Summary of the Methodology for Development of Geologic Storage Estimates for Carbon Dioxide

Prepared for

U.S. Department of Energy
National Energy Technology Laboratory
Carbon Storage Program

September 2010

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Contents

Executive Summary

The U.S. Department of Energy's Regional Carbon Sequestration Partnerships (RCSPs) were charged with providing a high-level, quantitative estimate of carbon dioxide (CO_2) storage resource available in subsurface environments of their regions. Environments considered for CO_2 storage were categorized into five major geologic systems: oil and gas reservoirs, saline formations, unmineable coal areas, shale, and basalt formations. Where possible, CO_2 storage resource estimates have been quantified for oil and gas reservoirs, saline formations, and unmineable coal areas in the third edition of the *Carbon Sequestration Atlas of the United States and Canada* (*Atlas III*). Shale and basalt formations are presented as future opportunities and are not assessed.

The methodology employed by the RCSPs is based on volumetric methods for estimating subsurface volumes. Subsurface storage volume estimates depend on geologic properties and storage efficiency. Storage efficiency for this methodology was determined using Monte Carlo sampling, which includes efficiency terms to define the pore volume that is amenable to geologic storage and displacement terms to define the pore volume immediately surrounding a single CO_2 injector well.

Methodologies used in *Atlas III* are intended to produce high-level, regional- and national- scale CO_2 resource estimates of potential geologic storage in the United States and Canada. At this scale, the estimates of CO_2 geologic storage have a high degree of uncertainty. Because of this uncertainty, estimates from *Atlas III* are not intended to be used as a substitute for site-specific characterization and assessment. As CO_2 storage sites move through the site characterization process, additional site-specific data is collected and analyzed, reducing uncertainty. Incorporation of this site-specific data allows for the refinement of CO_2 storage resource estimates and development of CO_2 storage capacities by future potential commercial project developers.

1. Introduction

Estimates of carbon dioxide (CO_2) geologic storage potential are required to assess the potential contribution of carbon capture and storage (CCS) technologies towards the reduction of CO_2 emissions. Governments and industries worldwide rely on CO_2 storage estimates for broad energy-related government policy and business decisions. Dependable CO_2 storage estimates are necessary to ensure successful deployment of CCS technologies (Bachu et al., 2007; Bradshaw et al., 2007). Several groups worldwide are conducting initiatives for assessing CO_2 geologic storage potential (Bachu et al., 2007; Bennion and Bachu, 2008; Birkholzer and Zhou, 2009; Birkholzer et al., 2009; Bradshaw et al., 2007; Brennan et al., 2010; Burruss et al., 2009; CEF, 2010; CO2CRC, 2008; CSLF, 2010; DOE-NETL, 2006, 2008, 2010b; Economides and Ehlig-Economides, 2009; Gorecki et al., 2009a; Gorecki et al., 2009b; Gorecki et al., 2009c; GSQ, 2010; IEA, 2009; Koide et al., 1992; Kopp et al., 2009a, b; Leetaru et al., 2009; Szulczewski and Juanes, 2009; van de Meer, 1992, 1993, 1995; van de Meer and van Wees, 2006; van de Meer and Egberts, 2008; van de Meer and Yavuz, 2009; van der Meer and Egberts, 2008; Xie and Economides, 2009; Zhou et al., 2008).

The Department of Energy (DOE), in collaboration with the Regional Carbon Sequestration Partnerships (RCSPs), developed the methodology described herein for estimating CO_2 geologic storage potential in the *Carbon Sequestration Atlas of the United States and Canada* (*Atlas III*) (DOE-NETL, 2010a) (DOE-NETL, 2006, 2008, 2010b). The following provides a summary of CO_2 storage resource definitions, the procedure used to estimate CO_2 storage resource, and details on CO_2 storage efficiency in resource estimates in *Atlas III*.

2. Purpose of CO_2 Storage Methodology

This methodology is intended for external users, such as the RCSPs, future project developers, and governmental entities, to produce high-level CO_2 storage resource estimates of potential geologic storage formations in the United States and Canada at the regional and national scale. Three types of CO_2 storage formations were evaluated—oil/gas reservoirs, saline formations, and unmineable coal areas. Oil/gas reservoirs were assessed at the field level, while saline formations and unmineable coal areas were assessed at the basin level. The CO_2 storage potential evaluated using this methodology is intended to be distributed in *Atlas III* (DOE-NETL, 2010b) and online by the National Carbon Sequestration Database and Geographic Information System (NATCARB) (DOE-NETL, 2010c). It is expected that this methodology will be refined in the future, incorporating results of the RCSP's Development Phase projects conducted from 2008 to 2018. DOE expects to update carbon dioxide storage estimates every 2 years in subsequent versions of the *Carbon Sequestration Atlas of the United States and Canada*.

Because this methodology is intended to produce high-level, regional- and national-scale CO_2 resource estimates of potential geologic storage in the United States and Canada, the estimates of CO_2 geologic storage have a high degree of uncertainty. One reason for this uncertainty is the lack of wells penetrating the potential storage formation, resulting in undefined rock properties and heterogeneity of the formation. Because of this uncertainty, CO_2 storage resource estimates are not intended to be used as a substitute for site-specific characterization and assessment. As CO_2 storage sites move through the site characterization process, additional site-specific data is collected and analyzed, reducing uncertainty. This data includes, but is not limited to, site-specific lithology, porosity, and permeability. Incorporation of this site-specific data allows for the refinement of CO_2 storage resource estimates and development of CO_2 storage capacities by future potential commercial project developers.

This methodology is based on volumetric methods for estimating subsurface volumes, in situ fluid distributions, and fluid displacement processes (Calhoun Jr., 1982). These volumetric methods are widely and routinely applied in petroleum, groundwater, underground natural gas storage, underground injection control (UIC) disposal, and CO_2 storage estimations (Bachu, 2008; Bachu et al., 2007; Calhoun Jr., 1982; Frailey et al., 2006; Lake, 1989). Subsurface storage volume estimates depend on geologic properties (area, thickness, and porosity of formations) and storage efficiency (the fraction of the accessible pore volume that will be occupied by the injected liquid or gas). Storage efficiency for this methodology was determined using Monte Carlo sampling, which includes efficiency terms to define the pore volume that is amenable to geologic storage and displacement terms to define the pore volume immediately surrounding a single CO_2 injector well.

3. Definitions of CO_2 Geologic Storage Estimates

Definitions of CO_2 geologic storage terms vary from one organization to the next. Therefore, the following is a summary of CO_2 geologic storage terms used in *Atlas III*.

3.1. CO_2 Storage Resource Estimates

Carbon dioxide storage resource estimates represent the fraction of pore volume of sedimentary rocks available for CO_2 storage and accessible to injected CO_2. Storage resource estimates are screened by criteria including, but not limited to: (1) isolation from shallow potable groundwater,[1] other strata, soils, and the atmosphere; (2) gravity segregation; (3) maximum allowed injection pressure imposed by regulatory agencies to avoid fracturing at the injection well and fracture propagation; (4) caprock or seal capillary entry pressure; and (5) displacement efficiency (Bachu, 2008).

Carbon dioxide storage resource estimates consider only physical trapping of CO_2. Economic or regulatory constraints are not considered in storage resource assessments. Chemical trapping mechanisms such as CO_2 brine dissolution and precipitation or mineralization effects are also not taken into account when calculating saline formation CO_2 storage resource estimates. The dissolution of injected CO_2 into brine and carbonate mineral formation reactions is complex process that is dependent on the temperature, pressure, and brine composition within a formation, as well as the effectiveness of the contact between free phase CO_2, the formation brine and, subsequently, the minerals in the formation strata (Bachu et al., 2007). As described in section 3.3, CO_2 storage resource estimates are based upon the assumption that in situ mobile fluids will either be displaced by the injected CO_2 into distant parts of the same formation or neighboring formations, or managed by means of fluid production, treatment, and disposal.

