Assessment of CO_2 Sequestration and ECBM Potential of U.S. Coalbeds

Topical Report

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Abstract

In October, 2000, the U.S. Department of Energy, through contractor Advanced Resources International, launched a multi-year government-industry R&D collaboration called the Coal-Seq project. The Coal-Seq project is investigating the feasibility of CO_2 sequestration in deep, unmineable coalseams, by performing detailed reservoir studies of two enhanced coalbed methane recovery (ECBM) field projects in the San Juan basin. The two sites are the Allison Unit, operated by Burlington Resources, and into which CO_2 is being injected, and the Tiffany Unit, operating by BP America, into which N_2 is being injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The purposes of the field studies are to understand the reservoir mechanisms of CO_2 and N_2 injection into coalseams, demonstrate the practical effectiveness of the ECBM and sequestration processes, an engineering capability to simulate them, and to evaluate sequestration economics. In support of these efforts, laboratory and theoretical studies are also being performed to understand and model multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection. This report describes the results of an important component of the overall project, applying the findings from the San Juan Basin to a national scale to develop a preliminary assessment of the CO_2 sequestration and ECBM recovery potential of U.S. coalbeds. Importantly, this assessment improves upon previous investigations by 1) including a more comprehensive list of U.S. coal basins, 2) adopting technical rationale for setting upper-bound limits on the results, and 3) incorporating new information on CO_2/CH_4 replacement ratios as a function of coal rank.

Based on the results of the assessment, the following conclusions have been drawn:

- The CO_2 sequestration capacity of U.S. coalbeds is estimated to be about 90 Gt. Of this, about 38 Gt is in Alaska (even after accounting for high costs associated with this province), 14 Gt is in the Powder River basin, 10 Gt is in the San Juan basin, and 8 Gt is in the Greater Green River basin. By comparison, total CO_2 emissions from power generation plants is currently about 2.2 Gt/year.

- The ECBM recovery potential associated with this sequestration is estimated to be over 150 Tcf. Of this, 47 Tcf is in Alaska (even after accounting for high costs associated with this province), 20 Tcf is in the Powder River basin, 19 Tcf is in the Greater Green River basin, and 16 Tcf is in the San Juan basin. By comparison, total CBM recoverable resources are currently estimated to be about 170 Tcf.

- Between 25 and 30 Gt of CO_2 can be sequestered at a profit, and 80 – 85 Gt can be sequestered at costs of less than \$5/ton. These estimates do not include any costs associated with CO_2 capture and transportation, and only represent geologic sequestration.

- Several Rocky Mountain basins, including the San Juan, Raton, Powder River and Uinta appear to hold the most favorable conditions for sequestration economics. The Gulf Coast and the Central Appalachian basin also appear to hold promise as economic sequestration targets, depending upon gas prices.

- In general, the "non-commercial" areas (those areas outside the main play area that are not expected to produce primary CBM commercially) appear more favorable for sequestration economics than the "commercial" areas. This is because there is more in-place methane to recover in these settings (the "commercial" areas having already been largely depleted of methane).

Table of Contents

List of Tables

List of Figures

1.0 Introduction and Objectives

In October, 2000, the Department of Energy (DOE), through contractor Advanced Resources International (ARI), launched a multi-year government-industry research and development (R&D) collaboration called the Coal-Seq project[1]. The Coal-Seq project is investigating the feasibility of carbon dioxide (CO_2) sequestration in deep, unmineable coalseams, by performing detailed reservoir studies of two enhanced coalbed methane recovery (ECBM) field projects in the San Juan basin. The two sites are the Allison Unit, operated by Burlington Resources, and into which CO_2 is being injected, and the Tiffany Unit, operated by BP America, into which nitrogen (N_2) is being injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The purposes of the field studies are to understand the reservoir mechanisms of CO_2 and N_2 injection into coalseams, demonstrate the practical effectiveness of the ECBM and sequestration processes, an engineering capability to simulate them, and to evaluate sequestration economics. In support of these efforts, laboratory and theoretical studies are also being performed to understand and model multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection. This report describes the results of an important component of the overall project, applying the findings from the San Juan Basin to a national scale to develop a preliminary assessment of the CO_2 sequestration and ECBM recovery potential of United States (U.S.) coalbeds.

In 1998, Stevens[2] performed a global assessment of the potential of coalseams to sequester CO_2 for the International Energy Agency Greenhouse Gas R&D Programme. In that work, he cited that the U.S. could potentially sequester up to 35 gigatonnes (Gt) of CO_2 in basins that included the San Juan, Uinta, Raton, Warrior, Northern and Central Appalachian, Powder River, Piceance and Greater Green River. This estimate was, simply stated, based on the assumption that total in-place methane resources for those basins were replaced by CO_2, at a ratio of 2:1. In addition, the potential for an estimated 328 trillions of cubic feet (Tcf) of incremental methane recovery was determined as a "by-product" of CO_2 injection (i.e., as a result of the CO_2-ECBM recovery process). This estimate essentially attributes the entire in-place methane resource as a potential ECBM resource. While this can be a useful first-order estimate of sequestration (and ECBM) capacity, a more rational assessment is required. Building upon the technical findings of the Coal-Seq project, specifically the results of both the field and laboratory studies, this assessment was undertaken to improve the previous estimates by incorporating:

- A more comprehensive list of U.S. coal basins,
- Improved technical rationale for setting upper-bound limits on the results, and
- New information on CO_2/CH_4 replacement ratios as a function of coal rank.

This report describes the methodology, assumptions and results of that assessment.

2.0 Methodology and Major Assumptions

The overall approach to this study was to estimate the CO_2 sequestration potential of U.S coals in three distinct steps:

- The replacement of methane produced by primary production with CO_2 (in the "commercial" area), according to the coal rank from which that production is expected to occur. This step assumes that a storage capacity voidage is created in the coal reservoir by the methane production, which can be replaced, up to the original coal reservoir pressure, by CO_2. Under this scenario, no incremental methane recovery is assumed to occur as a result of CO_2 injection. This coal resource is presumed readily available for sequestration since the wells and other infrastructure required for primary methane production exist and could be employed for sequestration operations.

- The recovery of additional methane, unrecovered by primary production within the "commercial" area, as a result of CO_2 injection, which creates additional voidage, and hence additional CO_2 sequestration capacity.

- The recovery of additional methane via the CO_2-ECBM recovery process, and the additional CO_2 sequestration capacity that creates, in the "non-commercial" area. This area is considered the "less favorable" area of each basin from which coalbed methane and CO_2 sequestration can be technically accomplished, but that is not favorable enough for commercial primary methane production.

The general methodology employed for the study was as follows:

- Select the basins to evaluate. The key criteria used for basin selection included the size (i.e., CO_2 sequestration and ECBM potential), as well as the availability of required information such as in-place and recoverable methane resources, and distribution of those resources by coal rank. Also, proximity of coal basins to large, coal-fired power plants and in states with high CO_2 emissions was also considered.

- For each basin, compile information on in-place and recoverable methane resources, how they are distributed according to coal rank, and where in the basin is the recoverable portion likely to come from. The result of this step was a distribution of in-place gas resources by coal rank, in the "commercial" and "non-commercial" areas, for each basin.

- Apply a relationship between CO_2-to-CH_4 replacement ratio and coal rank to each coal basin to estimate CO_2 sequestration capacity based on simple replacement of produced methane with CO_2 in the "commercial" area according to coal rank distribution in the "commercial" area.

- Use an estimated primary recovery factor (for wells in the "commercial" area), and the estimated recoverable methane resource, to determine the amount of unrecovered methane in the "commercial" area. Estimate incremental methane recovery from that remaining resource via CO_2-ECBM using a relationship between ECBM recovery factor (expressed as a % of in-place resource at the start of CO_2 injection) and coal rank in the "commercial" area. The result of this step is an estimate of total incremental methane recovery via CO_2-ECBM and additional CO_2 sequestration capacity in the "commercial" area.

- For the "non-commercial" area, apply a relationship between CO_2-ECBM recovery factor and coal rank. The result of this step is an estimate of incremental methane recovery and CO_2 sequestration capacity in the "non-commercial" area of each basin, according to coal rank distribution in the "non-commercial" area.

- The final step is to compile all the basin-specific assessments into a national assessment of ECBM recovery and CO_2 sequestration capacity in U.S. coalseams.

As alluded to above, several important relationships are required to perform the study. Specifically, these relationships are 1) CO_2-to-CH_4 replacement ratios as a function of coal rank, 2) ECBM recovery factor as a function of coal rank in the "commercial" area and 3), ECBM recovery factor as a function of coal rank in the "non-commercial" area (the "commercial" and "non-commercial" areas will have different reservoir characteristics, and thus recovery vs. rank relationships). The technical analyses to establish these relationships are provided in Sections 3.4 and 3.5 of this report.

In addition, certain key assumptions and "discount factors" are required to provide an improved rationale for "upper-bound" limits on the assessment results. The approach adopted for establishing these assumptions was to first estimate reasonable values on a national-average basis, and then to apply adjustment factors for each basin as appropriate. The key assumptions are:

Primary Recovery Factor - The recovery factor in the "commercial" area for primary production. Reasons to adjust this parameter from the base case could be in high rank coal settings, where recovery factors tend to be less, and for very deep coals where permeability loss could reduce recovery factors.

Voidage-Replacement and ECBM Efficiency in "Commercial" Area – The efficiency of CO_2 replacement for primary methane production in the "commercial" area. Reasons for less than 100% replacement efficiency could include not wanting to pressurize the coal with CO_2 to the original reservoir pressure (could be an issue in shallow coals), removal of the reservoir after methane production (in coal-mining areas), lack of surface access for CO_2 injection (heavily populated areas), etc. This factor is also assumed to apply to ECBM recovery in the "commercial" area.

"Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration – The amount of in-place methane resource in the "non-commercial" area that could be reasonably accessed for ECBM/sequestration purposes. Reasons for limited access could include surface restrictions and/or reservoir constraints (e.g., too deep or too shallow, too thin, too impermeable, etc.). Conversely, areas with large volumes of CO_2 emissions could have an increased level of accessibility due to the motivation to sequester CO_2 near the source.

The base-case assumptions for the above parameters are presented in Table 1. Section 3.3 (Individual Basin Summaries) provides the details of adjustment factors applied to each assumption for each basin.

Table 1: Base Case Assumptions

Parameter	Value	Remarks
Primary Recovery Factor	**65%**	**Estimate**
Voidage Replacement and ECBM Efficiency in "Commercial" Area	**75%**	**Estimate**
"Accessible" Portion of Non-Commercial Area for CO_2 ECBM/Sequestration	**50%**	**Estimate**

3.0 Technical Analysis

3.1 Selection of Basins

The first step in the analysis was to select the basins to be included in the study. Figure 1 provides a map of the major coal basins in the U.S. (lower-48). Also shown on the map are the locations of major coal-fired power plants (>1,000 megawatt (MW) nameplate capacity), as well as the states with high CO_2 emissions. This figure suggests that, in the east, the Northern and Central Appalachian basins should included, as should the Warrior. The Illinois Basin in the midwest is also important, as are the Cherokee, Forest City and Arkoma basins in the Mid-Continent. Due to the high volume of CO_2 emissions in Texas, the Gulf Coast basin is important to include. In the Rockies, the major basins important for inclusion are the San Juan, Raton, Piceance, Uinta, Greater Green River, Hanna-Carbon, Wind River and Powder River. In the west, the Western Washington basin is worthwhile including due to an absence of other CO_2 sequestration alternatives in that area. Finally, and not shown on the map, the vast coal (and implied methane) resources in Alaska compel its inclusion in the study. These 17 basins (or provinces) are the basis on which this study was performed.

