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CO_2-ECBM: A Review of its Status and Global Potential

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Abstract

In 1998, the IEA Greenhouse Gas R&D Programme (IEAGHG) assessed the global potential for CO_2 enhanced coal bed methane (CO_2-ECBM) recovery and associated CO_2 storage based on data from the one successful pilot project at the time in the San Juan Basin in the USA. After 1998, subsequent CO_2 injection projects in coal seams were generally determined not to be successful. Nonetheless, these projects contributed to "lessons learned" that helped advise further research and demonstration (R&D) activities.

IEAGHG recently reassessed the status of R&D in CO_2-ECBM and CO_2 storage. In this assessment, the primary objectives were to: (1) assess the global status of coalbed methane (CBM) production and the potential effects on CO_2 storage; (2) review the current status of research into the enhanced gas recovery (EGR) and geological storage of CO_2 in coals; and (3) develop an updated assessment of the global potential for EGR and geological storage of CO_2 in coal formations.

The paper summarizes the results of this work, along with other related activities. It reviews the results from more recent CO_2-ECBM and CO_2 storage trials in the San Juan Basin in the USA, the results of other small-scale demonstration projects conducted by the U.S. Department of Energy's (DOE's) Regional Carbon Sequestration Partnerships (RCSP) Program, and reviews the status of an ongoing DOE-funded project conducted by CONSOL and Virginia Tech University in the USA, as well as for the Coal-Seq Consortium.

The IEAGHG study concluded that the technical recovery potential for methane from the world's coal seams is estimated to be 79 trillion cubic meters (Tcm) globally, 29 Tcm associated with conventional CBM recovery, and 50 Tcm from the application of CO_2-ECBM recovery as a secondary production technique. This could facilitate the potential storage of nearly 488 billion metric tons (or gigatonnes (Gt)) of CO_2 in unmineable coal seams.

1. Introduction

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) and/or carbon dioxide (CO_2) to increase recovery of methane from coals without excessively lowering reservoir pressure. The concept of ECBM using CO_2 predates this; in 1972, Every and Dell'osso [3] found that methane was effectively removed from crushed coal by flowing a stream of CO_2 through it at ambient temperature.

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Thus, coal deposits have long been regarded as a potential CO_2 storage option, particularly in association with ECBM production. In 1998, the IEA Greenhouse Gas R&D Programme (IEAGHG) assessed the global potential for CO_2-ECBM based on data from the one successful pilot project at the time in the San Juan Basin in the USA [4]. At that time, it was concluded that there was significant geological storage capacity globally in unmineable coal seams. In a recent review of opportunities by the Carbon Sequestration Leadership Forum (CSLF) of CO_2 utilization options, however, ECBM with CO_2 injection was not even included [5]; whereas ten years before, CO_2-ECBM was considered a viable option for CO_2 storage. So – what happened?

After the IEAGHG assessment in 1998, several CO_2 injection projects in coal seams followed the initial San Juan Basin project in Canada, Poland and Japan, in thin bituminous coal seams. These projects were generally determined not to be successful. The reasons cited for this vary, but included swelling of the coal due to the presence of CO_2 near the injection well, reducing permeability, and thus impacting injectivity and limiting methane desorption. In addition, there were some design and implementation issues impacting project performance in these tests. Nonetheless, all contributed to "lessons learned" that help advise R&D activities. Subsequent research and pilot testing has built upon these lessons, with notable success.

IEAGHG recently looked at CO_2-ECBM once again [6]. In this assessment, summarized in this paper, some of the primary objectives related to CO_2 storage in coal seams were to: (1) assess the global status of coalbed methane (CBM) production and the potential effects on CO_2 storage; (2) review the current status of research into geological storage of CO_2 in coals; and (3) assess the global potential for geological storage of CO_2 in coal formations.

