO_2/CH_4/N_2$ on coal o Effects of multi-component gases o Unaltered coal behavior versus powdered coal. • Determine whether (or under what conditions) contact with CO_2 fundamentally alters the coal structure.
5. Develop updated estimates of realistic CO_2 storage capacity in coals.	• Incorporate the effects of alternative well designs and pattern configurations on CO_2 storage capacity. • Incorporate and use improved data base on coal settings and reservoir properties. • Incorporate definition of "unmineable" coals in calculating CO_2 storage capacity.
6. Develop improved monitoring, mitigation and verification systems, particularly to monitor the plume of injected CO_2 in a coal bed.	• Conduct laboratory studies of ECBM migration and displacement processes at multiple scales (micro and core scales). Should include measurement of: o Seismic wave propagation o Electrical conductivity changes.

Modified based on Advanced Resources International, *Technology Design and Implementation Plan for CO_2 Storage in Deep, Unmineable Coal Seams*, report prepared for U.S. Department of Energy, March 31, 2006

5. STATUS OF RD&D ON CO_2 STORAGE IN SHALES

5.1 Status of R&D

A summary of research activities related to CO_2 storage in gas shales is provided below. Additional details on the results of this research are described throughout this report.

DOE/NETL Assessment of Factors Influencing Effective CO_2 Storage Capacity and Injectivity in Eastern Gas Shales (U.S.)

USDOE/NETL is sponsoring a research project, being performed by Advanced Resources, to examine the ability of shale formations to act as CO_2 storage formations as part of their CO_2 storage research efforts.[81] This project is designed to expand upon previous and ongoing research to assess the factors influencing effective CO_2 storage capacity and injectivity in selected eastern gas shales. These shales are located in an area of the U.S. with a significant concentration of large CO_2 emission sources (coal-fired power plants), but where finding suitable geologic CO_2 storage sites is challenging.

The project has the following objectives:

- Acquire, analyze, and synthesize data on reservoir properties for selected eastern gas shales, through collaboration with selected state geological surveys, universities, and operators.
- Develop, through detailed reservoir simulation, a better understanding of shale characteristics that impact sealing integrity, storage capacity, and injectivity.
- Verify this understanding through a targeted, highly monitored, small-scale CO_2 injection test, to provide additional insight on CO_2 injection operations and monitoring.
- Test a new technology for monitoring the movement and fate of CO_2 in gas shales -- a smart particle early warning system.
- Characterize potential constraints to economic CO_2 storage in gas shales, as a function of shale characteristics; and based on this, identify possible development and production approaches to overcome these constraints, to guide future efforts in project design.
- Develop an updated characterization of the CO_2 storage potential of selected eastern U.S. gas shales (perhaps for incorporation into the DOE/NETL Carbon Sequestration Atlas).

For selected gas shales in the eastern U.S. where at least some data are available, well log data have been correlated to regional cross sections to develop preliminary estimates of theoretical maximum CO_2 storage capacity in shale gas basins. In this work, total organic content (TOC), density, porosity, and water saturation were calculated from well logs to estimate effective, or gas-filled, porosity. Adsorbed methane and CO_2 content were extrapolated based on available CO_2 and methane adsorption isotherms. Total methane gas in-place as adsorbed gas and "free" gas (non-adsorbed gas in effective porosity) were calculated for each study well. Individual well results were extrapolated to obtain estimates of total gas in-place and maximum CO_2 storage capacity for selected areas for the Marcellus and Utica shales in New York, Pennsylvania, Maryland, West Virginia, and Ohio.

The next step is to determine the portion of the theoretical storage capacity that could be considered "accessible" capacity. This will be based on reservoir simulation work performed to better understand the shale characteristics impacting sealing integrity, storage capacity, and injectivity.

In parallel, a targeted, highly monitored, small-scale CO_2 injection test was conducted to validate the understanding articulated in current preliminary reservoir models. The test was managed by the University of Kentucky Research Foundation on behalf of the Kentucky Geological Survey (KGS). Located in Johnson County, Kentucky, a pressure transient test will be performed by pumping about 100 metric tons of CO_2 into the Devonian shale in several stages. In a pressure transient test, reservoir pressure was allowed to build during pumping and then drop off during a shut in period to reveal information on the behavior of the reservoir and produced gases. The test well was fracture stimulated using N_2 when drilled in 2002 and the test was conducted below 365 meters (1,200 feet) deep at low pressure to prevent the formation of new fractures.

Acquisition of baseline logging was completed with regard to the scheduled field test. Initial baseline logging included the reservoir saturation tool (RST), PBMS (pressure & temperature), a Spinner log, and a multi-finger caliper (PMIT) log. The CO_2 injection and enhanced natural gas recovery field test took place in September 2012.

The injection and pressure fall off and flow back data and the log results (spinner results and RST saturation profiles) were initially analyzed and used to model the CO_2 injection. Preliminary analyses were conducted based on graphical CO_2 injection rate curves.

Kentucky Geological Survey - Eastern Kentucky Shale Gas Enhanced Recovery and CO_2 Storage Project (U.S.)

The injection test described above is being conducted as part of a larger research effort on the CO_2 storage potential in gas shales in Kentucky, led by the Kentucky Geological Survey. [82,83,84,85] The goal of the "Eastern Kentucky Shale Gas Enhanced Recovery and CO_2 Storage Project" is to test and demonstrate injecting CO_2 into organic-rich, black gas shales for long-term storage and enhanced natural gas production. The main tasks of this project are to acquire data for reservoir simulation; use the modeling to test and plan CO_2 injection; undertake site selection, construction, and injection for a small scale injection test; and assess the results of that test. CO_2 adsorption isotherms of gas shale samples and have been developed and relationships between CO_2 adsorption and methane desorption established for the Devonian Ohio Shale.

To date, the research has collected 43 samples and two advanced well logs (ECS) were acquired and analyzed. The log analysis indicates TOC content of the shale was estimated from density log data. The Lower Huron Member of the Ohio Shale was determined to have the greatest CO_2 adsorption capacity.

New York State Research and Development Authority (U.S.)

At the New York State Research and Development Authority (NYSERDA),[86] two research projects were conducted to characterize the geology of two sections of western New York to determine if CO_2 storage is possible there. A third project characterized the geology of central New York for CO_2 storage and assessed the potential for enhanced gas recovery in the area. Advanced Resources directed a project to assess gas shale formations for CO_2 storage and enhanced gas recovery potential throughout the state.[87]

Stanford University (U.S.)

Researchers at Stanford University are also investigating the feasibility of geologic CO_2 storage in shale gas reservoirs.[88] The overarching objective this work is to conduct a series of multi-scale, multi-physics, interdisciplinary laboratory and theoretical studies to assess the feasibility of using depleted organic-rich shale reservoirs for large-scale CO_2 storage. The objectives of this study are to determine how the physical and chemical processes associated with CO_2 interaction with organic-rich shales affect: (1) the ability to inject CO_2 over a long period of time, (2) the ability to store CO_2 as a free phase, and (3) the ability of the shale to adsorb and permanently store CO_2. Four main focus areas are being addressed:

- The physical and chemical interactions between injected CO_2 and shale within the pore spaces of the reservoir rock.
- Understanding how critical-state CO_2 migrates through man-made fractures generated during injection well development, naturally occurring fractures, and pore spaces within the reservoir rock.
- The chemical interactions that occur between injected CO_2 and ground water.
- Understanding how injected CO_2 is trapped and sealed within the reservoir rock.

University of Oklahoma (U.S.)

Researchers at the University of Oklahoma have developed a methodology to assess the potential for CO_2 storage in organic rich gas shales, with a focus on the New Albany and Barnett shales. They found that pore volume estimation is a crucial step for storage assessment, particular in terms of the CO_2 that can be adsorbed. They also conclude that gas transport within the shales takes place in the presence of dynamic porosity and permeability fields, and it could be dominated by the adsorbed-phase transport.[89] Experimental work to date demonstrates that the organic shale has the ability to store significant amounts of gas, due primarily to trapping of the adsorbed gas within the finely dispersed organic matter in the shale.

U.S. DOE Industrial Carbon Management Initiative – Research on CO_2 Storage in Depleted Shale Gas Reservoirs

As part of its Regional University Alliance (RUA), Industrial Carbon Management Initiative, the DOE/NETL is sponsoring research to characterize the potential to store CO_2 in and enhance gas recovery from shale gas wells that have been depleted through primary production. This activity involves experimental characterization of shale properties, reservoir simulation of CO_2 storage in and enhanced gas recovery from shales, and an initial, screening-level techno-economic assessment of the viability of those scenarios as might be applied in the Marcellus Shale Formation in the Appalachian Basin in the U.S.[90]

To date, preliminary experimental findings have shown that CO_2 sorption capacity in the Marcellus ranges from 1.6 to 10.3 cubic meters per metric ton. Organic rich facies have been shown to have the highest CO_2 and methane sorptive capacities, and are strongly related to TOC, and not to clay content. CO_2/methane sorption ratios range from 1.32 to 4.2. Hysteresis is exhibited in shale permeability as a function of net stress, while porosity of shale to CO_2 decreases in with increasing net stress.

Commonwealth Scientific and Industrial Research Organisation (CSIRO) (Australia)

Researchers at CSIRO in Australia conducted diffusive transport and gas sorption experiments on one well-characterized shale sample (Muderong Shale, Australia) and different clay minerals to obtain information on the sealing integrity and the CO_2 storage potential of these materials. All measurements were performed under reservoir conditions relevant for CO_2 storage (temperature = 45–50 ^{o}C; pressure < 20 MPa). Repeat diffusion experiments on one shale plug yielded increased effective diffusion coefficients and a decrease in the concentration of the bulk CO_2 volume. The CO_2 was believed to be dissolved in formation water, sorbed to mineral surfaces, or involved with geochemical reactions. For this shale sample, bulk volume CO_2 concentrations were found to be significantly greater within the experimental time frame when compared to coal and cemented sandstone. This high CO_2 storage potential could not fully be explained by CO_2 dissolution in water alone. Further gas sorption experiments were performed on crushed shale and various clay minerals, showing that high CO_2 sorption capacities are related to a combination of CO_2 dissolution in water and gas sorption on clay minerals.[91]

Council for Geoscience (CGS), University of Pretoria in South Africa

In collaboration with Sasol Petroleum International (SPI) and Chesapeake Energy, CGS is pursuing an assessment of the shale gas potential of the selected shale formations in the Karoo Basin in South Africa. The initial stages of this project involve preparation, sampling and logging of eight cores, performed at the CGS core warehouse in Donkerhoek. Sampling was done in different intervals ranging from 1 meter where the shale displays a dark color to 10 meters when the shale is light. The samples were taken to an analytical laboratory in the United States. Following the results of the gas content in the samples, future continuation of this project is expected.[92]

One aspect of this effort involves assessing the physicochemical properties of South African shales in the context of geological CO_2 storage. This work is focusing on the CO_2 adsorption capacity of the carbonaceous shales of the Ecca Group in the Basin. This is being done by analyzing adsorption isotherms from a volumetric adsorption system to attempt to investigate how much CO_2 can be stored per molecule of methane recovered.

5.2 Summary

Research on the potential for recovering methane and storing CO_2 in gas shales is significantly less advanced than that for coal seams. Ongoing reservoir characterization and reservoir simulation work is demonstrating that the basic concept that shales can store CO_2 based on trapping through adsorption on organic material (similar to coals), as well as with the natural fractures within the shales, is scientifically achievable. Still lacking, however, is sufficient testing of this concept with site-specific geologic and reservoir data and detailed reservoir simulation, verified by field tests, in a variety of gas shale settings.

Given this status, the key knowledge gaps and technical barriers identified for coals also exist for shales. Specifically:

1. A lack of information on the available storage capacity in gas shales in all but a few, targeted settings.
2. A lack of geological and reservoir data for defining the favorable settings for injecting and storing CO_2 in shales, particularly the lack of data on shale depositional settings and reservoir properties. This is true for assessing both the production and CO_2 storage potential in shales.
3. Understanding the near-term and longer-term interactions between CO_2 and shales, particularly the mechanisms of swelling in the presence of CO_2, shrinkage with release of methane, and the physics of CO_2/methane exchange under reservoir.
4. Formulating and testing alternative reliable, high volume CO_2 injection strategies and well designs.
5. Integrating CO_2 storage and enhanced recovery of methane in shales.

6. GLOBAL CO_2 STORAGE CAPACITIES IN COAL SEAMS

6.1 Review of Previous Work

Potential storage sites in coal seams are likely to be broadly distributed in many of the world's sedimentary basins, often located in the same region as many of the world's emission sources. In a 1998 report by Advanced Resources for IEAGHG, preliminary test data from U.S. and international CBM exploration projects was used to characterize deep coal reservoirs in terms of their CO_2 storage and ECBM potential.[93] A total of 27 individual coal basins in 14 countries were assessed. Numerous poorly documented coal basins were not assessed.

Table 6.1 shows the results from the 1998 study for the most prospective basins. CO_2 storage potential in these basins was estimated to be 150 billion metric tons or gigatones (Gt). The study concluded that if all world coal basins were included, including both those not assessed or located offshore, the potential could be several times larger.[94]

Table 6.1: CO_2-ECBM and Sequestration Potential of Selected Highly Ranked Coal Basins

Country	Basin	ECBM Potential		Sequestration Potential
		(billion m^3)	(Tcf)	(10^9 tonnes CO_2)
USA	San Juan	1.7	60	6.4
	Uinta	0.3	10	1.0
	Raton	0.3	10	1.1
Australia	Bowen	2.9	104	11.2
	Sydney	2.0	72	7.8
Canada	W. Canadian	2.2	79	8.6
China	Ordos	2.2	78	8.4
Indonesia	S.&C. Sumatra	3.4	121	13.0
World Total	*All*	*40*	*1,400*	*150*

The 2005 Intergovernmental Panel on Climate Change (IPCC) report on geologic storage stated that the storage capacity of unmineable coal formations is uncertain, with estimates ranging from as little as 3 Gt up to 200 Gt of CO_2.[95] Dooley et al. estimated the storage capacity in coal seams globally to be 58 Gt.[96] Massarotto et al. estimated that there is the potential to increase worldwide CBM production, utilizing ECBM, by 18 Tcm, while simultaneously sequestering 345 Gt of CO_2.[97]

For the United States, a report by Advanced Resources for DOE/NETL in 2003 concluded that the upside estimate for potential CO_2 storage capacity of U.S. coal beds was about 90 Gt, with about 38 Gt in Alaska, 14 Gt in the Powder River basin, 10 Gt in the San Juan basin, and 8 Gt in the Greater Green River basin. The ECBM recovery potential associated with this storage potential was estimated to be over 4.2 Tcm (150 Tcf), with 1.3 Tcm (47 Tcf) in Alaska, 0.6 Tcm (20 Tcf) in the Powder River basin, 0.5 Tcm (19 Tcf) in the Greater Green River basin, and 0.45 Tcm (16 Tcf) in the San Juan basin.[98]

A comparison of these results with the earlier study by IEAGHG is provided in **Table 6.2**. In general, the 2003 DOE/NETL study estimated higher CO_2 storage potential (due primarily to higher CO_2/methane replacement ratios in lower rank coals).

Table 6.2: Comparison of Results: IEAGHG and DOE/NETL Study

	CO_2 Sequestration Potential (Gt)	
Basin	1998 IEAGHG Study	2003 DOE/NETL Study
San Juan	6.4	10.4
Uinta	1.0	1.9
Raton	1.1	0.6
Black Warrior	2.1	0.8
N. & C. Appalachia	7.1	3.5
Powder River	3.2	13.6
Piceance	9.0	2.4
Greater Green River	5.1	7.9
Totals	35.0	41.1

More recently, the DOE/NETL *Carbon Sequestration Atlas of the United States and Canada* estimates that there is 56 to 114 Gt (61 billion to 126 billion tons)[1] of potential CO_2 storage potential in unmineable coal areas distributed over 25 states and one Canadian province.[99] *They note that this should be considered an upside estimate, unconstrained by methane production efficiency, injectivity constraints, or other technical and economic constraints*. The methane recovery potential through the application of ECBM was not assessed.

An earlier first-order regional-scale estimation of CO_2 storage capacity in coals under sub-critical conditions was applied to Cretaceous-Tertiary coal beds in Alberta, Canada. Regions suitable for CO_2 storage were defined on the basis of ground water depth and CO_2 phase at *in situ* conditions. The theoretical CO_2 storage capacity was estimated on the basis of CO_2 adsorption isotherms measured on coal samples. Regional capacity estimates ranged from 20 thousand tonnes or kilotonnes (kt) of CO_2/km^2 to 1,260 kt CO_2/km^2, for a total of approximately 20 Gt CO_2 for the province. (The DOE Atlas estimates 30 Gt CO_2 for Alberta.)[100] This theoretical storage capacity limit is that which would be attained if there would be no other gases present in the coals or they would be 100% replaced by CO_2, and if all the coals will be accessed by CO_2. Assuming that the economic threshold to develop the necessary infrastructure is 200 kt CO_2/km^2, the CO_2 storage capacity in Alberta coal beds would be reduced to 800 million metric tons.[101]

In China, the CO_2 storage potential associated with CBM and ECBM is estimated to be 143 Gt, with the production of methane from CBM and ECBM estimated to be 3 to 4 trillion cubic meters (106 to 142 Tcf);[102] earlier estimates of the storage potential for coal seams in China were considerably less.

In the Netherlands, four potential ECBM areas were assessed; where it was estimated that between 54 million tonnes and 9 Gt of CO_2 could be sequestered – depending on the technological advances for coal seam access.[103]

In Germany, considering coal seams between 800 and 1,500 meters depth, storage capacity could range from 0.6 to 1.7 Gt. Restricting this to areas without previous mining results in a estimated range of 0.4 to 1.0 Gt, with a median estimate of 0.6 Gt.[104]

Estimates have also been made for the coal seam storage potential in Europe,[105] South Africa,[106] and in India.[107]

[1] Appendix D of the same document has somewhat different numbers -- 54 to 113 billion metric tons (59 to 124 billion tons)

6.2 Estimation Approach Used in this Assessment

To assess CO_2 storage potential in worldwide coals, geologic and CBM resource data for major world basins was obtained from a variety of sources. Previous studies have established estimates of adsorption ratios based on vitrinite reflectance (Ro) data, which can be used with collected resource in place estimates to determine a theoretical maximum CO_2 storage potential.

