DISCUSSION PAPER

September 2008; revised July 2010 ■ RFF DP 08-29-REV

Long-Term Risks and Short-Term Regulations

Modeling the Transition from Enhanced Oil Recovery to Geologic Carbon Sequestration

Alexander J. Bandza and Shalini P. Vajjhala

1616 P St. NW
Washington, DC 20036
202-328-5000 www.rff.org

RESOURCES FOR THE FUTURE

Long-Term Risks and Short-Term Regulations: Modeling the Transition from Enhanced Oil Recovery to Geologic Carbon Sequestration

Alexander J. Bandza and Shalini P. Vajjhala

Abstract

Recent policy debates suggest that geologic carbon sequestration (GS) likely will play an important role in a carbon-constrained future. As GS evolves from the analogous technologies and practices of enhanced oil recovery (EOR) operations to a long-term, dedicated emissions mitigation option, regulations must evolve simultaneously to manage the risks associated with underground migration and surface tresspass of carbon dioxide (CO_2). In this paper, we develop a basic engineering-economic model of four illustrative strategies available to a sophisticated site operator to better understand key deployment pathways in the transition from EOR to GS operations. All of these strategies focus on whether or not a sophisticated site operator would store CO_2 in a geologic formation. We evaluate these strategies based on illustrative scenarios of (a) oil and CO_2 prices; (b) leakage estimates; and (c) transportation, injection, and monitoring costs, as obtained from our understanding of the literature. Major results reveal that CO_2 storage in depleted hydrocarbon reservoirs after oil recovery is associated with the greatest net revenues (i.e., the "most-preferred" strategy) under a range of scenarios. This finding ultimately suggests that GS regulatory design should anticipate the use of the potentially leakiest, or "worst," sites first.

Key Words: carbon sequestration, enhanced oil recovery, leakage, regulatory design, risk management

Contents

Long-Term Risks and Short-Term Regulations: Modeling the Transition from Enhanced Oil Recovery to Geologic Carbon Sequestration

Alexander J. Bandza and Shalini P. Vajjhala*

1. Introduction

Climate change has brought to bear a wide variety of new technologies, along with their potential risks and opportunities. Policies to reduce greenhouse-gas (GHG) emissions encompass a range of mitigation options, from small-scale technologies (*e.g.*, energy-efficient light bulbs and appliances) to large-scale deployment of low-carbon energy sources (*e.g.*, wind and solar power). The portfolio of potential climate-change mitigation options also includes less familiar, emerging technologies. One of the most prominent of these emerging technologies is carbon capture and sequestration (CCS).

CCS is a broad term that encompasses a range of processes and technologies, although the term generally refers to (a) the capture of carbon dioxide (CO_2) from anthropogenic sources; (b) the transport of CO_2 to the ultimate storage location; and (c) the sequestration of CO_2 in perpetuity. Geologic sequestration (GS) is one form of CCS, in which CO_2 is injected into geologic formations for the purpose of long-term storage.[1] As of this writing, 135 CCS projects are active around the world (DOE 2010c). Three of the largest of these projects are Sleipner (Norway), In-Salah (Algeria), and Weyburn (Canada), with annual injection rates of approximately one million metric tons (MMT) of CO_2 (IEA 2006). Despite their size, these operations represent a small fraction of annual global energy-related CO_2 emissions, which totaled approximately 29,700 MMT in 2007 (DOE 2010b).

Scientists have opined that 3,500 new GS projects worldwide—each comparable in size to the largest existing projects—must be operational within the next few decades for CCS to

*Alexander J. Bandza is a J.D. candidate at the University of California, Berkeley, School of Law in Berkeley, CA; abandza@berkeley.edu. Shalini P. Vajjhala, Ph.D. is a Deputy Assistant Administrator at the Office of International Affairs of the U.S. Environmental Protection Agency in Washington, DC, and was formerly a fellow at Resources for the Future.

[1] The terms "carbon sequestration" and "CCS" also are used generally to refer to the terrestrial storage of CO_2 in forests and soils. We focus solely on on-shore geologic carbon sequestration in this paper and use the term "GS" herein to avoid any confusion with other possible forms of CO_2 sequestration.

materially reduce anthropogenic CO_2 emissions (Pacala and Socolow 2004; IPCC 2005). The sheer number of new GS projects needed has raised questions about the adequacy of existing regulatory frameworks to effectively manage operational and *in-situ* risks, as well as to build public acceptance of the technology (Wilson et al. 2008). Ongoing operations have provided some preliminary characterizations of potential short- and long-term risks, which may include the underground migration and surface trespass of CO_2, with the resulting potential for environmental and biological impacts (Damen et al. 2006; Heinrich et al. 2003; Wilson et al. 2003).[2] Notwithstanding the limited number of GS projects brought on line to date, and the long-term technical and geophysical uncertainties, CCS is considered one of the few CO_2 mitigation options with the potential for large-scale, near-term deployment.