3.2. CO_2 Storage Capacity Estimates

Carbon dioxide storage capacity estimates represent the geologic storage potential when current economic and regulatory considerations are included. For the development of specific commercial-scale geologic storage sites, economic and regulatory constraints must be considered to determine the portion of the CO_2 storage resource estimate that is available under various development scenarios (Bachu, 2008). Under the most favorable economic and regulatory scenarios, 100 percent of the estimated CO_2 geologic storage resource would be considered CO_2 storage capacity. A methodology for calculating CO_2 storage capacity estimates is not provided since they require a higher level of analysis than regional- and national-scale CO_2 storage resource estimates. Furthermore, specific sites may not be representative of the formation as a whole, and extrapolation of this methodology to specific sites may overestimate capacity.

Examples of economic considerations involved with CO_2 storage include: (1) CO_2 injection rate and pressure, (2) the number of wells drilled into the formation, (3) types of wells (horizontal versus vertical), (4) the number of injection zones completed in each well, (5) operating expenses, (6) management of in situ formation fluids (Zhou et al., 2008), (7) injection site proximity to a CO_2 source (Lucier and Zoback, 2008), and (8) combination with enhanced oil recovery or enhanced gas recovery activities.

Examples of regulatory considerations include: (1) protection of potable water; (2) well spacing requirements, (3) maximum injection rates, (4) prescribed completion methods (cased vs. open-hole), (5) proximity to existing wells, (6) treatment of in situ fluids, and (7) surface usage considerations (Wilson et al., 2003). Many of these considerations are addressed through the EPA UIC Program's Class VI well final rule, which defines specific requirements for CO_2 injection projects. Additional regulatory considerations may exist at the State and Provincial levels. Due to the varied nature of regulatory regimes for potential CO_2 storage reservoirs, CO_2 storage capacity estimates require site-specific assessments.

3.3. Boundary Conditions

Defining boundary conditions is necessary for any type of subsurface assessment. Two systems, open and closed, can be used to define the boundaries for potential CO_2 storage reservoirs. Open systems are permeable fluid-filled reservoirs where in situ fluids are displaced away from the injection location into other parts of the formation or into neighboring formations (Birkholzer and Zhou, 2009; Gorecki et al., 2009b; IEA, 2009;

1 Potable waters, for the purposes of this assessment, represent waters protected by the Safe Drinking Water Act (SDWA), which are defined as waters with less than 10,000 parts per million (ppm) total dissolved solids (TDS).U.S. Environmental Protection Agency (EPA), 2010. Safe Drinking Water Act, Office of Ground Water & Drinking Water, http://www.epa.gov/safewater/sdwa.

Nicot, 2008; Zhou et al., 2008). Subsequently, the primary constraints on the percentage of pore space that can be filled with CO_2 in open systems are due to displacement efficiencies, rather than pressure increases, although there will often be a need to define a maximum bottom-hole injection pressure to reduce risks associated with injection (Gorecki et al., 2009b; IEA, 2009; Zhou et al., 2008). Displacement of fluids from reservoirs has been examined in recent studies, which focus on potential effects of fluid migration to other subsurface geologic formations (Birkholzer and Zhou, 2009; Birkholzer et al., 2009; Leetaru et al., 2009; Nicot, 2008; Zhou et al., 2008).

Closed systems are fluid-filled reservoirs where in situ fluid movement is restricted within the formation by means of impermeable barriers (Birkholzer and Zhou, 2009; Gorecki et al., 2009b; IEA, 2009; Nicot, 2008; Zhou et al., 2008). Storage volume in closed systems is constrained by the compressibility of the formation's native fluid and rock matrix (van de Meer, 1992, 1993, 1995; van de Meer and Egberts, 2008; van de Meer and Yavuz, 2009; van der Meer and Egberts, 2008). In addition, the CO_2 injection pressure cannot exceed the maximum allowable pressure of the formation because over-pressurization may damage natural formation seals (Burruss et al., 2009; Gorecki et al., 2009b; Zhou et al., 2008). The very low compressibility of formation fluids and rocks limit the capacity of closed systems to a very small percentage of total pore volume (Gorecki et al., 2009b; Xie and Economides, 2009; Zhou et al., 2008). Closed systems may be transformed into open systems by means of managing, treating, and disposing of in situ fluids in accordance with current technical, regulatory, and economic guidelines (Birkholzer and Zhou, 2009; Gorecki et al., 2009b; IEA, 2009; Nicot, 2008; Zhou et al., 2008).

As defined in Section 3.1, storage resource estimates for *Atlas III* are based on open systems in which in situ fluids will either be displaced from the injection zone or managed. Accordingly, CO_2 storage resource estimates provide an upper boundary for CO_2 storage. Realization of the full CO_2 storage resource estimate as a capacity estimate will rely on how site-specific geology, economics, and regulations restrict the management of in situ fluids.

4. Methodology for CO_2 Storage Resource Estimate Calculation

Two different approaches are typically used to estimate subsurface injection volumes—static and dynamic (Calhoun Jr., 1982). Static methods used to estimate CO_2 storage potential are based on volumetric and compressibility-based models (Bachu, 2008; Bachu et al., 2007; Bradshaw et al., 2007; Burruss et al., 2009; 2008; Gorecki et al., 2009b; IEA, 2009; Kopp et al., 2009a, b; Szulczewski and Juanes, 2009; van de Meer, 1995; van de Meer and Egberts, 2008; van de Meer and Yavuz, 2009; van der Meer and Egberts, 2008). Volumetric methods are applied when it is generally assumed that the formation is open and that formation fluids are displaced from the formation or managed via production. Compressibility-based methods can be applied at the site-specific scale if it is demonstrated that the system is closed. Meaningful dynamic simulations typically cannot be done before site-specific data is collected and field-measured CO_2 injection rates or well testing have been completed. The methodology used in *Atlas III* is based on the volumetric approach for estimating CO_2 storage resource potential in oil and gas reservoirs, saline formations, and unmineable coal areas.

4.1. Oil and Gas Reservoir CO_2 Storage Resource Estimates

This methodology defines CO_2 storage resource estimates on a volumetric basis or production basis for oil and gas reservoirs that have hosted natural accumulations of oil and gas and could be used to store CO_2. No distinction is made in this assessment for the maturity of the reservoir. Because oil and gas reservoirs can be productive across a wide variety of depths, no minimum or maximum depth criteria were used for CO_2 storage resource estimates. Oil and gas reservoirs with a water TDS concentration of 10,000 ppm and higher were included, unless specifically noted and justified.

Storage volume methodology for oil and gas reservoirs was based on quantifying the volume of oil and gas that has or could be produced, and assuming that it could be replaced by an equivalent volume of CO_2. With this method, both oil/gas and CO_2 volumes are calculated at initial formation pressure or a pressure that is considered a maximum CO_2 storage pressure. However, there is not always a one-to-one relationship between the oil and gas volume footprint and a trap footprint for holding hydrocarbons (Nicot and Hovorka, 2009). Two main methods were used in *Atlas III* to estimate the CO_2 storage resource for oil and gas reservoirs: (1) a volumetrics-based CO_2 storage resource estimate and (2) a production-based CO_2 storage resource estimate. The method used by each RSCP was based on available data. The two methods have storage efficiency factors built into their respective equations and, therefore, CO_2 storage resource estimates are proposed as a single value for oil and gas reservoirs. Production-based CO_2 storage resource estimates are generally preferred over volumetrics-based CO_2 storage resource estimates because production data contains detailed information collected from the formation. If no production data is available, then volumetrics-based CO_2 storage resource estimates may be applied.