Coals first need to be dewatered and degassed in order to reach conditions that are acceptable for injection. Additionally, coal maturity and homogeneity can change within the confines of the basin, leading to higher performing sweet spots. Therefore, estimates for CO_2 storage potential for the world's coal basins were based on an estimate of the amount of methane produced from each coal seam, both in terms of conventional CBM production, as well as that produced from the application of ECBM.

The overall approach to this study, building on previous work focus on U.S. basins,[108] was to estimate the CO_2 storage potential of the world's coal basins in several steps. The first step involves estimating the replacement of methane produced by primary production with CO_2, according to the representative coal rank defined for each basin. This step assumes that a storage capacity voidage is created in the coal reservoir by the CBM production, which can be replaced, up to original reservoir pressure, by CO_2. Under this scenario, no incremental methane recovery is assumed to occur as a result of CO_2 injection.

The second step involves estimating the recovery of additional methane, unrecovered by primary production, as a result of CO_2 injection for ECBM, which creates additional voidage, and hence additional CO_2 storage capacity.

In some cases, estimates were developed for individual basins within a country, and then summed to the country level. In other cases, basin-specific numbers were not available, so country-specific estimates were developed.

The general methodology employed for the study is described below.

Select Basins to Include in Assessment

The key criteria used for basin/country selection included the size of its potential (i.e., CO_2 storage and ECBM), as well as the availability of required information such as estimates of CBM resources in-place and/or recoverable. This was not available for all basins. Nonetheless, estimates could be developed for basins/countries representing over 90% of the world's coal reserves. Estimates of in-place and/or recoverable resources were either obtained from the literature, or were based on previous country/basin specific estimates developed by Advanced Resources (and summarized in Table 2.2).

Specify Coal Rank Most Representative of the Basin

Although recognizing that coals of various ranks often exist within a given basin or coal seam, for this assessment, we determined a specific coal rank most representative of each basin/country considered. This was based on information and resource characterizations obtained in the literature, or developed as the result of previous work by Advanced Resources. The assumptions for coal rank and other key inputs to this assessment process are presented, by basin/country, in Appendix A.

Estimate Technically Recoverable "Primary" CBM Resources

In some basins, like those in the U.S. and the countries summarized in Table 2.2, estimates for recoverable CBM resources were already developed by Advanced Resources. In others, estimates were obtained from other sources in the literature. Where estimates for CBM recoverable potential were not otherwise available, an estimated primary recovery factor of 10% was assumed, applied to the estimates of CBM resources in place. These results are presented in Appendix B, and are summarized by country and region in **Table 6.3**. As shown, this country-by-country assessment of CBM resources in place is 201 Tcm (7,011 Tcf), with an estimated 29 Tcm (1,030 Tcf) recoverable. The largest CBM resources are in the former Soviet Union, Canada, China, Australia and the United States.

Table 6.3: Coal Bed Methane Resources by Country/Region

COUNTRY	Coal Reserves Million Tonnes	CBM Gas-in-place Tcf	CBM Gas-in-place Tcm	CBM Recoverable Tcf	CBM Recoverable Tcm
UNITED STATES	237,295	1,746	49	170	4.82
CANADA	6,582	550	15.6	184	5.21
MEXICO	1,211	9	0.3	1	0.04
North America	245,088	2,305	65.3	355	10.06
BRAZIL	4,559 *	36	1.0	5	0.15
COLOMBIA	6,746	23	0.7	3	0.10
VENEZUALA	479	17	0.5	3	0.07
Other S. & Cent. America	724 *		0.0	0	0.00
South & Central America	12,508	76	2.2	11	0.32
BULGARIA	2,366				
CZECH REPUBLIC	1,100	13	0.4	2	0.06
GERMANY	40,699	106	3.0	16	0.45
GREECE	3,020		0.0	0	0.00
HUNGARY	1,660	4	0.1	1	0.02
KAZAKHSTAN	33,600	50	1.4	10	0.28
POLAND	5,709	50	1.4	5	0.14
ROMANIA	291				
RUSSIAN FEDERATION	157,010	1,682	47.6	200	5.66
SPAIN	530				
TURKEY	2,343	51	1.4	10	0.28
UKRAINE	33,873	170	4.8	25	0.71
UNITED KINGDOM	228	102	2.9	15	0.43
Other Europe & Eurasia	22,175				
Europe & Eurasia	304,604	2,228	63.1	284	8.04
Botswana		105	3.0	16	0.45
Mozambique		88	2.5	13	0.37
Namibia		104	2.9	16	0.44
South Africa	30,156	60	1.7	9	0.25
Zimbabwe	502	60	1.7	9	0.25
Other Africa	1,034 *				
Middle East	1,203 *				
Middle East & Africa	32,895	417	11.8	63	1.77
AUSTRALIA	76,400	153	6.4	34	0.95
CHINA	114,500	1,299	36.8	195	5.52
INDIA	60,600	80	2.3	20	0.57
INDONESIA	5,529	453	12.8	68	1.93
Japan	350				
New Zealand	571				
North Korea	600				
Pakistan	2,070 *				
South Korea	126				
Thailand	1,239				
Vietnam	150				
Other Asia Pacific	3,707				
Asia Pacific	265,843	1,985	58.2	316	8.96
Total World	860,938	7,011	201	1,030	29.15

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Estimate Incremental Methane Recovery via CO_2-ECBM

This estimate was developed using a relationship between CO_2-ECBM recovery factor (expressed as a % of in-place resource at the start of CO_2 injection) and coal rank. Another important component of this assessment is the relationship between coal rank and incremental methane recovery with CO_2 injection, or ECBM. As part of previous work by Advanced Resources,[109] relationships were established based the *COMET2* reservoir simulator. The reservoir engineering constants used for the simulations provided the basis for these determinations, and are summarized in **Table 6.4**. **Figure 6.1** provides the relative permeability curves employed; **Figure 6.2** provides the CO_2 and methane isotherms used for each coal rank.

Based on these simulations, estimated recovery factors for the percentage of remaining in-place CBM resources at the start of CO_2 injection that can be recovered through the application of ECBM were developed based on estimates of vitrinite reflectance (Ro). An estimate of vitrinite reflectance was developed as a function of coal rank, based on the relationships in **Figure 6.3**.

Based on this representation, estimates of recovery factors as a function of average values for vitrinite reflectance, based on coal rank, were developed as summarized in **Table 6.5**. As shown, lower rank coals are assumed to have higher recoveries. This is because the lower coal ranks require less CO_2 and lower pressures to displace the in-place methane.

The assumptions for vitrinite reflectance and CO_2/methane ratios assumed for each basin/country in this assessment are presented Appendix A.

Table 6.4: Reservoir Constants Used in Simulation Model

Parameter	Value
Reservoir Pressure	0.43 psi/ft.
Reservoir Temperature	60 deg + 2 deg/100 ft. , in deg. F
Porosity	0.25%
Cleat Spacing	0.5 inches
Sorption Time	10 days
Well Spacing	80 acres

Figure 6.1: Relative Permeability Curves Used in ECBM Simulation Runs

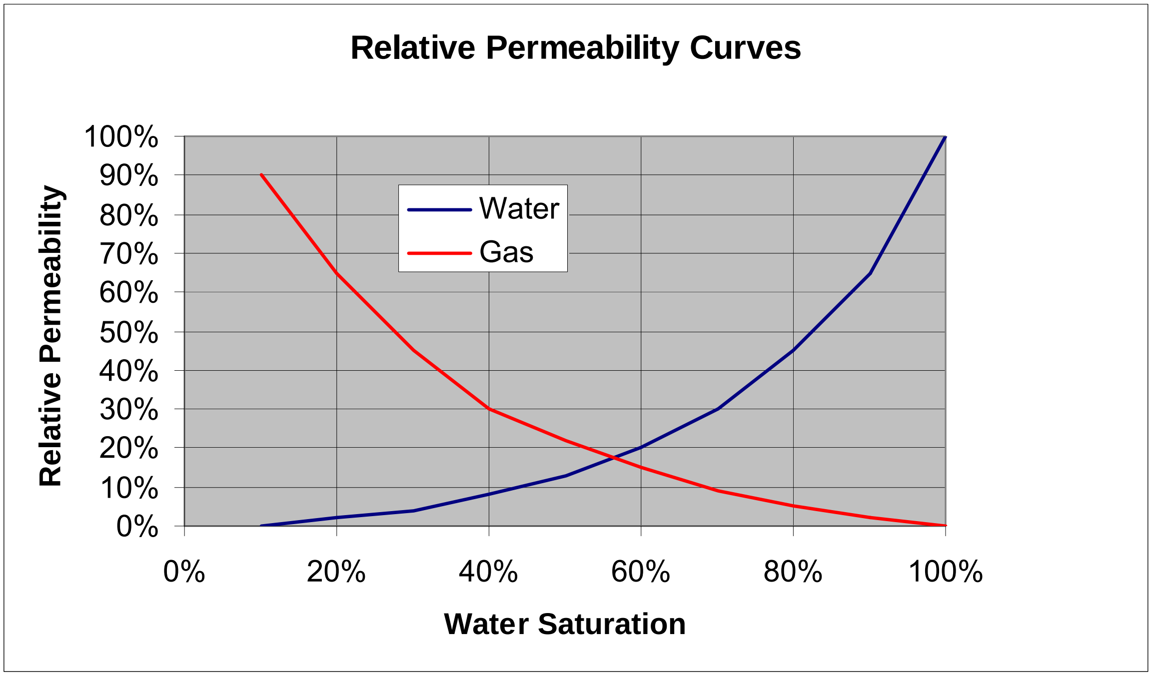

Figure 6.2: CO_2/Methane Sorption Isotherms Used in ECBM Simulation Runs

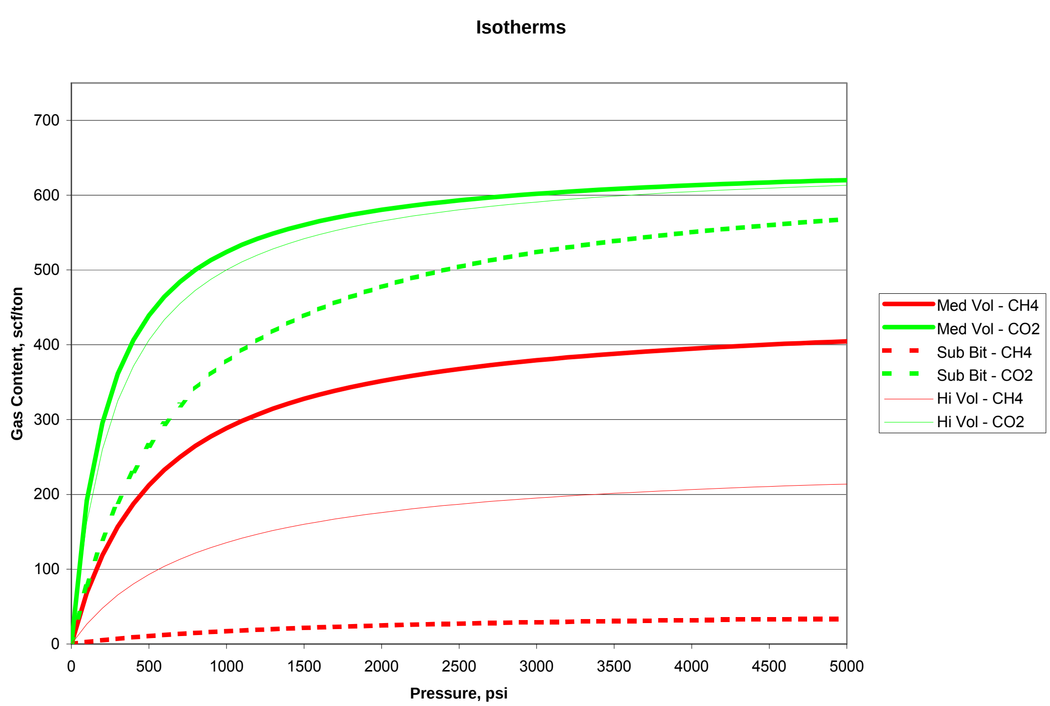

Figure 6.3: Classification of Coals Based on Rank and Thermal Maturity[110]

Coal rank: Class	Coal rank: Group	Vitrinite reflectance (random)	Volatile matter (wt.% dmmf)[1]	Bed moisture (wt %)	Calorific value MJ/kg (moist,mmf)	Hydro-carbon generation	Principal uses
Anthracitic[2]	Meta-anthracite		2			Dry Gas	Space heating; Chemical production
	Anthracite	2.50	8				
	Semianthracite	1.92	14				
Bituminous	Low volatile bituminous	1.51	22			Wet Gas	Metallurgical coke production; Cement production; Thermal electric power generation
	Medium volatile bituminous	1.12	31				
	High volatile A bituminous	0.75			32.6	Oil and Gas	
	High volatile B bituminous	0.50-0.75			30.2		
	High volatile C bituminous	0.50 ?		8-10	26.8		
Subbituminous	Subbituminous A[3]				24.4	Early Gas	Thermal electric power generation; Conversion to liquid and gaseous petroleum substitutes
	Subbituminous B			25	22.1		
	Subbituminous C	0.42			19.3		
Lignitic	Lignite A			35	14.7		Thermal electric power generation; Char production; Space heating
	Lignite B			75			
	Peat						

1) dmmf - Dry, mineral matter free

2) Non-agglomerating; if agglomerating, classified as low volatile bituminous

3) If agglomerating, classified as high volatile C bituminous

Figure 33.1 Classification of coals by rank and indices of organic maturity. The chart is a composite modified from ASTM (1981), Teichmüller and Teichmüller (*in* Stach et al., 1982), Dow (1977) and Cameron (1989).

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Table 6.5: Recovery Factors by Coal Rank

	Vitrinite Reflectance			ECBM Recovery Factor
Rank	Low	High	Avg	
Anthracite	2.5	4	3.25	25%
Semi anthracite	1.92	2.5	2.21	25%
Bituminous	0.5	1.92	1.21	42%
Low Volatile Bituminous	1.51	1.92	1.72	25%
Medium Volatile Bituminous	1.12	1.51	1.32	32%
High Volatile A Bituminous	0.75	1.15	0.95	37%
High Volatile B Bituminous	0.5	0.75	0.63	42%
High Volatile C Bituminous	0.5	0.75	0.63	42%
Sub-bituminous	0.42	0.5	0.46	42%
Lignite	0.27	0.42	0.35	21%

Estimate CO_2 Storage Capacity Associated with CBM and ECBM

The relationship shown in **Figure 3.2** was used to determine a CO_2-to-methane replacement ratio as a function of coal rank, characterized in terms of vitrinite reflectance, for each coal basin. Then, CO_2 storage capacity was estimated based on simple replacement of produced methane with CO_2 that is produced. This applies to both the voidage resulting from primary CBM and the additional CO_2 storage capacity resulting from ECBM.

6.3 Results for Coal Seams

All of the basin-specific assessments were combined to develop a global assessment of primary CBM recovery, ECBM recovery and CO_2 storage capacity in coal seams. Where possible, resource characterization information was developed at the basin level. However, this was not possible in all areas. Therefore, in some cases, the lowest level of disaggregation possible was at the country level.

The estimates for primary CBM and ECBM potential, along with the associated potential CO_2 storage capacity in unmineable coal seams, are presented, by basin/country, in Appendix C, and are summarized by country in **Table 6.6**. As shown, it is estimated that 79 Tcm of CBM are potentially recoverable globally, 29 Tcm from conventional CBM, and 50 Tcm from the application of ECBM. This would facilitate the potential storage of nearly 488 Gt of CO_2.

Table 6.6: CO_2 Storage and Methane Production Potential of the World's Coal Basins

	Estimated Methane Recovery (Tcm)			CO_2 Storage	CO_2 Storage
COUNTRY	**PRIMARY**	**ECBM**	**TOTAL**	**Tcm**	**Gt**
UNITED STATES	4.82	7.54	12.4	52.82	86.16
CANADA	5.21	4.35	9.6	17.85	29.11
MEXICO	0.04	0.09	0.1	0.34	0.55
Total North America	**10.06**	**11.99**	**22.1**	**71.01**	**115.82**
BRAZIL	0.15	0.00	0.2	0.57	0.93
COLOMBIA	0.10	0.22	0.3	1.29	2.11
VENEZUALA	0.07	0.30	0.4	3.57	5.83
Total S. & Cent. America	**0.32**	**0.52**	**0.85**	**5.44**	**8.87**
CZECH REPUBLIC	0.06	0.00	0.1	0.00	0.00
GERMANY	0.45	0.00	0.5	0.62	1.01
HUNGARY	0.02	0.04	0.1	0.10	0.17
KAZAKHSTAN	0.28	0.00	0.3	0.50	0.82
POLAND	0.14	0.94	1.1	4.07	6.63
RUSSIAN FEDERATION	5.66	12.61	18.3	35.20	57.41
TURKEY	0.28	0.00	0.3	0.58	0.94
UKRAINE	0.71	1.72	2.4	4.54	7.41
UNITED KINGDOM	0.43	1.03	1.5	2.73	4.46
Total Europe & Eurasia	**8.04**	**16.35**	**24.39**	**48.34**	**78.84**
				0.00	0.00
Botswana	0.45	1.06	1.5	9.18	14.97
Mozambique	0.37	0.89	1.3	1.84	3.01
Namibia	0.44	1.05	1.5	2.18	3.56
South Africa	0.25	0.61	0.9	1.26	2.05
Zimbabwe	0.25	0.61	0.9	3.44	5.62
Total Middle East & Africa	**1.77**	**4.22**	**5.99**	**17.90**	**29.20**
AUSTRALIA	0.95	0.67	1.62	9.01	14.70
CHINA	5.52	7.13	12.64	47.83	78.01
INDIA	0.57	0.63	1.2	4.04	6.60
INDONESIA	1.93	8.05	9.97	95.40	155.60
Total Asia Pacific	8.96	16.47	25.43	156.28	254.91
Total World	29.15	49.55	78.7	298.97	487.64

6.4 Caveat

The estimates presented here reflect only the CO_2 storage capacity associated with the coal seams that have been the target of advanced recovery operations. Coal seams usually occur in association with sandstones and other lithologies, and in many cases coal may not be the dominant rock type. Therefore, the storage capacity associated with coal seams is likely to be only a part of the storage capacity of the whole, coaly sediment unit. Injected CO_2 could (perhaps even preferentially) migrate through sandstones, shales, and/or coal seams, as part of a geologic sequence in a given location. This would imply that the storage potential in each region could be (perhaps substantially) larger than that just associated with coal seams.