An effective and robust regulatory framework to manage these uncertainties likely will require a comprehensive view of all GS projects. Recent studies have examined the probability of leakage associated with specific *types* of geologic formations, sites, and project contexts (Benson 2005; Hovorka et al. 2006).[3] However, possible *deployment pathways* of GS projects (*i.e.*, a collection of investments in GS operations not limited to one geologic formation or context) remain poorly understood. This gap in understanding poses a challenge for regulatory design—balancing regulations that are stringent enough to build public confidence in GS, yet flexible enough to avoid stymieing deployment (Wilson et al. 2008).

The varied underground formations appropriate for GS potentially can exacerbate this regulatory challenge. These formations include (a) depleted hydrocarbon reservoirs; (b) deep saline aquifers; and (c) unmineable coal seams. It is expected that initial GS operations will employ depleted hydrocarbon reservoirs. Depleted hydrocarbon reservoirs are familiar to the industry through decades of enhanced oil recovery (EOR) operations, an oil-industry practice in which CO_2 (or other media) is injected underground into declining production sites to extract additional oil (SPE 2010). Further, revenues from the oil produced in EOR operations can offset the large expense of undertaking a GS operation.

[2] By way of example, these risks may be related to (a) short-term impacts, including the suffocation of humans and other animals, biological impacts on plants, and seismic effects or local ground heave; or (b) longer-term impacts from gradual releases, including the contamination of groundwater or drinking-water sources through mineral mobilization or displacement of brine or hydrocarbons (Wilson et al. 2003).

[3] We note in this regard that the site-specific variation in the geologic characteristics of potential GS formations may be significant. Notwithstanding this variation, some project types inherently could be riskier than others.

However, there are reasons to believe that GS likely will be deployed widely in formations other than depleted hydrocarbon reservoirs. Globally, significantly more storage volume is available in deep saline aquifers than in depleted hydrocarbon reservoirs (IPCC 2005). In addition, deep saline aquifers tend to be less geologically disturbed than depleted hydrocarbon reservoirs, which contain tens, if not hundreds, of remaining production and injection wells that might later serve as leakage pathways for injected CO_2.

In light of these challenges, we characterize the big-picture differences in the geologic formations and operational goals of EOR and GS to address two main research questions: (1) Which types of GS projects are likely to emerge initially and in greatest numbers under different scenarios (*e.g.*, global oil and CO_2 prices)?; and (2) What are the implications of these different deployment pathways for GS regulatory design? To address these questions, we model four illustrative site strategies that may emerge within the total portfolio of North American GS projects. These strategies qualify our hypothesis that the deployment of GS operations may shift first from existing EOR operations to increasing numbers of hybrid EOR-GS projects,[4] and later to dedicated GS operations.

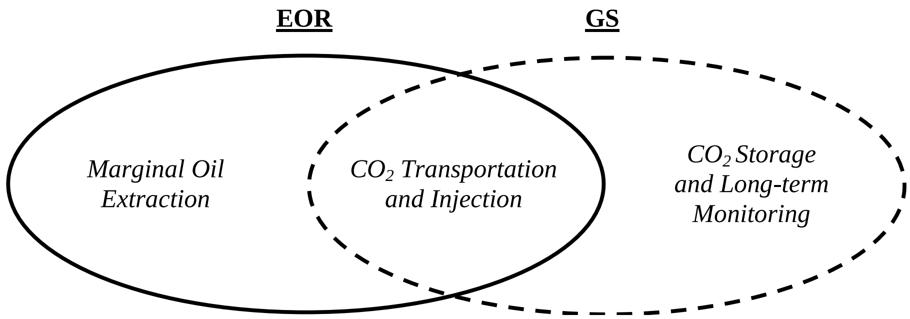
We develop this strategy-based approach for several scenarios of the major cost and revenue drivers of GS, in order to examine this compositional shift in GS deployment pathways. In the following sections, we (a) provide a brief background on EOR and GS technologies, practices, and regulations (Section 2); (b) introduce our four key strategies and model framework (Section 3); (c) outline our key variables and assumptions (Section 4); (d) present our major results (Section 5); and (e) discuss policy implications (Section 6).

2. Linking Enhanced Oil Recovery and Geologic Sequestration

EOR can serve as an analogue for GS, because EOR and GS share several processes, and GS likely will use several EOR technologies. The main components of EOR include (a) transportation of CO_2 to a mature oil field; (b) injection of pressurized CO_2 into the field; and (c) extraction of oil. GS projects share the initial transportation and injection components of EOR and further involve (a) permanently securing the CO_2 underground; and (b) long-term monitoring of the site for CO_2 leakage. The overlap in EOR and GS components is shown in Figure 1 below.

