CO_2 Storage Resource Assessment Methodologies: Current Status and Comparative Analysis

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1. Introduction

Basin-scale carbon dioxide (CO_2) storage resource assessments in one form or another have been conducted for about two decades. Today, there is increased emphasis on the presence, extent, potential volume, and cost to develop geologic sequestration resources; this work will no doubt define the spatial distribution of Carbon Capture and Sequestration (CCS) technologies. The need to make accurate and clearly understandable assessments that can be used by government and industry to plan for technology deployment has never been greater.

Through the Regional Carbon Sequestration Partnerships, the U.S. Department of Energy (DOE) has performed a high level estimate of sequestration resource for the continental United States and has estimated that the resource is sufficient to sequester between 1,856 and 20,473 billion metric tons of CO_2 onshore in the U.S. (Table 1). The DOE evaluated CO_2 sequestration resources, defined as the volume of porous and permeable sedimentary rocks available for CO_2 sequestration and accessible for injected CO_2 through wellbores. The DOE provided an assessment for three major types of reservoirs: deep saline formations, unmineable coal sreams, and oil and gas reservoirs.

Table 1. DOE's estimates of CO_2 sequestration potential in North America (billion metric tons).
Source: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/2010AtlasIII_Intro-National.pdf

Reservoir Types	Low	High
Deep Saline Formations	1,653	20,213
Unmineable Coal Seams	60	117
Oil and Gas Fields	143	143
Total	1,856	20,473

The CO_2 sequestration capacity that can actually be used is a subset of the total resource, constrained by external factors, much as oil and gas reserves are a subset of the total resource (McKelvey, 1972). Capacity assessments must include economic, legal, and regulatory constraints on physical sequestration resource estimates. Under the most favorable geologic, economic, and regulatory scenarios, 100 percent of the estimated CO_2 sequestration resource may then be considered CO_2 capacity (Bradshaw, J., S. Bachu, et al., 2007). These scenarios are unlikely, however; as such ideal conditions are rarely present.

This study compares three CO_2 storage assessment methodologies: the approach applied by the U.S. Department of Energy (DOE) in its Carbon Atlas III (NETL, 2010); the modified U.S. Geological Survey (USGS) methodology (Brennan et al., 2010); and the CO_2 Geological Storage Solutions (CGSS) methodology (Spencer et al., 2011).

AAPG Search and Discovery Article #90142 © 2012 AAPG Annual Convention and Exhibition, April 22-25, 2012, Long Beach, California

Captured CO_2 can be stored in different types of subsurface geologic formations. To be suitable for carbon sequestration, geologic media must have (1) sufficient capacity and injectivity and (2) a structure that will preclude CO_2 return to the atmosphere for geologically long periods of time. Geologic environments that could be potentially used as permanent repositories for anthropogenic CO_2 include depleted/depleting oil and gas reservoirs, deep saline formations, unmineable coal beds, and – potentially - shale and basalt formations. All three methodologies listed above address storage resources in porous geologic media in sedimentary basins, namely oil and gas reservoirs and saline formations. Methods to estimate the CO_2 storage potential of unmineable coal areas, shale and basalt are not considered in this article.

When CO_2 is injected into porous media, there are multiple physical phenomena that "trap" the fluid in the geologic formation. There are a number of studies that examine the mechanisms of CO_2 trapping in the subsurface (Burton et al., 2009, Bennion, et al., 2006, and Metz et al., 2005). Metz et al. (2005) describe four of these trapping mechanisms: structural and stratigraphic trapping (physical), residual CO_2 trapping (physical), solubility trapping (geochemical) and mineral trapping (geochemical). The time scales associated with geochemical trapping mechanisms are much larger than those of physical trapping mechanisms and become important when talking about very long-term retention (i.e., greater than thousands of years).

2. Estimation of sequestration resource and capacity

2.1. Concepts and approaches

Methodical evaluation of geologic CO_2 sequestration resources at large scales dates back nearly two decades, thus there is a substantial body of literature examining sequestration potential at the national, regional or basin levels (van der Meer, 1992; Bergman & Winter, 1995; Bradshaw et al., 2004; Dilmore, et al., 2008; NETL, 2006, 2008, 2010; Michael et al., 2009[a,b]; Frailey, 2009[a,b]; Burruss et al., 2009; Brennan et al., 2010; Dahowsky et al., 2010, Goodman et al., 2011). Studies on sequestration resource evaluation at a basin scale help us to understand how CCS technologies may work in theory; in other words, these studies provide a preliminary assessment of the prospective impact of CCS technology deployment on CO_2 emission reduction at the national or regional level. The value of these studies is to inform decision makers as to whether CCS is a climate mitigation option worth pursuing in those regions (Dooley, 2010).