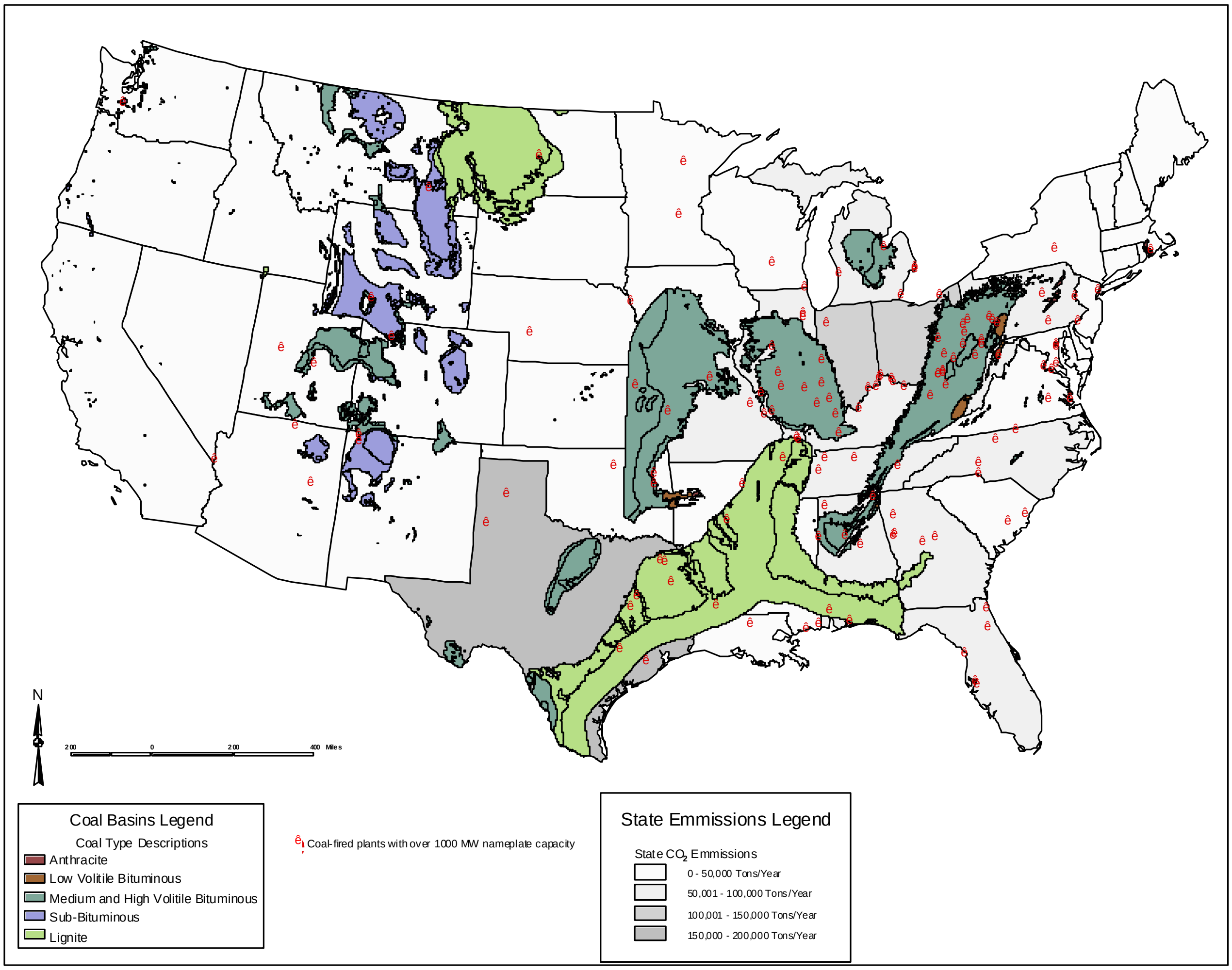

Figure 1: Location of Major Coal Basins, Coal-Fired Power Plants, and CO_2 Emissions States

3.2 CBM Resources by Basin

The next step was to estimate the in-place and recoverable resources for each of the 17 basins selected. There are numerous sources from which to collect the in-place resource information, most notably the initial work on this topic by Rightmire, Eddy and Kirr[3] in the early 1980's. This work, performed by TRW, funded by The Gas Research Institute (GRI), and published by the American Association of Petroleum Geologists (AAPG), relied heavily on the national coal resource information as published by Averitt[4], and thus largely focused on shallower, mineable coals. Also, due to the limited experience with and infancy of coalbed methane (CBM) production in the U.S. at that time, much of the information needed to make a reasonable assessment of resources (such as isotherms and gas content correlations) was simply not available. Nevertheless, information on the 13 basins assessed in that work was useful to this study.

Subsequent to that, in the late 1980's and early 1990's, ARI, and its' predecessor company, ICF Resources, also under GRI sponsorship, conducted more detailed resource assessments of six high-potential basins[5,6,7,8,9,10,11]. This work improved upon the earlier assessments by including deeper, unmineable coals, eliminating shallow and very thin coals that were unlikely to be developed, and took advantage of the rapidly growing body of information related to gas content as a function of both coal rank and depth.

After that, there were no further systematic assessments of CBM resources in the U.S. Rather, there have been a series of individual basin assessments performed by a variety of investigators[12,13,14,15,16,17,18,19] for different purposes and organizations. Notable, however, is that in 2001 the Gas Technology Institute (GTI) (formerly GRI), created a compilation of CBM resource information in their North American Coalbed Methane Resource Map[12].

The results of these assessments for the 17 basins targeted in this study are presented in Table 2. Generally speaking, when multiple estimates for a given basin were available, the latter studies were given preference, based on the assumption that more information was available for making the assessment later rather than earlier. The total estimated in-place methane resources for the basins included in this study is 1,746 Tcf. Of this, Alaska (with 1,045 Tcf) and the Green River basin (with 314 Tcf), together account for 78% of the estimated U.S. in-place CBM resource.

Table 2: Comparison of Coalbed Methane In-Place Resource Assessments, by Basin

CBM Resource in Tcf				
Basin	**TRW/GRI/AAPG**	**ICF/ARI/GRI**	**Others**	**Used in Study**
N. Appalachian	61	61	-----	61
C. Appalachian	10-48	5	-----	5
Black Warrior	7-10	19	-----	19
Illinois	5-21	-----	-----	13
Cherokee/Forest City	-----	-----	7[12]*	7
Arkoma	2-4	-----	-----	3
Gulf Coast	-----	-----	4-8[13]	6
San Juan	31	72-84**	43-49[14]	78
Raton	8-18	8-12	-----	10
Piceance	30-110	81	-----	81
Uinta	1-5	-----	10[15]	10
Greater Green River	0-30	-----	314[16]	314
Hanna-Carbon	-----	-----	15[12]	15
Wind River	0-2	-----	6[12]	6
Powder River	3-65	-----	61[17]	61
Western Washington	8-24	-----	-----	12
Alaska	-----	-----	1045[18,19]***	1045
			Total =	**1,746 Tcf**

*Kansas only

** includes Menefee formation

*** North Slope and Cook Inlet

The next piece of information required was what portion of these total in-place methane resources are expected to be commercially recovered. While there are numerous sources of this type of information, for this effort we focused on four widely recognized and acknowledged sources. Those are the 1995 United States Geological Survey (USGS) assessment of U.S. oil and gas resources[20], the 1999 National Petroleum Council (NPC) assessment[21], the 2000 Potential Gas Committee (PGC) assessment[22], and ARI's 2001 results from the Model of Unconventional Gas Supply (MUGS)[23]. The MUGS model is used by the Energy Information Agency (EIA) to forecast U.S. unconventional gas supply for use in it's Oil and Gas Supply Model (OGSM) and the National Energy Modeling System (NEMS).

A comparison of the recoverable methane resources from each of these sources for each of the target 17 basins is presented in Table 3. Note that comparing results based on regions (as opposed to individual basins) was required due to the different ways each assessment reported its results. One can easily see the wide range of results, ranging from a low of about 50 Tcf to a high of about 150 Tcf.

For use in this assessment, preference was again given to the later studies, for the same reasons that a similar preference scheme was used for the in-place resources. In addition however, the later studies, specifically the MUGS model and the 2000 PGC assessment, provide the resource information on a detailed basin scale, as required here. As such, the MUGS information was used if it was available and if not, the 2000 PGC study was used.

Table 3: Comparison of Coalbed Methane (Future) Recoverable Resource Assessments by Region

		in Tcf			
Region	**Major Basins Included**	**1995 USGS Assessment**	**1999 NPC Assessment**	**2000 PGC Assessment**	**2001 MUGS Assessment**
Appalachia	Northern & Central Appalachian	14.6	19.4	12.9	10.8
Warrior	Black Warrior, Cahaba, Coosa	2.6	5.2	4.4	3.4
North Central	Michigan, Illinois	1.6	2.5	2.2	0.6
Gulf Coast	Gulf Coast	-----	-----	-----	------
Mid-Continent	Forest City, Cherokee Platform, Arkoma, Southwest Coal Region	5.0	7.4	10.3	3.2
San Juan	San Juan	7.5	10.1	10.2	18.5
Rock Mountains	Powder River, Big Horn, Wind River, Hanna-Carbon, Greater Green River, Uinta, Piceance, Raton, Henry Mtns, Black Mesa	17.9	29.4	48.4	42.0
Pacific Coast	Western Washington	0.7	-----	2.0	-----
Alaska	North Slope, Cook Inlet	-----	-----	57.0	-----
	Totals	**49.9**	**74.0**	**147.4**	**78.5**

The information presented in Table 3 represents the future remaining recoverable resources. It does not include prior production, nor currently booked reserves. This information must be incorporated into the analysis to arrive at a total recoverable resource to match against the total in-place resources. This information was obtained from the EIA's 2001 annual reserves report[24]. In addition, since the EIA CBM production data only goes back to 1989, earlier production, specifically from 1984 to 1989, was obtained from GTI[25]. Table 4 then presents the final results for the methane resource compilation for use in this study. Note that production and reserve figures for 2000 were used (as opposed to 2001 figures) since both the PGC and MUGS data were forecasts from 2000 forward. This avoided "double-counting" the 2001 data.

Note that none of the assessments presented in Table 3 had recoverable resource estimates for the Gulf Coast basin. To estimate one, the recovery factors for all the other basins were averaged, and applied to the Gulf Coast basin. The arithmetic average of the 16 other basins was about 30%, which was applied to the Gulf Coast basin, yielding a recoverable methane resource of 1.8 Tcf.

Of the 1,746 Tcf of in-place CBM resources, it is estimated that 170 Tcf is recoverable, or about 10%. Of this recoverable, a full third is expected to come from Alaska. The fact that Alaska is so remote from the major CO_2 emissions sources of the U.S. (mostly in the lower-48) was an important consideration in this assessment.

Table 4: Comparison of In-Place and Total Recoverable Coalbed Methane Resources, by Basin

Basin	In-Place Resources* (Bcf)	Production through 2000** (Bcf)	Reserves as of 2000 (Bcf)	Remaining Recoverable Resource*** (Bcf)	Total Recoverable Resource (Bcf)	Recovery Factor
N. Appalachian	61,000	58	1,399	7,641	9,098	15%
C. Appalachian	5,000	-----	-----	3,140	3,140	63%
Black Warrior	19,000	1,165	1,241	2,416	4,822	25%
Illinois	13,000	-----	-----	582	582	4%
Cherokee/Forest City	7,000	4	41	1,757	1,802	26%
Arkoma	3,000	-----	-----	1,408	1,408	47%
Gulf Coast	6,000	-----	-----	1,800****	1,800	30%
San Juan	78,000	7,836	9,895	18,485	36,216	46%
Raton	10,000	-----	-----	6,041	6,041	60%
Piceance	81,000	-----	-----	8,391	8,391	10%
Uinta	10,000	74	1,592	7,213	8,879	89%
Greater Green River	314,000	------	-----	11,030	11,030	4%
Hanna-Carbon	15,000	-----	-----	4,371	4,371	29%
Wind River	6,000	-----	-----	2,450	2,450	41%
Powder River	61,000	133	1540	9,456	11,129	18%
Western Washington	12,000			1,965	1,965	16%
Alaska	1,045,000			57,000	57,000	5%
TOTALS	**1,746,000**	**9,270**	**15,708**	**145,146**	**170,124**	**10%**

* From Table 2
** Since 1984
*** Derived from Table 3
**** Calculated based on a 30% recovery factor.