[4] We define "hybrid EOR-GS" projects to be any project with both EOR and GS objectives.

Figure 1: Shared Components of EOR and GS Operations



While the technical foundation for some components of EOR and GS may be substantially similar, EOR and GS operations diverge in their objectives. The primary objective of EOR operations is to maximize the amount of oil extracted per unit of CO_2 injected, without regard for CO_2 storage. Conversely, the goal of GS operations is to maximize the amount of CO_2 stored per unit of CO_2 injected, without regard for oil production. In the following subsections, we briefly describe the key features of EOR and GS operations and the associated regulatory challenges.

2.1 Enhanced Oil Recovery

EOR is a mature process that has been used worldwide for more than 30 years and employs a variety of methods and injection media (Anderson and Newell 2004). CO_2 is one of the primary media used for EOR, and therefore EOR operations offer direct industry experience with the transport and underground injection of CO_2.[5]

Most CO_2-based EOR operations employ *miscible* CO_2 injection.[6] In this process, much of the CO_2 returns to the surface with the extracted oil. To minimize the total amount of CO_2 used, the returned CO_2 generally is separated and re-injected. It is possible to benchmark the efficiency of the EOR operation by calculating the *oil response ratio* (ORR)—the ratio of the

[5] The term "EOR" can refer to injection media other than CO_2. By way of example, other injection media include steam and nitrogen (Koottungal 2008). As used herein, "EOR" shall refer only to CO_2-based EOR.

[6] "Miscible" CO_2 injection is a process in which CO_2 is injected above a certain pressure to create a single homogeneous phase of CO_2 and oil. Mixing CO_2 and oil in a single phase above the minimum miscibility pressure reduces the oil's viscosity and causes it to swell, facilitating extraction. Because this process depends on the pressure and weight of the crude oil being extracted, miscible CO_2 injection is not possible in all cases (Koottungal 2008).

amount of oil recovered over the amount of CO_2 injected. On completion of an EOR operation, site operators have little financial incentive for *in-situ* CO_2 storage, and they typically recycle or sell the remaining CO_2.[7]

2.2 Geologic Carbon Sequestration

Whereas most EOR operations employ CO_2 obtained from naturally occurring sources, GS for the purposes of climate-change mitigation must employ CO_2 captured *only* from anthropogenic sources.[8] CO_2 can be captured from large, stationary CO_2 sources using gas absorbers or scrubbers, which have been employed in a variety of industrial applications for more than 60 years.[9]

In a typical GS project, the captured CO_2 is transported to the storage site by pipeline, ship, or road, and then is injected deep underground into a secure geologic formation.[10] At most GS sites, CO_2 injection is expected to occur over several decades. CO_2 transportation and injection are mature practices that rely on developed technologies—in the U.S. alone, there are over 2,500 km of pipeline transporting approximately 50 MMT CO_2 annually to supply underground injection, all with a notable lack of injuries or fatalities (de Figueiredo 2007; IPCC 2005).

Geologic formations appropriate for GS include (a) depleted hydrocarbon reservoirs; (b) deep saline aquifers; and (c) unmineable coal seams. EOR operations occur in depleted hydrocarbon reservoirs, and the extent of industry experience with EOR suggests an initial use of these formations for CO_2 storage. Conversely, deep saline aquifers may prove more attractive in

[7] In some situations, site operators also will reclaim previously injected CO_2 that did not return to the surface with the extracted oil. This process is known as “blowdown.”

[8] CO_2 captured from naturally occuring sources would not satisfy an “avoided” amount of CO_2 for the purposes of any CO_2 reduction policy.

[9] By way of example, industrial processes amenable to CO_2 capture include (a) fuel combustion for power generation; (b) refinement of fossil fuels; and (c) production of carbon-intensive industrial materials like iron, steel, hydrogen, ammonia, and cement (IPCC 2005).

[10] The transportation and injection of captured CO_2 from anthropogenic sources pose additional risks associated with the purity of the CO_2 stream. In contrast to natural CO_2 deposits, captured CO_2 may have hydrogen sulfide or other contaminants entrained that could corrode pipelines and injection-well heads, resulting in a higher probability of contamination or leakage (Damen et al. 2006; Heinrich et al. 2003). These contaminants may have integrity-management implications for existing oil and gas wells that were not designed for “contaminated” CO_2.

the long run, given their greater availability and capacity, as well as less disturbed geologic characteristics.

After CO_2 injection is complete and a site is closed, monitoring and verification of the stored CO_2 must occur over several decades, possibly centuries, to ensure environmental integrity. Monitoring techniques from ongoing EOR operations can be adapted for GS projects, such as seismic imaging and surveying (IPCC 2005).