7. GLOBAL CO_2 STORAGE CAPACITIES IN GAS SHALES

7.1 Review of Previous Work

No previous estimates have been made of the global CO_2 storage potential in gas shales. However, some regional assessments have been made. For example, the Kentucky Geological Survey (KGS) developed initial volumetric estimates of the CO_2 storage capacity of the Carbonaceous (black) Devonian gas shales that underlie approximately two-thirds of the state of Kentucky in the U.S., and concluded that as much as 28 Gt could be stored in the deeper and thicker parts of these shales.[111]

NETL used the same procedure as KGS to estimate the CO_2 storage potential across the entire Marcellus shale formation in the Appalachian Basin in the eastern U.S. Their estimates are based on data for the adsorption of CO_2 onto organic shales of 0.4 to 4 cubic meters per metric ton (14 to 136 standard cubic feet (scf)/ton) of shale at 2.8 MPa (400 psi) and the following Marcellus formation characteristics:

- Density = 10 kilograms per cubic meter (159 pounds per cubic foot of shale)
- Area = 246,000 square kilometres (95,000 square miles)
- Average Thickness = 30 meters (100 feet)
- CO_2 Gas Density = 1.8 x 10^{-6} cubic meters/metric ton (5.8 x 10^{-5} scf/ton)

From this, they estimated that the Marcellus shale has the potential to store from 17 to 166 Gt of CO_2.[112]

One effort sponsored by DOE/NETL is underway by Advanced Resources to assess the factors influencing effective CO_2 storage capacity and injectivity in selected gas shales in the Eastern United States.[113] One output of this effort will be basin-level estimates of the CO_2 storage capacity of the Marcellus and Utica shales in the eastern U.S.

Geological characterization was conducted that estimated total gas in-place and theoretical maximum CO_2 storage capacity within the Marcellus. Theoretical maximum CO_2 storage capacity assumes 100% of methane in-place, either as adsorbed or “free” gas, is replaced by injected CO_2.

Detailed reservoir characterization was conducted to determine depth, thickness, total organic carbon, effective porosity, apparent gas saturation, CO_2 and methane adsorption isotherms, and permeability throughout the Marcellus Shale. Detailed reservoir simulation was performed to develop a better understanding of the shale characteristics influencing potential enhanced gas recovery, storage capacity and injectivity. A reservoir model was developed based on these data, and reservoir simulation was performed. Simulated production results were compared to available data to demonstrate that the reservoir models are representative of existing field conditions.

Typical gas recovery factors for gas shales range from 20% to 35%, with an average factor of 25% for shale gas basins and formations that have a medium clay content, moderate geologic complexity, and average reservoir pressure and properties. Simulation results indicate that at optimal spacing between the injection and production wells, 7% incremental (enhanced) gas production due to CO_2 injection can be realized. Combining this with a 25% primary recovery efficiency gives a total recovery efficiency of 32%. Assuming this, for the entire Marcellus shale study area, approximately 26 Tcm of methane were estimated to be technically recoverable in the Marcellus shale, and would result in 52 Gt of CO_2 storage capacity.

While this methodology is not generally applicable for most global shale basins because of a lack of well data, this analytical experience can be used to develop “rules of thumb” relationships between estimated gas in place, recoverable shale gas resources, and potential CO_2 storage capacity for the shale gas basins based on more general geologic characteristics and analogs.

7.2 Estimation Approach for Shale Gas Resource Assessment

For the purposes of this study, the U.S. Energy Information Administration (EIA) assessment on worldwide shale gas resources was used as a foundation.[114] Much of the description summarized here is provided in detail in this report for EIA. In addition, data on shale basin geological characteristics upon which these estimates are based are also documented in the EIA report.

This assessment captures a “first-order” view of the gas in-place and technically recoverable resource for 48 shale gas basins and 69 shale gas formations in 32 countries. The assessment documents shale formation characteristics used to estimate methane gas-in-place. In addition to areal and depth extents, characteristics such as pressure, temperature, porosity, saturation levels, and thermal maturity were documented in the EIA report. Because of the considerable volume of data used in these assessments, this information is not reported here, and readers are encouraged to review the EIA report.

The methodology for conducting the basin- and formation-level assessments of shale gas resources includes the following:

- Conducting preliminary geologic and reservoir characterization of shale basins and formation(s).
- Establishing the areal extent of the major shale gas formations.
- Defining the prospective area for each shale gas formation.
- Estimating the risked shale gas in-place.
- Calculating the technically recoverable shale gas resource.

Each of these five shale gas resource assessment steps is further discussed below.

Preliminary Geologic and Reservoir Characterization of Shale Basins

The resource assessment begins with the compilation of data from multiple public and private sources to define the shale gas basins and to select the major shale gas formations to be assessed. Stratigraphic columns and well logs, showing the geologic age, the source rocks and other data, are used to select the major shale formations for further study. Preliminary geological and reservoir data are assembled for each major shale formation, including depositional environment of shale (marine vs non-marine), depth (to top and base of shale interval), structure, including major faults, gross shale interval, organically-rich gross and net shale thickness, total organic content (TOC, by wt.), and thermal maturity (Ro).

These geologic and reservoir properties are used to provide a first order overview of the geologic characteristics of the major shale gas formations and to help select the shale gas formations deemed worthy of more intensive assessment.

Establish Areal Extent of Shale Formations

Having identified the major shale gas formations, the next step was to define the areal extent for each basin/formation included, based on the technical literature as well as detailed, local cross-sections identifying the shale gas formations of interest. In addition, the study team drew on internal cross-sections previously prepared by Advanced Resources and, where necessary, assembled well data to construct new cross-sections. The regional cross-sections were used to define the lateral extent of the shale formation in the basin and/or to identify the regional depth and gross interval of the shale formation.

Define Prospective Area of Each Shale Formation

An important and challenging resource assessment step was to establish the portions of the basin that were deemed to be prospective for development. The criteria used for establishing this prospective area included the depositional environment, depth, TOC, thermal maturity, and geographic location. The prospective area was limited to the onshore portion of the shale gas basin. The prospective area contains the higher quality portion of the shale gas resource and, in general, covers less than half of the overall basin area. The prospective area will contain a series of shale gas quality areas, typically including a geologically favorable, high resource concentration “core area” and a series of lower quality and lower resource concentration extension areas. However, the further delineation of the prospective area was beyond the scope of this initial resource assessment study.

Estimate Risked Gas In-Place (GIP)

Detailed geologic and reservoir data were assembled to establish the free as well as the adsorbed gas in-place (GIP) for the prospective area. Adsorbed gas can be the dominant in-place resource for shallow and highly organically rich shales. Free gas becomes the dominant in-place resource for deeper, higher clastic content shales.

The calculation of free GIP for a given areal extent was governed, to a large extent, by four characteristics of the shale formation - - pressure, temperature, gas-filled porosity and net organically-rich shale thickness. These were combined using established reservoir engineering equations and conversion factors to calculate free GIP per unit area.

In addition to free gas, shales can hold significant quantities of gas adsorbed on the surface of the organics (and clays) in the shale formation. A Langmuir isotherm was established for the prospective area of each basin using available data on TOC and on thermal maturity to establish the Langmuir volume (V_L) and the Langmuir pressure (P_L).

Adsorbed GIP was then calculated using the formula below (where P is original reservoir pressure).

$$G_C = (V_L * P) / (P_L + P)$$

Advanced Resources International, Inc.

The above gas content (G_C) (typically measured as volume per unit mass) was converted to gas concentration (adsorbed GIP per unit area) using actual or typical values for shale density. (Density values for shale are typically in the range of 2.65 to 2.8 grams per cubic centimeter (gm/cc) and depend on the mineralogy and organic content of the shale.)

The estimates of the Langmuir value (V_L) and pressure (P_L) for adsorbed gas in-place calculations were based on either publically available data in the technical literature or data developed by Advanced Resources.

The free and adsorbed GIP estimates were combined to provide an estimate of the resource concentration (on a volume per unit area basis) for the prospective area of each basin.

Two specific judgmentally established success/risk factors were used to estimate risked GIP within the prospective area of the shale gas formation. These two factors are as follows:

- Play Success Probability Factor. The shale gas play success probability factor captures the likelihood that at least some significant portion of the shale gas formation will provide gas at attractive flow rates and become developed. Certain shale gas formations are already under development would have a play probability factor of 100%. More speculative shale gas formations with limited geologic and reservoir data may only have a play success probability factor of 30% to 40%. As exploration wells are drilled, tested and produced and information on the viability of the shale gas play is established, the play success probability factor will change. (It is worth noting that success for shale gas development may not necessarily imply success for CO_2 storage but, even though, for purposes of this assessment, that equivalency was assumed.)
- Prospective Area Success (Risk) Factor: The prospective area success (risk) factor combines a series of concerns that could relegate a portion of the prospective area to be unsuccessful or unproductive for gas production. These concerns include areas with high structural complexity (e.g., deep faults, upthrust fault blocks); areas with lower thermal maturity (Ro between 1.0 and 1.2); the outer edge areas of the prospective area with lower net organic thickness; and other information appropriate to include in the success (risk) factor. The factor also captures the amount of available geologic/reservoir data and the extent of exploration that has occurred in the prospective area of the basin to determine what portion of the prospective area has been sufficiently “de-risked”. As exploration and delineation proceed, providing a more rigorous definition of the prospective area, the prospective area success (risk) factor will change.

These two success/risk factors were combined to derive a single composite success factor to risk the GIP for the prospective area. The history of shale gas exploration has shown that the success/risk factors, particularly the prospective area success/risk factor, change over time. As exploration wells are drilled and the favorable shale gas reservoir settings and prospective areas are more fully established, revised assessments of the gas in-place will result.

Estimate Technically Recoverable Resource

The technically recoverable resource was established by multiplying the risked GIP by a shale gas recovery factor, which incorporates a number of geological inputs and analogs appropriate to each shale gas basin and formation. The recovery factor uses information on the mineralogy of the shale to determine its favorability for applying hydraulic fracturing to "shatter" the shale matrix. The recovery factor also considers other information that would impact gas well productivity, such as: presence of favorable micro-scale natural fractures; the absence of unfavorable deep cutting faults; the state of stress (compressibility) for the shale formations in the prospective area; the relative volumes of free and adsorbed gas concentrations; and the reservoir pressure in the prospective area.

Three basic gas recovery factors, incorporating shale mineralogy, reservoir properties and geologic complexity, are used in the resource assessment:

- <u>Favorable Gas Recovery</u>. A 30% recovery factor of the gas in-place is used for shale gas basins and formations that have low clay content, low to moderate geologic complexity and favorable reservoir properties such as an over-pressured shale formation and high gas-filled porosity.
- <u>Average Gas Recovery</u>. A 25% recovery factor of the gas in-place is used for shale gas basins and formations that have a medium clay content, moderate geologic complexity and average reservoir pressure and properties.
- <u>Less Favorable Gas Recovery</u>. A 20% recovery factor of the gas in-place is used for shale gas basins and formations that have medium to high clay content, moderate to high geologic complexity and below average reservoir properties.

A recovery factor of 35% is applied in a few exceptional cases with established high rates of well performance. A recovery factor of 15% is applied in exceptional cases of severe under-pressure and reservoir complexity.

Finally, shale gas basins and formations that have very high clay content (e.g., non-marine shales) and/or have very high geologic complexity (e.g., thrusted and high stress) were categorized as non-prospective and excluded from this shale gas resource assessment. Subsequent, more intensive and smaller-scale (rather than regional-scale) resource assessments may identify the more favorable areas of a basin, enabling portions of the basin currently deemed non-prospective to be added to the shale gas resource assessment. Similarly, advances in well completion practices may enable more of the very high clay content shale formations to be efficiently stimulated, also enabling these basins and formations to be added to the resource assessment.

Table 7.1 provides a summary of the data input into of the resource assessment for all of the basins considered in the EIA report. The table summarizes the key data and results for two major shale gas basins and four shale gas formations in Central North Africa. Additional detail is provided in each of the 14 regional shale gas resource assessment reports.

Table 7.1: Reservoir Properties and Resources of Central North Africa

			Ghadames Basin (121,000 mi^2)		Sirt Basin (177,000 mi^2)	
Basic Data	Basin/Gross Area		Ghadames Basin (121,000 mi^2)		Sirt Basin (177,000 mi^2)	
	Shale Formation		Tannezuft	Frasnian	Sirt-Rachmat	Etel
	Geologic Age		Silurian	Middle Devonian	Upper Cretaceous	Upper Cretaceous
Physical Extent	Prospective Area (mi^2)		39,700	12,900	70,800	70,800
	Thickness (ft)	Interval	1,000 - 1,800	200 - 500	1,000 - 3,000	200 - 1,000
		Organically Rich	115	197	2,000	600
		Net	104	177	200	120
	Depth (ft)	Interval	9,000 - 16,500	8,200 - 10,500	9,000 - 11,000	11,000 - 13,000
		Average	12,900	9,350	10,000	12,000
Reservoir Properties	Reservoir Pressure		Overpressured	Overpressured	Normal	Normal
	Average TOC (wt. %)		5.7%	4.2%	2.8%	3.6%
	Thermal Maturity (%Ro)		1.15%	1.15%	1.10%	1.10%
	Clay Content		Medium	Medium	Medium/High	Medium/High
Resource	GIP Concentration (Bcf/mi^2)		44	65	61	42
	Risked GIP (Tcf)		520	251	647	443
	Risked Recoverable (Tcf)		156	75	162	111

Similar data are provided for all the shale gas basins and formations considered in the EIA report. Again, those wishing to obtain greater detail on the basis of these shale gas resource estimates are encouraged to consult the EIA report.

The step-by-step application of the above discussed shale gas resource assessment methodology leads to three key assessment values for each major shale gas formation: (1) gas in-place concentration, reported as a volume per unit area; 2) risked gas in-place, and (3) risked recoverable gas.

7.3 Estimation Approach for CO_2 Storage Potential in Shale Gas Basins

Unfortunately, isotherm data for CO_2 in shales is limited. However, in previous CO_2 storage studies focusing on coal formations, isotherm tests of both methane and CO_2 have been developed using formation core and drill cuttings. The isotherms have repeatedly illustrated that CO_2 tends to be preferentially adsorbed over methane in coals. For the purposes of this study, this preferential relationship in shale was assumed to be a ratio of 3 to 1. That is, the shale formations in this study are assumed to preferentially store CO_2 at three times the volume of the methane adsorbed. This ratio is applied to the estimated technically recoverable resource in each shale play.

7.4 Discussion of Results for Gas Shales

All of the basin-specific assessments were combined to develop this global assessment of technically recoverable shale and potential CO_2 storage capacity in gas shales. Resource characterization information was developed at the basin level for basins for which data was obtainable. However, this was not possible in all basins; so a number of basins with potentially significant shale gas resources were not included in this assessment.

The estimates for technically recoverable shale and potential CO_2 storage capacity in gas shales are presented, for non-U.S. basins, in Appendix D, and for U.S. regions, based on the 2010 estimates of EIA for technically recoverable shale resources,[115] in Appendix E. These results are summarized by country in **Table 7.2**. As shown, it is estimated that 188 Tcm of shale gas resources are potentially recoverable globally, and could facilitate the potential storage of 740 Gt of CO_2.

7.5 Caveat

Similar to the discussion in the previous chapter with regard to coal seams, the estimates presented here, along with other estimates reported earlier in this chapter, reflect only the CO_2 storage capacity associated with the potential targeted shale formations. These shale formations often occur in association with sandstones, limestones, other shale formations, and other lithologies, and in many cases the targeted shale may not be the dominant rock type. Therefore, the storage capacity associated with the targeted shale formation is likely to be only a part of the storage capacity of an entire sediment unit. Injected CO_2 could migrate (perhaps even preferentially) migrate through sandstones, shales, and/or coal seams, as part of a geologic sequence in a given location. This would imply that the storage potential in this region could be (perhaps substantially) larger than that just associated with the targeted shale formations.

Table 7.2: Summary of Technically Recoverable Resources and CO_2 Storage Potential of the World's Gas Shale Basins, by Country

Region	Country	Risked Gas In-Place (Tcm)	Risked Technically Recoverable (Tcm)	Risked CO_2 Storage Potential (Gt)
North America	United States	93	24	134
	I. Canada	42	11	43
	II. Mexico	67	19	72
	Sub-Total	*202*	*55*	*249*
South America	III. Northern South America	3	1	3
	IV. Southern South America	126	34	119
	Sub-Total	*129*	*35*	*122*
Europe	V. Poland	22	5	19
	VI. Eastern Europe	8	2	7
	VII. Western Europe	43	11	47
	Sub-Total	*73*	*18*	*72*
Africa	VIII. Central North Africa	53	14	55
	IX. Morocco	8	2	6
	X. South Africa	52	14	52
	Sub-Total	*112*	*30*	*113*
Asia	XI. China	145	36	132
	XII. India/Pakistan	14	3	11
	XIII. Turkey	2	0	2
	Sub-Total	*160*	*40*	*144*
Oceania	XIV. Australia	39	11	39
Grand Total		**717**	**188**	**740**

8. ISSUES ASSOCIATED WITH CO_2 INJECTIVITY INTO SHALES AND COALS

Injectivity can be defined as the ability of the formation to accept fluids, such as CO_2, by injection through a well. A recent IEAGHG-sponsored study reviewed the literature addressing the relative importance of various parameters influencing injectivity and storage capacity associated with CO_2 storage, including the uncertainty associated with estimating these parameters.[116] A variety of injection and development strategies were investigated to determine optimum injection strategies in different storage reservoir settings. The report found that the factors affecting injectivity are varied, but perhaps the most limiting factor affecting the maximum injection rate for an individual well is the maximum allowable bottom-hole injection pressure.

Bottom-hole pressure is controlled by absolute and relative permeability in the formation, reservoir thickness, viscosity between reservoir fluids and CO_2, and injected fluid compressibility. If this bottom-hole pressure exceeds the reservoir fracture pressure, then migration and leakage could occur. Therefore, remaining safely below fracture pressure during injection operations is of primary importance.

Deep coal and shale gas reservoirs are known to be generally low in Darcy-flow permeability (0.001 md to 0.1 md). Since injectivity is a function of bottom-hole pressure, and bottom-hole pressure is controlled by permeability in the formation, then injectivity in low permeability coals and shales is perhaps a more important consideration than that in higher permeability storage targets. However, as is demonstrated in producing gas from coal and shale reservoirs, the effective permeability of such reservoirs can be significantly increased by hydraulic fracturing.