Some published studies examine analytical equations as a means of providing a quick spatial characterization of a CO_2 plume using minimal information for a given range of reservoir conditions. Nordbotten et al. (2005) present a solution for viscosity-dominated regimes. Denz and Tartakovsky (2008) introduce an analytical expression and use a calculation technique to account for buoyancy-dominated regimes. Szulczewski and Juanes (2009) present a sharp-interface mathematical model of CO_2 migration in deep saline formations, which accounts for gravity override, capillary trapping, natural groundwater flow, and the shape of the plume during the injection period. The main outcome is an analytical equation that defines the ultimate footprint of the CO_2 plume and the time scale required for complete trapping. The model is suitable for storage resource estimates by capillary trapping at the basin scale.

Other models have been developed to examine the amount of CO_2 that can be sequestered given constraints on reservoir pressure (Zhou et al., 2008, Mathias et al., 2009). Because these types of analytical models consider pressure, they also allow injectivity constraints on capacity to be considered - that is, the rate at which CO_2 can be injected into a specific geological formation is limited by pressure conditions.

Models considering injectivity or the spatial extent of injected CO_2 require a significant amount of information on reservoir properties and, as such, may only be applied in cases where reservoir parameters are well known, e.g., for screening candidate reservoirs for a specific CO_2 sequestration project. For the assessment of sequestration potential of deep saline formations on a basin scale, implementation of analytical techniques is difficult because little is typically known about the formation(s)' subsurface structure and the reservoir properties.

There is also a body of work that examines issues relating to CCS regulation. The CCSReg project (CCSReg, 2009; 2010) examined the technical capabilities, legal framework, regulatory rulemaking, and administrative procedures that must be developed to make deep geological sequestration of CO_2 a practical reality in the United States. They consider issues such as safety, environmental quality, reliability, liability, cost-effectiveness, project financing and management, long-term stewardship, and political and social feasibility associated with the life-cycle of a CCS project. Such findings are necessary for storage capacity assessments, which include economic, legal, and regulatory constraints on physical sequestration resource estimates.

Ideally CO_2 storage resource estimates should be made on the basis of detailed geological and geophysical analysis and modeling. However, high-level assessments are required to understand where public and private resources should be focused, as well as provide a regional understanding of the role that CCS can play in reducing emissions. While site assessments require detailed geological and reservoir simulation modeling to determine if the site has the capacity to contain the volumes proposed for injection, basin-scale estimates need a more general, more aggregate approach to allow high-level assessment of the total potential resource. When a CO_2 sequestration industry emerges, storage resource and capacity estimates will be considered a commodity. The relationship between resource and capacity is much like the relationship between "resources" and "reserves" in the National Oil and Gas Assessment (NOGA) classification (DOI, 2008), but with the additional caveat that CO_2 storage capacity estimates must meet economic and regulatory requirements at the time of the storage assessment.

Specifically, resources are estimated quantities of a commodity that exist at a given time within a given geographic area or jurisdiction. Resources are of two types - discovered (in-place) and undiscovered (inferred). Reserves are estimated quantities of a commodity that are known to exist and economically recoverable from known accumulations. Technology, economic, and regulation cutoffs are used to define reserves as a subset of resources. Similarly, a CO_2 resource estimate is defined as the volume of porous and permeable sedimentary rocks that is accessible to injected CO_2 via drilled and completed wellbores and includes estimates of geologic storage reflecting physical constraints, but does not include economic or regulatory constraints. A CO_2 capacity estimate includes economic and regulatory constraints, such as land use, minimum well spacing, maximum injection rate and pressure, number and type of wells, operating costs, and proximity to a CO_2 source.

The methodologies explored in this article - DOE (NETL, 2010), USGS (Brennan et al, 2010), and CGSS (Spencer et al., 2011) - classify a CO_2 resource as a volume of porous sedimentary rocks available for CO_2 storage and accessible to injected CO_2 under current technologies. In other words, these methodologies address the technically accessible resource that may be available using present-day geological and engineering knowledge and technology for CO_2 injection into geologic formations. The investigated methodologies are not intended for CO_2 storage capacity assessment.