2.3 Risk Management and Regulatory Design

The extensive use of EOR over several decades indicates the apparent industry understanding of EOR-specific risks and regulations. However, the divergent aims of EOR and GS suggest a careful evaluation of (a) GS-specific risks; and (b) any reliance on EOR-specific regulatory frameworks to manage GS-specific risks.

It remains ambiguous how policies to price CO_2 and/or provide incentives for GS deployment might influence the number and timing of EOR and GS projects in the long run. Given the time span over which a reservoir might be operational, it is plausible that EOR and GS operations could exist in the same reservoir. For example, depending on long-term average prices of CO_2 and oil, one might expect to initially see a number of EOR and GS operations in the same reservoir (*i.e.*, hybrid EOR-GS projects) if the price of CO_2 is not high enough to incent dedicated CO_2 storage (*i.e.*, GS without EOR). The technical feasibility and potential attractiveness of CO_2 storage as an afterthought to an EOR operation suggest a pathway-based approach that views EOR and GS operations along a "technical continuum," as opposed to two entirely different project types.

Conversely, the differences in the operational goals and underground formations available for EOR and GS warrant caution in viewing EOR and GS along a "regulatory continuum." Notwithstanding differences in the goals of each operation, GS simply requires a larger amount of CO_2 than EOR (Heinrich et al. 2003). Even in an identical reservoir, modeling suggests that the amount of CO_2 injected for the purpose of GS is larger than the amount for

EOR (Kovscek and Cakici 2005).[11] With respect to this difference in the scale of CO_2 injection, regulations applicable to EOR operations may be unsuitable and/or irrelevant for GS operations.

The underground formations available to EOR and GS operations also pose a unique set of risks. Depleted hydrocarbon reservoirs—a formation appropriate for both EOR and GS—contain tens, if not hundreds, of injection and production wells that have punctured the cap rock of the reservoir. A site with extensive cap-rock puncturing tends to pose a higher risk of leakage to the surface than a site with an undisturbed cap rock (Bossie-Codreanu and Le Gallo 2004). The tens, if not hundreds, of injection and production wells inherent to an oil recovery operation introduce potential leakage pathways into the cap rock. Although depleted hydrocarbon reservoirs initially might be attractive due to broader industry experience with them, the lower propensity for surface leakage of deep saline aquifers might make aquifers more attractive in the long term. Therefore, GS-specific regulations need to recognize this potential shift in usage from depleted hydrocarbon reservoirs to deep saline aquifers.

Governments around the world are implementing efforts to encourage GS[12] in light of apparently inadequate or inappropriate existing regulatory structures (Wilson et al. 2008; Stephens and van der Zwaan 2005). Efforts are underway in the U.S. to address this gap—in 2008, the U.S. Environmental Protection Agency (EPA) proposed rules to clarify injection regulations for GS operations under the Underground Injection Control (UIC) program.[13]

---

[11] We note in this regard that reservoir modeling of CO_2 injection for EOR suggests that the total volume of CO_2 injected for the purposes of EOR, even in cases of "overinjection" (*i.e.*, beyond the point of profitable oil recovery), would occupy a maximum of 60% of a reservoir's volume (Kovscek and Cakici 2005). In this regard, the amount of CO_2 injected for EOR operations is limited by the maximum oil production rate, whereas the amount for GS operations is limited only by the CO_2 capacity of the reservoir. We understand that the former is generally more limiting with respect to the amount of CO_2 injected.

[12] By way of example, the European Union has advanced proposals to include GS projects under Phase II of the Emissions Trading Scheme (ETS). The European Commission also has issued statements on the importance of options for coal in a carbon-constrained world (European Commission 2006). Public-private partnerships and regional carbon-sequestration partnerships in the United States are attempting to advance GS demonstration and deployment (Anderson and Newell 2004; DOE 2008).

[13] Underground injection of CO_2 is regulated federally through the EPA UIC Program, as authorized under the Safe Drinking Water Act (Safe Drinking Water Act of 1974). The UIC Program regulates wells according to five injection-well classes based on design and operating techniques; EOR operations fall under Class II (EPA 2008). In July 2008, EPA proposed to modify the UIC program to create a new class of wells—Class VI—for GS projects and establish minimum technical requirements for sequestration operations (EPA 2008). As well, EPA apparently expects the use of reservoirs for both EOR and GS purposes. It is our understanding that under this proposed modification hybrid EOR-GS operations will be regulated according to the instant operational objective of the site—*i.e.*, hybrid EOR-GS operations initially would be permitted in Class II until EOR is complete, with reapplication required to continue as a GS operation under Class VI.

Developing regulatory standards for GS operations will require balancing efforts to encourage GS with the need for careful risk management under the wide range of possible GS project types and underground formations. Depending on the incentives and uncertainties surrounding new GS projects, the composition of the GS project portfolio could vary significantly over time. This deployment-focused view is especially critical when evaluating how the earliest GS projects could evolve from current EOR operations.