Moreover, with CO_2 injection, permeability in coals and shales can change over time, influenced by dynamic changes affecting stress, shrinkage/swelling, and gas content. Complex geomechanical processes (horizontal stresses and vertical strains) and chemical interactions between CO_2, water and mineral matter content are some factors responsible for how permeability evolves. For example, adsorption of CO_2 in micro-pores may result in matrix swelling, squeezing the existing natural fractures and lowering the ability of fluid to flow. On the other hand, the presence of water may react with CO_2 forming carbonic acid and removing carbonate mineral matter - either increasing or decreasing permeability.

As described throughout this report, CO_2 adsorption can result in the swelling of the coal matrix in the reservoir into which CO_2 has been injected. Coal has been shown to shrink on desorption of CO_2 and to expand again on re-adsorption. Based on efforts to date, coal swelling is observed as perhaps the most significant barrier to CO_2 injection into coal seams. It is still not clear the extent to which this same phenomenon will be experienced in shales, given the general overall lower level of organic matter present in shales relative to coals.

In coal seams, during primary methane production, two distinct phenomena are known to be associated with reservoir depletion, with opposing effects on coal permeability. The first is reservoir compaction due to pressure depletion, which causes an increase in the effective horizontal stress as the reservoir is confined laterally. The second is gas (primarily methane) desorption from the coal matrix resulting in coal matrix shrinkage, and thus a reduction in the horizontal stress and an increase in cleat permeability.

During ECBM/CO_2 storage in coal, adsorption of CO_2, which has a greater sorption capacity than methane, causes matrix swelling and thus, in contrast to gas desorption, could potentially have a detrimental impact on matrix permeability of coal. Swelling of coal in the presence of CO_2 can reduce the permeability of coal seams, thus affecting the viability of ECBM or CO_2 storage operations.

Early research suggested that matrix shrinkage/swelling was proportional to the volume of gas desorbed/adsorbed, rather than the change in sorption pressure.[117] Laboratory studies on the impact of matrix swelling on coal permeability have confirmed these results. Moreover, these laboratory results appear to be confirmed in field tests.

However, such results have not consistently been observed. Mavor and Gunter[118] found that CO_2 injection actually increased absolute and effective permeability to a level easily allowing injection into a low permeability seam at the Fenn Big Valley, Canada project. They also observed that CO_2 injectivity was greater than that for weakly adsorbing N_2, and contributed this to the use of alternating injection and shut-in consequences and perhaps as the result of coal weakening.

Shi and Durucan[119] report other factors that could affect the CO_2 injectivity in coal bed reservoirs:

- <u>Thermal effect of CO_2 injection</u>: Temperature of the injected CO_2 could be different from the temperature of the reservoir; therefore, the non-isothermal effects of gas flow may affect injectivity in the reservoir.

- Wellbore effects: Drilling, production and/or injection of fluids affect the stress regime around the wellbore. As well as being affected by the pore pressure effects, the permeability regime around the borehole may be mechanically altered, affecting injectivity.
- Precipitate formation: An understanding of potential geochemical reactions between injected CO_2, the reservoir rock, and coal formation water is needed through laboratory and theoretical studies in order to evaluate the potential for precipitate formation. If these reactions do occur, there will be important implications for coalbed permeability, thus affecting the injectivity of CO_2. Detailed water geochemical analyses as well as rock mineralogy, wellbore and reservoir temperature, and pressure information is needed.

Little research on the topic of precipitate formation has yet been performed, or at least published, for either coal seams or shales. In addition, some are concerned that salt can build up due to CO_2 desiccation of saline formation waters that may be present in the coal formation. This should be the subject of future research.

In order to alleviate the impact of CO_2 matrix swelling on well injectivity, Durucan and Shi[120] report on the performance comparison for different CO_2-ECBM schemes in relatively thin unmineable seams typical of Northern Appalachian coal basin using a horizontal well configuration, which they demonstrate to be much preferred over vertical wells. They performed numerical simulations based upon public-domain coalbed reservoir properties which indicated that injection of pure CO_2 is likely to result in only limited incremental methane recovery over primary recovery, due to the low injection rates that can be achieved. On the other hand, the presence of N_2 in the injected gas stream was demonstrated to be capable of improving the efficiency of methane recovery significantly without compromising the net CO_2 injection rates, as a result of improved injectivity over pure CO_2 injection. They note that there is a trade-off between incremental methane recovery and produced gas purity, however, due to early N_2 breakthrough.

Durucan and Shi[121] also suggest that well injectivity might be maintained by adopting a CO_2-alternating-N_2 injection strategy. Or perhaps more favorable in the context of CO_2 storage and ECBM, injecting flue gas from a fossil fuel power plants with minimum treatment may be considered. With N_2 flooding, injecting flue gas would lead to early N_2 breakthrough, however, which can cause rapid deterioration in the quality of the produced gas. Numerical simulations with different CO_2-ECBM schemes suggest that power plant flue gas may be enriched with a pure CO_2 stream to achieve an optimized balance between methane recovery, produced gas quality (methane purity), and the volume of CO_2 injected/stored over the entire project period.

The relative performances of different gas mixtures are expected to be strongly influenced by the sorption characteristics and associated dynamic permeability behavior of the targeted coal beds under ECBM and CO_2 storage conditions.

For a given coalfield, the range of optimum gas mixtures would depend upon whether CO_2 storage or methane recovery was the primary objective, operational constrains (e.g. the degree of N_2 impurity that could be tolerated in the gas stream), and the economics associated with gas treatment (e.g. enriching flue gas with CO_2 would incur additional costs). Finally, the acceptable level of N_2 purity in the produced gas stream to a large extent is dictated by how the produced gas will be utilized (e.g., sold for pipeline transport or used on site, where use of a lower quality gas stream may be acceptable).

Some of these same issues are expected to arise with regard to CO_2 injection in shales, but research to date is not sufficiently far enough along to confirm.

Horizontal wells have been extensively used in oil and natural gas production; and they are particularly suitable for naturally fractured reservoirs such as coals and shales. Being able to access a larger reservoir area than vertical wells, horizontal wells may be used to help alleviate permeability reduction and injectivity loss in shales and coals, facilitating incremental recovery and enhancing the opportunity for CO_2 storage. In addition, the permeability of coal seams and shale formations is inherently anisotropic. For example, in coals, the permeability in the direction of face cleat is generally considerably larger than that in the direction of butt cleat. Therefore, horizontal wells can be designed to take advantage of the orientation of natural fractures in coal seams and shales, resulting in improved access to the reservoir through the natural fracture network. As discussed above, Durucan and Shi[122] reports on the performance comparison for different CO_2-ECBM schemes in relatively thin unmineable seams typical of Northern Appalachian coal basin using a horizontal well configuration, which they demonstrate to be much preferred over vertical wells.

9. STORAGE INTEGRITY AND POTENTIAL RISKS OF STORING CO_2 IN COALS AND SHALES

9.1 Overview of Issues Related to Cap Rock Integrity and CO_2 Storage

Effective CO_2 storage requires assurance of the confinement of the injected CO_2 at each storage site. The most critical element in assuring confinement is the integrity of the cap rock system overlying the storage formation. In order to assess the risk of leakage to the atmosphere or into overlying formations, understanding the entire confining system is critical.

The primary objective of the cap rock in a CO_2 storage project is to prevent migration of CO_2 into ground water sources and, ultimately, perhaps to the atmosphere. In other work for IEAGHG, ground water systems are defined as the "…petrophysical, geometric, geomechanical, and geochemical properties of the cap rock, the faults or fractures which pass through it, and the hydrodynamics regime in which it occurs."[123]

A significant component of the cap rock is its seal potential, defined in terms of the seal's capacity, geometry, and integrity, as follows:

- *Sealing capacity* refers to the CO_2 column height that the cap rock can retain before capillary forces allow CO_2 migration through the cap rock.
- *Seal geometry* refers to the thickness (it must be thick enough to maintain an effective seal across faults and displace it) and lateral extent of the cap rock (sufficient to cover whatever structural, stratigraphic, or hydrodynamic storage reservoir is the target of CO_2 injection).
- *Seal integrity* refers to the geomechanical properties of the cap rock, controlled by mineralogy, regional and local stress fields, and any stress changes induced by injection of CO_2 or withdrawal of fluids.

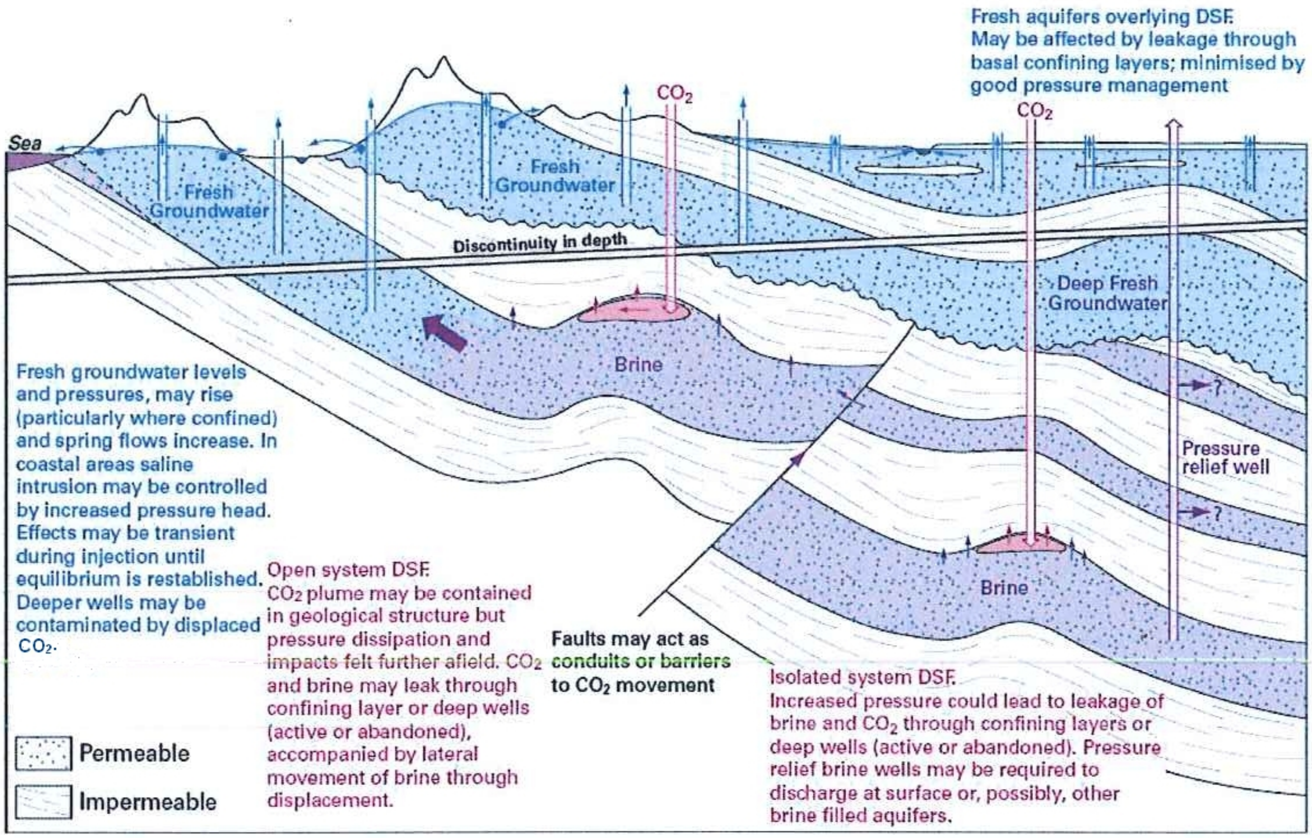
Geochemical interactions between the cap rock and CO_2 are important considerations. Depending on mineralogy, the reaction of acidic CO_2-rich fluids and the cap rock can be either advantageous or disadvantageous. The reaction could cause leaching of minerals, which could increase permeability in the cap rock and facilitate CO_2 movement. On the other hand, mineral precipitation could occur, reducing cap rock permeability. Because the pH buffering capabilities of the seal lithology are generally greater than the dissolution capabilities of carbonic acid (formed when CO_2 and water combine), precipitation is probably more likely in most settings. In either case, such interactions are likely to be limited to just a small part of the base of the overall cap rock system.

Geological sequestration requires a permeable geological formation into which captured CO_2 can be injected, and an overlying impermeable cap rock that keeps the buoyant CO_2 within the injection formation. Shale formations typically have very low permeability and are considered to be good cap rock formations. Production of natural gas from shale and other tight formations involves fracturing the shale. As such, shale gas production could be considered in direct conflict with the use of shale formations as a cap rock barrier to CO_2 migration.

In work sponsored by IEAGHG and performed by CO_2GeoNet,[124] areas of geographical overlap between potential CO_2 storage in deep saline aquifer and overlying potable aquifers were identified, and regional maps of this overlap were developed. A classification scheme was developed for various geological settings in which conflicts could occur. Two approaches were used to address potential impact mechanisms of CO_2 storage projects on the hydrodynamics and chemistry of shallow ground water: (1) natural or industrial analogues and laboratory experiments, and (2) hydrodynamic and geochemical models. Based on the potential impact mechanisms identified, possible mitigation options were assessed. The potential leakage mechanisms and impacts are illustrated in **Figure 9.1.**

Busch, et al.[125] note that leakage through cap rocks may occur in three ways: (1) rapid (‘‘catastrophic’’) leakage by seal-breaching (mechanical failure) or damage of well casing (corrosion of pipes and cements), resulting in gas flow through a (micro-) fracture network, (2) long-term leakage controlled by capillary sealing efficiency and permeability (after capillary breakthrough pressure is exceeded) and (3) diffusive loss of dissolved gas through water-saturated pore space.

Figure 9.1: Schematic Representation of Potential Leakage Mechanisms and Impacts of CO_2 Storage on Fresh Ground Water
(Not to Scale)



Source: IEAGHG, Potential Impacts on Groundwater Resources of CO_2 Storage, 2011/11, October 2011

In general, the potential impact mechanisms and impacts for CO_2 storage in coal seams and shales are the same as those identified for deep saline aquifers. Similar to all types of settings for geologic storage, the potential leakage paths for CO_2 storage in coal bed and gas shale reservoirs are:

- Natural pathways such as faults and/or fractures
- Poorly cemented wellbores
- Migration of CO_2 dissolved in formation water
- Wellbore and/or cap rock failure

The assessment of the risks associated with the storage of CO_2 in coal seams and shales requires the identification of the potential subsurface leakage processes, the likelihood of an actual leakage, the leak rate over time, and long-term implications for safe storage.

9.2 Storage Integrity and Potential Risks of Storing CO_2 in Coals

Many of the of the sedimentary basins around the world that have potential for CO_2 storage in coals seams may also contain potable ground water sources, either at shallower depths, or, in some cases like the Black Warrior Basin in Alabama in the U.S., coincident with storage target.[126] (Because of this, such coal seams, however, may not be target for CO_2 storage, expect, perhaps, where CBM production has already taken place.)

The practice of testing seal integrity is not routinely performed as part of CBM production projects, but will be a critical factor in determining the viability of a particular coal seam formation as a CO_2 storage site. As part of the CO_2 Capture Project,[127] researchers conducted a probabilistic risk assessment study of CO_2 storage in coal.[128] A mathematical model was developed for probabilistic risk assessment, and was applied to an assessment of the risks associated with CO_2 and methane leakage in a CO_2 storage project in a coal seam. This mathematical model consisted of six functional constituents: initiators, processes, failure modes, consequences (effects), indicators, and inference queries. The assessment focused on the evaluation of geomechanical factors that need to be taken into account in assessing CO_2 leakage risks in coal seam storage.

The study determined that geomechanical processes lead to risks of developing leakage pathways for CO_2 and/or methane at each step in a CBM recovery/CO_2 storage project. In addition to the risk scenarios common to other geologic formations, CO_2 storage in coals was found to face other unique risks, including:

- Insufficient CO_2-coal contact volume due to coal bed heterogeneity
- Injectivity loss due to coal swelling caused by CO_2 adsorption
- CO_2 and/or methane leakage through pre-existing faults and discontinuities
- CO_2 and/or methane leakage through outcrops
- CO_2 and/or methane desorption caused by potential future coal bed water extraction.

While recognizing that the risks identified in the study need to be evaluated specifically for individual sites, the following general conclusions were drawn with regard to CO_2 storage in coal seams:

- Risks of leakage are much higher for open cavity well completions than for cased well completions.
- Coal properties and available technology should minimize the risk that the hydraulic fractures, used as part of well completion, will grow out of interval; though techniques to monitor fracture height need further development and demonstration.
- The processes of depressurization during dewatering and methane production, followed by repressurization during CO_2 injection, lead to risks of leakage path formation by failure of the coal and slip and discontinuities in the coal and overburden.
- The most likely mechanism for leakage path formation is slip on pre-existing discontinuities which cut across the coal seam. Sensitivity studies need to be performed to better evaluate this risk.
- Relationships between the amount of slip and the increase in flow (if any) along a discontinuity need to be developed.