The DOE, USGS, and CGSS methodologies consider only physical CO_2 trapping mechanisms (i.e., structural, stratigraphic, and residual trapping), not geochemical trapping mechanisms (i.e., solubility and mineral trapping). Because time scales associated with geochemical trapping mechanisms are much larger than those of physical trapping mechanisms, the former play an important role only when considering very long-term retention (i.e., hundreds to thousands of years) (Burton et al., 2009, Bennion et al., 2006, and Metz et al., 2005). Since these three methodologies are intended to assess CO_2 storage resource available for immediate use. For these reasons, then, dissolution in brine and mineral precipitation are not considered in the estimates presented herein.

Methods for estimating subsurface volumes in porous and permeable geologic formations used by these approaches are widely applied in the oil and gas industry, for underground natural gas storage, groundwater assessments, and the underground disposal of fluids. By and large, these methods can be divided into two categories: static and dynamic. While dynamic methods involve injection volumes and reservoir pressure calculations, static models require only rock and fluid properties. Static methods include volumetric models and compressibility; dynamic methods utilize decline curve analyses, mass (or volumetric) balance, and reservoir simulation results.

All three methodologies address two boundary condition assumptions: open and closed systems. Open boundary conditions imply that in situ formation fluids are displaced away from the injection well into other parts of the formation or into adjacent formations. Conversely, closed systems are fluid-filled formations where fluid movement is restricted within the formation boundaries by impermeable barriers. Storage volume in the closed system is constrained by the compressibility of the formation's native fluids and rock matrix. It is difficult to collect hydrodynamic data on a basin-scale level to characterize closed system boundary conditions. Expectedly, the authors of the three methodologies evaluated in this article base their storage resource calculations on open systems in which in-situ fluids are either displaced away from the injection zone into other parts of the formation or otherwise managed.

Since detailed site injectivity and pressure data are generally not available prior to CO_2 injection or collection of field measured injection rates and pressure dynamics, all three methods use static volumetric models based on commonly accepted assumptions about in-situ fluid distribution in porous media and fluid displacement processes.

The volumetric methods employ a relatively simple description of (a) formation topology that includes formation thickness and area, (b) formation porosity, and (c) some type of factor that reflects the pore volume that injected CO_2 can fill.

2.2. Applicability

Subsurface units suitable for geologic CO_2 sequestration are regarded as those located approximately 800 meters (m) (2,625 feet (ft)) or more below ground surface, so that the increased pressure and temperature at depth are in excess of the critical point of CO_2. This means that CO_2 injected at these temperatures and pressures will be in the supercritical condition. Fluids in the supercritical state, including CO_2, typically exhibit gas-like viscosity, reducing resistance to flow relative to a liquid, and liquid-like density, reducing the volume required to store a given mass of fluid. CO_2 exists as a supercritical fluid at a temperature and a pressure above a critical point: 304 Kelvin (K) (31.0° Celsius (C)) and 7.38 Megapascal (MPa) (73.8 bar), respectively. The 800-m (2,625-ft) criterion is only an approximation, and varies somewhat depending on the geothermal gradient and formation pressure at a given site (Bachu, 2003).

While the CGSS approach does not recommend any specific screening criteria, the DOE and USGS methodologies clearly define requirements for the formation depth. DOE recommends taking into consideration only formations deeper than 800 m (2,625 ft) (or the depth needed to ensure that CO_2 is in a supercritical phase), but does not explicitly specify a lower depth limit. USGS recommends formation depth limits of 914 m (2,999 ft) and 3,962 m (13,999 ft). The lower vertical limit for a potential storage formation of 3,962 m (13,999 ft) is based on the imputed CO_2 injection depth at pipeline pressures without additional compression at the surface (Burruss at al., 2009). Additionally, both methodologies recommend excluding from CO_2 resource estimates those formations with water having a salinity less than 10,000 milligrams per liter (mg/l) (or parts per million (ppm)) total dissolved solids (TDS) regardless of depth, to ensure that potentially potable water-bearing units according to the Safe Drinking Water Act are not included or potentially affected by sequestration activities (Environmental Protection Agency, 2009).

2.3. Findings

In this section we present the results of our comparative study of three CO2 storage assessment methodologies used by the DOE, USGS, and CGSS. Tables 4-8 provide side-by-side comparisons across methodologies in terms of physical setting, physical processes, key equations/input parameters, and storage efficiencies.A

With respect to physical setting (Table 2), the investigated methodologies are designed to assess permeable formations occurring in sedimentary basins. Even so, these entities use different language to define an assessment unit/formation. The DOE methodology discriminates oil and gas fields and saline formations; the USGS methodology defines storage formations within storage assessment units; and the CGSS methodology identifies basin-scale reservoirs as permeable formations. The DOE and USGS methodologies are consistent with a resource-reserve pyramid concept, while the authors of the CGSS methodology do not structure their approach in terms of this framework.