3.3 Individual Basin Summaries

The next phase of the assessment involved the examination of each of the 17 basins individually to determine the distribution of both in-place and recoverable methane resources by coal rank, as well as to make any adjustments to the major assumptions presented in Table 1. This section describes those results for each basin.

Northern Appalachian Basin

Distribution of Gas Resource by Coal Rank

The resource assessment performed for the Northern Appalachian basin[8] provided a gas-in-place estimate for each individual coal seam, as well as the areal coal rank distribution for each coal seam. The distribution of gas-in-place by coal rank was performed by allocating the gas-in-place for each coal according to the areal distribution of coal rank. While this is not strictly correct (the actual gas-in-place would have had a greater weighting in the higher rank coals than estimated based purely on their areal distribution), it should be suitable for the purposes of this analysis. The result is presented in Table 5.

Table 5: Gas-in-Place Distribution by Coal Rank, Northern Appalachian Basin

Coal	Gas In Place (Tcf)	Areal Coal Rank Distribution, % LV	MV	HVA	HV	Sub
Waynesburg	1.5	-----	-----	100	-----	-----
Sewickley	1.8	-----	-----	86	14	-----
Pittsburgh	7.0	-----	-----	80	20	-----
Freeport	15.5	2	11	82	5	-----
Kittanning	24.1	6	5	72	17	-----
Brookville/Clarion	10.8	4	10	70	16	-----
Total	**60.7**	**3%**	**7%**	**76%**	**14%**	**0%**

A review of activity in the Northern Appalachian basin[26,27] suggests that the development activity is very heavily weighted in the area and seams dominated by HVA coal (see terminology footnote); the coal rank distribution assigned for the "commercial" area is thus presented in Table 6. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 6: Gas-in-Place Distribution by Coal Rank and Area, Northern Appalachian Basin

Area	Estimated Coal Rank Distribution, % LV	MV	HVA	HV	Sub
"Commercial"	0%	0%	100%	0%	0%
"Non- Commercial"	4%	9%	69%	18%	0%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Northern Appalachian basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: Due to intense coal-mining activity and rough terrain, an adjustment factor of 0.75 was applied.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: Due to the large volumes of CO_2 being emitted in this area, there will presumably be a strong motivation to utilize these coals for sequestration purposes. Therefore an adjustment factor of 1.5 was applied.

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

Central Appalachian Basin

Distribution of Gas Resource by Coal Rank

The resource assessment performed for the Central Appalachian basin[9] provided a gas-in-place estimate for each individual coal seam, as well as maps of coal rank distribution for each coal seam. The distribution of gas-in-place by coal rank was performed by allocating the gas-in-place for each coal according to the areal distribution of coal rank based on the maps (which were digitized). While this is not strictly correct (the actual gas-in-place would have had a greater weighting in the higher rank coals than estimated based purely on their areal distribution), it should be suitable for the purposes of this analysis. The result is presented in Table 7.

Table 7: Gas-in-Place Distribution by Coal Rank, Central Appalachian Basin

		Areal Coal Rank Distribution, %				
Coal Bed	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
Iaeger/Jawbone	0.2	69	31	----	-----	-----
Sewell/Lower Seaboard	0.4	75	25	-----	-----	------
Beckley/War Creek	1.0	62	28	10	-----	-----
Fire Creek/Lower Horsepen	0.7	74	26	-----	-----	-----
Pocahontas No. 4	1.1	80	20	-----	-----	-----
Pocahontas No. 3	1.6	75	25	-----	-----	-----
Total	**5.0**	**73%**	**25%**	**2%**	**0%**	**0%**

A review of activity in the Central Appalachian basin[26,28] suggests that the development activity is weighted in the area and seams dominated by LV coal, with some MV coal; the assigned coal rank distribution for the "commercial" area is thus presented in Table 8. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 8: Gas-in-Place Distribution by Coal Rank and Area, Central Appalachian Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	75%	25%	0%	0%	0%
"Non- Commercial"	16%	25%	59%	0%	0%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Central Appalachian basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: Due to intense coal mining activity and rough terrain, an adjustment factor of 0.75 was applied.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: Due to the large volumes of CO_2 being emitted in this area, there will presumably be a strong motivation to utilize these coals for sequestration purposes. Therefore an adjustment factor of 1.5 was applied.

Black Warrior Basin

Distribution of Gas Resource by Coal Rank

The resource assessment performed for the Warrior basin[5] provided gas-in-place maps for each individual coal seam, as well as maps of coal rank distribution for each coal seam. The distribution of gas-in-place by coal rank was performed by digitizing and integrating the information from the maps to establish an accurate distribution of gas-in-place by coal rank. The result is presented in Table 9.

Table 9: Gas-in-Place Distribution by Coal Rank, Black Warrior Basin

		Estimated Coal Rank Distribution, %				
Coal Group	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
Cobb	1.2	-----	3	94	3	-----
Pratt	4.1	-----	15	80	5	-----
Mary Lee	6.6	2	21	73	4	-----
Black Creek	7.5	4	21	70	5	-----
Total	**19.4**	**2%**	**19%**	**75%**	**4%**	**0%**

A review of activity in the Warrior basin[26,29] suggests that the development activity is weighted in the area and seams dominated by MV and HVA coal, but also includes the areas with LV coal. Absent in the "commercial" area is the presence of HV coal. The assigned coal rank distribution for the "commercial" area is thus presented in Table 10. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 10: Gas-in-Place Distribution by Coal Rank and Area, Black Warrior Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	5%	45%	50%	0%	0%
"Non- Commercial"	0%	2%	91%	7%	0%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Black Warrior basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: Due to intense coal-mining in the area, an adjustment factor of 0.85 was applied.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Illinois Basin

Distribution of Gas Resource by Coal Rank

The resource assessment performed for the Illinois basin[3] did not provide any quantitative information on gas-in-place distribution by coal rank. However a coal rank map for the Herrin seam was provided, and indicated that 95+% of the coal was HV, with the small remainder being HVA. The distribution of gas-in-place by coal rank was estimated on that basis; the result is presented in Table 11.

Table 11: Gas-in-Place Distribution by Coal Rank, Illinois Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
All	13	0%	0%	3%	97%	0%

A review of activity in the Illinois basin[26,30,31] suggests that the development activity, while largely in the HV coal area, does cover the HVA area in the southeast portion of the basin. Therefore the assigned coal rank distribution for the "commercial" area, presented in Table 12, was designed to have a slightly higher percentage of HVA coal than the basin average. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 12: Gas-in-Place Distribution by Coal Rank and Area, Illinois Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	0%	10%	90%	0%
"Non- Commercial"	0%	0%	2%	98%	0%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Illinois basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: Due to the many power plants overlying the basin, there will presumably be an incentive to utilize these coals for sequestration purposes. Therefore an adjustment factor of 1.5 was applied.

Cherokee Platform/Forest City Basin

Distribution of Gas Resource by Coal Rank

The resource assessment performed for the Cherokee Platform/Forest City Basin[12] did not provide any quantitative information on gas-in-place distribution by coal rank. However, other information on the basin[26,32,33] suggests that the coal rank, at least in the Kansas area, is dominated by HV coal. It is also known that the coal rank can be sub-bituminous in the eastern portion of the basin, and increase to at least HVA in the central basin. The assigned distribution of gas-in-place by coal rank, estimated on that basis, is presented in Table 13.

Table 13: Gas-in-Place Distribution by Coal Rank, Cherokee Platform/Forest City Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
All	7	0%	0%	5%	90%	5%

A review of activity in the Illinois basin[26,32] suggests that the development activity seems to be west of the sub-bituminous area, and therefore the weighting of this coal rank was reduced in the "commercial" area. The assigned coal rank distribution for the "commercial" area, based on this observation, is presented in Table 14. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 14: Gas-in-Place Distribution by Coal Rank and Area, Cherokee Platform/Forest City Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	0%	10%	90%	0%
"Non- Commercial"	0%	0%	2%	90%	8%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Cherokee Platform/Forest City basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Arkoma Basin

Distribution of Gas Resource by Coal Rank

The resource assessment performed for the Arkoma Basin[3] did not provide any quantitative information on gas-in-place distribution by coal rank. However, a coal rank map of the Pennsylvanian coals was presented. That information suggested that the coal rank is mostly LV in the east, with the western portion of the basin containing MV and HVA coals. The assigned distribution of gas-in-place by coal rank, estimated on that basis, is presented in Table 15.

Table 15: Gas-in-Place Distribution by Coal Rank, Arkoma Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
All	3	50%	25%	25%	0%	0%

A review of activity in the Arkoma basin[26,34] suggests that the bulk of current development activity seems to be in Haskell county (HVA & MV coals), but also in Pittsburgh (HVA and MV coals) and Le Flore (LV coals) counties. The assigned coal rank distribution for the "commercial" area, based on this observation, is presented in Table 16. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 16: Gas-in-Place Distribution by Coal Rank and Area, Arkoma Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	40%	30%	30%	0%	0%
"Non- Commercial"	91%	5%	4%	0%	0%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Arkoma basin are summarized below:

- Primary Recovery Factor: Due to a significant resource in high-rank coals, an adjustment factor of 0.9 was applied.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Gulf Coast Basin

Distribution of Gas Resource by Coal Rank

Preliminary work to assess the CBM resources in the Gulf Coast basin[13] did not provide any quantitative information on gas-in-place distribution by coal rank. Indications are that the vast majority of the coalbed methane resource coals are contained in sub-bituminous coals. However, there does appear to exist some HV coals in the western portion of the basin near Mexico, as well as the deeper parts of the basin. The assigned distribution of gas-in-place by coal rank, estimated on that basis, is presented in Table 17.

Table 17: Gas-in-Place Distribution by Coal Rank, Gulf Coast Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
All	6	0%	0%	0%	10%	90%

There is no significant CBM development activity in the Gulf Coast basin[35]. The USGS has identified several areas that appear prospective however. Lacking any further information, the assigned coal rank distribution for the "commercial" area, was kept the same as the assumed gas-in-place distribution, and is presented in Table 18. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 18: Gas-in-Place Distribution by Coal Rank and Area, Gulf Coast Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	0%	0%	10%	90%
"Non- Commercial"	0%	0%	0%	10%	90%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Gulf Coast basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: Due to the large CO_2 emissions in Texas and the presumed need to sequester them near the source, an adjustment factor of 1.5 was applied.

San Juan Basin

Distribution of Gas Resource by Coal Rank

The resource assessments performed for the San Juan basin[7,10] provided gas-in-place maps for both the Fruitland and Menefee formations, as well as maps of coal rank distribution for each coal formation. The distribution of gas-in-place by coal rank was performed by digitizing and integrating the information from the maps to establish an accurate distribution of gas-in-place by coal rank. The result is presented in Table 19.

Table 19: Gas-in-Place Distribution by Coal Rank, San Juan Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
Fruitland	50	-----	17	36	47	-----
Menefee	28	12	24	21	53	-----
Total	**78**	**4%**	**16%**	**31%**	**49%**	**0%**

A review of activity in the San Juan basin[26,36] suggests that the development activity is entirely in the Fruitland coal (there is no known Menefee production), and in the area more heavily weighted with high-rank coals. The assigned coal rank distribution for the "commercial" area, based on this information, is presented in Table 20. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 20: Gas-in-Place Distribution by Coal Rank and Area, San Juan Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	20%	40%	40%	0%
"Non- Commercial"	14%	6%	8%	72%	0%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the San Juan basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: Due to the considerable infrastructure, and preferable reservoir conditions for ECBM recovery, an adjustment factor of 1.25 was applied.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Raton Basin

Distribution of Gas Resource by Coal Rank

The resource assessment performed for the Raton basin[11] provided a combined gas-in-place map for both the Raton and Vermejo formations, as well as a (single) map of coal rank distribution. The distribution of gas-in-place by coal rank was performed by digitizing and integrating the information from the maps to establish an accurate distribution of gas-in-place by coal rank. The result is presented in Table 21.