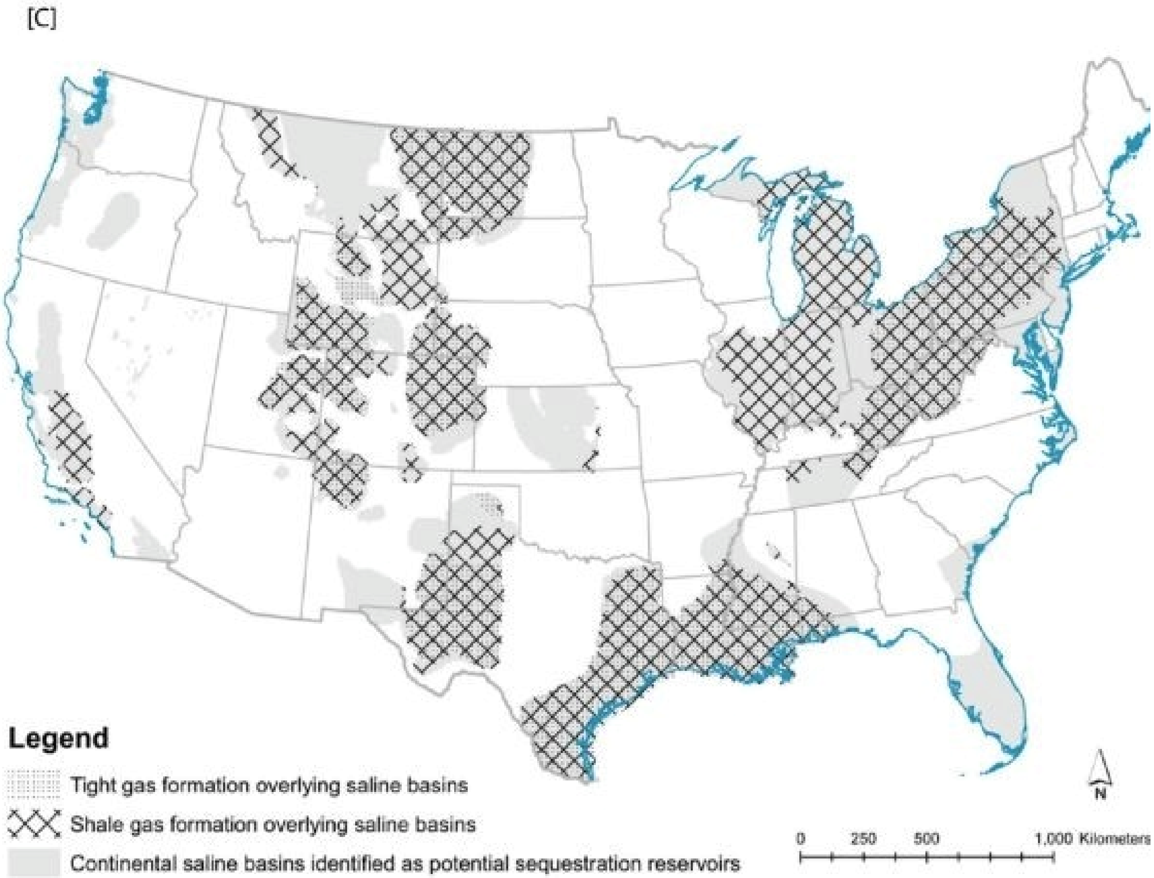
Finally, in limited laboratory experiments in coals, organic matter extracted by supercritical CO_2 was consistently qualitatively similar to the organic matter present in the coal itself.[129] A positive correlation was found between CO_2 sorption capacity and fixed carbon content, implying that coal rank is the primary determinant of CO_2 storage capacity. However, it may raise a concern about the mobilization of organics from CO_2 injection into hydrocarbon bearing formations such as coals and shales, which should be further investigated.

9.3 Storage Integrity and Potential Risks of Storing CO_2 Gas Shales -- Concerns about Shales as Storage Reservoir vs. Cap Rock

The low permeability of gas shales can make them ideal cap rocks. However, their function as a cap rock may negatively impact their use as either a storage reservoir or for production as a hydrocarbon reservoir. In order to use gas shales as a storage formation, it generally is necessary to increase effective porosity and permeability through horizontal drilling and hydraulic fracturing, which could, potentially, damage a formation's capability to serve as a cap rock.

Elliot and Celia[130] examined locations in the United States where deep saline aquifers, suitable for CO_2 storage, exist, as well as the locations of gas production from shale and other tight formations. They conclude that 80% of the capacity of deep saline aquifers in the U.S. has areal overlap with potential shale-gas production regions and could be adversely affected by shale and tight gas production (**Figure 9.2**). They also conclude that about two-thirds of the emissions from large emissions sources are located within 32 km (20 miles) of a deep saline aquifer, and potential shale and tight gas production could affect up to 85% of these sources.

Figure 9.2: Map from Elliott and Celia Showing Overlap of Deep Saline Aquifers and Shale Gas Basins in the United States



Elliot and Celia themselves note that because they only considered areal overlap, and do not consider the actual geological structure in the vertical direction. Because of this, they state that their representation should be considered an upper bound on the impacts. They note that "…We currently do not have sufficient data on vertical structure within the identified areas to perform a full three-dimensional analysis, so our results should be seen strictly as a first-cut areal analysis to identify the fraction of potential CO_2 sequestration locations that could be impacted by hydraulic fracturing."[131]

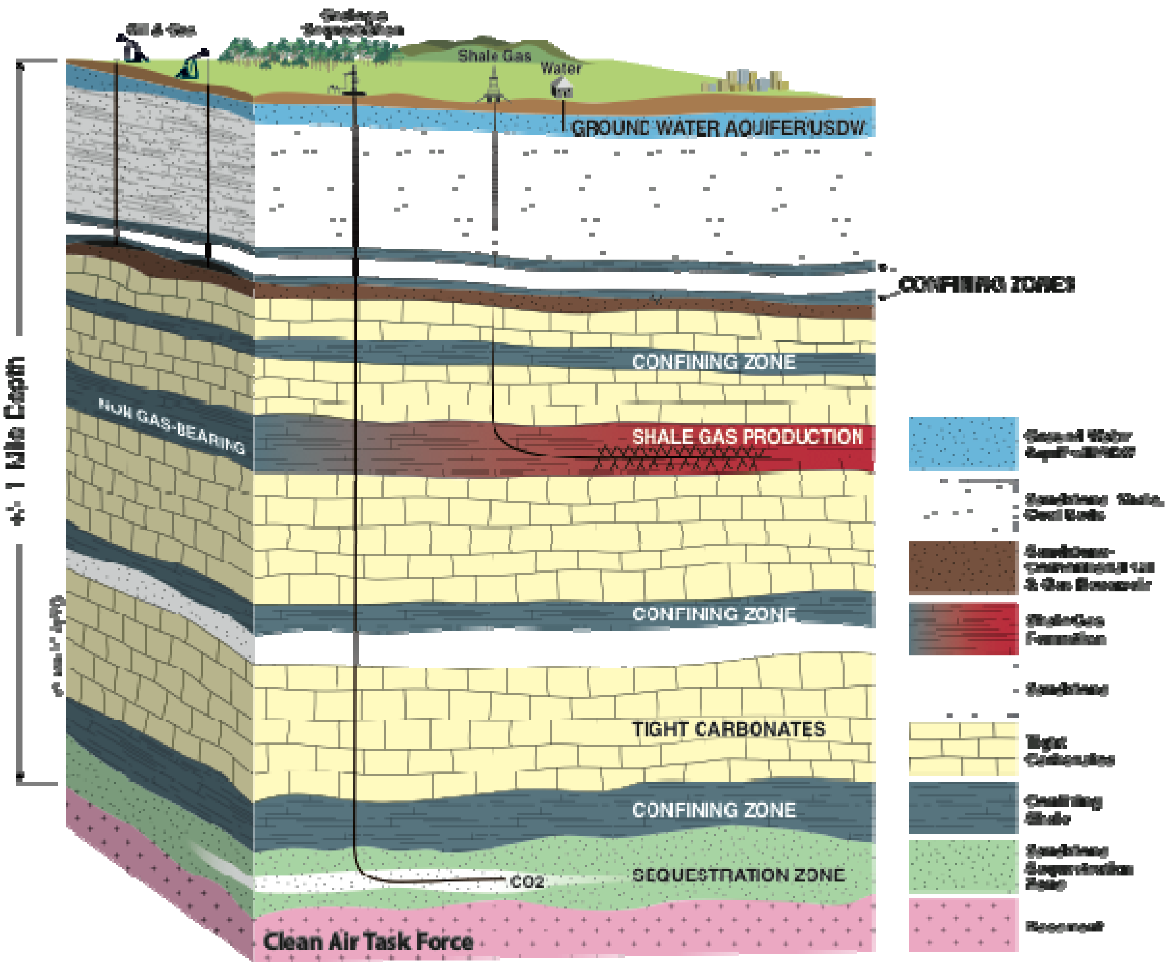
Many have expressed concern that care should be exercised in the interpretation of this analysis,[132] especially in light of press reports of these findings. In particular, they note that Elliot and Celia overlooked the critical third dimension – depth — and the thousands of feet of physical separation of the formations and attendant geologic complexity that typically exists below the surface of the earth.

Sedimentary rock can be very thick, with multiple layers of rock offering protection against leakage from a CO_2 storage target. Sedimentary basins do not consist of just two simple layers, i.e., the CO_2 reservoir and the cap rock/shale gas layer. Instead, sedimentary sequences typically consist of hundreds to thousands of meters of sedimentary fill, with multiple layers of shale, sandstones, and limestones (that may also be “tight” or largely impermeable). If one layer above the storage zone is fractured; additional layers of impermeable rock between the fractured area and the targeted storage formation could block migration of the CO_2; additional impermeable layers could also exist above the fractured shale layer.

This is illustrated in **Figure 9.3**, an idealized schematic of the basin geology in the Illinois Basin, where a storage target underlies a potentially productive shale formation. In this case, several confining zones lie between the storage target and the producing shale formation, providing perfectly adequate confining cap rock.

In most settings, multiple layers of shale formations exist that could serve as cap rocks, with generally only a few conceivable targets for commercial shale gas development and production. Other low permeability formations could also serve as cap rocks. Experience to date with regard to pursuing resource development in both coals and shales has focused on the higher quality, higher permeability settings. Those settings with good productivity should also be better candidates for CO_2 storage. Likewise, the lower quality, lower permeability settings are not good candidates for development, and would therefore not be good candidates for storage. However, these low quality and low permeability formations could be very good candidates for cap rocks overlying the potential formations targeted for storage. Those formations are not commercial because of their very low permeability, and are therefore the most attractive as cap rocks.

Figure 9.3: Idealized Schematic of the Basin Geology in the Illinois Basin

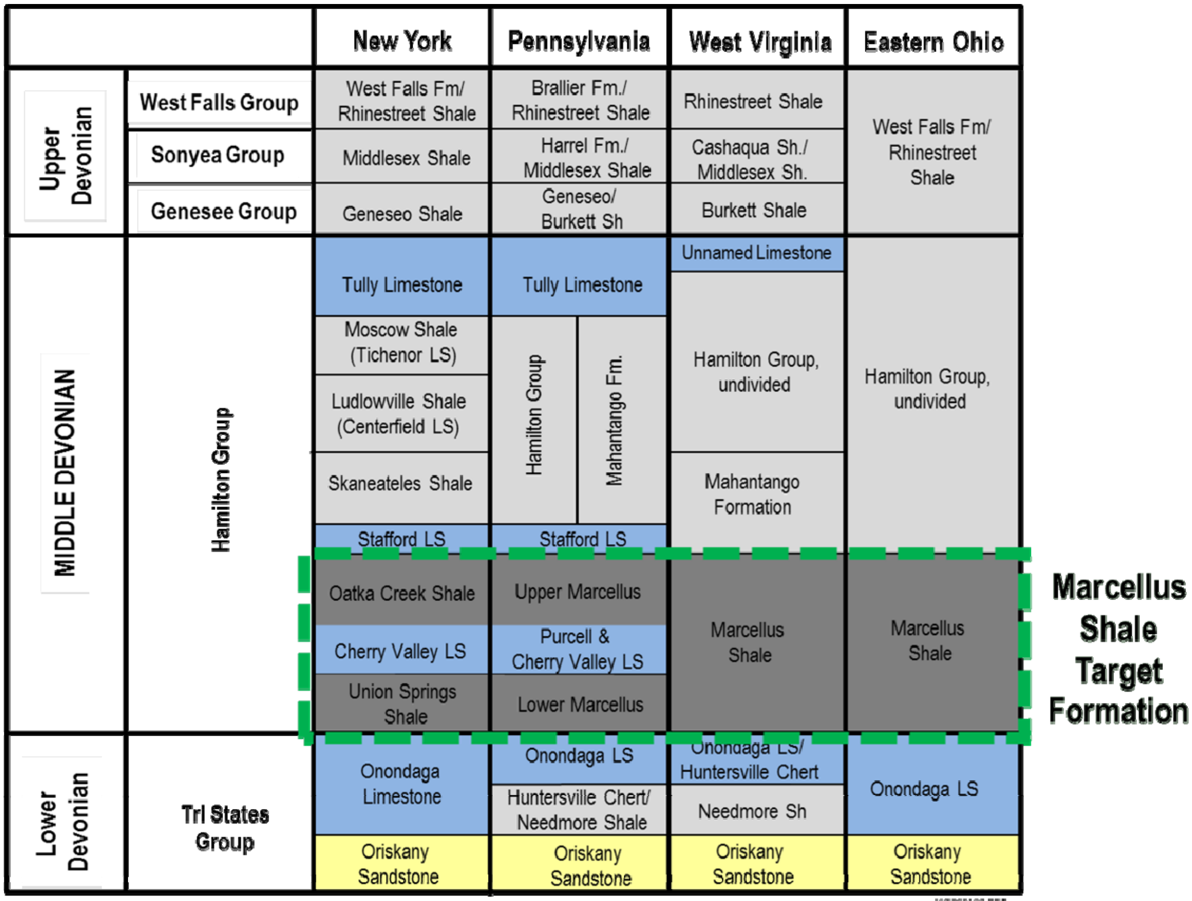


Source: Clean Air Task Force

Figure 9.4 shows the actual stratigraphy of four states in the Appalachian Basin. A primary shale gas development (and possible storage target), the Marcellus shale, is overlain by multiple, very low permeability shales, sandstones, and mudstones, none of which make very good targets for gas production because of their low permeability. Thus, even if the Marcellus shale is eventually used for CO_2 storage after gas development runs its course, numerous more shallow, less permeable potential cap rock formations can serve to contain any CO_2 that could potentially leak from the Marcellus.

Advanced Resources International, Inc.

Figure 9.4: Stratigraphic Correlation Chart for the Marcellus Shale in the Appalachian Basin



Sources: New York State Museum, Ohio Geological Survey, Pennsylvania Department of Conservation and Natural Resources, United States Geological Survey, West Virginia Geological Survey.

While it is conceivable that the production of hydrocarbons from shales may affect the seal integrity and hence the potential use for CO_2 storage of formations directly underlying the shale formation, it will not affect other deeper saline formations or hydrocarbon reservoirs at other levels in the sedimentary succession. In fact, if a cap rock is fractured, it would be unlikely to warrant approval as a storage location for CO_2 in the first place. The Class VI injection well program for a CO_2 storage site under U.S. federal regulations, for example, requires storage site developers to perform thorough seismic measurements of the subsurface and ensure a stable overhead rock before granting a permit to inject CO_2 underground. The regulations also require continual monitoring of underground plumes of injected CO_2. An already-fractured cap rock, directly overlaying a formation targeted for CO_2 storage, will not win approval for CO_2 injection in the first place.

In fact, many shale formations contain an insufficient amount of organic matter, did not attain thermal maturity, and are therefore not likely to produce economic quantities of hydrocarbons, even if they were hydraulically fractured.

Guidelines for pursuing efforts with regard to this type of characterization to ensure caprock integrity has been described in detail in the IEAGHG report entitled *Caprock Systems for CO_2 Geologic Storage*.[133]

The scenario raised by the Elliot and Celia study would be mainly relevant in one scenario, where gas producers wanted to come into an area after CO_2 injection. However, if gas producers did become interested in the same formation holding CO_2, there would likely be an extensive record of the injection of the CO_2, making it known where to avoid.

Even if overlap does occur between formations targeted for shale gas development and production and formations targeted for CO_2 storage, there will likely still be substantial storage capacity available where overlap does not occur to provide decades of storage capacity at current rates of emissions. Shale formations are geographically and geologically extensive. Most basins in the world containing shale gas resources cover large areas. For example, the Appalachian Basin which contains the Marcellus, Utica, Ohio, and other shales is approximately 480 kilometers (300 miles) wide and 970 kilometers (600 miles) long. Not all of this area will be the target of the shale gas development.

Bruce Hill of the Clean Air Task Force notes that "…Despite the conclusions of the [Elliot and Celia] paper, the overwhelming evidence suggests that geologic storage can indeed coexist safely with other subsurface activities, including oil and gas extraction and shale gas operations."[134]

9.4 Potential Impacts of Induced Seismicity on Shale Gas and CBM Production and CO_2 Storage

Recent work by Zobak and Gorelick contends that the probability of induced seismicity from large-scale geologic storage of CO_2 in brittle rocks of continental interiors is relatively high.[135] The potential to induce small- to moderate-sized earthquakes poses a threat to the integrity of primary sealing layers (for porous/permeable target formations) that calls the viability of large-scale CO_2 storage as a technology option to address global climate change into question.

However, the broader geoscience community is not in accord with these conclusions. Many geoscientists believe that induced seismicity is an issue to be dealt with by rigorous site selection, but is not a show stopper. Counterarguments to the Zoback paper have been published in blogs[136] and news reports,[137] including reports announcing the publication of these research results.[138] Moreover, this topic has been the subject of extensive research and risk assessment for current CCS projects.

Finally, IEAGHG is in the process of completing a study that will review the mechanisms that could cause induced seismicity and their application to geological storage of CO_2, involving a detailed literature review of recent and ongoing research and an analysis drawn from the findings.

While the National Academy of Sciences concluded that hydraulic fracturing for coalbed methane recovery and shale gas production is understood to not pose significant risk of induced seismicity, they did note that CO_2 injection into those fractured low-permeability formations with collocated storage in porous/permeable formations could lead to interactions between these subsurface activities that would make characterization of the performance of the compound system more complex.[139]

Understanding CO_2 storage risks – both for CO_2 storage in coals and shales and for CO_2 storage in saline formations that underlie fractured shales – requires further research. In particular, a detailed consideration of system risks would be required to improve confidence in viability of shale gas/ECBM production and CO_2 storage scenarios, which should include efforts to inventory features, events, and processes of the system and quantitative assessment of system performance to capture important behaviors of representative scenarios. The U.S. Department of Energy's National Risk Assessment Partnership[140] is building science-based quantitative assessments of CO_2 utilization and storage risks through rigorous numerical simulation of key storage system elements and incorporation of those system elements in an integrated assessment modeling framework. This Partnership hopefully can provide further insight and understanding of system risks associated with shale gas/ECBM production and CO_2 storage.

Widely associated with both coal seams and shales are other large volume sedimentary layers, allowing for the potential of "stacked storage." Stacked storage involves carefully managed CO_2 injection and storage in multiple formations, including sandstones or carbonate rocks, above or below the producing intervals in coal seams and gas shale formations. Furthermore, specific geologic sequestration rules and regulations require that operators inject CO_2 at pressures that would not induce rock failure, and that monitoring take place that assure excessive geomechanical stresses do not occur. Thus, operators and regulators of CO_2 storage sites should take care to ensure that significant induced seismicity does not occur.

9.5 Co-development of Gas Shales for Production and CO_2 Storage

In considering carbon capture and storage (CCS) in relation to production from gas shales, both the positive and negative potential impacts of shale gas production and CO_2 storage will need to be considered. The entire chain of activities involved, not just the injection of CO_2, must be considered. In fact, a double chain is involved: the first consisting of drilling the gas well, fracturing the formation, producing methane, and pipelining it to market (which could be a power plant); the second involving capturing CO_2 from the flue gas, transporting it by pipeline to a storage site the shale, and ending with injection and ultimate CO_2 storage.