3. A Framework for Deployment-Pathway Analysis

To date, most studies of GS risks have been site specific, examining the technical feasibility of GS using reservoir modeling, experiments, or observations of industry practice (Benson 2005; Kovscek and Cakici 2005). Studies of GS deployment at larger scales have focused on incentives for and barriers to GS operations relative to other types of emissions reduction options (Dooley et al. 2004; Newell and Anderson 2004; Bielicki 2008). However, little attention has been given to the shift from EOR operations to hybrid EOR-GS and ultimately to dedicated GS operations. Herein, we introduce a deployment-pathway approach to evaluate this transition.

We hypothesize that transitions from EOR to GS operations occur due to shifts in the lifetime costs and benefits of recovering oil and/or storing CO_2. These shifts are the result of a sophisticated site operator optimizing whether to (a) maximize oil recovery; (b) maximize CO_2 storage; or (c) both. To illustrate the key points along this transition, we develop the following four strategies outlined in Table 1 below.

Table 1: Illustrative Strategies in the Model

Strategy	Process(es) Optimized	Oil extraction	CO_2 storage	Description
Indifferent	EOR	✓		Oil extraction is the sole objective without consideration of CO_2 storage.
Afterthought	EOR *then* GS	✓	✓	Oil extraction is the initial objective, and CO_2 storage is the final objective.
Planned	EOR *and* GS	✓	✓	Co-optimization of oil extraction and CO_2 storage is the objective for the entirety of the operation.
Dedicated	GS		✓	CO_2 storage is the sole objective without consideration of oil extraction.

The <u>Indifferent</u> strategy is comparable to current EOR operations. Oil recovery is the only source of revenues, and no payments are provided for any CO_2 that remains underground at the end of the operation (*i.e.*, the site operator is indifferent to CO_2 storage). The <u>Afterthought</u> strategy represents our characterization of the "first step" toward GS—a sophisticated site operator seeks additional revenues as an afterthought to the EOR operation by securing the remaining CO_2 (and may even inject additional CO_2) to obtain credit and/or offset revenues at the prevailing price of CO_2. The Planned strategy is our estimation of the incremental step after the Afterthought strategy—a sophisticated site operator plans from the beginning for the operation to co-optimize oil recovery and CO_2 storage. Finally, the Dedicated strategy represents an operation consistent with our understanding of widespread GS deployment—dedicated CO_2 storage in underground formations unrelated to oil recovery.

We believe these strategies broadly cover the types of projects that might comprise the total portfolio of EOR and GS operations in the coming decades. Given a set of reservoir characteristics and costs for each strategy, we employ a simplified cost-benefit analysis to determine which strategy has the highest revenues for particular scenarios of oil and CO_2 prices. The strategy with the highest net revenues under that scenario of oil and CO_2 prices would be the one we expect to "dominate" the investment decisions of sophisticated site operators at that moment.[14] We believe this illustrative exercise can yield an initial understanding of what prices of oil and CO_2 might incent a sophisticated site operator to shift from EOR to GS operations.

4. Model Formulation and Key Variables

In the subsections that follow, we outline the model and its key variables and assumptions used for our lifetime cost-benefit analysis. We focus on three key drivers of EOR and GS operations: (a) the oil response ratio (ORR); (b) the lifetime leakage rate (LLR); and (c) the total cost of the operation, which includes transportation, storage, and monitoring costs. For each of these variables, we have obtained mean values and/or upper and lower bounds from our understanding of the literature. Using this approach, we define a specific range of values for each variable in each strategy.

[14] We focus solely on the dominant strategy under different scenarios of oil and CO_2 prices. We particularly note that non-dominant strategies also might be "profitable," in that they yield positive net revenues; however, by definition, they are not the *most* profitable. This approach is intended to highlight the points at which specific operational strategies might become attractive to sophisticated site operators. Investors in these operations, faced with a multitude of technical, legal, and regulatory uncertainties surrounding GS, likely will require higher returns to mitigate the long-term financial risks associated with deploying a new technology. We believe this dominant-strategy approach is consistent with the emphasis on high returns that a sophisticated site operator would require to shift operational strategies.

4.1 Model Formulation

To determine the dominant strategy for a given scenario, we employ the following equation across all strategies to calculate net revenues:

$$\Pi = Q_{CO2\ injected} * [(7.33)(ORR)(P_{oil}) + (1 - LLR)(P_{CO2}) - Cost]$$

where:

(a) Π is the net revenue of the operation;
(b) $Q_{CO2\ injected}$ is the total amount of CO_2 injected (metric tons);
(c) 7.33 is the conversion factor from barrels to metric tons of oil;[15]
(d) *ORR* is the ratio of oil recovered (metric tons) per CO_2 injected (metric tons);
(e) P_{oil} is the price of oil (USD/barrel);
(f) *LRR* is the ratio of CO_2 lost per CO_2 injected (metric tons);
(g) P_{CO2} is the price of CO_2 (USD/metric ton); and
(h) *Cost* is the sum of transport, storage, and monitoring costs (USD/metric ton).