2. Factors Influencing CO_2 Storage and Enhanced Gas Recovery in Coal Seams

The process of ECBM and storage of CO_2 in coal seams involves capturing CO_2 from a flue gas stream, compressing it for transport to an injection site, followed by injection of CO_2 into the coal to enhance methane recovery and/or store CO_2. 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. The main methods which can induce methane release from coal formations are to reduce the overall pressure, usually by dewatering the formation, generally through pumping; or to reduce the partial pressure of the methane by injecting another inert gas into the formation, such as CO_2, where the methane on the surface gets displaced by the other gas, **Figure 1**

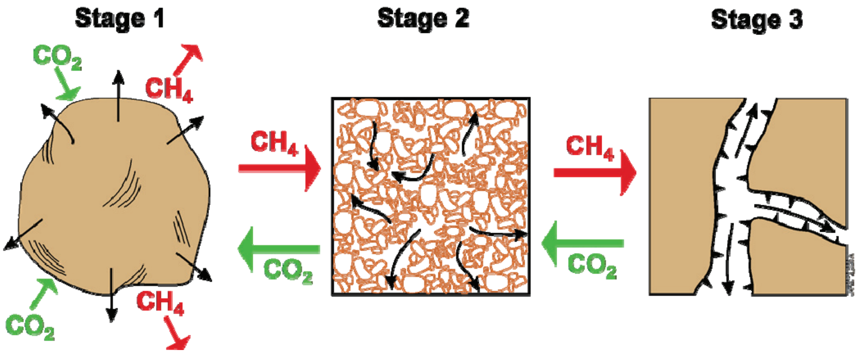


Figure 1: Schematic of the Flow Dynamics of CO_2 and CH_4 in Coal Seams

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. 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 production.

CBM 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.

When injected, 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, CO_2 has a higher affinity to become adsorbed onto the reservoir rock surfaces than 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. As much as another 20% could potentially be recovered through the application of CO_2-ECBM [7]. In addition, 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.

3. Review of R&D and Project Experience Associated with ECBM and CO_2 Storage in Coal Seams

The most recent assessment by IEAGHG included a thorough review of the status of research into geological storage of CO_2 in gas shales and coals. This included review of the current understanding of the 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, and methods for assessing storage capacities for CO_2 storage in gas shales and coals.

The processes and technologies for ECBM and CO_2 storage are still in the development phase. In 2006, in support of a USDOE "Carbon Sequestration Technology Roadmap and Program Plan," Advanced Resources developed a "Technology Design and Implementation Plan" for CO_2 storage in deep, unmineable coal seams. It provided a baseline of ongoing research and field tests in the area of CO_2 storage in coals at the time [8]. As part of this effort, information and opinions were gathered from a group of 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. 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 were:

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-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, to help reduce the number of wells required for storing significant volumes of CO_2.
6. Integrating CO_2 storage and enhanced recovery of coalbed methane.

CO_2-ECBM and CO_2 storage trials in the San Juan Basin. Several ECBM/CO_2 storage field-level tests on the injection and storage of CO_2 in coals, combined with ECBM, were conducted in the San Juan Basin of the USA.

- One of the longest-operated field pilots was the Allison Unit CO_2-ECBM pilot [9]. During six years of operation (1995-2001), approximately 335,000 metric tons of CO_2 were injected into the 900 meter deep Fruitland coal seams. The project recovered 45 million cubic meters (1.6 Bcf) of incremental CBM and stored 270,000 metric tons of CO_2. The main conclusions drawn from the project were: (1) CO_2 injection into coal can significantly improve methane recovery; recovery was improved from 77% (under traditional practices) to 95% (using CO_2 injection) of original gas in place within the central pilot area; (2) injectivity losses are likely when CO_2 is first introduced into the coal seam; initial CO_2 injectivity was reduced by 60% (with coal permeability reduced by an order of magnitude near the wells); the loss of CO_2 injectivity was modest and a steady rebound in CO_2 injectivity was noted with time as methane was produced; (3) improvements are required in reservoir simulation models to properly capture the interaction of CO_2 injection, methane release, and the coal reservoir; though existing reservoir simulation models provide a reasonable match of project performance; and (4) advances in well injectivity technology could unlock the massive CO_2 storage potential of CBM resources in deep coals; particularly if technology is developed to overcome reduced injectivity due to matrix swelling.
- The potential benefits of using CO_2/N_2 mixtures to possibly overcome the limitations from swelling associated with injecting pure CO_2 was a primary feature of the Tiffany ECBM pilot [10]. BP (formerly Amoco) began to investigate ECBM techniques in the late 1980s. Building on laboratory and pilot tests, after nine years of primary CBM production, N_2 injection 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 <u>increase</u> in the cleat permeability; interestingly, this is the

opposite behavior of what happened at the Allison Unit. At Allison, 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, 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.