In addition, as pointed out by Nicot and Duncan (2012),[141] there is considerable potential synergy between shale gas development and CO_2 storage:

> "Recent intense development of shale resources translates into a reduced need for sequestration capacity. It has also resulted in technological innovations directly transferable to the carbon-storage industry, in particular progress on well completion, such as new approaches to cementing, more mature horizontal drilling methods, and development of field-treatment techniques for saline water. In addition, knowledge collected by operators on stratigraphy and faults – for example, using 3D seismic – and on abandoned wells is directly useful in reducing risk in future carbon-storage projects. Both industries can benefit from development of regional transmission pipelines, pipeline rights-of-way, and a trained workforce."

In fact, Nicot and Duncan point out that, geologically, it should be anticipated that potential storage reservoirs and reservoirs and formations with shale gas production should overlap geographically. Essentially, all geological storage capacity exists within sedimentary basins, which, of course, is also where oil and gas resources are located.

Finally, both geologic storage and fracturing operations are primarily concerned with risks related to the same leakage conduits (abandoned wells, injection/production wells, faults), and both can mobilize subsurface chemical species and bring them to the shallow subsurface and surface. Both could potentially displace brines upward through these conduits because of the overpressure. Both CO_2 injected for storage and methane produced from shales are buoyant and will tend to migrate upward if a pathway is available. As a result, any and all regulatory oversight of both fracturing and CO_2 storage operations will have the same common objective and focus.

There are two options for injection and storage: 1) CO_2 could be injected and stored into a depleted (likely higher permeability) shale formation targeted for production, with other, lower permeability shale formations acting as the overlying seals, or 2) CO_2 could be injected into a saline formation below a shale formation, provided that a shale formation directly overlaying the targeted formation for CO_2 storage had not been detrimentally fractured.

For example, as described above for the Marcellus shale in the U.S., CO_2 could be injected into the depleted Marcellus formation after gas has been produced, with the Hamilton and Mahantango shale formations acting as the overlying seals (Figure 9.4). Alternatively, CO_2 could be injected into a saline formation below the Marcellus shale; and the Marcellus would act as the primary seal (provided it had not been fractured), with the Hamilton and Mahantango acting as secondary seals.[142]

A shale formation that had been extensively fractured and produced would not likely be considered as the primary sealing formation, or cap rock, for a CO_2 storage site. Storage project developers and regulators overseeing these projects will need to pay close attention to the interplay of shale gas and CO_2 storage development activities. Subsurface activities such as geologic storage and shale gas operations require geologic review, ongoing monitoring, and regulatory oversight to avoid conflicts. With sensible safeguards, CO_2 storage reservoirs can, in most areas, coexist in the same space with conventional and unconventional oil and gas operations, including shale gas production and hydraulic fracturing.

Experience to date with regard to assessing potential and pursuing methane resource development in both coals and shales has focused on the higher quality, higher permeability settings. Obviously, those settings with good productivity should also be better candidates for CO_2 storage. Likewise, the lower quality, lower permeability settings, especially as applied to shale, are not good candidates for development, and would also not be good candidate formations for storage. However, these could very well be very good candidates for cap rock overlying potential formations targeted for storage.

Finally, the use of CO_2 to actually facilitate fracturing may be viable in some geologic settings.[143] Some reservoirs do not respond effectively to conventional hydraulic stimulations using water as the transport fluid. Sometimes the nature of the reservoir is such that the fracturing liquids can become trapped because the reservoir is at a lower pressure and does not have sufficient energy to push the liquids back to the well bore. The use of CO_2 for hydraulic fracturing is unique because it can be pumped as a liquid and then it vaporizes to a gas and flows from the reservoir leaving no liquid or chemical damage. The process is best applied in tighter (less permeable), lower pressure, dry gas reservoirs where stimulation liquids are foreign to the formation and reduce its permeability to gas, and also in higher permeability reservoirs where near well bore formation damage can be removed with this non-damaging process.

A comparison of coal seam and shale gas formations that are most attractive for natural gas production with those that are less attractive, and would thus be better candidates as cap rocks for storage, is specific to the geologic setting of a basin. Such a characterization should be performed based on the specific geological characteristics of the respective formations, as well as their relative location in the geologic depositional sequence.

10. POTENTIAL ECONOMIC IMPLICATIONS OF CO_2 STORAGE IN SHALES AND COALS

Work examining the potential economic implications of CO_2 storage in coal seams and shales is quite limited, though there is more field-test experience with coals upon which to draw insights. Most economic studies have been on hypothetical case studies,[144,145] which may not necessarily reflect “real-world” conditions.

Essentially all CBM operations still employ primary recovery methods, generally by pumping off large volumes of formation water to lower reservoir pressure and facilitate methane desorption. Primary production of coal bed methane recovers 20% to 60% of the original gas-in-place, depending on coal seam permeability, gas saturation, and other reservoir properties. Well spacing and other operational practices also will affect recovery efficiency.

ECBM technology is still in the development phase, though this is in large part due to current lack of commercial incentive for the process, as opposed to any insurmountable technical hurdles.

Two approaches are generally considered for applying ECBM to recover a larger fraction of gas in place: 1) inert gas stripping using N_2 injection; and 2) displacement desorption employing CO_2 injection.

The same engineering techniques for enhancing methane production from gas shales and coals – dense well spacing, horizontal drilling, and/or hydraulic fracturing – will also likely be needed to enhance CO_2 injectivity and storage in these formations. This conclusion is supported by small scale field tests and associated simulation work, but no large scale tests have yet to be conducted in either coal or shales, and with the only moderately sized injection test in coal seams being the Pump Canyon demonstration project in the San Juan basin in the south western United States, where about 18,000 tons of CO_2 were injected over a 12-month period.[146]

Gale and Freund concluded that based on costs and performance experience ten years ago, CO_2-ECBM might be profitable in the United States at wellhead natural gas prices of U.S. $1.75 to $2.00/Mcf. Given this, they concluded, based on an analysis of representative CO_2-

ECBM projects, that 5 to 15 Gt of CO_2 could conceivably be stored at a net profit, while about 60 Gt of storage capacity may be available at moderate costs of under $50 per metric ton of CO_2.[147]

The 2003 Advanced Resources report for DOE/NETL[148] estimated that between 25 and 30 Gt of CO_2 was estimated to be economical to store (assuming wellhead natural gas prices of $3.00/Mcf), and 80 to 85 Gt of storage potential was estimated at costs of less than $5 per metric ton. These estimates did not include any costs associated with CO_2 capture and transportation, only representing the costs associated with geologic storage.

Some critical questions that need to be addressed when understanding the economic potential for ECBM and enhanced shale gas recovery, combined with CO_2 storage, include:

- What type of source of CO_2 emissions provides the best recovery and storage economics?
- What impact does the phasing of primary and ECBM recovery have on the effectiveness of CO_2 storage?
- What considerations need to be addressed regarding the management and disposal of produced water?
- What coal and shale reservoir environment provides the best economics (e.g. permeability, depth, rank/TOC, rate, spacing, etc.)?
- What gas composition provides best storage economics?
- Are greenfield or brownfield projects better?
- How sensitive are results to hydrocarbon prices?
- How might CO_2 emission reduction credits impact the results?
- How important is scale?
- How important is distance between source and sink?
- What might be possible interactions, and their implication, with ground water and other resources?

As discussed above, research to date demonstrates that there may be cases where CO_2-ECBM can be technically and economically successful. Review of efforts to date highlight key lessons applicable to CO_2-ECBM and CO_2 storage in coal beds:[149]

- With a depleted reservoir due to previous gas production operations, initial injection rates can be quite robust.
- Injection rates will decline due to re-pressurization and swelling of the coal reservoir.
- The presence of hydraulic fractures may complicate things.
- N_2 (as a tracer) may be a strong indicator of pending breakthrough.

In cases where the rank and permeability are not adequate for enhanced recovery and storage operations, there may be opportunities for pulsing and or mixing N_2 into the injection stream to improve injectivity during storage and enhanced recovery operations. Moreover, while the executed field tests to date do provide some insights into the long-term viability of enhanced recovery and storage in shales and coal seams, it is clear that there is much more to learn.

11. CONCLUSIONS AND RECOMMENDATIONS

Building upon combined developments in horizontal drilling and hydraulic fracturing technologies, production of natural gas from organic-rich gas shale formations and coal deposits is rapidly developing as a major hydrocarbon energy supply option in North America, Europe, Asia, and Australia, with opportunities for development being assessed in other regions of the world. Moreover, gas shales and coal seams can also serve as potential storage formations for CO_2, though this has not been demonstrated on a field scale yet in shales. The same technologies – horizontal drilling and hydraulic fracturing – that have contributed to the recent rapid increase in shale gas development and production may also open up the possibility of using shale formations and unmineable coal seams as actual storage media for CO_2 by increasing permeability and injectivity, allowing storage to potentially be more cost effective.

The technical recovery potential for methane from the world's coal seams is estimated to be 79 Tcm globally, 29 Tcm from conventional CBM recovery, and 50 Tcm from the application of ECBM recovery through the injection of CO_2. This could facilitate the potential storage of nearly 488 Gt of CO_2 in unmineable coal seams. In gas shales, an estimated 188 Tcm of shale gas resources are potentially technically recoverable globally, and could facilitate the potential storage of 740 Gt of CO_2 in gas shales.

Some have concluded that there is considerable overlap of deep saline aquifers in the United States with potential shale gas production regions and, therefore conclude that the use of these saline aquifers as storage targets could be adversely affected by shale and tight gas production. However, such a conclusion overlooks the critical third dimension – depth. Sedimentary basins do not consist of just two simple layers, i.e., the CO_2 storage reservoir and the cap rock/shale layer. Instead, sedimentary sequences typically consist of thousands of meters of bedrock, with multiple layers of shale, sandstones, limestones, etc. (that may also be "tight" or largely impermeable). If one layer above the storage zone is fractured; additional layers of impermeable rock overlying the fractured area could block migration of the CO_2.

Storage project developers and regulators overseeing these projects will need to pay close attention to the interplay of shale gas and CO_2 storage development activities. Subsurface activities such as geologic storage and shale gas operations require geologic review, ongoing monitoring, and regulatory oversight to avoid conflicts. With sensible safeguards, CO_2 storage reservoirs can, in most areas, coexist in the same space with conventional and unconventional oil and gas operations, including shale gas production and hydraulic fracturing.

Based on a comprehensive review of the status of research into geological storage of CO_2 in gas shales and coals, the key knowledge gaps and technical barriers identified that could impact the achievement of this potential include:

1. A lack of critical formation-specific information on the available storage capacity in coal seams and gas shales in all but a few, targeted settings.
2. A lack of geological and reservoir data for defining the favorable settings for injecting and storing CO_2 in coals and shales; this is also true for assessing methane production potential.
3. Understanding the nearer- and longer-term interactions between CO_2 and coals and shales, particularly the mechanisms of swelling in the presence of CO_2, shrinkage with release of methane, and the physics of CO_2/methane exchange under reservoir conditions.
4. Formulating and testing alternative reliable, high volume CO_2 injection strategies and well designs.
5. Developing integrated, cost-effective strategies for enhanced recovery of methane and CO_2 storage in both coals and shales.

While significant progress has been made on overcoming these gaps and barriers, with additional efforts currently being pursued, these gaps and barriers still exist. In particular, research on the potential for recovering methane and storing CO_2 in gas shales is significantly less advanced than that for coal seams.

Finally, as with the “Shale Gas Revolution,” the emerging “Tight Oil (Liquids-Rich Shale) Revolution” requires overcoming certain entrenched aspects of “conventional wisdom” that liquids cannot be economically produced from such low permeability settings. The Bakken Shale, in which oil is primarily produced from a permeable carbonate layer sandwiched between low permeability shale source rocks, was seen as an exception. However, with oil and condensate production from the Eagle Ford Shale, along with the development and subsequent rapid growth in production from numerous other liquids-rich shale plays occurring in the U.S., the “conventional wisdom” regarding the potential of liquids-rich shales is getting turned on its head.

It is recommended that efforts build upon the results of this study to expand and focus reservoir characterization research in liquid-rich shale settings globally to evaluate alternative development optimization strategies for these reservoirs, encompassing, both “primary” and “enhanced” or “improved” recovery, and, also providing for the long term storage of CO_2.

Finally, much about the mechanisms and potential for storing CO_2 and enhancing methane recovery in shales and coal seams remain unknown. At field scale, only a few projects of any appreciable scale have been performed in coal seams, and none have yet been pursued in shales. As a result, future research in necessary, and the results of this research could dramatically change the conclusions documented in this report. low level of development of CO2 storage in coal and especially in shale could be more emphasized in the conclusion and in the executive summary, by making clear that few examples of CO_2 storage in coal exist today and that no one does for shale.

APPENDIX A

ASSUMPTIONS FOR COAL RANK AND OTHER KEY INPUTS USED THIS ASSESSMENT

COUNTRY	BASIN	DEPTH	THICKNESS	DENSITY	GAS CONTENT	RANK	Ro (%) inferred	Ro (%) sourced
United States	USA - Northern Appalachia	<2000	20-50		150-200	High Volatile A Bituminous	0.95	
United States	USA - Central Appalachia	<2500	20-50		500-600	High Volatile A Bituminous	0.95	
United States	Warrior Basin	500-4500	20-50		420-520	High Volatile A Bituminous	0.95	
United States	UINTA	1200-3400 ft	24 ft		330 ft3/ton	High Volatile B Bituminous	0.625	
United States	RATON	400-4000ft	10-40 ft		50-400 scf/ton	High Volatile B Bituminous	0.625	
United States	POWDER RIVER	200-2500ft	75 ft		30scf/ton	Sub-bituminous	0.46	
United States	GREEN RIVER					Bituminous	1.21	
United States	PICEANCE					High Volatile A Bituminous	0.95	
United States	ILLINOIS					High Volatile A Bituminous	0.95	
United States	SAN JUAN	550-4000ft	20-80ft		350-400scf/ton	Sub-bituminous	0.46	
United States	CHEROKEE/FOREST CITY					High Volatile A Bituminous	0.95	
United States	ARKOMA					High Volatile A Bituminous	0.95	
United States	GULF COAST					Lignite	0.345	
United States	HANNA-CARBON							
United States	WIND RIVER	915-4265m				Sub-bituminous	0.46	
United States	WESTERN WASHINGTON					Sub-bituminous	0.46	
United States	ALASKA							
UNITED STATES	**TOTAL**							0.8
Canada	Western	200-1300m				Bituminous	1.21	
Canada	Atlantic					Bituminous	1.21	
CANADA	**TOTAL**							
MEXICO	**TOTAL**					Bituminous	1.21	0.99
Total North America								
Brazil	Parana					Bituminous	1.21	0.8
BRAZIL	**TOTAL**							0.8
Colombia	Cesar					High Volatile B Bituminous	0.625	
Colombia	Guajira					High Volatile B Bituminous	0.625	
Colombia	Boyaca					High Volatile A Bituminous	0.95	
Colombia	Cundinamarca					Bituminous	1.21	
Colombia	Valle del Cauca					High Volatile A Bituminous	0.95	
Colombia	Norte De Santander					Low Volatile Bituminous	1.715	
Colombia	Cordoba					High Volatile B Bituminous	0.625	
Colombia	Antioquia					High Volatile B Bituminous	0.625	
Colombia	Santander					Bituminous	1.21	
COLOMBIA	**TOTAL**					Bituminous	1.21	0.6
VENEZUALA	**TOTAL**					Sub-bituminous	0.46	
Other S. & Cent. America								
Total S. & Cent. America								

COUNTRY	BASIN	DEPTH	THICKNESS	DENSITY	GAS CONTENT	RANK	Ro (%) inferred	Ro (%) sourced	CO_2:CH_4
BULGARIA	**TOTAL**								
CZECH REPUBLIC	**TOTAL**								
GERMANY	**TOTAL**							1.45	1.4
GREECE	**TOTAL**								
Hungary	Mecsek	0-1100m	30m	1.5 tonne/m3	50 m3/ton	Bituminous	1.21	1.21	1.9
HUNGARY	**TOTAL**					Bituminous	1.21	1.25	1.8
KAZAKHSTAN	**TOTAL**						0		
Poland	Lublin						0		
Poland	Lower Silesian					Sub-bituminous	0.46	0.68	4.9
Poland	Upper Silesian					Sub-bituminous	0.46	0.68	4.9
POLAND	**TOTAL**	900-1250m	1000m			Sub-bituminous	0.46	0.8	3.7
ROMANIA	**TOTAL**						0	0	
Russian Federation	KUZBASS	<1350m	80m		19-25m3/t	Anthracite	3.25	0.975	2.7
Russian Federation	PECHORA					Medium Volatile Bituminous	1.315		1.6
Russian Federation	EASTERN DONBASS					Bituminous	1.21		1.9
Russian Federation	SOUTH YAKUTIA					Bituminous	1.21		1.9
Russian Federation	ZIRYANSK					Bituminous	1.21		1.9
Russian Federation	TUNGUSKA					Bituminous	1.21		1.9
Russian Federation	LENSK					Bituminous	1.21		1.9
Russian Federation	TAYMIR					Bituminous	1.21		1.9
RUSSIAN FEDERATION	**TOTAL**							1.1	2.2
SPAIN	**TOTAL**							2.54	0.5
TURKEY	**TOTAL**							1.15	2.0
Ukraine	Donets (Donbas)	1600-1800m	1-2.5 m		10-35 m3/t	Bituminous	1.21	1.21	1.9
UKRAINE	**TOTAL**					Bituminous	1.21		1.9
UNITED KINGDOM	**TOTAL**					Bituminous	1.21		1.9
Other Europe & Eurasia	**TOTAL**								
Total Europe & Eurasia	**TOTAL**								
Botswana	**TOTAL**	>1000	>50		90-125	Bituminous	1.21	0.6	6.1
Mozambique	**TOTAL**	>650	44-130		80-100	Bituminous	1.21	1.4	1.5
Namibia	**TOTAL**	>650	10 to 60		80-100	Bituminous	1.21	1.4	1.5
South Africa	**TOTAL**	650-1000	>50		40-140	Bituminous	1.21	1.4	1.5
Zimbabwe	**TOTAL**		20-45			Bituminous	1.21	0.77	4.0
Other Africa	**TOTAL**								
Middle East	**TOTAL**								
Total Middle East & Africa	**TOTAL**						0		