In the oil and gas industry, hydrocarbon recovery related attributes are calculated and applied with respect to the original oil or gas in place (at surface conditions, e.g. stock tank barrels of oil) regardless of the maturity of the oil or gas field development. Likewise, for estimating CO_2 storage resource in oil and gas reservoirs, CO_2 storage efficiency was developed as a function of the original hydrocarbon in place.

The volumetrics-based CO_2 storage resource estimate is based off the standard industry method to calculate original oil-in-place (OOIP) (Calhoun Jr., 1982; Lake, 1989). The general form of the volumetric equation to calculate the CO_2 storage resource mass estimate (G_{CO2}) for geologic storage in oil and gas reservoirs is as follows:

$$G_{CO2} = A\, h_n\, \phi_e\, (1-S_{wi}) B\, \rho_{CO2std}\, E_{oil/gas} \qquad (1)$$

The product of the area (A), net thickness (hn), average effective porosity (ϕe), original hydrocarbon saturation (1-initial water saturation, expressed as a fraction [S_{wi}]), and the initial oil (or gas) formation volume factor (B) yield the OOIP (or OGIP). The storage efficiency factor ($E_{oil/gas}$) is derived from local CO_2 EOR experience or reservoir simulation as standard volume of CO_2 per volume of OOIP. (In oilfield terms, the CO_2 EOR oil recovery factor and the CO_2 net utilization is equal to the storage efficiency factor.) The standard CO_2 density (ρ_{co2std}) converts standard CO_2 volume to mass. Because of previous extensive experience in estimating volumetrics of formations, each RCSP supplies regional, play, or formation-specific efficiency values. Table 1 summarizes the terms shown in eq 1.

Table 1. Oil and Gas Reservoir CO_2 Storage Resource Estimates

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of oil and gas reservoir CO_2 storage resource.
A	L^2	Area that defines the oil or gas reservoir that is being assessed for CO_2 storage.
h_n	L	Net oil and gas column height in the reservoir.
ϕ_e	L^3/L^3	Average effective porosity in volume defined by the net thickness.
S_{wi}	L^3/L^3	Average initial water saturation within the total area (A) and net thickness (h_n).
B	L^3/L^3	Fluid formation volume factor; converts standard oil or gas volume to subsurface volume (at reservoir pressure and temperature), e.g. stock tank volume of oil per reservoir volume of oil.
ρ_{CO2std}	M/ L^3	Standard density of CO_2 evaluated at standard pressure and temperature
$E_{oil/gas}$	L^3/L^3	CO_2 storage efficiency factor, the volume of CO_2 stored in and oil or gas reservoir per unit volume of original oil or gas in place (OOIP or OGIP).

* L is length; M is mass.

A production-based CO_2 storage resource estimate is possible if acceptable records are available on volumes of oil and gas produced. Produced water is not considered in the estimates, nor is injected water (waterflooding), although these volumes may be useful in site-specific calculations (Bachu et al., 2007). In cases where a field has not reached a mature stage, it is beneficial to apply decline curve analysis to better approximate the estimated ultimate recovery, which represents the expected volume of produced oil and gas (Calhoun Jr., 1982; Lake, 1989).

It is necessary to apply an appropriate reservoir volume factor (B) to convert surface oil and gas volumes (reported as production) to subsurface volumes (including correction of solution gas volumes if gas production in an oil reservoir is included). No area, column height, porosity, residual water saturation, or estimation of the fraction of OOIP accessible to CO_2 is required because production reflects these reservoir characteristics. If information is available, it is possible to apply efficiency to production data to convert them to CO_2 storage volumes; otherwise, replacement of produced oil and gas by CO_2 on a volume-for-volume basis (at reservoir pressure and temperature) may be acceptable.

4.2. Saline Formation CO_2 Storage Resource Estimates

Saline formations are composed of water-saturated porous rock and capped by one or more regionally extensive low-permeability rock formations. A saline formation assessed for CO_2 storage is defined as a porous and permeable body of rock containing water with TDS greater than 10,000 ppm. A saline formation can include more than one named geologic stratigraphic unit or be defined as only a part of a stratigraphic unit. Mechanisms for CO_2 storage in saline formations include structural trapping, hydrodynamic trapping, residual trapping, dissolution, and mineralization (Bachu et al., 2007; Kopp et al., 2009b; Xie and Economides, 2009). Structural, hydrodynamic, and residual trapping are initially the dominant trapping mechanisms and are the focus of this methodology.

Saline formations assessed for storage are restricted to those meeting basic criteria including:(1) adequate pressure and temperature conditions in the saline formation to keep the CO_2 liquid or supercritical; (2) presence of a suitable seal system, such as a caprock, to limit vertical flow of the CO_2 to the surface; and (3) a combination of hydrogeologic conditions to isolate the CO_2 within the saline formation.

The storage of CO_2 in saline formations is limited to sedimentary basins with vertical flow barriers and depths exceeding 800 meters. Sedimentary basins include porous and permeable sandstone and carbonate rocks. The 800-meter cutoff is an arbitrary attempt to select a depth that reflects pressure and temperature that yields high-density liquid or supercritical CO_2. All sedimentary rocks included in the saline formation CO_2 storage resource estimate must have seal systems consisting of low-permeability sealing rocks, such as shales, anhydrites, and other evaporates; however, the thickness of these sealing systems is not considered in this methodology. For increasing confidence in a storage resource estimates, other criteria including seal effectiveness (e.g., salinity and pressure above and below the seal system), minimum permeability, minimum threshold capillary pressure, and fracture propagation pressure of a seal system should be considered.

The volumetric equation to calculate the CO_2 storage resource mass estimate (G_{CO2}) for geologic storage in saline formations is:

$$G_{CO2} = A_t\, h_g\, \phi_{tot}\, \rho E_{saline} \qquad (2)$$

The total area (A_t), gross formation thickness (h_g), and total porosity (ϕ_{tot}) terms account for the total bulk volume of pore space available. The CO_2 density (ρ) converts the reservoir volume of CO_2 to mass. Rather than using an irreducible water saturation parameter explicitly, the storage efficiency factor (E_{saline}) reflects the fraction of the total pore volume that will be occupied by the injected CO_2. As described in section 5.1., E_{saline} factors range between 0.40 and 5.5 percent over the 10th to 90th percent probability range. Table 2 summarizes the terms shown in eq 2.

Table 2: Saline Formation CO_2 Storage Resource Estimating

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of saline formation CO_2 storage resource.
A_t	L^2	Geographical area that defines the basin or region being assessed for CO_2 storage.
h_g	L	Gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by A.
ϕ_{tot}	L^3/L^3	Total porosity in volume defined by the net thickness.
ρ	M/L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over h_g and A_t.
E_{saline}	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled by CO_2.

* L is length; M is mass.