- The Pump Canyon CO_2-ECBM/storage demonstration, conducted as part of the Southwest Regional Partnership for Carbon Sequestration (SWP), involved a new CO_2 injection well drilled into Fruitland coals within an existing CBM production operation by ConocoPhillips [11]. CO_2 injection in three coal seams was initiated in late July 2008 and stopped in August 2009. A variety of monitoring, verification and accounting (MVA) methods were employed to track the movement of the CO_2. Detailed geologic characterization and reservoir modeling was implemented in order to reproduce and understand the behavior of the reservoir. No CO_2 breakthrough occurred. Overall, 9 million cubic meters of CO_2 were injected at rates up to 70,000 cubic meters per day. However coal swelling and reservoir pressuring decreased injectivity, with injection rates decreasing to 14,000 cubic meters per day**.** The effectiveness of methane recovery and CO_2 storage was determined to probably be limited due to the small amount of CO_2 injected.

Other small-scale demonstration projects by the USDOE's Regional Carbon Sequestration Partnerships (RCSP). In addition to the Pump Canyon project, three other small-scale projects were conducted as part of the RCSP program to assess the potential for ECBM recovery and CO_2 storage in a variety of settings. Three of these are summarized below:

- The Midwest Geological Sequestration Consortium (MGSC) conducted a pilot test to determine the ECBM recovery potential and CO_2 injection and storage capability at a site in Wabash County, Illinois. The target formation was the Pennsylvanian Carbondale formation at a depth of 275 meters in a 2 meter 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. 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 [12].
- 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 in Burke County, North Dakota, at a depth of approximately 370 meters, to determine the suitability of these strata for both CO_2 storage and ECBM production. One CO_2 injection well and four monitoring wells were completed in a five-spot pattern during the summer of 2007. 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 [13].
- 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 --, with depths ranging from 305 to 610 meters, 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 [14, 15].

DOE-funded projects by CONSOL and Virginia Tech University in the USA. Finally, several other DOE funded projects have taken place or are underway in the Central Appalachian Basin in the U.S. to assess storage opportunities in unmineable coal seams. One project planned to inject 900 metric tons of CO_2 into multiple coal seams of the Pocahontas and Lee Formations at depths ranging between 425 and 670 meters. 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. The reservoir consists of approximately 15 coal seams, distributed over 270 meters of section. This reservoir geometry creates an unusual target for CO_2 injection, and is also challenging for many monitoring and imaging techniques. The project aims to reduce this uncertainty by designing and implementing characterisation, injection and monitoring activities to test stacked formations and track the migration of CO_2 throughout the injection and post-injection phases. A detailed geological characterisation of the proposed injection site indicates that regional geological structures, coal permeability and reservoir seals are adequate for the 20,000 metric ton test. The proposed research will provide needed information on other stacked storage options and provide an additional benefit of proven carbon storage potential in coal seams with ECBM and other stacked unconventional formations in Central Appalachia [16, 17]. 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 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.

Coal-Seq Consortium. The U.S. DOE-sponsored Coal-Seq Consortium (Coal-Seq) has also been underway for 14 years with the purpose of advancing the science of CO_2 storage in unmineable coal seams and gas shale reservoirs [18]. The initial Coal-Seq Project, which ran from 2000 – 2004, was solely DOE funded. Subsequent phases have been 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.

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 will 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; 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 to be published in 2014 or 2015.

Summary of Lessons Learned from R&D to Date. 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 [19]:

- 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.

