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Contributing Paper: Geologic Sequestration of Carbon Dioxide in the Next 10 to 50 Years: An Energy Resource Perspective

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I. Introduction

The three main options for geologic sequestration of carbon dioxide are storage in depleted oil and gas reservoirs, in salt-water formations, and in coalbeds. Benson (this volume) discusses the potential role of geologic sequestration in a portfolio of carbon management options to decrease emissions of carbon dioxide to the atmosphere. Each of the options is currently undergoing field trials ranging in size from a few thousand metric tons of total injected CO_2 to large projects like Sleipner and Weyburn that each inject about one million metric tons of CO_2 per year and will have lifetimes of about 20 years (Benson, Table 2, this volume). The most technologically mature option is injection into depleted oil and gas reservoirs because the oil and gas industry has 25 years experience injecting CO_2 into petroleum reservoirs for enhanced oil recovery (EOR).

The obvious first order question about geologic storage of CO_2 is, do we have enough storage space? Initial, global estimates cited by Benson (this volume, Table 3) certainly suggest that we do, especially when we combine the capacities of all three geologic options. The difficult questions are in the details of implementing geologic sequestration on a national scale. We can estimate the capital costs of carbon capture from existing power plants and from future generations of gasification power stations (Simbeck, 2001, 2003; Simbeck and McDonald, 2001). However if the volume of CO_2 that must be stored is so great that the best long-term storage sites are exhausted in only a few years, the role of geologic sequestration in controlling CO_2 emissions will be limited. The corollaries to the question of total storage volume are 1) how much is enough; 2) what characteristics define the best storage sites; and 3) where are such sites located relative to large CO_2 point sources of emissions. None of these questions is simple to answer.

II. Near Term Storage Requirements in the United States

One way to set a target for storage capacity in the United States is to examine CO_2 emissions from fossil fuel combustion shown in Table 1. The obvious targets for CO_2 capture and storage are the largest stationary sources, coal and natural gas fired electrical generating stations. Total emissions from electrical generation are about 0.5 billion metric tons of carbon (gigatons, Gt(C)) per year, or about 35 trillion cubic feet (TCF) of CO_2 gas. This amount of CO_2, about one-third of total annual U.S. emissions, is about the maximum amount that can be captured from the present energy infrastructure in the U.S. Capture of CO_2 from industrial sources such as gas processing, fertilizer production, cement kilns, and petroleum refineries could eliminate an additional 10% of emissions.

Table 1. U.S. fossil energy production[1] and CO_2 emissions[2], (EIA, 1999)

Energy Source	Total Energy[3] (QBTU)	% Electricity Generation	% Transportation	Carbon (Gt)	CO_2 (Gt)
Natural Gas	22.8	14	3	0.31	1.14
Coal	23.5	82	0	0.54	1.98
Petroleum	37.7	2.7	67	0.64	2.33

[1] Total domestic production plus imports

[2] Emissions are given in units of gigatons (Gt) of carbon and Gt of CO_2. To convert Gt (C) to Gt CO_2, multiply by 3.67. This factor is the ratio of the molecular weight of CO_2 to the atomic weight of carbon and accounts for the additional mass of oxygen in CO_2 compared to the mass of pure carbon. Other conversions that are important for this paper are the volume of CO_2 gas at surface conditions that is equal to 1 metric ton of CO_2, 1 metric ton CO_2 = 18,900 standard cubic feet (SCF), and the fact that at depths in the subsurface of 1.5 to 2.0 km, CO_2 has a liquid-like density such that 1 metric ton has a volume that is equivalent to about 11 barrels of petroleum (at 42 gallons/petroleum barrel).

[3] QBTU = quadrillion British thermal units (10^{15} BTU, commonly called "Quads")

About 40% of current U.S. emissions are from transportation fuels. Emissions from mobile sources cannot be captured and stored with known, practical methods. Therefore, reduction in emissions from transportation will require either more energy efficient vehicles that emit less CO_2 per passenger-mile traveled, or replacement of current technology with hydrogen technology. Most scenarios for hydrogen production are based on large-scale centralized plants that integrate CO_2 capture with hydrogen production and electrical generation either through coal gasification or reforming natural gas (Simbeck, 2003). A transportation system powered by centrally generated hydrogen would allow geologic sequestration of the CO_2 waste stream from hydrogen production.