4.3. Unmineable Coal Area CO_2 Storage Resource Estimates

Only coal areas containing water with TDS greater than 10,000 ppm merited evaluation for potential CO_2 storage (EPA, 1991). Where water quality data are scarce or unavailable, analogy to other geologic basins was used to estimate the minimum depth criteria. The maximum depth was arbitrarily selected for each basin to account for practicalities of CO_2 storage by sorption in coal. Depending on the geothermal and geo-pressure gradients in a formation, gaseous CO_2 adsorption may only be possible down to depths of about 3,000 ft (900 m) (Ryan and Littke, 2005). At greater depths and depending on coal rank, supercritical CO_2 may enter the solid coal and change its properties, which swells the coal matrix and causes injectivity problems (Metz et al., 2005). Cleat closure induced by increasing effective stress will further decrease permeability to such an extent that coalbed methane cannot be produced below 5,000 ft (1,500 m) (Bachu et al., 2007). Currently, this is defined as the maximum depth limit for potential CO_2 storage in coal (Metz et al., 2005). Beyond this limit, CO_2 storage is limited by the compression costs, which escalate below 11,000 ft (3,300 m) (van de Meer, 1993).

Within the depth intervals selected for a particular basin, a determination was made as to which coals are unmineable by today's state-of-the-art standards of technology. Although advancements in mining technology and changes in the value of the commodity may enable some of the coal areas that are currently deemed unmineable to be mineable in the future, it is beyond the scope of this effort to forecast long-term developments and their impact. Only coals deemed unmineable are included in this CO_2 storage resource estimate.

The following is the volumetric equation to calculate the CO_2 storage resource mass estimate (G_{CO2}) for geologic storage in unmineable coal areas:

$$G_{CO2} = A\, h_g\, C_{s,max}\, \rho_{CO2std}\, E_{coal} \qquad (3)$$

The total area (A) and gross area thickness (h_g) terms account for the total bulk volume containing the coal(s) to be assessed. $C_{s,max}$ is the maximum volume of CO_2 at standard conditions that can be sorbed per volume of coal (e.g., the Langmuir isotherm volume constant), and is assumed to be on an in situ or "as is" basis. (A conversion from mass or dry-ash-free volume basis may be necessary.) A component within the calculation of E_{coal}, includes the degree of saturation achievable for an in situ coal compared with the theoretical maximum predicted by the CO_2 Langmuir isotherm (section 5.2). The CO_2 density (ρ_{co2std}) converts the standard CO_2 volume in the Langmuir term (C) to mass. The storage efficiency factor (E_{coal}) reflects the fraction of the total bulk coal volume that will store the injected CO_2. As in section 5.2., E_{coal} factors range between 21 and 48 percent at the 10^{th} to 90^{th} percent probability range. Table 3 summarizes the terms shown in eq 3.

Table 3: *Unmineable Coal Area CO_2 Storage Resource Estimating*

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of CO_2 resource of one or more coal beds.
A	L^2	Geographical area that outlines the coal basin or region for CO_2 storage calculation.
h_g	L	Gross thickness of coal area(s) for which CO_2 storage is assessed within the basin or region defined by A.
$C_{s,max}$	L^3/L^3	Adsorbed maximum standard CO_2 volume per unit of in situ coal volume (Langmuir or alternative); assumes 100% CO_2 saturated coal conditions; if on dry-ash-free (daf) basis, conversion should be made.
ρ_{CO2std}	M/L^3	Standard density of CO_2.
E_{coal}	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total coal bulk volume that is contacted by CO_2.

* L is length; M is mass.

The maximum CO_2 sorption capacity of coal at saturation ($C_{s,max}$), which depends on the coal characteristics and, to a certain extent, on temperature, can be reported on per unit-of-coal-mass basis ($n_{s,max}$). Conversion into per unit-volume basis ($C_{s,max}$) requires the knowledge of coal bulk density ($\rho_{c,dry}$) as well as moisture and/or ash content, depending on the reporting format (such as dry, ash free). The average density of sorbed CO_2 in coal under saturated conditions is described by eq 4:

$$C_{s,max} = n_{s,max}\, \rho_{c,dry}\, (1 - f_{a,dry}) \qquad (4)$$

where $f_{a,dry}$ is the ash weight fraction of the dry coal bulk density ($\rho_{c,dry}$). For consistency with the distinction between the micropore sorption and hydrodynamic trapping due to fracture porosity, the coal bulk density should be measured as inclusive of micropore volume (e.g., mercury density of coal) (Gan et al., 1972). However, the helium density of coal, which is the most readily available data, is a good approximation as long as the micropore volume is accounted for in the fracture porosity (Huang et al., 1995).

The in situ fraction of CO_2 (C_s) that is stored per unit of coal under reservoir conditions, as opposed to under ideal (maximum) pressure conditions, depends on reservoir pressure after injection, moisture content, and the amount of gas in place (Clarkson and Bustin, 2000). However, the pressure effect can be approximated by a standard (e.g., Langmuir) isotherm equation. For lower rank coals, care should be taken to perform laboratory testing under reservoir conditions because chemical heterogeneity increases the difference in accessible micropore volumes between wet and dry coals observed at low pressure (low surface coverage) (Prinz and Littke, 2005). If data are available, different isotherms for different coal ranks are used. If no CO_2 isotherm is available, isotherms from similar rank coals in analog basins can be used, such as the isotherm data plotted in Figure 1 (Botnen et al., 2009; Bromhal et al., 2005; Busch et al., 2003; Chikatamarla et al., 2004; Clarkson and Bustin, 1999; Day et al., 2008a; Durucan and Q., 2009; Fitzgerald et al., 2005; Fitzgerald et al., 2006; Goodman et al., 2007; Harpalani and Mitra, 2010; Harpalani et al., 2006; Jessen et al., 2008; Ozdemir and Schroeder, 2009; Pini et al., 2010; 2008; Reeves et al., 2005; Romanov and Soong, 2008; Ross et al., 2009; Siemons and Busch, 2007).

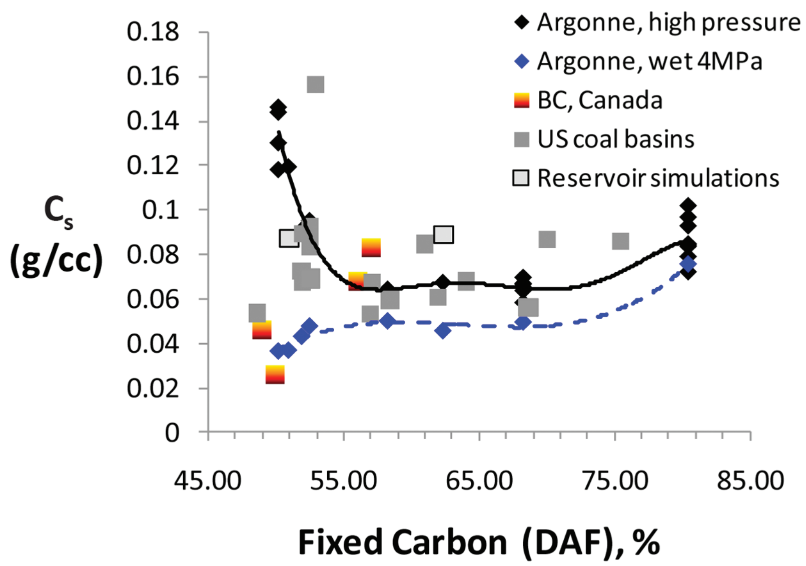

Figure 1. Average CO_2 Sorption (expressed in g/cc) vs. Coal Rank (expressed as percent fixed carbon on a dry and ash free basis (daf)). Red and gray solid squares represent experimental data for Canadian and North American coals, respectively. Black and blue solid diamonds represent experimental data for Argonne premium coals at saturation (high pressure) and at low pressure (4 MPa wet), respectively. Gray solid squares with black outline represent data for two reservoir simulations. (Botnen et al., 2009; Bromhal et al., 2005; Busch et al., 2003; Chikatamarla et al., 2004; Clarkson and Bustin, 1999; Day et al., 2008a; Durucan and Q., 2009; Fitzgerald et al., 2005; Fitzgerald et al., 2006; Goodman et al., 2007; Harpalani and Mitra, 2010; Harpalani et al., 2006; Jessen et al., 2008; Ozdemir and Schroeder, 2009; Reeves et al., 2005; Romanov and Soong, 2008; Ross et al., 2009; Siemons and Busch, 2007).