We outline below our estimates of each variable in this equation. Because of the uncertainty surrounding specific strategies and variables, means and/or ranges of variables are sometimes poorly characterized or unavailable. For these variables, we estimate the upper and lower bounds from multiple sources. If this still is not possible, we use a margin of error of ±10% around the mean value for each strategy as a preliminary sensitivity analysis. We close this section with the major assumptions that we used in the model.

4.2 Key Variables

4.2.1 Oil Response Ratio

The ORR represents the “efficiency” of the EOR operation, and indicates the ratio of the amount of oil recovered over the amount of CO_2 injected. The ORR in the context of EOR operations apparently is well understood from decades of industry experience. However, the ORRs for our stylized strategies are less known, and our estimates are meant to serve as illustrative. Table 2 below indicates the ranges of ORRs used in each strategy.

[15] Conversion factor obtained from DOE (2009a).

Table 2: ORRs by Strategy

Strategy	Values[a] Low	Mean	High	Notes
Indifferent	0.24[b]	0.60[c]	1.04[b]	Current EOR in depleted hydrocarbon reservoirs.
Afterthought	0.10[d]	0.18[e]	0.60[f]	Additional CO_2 is injected to fill the reservoir for long-term storage, resulting in a greater volume of total CO_2 injected and generally lower ORRs than in the Indifferent strategy.
Planned	0.05[h]	0.30[i]	0.52[i]	Co-optimization of EOR and GS suggests lower ORRs than in the Indifferent strategy. Oil recovery may be limited to improve CO_2 storage, which also drives down ORRs.
Dedicated	-	-	-	Anticipated GS in deep saline aquifers. No oil recovery is possible.

Notes:
a. Indicates the ratio of oil barrels recovered per metric ton of CO_2 injected.
b. Converted from the Martin and Taber (1992) range of 2.5-11.0 Mcf of CO_2 injected per barrel of oil produced.
c. Typical ORR from EOR operations (Kallbekken and Torvanger 2004).
d. Our estimate. May be the result of worse-than-expected oil recovery or greater-than-anticipated CO_2 injection capacity.
e. Our estimate. Emberley et al. (2004) and White et al. (2007) calculate the total oil recovery potential in the Weyburn EOR reservoir in Canada, a formation undergoing feasibility analysis for CO_2 storage. Both studies estimate oil recovery of approximately 18 MMT. Emberley et al. (2004) notes that Weyburn has 100 MMT of CO_2 storage potential. Assuming that no extra oil is recovered when additional CO_2 is injected for the purposes of GS, Weyburn would have an ORR of 0.18 (18 MMT of oil/100 MMT of CO_2 injected).
f. Our estimate. Reservoir modeling suggests that the amount of CO_2 injected for EOR operations may approach 60 percent of a reservoir's volume (Kovscek and Cakici 2005). It would seem unlikely that the ORR in an EOR-GS hybrid operation would ever exceed the ORR related to EOR alone. Therefore, we limit this range to the mean of the Indifferent strategy at 0.60.
h. Our estimate. The greater emphasis on CO_2 storage relative to both the Afterthought and Indifferent strategies would yield an ORR at half the corresponding value in the Afterthought strategy.
i. Our estimate. Kovscek and Cakici (2005) indicate that well-control methods during EOR can double CO_2 storage for the same amount of oil recovered over traditional EOR methods. Therefore, we estimate this value at half of the corresponding value in the Indifferent strategy.

4.2.2 Lifetime Leakage Rates

We define leakage as the total amount of injected CO_2 lost from a reservoir over the lifetime of the operation.[16] The LLR is the percentage of injected CO_2 that is lost over the lifetime of the project. Therefore, the quantity (1 – *leakage*) indicates the long-term storage potential of the reservoir.[17]

Ha-Duong and Keith (2003) consider an annual leakage rate of 0.1 percent to be essentially "perfect" storage, and suggest that an annual leakage rate of 0.5 percent is too great

[16] We focus solely on leakage to the surface; *i.e.*, we do not take into account any seepage or migration of CO_2 underground. Leakage pathways (*e.g.*, cap-rock fractures and inadequately plugged wells) remain poorly understood, and there is little to suggest that the strategies evaluated in our analysis are associated with substantially different *types* of leakage (Damen et al. 2006; Wilson et al. 2003). As a result, we do not differentiate between sudden, large leaks and gradual, diffuse leaks. Instead, we assume that leakage pathways are substantially similar across all strategies, and the only material difference is the total amount of CO_2 lost over the lifetime of the operation. We assume that site operators only stand to earn revenues for injected CO_2 that remains in the resevoir. We further do not account for additional costs (*e.g.*, insurance premiums and/or risk-spreading instruments) that might be incurred to mitigate the financial liabitilies related to the risk of catastrophic leakage.