III. Storage Capacity in a 10 to 50 Year Time Frame

Important questions for large-scale implementation of geologic sequestration of CO_2 are the definition of the "best" sites for geological storage, or definition of the criteria to rank the quality of storage sites, and the aggregate volume of the "best" sites. From the perspective of petroleum geology[1], known petroleum reservoirs are the best near-term storage sites for carbon dioxide. Reservoirs have 3-dimensional closure and a seal. These structures are known to be capable of retaining petroleum (crude oil and natural gas) for millions of years. CO_2 at subsurface pressures and temperatures has physical properties similar to volatile, liquid petroleum, so that CO_2 will fill these structures in much the same way as petroleum has filled reservoirs naturally. Also, CO_2 storage in depleted oil and gas reservoirs allows recovery of residual fossil fuel resources (enhanced oil recovery, EOR) that can be marketed to offset the costs of CO_2 storage. The volume of incremental recovery of oil, in particular, is potentially large, on the order of 10's of billions of barrels of oil, which could offset a fraction of current and future oil imports (Fischer, 1987). Although CO_2 storage integrated with enhanced oil recovery is the most promising route to near-term geologic sequestration of CO_2, storage in gas reservoirs with enhanced recovery of natural gas (Oldenburg, Stevens, and Benson, 2003), and in coals with enhanced coalbed methane recovery (Reeves, 2003) is also possible. Each of these options has the potential for economic returns from resource recovery that can partially offset the costs for sequestration projects.

IV. CO_2 Storage in Petroleum Reservoirs, Saline Formations, and Coalbeds

Carbon dioxide storage in petroleum reservoirs is closely related to storage in saline formations. Most conventional petroleum reservoirs have a base defined by an oil or gas-water contact. The water at the contact is usually the saline formation water (brine) that fills the porosity of geologic formations in the absence of a petroleum accumulation. A petroleum reservoir is commonly a part of a geological formation that can be called a saline formation. The hydrologic properties of the formation that control injection of CO_2 into a petroleum reservoir will apply to injection into adjacent brine formation. The relationship of CO_2 storage in petroleum traps and saline formations is important for assessment purposes because petroleum traps can be considered the "known resource" of CO_2 storage volume in a saline formation. This is the volume that was characterized by geologic and engineering studies undertaken to optimize petroleum production. It is the volume that is most "bankable" from the perspective of a financial analysis of CO_2 storage costs in the near term. In my opinion, it is the volume that is most appropriate for immediate to near-term implementation of CO_2 storage. In the emerging protocols for establishing emissions reduction credits (ERCs), geologic storage in a reservoir of known dimensions and geographic location will aid in establishing and maintaining title to the stored CO_2 and the associated, financially tradable credit.

The potential storage volume of saline formations exceeds other geologic options (Benson, Table 3, this volume). Whether we can actually use all or a large fraction of this volume is unclear. The general trapping mechanism in saline formations is called "hydrodynamic trapping" and is based on the assumption that the flow rate of a separate CO_2 phase in porous media is relatively slow. This then implies that the CO_2 would not return to the surface in times less than 1000's of years. Saline formations may also have low permeability seals that will inhibit vertical migration. However, where saline formations are not petroleum bearing, they are not well characterized at present. Therefore, identification of the best parts of a saline formation for initial, large-scale CO_2 storage projects is difficult. Adequate characterization of porosity, permeability, distribution of seals, and other attributes will require geologic and geophysical studies that are somewhat analogous to studies conducted for petroleum exploration. In this case we are exploring for adequate storage space.

Storage of CO_2 in coal beds also has large uncertainties. The coal used for CO_2 storage needs to be identified as unmineable because mining after storage will release the CO_2. The criteria for identifying unmineable coal are not well defined. Second, we have relatively little information on the properties that control the maximum amount of CO_2 that coals can adsorb and store. Recent research shows that the volume of CO_2 adsorbed per unit volume of coal can vary by a factor of two among different coal types. If we include use of CO_2 for enhanced coalbed methane recovery to offset costs of sequestration, the uncertainties get larger, perhaps as much as a factor of 10. The ratio of carbon dioxide to methane adsorption on coals varies by an order of magnitude across the full range of coal rank. There is no doubt that coal can be used to store

CO_2, and it is clear that CO_2 injection can enhance coalbed methane recovery, but it is not clear what fraction of known coal occurrences could be used for storage.