Nonetheless, despite a number of setbacks, the sum total of the "lessons learned" from past and ongoing R&D activities continues to confirm that ECBM and CO_2 storage (perhaps in combination with N_2 injection) can be commercially viable, and should continue to be included in the set of potentially viable options under consideration for CO_2 storage.

4. Estimating the Global CO_2 Storage Capacity in Coal Seams

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 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 focused on U.S. basins [20], 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 is summarized 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 (summarized in **Table 1**). Note that insufficient data were available for some countries to make estimates, even though these countries are believed to have some potential.

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.

Estimate Technically Recoverable "Primary" CBM Resources. In some areas, like those in the U.S. and the countries summarized in Table 1, 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 summarized by region in Table 1. As shown, it is estimated that CBM resources in place is 201 Tcm (7,011 Tcf), with an estimated 29 Tcm (1,030 Tcf) recoverable. The largest CBM resource potential is in the former Soviet Union, Canada, China, Australia and the United States.

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 [20], 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 2**. **Figure 2** provides the relative permeability curves employed; **Figure 3** 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 4**.

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 3**. 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.

Assumptions for vitrinite reflectance and CO_2/methane ratios were made for each basin/country assessed.

Table 1: 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

Table 2: 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

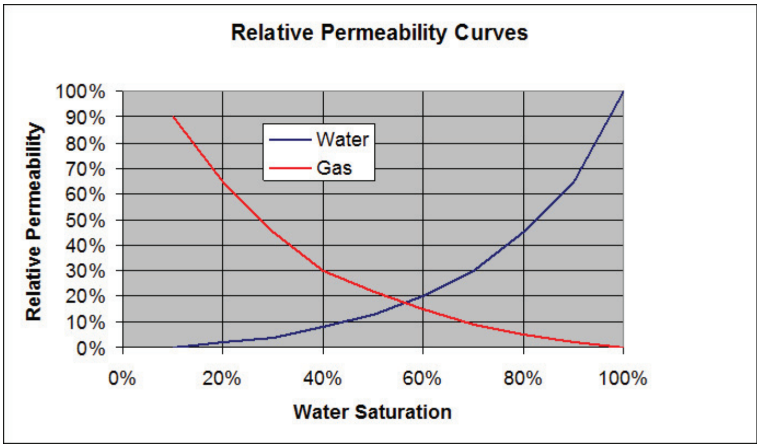


Figure 2: Relative Permeability Curves Used in ECBM Simulation Runs

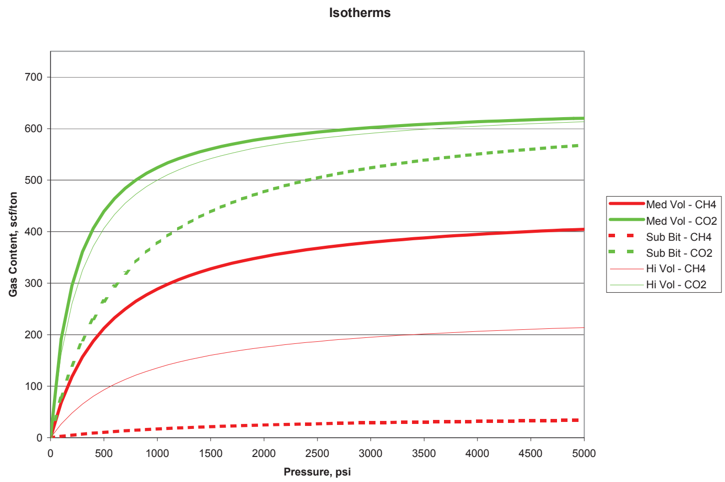
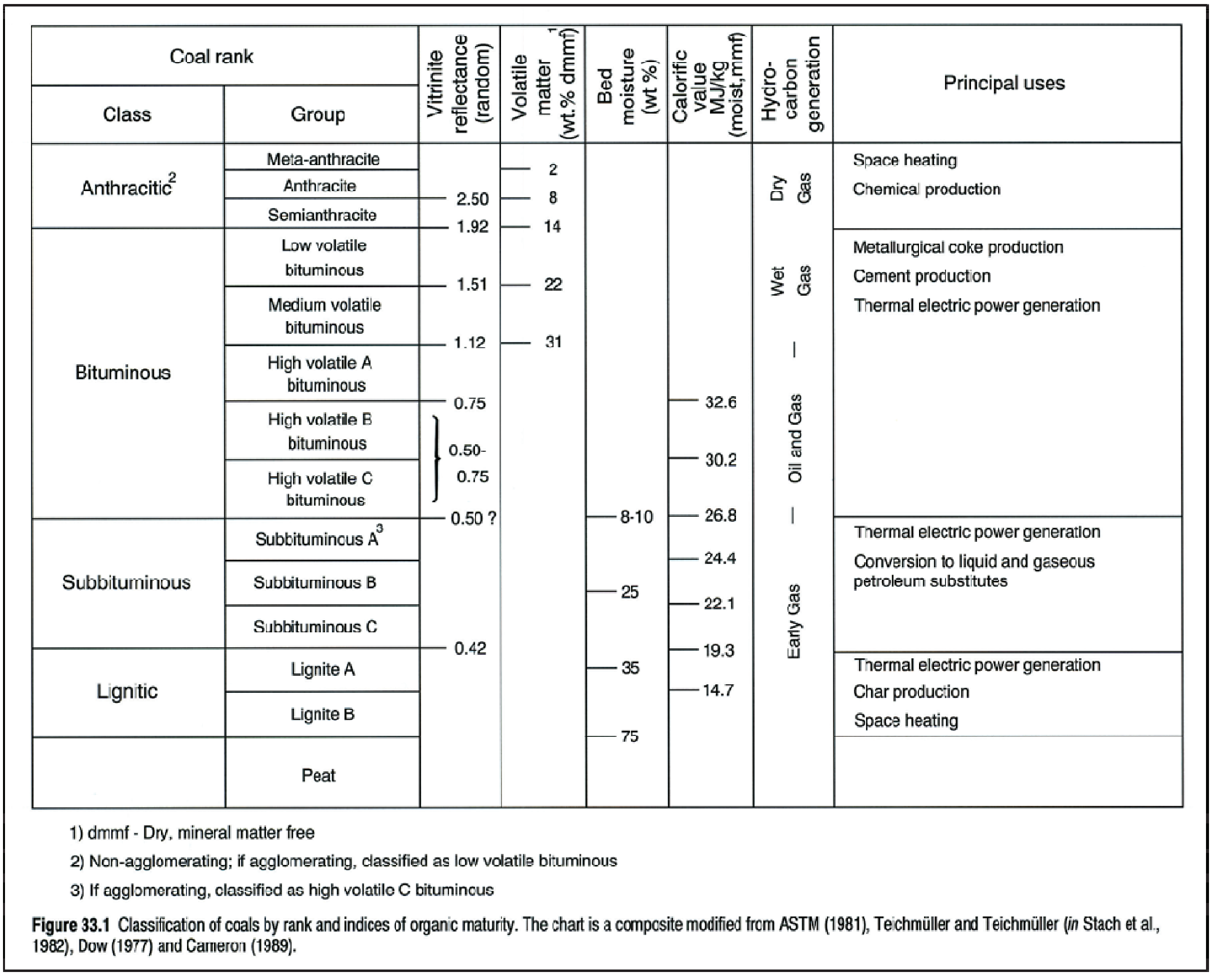


Figure 3: CO_2/Methane Sorption Isotherms Used in ECBM Simulation Runs



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).

Figure 4: Classification of Coals Based on Rank and Thermal Maturity [20]

Table 3: 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 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.

Summary of Results. 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 4**. 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.

This compares to the 1998 IEAGHG study for the more prospective basins [4, 21], that concluded that 40 Tcm was potentially recoverable globally, and would facilitate the potential storage of nearly 150 Gt of CO_2.

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.

Table 4: 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
Botsw ana	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
Zimbabw e	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

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