Table 21: Gas-in-Place Distribution by Coal Rank, Raton Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
Raton & Vermejo	10.2	-----	72%	28%	----	-----

A review of activity in the Raton basin[26,37] suggests that most of the development activity is in the central basin, which is dominated by MV coals. The assigned coal rank distribution for the "commercial" area, based on this information, was more heavily weighted towards MV coals, and is presented in Table 22. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 22: Gas-in-Place Distribution by Coal Rank and Area, Raton Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	75%	25%	0%	0%
"Non- Commercial"	0%	33%	65%	0%	0%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Raton basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Piceance Basin

Distribution of Gas Resource by Coal Rank

The resource assessment performed for the Piceance basin[6] provided a individual gas-in-place maps for the Coal Ridge, Cameo and Black Diamond coal groups, as well as individual maps of coal rank distribution for each group. The distribution of gas-in-place by coal rank was performed by digitizing and integrating the information from the maps to establish an accurate distribution of gas-in-place by coal rank. The result is presented in Table 23.

Table 23: Gas-in-Place Distribution by Coal Rank, Piceance Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
Coal Ridge	9.5	27	43	20	10	-----
Cameo	63.2	40	21	17	22	-----
Black Diamond	8.6	41	14	15	30	-----
Total	**81.3**	**39%**	**23%**	**17%**	**21%**	**0%**

A review of activity in the Piceance basin[26,38] suggests that the limited historical development activity was in the central basin, which is dominated by higher rank coals. However, the Tom Brown White River Dome field, in the north-central portion of the basin, is dominated by HVA coals. The assigned coal rank distribution for the "commercial" area, based on this information, was distributed in the LV – HVA range, with little contribution from the lower coal ranks, as presented in Table 24. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 24: Gas-in-Place Distribution by Coal Rank and Area, Piceance Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	45%	30%	25%	0%	0%
"Non- Commercial"	37%	21%	15%	27%	0%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Piceance basin are summarized below:

- Primary Recovery Factor: Due to a weighting towards high-rank coals, an adjustment factor of 0.75 was applied.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Uinta Basin

Distribution of Gas Resource by Coal Rank

The preliminary work by the Utah Geological Survey to assess the CBM resources in the Uinta basin[15] did not provide any quantitative information on gas-in-place distribution by coal rank. However, a map is available that shows coal rank distribution in the basin for the Ferron sandstone coals. This map suggests the coal rank is HV along the eastern basin margin, and increases to HVA towards the basin center. Without any further indications of gas-in-place distribution by coal rank, the assigned values are presented in Table 25.

Table 25: Gas-in-Place Distribution by Coal Rank, Uinta Basin

		Estimated Coal Rank Distribution, %				
Coal	Gas In Place (Tcf)	LV	MV	HVA	HV	Sub
All	10	0%	0%	50%	50%	0%

The available information on CBM development activity in the Uinta basin[26,39] suggests that the existing development straddles both of these two coal ranks. As such, the assigned coal rank distribution for the "commercial" area, was kept the same as the gas-in-place distribution, and is presented in Table 26. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 26: Gas-in-Place Distribution by Coal Rank and Area, Uinta Basin

	Estimated Coal Rank Distribution, %				
Area	LV	MV	HVA	HV	Sub
"Commercial"	0%	0%	50%	50%	0%
"Non- Commercial"	0%	0%	50%	50%	0%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Uinta basin are summarized below:

- Primary Recovery Factor: Since the estimated recoverable resource was so close to the estimated in-place resource (a recovery factor of 89%), the recovery factor used for primary production has to be increased to maintain integrity of the calculations. Therefore an adjustment factor of 1.5 was applied to this parameter.

- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.

- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Greater Green River Basin

Distribution of Gas Resource by Coal Rank

The resource assessment for the Greater Green River basin[16] did not provide any quantitative information on gas-in-place distribution by coal rank. However, maps of coal rank were provided for the two coal groups that accounted for about 85% on the in-place resource, the Upper Mesaverde and the Rock Springs formation. The distribution of gas-in-place by coal rank was performed by allocating the gas-in-place for each coal according to the areal distribution of coal rank. While this is not strictly correct (the actual gas-in-place would have had a greater weighting in the higher rank coals than estimated based purely on their areal distribution), it should be suitable for the purposes of this analysis. The distribution for the Fort Union was assumed to be the average of the other two formations. The result is presented in Table 27.

Table 27: Gas-in-Place Distribution by Coal Rank, Greater Green River Basin

		Areal Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
Fort Union	50	0%	1%	14%	64%	21%
Upper Mesaverde	166	7%	19%	32%	37%	5%
Rock Springs	98	5%	15%	28%	43%	9%
Total	**314**	**5%**	**15%**	**28%**	**43%**	**9%**

The available information on the limited CBM development activity in the Greater Green River basin[26,40] suggests that it is spread over a considerable area of the basin, but seems to be concentrated in coals of the sub-bituminous and HV rank. Therefore, the assigned coal rank distribution for the "commercial" area, was divided between these two coal ranks, with some contribution from HVA coals, as presented in Table 28. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 28: Gas-in-Place Distribution by Coal Rank and Area, Greater Green River Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	0%	20%	40%	40%
"Non- Commercial"	5%	16%	28%	43%	7%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Greater Green River basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: Due to the large amount of coal and gas resource at depths greater than 6,000 feet in this basin (>85%), plus the fact that surface access restrictions are considerable in this area, and the large geographic area involved, an adjustment factor of 0.25 was applied to this parameter.

Hanna-Carbon Basin

Distribution of Gas Resource by Coal Rank

The resource assessment for the Hanna-Carbon basin[12] did not provide any information on gas-in-place distribution by coal rank. All that was available was an indication that the coal ranks ranged from sub-bituminous to HV. Therefore, the gas-in-place resource distribution by coal rank was split between these two coal ranks, as presented in Table 29.

Table 29: Gas-in-Place Distribution by Coal Rank, Hanna-Carbon Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
All	15	0%	0%	0%	50%	50%

There is very little information on the limited CBM development activity in the Hanna-Carbon basin. Without such information, it was assumed that the coal rank distribution in the "commercial" area was the same as the total gas-in-place distribution. The result is presented in Table 30. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 30: Gas-in-Place Distribution by Coal Rank and Area, Hanna Carbon Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	0%	0%	50%	50%
"Non- Commercial"	0%	0%	0%	50%	50%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Hanna-Carbon basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Wind River Basin

Distribution of Gas Resource by Coal Rank

The resource assessment for the Wind River basin[12] did not provide any information on gas-in-place distribution by coal rank. All that was available was an indication that the coal ranks ranged from sub-bituminous to HV. Therefore, the gas-in-place resource distribution by coal rank was split between these two coal ranks, as presented in Table 31.

Table 31: Gas-in-Place Distribution by Coal Rank, Wind River Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
All	6	0%	0%	0%	50%	50%

There is very little information on the limited CBM development activity in the Wind River basin. Without such information, it was assumed that the coal rank distribution in the "commercial" area was the same as the total gas-in-place distribution. The result is presented in Table 32. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 32: Gas-in-Place Distribution by Coal Rank and Area, Wind River Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	0%	0%	50%	50%
"Non- Commercial"	0%	0%	0%	50%	50%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Wind River basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Powder River Basin

Distribution of Gas Resource by Coal Rank.

The resource assessment for the Powder River basin[17] suggests all the coals throughout this basin are sub-bituminous. Therefore, the total gas-in-place was assigned to this coal rank, as were the "commercial" and "non-commercial" areas.

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Powder River basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: Due to the shallow nature of these coals, there may be a desire not to store CO_2 to the same pressure as the original value. Therefore an adjustment factor of 0.75 was applied to this parameter.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Western Washington Basin

Distribution of Gas Resource by Coal Rank.

The resource assessment for the Western Washington basin[3] did not provide any information on gas-in-place distribution by coal rank. However, it was estimated that about 70% of the coal resource was sub-bituminous, and the remaining 30 % bituminous. Other work[12] suggests that the highest coal rank is HV. Therefore, the implied gas-in-place resource distribution by coal rank is as presented in Table 33.

Table 33: Gas-in-Place Distribution by Coal Rank, Western Washington Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
All	12	0%	0%	0%	30%	70%

Since there very little CBM development activity in the Western Washington basin, it is assumed that the coal rank distribution in the "commercial" area is the same as that for the total resource. This resulting coal rank distribution in the "commercial" and "non-commercial" areas are presented in Table 34. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 34: Gas-in-Place Distribution by Coal Rank and Area, Western Washington Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	0%	0%	30%	70%
"Non- Commercial"	0%	0%	0%	30%	70%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Western Washington basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: No adjustment.

Alaska

Distribution of Gas Resource by Coal Rank.

The resource assessment information for Alaska[18,19] did not provide any information on gas-in-place distribution by coal rank. However, the information available does suggest that the coal resources are largely sub-bituminous and HV. Therefore, the gas-in-place distribution by coal rank was split between these two coal types, as presented in Table 35.

Table 35: Gas-in-Place Distribution by Coal Rank, Alaska Basin

		Estimated Coal Rank Distribution, %				
Coal	**Gas In Place (Tcf)**	**LV**	**MV**	**HVA**	**HV**	**Sub**
All	1,045	0%	0%	0%	50%	50%

Since there very little CBM development activity in Alaska[41], it is assumed that the coal rank distribution in the "commercial" area is the same as that for the total resource. This resulting coal rank distribution in the "commercial" and "non-commercial" areas are presented in Table 35. Note that the coal rank distribution in the "non-commercial" area is computed to achieve material balance with the in-place distribution of coal rank.

Table 36: Gas-in-Place Distribution by Coal Rank and Area, Alaska Basin

	Estimated Coal Rank Distribution, %				
Area	**LV**	**MV**	**HVA**	**HV**	**Sub**
"Commercial"	0%	0%	0%	50%	50%
"Non- Commercial"	0%	0%	0%	50%	50%

Adjustments to Major Assumptions

Adjustments to the base-case major assumptions for the Alaska basin are summarized below:

- Primary Recovery Factor: No adjustment.
- Voidage Replacement and ECBM Efficiency in "Commercial" Area: No adjustment.
- "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration: Due to the remoteness of Alaska to the major CO_2 emitting areas of the U.S., the lack of transportation infrastructure, and the harsh environment, an adjustment factor of 0.1 was applied to this parameter.

Basin Summaries

A summary of basin-specific adjustments to the major assumptions is presented in Table 37.

Table 37: Summary Basin-Specific Adjustments to Major Assumptions

Basin	Primary Recovery Factor	Voidage-Replacement and ECBM Efficiency in "Commercial" Area	"Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration
Northern Appalachian	None	0.75	1.5
Central Appalachian	None	0.75	1.5
Black Warrior	None	0.85	None
Illinois	None	None	1.5
Cherokee/Forest City	None	None	None
Arkoma	0.9	None	None
Gulf Coast	None	None	1.5
San Juan	None	1.25	None
Raton	None	None	None
Piceance	0.75	None	None
Uinta	1.5	None	None
Greater Green River	None	None	0.25
Hanna-Carbon	None	None	None
Wind River	None	None	None
Powder River	None	0.75	None
Western Washington	None	None	None
Alaska	None	None	0.1

3.4 CO_2-to-CH_4 Replacement Ratios by Coal Rank

One of the key advancements this study is providing over previous analyses of this type is the incorporation of emerging information on how CO_2-to-CH_4 replacement ratios change as a function of coal rank. At the Coal-Seq I forum, Bustin[42] conceptually presented sorption capacities for CO_2 and CH_4 as a function of coal rank. That slide, reproduced here as Figure 2, suggests the replacement ratio of CO_2-to-CH_4 is highest for low rank coals, and decreases with increasing coal rank. The high replacement ratios associated with low rank coals have also been reported by Stanton et al[43] for samples from the Powder River and Gulf Coast basins.