Table 2. Physical setting.

	DOE	USGS	CGSS
Regional setting	Sedimentary basins	Sedimentary basins subdivided into storage assessment units (SAUs)	Sedimentary basins
Assessment unit/ formation	Oil and gas fields Deep saline formations	Storage Formations (SFs)	Reservoirs as permeable formations

Regarding physical processes (Table 3), the DOE methodology references structural and stratigraphic trapping as the dominant mechanism for retaining CO_2 in oil and gas fields, and residual trapping as the dominant mechanism in saline formations. The USGS methodology differentiates buoyant (structural and stratigraphic) trapping and residual trapping within storage formations. What the USGS refers to as residual trapping is not the same as what DOE means by the same term. In the USGS method, any pore space that is not found in a

known dry structural or stratigraphic trap is treated as residual pore space (whether or not the principle trapping mechanism is residual phase trapping). Thus, the USGS is using different storage efficiencies to account for a lack of knowledge about the subsurface rather than making a judgment about what mechanism is at play in trapping CO_2. Unlike these two approaches, the CGSS methodology considers only residual trapping.

Table 3. Physical processes.

	DOE	USGS	CGSS
Trapping mechanism	Structural and stratigraphic trapping for oil and gas fields Residual trapping for saline formations	Buoyant trapping (structural and stratigraphic) within SFs Residual trapping within SFs	Residual trapping through migration assisted storage (MAS) trapping
Operating time frames	Months to thousands of years	Months to thousands of years	Months to thousands of years
Boundary conditions	Open system	Open system	Open system

All three methodologies discuss the boundary condition assumptions: the two endpoints defined for potential CO_2 storage reservoirs are open and closed. However, it is difficult or impossible to collect hydrodynamic data on a basin-scale level to characterize closed system boundary conditions. Hence, the authors of the proposed methodologies base their storage resource calculations on open systems in which in-situ fluids are either displaced away from the injection zone into other parts of formation or managed.

In terms of dealing with uncertainty the DOE and USGS methodologies are probabilistic approaches, meaning that both methodologies use Monte Carlo simulation for estimating formation parameters. Conversely, the CGSS approach relies on a geological prospectivity of sedimentary basins and detailed geological data and apply geological, geophysical, and chemical constrains; in other words, the CGSS methodology is deterministic.

The methodologies proposed by DOE for oil and gas fields and USGS for buoyant trapping in storage formations use static volumetric methods for estimating subsurface CO_2 storage resource. These methods rely on parameters that are related to the geologic description of an assessment formation, e.g. thickness, porosity, temperature, and pressure. The DOE equation for calculation of CO_2 storage resource is based on geometry of the reservoirs (reservoir area and thickness) and water saturation as given in reserve databases. The CO_2 storage efficiency factor involves the original oil and gas in-place and recovery factor and can be derived based on experience, especially in the cases where good production records are available. The alternate USGS volumetric equation is a production-based formula where CO_2 storage resource is calculated on the basis of reservoir properties such as original oil and gas in-place, recovery factor, and in situ CO_2 density defined by reservoir temperature and pressure. It also requires reliable production records - the volume of known recovery of petroleum, scaled to subsurface volume, particularly when cumulative production is greater than original oil and gas in place. In addition, according to the USGS methodology buoyant trapping storage resource in storage formations includes the mass of CO_2 that can be stored in dry traps. Comparing the two methodologies, we have identified several analogies and distinctions:

- Static volumetric storage of CO_2 in free phase is considered by both methodologies.

- Methods for CO_2 storage resource calculation are production-based for both approaches, although the DOE equation is based on reservoir geometry and properties, as well as oil and gas production data. Unlike the DOE formula, the USGS equation does not require reservoir area and thickness; it utilizes known recovery of oil and gas and reservoir properties.
- The DOE methodology does not explicitly include the volume of dry traps (without petroleum production) in CO_2 storage resource estimates for oil and gas fields. On the other hand, the USGS approach incorporates the volume of dry traps into the CO_2 storage resource for buoyant trapping in storage formations, where data are available.
- As for storage efficiency, both methodologies use the buoyant trapping (oil and gas fields under the DOE classification) storage efficiency based on known production data.