5. CO_2 Storage Efficiency for Resource Estimates

Carbon dioxide storage efficiency gauges the fraction of accessible pore volume that will be occupied by the injected CO_2. In open systems, the fraction of accessible pore volume is estimated by geologic terms (area, thickness, and porosity) and displacement terms (areal, vertical, gravity, and microscopic displacement) (Lake, 1989). Monte Carlo sampling techniques, as described in Sections 5.1 and 5.2, were used to estimate efficiency factors for CO_2 storage resource estimates for both saline formations and unmineable coal areas over the P_{10}, P_{50}, and P_{90} percent probability range. Efficiency in this methodology is comprised of statistical properties of geologic and displacement parameters.

5.1. Storage Efficiency of Saline Formations

For saline formations, the CO_2 storage efficiency factor is a function of geologic parameters, such as area ($E_{An/At}$), gross thickness ($E_{hn/hg}$), and total porosity ($E_{\phi e/\phi tot}$), that reflect the percentage of volume amenable to CO_2 sequestration and displacement efficiency components, such as areal (E_A), vertical (E_L), gravity (E_g), and microsocopic (E_d), that reflect different physical barriers that inhibit CO_2 from contacting 100 percent of the pore volume of a given basin or region (Bachu et al., 2007; Doughty and Pruess, 2004; Koide et al., 1992; Shafeen et al., 2004; van de Meer, 1992). Equation 5 describes the individual parameters required to estimate the CO_2 storage efficiency factor for saline formations:

$$E_{saline} = E_{An/At}\, E_{hn/hg}\, E_{\phi e/\phi tot}\, E_A\, E_L\, E_g\, E_d \qquad (5)$$

The net-to-total area $E_{An/At}$ ratio is the fraction of the total basin or region area that is suitable for CO_2 storage. The net-to-gross thickness $E_{hn/hg}$ ratio is the fraction of the total geologic unit that meets minimum porosity and permeability requirements for injection. The effective-to-total porosity $E_{\phi e/\phi tot}$ ratio is the fraction of total interconnected porosity (Table 4).

The areal displacement (E_A) efficiency is the fraction of planar area surrounding the injection well that CO_2 can contact. This term is influenced by areal geologic heterogeneity, such as faults or permeability, and by CO_2 mobility (Lake, 1989). The vertical (geologic layering) displacement (E_L) efficiency is the fraction of vertical cross section or thickness with the volume defined by the area (A) that can be contacted by the CO_2 plume from a single well, which can be affected by the aquifer dip and by CO_2 buoyancy (Lake, 1989). This term is influenced by variations in porosity and permeability between sub-layers in the same geologic unit. If one zone has higher permeability than other zones, the CO_2 will fill this zone quickly and leave the other zones with less or no CO_2. The gravity displacement (E_g) efficiency is the fraction of net thickness that is contacted by CO_2 as a consequence of the density and mobility difference between CO_2 and in situ water. In other words, 1-E_g is the portion of the net thickness not contacted by CO_2 because the CO_2 rises within the geologic unit. The microscopic displacement (E_d) efficiency is the fraction of water-filled pore volume that can be replaced by CO_2 (Lake, 1989). This term is directly related to irreducible water saturation in the presence of CO_2. For the areal, vertical, and gravity displacement terms, it is assumed that CO_2 fully displaces all in situ fluids. Since 100 percent displacement of fluid is neither theoretically nor technically feasible, the microscopic displacement term identifies the fraction of pore space unavailable due to immobile in situ fluids (Figures 2 and 3). The displacement terms are shown schematically in Figures 2 and 3 and compiled into Table 4.

Efficiency estimates using Monte Carlo sampling are based on statistical properties, such as mean values, standard deviation, ranges, and distributions, that describe geologic and displacement parameters. Little information is known regarding the statistical characteristics of saline formations because geologic parameters and formations are not well characterized (Bachu et al., 2007; Burruss et al., 2009; 2006, 2008, 2010b; Doughty and Pruess, 2004; Gorecki et al., 2009a; Gorecki et al., 2009b; Gorecki et al., 2009c; IEA, 2009). Recently, the International

Table 4: *Parameters for Saline Formation Efficiency*

Term	Symbol	P_{10}/P_{90} Values by Lithology			Description
		Clastics	Dolomite	Limestone	
Geologic terms used to define the entire basin or region pore volume					
Net-to-Total Area	$E_{An/At}$	0.2/0.8	0.2/0.8	0.2/0.8	Fraction of total basin or region area with a suitable formation.
Net-to-Gross Thickness	$E_{hn/hg}$	0.21/0.76*	0.17/0.68*	0.13/0.62*	Fraction of total geologic unit that meets minimum porosity and permeability requirements for injection.
Effective-to-Total Porosity	$E_{\phi e/\phi tot}$	0.64/0.77*	0.53/0.71*	0.64/0.75*	Fraction of total porosity that is effective, i.e., interconnected.
Displacement terms used to define the pore volume immediately surrounding a single well CO_2 injector					
Volumetric Displacement Efficiency	E_V	0.16/0.39*	0.26/0.43*	0.33/0.57*	Combined fraction of immediate volume surrounding an injection well that can be contacted by CO_2 and fraction of net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and in situ water.
Microscopic Displacement Efficiency	E_d	0.35/0.76*	0.57/0.64*	0.27/0.42*	Fraction of pore space unavailable due to immobile in situ fluids.

*Values from IEA (2009)

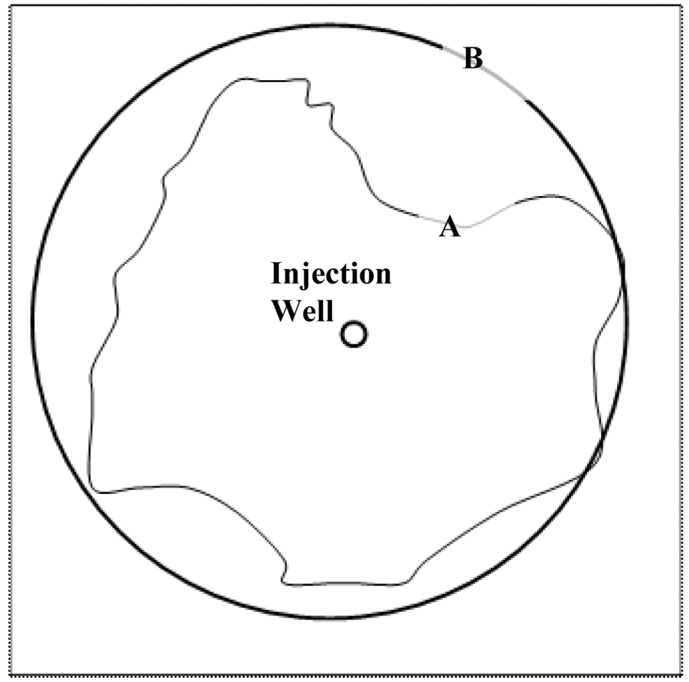

Figure 2: Top-view of injection well and plume area. The area within the irregular shape inside the circle is the areal view of the 3-dimensional CO_2 plume (A). The area inside the larger circle (B) is the accessible pore volume for areal displacement. The areal displacement term, E_A = net area contacted by CO_2 (A) / Total area (B).