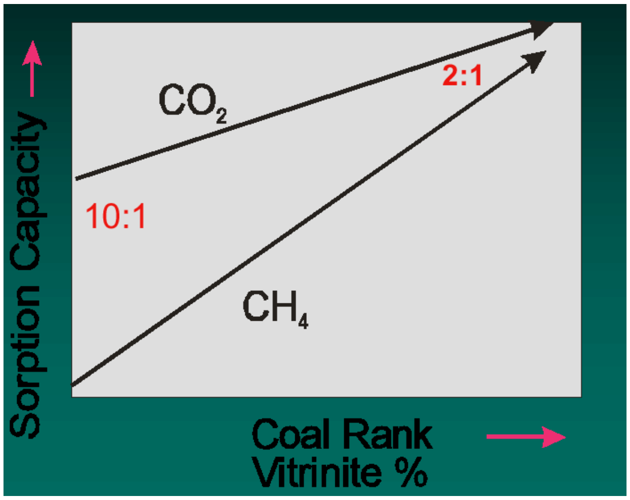

Figure 2: CO_2/CH_4 Sorption Capacities vs. Coal Rank, from Bustin[42]

However, there is a void of publicly available data to better quantify these relationships. Importantly, accurate coal rank information is required in addition to isotherm results to generate a quantitative relationship, greatly reducing the public-domain data that can be used. As part of this study, selected data were gathered and analyzed to provide a foundation upon which such a relationship could be established and used for this assessment. Quantitative data were obtained from several sources:

- As part of the Coal-Seq project, CH_4 and CO_2 isotherm and coal rank data were obtained for San Juan basin coal, from the Tiffany Unit[44].
- Pashin[45] also presented CO_2 and CH_4 isotherms at the Coal-Seq I forum. Langmuir coefficients and coal rank data were later published for those data[46].
- For low rank coals, Nelson[47] published some coal isotherm and rank information from the Powder River basin.

These sources provided four data points upon which to develop a relationship. While not an overwhelming amount of information, to the best of our knowledge this is the first "quantitative" presentation of its type, and hence represents the start what we hope to be a growing body of information on this topic.

That relationship is presented in Figure 3. As expected, there is a trend of decreasing ratio with increasing coal rank. Quantitatively, the ratios are in the range of 10:1 for sub-bituminous coals, decreasing to 1:1 for LV coal.

Note that 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 carbon sequestration projects, the power-law curve fit shown is for a pressure of 1,000 psi.

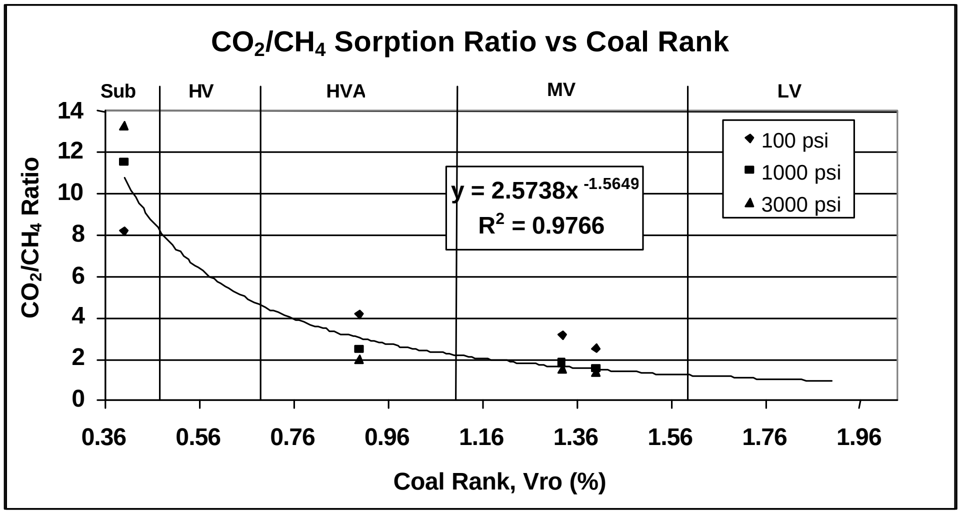

Figure 3: CO_2/CH_4 Replacement Ratios vs. Coal Rank.

Illustrating the same information in another way, Figure 4 shows the CO_2 and CH_4 sorption capacity, as defined by the Langmuir Volume, as a function of coal rank. Note the similarity in appearance with Figure 2. This suggests that the changes of CO_2 sorption capacity with coal rank are only very minor, whereas those with CH_4 are significant, as is well known.

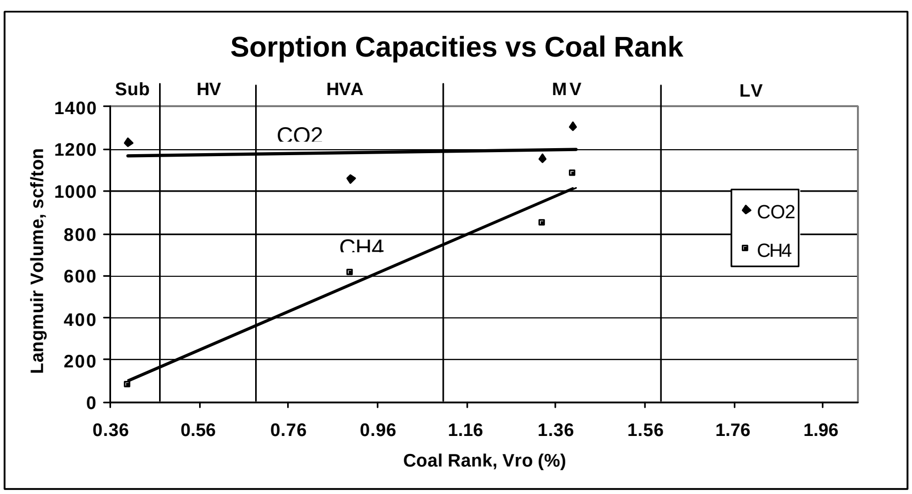

Figure 4: CO_2/CH_4 Sorption Capacities Ratio vs Coal Rank

Based on this information, the ratios used to compute the CO_2 sequestration potential of U.S. coalbeds in this assessment are in Table 38.

Table 38: CO_2/CH_4 Ratios used in this Study

Coal Rank	CO_2/CH_4 Ratio
LV	1:1
MV	1.5:1
HVA	3:1
HV	6:1
Sub	10:1

3.5 ECBM Recovery Factors by Coal Rank

Another important component of this assessment was to develop a relationship between coal rank and incremental methane recovery with CO_2 injection. Further, different relationships were developed for the "commercial" and "non-commercial" areas due to their different reservoir conditions.

To establish these relationships, reservoir simulation was employed, specifically ARI's proprietary COMET2 reservoir simulator. The reservoir engineering constants used for the model are provided in Table 39. Figures 5 and 6 provide the relative permeability curves employed, as well as the CO_2 and CH_4 isotherms for each coal rank (three coal ranks were studied, MV, HV and Sub).

Table 39: Reservoir Constants used in Simulation Model

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

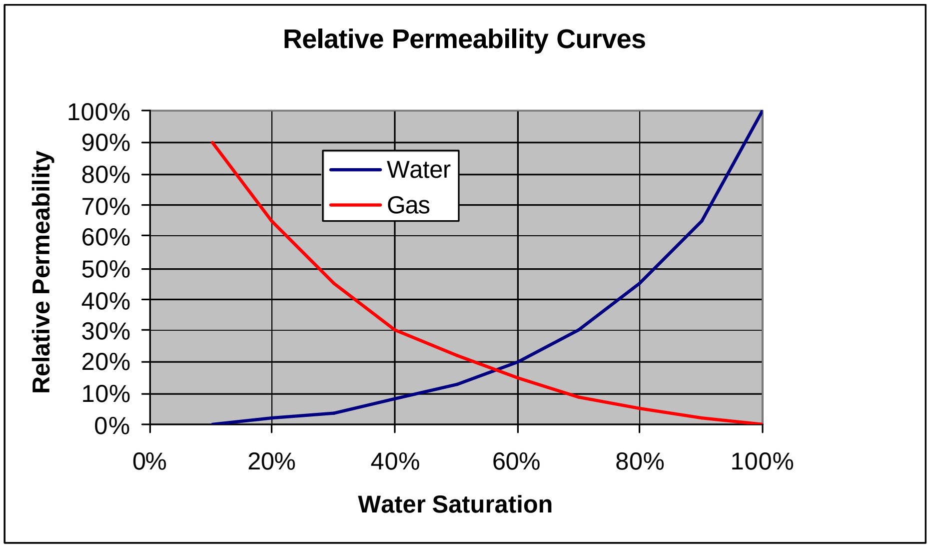

Figure 5: Relative Permeability Curves

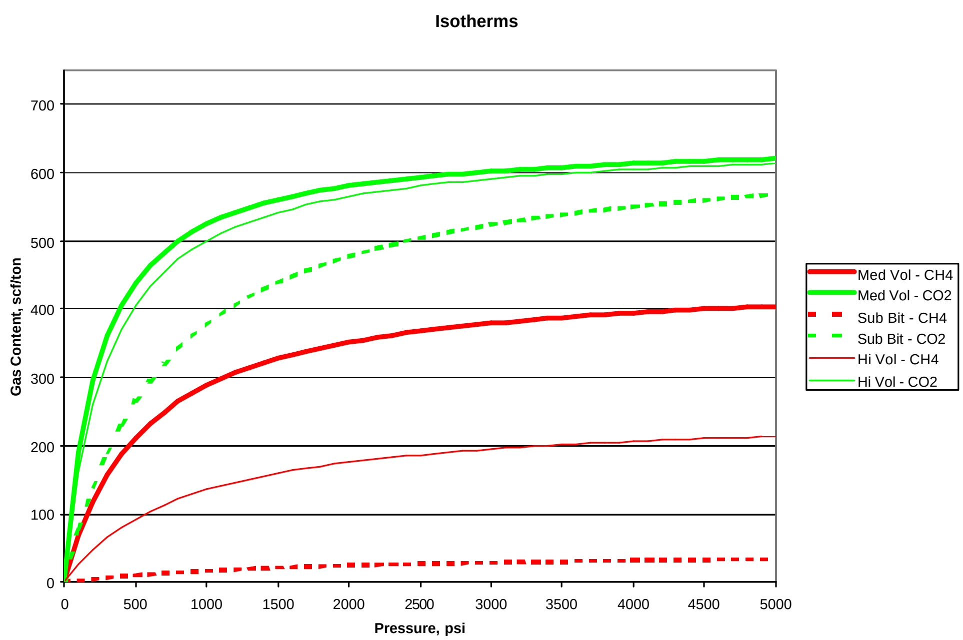

Figure 6: CO_2/CH_4 Sorption Isotherms

The differences in properties used for the "commercial" and "non-commercial" areas are provided in Table 40. The main differences between the two are that the "non-commercial" areas are deeper, have thinner coals, and are less permeable than the "commercial" areas. While far from precise, if at least some of these conditions were not true, the "non-commercial" areas would probably be "commercial". As a consequence, the normalized CO_2 injection rates in the "commercial" area are also higher than in the "non-commercial" area. Finally, wells in the "commercial" area are produced for 10 years prior to CO_2 injection, whereas those in the "non-commercial" area are not (CO_2 injection begins immediately).

Table 40: Model Input Parameters "Commercial" vs. "Non-Commercial" Areas

Parameter	"Commercial" Area	"Non-Commercial" Area
Depth (Press, Temp)	2000 ft.	5000 ft.
Thickness	25 ft.	10 ft.
Permeability	10 md.	1 md.
Injection Rate	50 Mcfd/ft. of coal	25 Mcfd/ft. of coal
Injection Timing	Produce 10 years, then inject 10 years	Inject 10 years

The results of the six simulation runs ("commercial" and "non-commercial" cases for each of 3 coal ranks) are presented in Figure 7. The methane recovery factors represent the percentage of in-place methane *at the start of CO_2 injection* that are recovered. The general trends are that:

- Lower rank coals have higher recoveries. This is because the lower coal ranks require less CO_2 and lower pressures to displace the in-place methane.
- The recovery factors in the "commercial" area are higher than in the "non-commercial" area. This is not only due to the better reservoir properties, but also the fact that considerable methane has already been produced prior to CO_2 injection (i.e., less in-place resource to recover), and that more CO_2 is injected (higher injection rates).

Based on this analysis, the recovery factors used in this assessment are provided in Table 41.