V. The "Known Resource" of Storage Capacity

The "known resource" of any fossil fuel is the cumulative production plus the known reserve. The continental United States and the offshore Gulf of Mexico have been extensively explored for oil and gas with over three million wells drilled. Cumulative production of oil from these areas is about 188 BBO and gas is about 1000 TCF as of 2001. If we make a very simplistic model of sequestration of CO_2 in oil and gas reservoirs as replacement of fluid on a volume of CO_2 per volume of oil or gas, then we can calculate the storage capacity of known oil and gas traps. If we simply divide the equivalent volumes of CO_2 gas or oil for 0.5 Gt(C) into the volume of cumulative production, we can estimate that depleted gas reservoirs could provide about 28 years of storage and depleted oil reservoirs about 34 years of storage. If these numbers are combined conservatively, there is on the order of 50 years of storage capacity at a storage rate of 0.5 Gt(C) per year.

By using the term "known resource" of CO_2 storage capacity I am making an analogy to petroleum resource assessment. Petroleum reservoirs are potential storage sites that are well characterized with a known seal and trapping volume. However, because petroleum reservoirs are part of saline formations, they can be considered the "best" part of saline formations for near-term sequestration sites. The volume of saline formations outside of petroleum accumulations, and the volume of unmineable coal, can be considered the "potential resource". We know that there is more storage volume than the known resource, but we must do further characterization to move that additional volume from "potential" to "known".

VI. Critical Issues

The storage volume for emissions from individual power plants is large. The projected area at the surface of the CO_2 storage volume required for large (1000 MWe, 8 Mt/yr CO_2) power plants over a 50 year project lifetime will be large, on the order of 100 square miles with a volume larger than a one billion barrel oil field (Brennan and Burruss, 2003). The number of individual petroleum reservoirs of this size is limited. Implementation of CO_2 capture and storage at the scale of current U.S. emissions from power plants will exceed the volume of known petroleum reservoirs in the U.S. in 50 to 100 years and require storage in saline formations. This will require characterization and monitoring of large rock volumes. Three-dimensional (3-D) and time-lapse 3-D seismic methods are obvious possible approaches but additional methods and new technologies will be necessary (Benson and Myer, 2002).

The technology for CO_2 capture will impact implementation of geologic sequestration because it will affect the relative locations of sources and sinks and the infrastructure necessary to connect them. Most of the largest point sources of CO_2 are in the eastern U.S. whereas most of the largest depleted oil and gas traps are in the southern and western U.S. (Burruss, Brennan, and Glazebrook, 2003). Current or future technology for CO_2 capture that can be retrofitted to existing coal-fired power stations will require an extensive CO_2 pipeline network to move large volumes of CO_2 from source to sink. The alternative is CO_2 capture integrated into new gasification power plants for hydrogen production and electrical generation. These installations could be located at the sites for CO_2 storage with power distributed through the electrical grid and a hydrogen transportation system.

VII. Conclusions and Future Directions

The CO_2 storage capacity of known oil and gas reservoirs in the United States is adequate to accumulate emissions from large point sources with total annual emissions of about 0.5 Gt carbon for a period of 20 to 50 years. These traps have retained buoyant fluids for millions of years.

Near-term large-scale geologic sequestration projects will probably proceed as CO_2 enhanced oil recovery projects. The economic return from oil recovery will significantly offset the cost of CO_2 capture and storage. Such projects must be large enough (equal to or larger than existing projects of 0.5 to 1.0 million tons CO_2 per year) to allow evaluation of technologies for measuring, monitoring and verification that can be scaled up to the size of realistic coal-fired power stations (1000 MWe). As the technologies evolve for CO_2 capture and storage and measurement, monitoring, and verification of stored CO_2, the storage capacity of known oil and gas traps will increase (similar to reserve growth in petroleum resource assessments (Fischer, 2002)). However, at some point we will exhaust the “best” traps, especially those best for integrated sequestration and EOR. Although additional storage capacity will be available in saline formations, we must be moving forward with low-CO_2 energy technologies that will decrease the demand for CO_2 storage as worldwide demand for energy continues to grow.

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[1] This is an important distinction to make. From the perspective of groundwater hydrology, the term “reservoir” applies to the whole formation from which water can be produced. This is distinct from the common use of this term in petroleum geology to define a specific three-dimensional structure with a low-permeability seal that can retain buoyant fluids.