COUNTRY	BASIN	DEPTH	THICKNESS	DENSITY	GAS CONTENT	RANK	Ro (%) inferred	Ro (%) sourced	CO_2:CH_4
Australia	SYDNEY	250-850m				Bituminous	1.21	1.266	1.7
Australia	SURAT							0.475	9.0
Australia	GLOUCESTER								
Australia	BOWEN					Bituminous	1.21	0.825	3.6
Australia	CLARENCE-MORETON							0.475	9.0
Australia	GUNNEDAH					Bituminous	1.21	1.21	1.9
AUSTRALIA	**TOTAL**							0.95	2.8
China	Qinshui Basin								
China	Ordos Basin		8-20m		12-18m3/mton	Medium Volatile Bituminous	1.315	1.3	1.7
China	Junggar Basin					Sub-bituminous	0.46		9.5
China	Erlian Basin						0		
China	Dian-Qian-Gui						0		
China	Tuha						0		
China	Halar						0		
China	Yili					Bituminous	1.21		1.9
China	Others								
CHINA	**TOTAL**							0.95	2.8
India	Gondwana								
INDIA	**TOTAL**					High Volatile A Bituminous	0.95	0.85	3.4
Indonesia	S. Sumatra	762	37			Sub-bituminous	0.46	0.47	9.2
Indonesia	Barito	915	28			Sub-bituminous	0.46	0.45	9.9
Indonesia	Kutei	915	21			Sub-bituminous	0.46	0.5	8.3
Indonesia	C. Sumatra	762	15			Sub-bituminous	0.46	0.4	12.1
Indonesia	N. Tarakan	701	15			Sub-bituminous	0.46	0.45	9.9
Indonesia	Berau	671	24			Sub-bituminous	0.46	0.45	9.9
Indonesia	Ombilin	762	24			High Volatile A Bituminous	0.95	0.8	3.7
Indonesia	Pasir/Asem	701	15			Sub-bituminous	0.46	0.45	9.9
Indonesia	NW Java	1524	6			High Volatile B Bituminous	0.625	0.7	4.7
Indonesia	Sulawesi	610	6			High Volatile C Bituminous	0.625	0.55	7.0
Indonesia	Bengkulu	610	12			Sub-bituminous	0.46	0.4	12.1
INDONESIA	**TOTAL**				150-200				
Japan									
New Zealand		1150-1800	60-120		120-225			0.75	4.2
North Korea									
Pakistan									
South Korea									
Thailand		<1000	100-200		100			0.8	3.7
Vietnam		>1000	150-300		60-200				
Other Asia Pacific									
Total Asia Pacific									
Total World									

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APPENDIX B

GLOBAL ESTIMATES OF CBM RESOURCE POTENTIAL

		Coal Reserves	CBM Gas-in-place		CBM Recoverable	
COUNTRY	BASIN	Million Tonnes	Tcf	Tcm	Tcf	Tcm
United States	USA - Northern Appalachia		61	1.73	9	0.26
United States	USA - Central Appalachia		5	0.14	3	0.09
United States	Warrior Basin		19	0.54	5	0.14
United States	UINTA		10	0.28	9	0.25
United States	RATON		10	0.28	6	0.17
United States	POWDER RIVER		61	1.73	11	0.32
United States	GREEN RIVER		314	8.89	11	0.31
United States	PICEANCE		81	2.29	8	0.24
United States	ILLINOIS		13	0.37	1	0.02
United States	SAN JUAN		78	2.21	36	1.03
United States	CHEROKEE/FOREST CITY		7	0.20	2	0.05
United States	ARKOMA		3	0.08	1	0.04
United States	GULF COAST		6	0.17	2	0.05
United States	HANNA-CARBON		15	0.42	4	0.12
United States	WIND RIVER		6	0.17	2	0.07
United States	WESTERN WASHINGTON		12	0.34	2	0.06
United States	ALASKA		1,045	29.59	57	1.61
UNITED STATES	**TOTAL**	**237,295**	**1,746**	**49**	**170**	**4.82**
Canada	Western		528	15.0	177	5.00
Canada	Atlantic		22	0.6	7	0.21
CANADA	**TOTAL**	**6,582**	**550**	**15.6**	**184**	**5.21**
MEXICO	**TOTAL**	**1,211**	**9**	**0.3**	**1**	**0.04**
North America		**245,088**	**2,305**	**65.3**	355	10.06
Brazil	Parana				0	
BRAZIL	**TOTAL**	**4,559** *	**36**	**1.0**	**5**	**0.15**
Colombia	Cesar		4	0.1	**1**	0.02
Colombia	Guajira		6	0.2	**1**	0.03
Colombia	Boyaca		4	0.1	**1**	0.02
Colombia	Cundinamarca		4	0.1	**1**	0.01
Colombia	Valle del Cauca		3	0.1	**0**	0.01
Colombia	Norte De Santander		1	0.0	**0**	0.00
Colombia	Cordoba		0	0.0	**0**	0.00
Colombia	Antioquia		0	0.0	**0**	0.00
Colombia	Santander		1	0.0	**0**	0.00
COLOMBIA	**TOTAL**	**6,746**	**23**	**0.7**	**3**	**0.10**
VENEZUALA	**TOTAL**	**479**	**17**	**0.5**	**3**	**0.07**
Other S. & Cent. America	**TOTAL**	**724** *		**0.0**	**0**	**0.00**
South & Central America		**12,508**	**76**	**2.2**	**11**	**0.32**

		Coal Reserves	CBM Gas-in-place		CBM Recoverable	
COUNTRY	**BASIN**	**Million Tonnes**	**Tcf**	**Tcm**	**Tcf**	**Tcm**
BULGARIA	**TOTAL**	**2,366**				
CZECH REPUBLIC	**TOTAL**	**1,100**	**13**	**0.4**	**2**	**0.06**
GERMANY	**TOTAL**	**40,699**	**106**	**3.0**	**16**	**0.45**
GREECE	**TOTAL**	**3,020**		**0.0**	**0**	**0.00**
Hungary	Mecsek			0.0	0	0.00
HUNGARY	**TOTAL**	**1,660**	**4**	**0.1**	**1**	**0.02**
KAZAKHSTAN	**TOTAL**	**33,600**	**50**	**1.4**	**10**	**0.28**
Poland	Lublin			0.0	0	0.00
Poland	Low er Silesian			0.0	0	0.00
Poland	Upper Silesian			0.0	0	0.00
POLAND	**TOTAL**	**5,709**	**50**	**1.4**	**5**	**0.14**
ROMANIA	**TOTAL**	**291**				
Russian Federation	KUZBASS		462	13.1	55	1.56
Russian Federation	PECHORA		69	1.9	8	0.23
Russian Federation	EASTERN DONBASS		3	0.1	0	0.01
Russian Federation	SOUTH YAKUTIA		32	0.9	4	0.11
Russian Federation	ZIRYANSK		3	0.1	0	0.01
Russian Federation	TUNGUSKA		706	20.0	84	2.38
Russian Federation	LENSK		212	6.0	25	0.71
Russian Federation	TAYMIR		194	5.5	23	0.65
RUSSIAN FEDERATION	**TOTAL**	**157,010**	**1,682**	**47.6**	**200**	**5.66**
SPAIN	**TOTAL**	**530**				
TURKEY	**TOTAL**	**2,343**	**51**	**1.4**	**10**	**0.28**
Ukraine	Donbass		170	4.8		0.00
UKRAINE	**TOTAL**	**33,873**	**170**	**4.8**	**25**	**0.71**
UNITED KINGDOM	**TOTAL**	**228**	**102**	**2.9**	**15**	**0.43**
Other Europe & Eurasia	**TOTAL**	**22,175**				
Europe & Eurasia	**TOTAL**	**304,604**	**2,228**	**63.1**	**284**	**8.04**
Botswana	**TOTAL**		**105**	**3.0**	**16**	**0.45**
Mozambique	**TOTAL**		**88**	**2.5**	**13**	**0.37**
Namibia	**TOTAL**		**104**	**2.9**	**16**	**0.44**
South Africa	**TOTAL**	**30,156**	**60**	**1.7**	**9**	**0.25**
Zimbabwe	**TOTAL**	**502**	**60**	**1.7**	**9**	**0.25**
Other Africa	**TOTAL**	**1,034** *				
Middle East	**TOTAL**	**1,203** *				
Middle East & Africa	**TOTAL**	**32,895**	**417**	**11.8**	**63**	**1.77**

		Coal Reserves	CBM Gas-in-place		CBM Recoverable	
COUNTRY	**BASIN**	**Million Tonnes**	**Tcf**	**Tcm**	**Tcf**	**Tcm**
Australia	SYDNEY		2	0.1	0.3	0.01
Australia	SURAT		152	4.3	22.8	0.65
Australia	GLOUCESTER		4	0.1	0.6	0.02
Australia	BOWEN		55	1.6	8.2	0.23
Australia	CLARENCE-MORETON		2	0.1	0.4	0.01
Australia	GUNNEDAH		9	0.3	1.4	0.04
AUSTRALIA	**TOTAL**	**76,400**	**153**	**6.4**	**34**	**0.95**
China	Qinshui Basin		170	4.8	26	0.72
China	Ordos Basin		436	12.3	65	1.85
China	Junggar Basin		179	5.1	27	0.76
China	Erlian Basin		95	2.7	14	0.40
China	Dian-Qian-Gui		165	4.7	25	0.70
China	Tuha		99	2.8	15	0.42
China	Halar		75	2.1	11	0.32
China	Yili		57	1.6	9	0.24
China	Others		22	0.6	3	0.09
CHINA	**TOTAL**	**114,500**	**1,299**	**36.8**	**195**	**5.52**
India	Gondwana					
INDIA	**TOTAL**	**60,600**	**80**	**2.3**	**20**	**0.57**
Indonesia	S. Sumatra		183	5.2	27	0.78
Indonesia	Barito		102	2.9	15	0.43
Indonesia	Kutei		80	2.3	12	0.34
Indonesia	C. Sumatra		53	1.5	8	0.22
Indonesia	N. Tarakan		18	0.5	3	0.07
Indonesia	Berau		8	0.2	1	0.04
Indonesia	Ombilin		1	0.0	0	0.00
Indonesia	Pasir/Asem		3	0.1	0	0.01
Indonesia	NW Java		1	0.0	0	0.00
Indonesia	Sulawesi		2	0.1	0	0.01
Indonesia	Bengkulu		4	0.1	1	0.02
INDONESIA	**TOTAL**	**5,529**	**453**	**12.8**	**68**	**1.93**
Japan	**TOTAL**	**350**				
New Zealand	**TOTAL**	**571**				
North Korea	**TOTAL**	**600**				
Pakistan	**TOTAL**	**2,070** *				
South Korea	**TOTAL**	**126**				
Thailand	**TOTAL**	**1,239**				
Vietnam	**TOTAL**	**150**				
Other Asia Pacific	**TOTAL**	**3,707**				
Asia Pacific		**265,843**	**1,985**	**58.2**	**316**	**8.96**
Total World		**860,938**	**7,011**	**201**	**1,030**	**29.15**

APPENDIX C

GLOBAL ESTIMATES OF ECBM AND CO_2 STORAGE POTENTIAL IN COAL SEAMS

	Estimated Methane Recovery (Tcm)			CO_2 Storage	CO_2 Storage
COUNTRY	PRIMARY	ECBM	TOTAL	Tcm	Gt
United States	0.26	0.54	0.80	2.25	3.67
United States	0.09	0.02	0.11	0.30	0.49
United States	0.14	0.15	0.29	0.80	1.30
United States	0.25	0.01	0.26	1.50	2.45
United States	0.17	0.05	0.22	1.24	2.02
United States	0.32	1.05	1.36	12.95	21.13
United States	0.31	3.60	3.92	7.31	11.92
United States	0.24	0.76	1.00	2.80	4.57
United States	0.02	0.13	0.15	0.41	0.67
United States	1.03	0.88	1.90	18.10	29.53
United States	0.05	0.05	0.11	0.30	0.48
United States	0.04	0.02	0.06	0.16	0.26
United States	0.05	0.00	0.05	0.79	1.29
United States	0.12	0.00	0.12	0.00	0.00
United States	0.07	0.07	0.14	1.37	2.23
United States	0.06	0.21	0.27	2.53	4.13
United States	1.61	0.00	1.61	0.00	0.00
UNITED STATES	4.82	7.54	12.4	52.82	86.16
Canada	5.00	4.18	9.2	17.14	27.95
Canada	0.21	0.18	0.4	0.71	1.16
CANADA	5.21	4.35	9.6	17.85	29.11
MEXICO	0.04	0.09	0.1	0.34	0.55
Total North America	**10.06**	**11.99**	**22.1**	**71.01**	**115.82**
Brazil	0.00	0.00	0.0	0.00	0.00
BRAZIL	0.15	0.00	0.2	0.57	0.93
Colombia	0.02	0.04	0.1	0.35	0.57
Colombia	0.03	0.06	0.1	0.51	0.83
Colombia	0.02	0.03	0.0	0.13	0.21
Colombia	0.01	0.04	0.1	0.09	0.15
Colombia	0.01	0.03	0.0	0.12	0.19
Colombia	0.00	0.01	0.0	0.01	0.02
Colombia	0.00	0.00	0.0	0.04	0.06
Colombia	0.00	0.00	0.0	0.03	0.05
Colombia	0.00	0.01	0.0	0.02	0.03
COLOMBIA	0.10	0.22	0.3	1.29	2.11
VENEZUALA	0.07	0.30	0.4	3.57	5.83
Other S. & Cent. America					
Total S. & Cent. America	**0.32**	**0.52**	**0.85**	**5.44**	**8.87**

	Estimated Methane Recovery (Tcm)			CO_2 Storage	CO_2 Storage
COUNTRY	PRIMARY	ECBM	TOTAL	Tcm	Gt
BULGARIA					
CZECH REPUBLIC	0.06	0.00	0.1	0.00	0.00
GERMANY	0.45	0.00	0.5	0.62	1.01
GREECE					
Hungary	0.00	0.00	0.0	0.00	0.00
HUNGARY	0.02	0.04	0.1	0.10	0.17
KAZAKHSTAN	0.28	0.00	0.3	0.50	0.82
Poland	0.00	0.00	0.0	0.00	0.00
Poland	0.00	0.00	0.0	0.00	0.00
Poland	0.00	0.00	0.0	0.00	0.00
POLAND	0.14	0.94	1.1	4.07	6.63
ROMANIA					
Russian Federation	1.56	0.00	1.6	4.18	6.81
Russian Federation	0.23	0.55	0.8	1.26	2.06
Russian Federation	0.01	0.04	0.0	0.09	0.14
Russian Federation	0.11	0.34	0.4	0.84	1.37
Russian Federation	0.01	0.04	0.0	0.09	0.15
Russian Federation	2.38	7.40	9.8	18.25	29.76
Russian Federation	0.71	2.22	2.9	5.47	8.93
Russian Federation	0.65	2.03	2.7	5.02	8.19
RUSSIAN FEDERATION	5.66	12.61	18.3	35.20	57.41
SPAIN					
TURKEY	0.28	0.00	0.3	0.58	0.94
Ukraine	0.00	2.02	2.0	3.77	6.16
UKRAINE	0.71	1.72	2.4	4.54	7.41
UNITED KINGDOM	0.43	1.03	1.5	2.73	4.46
Other Europe & Eurasia					
Total Europe & Eurasia	**8.04**	**16.35**	**24.39**	**48.34**	**78.84**
				0.00	0.00
Botswana	0.45	1.06	1.5	9.18	14.97
Mozambique	0.37	0.89	1.3	1.84	3.01
Namibia	0.44	1.05	1.5	2.18	3.56
South Africa	0.25	0.61	0.9	1.26	2.05
Zimbabwe	0.25	0.61	0.9	3.44	5.62
Other Africa					
Middle East					
Total Middle East & Africa	**1.77**	**4.22**	**5.99**	**17.90**	**29.20**

	Estimated Methane Recovery (Tcm)			CO_2 Storage	CO_2 Storage
COUNTRY	**PRIMARY**	**ECBM**	**TOTAL**	**Tcm**	**Gt**
Australia	0.01	0.02	0.0	0.04	0.07
Australia	0.65	0.00	0.6	5.82	9.49
Australia	0.02	0.00	0.0	0.00	0.00
Australia	0.23	0.55	0.8	2.80	4.57
Australia	0.01	0.00	0.0	0.09	0.15
Australia	0.04	0.09	0.1	0.25	0.41
AUSTRALIA	0.95	0.67	1.62	9.01	14.70
China	0.72	0.00	0.7	0.00	0.00
China	1.85	3.35	5.2	8.61	14.04
China	0.76	3.20	4.0	37.69	61.47
China	0.40	0.00	0.4	0.00	0.00
China	0.70	0.00	0.7	0.00	0.00
China	0.42	0.00	0.4	0.00	0.00
China	0.32	0.00	0.3	0.00	0.00
China	0.24	0.58	0.8	1.53	2.50
China	0.09	0.00	0.1	0.00	0.00
CHINA	5.52	7.13	12.64	47.83	78.01
India					
INDIA	0.57	0.63	1.2	4.04	6.60
Indonesia	0.78	3.26	4.0	37.08	60.47
Indonesia	0.43	1.81	2.2	22.15	36.13
Indonesia	0.34	1.43	1.8	14.68	23.94
Indonesia	0.22	0.94	1.2	13.96	22.77
Indonesia	0.07	0.31	0.4	3.82	6.22
Indonesia	0.04	0.15	0.2	1.83	2.99
Indonesia	0.00	0.00	0.0	0.02	0.04
Indonesia	0.01	0.05	0.1	0.65	1.07
Indonesia	0.00	0.01	0.0	0.05	0.09
Indonesia	0.01	0.02	0.0	0.20	0.33
Indonesia	0.02	0.06	0.1	0.96	1.56
INDONESIA	1.93	8.05	9.97	95.40	155.60
Japan					
New Zealand					
North Korea					
Pakistan					
South Korea					
Thailand					
Vietnam					
Other Asia Pacific					
Total Asia Pacific	8.96	16.47	25.43	156.28	254.91
Total World	29.15	49.55	78.7	298.97	487.64