CO_2 storage resource assessment methodologies developed by the DOE for saline formations, USGS for residual trapping in storage formations, and CGSS for migration assisted storage trapping in basin-scale porous reservoirs are computationally equivalent and use volumetric-based CO_2 storage estimates. The volumetric models rely on parameters that are directly related to the geologic description of the sedimentary basin and formation properties: area, thickness, porosity, temperature, and pressure, where the last two parameters define CO_2 density at in situ conditions. We find both similarities and differences among the methodologies:

- The DOE methodology considers an assessment formation as an undivided unit and provides storage resource calculations for the formation as a whole, while the USGS methodology subdivides a storage formation into three rock classes or ‘injectivity category allotments’ on the basis of permeability. CO_2 storage resource is determined for each class; consequently, the computed values are summed iteratively to calculate the total residual trapping storage resource. Unlike the DOE and USGS approaches, the CGSS methodology assumes that in the process of the MAS trapping only 15 m of formation thickness is affected by the migrating CO_2 plume.
- Storage efficiency: the proposed methodologies introduce storage efficiency factors in calculations. The DOE methodology provides a range of values of storage efficiency for saline formations, which are between 0.51 and 5.5%. On the other hand, the USGS methodology suggests that for calculation of residual trapping CO_2 storage resource, a specific range of storage efficiency values should be applied for each rock class (Table 4).
- Unlike the DOE and USGS approaches, the CGSS methodology assumes that only a thin layer beneath the seal will be affected by the migrating plume. A generic thickness migrating plume used in the Queensland Atlas is 15 m. MAS reservoir efficiency factors are calculated for each assessment unit: the thicker the reservoir the smaller this number will be, so the derived storage efficiency factors are typically more than an order of magnitude less than what the DOE and USGS methodologies suggest (Table 4). For these reasons, the CGSS approach would produce the most conservative storage estimates if applied for the same assessment formation.

Table 4. Storage efficiency comparison.

	DOE	**USGS**	**CGSS**
Storage efficiency	Oil and gas fields	Storage Formation Buoyant trapping	NA
	10-60% formation specific efficiency, based on oil recovery factor for the given field	10-60% formation specific efficiency, based on oil recovery factor for the given field	-
Storage efficiency	Saline formations	Storage Formation Residual trapping	Permeable Formation Residual trapping
	0.4-5.5 %	1 - 7% for Rock class I 1 - 15% for Rock class II 0 - 7% for Rock class III	0.10 - 0.15%

3. Conclusions and Summary

Prior efforts to assess CO_2 storage resource used an array of approaches and methodologies, employing data sets of variable size and quality and resulting in a broad range of estimates with a high degree of uncertainty. Through its Regional Carbon Sequestration Partnership Program, the DOE developed standards for CO_2 storage resource estimation in oil and gas fields and deep saline formations for producing a Carbon Sequestration Atlas of the United States and Canada. In parallel, the USGS generated a report that provides a coherent set of methods for estimating CO_2 sequestration resource in storage formations including buoyant and residual trapping. In addition, the CGSS recommended a methodology for assessing CO_2 storage resource in basin-scale porous reservoirs, which was utilized in the 2009 Queensland CO_2 Geological Storage Atlas. A concise comparison of these methodologies is provided in Table 5.

Table 5. Comparison at a glance.

	DOE	USGS	CGSS
Regional setting	Sedimentary basins	Sedimentary basins subdivided into storage assessment units (SAUs) that contain storage formations (SFs)	Sedimentary basins
Trapping mechanism	Structural and stratigraphic trapping for oil and gas fields Residual trapping for saline formations	Buoyant trapping (structural and stratigraphic) within SFs Residual trapping within SFs	Residual trapping through migration assisted storage (MAS) trapping
Equations/ methods	Volumetric	Volumetric	Volumetric
Resource-reserve pyramid concept	Consistent	Consistent	Not specified
Dealing with uncertainty	Probabilistic	Probabilistic	Deterministic

Based on our analyses, these methodologies are similar in terms of computational formulation. Specifically, the explored methodologies use static volumetric methods to calculate CO_2 storage resource in open systems and are applicable at either regional or basin-scale levels. The methodologies, however, are not intended for site screening and selection. Siting of specific CCS facilities requires estimates of storage resource capacity for candidate formations, based on numerical modeling that takes into consideration the site-specific CO_2 injection rates, reservoir properties, and dynamics of the CO_2 plume.

We find that each of the proposed methodologies is science- and engineering-based. As such, they are important in identifying the geographical distribution of CO_2 storage resource and regional carbon sequestration potential at the national and basin-scale levels for use in energy-related government policy and business decisions. Policy makers need these high level estimates to evaluate the prospective role that CCS technologies can play in reducing nation's or region's CO_2 emissions over long term. The value of these high level assessments of CO_2 storage resource is to help inform decision makers in governments and industry as to whether CCS is a climate mitigation option worth pursuing in particular regions.

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