[17] As noted, the quantity (1 – *leakage*) also represents the amount of CO_2 that may earn revenues at the prevailing price of CO_2.

for the purposes of climate-change mitigation. Pacala (2003) opines that a 100-year time frame is useful for evaluating the emissions reduction potential of GS operations.[18] After 100 years, an annual leakage rate of 0.1 percent would result in the retention of approximately 90 percent of the original CO_2 injected, corresponding to an LLR of 10 percent. There is nothing to suggest, however, that an LLR of 10 percent is the absolute lowest amount of leakage possible in any reservoir. An annual leakage rate of 0.5 percent is equivalent to 60 percent retained, or an LLR of 40 percent. Therefore, we use 40 percent as the upper bound of LLR across all strategies.[19]

Identifying a mean LLR and setting ranges for each strategy within this larger range is more complicated. The difference between the leakage potential of depleted hydrocarbon reservoirs (*i.e.*, the Afterthought and Planned strategies) and deep saline aquifers (*i.e.*, the Dedicated strategy) is not well understood. In light of this uncertainty, we outline the LLRs for each strategy in Table 3 below.

Table 3: LLRs by Strategy

	Values[a]			
Strategy	**Low**	**Mean**	**High**	**Notes**
Indifferent	-	-	-	Current EOR operations do not earn revenues related to CO_2 storage.
Afterthought	0.20[b]	0.30[b]	0.40[b]	At the end of a typical EOR operation, the reservoir geology likely is compromised from tens, if not hundreds, of production wells. We expect the LLR to be highest in this strategy.
Planned	0.10[c]	0.20[c]	0.30[c]	We expect well control and other methods for the co-optimization of oil recovery and CO_2 storage to yield better LLRs than the Afterthought strategy.
Dedicated	0.01[d]	0.055[d]	0.10[d]	GS operations in deep saline aquifers, with lightly disturbed reservoir geology, should yield the lowest LLRs of any strategy.

Notes:
a. Indicates the ratio of CO_2 stored relative to CO_2 injected.
b. Our estimate. Based on the higher end of the range identified by Ha-Duong and Keith (2003).
c. Our estimate. Based on the lower end of the range identified by Ha-Duong and Keith (2003).
d. Our estimate. Based on the Hepple and Benson (2005) GS goal of 90 to 99 percent retention of injected CO_2. Only undisturbed deep saline aquifers are used, as Bossie-Codreanu and Le Gallo (2004) note that cap-rock integrity is a key factor related to the leakage potential of the site.

18 We note in this regard that several trapping mechanisms (*e.g.*, structural, capillary, solubility, and mineral) mitigate leakage at different periods and to different degrees over the lifetime of the project (Benson and Cole 2008). Therefore, within this 100-year time frame, periods of non-zero leakage appear possible. As we focus on project lifetimes in this analysis, we are more interested in the total amount of CO_2 leaked over the lifetime of the project, as opposed to variations in leakage rates over certain periods of a project.

19 Hepple and Benson (2005) suggest that the goal of sequestration should be the retention of 90 to 99 percent of the original CO_2 injected. Because site operators in this model receive compensation for only the amount of original CO_2 not leaked over the lifetime of the project, the extrapolated Ha-Duong and Keith (2003) range of 60 to 90 percent of the injected CO_2 retained provides a conservative estimate for revenues from CO_2 sequestration.

4.2.3. Total Project Costs

We consider three categories of costs for each strategy: (a) transportation; (b) storage (injection); and (c) monitoring. We discuss each of these costs individually below. All costs are in USD per metric ton of CO_2 unless otherwise noted.

Transportation Costs

CO_2 transportation by pipeline for EOR operations is a mature practice in the U.S., with over 2,500 km of pipeline transporting 40 $MtCO_2$ annually to supply underground injection (de Figueiredo 2007; IPCC 2005). Pipelines also are expected to be the least-cost transportation option for long-term GS operations (Bielicki 2008).

Total transportation costs for any operation are partially a function of pipeline distance from the CO_2 source to an injection site (Bielicki 2008; McCoy and Rubin 2008). Geospatial modeling by Dahowski and Dooley (2004) indicates that most depleted hydrocarbon reservoirs lie more than 50 miles from existing large-scale CO_2 sources, whereas most aquifer storage lies fewer than 50 miles from the same sources. Therefore, strategies that employ storage with some type of EOR (*i.e.*, the Indifferent, Afterthought, and Planned strategies) face longer transport distances in this model than the strategy without EOR (*i.e.*, the Dedicated strategy). Our estimates and assumptions for transportation costs are outlined in Table 4 below.