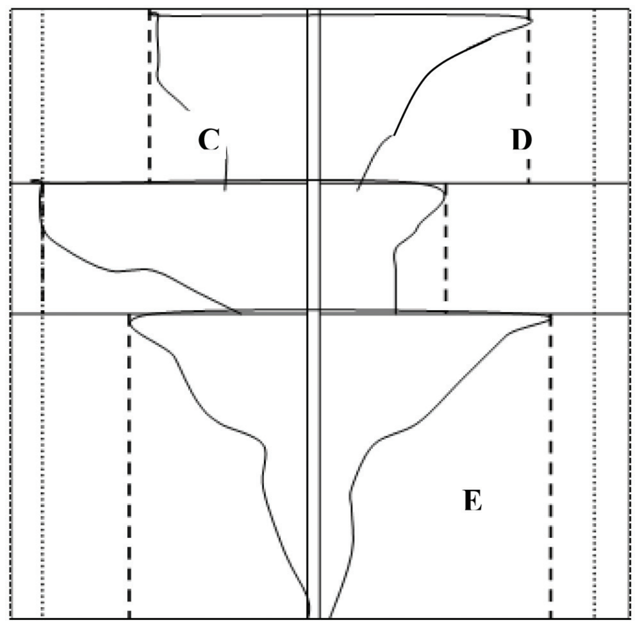

Figure 3: Side view of injection well and plume area. The outer vertical dotted lines are defined by the outer areal circle (Depicted by B in Figure 2). The "plume" area enclosed within each interval that is bound by vertical dashed lines represents the numerator of the E_L term (area enclosed within C); the denominator is the entire space outlined by the dotted line (area enclosed within D). Within the area bound by the dashed lines, the lower portion is not contacted due to gravity (area depicted by E) and is removed by the E_g term. The E_d term then defines the CO_2 displacement efficiency in the plume region.

Energy Agency (IEA [2009]) and Kopp et al. (2009a,b) used field data from oil and gas reservoirs and numerical simulations employing relative-permeability data for CO_2-brine systems measured in the laboratory (Bennion and Bachu, 2008) to predict appropriate ranges for geologic and displacement parameters for saline formations as a function of lithology. A similar report is also available from Gorecki et al. (2009a; 2009b; 2009c). It was assumed that saline formations do not differ fundamentally from oil and gas reservoirs (IEA, 2009; Kopp et al., 2009a). Table 4 includes values reported by IEA (2009) of the P_{10} and P_{90} ranges of geologic and displacement parameters for clastics, dolomite, and limestone lithologies for saline formations.[2] The P_{10} notation reflects that there is a 10 percent probability that the value is less than the P_{10} value, and the P_{90} notation reflects that there is a 90 percent probability that the value is less than the P_{90} value. Because of the difficulty in separating the E_A, E_L, and E_g displacement terms shown in eq 5 in a heterogeneous scenario, these terms were combined by IEA (2009) into a single volumetric displacement term, E_V.

In this methodology, efficiency, as estimated by Monte Carlo sampling, for saline formations was based directly on the P_{10} and P_{90} ranges for net-to-gross thickness $E_{hn/hg}$, effective-to-total porosity $E_{\phi e/\phi tot}$, volumetric displacement (E_v), and microsocopic displacement (E_d) as reported by IEA (2009) (Table 4). Because no documented data for the area $E_{An/At}$ term are available, it was assumed that CO_2 will occupy between 20 and 80 percent of the formation for the purposes of these simulations (DOE-NETL, 2006, 2008).The equation, parameters, symbols, ranges, and description used to calculate efficiency for saline formations are summarized by eq 6 and Table 4.

$$E_{saline} = E_{An/At}\, E_{hn/hg}\, E_{\phi e/\phi tot}\, E_v\, E_d \qquad (6)$$

The area $E_{An/At}$, thickness $E_{hn/hg}$, and porosity $E_{\phi e/\phi tot}$ terms gauge the percentage of volume that is amenable to CO_2 sequestration. The volumetric displacement term (E_v) corrects for the effective CO_2 plume shape. The microscopic displacement term (E_d) corrects for the accessible pore volume available to CO_2.

Efficiency (E_{saline}) was estimated from the individual terms in eq 6 by Monte Carlo sampling. Each individual term in eq 6 is given by a fraction, p. Various parametric distribution functions, such as normal, uniform, and lognormal, could be used to represent the distributions of the p's. Currently, there is not enough data available to support assigning a specific distribution function to each of the individual terms in eq 6 at the regional and national scale. Since the p's are fractions, they are constrained to the range between 0 and 1. Thus, the most appropriate distribution functions will be those that are constrained to the range between 0 and 1. Two distribution functions meeting this criterion and considered in this work are the beta distribution and the log-odds normal distribution. While both distributions are appropriate, the log-odds normal distribution, also known as the logistics-normal distribution (Aitchison and Shen, 1980), was chosen because of its ability to directly integrate the P_{10} and P_{90} ranges of geologic and displacement parameters provided by IEA (2009) as presented in Table 4. It was assumed that the individual efficiency terms in eq 6 could all be represented using a log-odds normal distribution at the regional and national scale. From the limited data available (IEA, 2009), all parameters were assumed to be independent since no correlation was found between the parameters. However, parameters may be linked at the site-specific scale.

The log-odds normal distribution transforms a fraction, p, by eq 7 and assumes that the transformed variable can be normally distributed.

$$X = \ln\left(\frac{p}{1-p}\right) \qquad (7)$$

The distribution is so named because the p/(1–p) term in eq 7 is the "odds" for a fraction or probability p; therefore, ln[p/(1–p)] is the "log odds." The use of this distribution is referred to as the log odds method when applied with Monte Carlo sampling (Devore, 2004). The transformed variable, X, is then normally distributed and sampled with Monte Carlo techniques. Then, the X value is transformed back to the corresponding p value by eq 8, which is the inversion of eq 7:

$$p = \frac{1}{1+e^{-X}} \qquad (8)$$

Since the relationship between eqs 7 and 8 is monotonic, X_{10} and X_{90} ranges of geologic and displacement parameters provided by IEA (2009) can be computed directly from P_{10} and P_{90} ranges, respectively, using eq 7.

The log odds approach thus transforms p values of a range into corresponding X values of a range. This allows the mean and standard deviation of X to be determined from the X_{10} and X_{90} values. The mean and standard deviation of X fully specify its normal distribution, and these moments are then used as input parameters into the Monte Carlo sampling tools. The P_{10} and P_{90} values of the ranges presented in Table 4 were converted to X_{10} and X_{90} values by eq 7 and are shown in Table 5.

Table 5: X_{10} and X_{90} Values Converted from P_{10} and P_{90} Values from Equation 7

X_{10} and X_{90} Values Converted from P_{10} and P_{90} Values	Clastics		Dolomite		Limestone	
	X_{10}	X_{90}	X_{10}	X_{90}	X_{10}	X_{90}
$E_{An/At}$	-1.4	1.4	-1.4	1.4	-1.4	1.4
$E_{hn/hg}$	-1.32	1.15	-1.59	0.75	-1.90	0.49
$E_{\phi e/\phi tot}$	0.58	1.21	0.12	0.90	0.58	1.10
E_V	-1.66	-0.45	-1.05	-0.28	-0.71	0.28
E_d	-0.62	1.15	0.28	0.58	-0.99	-0.32

2 Ranges of geologic and displacement parameters for clastics, dolomite, and limestone lithologies for saline formations were used directly from Table 11 found in the IEA (2009) report.