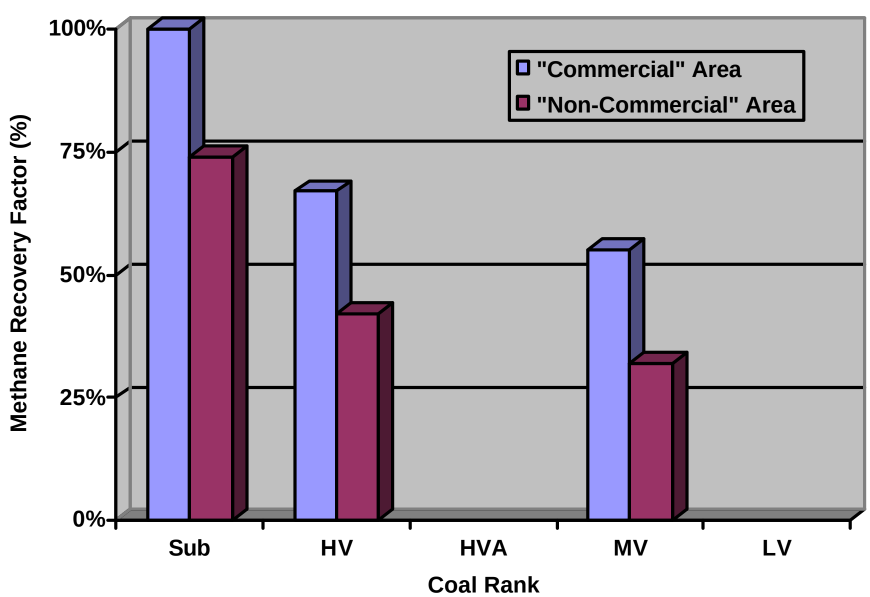

Figure 7: Recovery Factors as in Function of Coal Rank

Table 41: Recovery Factors by Coal Rank

Coal Rank	"Commercial" Area	"Non-Commercial" Area
Sub	100%	74%
HV	67%	42%
HVA	61%	37%
MV	55%	32%
LV	50%	25%

4.0 Assessment Results

Following the methodology presented in Section 2, and applying the basin-specific adjustments and relationships presented in Section 3, a summary of CO_2 sequestration and ECBM potentials by basin is provided in Table 42. A copy of the actual computational spreadsheet is provided in Appendix A.

Table 42: Summary of CO_2 Sequestration and ECBM Potential of U.S. Coal Basins

	CO_2 Sequestration Potential (Gt)					ECBM Potential (Tcf)			
Basin	Replace-ment of Primary Recovery Volume	Injection for ECBM in "Com-mercial" Area	Injection for CO_2 Sequestra-tion in "Non-Commer-cial" Area	Total (Gt)	% of Total	Incre-mental Recovery in "Commer-cial" Area	Incremental Recovery in "Non-Commercial" Area	Total (Tcf)	% of Total
N. Appalachia	0.8	0.3	2.3	3.4	4%	1.7	13.0	14.7	10%
C. Appalachia	0.1	0.0	0.0	0.1	0%	0.5	0.0	0.5	0%
Black Warrior	0.4	0.1	0.4	0.8	1%	1.0	2.2	3.1	2%
Illinois	0.1	0.0	1.2	1.4	2%	0.2	3.8	4.0	3%
Cherokee/ Forest City	0.4	0.1	0.3	0.9	1%	0.5	0.9	1.4	1%
Arkoma	0.1	0.0	0.0	0.1	0%	0.4	0.1	0.5	0%
Gulf Coast	0.7	0.4	0.9	1.9	2%	0.7	1.7	2.4	2%
San Juan	7.0	2.3	1.1	10.4	12%	11.4	4.3	15.7	10%
Raton	0.4	0.1	0.0	0.6	1%	1.4	0.1	1.5	1%
Piceance	0.5	0.3	1.5	2.4	3%	3.6	10.5	14.0	9%
Uinta	1.6	0.3	0.0	1.9	2%	0.1	0.2	0.3	0%
Greater Green River	3.0	1.3	3.5	7.9	9%	3.5	15.0	18.5	12%
Hanna-Carbon	1.4	0.6	1.0	3.0	3%	1.5	2.4	3.9	3%
Wind River	0.8	0.3	0.3	1.4	2%	0.8	0.6	1.5	1%
Powder River	3.3	1.8	8.5	13.6	15%	3.4	16.2	19.6	13%
Western Washington	0.7	0.3	1.3	2.3	3%	0.7	2.9	3.6	2%
Alaska	18.0	8.1	11.7	37.7	42%	19.2	27.8	47.0	31%
TOTALS	**39.3**	**16.3**	**34.0**	**89.8**	**100%**	**50.6**	**101.7**	**152.2**	**100%**

In total, about 90 Gt of CO_2 sequestration and 152 Tcf of ECBM potential is indicated. To put the sequestration capacity estimate into perspective, in 2001, total estimated CO_2 emissions in the U.S. were 5.8 Gt[48], Of this, an estimated 2.2 Gt came from the electric power generation sector, the most likely source of CO_2 for coalseam sequestration. As such, coalseams could sequester over 40 years of CO_2 from these sources at current emissions levels. To put the ECBM potential into perspective, the current CBM recoverable resource estimate for the U.S. is over 170 Tcf (Table 4). ECBM could almost double this CBM resource, which is already recognized as an essential component of the future U.S. gas supply portfolio.

The major contributors to CO_2 sequestration potential include Alaska (42%), Power River Basin (15%), San Juan Basin (12%), and Greater Green River Basin (9%). The major contributors to ECBM potential include Alaska (31%), Powder River Basin (13%), Greater Green River Basin (12%), San Juan Basin (10%) and Northern Appalachian Basin (10%). It is also interesting to note that CO_2

sequestration potential is greatest when replacing primary methane recovery, followed by sequestration in the "non-commercial" area. ECBM potential is also greatest in the "non-commercial" area, presumably due to its large geographic size as compared to the "commercial" area. The CO_2 sequestration and ECBM potential of the "commercial" areas are small in comparison; however this result does not consider economics.

A comparison of results from this study with those of Stevens[2], for the basins assessed in the earlier study, is presented in Table 43. In general, this study indicates higher CO_2 sequestration potential (due primarily to higher CO_2/CH_4 replacement ratios in lower rank coals), and less ECBM recovery potential (due to the application of technical rationale to place "upper-bound" limits on the results).

Table 43: Comparison of Results to Earlier Study

Basin	CO_2 Sequestration Potential (Gt)		ECBM Potential (Tcf)	
	Stevens[2] Study	This Study	Stevens[2] Study	This Study
San Juan	6.4	10.4	60.0	15.7
Uinta	1.0	1.9	10.0	0.3
Raton	1.1	0.6	10.2	1.5
Black Warrior	2.1	0.8	19.8	3.1
N. & C. Appalachian	7.1	3.5	66.0	15.2
Powder River	3.2	13.6	30.0	19.6
Piceance	9.0	2.4	84.0	14.0
Greater Green River	5.1	7.9	48.0	18.5
Totals	35.0	41.1	328.0	87.9

5.0 Sensitivity of Results to Major Assumptions

A Monte-Carlo simulation of the assessment results was performed to provide a probabilistic view of the outcome. The distributions assumed for each of the major assumptions are presented in Table 44, and illustrated in Figures 8 - 10.

Table 44: Distributions Assumed for Major Assumptions

Assumption	Distribution Type	Mean	Distribution Controls
Primary Recovery Factor	Normal	65%	Standard Deviation = 10%
Voidage-Replacement and ECBM Efficiency in "Commercial" Area	Beta	75%	Alpha = 6.0 Beta = 1.75 Max = 95%
"Accessible" Portion of "Non-commercial" Area for CO_2 ECBM/Sequestration	Normal	50%	Standard Deviation = 15%

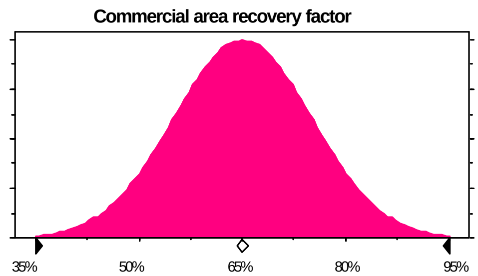

Figure 8: Distribution for Primary Recovery Factor

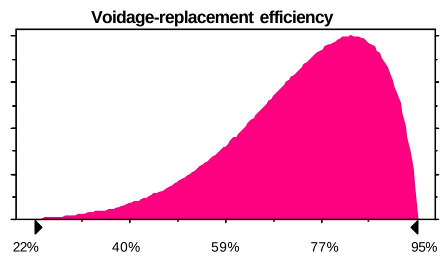

Figure 9: Distribution for Voidage-Replacement and ECBM Efficiency in "Commercial" Area

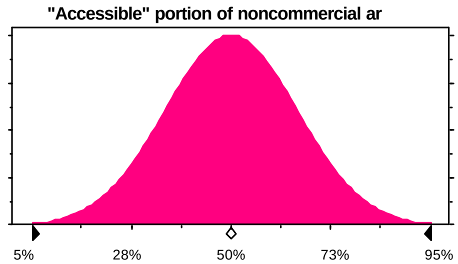

Figure 10: Distribution for "Accessible" Portion of "Non-Commercial" Area for CO_2 ECBM/Sequestration

The results from 1000 trial simulations are presented in Figures 11 and 12, and summarized in Table 45.

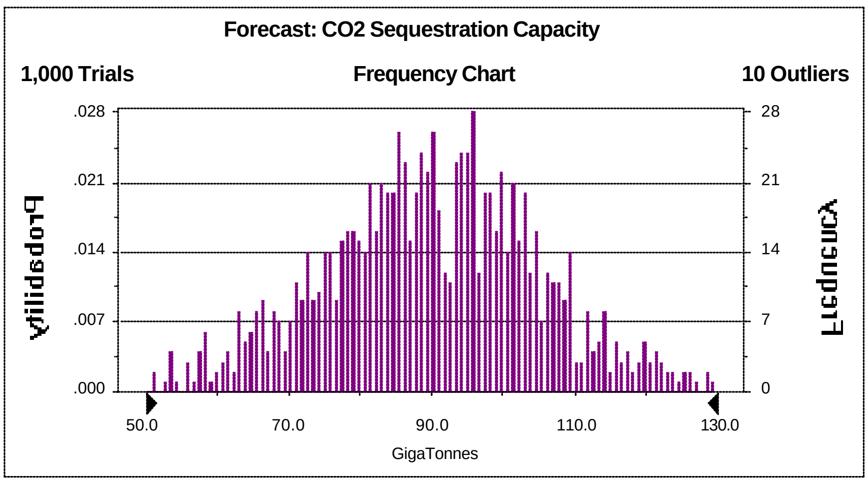

Figure 11: Monte-Carlo Simulation Results – CO_2 Sequestration Capacity

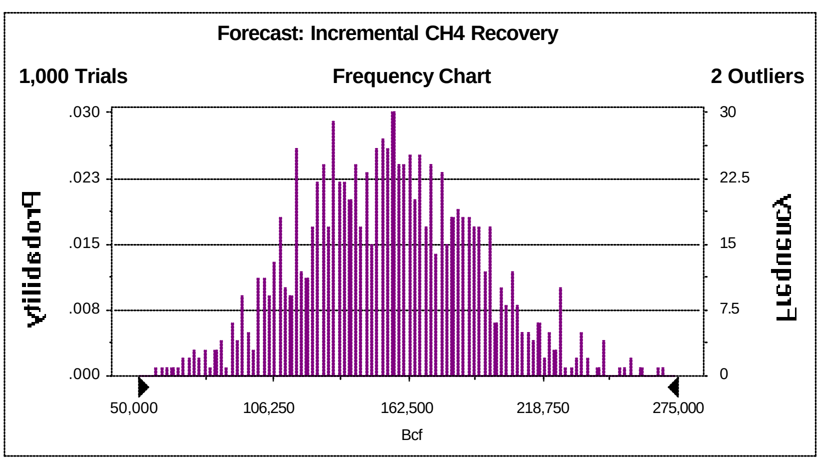

Figure 12: Monte-Carlo Simulation Results – ECBM Potential

Table 45: Results of Monte-Carlo Simulation

	Mean	P_{10}	P_{90}
CO_2 Sequestration Potential (Gt)	90.0	70.1	108.9
ECBM Potential (Tcf)	154.8	108.5	200.9

The results suggest that there is a 90% probability that the CO_2 Sequestration and ECBM potential will exceed 70 Gt and 109 Tcf respectively. There is a 10% probability that these potentials could be as high as 109 Gt and 201 Tcf respectively.