APPENDIX D

NON-U.S. ESTIMATES OF TECHNICAL RECOVERABLE METHANE RESOURCES AND CO_2 STORAGE POTENTIAL IN GAS SHALES

Region	Basin	Formation	Area (square miles)	Prospective Area (square miles)	Prospective Area Factor (%)	Play Success Probability Factor (%)	Prospective Area Success Factor (%)	Recovery Efficiency (%)	Unrisked Gas In Place (Tcf)	Risked GIP (Tcf)	Recoverable Resource (Risked; Tcf)	Storage Potential (Tcf)	Storage Potential (Gt)
Eastern Canada	**Appalachian Fold Belt**	Utica	3,500	2,900	83%	100%	40%	20%	388	155	31	**61**	**3.2**
	Windsor Basin	Horton Bluff	650	524	81%	50%	40%	20%	43	9	2	**5**	**0.3**
Western Canada	**Horn River**	Muskwa/Otter Park	8,100	3,320	41%	100%	75%	35%	504	378	132	**280**	**14.5**
		Evie/Klua	8,100	3,320	41%	80%	75%	30%	183	110	33	**70**	**3.6**
	Cordova	Muskwa/Otter Park	4,290	2,850	66%	80%	60%	35%	173	83	29	**67**	**3.5**
	Liard	Lower Besa River	4,300	1,940	45%	80%	50%	25%	313	125	31	**67**	**3.5**
	Deep Basin	Montney Shale	2,650	1,900	72%	100%	75%	35%	188	141	49	**111**	**5.8**
		Doig Phosphate	24,800	3,000	12%	80%	50%	25%	201	81	20	**44**	**2.3**
	Colorado Group	2WS & Fish Scales	124,000	48,750	39%	80%	50%	15%	1,020	408	61	**125**	**6.5**
Mexico	**Burgos Basin**	Eagle Ford Shale	24,200	18,100	75%	80%	50%	30%	3,786	1,514	454	**907**	**47.1**
		Tithonian Shales		14,520	60%	50%	50%	30%	1,088	272	82	**158**	**8.2**
	Sabinas Basin	Eagle Ford Shale	23,900	12,000	50%	40%	40%	20%	1,360	218	44	**96**	**5.0**
		Tithonian La Casita		12,000	50%	40%	20%	20%	702	56	11	**22**	**1.1**
	Tampico Basin	Pimienta	15,000	14,240	95%	60%	40%	30%	896	215	65	**147**	**7.6**
	Tuxpan Platform	Tamaulipas	2,810	1,950	69%	40%	50%	30%	127	25	8	**16**	**0.9**
		Pimienta		1,950	69%	40%	50%	30%	141	28	8	**18**	**0.9**
	Veracruz Basin	Maltrata	9,030	8,150	90%	40%	40%	25%	237	38	9	**19**	**1.0**
Northern South America	**Maracaibo Basin**	La Luna Fm	20,420	1,800	9%	50%	50%	25%	168	42	11	**22**	**1.1**
	Catatumbo Sub-Basin	La Luna Fm	2,380	1,310	55%	50%	60%	25%	97	29	7	**15**	**0.8**
		Capacho Fm		1,550	65%	50%	60%	25%	165	49	12	**21**	**1.1**

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Region	Basin	Formation	Area (square miles)	Prospective Area (square miles)	Prospective Area Factor (%)	Play Success Probability Factor (%)	Prospective Area Success Factor (%)	Recovery Efficiency (%)	Unrisked Gas In Place (Tcf)	Risked GIP (Tcf)	Recoverable Resource (Risked; Tcf)	Storage Potential (Tcf)	Storage Potential (Gt)
Southern South America	Neuquen Basin	Los Molles Fm	66,900	9,730	15%	80%	50%	35%	1,194	478	167	**270**	**14.0**
		Vaca Muerta Fm		8,540	13%	80%	60%	35%	1,431	687	240	**477**	**24.8**
	San Jorge Basin	Aguada Bandera Fm	46,000	8,380	18%	50%	40%	20%	1,248	250	50	**90**	**4.7**
		Pozo D-129 Fm		4,990	11%	60%	40%	25%	752	180	45	**78**	**4.1**
	Austral-Magallanes Basin	L. Inoceramus	65,000	19,500	30%	50%	50%	20%	1,679	420	84	**159**	**8.3**
		Magnas Verdes		19,500	30%	50%	50%	25%	1,405	351	88	**171**	**8.9**
	Parana-Chaco Basin	San Alfredo	500,000	50,000	10%	30%	40%	25%	17,362	2,083	521	**1047**	**54.4**
Poland	Baltic Basin	Lower Silurian	101,611	8,846	9%	80%	50%	25%	1,286	514	129	**253**	**13.1**
	Lublin Basin	Lower Silurian	11,882	11,660	98%	60%	40%	20%	925	222	44	**78**	**4.1**
	Podlasie Basin	Lower Silurian	4,306	1,325	31%	60%	50%	25%	188	56	14	**31**	**1.6**
Eastern Europe	Baltic Basin	Lower Silurian	101,611	3,071	3%	60%	50%	25%	311	93	23	**50**	**2.6**
	Dnieper-Donets	Rudov Bed	38,554	7,134	19%	40%	40%	25%	298	48	12	**24**	**1.3**
	Lublin Basin	Lower Silurian	26,500	7,850	30%	60%	40%	20%	620	149	30	**56**	**2.9**
Western Europe	France South-East Basin	"Terres Noires"	17,800	16,900	95%	50%	50%	25%	449	112	28	**68**	**3.5**
		Liassic Shales		17,800	100%	60%	50%	25%	1,016	305	76	**143**	**7.4**
	France Paris Basin	Permian-Carboniferous	61,454	17,942	29%	60%	60%	25%	841	303	76	**156**	**8.1**
	North Sea-German Basin	Namurian Shale	78,126	3,969	5%	60%	50%	25%	214	64	16	**31**	**1.6**
		Posidonia Shale		2,650	3%	60%	50%	25%	87	26	7	**16**	**0.9**
		Wealden Shale		1,810	2%	50%	40%	25%	47	9	2	**5**	**0.3**
	Scandanivia Region	Alum Shale	38,221	38,221	100%	50%	40%	25%	2,943	589	147	**431**	**22.4**
	.K. Northern Petroleum Syste	Bowland Shale	22,431	9,822	44%	40%	50%	20%	476	95	19	**49**	**2.5**
	.K. Southern Petroleum Syste	Liassic Shales	7,644	160	2%	40%	60%	25%	7	2	0	**1**	**0.0**
Central North Africa	Ghadames Basin	Tannezuft	121,000	39,700	33%	60%	50%	30%	1,734	520	156	**350**	**18.2**
		Frasnian "Hot Shale"		12,900	11%	60%	50%	30%	836	251	75	**159**	**8.3**
	Sirt Basin	Sirt Shale	177,000	70,800	40%	50%	30%	25%	4,311	647	162	**322**	**16.7**
		Etel Shale		70,800	40%	50%	30%	25%	2,953	443	111	**226**	**11.7**
Morocco	Tindouf Basin	Lower Silurian	89,267	55,340	50%	50%	50%	20%	1,005	251	50	**110**	**5.7**
	Tadla Basin	Lower Silurian	2,794	1,670	60%	40%	50%	20%	82	16	3	**7**	**0.4**
South Africa	Karoo Basin	Prince Albert Fm	236,400	70,800	30%	50%	30%	20%	3,022	453	91	**177**	**9.2**
		Whitehill Fm		70,800	30%	60%	40%	30%	4,144	995	298	**621**	**32.3**
		Collingham Fm		70,800	30%	50%	30%	25%	2,572	386	96	**196**	**10.2**

Region	Basin	Formation	Area (square miles)	Prospective Area (square miles)	Prospective Area Factor (%)	Play Success Probability Factor (%)	Prospective Area Success Factor (%)	Recovery Efficiency (%)	Unrisked Gas In Place (Tcf)	Risked GIP (Tcf)	Recoverable Resource (Risked; Tcf)	Storage Potential (Tcf)	Storage Potential (Gt)
China	**Sichuan Basin**	Longmaxi	81,500	56,875	70%	60%	50%	25%	4,575	1,373	343	**736**	**38.2**
		Qiongzhusi		81,500	100%	60%	50%	25%	4,648	1,394	349	**743**	**38.6**
	Tarim Basin	$O_1/O_2/O_3$ Shales	234,200	55,042	24%	40%	40%	25%	5,608	897	224	**400**	**20.8**
		Cambrian Shales		63,560	27%	40%	40%	25%	8,984	1,437	359	**657**	**34.1**
India Pakistan	**Cambay Basin**	Cambay Shale	20,000	940	5%	60%	60%	25%	217	78	20	**34**	**1.8**
	Damodar Valley Basin	Barren Measure	1,410	1,080	77%	50%	50%	20%	132	33	6.6	**15**	**0.8**
	Krishna-Godavari Basin	Kommugudem Shale	7,800	4,340	56%	50%	40%	20%	678	136	27.1	**57**	**2.9**
	Cauvery Basin	Andimadam Formation	9,100	1,005	11%	50%	60%	20%	144	43	8.6	**15**	**0.8**
	Southern Indus Basin	Sembar Formation	67,000	4,000	6%	50%	40%	25%	402	80	20.1	**36**	**1.9**
		Ranikot Formation		4,000	6%	50%	40%	25%	630	126	31.5	**55**	**2.9**
Turkey	**SE Anatolia Basin**	Dadas Shale	32,450	2,950	9%	40%	60%	20%	180	43	9	**19**	**1.0**
	Thrace Basin	Hamitabat	8,586	312	4%	60%	60%	25%	40	14	4	**8**	**0.4**
		Mezardere		303	4%	60%	50%	25%	22	7	2	**4**	**0.2**
Australia	**Cooper Basin**	Roseneath-Epsilon-Murteree	46,900	5,810	12%	75%	75%	25%	608	342	85	**163**	**8.4**
	Maryborough Basin	Goodwood/Cherwell Mudston	4,290	1,555	36%	75%	60%	30%	171	77	23	**41**	**2.1**
	Perth Basin	Carynginia Shale	12,560	2,180	17%	60%	70%	30%	234	98	29	**59**	**3.1**
		Kockatea Fm		2,180	17%	60%	70%	30%	239	100	30	**64**	**3.3**
	Canning Basin	Goldwyer Fm	181,000	48,100	27%	60%	25%	30%	5,090	764	229	**431**	**22.4**
									99,819	**22,018**	**5,761**	**11,661**	**606**

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APPENDIX E

U.S. ESTIMATES OF TECHNICAL RECOVERABLE METHANE RESOURCES AND CO_2 STORAGE POTENTIAL IN GAS SHALES

	Technically Recoverable Methane Resources		**CO_2 Storage Potential**		
	Tcf	**Tcm**	**Tcf**	**Tcm**	**Gt**
Northeast	477.0	13.52	1,431	40.6	74
Gulf Coast	106.9	3.03	321	9.1	17
Mid-Continent	69.9	1.98	210	5.9	11
Southwest	108.2	3.07	325	9.2	17
Rocky Mountain	58.3	1.65	175	5.0	9
West Coast	41.3	1.17	124	3.5	6
	861.6	**24.4**	**2,585**	**73.2**	**134**

Source for estimates for Technically Recoverable Methane Resources: U.S. Energy Information Administration, *Assumption to the Annual Energy Outlook, 2011*, Table 9.2

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the ENERGY lab

PROJECT FACTS

Carbon Storage - GSRA

Sequestration of Carbon Dioxide Gas in Coal Seams

Background

The overall goal of the Department of Energy's (DOE) Carbon Storage Program is to develop and advance technologies that will significantly improve the effectiveness of geologic carbon storage, reduce the cost of implementation, and prepare for widespread commercial deployment between 2020 and 2030. Research conducted to develop these technologies will ensure safe and permanent storage of carbon dioxide (CO_2) to reduce greenhouse gas (GHG) emissions without adversely affecting energy use or hindering economic growth.

Geologic carbon storage involves the injection of CO_2 into underground formations that have the ability to securely contain the CO_2 permanently. Technologies being developed for geologic carbon storage are focused on five storage types: oil and gas reservoirs, saline formations, unmineable coal seams, basalts, and organic-rich shales. Technologies being developed will work towards meeting carbon storage programmatic goals of (1) estimating CO_2 storage capacity +/- 30 percent in geologic formations; (2) ensuring 99 percent storage permanence; (3) improving efficiency of storage operations; and (4) developing Best Practices Manuals. These technologies will lead to future CO_2 management for coal-based electric power generating facilities and other industrial CO_2 emitters by enabling the storage and utilization of CO_2 in all storage types.

The DOE Carbon Storage Program encompasses five Technology Areas: (1) Geologic Storage and Simulation and Risk Assessment (GSRA), (2) Monitoring, Verification, Accounting (MVA) and Assessment, (3) CO_2 Use and Re-Use, (4) Regional Carbon Sequestration Partnerships (RCSP), and (5) Focus Area for Sequestration Science. The first three Technology Areas comprise the Core Research and Development (R&D) that includes studies ranging from applied laboratory to pilot-scale research focused on developing new technologies and systems for GHG mitigation through carbon storage. This project is part of the Core R&D GSRA Technology Area and works to develop technologies and simulation tools to ensure secure geologic storage of CO_2. It is critical that these technologies are available to aid in characterizing geologic formations before CO_2-injection takes place in order to predict the CO_2 storage resource and develop CO_2 injection techniques that achieve optimal use of the pore space in the reservoir and avoid fracturing the confining zone (caprock). The program's R&D strategy includes adapting and applying existing technologies that can be utilized in the next five years, while concurrently developing innovative and advanced technologies that will be deployed in the decade beyond. This project demonstrates a novel drilling and production process that will help control and produce coal methane while creating potential geologic storage for CO_2.

CONTACTS

Traci Rodosta
Carbon Storage Technology Manager
National Energy Technology Laboratory
3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507
304-285-1345
traci.rodosta@netl.doe.gov

William O'Dowd
Project Manager
National Energy Technology Laboratory
626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236
412-386-4778
william.odowd@netl.doe.gov

James Locke
Principal Investigator
CONSOL Energy, Inc.
4000 Brownsville Road
South Park, PA 15129-9566
412-854-6607
jimlocke@consolenergy.com

PARTNERS

None

PROJECT DURATION

Start Date	**End Date**
9/21/2001	12/31/2013

COST

Total Project Value
$13,216,903

DOE/Non-DOE Share
$8,983,942 / $4,232,961

PROJECT NUMBER

FC26-01NT41148

U.S. DEPARTMENT OF ENERGY

Project Description

CONSOL Energy Inc. (CONSOL) is demonstrating a horizontal drilling and production process that reduces potential methane emissions from coal mining, produces usable methane (natural gas), and creates a geologic storage option for carbon dioxide (CO_2) in unmineable coal seams. The CONSOL project has employed horizontal drilling to drain coalbed methane (CBM) from a mineable coal seam and an underlying unmineable coal seam. After drainage of 50-60 percent of the CBM, two of the wells are being used for CO_2 injection (Figure 1) to stimulate additional methane production and store the CO_2 in the unmineable seam. The technique starts with drilling a vertical well from the surface followed by a guided borehole that extends up to 3,000 feet horizontally in the coal seam, allowing for production over a large area from relatively few surface locations.

Figure 1: CO_2 injection site, Marshall County, WV. Figure shows the equipment used to prepare the CO_2 for injection as a gas into the coal seam.

The project involves development of two stacked coal seams in a 200-acre area (Figure 2). The lower, unmineable seam was initially degassed and is now being injected with CO_2 to increase both storage and methane production in nearby production wells. The upper, mineable seam was degassed to produce coalbed methane, thus avoiding methane emissions when the seam is mined. The upper, mineable seam is isolated from the lower, unmineable seam to prevent CO_2 migration from the unmineable seam into the mineable seam.

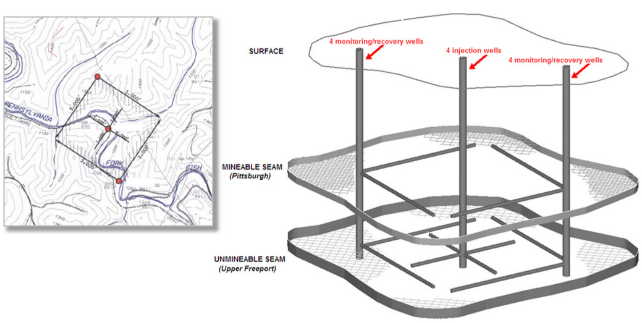

Figure 2: Site well layout

Goals/Objectives

The project goals include performing the first-ever geologic storage of CO_2 and simultaneous enhanced CBM (ECBM) production using horizontal drilling technology in an unmineable coal seam in the Northern Appalachian Basin and evaluating the effectiveness and conceptual economics of a commercial-scale project. Specific objectives include:

- Demonstrate the use of horizontal drilling technology for CBM production from two relatively thin, undulating coal seams.
- Demonstrate, after using the horizontal wells to partially degasify the coal seam, that CO_2 can be injected into the unmineable seam for storage and for simultaneous enhanced CBM production.
- Demonstrate that CO_2 remains in the coal seam in which it was injected by monitoring the behavior of the injected CO_2.
- Demonstrate the application of coal seam methane production technology using horizontal drilling to degasify an unmineable coal seam.

Accomplishments

- To date, approximately 3,265 metric tons of CO_2 have been injected at pressures of up to 930 pound-force per square inch gage (psig).
- A step-rate pressure test was performed to determine if conditions would allow for the injection of CO_2 at higher pressure in order to increase injection volumes. The West Virginia Department of Environmental Protection (WVDEP) accepted the results and allowed CONSOL to increase pressure to approximately 1,400 pounds per square inch (psi). Injection pressures were increased from 930 psi to 1,060 psi, facilitating an increase from five tons/day to approximately 17 tons/day. This supports the objective to demonstrate that CO_2 storage is a viable option in coal seams.
- No breakthrough of CO_2 has been observed in any of the production wells, supporting the objective to demonstrate that CO_2 remains stored in the coal seam.
- Production wells may be showing signs of increased methane production as a result of increased sustained injection rates. This demonstrates the economic benefit associated with producing coal bed methane during carbon storage operations.

Benefits

This project will provide a documented case study of the effectiveness and economics of geologic storage of carbon dioxide in an unmineable coal seam. It will demonstrate that methane can be degassed from, and CO_2 can be successfully stored in, coal seams with the added benefit of increased CBM production. This helps NETL's Carbon Storage program meet the goal of estimating storage potential in coals seam formations within +/- 30 percent, developing and validating technologies that demonstrate 99 percent storage permanence, and providing insight on improving reservoir storage efficiency while ensuring containment effectiveness. This project is the first effort to investigate the effects of injecting CO_2 into coal seams and recovering CBM and has greatly increased the understanding of the potential for using coal seams for CO_2 storage, and has also provided insight on how CO_2 interacts with coal and CBM production. Additionally, the results can be used by mining and power generation companies that wish to store CO_2 in unmineable coal seams, and also by regulatory agencies and the public to aid in policy and permitting decisions.