The mean (μ_x) and standard deviation (σ_x) are calculated from the X_{10} and X_{90} values using standard relationships between the percentiles and moments of a normal distribution

$$\sigma_X = \frac{(X_{90} - X_{10})}{(Z_{90} - Z_{10})} \quad (9)$$

$$\mu_X = X_{10} - \sigma_X Z_{10} \quad (10)$$

where Z_p is the P^{th} percentile value of the standard normal distribution. In this case, Z_{10} equals -1.28 and Z_{90} equals 1.28. Note that the standard deviation is computed first using eq 9, and this value is then used to compute the mean in eq 10. The values of the moments for X computed using eq 9 and 10 are shown in Table 6.

Table 6: μ_x and σ_x Values Calculated from X_{10} and X_{90} Values from Equations 9 and 10

μ_x and σ_x Values Calculated from X_{10} and X_{90} Values						
	Clastics		Dolomite		Limestone	
	μ_X	σ_X	μ_X	σ_X	μ_X	σ_X
$E_{An/At}$	0	1.1	0	1.1	0	1.1
$E_{hn/hg}$	-0.09	0.97	-0.42	0.91	-0.71	0.93
$E_{\phi e/\phi tot}$	0.89	0.25	0.51	0.30	0.84	0.20
E_v	-1.05	0.47	-0.66	0.30	-0.21	0.39
E_d	0.27	0.69	0.43	0.11	-0.66	0.26

Monte Carlo sampling, using the commercial program GoldSim, was run using the mean (μ_x) and standard deviation (σ_x) values tabulated in Table 6 as input parameters. The respective X values are sampled using normal distributions with a sample size of 5,000 iterations for each. The corresponding values of p are computed using eq 8, and the individual p values are multiplied together to determine the storage efficiency factor E as shown in eq 11:

$$E = p(E_{An/At})\, p(E_{hn/hg})\, p(E_{\varphi e/\sigma tot})\, p(E_v)\, p(E_d) \quad (11)$$

or equivalently,

$$E = \left(\frac{1}{1 + e^{-X(E_{An/At})}}\right)\left(\frac{1}{1 + e^{-X(E_{hn/hg})}}\right)\left(\frac{1}{1 + e^{-X(E_{\varphi e/\sigma tot})}}\right)\left(\frac{1}{1 + e^{-X(E_v)}}\right)\left(\frac{1}{1 + e^{-X(E_d)}}\right)$$

A value of E is thus obtained for each of the 5,000 simulations, and the overall percentiles for the computed E are then estimated. Ranking from smallest to largest, the 500th result corresponds to P_{10}, the 2,500th result corresponds to P_{50}, and the 4,500th result corresponds to P_{90}. These results are shown in Table 7.

Table 7: Saline Formation Efficiency Factors For Geologic and Displacement Terms

Saline Formation Efficiency Factors for Geologic and Displacement Terms $E_{saline} = E_{An/At}\, E_{hn/hg}\, E_{\phi e/\phi tot}\, E_v\, E_d$			
Lithology	**P_{10}**	**P_{50}**	**P_{90}**
Clastics	0.51%	2.0%	5.4%
Dolomite	0.64%	2.2%	5.5%
Limestone	0.40%	1.5%	4.1%

The overall efficiency for saline formations ranges from 0.40 to 5.5 percent for the three different lithologies over the 10 and 90 percent probability range, respectively. These efficiency factors are based on documented ranges derived from oil and gas reservoirs and numerical simulations (IEA, 2009). With previous versions of the *Carbon Sequestration Atlas of the United States and Canada*, geologic and displacement parameters were not based on documented ranges (DOE-NETL, 2006, 2008). These saline formation efficiency factors ranged between 1 and 4 percent over the P_{15} and P_{85} percent probability range (DOE-NETL, 2006, 2008). When undocumented ranges for saline formations for previous editions of the Atlas (DOE-NETL, 2006, 2008) were applied using the log odds method described here, the P_{10}, P_{50}, and P_{90} percent probability ranges were 0.51 percent, 2.0 percent, and 5.5 percent, respectively. While the two sets of input ranges generate similar overall efficiency factors for saline formations, the efficiency factors reported here are based on documented P_{10} and P_{90} ranges of geologic and displacement parameters for clastics, dolomite, and limestone lithologies and appropriate distribution functions, log-odds normal in this case, that are constrained to the range between 0 and 1 whereas previous efficiencies were not.

In the case where net-to-total area $E_{An/At}$, net-to-gross thickness $E_{hn/hg}$, and effective-to-total porosity $E_{\phi e/\phi tot}$ are known for a region or basin, the geologic efficiency values can be used directly in eq 6. In this instance, only the displacement efficiency factor is needed, which ranges between 7.4 and 26 percent over the 10 and 90 percent probability range (Table 8).

Overall, CO_2 storage resource estimates for saline formations are calculated from volumetric parameters (eq 2) and efficiency factors (eq 6) over the P_{10}, P_{50}, and P_{90} percent probability range (Tables 7 and 8).

$$G_{CO2} = A_t\, h_g\, \phi_{tot}\, \rho E_{saline} \quad (2)$$

$$P_{10} \quad E_{saline} = E_{An/At}\, E_{hn/hg}\, E_{\phi e/\phi tot}\, E_v\, E_d \quad (6)$$

$$P_{50} \quad E_{saline} = E_{An/At}\, E_{hn/hg}\, E_{\phi e/\phi tot}\, E_v\, E_d$$

$$P_{90} \quad E_{saline} = E_{An/At}\, E_{hn/h}g\, E_{\phi e/\phi tot}\, E_v\, E_d$$

Table 8: Saline Formation Efficiency Factors for Displacement Terms

Saline Formation Efficiency Factors for Displacement Terms $E_{saline}{}^{*} = E_v E_d$			
Lithology	P_{10}	P_{50}	P_{90}
Clastics	7.4%	14%	24%
Dolomite	16%	21%	26%
Limestone	10%	15%	21%

*$E_{An/At}$, $E_{hn/hg}$, and $E_{\phi e/\phi tot}$ values are known directly

Table 9. Parameters for Unmineable Coal Area Efficiency

Term	Symbol	P_{10}/P_{90} Values	Description
Geologic terms used to define the entire basin or region pore volume			
Net-to-Total Area	$E_{An/At}$	0.6/0.8	Fraction of total basin or region area that has bulk coal present.
Net-to-Gross Thickness	$E_{hn/hg}$	0.75/0.90	Fraction of coal area thickness that has adsorptive capability.
Displacement terms used to define the pore volume immediately surrounding a single well CO_2 injector			
Areal Displacement Efficiency	E_A	0.7/0.95	Fraction of the immediate area surrounding an injection well that can be contacted by CO_2.
Vertical Displacement Efficiency	E_L	0.8/0.95	Fraction of the vertical cross section (thickness), with the volume defined by the area (A) that can be contacted by a single well.
Gravity	Eg	0.9/1.0*	Fraction of the net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and the in situ water in the cleats.
Microscopic Displacement Efficiency	E_d	0.75/0.95	Reflects the degree of saturation achievable for in situ coal compared with the theoretical maximum predicted by the CO_2 Langmuir Isotherm.

*0.999999999999999 used due to inability to divide by zero when using log odds method.