Finally, a sensitivity analysis of the results to the major assumptions was performed. The analysis, presented in terms of correlation coefficients between assumptions and results, provides a meaningful measure of the degree to which they change together, and account for both the uncertainty and sensitivity associated with each assumption. The results are illustrated in Figures 13 and 14.

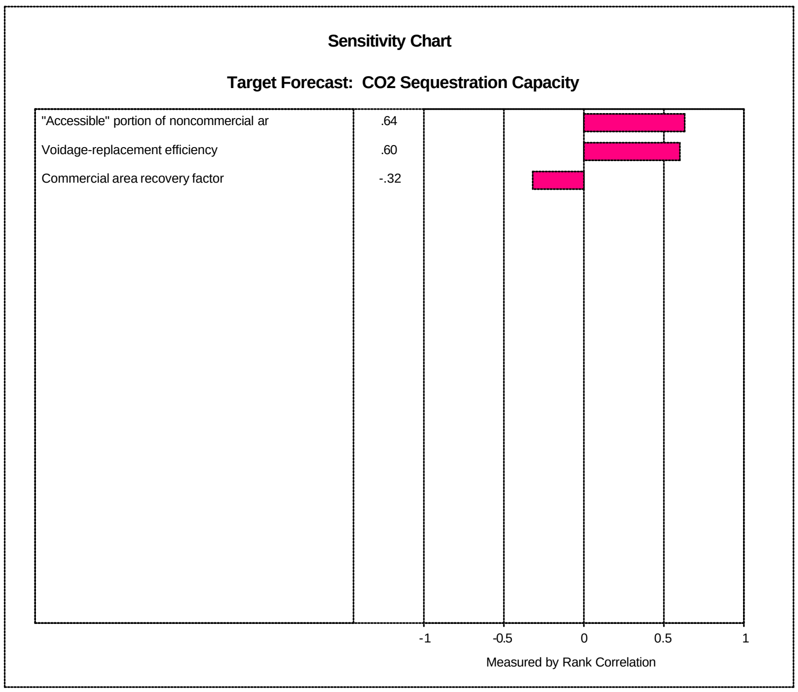

Figure 13: Sensitivity of CO_2 Sequestration Capacity to Major Assumptions

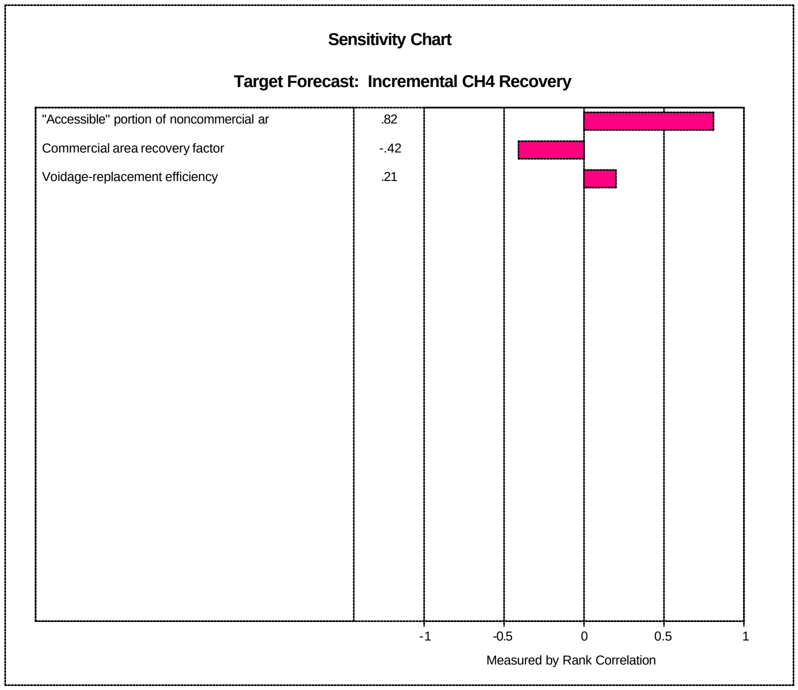

Figure 14: Sensitivity of ECBM Potential to Major Assumptions

The results clearly indicate that the "accessible" portion of the "non-commercial" area for CO_2 ECBM/Sequestration has the greatest impact on both CO_2 sequestration capacity and ECBM potential, with higher (percentage) portions yielding larger capacities/potentials. The voidage-replacement and ECBM efficiency in the "commercial" area also has a meaningful impact on CO_2 sequestration capacity (positively correlated), but only has a relatively small impact on ECBM potential (also positively correlated). The "commercial" area recovery factor has the least impact on CO_2 sequestration capacity, but is more important to ECBM potential. This assumption is negatively correlated to both of these outputs.

6.0 Economics

The final step of this assessment was to evaluate the results of the study from an economic perspective. The economics of CO_2 sequestration were estimated separately for both the "commercial" and "non-commercial" areas of each basin, using the following general procedures:

<u>"Commercial" Area</u>

- Estimate the total number of production wells in the "commercial" area based on the average methane recovery per well and the total recoverable methane estimate.

- Use a ratio of injector-to-producer wells to compute the total number of injection wells required, accounting for the fact that the entire area will not be used for CO_2 ECBM/sequestration. It was assumed that 75% of the "commercial" area would be used for ECBM/sequestration operations, and within that area the injector-to-producer ratio was 1:1 (i.e., a conventional 5-spot pattern).

- Compute the capital expenditures required to drill the injection wells using well cost estimates and accounting for costs that would be required for monitoring and verification. Apply a factor to the capital expenditures to account for the time value of money.

- Compute the income from incremental ECBM based on the estimated methane volumes and gas price, expense and financial assumptions.

- Calculate the net sequestration income (expense) in $/ton by dividing the difference between ECBM income and capital expenditures by the total CO_2 sequestration volumes.

<u>"Non-Commercial" Area</u>

- Estimate the total number of new production wells required in the "non-commercial" area based on the average methane recovery per well (same as for "commercial" area – the rationale for this is that via ECBM, the wells in the "non-commercial" area will produce about the same amount of methane as wells in the "commercial" area do via primary production) and the total ECBM methane estimate.

- Use a ratio of injector-to-producer wells to compute the total number of injection wells required. Unlike the "commercial" area, the entire area would be used for ECBM since this is the purpose of the development in the "non-commercial" area. Similar to the "commercial" area, a 1:1 ratio was assumed.

- Compute the capital expenditures required to drill both the production and injection wells using well cost estimates, and accounting for costs that would be required for monitoring and verification. Apply a factor to the capital expenditures to account for the time value of money.

- Compute the income from incremental ECBM based on the estimated methane volumes and gas price, expense and financial assumptions.

- Calculate the net sequestration income (expense) in $/ton by dividing the difference between ECBM income and capital expenditures by the total CO_2 sequestration volumes.

As can be deduced from the above procedures, there are several key data and assumptions used in the analysis. First, Table 46 provides the average well recoveries, production well capital expenditures (Capex), basin (gas price) differentials, gas heating value adjustments (based on difference between actual gas heating value and that of 1,000 British Thermal Units (BTU's)), and production well expenditures (Opex). These data were obtained from the MUGS model[23].

Table 46: Economic Model Input Data, from MUGS Model

Basin	Average Well Recovery (Bcf/well)	Prod Well Capex* ($/well)	Basin Differential ($/Mcf)	BTU Adjustment (%)	Prod Well Opex ($/Mcf)
Northern Appalachian	0.2	$ 158,000	$ (0.35)	-9.00%	$ 1.16
Central Appalachian	0.6	$ 264,000	$ (0.35)	0.00%	$ 0.85
Black Warrior	0.4	$ 236,000	$ (0.25)	0.40%	$ 1.01
Illinois	0.2	$ 162,000	$ (0.25)	2.20%	$ 0.80
Cherokee/Forest City	0.2	$ 149,000	$ -	2.50%	$ 1.11
Arkoma	0.2	$ 171,000	$ -	-0.20%	$ 0.78
Gulf Coast	0.5	$ 173,000	$ -	2.00%	$ 0.60
San Juan	4.8	$ 578,000	$ 0.25	2.30%	$ 0.52
Raton	1.9	$ 526,000	$ 0.25	2.50%	$ 0.60
Piceance	1.0	$ 835,000	$ 0.25	4.60%	$ 0.73
Uinta	1.7	$ 503,000	$ 0.25	2.60%	$ 0.67
Greater Green River	1.0	$1,050,000	$ 0.25	12.30%	$ 0.77
Hanna-Carbon	1.0	$ 500,000	$ 0.25	2.00%	$ 0.60
Wind River	1.0	$ 750,000	$ 0.25	2.00%	$ 0.75
Powder River	0.5	$ 115,000	$ 0.25	3.10%	$ 0.60
Western Washington	0.6	$ 300,000	$ 0.35	2.00%	$ 0.80
Alaska	0.5	$ 345,000	$ 1.00	2.00%	$ 1.20

Note: Shaded values were estimated (not included in MUGS model).
* Before application of SMV premium or TVM multiplier.

In addition, more general financial assumptions used are provided in Table 47.

Table 47: General Financial Assumptions

Parameters	Value	Remarks
Prod Taxes & Royalties	20%	
Production/Injection Well Cost Ratio	0.70	Ratio used to compute injection well costs.
SMV Capex Premium	25%	Premium added to both new production and injection wells for CO2 storage monitoring and verification (SMV).
Capex TMV Multiplier	2.00	Capex multiplier to correct for time value of money (TVM).

Finally the economics were computed at wellhead gas prices of $3.00/Mcf and $4.50/Mcf. The results of the analysis, presented in rank order of sequestration income (expense) by basin and area, are provided in Tables 48 and 49. They are also graphically presented in Figure 15. Appendix B provides the analytic spreadsheets used to compute the results.

Table 48: Economic Ranking of Basins for CO_2 Sequestration Economics, $3.00/Mcf

Basin	Area	Sequestration Volume (Gt)	Sequestration Profit (Cost) ($/ton)
San Juan	Non-Comm	1.08	$ 4.03
Raton	Non-Comm	0.02	$ 2.50
San Juan	Comm	9.29	$ 1.01
Powder River	Non-Comm	8.53	$ 0.95
Uinta	Non-Comm	0.04	$ 0.81
Gulf Coast	Non-Comm	0.87	$ 0.51
Powder River	Comm	5.06	$ 0.06
Gulf Coast	Comm	1.04	$ 0.05
Central Appalachian	Non-Comm	0.01	$ (0.30)
Hanna-Carbon	Comm	2.00	$ (0.83)
Western Washington	Comm	1.01	$ (0.84)
Hanna-Carbon	Non-Comm	1.01	$ (1.24)
Raton	Comm	0.58	$ (1.59)
Western Washington	Non-Comm	1.34	$ (1.68)
Wind River	Comm	1.12	$ (1.86)
Uinta	Comm	1.89	$ (2.30)
Alaska	Comm	26.05	$ (2.34)
Illinois	Comm	0.18	$ (3.14)
Cherokee/Forest City	Comm	0.55	$ (3.19)
Greater Green River	Comm	4.34	$ (3.73)
Alaska	Non-Comm	11.67	$ (3.75)
Wind River	Non-Comm	0.27	$ (3.86)
Illinois	Non-Comm	1.18	$ (4.95)
Black Warrior	Non-Comm	0.36	$ (5.08)
Cherokee/Forest City	Non-Comm	0.31	$ (5.33)
Black Warrior	Comm	0.47	$ (7.40)
Northern Appalachian	Non-Comm	2.28	$ (8.42)
Piceance	Comm	0.86	$ (8.80)
Northern Appalachian	Comm	1.07	$ (8.98)
Arkoma	Comm	0.13	$ (10.76)
Central Appalachian	Comm	0.13	$ (11.63)
Greater Green River	Non-Comm	3.51	$ (12.91)
Piceance	Non-Comm	1.50	$ (13.84)
Arkoma	Non-Comm	0.00	$ (31.09)

Table 49: Economic Ranking of Basins for CO_2 Sequestration Economics, $4.50/Mcf

Basin	Area	Sequestration Volume (Gt)	Sequestration Profit (Cost) ($/ton)
Raton	Non-Comm	0.02	$ 10.56
Central Appalachian	Non-Comm	0.01	$ 8.70
San Juan	Non-Comm	1.08	$ 8.28
Uinta	Non-Comm	0.04	$ 5.30
Powder River	Non-Comm	8.53	$ 2.96
Gulf Coast	Non-Comm	0.87	$ 2.63
San Juan	Comm	9.29	$ 2.31
Black Warrior	Non-Comm	0.36	$ 1.47
Hanna-Carbon	Non-Comm	1.01	$ 1.30
Raton	Comm	0.58	$ 0.92
Gulf Coast	Comm	1.04	$ 0.78
Powder River	Comm	5.06	$ 0.76
Western Washington	Non-Comm	1.34	$ 0.63
Hanna-Carbon	Comm	2.00	$ (0.04)
Western Washington	Comm	1.01	$ (0.09)
Wind River	Comm	1.12	$ (1.07)
Alaska	Non-Comm	11.67	$ (1.15)
Wind River	Non-Comm	0.27	$ (1.32)
Illinois	Non-Comm	1.18	$ (1.52)
Alaska	Comm	26.05	$ (1.55)
Northern Appalachian	Non-Comm	2.28	$ (1.63)
Cherokee/Forest City	Non-Comm	0.31	$ (2.11)
Illinois	Comm	0.18	$ (2.20)
Uinta	Comm	1.89	$ (2.24)
Cherokee/Forest City	Comm	0.55	$ (2.26)
Greater Green River	Comm	4.34	$ (2.95)
Piceance	Comm	0.86	$ (4.44)
Black Warrior	Comm	0.47	$ (5.20)
Piceance	Non-Comm	1.50	$ (6.60)
Northern Appalachian	Comm	1.07	$ (7.12)
Arkoma	Comm	0.13	$ (7.43)
Central Appalachian	Comm	0.13	$ (7.64)
Greater Green River	Non-Comm	3.51	$ (8.83)
Arkoma	Non-Comm	0.00	$ (12.48)

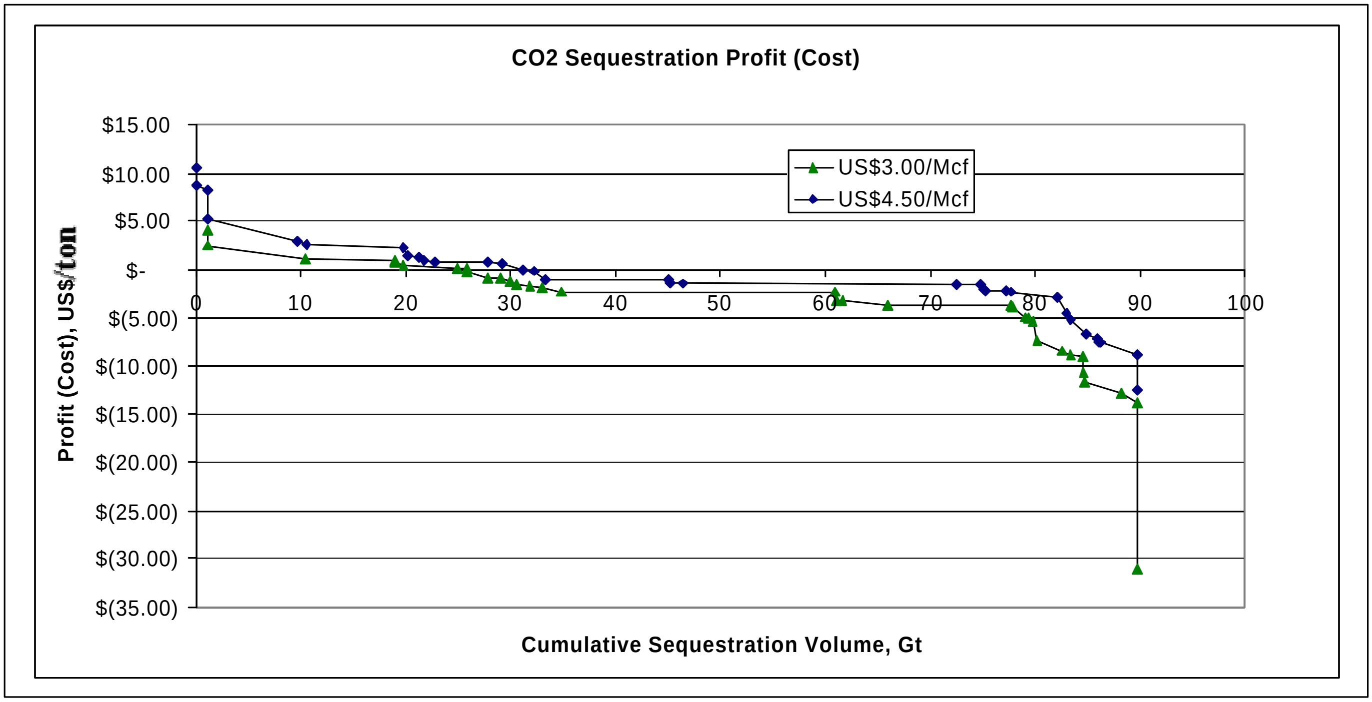

Figure 15: Illustration of Sequestration Economics as a Function of Cumulative CO_2 Sequestration Capacity

Before discussing the results, it must be emphasized that these estimates assume a CO_2 cost of zero; any costs for CO_2 capture and transportation to the field would have to be added to these values to reach a "total-system" CO_2 capture, transportation and sequestration cost. That said, some of the conclusions that can be drawn from these results include:

- Gas price does impact the CO_2 sequestration economics, with higher gas prices lending to offset (lower) net-sequestration costs.
- Between 25 and 30 Gt of CO_2 can be sequestered at a profit; between 80 and 85 Gt can be sequestered at costs of less then $5/ton.
- Several Rocky Mountain basins, including the San Juan, Raton, Powder River and Uinta appear to hold the most favorable conditions for sequestration economics. The Gulf Coast and the Central Appalachian basin also appear to hold promise as economic sequestration targets, depending upon gas prices.
- In general, the "non-commercial" areas appear more favorable for sequestration economics than the "commercial" areas. This is because there is more in-place methane to recover in these setting (the "commercial" areas having already been largely depleted of methane).

The results for two of the more attractive basins, the San Juan and the Powder River, and for both the "commercial" and "non-commercial" areas, are presented in unit terms ($/Mcf) in Tables 50 and 51 (for a gas price of $3.00/Mcf).

Table 50: San Juan and Powder River Basin Results, "Commercial" Area, $3.00/Mcf

	San Juan Basin ($/Mcf)	Powder River Basin ($/Mcf)
Gas Price	$ 3.00	$ 3.00
less basin differential	$ (0.25)	$ (0.25)
less BTU adjustment	$ (0.07)	$ (0.09)
Wellhead Netback	$ 2.68	$ 2.66
less royalties, taxes	$ (0.54)	$ (0.53)
less Opex	$ (0.52)	$ (0.60)
Gross Margin	$ 1.62	$ 1.53
less Capex	$ (0.72)	$ (1.43)
Net Margin	$ 0.90*	$ 0.10*
times ECBM recovery	11,371 Bcf	3,371 Bcf
divided by CO_2 sequestration volume	10,218 million tons	5,567 million tons
Sequestration Profit (Cost)	$ 1.01/ton	$ 0.06/ton

*Assumes zero cost for CO_2

Table 51: San Juan and Powder River Basin Results, "Non-Commercial" Area, $3.00/Mcf

	San Juan Basin ($/Mcf)	Powder River Basin ($/Mcf)
Gas Price	$ 3.00	$ 3.00
less basin differential	$ (0.25)	$ (0.25)
less BTU adjustment	$ (0.07)	$ (0.09)
Wellhead Netback	$ 2.68	$ 2.66
less royalties, taxes	$ (0.54)	$ (0.53)
less Opex	$ (0.52)	$ (0.60)
Gross Margin	$ 1.62	$ 1.53
less Capex	$ (0.51)	$ (0.98)
Net Margin	$ 1.11*	$ 0.55*
times ECBM recovery	4,300 Bcf	16,235 Bcf
divided by CO_2 sequestration volume	1,187 million tons	9,384 million tons
Sequestration Profit (Cost)	$ 4.03/ton	$ 0.15/ton

*Assumes zero cost for CO_2

These results illustrate more clearly how the economic calculations work on a unit scale.

7.0 Conclusions

Based on the results of the assessment, the following conclusions have been drawn:

- The CO_2 sequestration capacity of U.S. coalbeds is estimated to be about 90 Gt. Of this, about 38 Gt is in Alaska (even after accounting for high costs associated with this province), 14 Gt is in the Powder River basin, 10 Gt is in the San Juan basin, and 8 Gt is in the Greater Green River basin. By comparison, total CO_2 emissions from power generation plants is currently about 2.2 Gt/year.

- The ECBM recovery potential associated with this sequestration is estimated to be over 150 Tcf. Of this, 47 Tcf is in Alaska (even after accounting for high costs associated with this province), 20 Tcf is in the Powder River basin, 19 Tcf is in the Greater Green River basin, and 16 Tcf is in the San Juan basin. By comparison, total CBM recoverable resources are currently estimated to be about 170 Tcf.

- Between 25 and 30 Gt of CO_2 can be sequestered at a profit, and 80 – 85 Gt can be sequestered at costs of less than $5/ton. These estimates do not include any costs associated with CO_2 capture and transportation, and only represent geologic sequestration.

- Several Rocky Mountain basins, including the San Juan, Raton, Powder River and Uinta appear to hold the most favorable conditions for sequestration economics. The Gulf Coast and the Central Appalachian basin also appear to hold promise as economic sequestration targets, depending upon gas prices.

- In general, the “non-commercial” areas (those areas outside the main play area that are not expected to produce primary CBM commercially) appear more favorable for sequestration economics than the “commercial” areas. This is because there is more in-place methane to recover in these settings (the “commercial” areas having already been largely depleted of methane).

8.0 Nomenclature

AAPG	-	American Association of Petroleum Geologists
ARI	-	Advanced Resources International
Bcf	-	billions of cubic feet
BTV	-	British Thermal Units
Capex	-	capital expenditures
CBM	-	coalbed methane
CO_2	-	carbon dioxide
$	-	dollars (U.S.)
deg	-	degrees
DOE	-	Department of Energy
ECBM	-	enhanced coalbed methane recovery
EIA	-	Energy Information Agency
ft	-	feet
GRI	-	Gas Research Institute
Gt	-	gigatonnes
GTI	-	Gas Technology Institute
HV	-	high volatile
HVA	-	high volatile A
LV	-	low volatile
Mcf	-	thousand of cubit feet
Mcfd	-	thousands of cubic feet per day
md	-	millidarcies
MUGS	-	Model of Unconventional Gas Supply
MV	-	medium volatile
MW	-	megawatts
N_2	-	nitrogen
NEMS	-	National Energy Modeling System
NPC	-	National Petroleum Council
OGSM	-	Oil and Gas Supply Model
Opex	-	operating expenditures
%	-	percent
PGC	-	Potential Gas Committee
psi	-	pounds per square inch
R&D	-	research and development
Smv	-	storage monitoring and verification
Sub	-	sub-bituminous
Tcf	-	trillions of cubic feet
Tvm	-	time value of money
U.S.	-	United States
U.S.G.S.	-	United States Geological Survey
vs	-	versus

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Appendix A: Resource Analysis Spreadsheet

Appendix B: Economic Analysis Spreadsheet