P_{10} and P_{90} serve as nominal lower and upper bounds that demark a plausible range of efficiency factors, defined in a consistent probabilistic manner. If the 10th and 90th percentile values of the individual terms are properly specified for the targeted application, such as geologic storage, and the distributions for each term are independent and reasonably represented by the log-odds normal assumption, then the computed 10th and 90th percentile values for efficiency factors are properly estimated. However, because these limits are based on a combination of data with varying quality and expert judgment, the P_{10} and P_{90} limits should be interpreted as general, rather than strictly mathematical, limits. That is, with reasonable 10th and 90th percentile limits chosen for each factor, the results provide reasonable 10th and 90th percentile limits for efficiency factors.

5.2. Efficiency of Unmineable Coal Areas

For coal areas, the CO_2 storage efficiency factor is a function of geologic parameters, such as area ($E_{An/At}$) and thickness ($E_{hn/hg}$), which reflect the percentage of volume that is amenable to CO_2 geologic storage and displacement efficiency components, such as areal (E_A), vertical (E_L), gravity (E_g), and microscopic (E_d), which reflect the portion of a basin's or region's coal bulk volume that CO_2 is expected to contact (Bachu et al., 2007; Doughty and Pruess, 2004; Koide et al., 1992; Shafeen et al., 2004; van de Meer, 1992). The effective-to-total porosity term is not applicable in coal areas. Equation 12 describes CO_2 storage efficiency for coal areas:

$$E_{coal} = E_{An/At}\, E_{hn/hg}\, E_A\, E_L\, E_g\, E_d \qquad (12)$$

The area ($E_{An/At}$) and thickness ($E_{hn/hg}$) terms gauge the portion of a basin's volume that coal is present. The volumetric displacement terms (E_A, E_L, and E_g) identify the portion of the in situ coal volume that CO_2 is accessible. The microscopic displacement term (E_d) identifies the degree of CO_2 saturation (with respect to the maximum predicted by the Langmuir isotherm) within the CO_2-accessible.

The net-to-total area $E_{An/At}$ ratio is the fraction of total basin or region area that has bulk coal present. This term accounts for known or suspected locations that are within a basin or region outline where a coal area may be discontinuous. In the Illinois Basin, for example, there are subregions within the basin where sand channels have incised and replaced coal (DOE-NETL, 2008). The net-to-gross thickness $E_{hn/hg}$ ratio is the fraction of total coal area thickness that has adsorptive capability. The areal displacement (E_A) efficiency is the fraction of the immediate area surrounding an injection well that can be contacted by CO_2. This term is influenced by areal geologic heterogeneity such as faults and permeability anisotropy. The vertical displacement (E_L) efficiency is the fraction of the vertical cross section or thickness, with the volume defined by the area (A) that can be contacted by CO_2 from a single well. This term is influenced by variations in the cleat system within the coal. If one zone has higher permeability than other zones, the CO_2 will fill it quickly and leave the other zones with less or no CO_2. The gravity displacement (E_g) efficiency is the fraction of the net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and in situ water in the cleats. In other words, 1-E_g is the portion of the net thickness not contacted by CO_2 because the CO_2 rises within the coal area. The microscopic displacement (E_d) efficiency reflects the degree of saturation achievable for in situ coal compared with the theoretical maximum predicted by the CO_2 Langmuir Isotherm.

Because there is no documented database describing the statistical properties of coal areas, Monte Carlo simulations of storage efficiency for coal areas are based tentatively on coalbed methane production and computer modeling observations (DOE-NETL, 2006, 2008). In comparison with efficiency terms for saline formations, coal area efficiency terms for area and thickness are increased because most coal basins are better defined than saline formations. Displacement efficiency terms for coal are also much higher than similar terms for porous media found in saline formations due to the adsorptive nature of coal. The gravity displacement term will likely be insignificant since coal areas are typically thinner than saline formations. Although it is known that coal swells in the presence of CO_2 and causes a reduction in permeability, coal swelling is not included in the efficiency equation at this time (Day et al., 2008b; Xie and Economides, 2009). The equation, parameters, symbols, ranges, and description used to calculate the storage efficiency factor for coal areas are summarized by eq 12 and Table 9.

Efficiency factors for coal areas were determined by using the log odds method when applied with Monte Carlo sampling by eqs 7–11 as described in the Section 5.1 (Devore, 2004). The overall storage efficiency factor for coal areas ranges from 21 to 48 percent over the 10 and 90 percent probability range (Table 10). In the case where net-to-total area $E_{An/At}$ and net-to-gross thickness $E_{hn/hg}$ are known for an unmineable coal area, the geologic efficiency values can be used directly in eq 12. In this instance, only the displacement efficiency factor is needed, which ranges between 39 and 77 percent over the 10 and 90 percent probability range (Table 11).

Overall, CO_2 storage resource estimates for unmineable coal areas are calculated from volumetric parameters (eq 3) and efficiency factors (eq 12) over the P_{10}, P_{50}, and P_{90} percent probability range (Tables 10 and 11).

Table 10: Coal Area Efficiency Factors

Coal Area Efficiency Factors $E_{coal} = E_{An/At}\,E_{hn/hg}\,E_A\,E_L\,E_g\,E_d$		
P_{10}	P_{50}	P_{90}
21%	37%	48%

Table 11: Coal Area Efficiency Factors for Displacement Terms

Coal Area Efficiency Factors for Displacement Terms $E_{coal}{}^{*} = E_A\,E_L\,E_g\,E_d$		
P_{10}	P_{50}	P_{90}
39%	64%	77%

*$E_{An/At}$ and $E_{hn/hg}$ values known directly

$$G_{CO2} = A\,h_g\,C_{s,max}\,\rho_{CO2std}\,E_{coal} \quad (3)$$

$$P_{10} \quad E_{coal} = E_{An/At}\,E_{hn/hg}\,E_A\,E_L\,E_g\,E_d \quad (12)$$

$$P_{50} \quad E_{coal} = E_{An/At}\,E_{hn/hg}\,E_A\,E_L\,E_g\,E_d$$

$$P_{90} \quad E_{coal} = E_{An/At}\,E_{hn/hg}\,E_A\,E_L\,E_g\,E_d$$

P_{10} and P_{90} serve as nominal lower and upper bounds that demark a plausible range of efficiency factors, defined in a consistent probabilistic manner. If the 10^{th} and 90^{th} percentile values of the individual terms are properly specified for the targeted application, such as geologic storage, and the distributions for each term are independent and reasonably represented by the log-odds normal assumption, then the computed 10^{th} and 90^{th} percentile values for efficiency factors are properly estimated. However, because these limits are based on a combination of data with varying quality and expert judgment, the P_{10} and P_{90} limits should be interpreted as general, rather than strictly mathematical, limits. That is, with reasonable 10^{th} and 90^{th} percentile limits chosen for each factor, the results provide reasonable 10^{th} and 90^{th} percentile limits for efficiency factors.

6. Summary and Conclusions

A summary of the methodology for estimating CO_2 storage resource potential for geologic CO_2 storage in *Atlas III* is presented. The RCSPs used this methodology for determining CO_2 storage resource estimates for three types of geologic formations: oil/gas reservoirs, saline formations, and unmineable coal areas. These CO_2 storage resource estimates are based on physically accessible CO_2 storage pore volume in formations and on the assumption that the storage reservoirs are open systems in which the in situ fluids will either be displaced from the injection zone or managed. Economic and regulatory constraints are not considered; hence site-specific assessments should not be performed using this methodology. Carbon dioxide storage resource estimates are intended for use by external users, such as RCSPs, future project developers, and governmental entities, for high-level assessments of potential CO_2 storage reservoirs in the United States and Canada at the regional and national scale.

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