Table 4: Transportation Costs by Strategy

Strategy	Values[a] Low	Mean	High	Notes
Indifferent	$3.79[b]	$5.41[c]	$7.03[d]	Estimate of a 200-km pipeline.
Afterthought	$3.79[b]	$5.41[c]	$7.03[d]	Estimate of a 200-km pipeline.
Planned	$3.79[b]	$5.41[c]	$7.03[d]	Estimate of a 200-km pipeline.
Dedicated	$0.75[e]	$1.16[f]	$3.56[g]	Estimate of a 100-km pipeline. May be conservative based on the average distance from CO_2 source to aquifer of less than 50 km, as reported by Dahowski and Dooley (2004).

Notes:
a. Indicates cost (USD) per metric ton of CO_2 injected.
b. Our estimate. McCoy and Rubin (2008) note 30 percent variation in costs; calculated as 30 percent less than the corresponding mean value.
c. Estimated levelized cost of a 200-km pipeline with a 75 percent capacity factor (McCoy and Rubin 2008).
d. Our estimate. McCoy and Rubin (2008) note 30 percent variation in costs; calculated as 30 percent greater than the corresponding mean value.
e. Minimum value predicted by the McCoy and Rubin (2008) model for a 100-km pipeline with a 100 percent capacity factor.
f. Estimated levelized cost of a 100-km pipeline with a 100 percent capacity factor (McCoy and Rubin 2008).
g. Maximum value predicted by the McCoy and Rubin (2008) model for a 100-km pipeline with a 100 percent capacity factor.

Storage Costs

Storage costs encompass all costs incurred by site operators in the injection, operation, maintenance, and closure of a site secured for long-term GS. These costs are largely a function of the amount of CO_2 initially injected. The IPCC (2005) has identified storage costs based on reservoir type, which we deem applicable to all strategies of the model. The estimates for storage costs are listed in Table 5 below.

Table 5: Storage Costs by Strategy

Strategy	Values[a,b] Low	Mean	High	Notes
Indifferent	-	-	-	Current EOR operations do not seek long-term CO_2 storage.
Afterthought	\$0.50	\$1.30	\$4.00	Storage costs for a depleted hydrocarbon reservoir in the U.S.
Planned	\$0.50	\$1.30	\$4.00	Storage costs for a depleted hydrocarbon reservoir in the U.S.
Dedicated	\$0.40	\$0.50	\$4.50	Storage costs for a deep saline aquifer in the U.S.

Notes:
a. Indicates cost (USD) per metric ton of CO_2 injected.
b. IPCC (2005).

Monitoring Costs

The final component of total project cost is the cost related to long-term monitoring of the site to ensure environmental integrity. It appears that many monitoring technologies and practices used for ongoing EOR operations can be adapted for the long-term monitoring of stored CO_2. Table 6 outlines our estimates for monitoring costs.

Table 6: Monitoring Costs by Strategy

Strategy	Values[a] Low	Mean	High	Notes
Indifferent	-	-	-	Long-term CO_2 monitoring not appropriate for current EOR operations.
Afterthought	\$0.27[b]	\$0.30[c]	\$0.33[d]	Storage costs for a depleted hydrocarbon reservoir in the U.S.
Planned	\$0.15[b]	\$0.17[e]	\$0.19[d]	Storage costs for a depleted hydrocarbon reservoir in the U.S.
Dedicated	\$0.16[f]	\$0.18[g]	\$0.19[h]	Storage costs for a deep saline aquifer in the U.S.

Notes:
a. Indicates cost (USD) per metric ton of CO_2 injected.
b. Our estimate. Minus 10 percent of the corresponding mean value.
c. “Enhanced monitoring package” for an “EOR reservoir” from Benson et al. (2004).
d. Our estimate. Plus 10 percent of the corresponding mean value.
e “Basic monitoring package” for an “EOR reservoir” from Benson et al. (2004).
f. Lower end of the “basic monitoring package” for a “saline formation” from Benson et al. (2004).
g. Straight-line average of the corresponding low and high values.
h. Upper end of the “basic monitoring package” for a “saline formation” from Benson et al. (2004).

4.3 Major Assumptions

In this analysis, we fix the quantity of CO_2 injected across all scenarios to enable the comparison between EOR and GS operations.[20] We assume that the amount of CO_2 injected is

[20] This approach is analogous to examining the per-ton return to injecting CO_2, regardless of operational purpose.

optimized for the operational purposes of that strategy. To achieve this optimization, we allow the size of the reservoir across strategies to vary.[21] By fixing the total amount of CO_2 injected across strategies, we can compare the lifetime net revenues of each *strategy*, instead of comparing the lifetime net revenues of different strategies *for a particular storage site*.

This "reservoir-less" approach permits a broad examination of GS versus EOR operations, rather than focusing on the idiosyncrasies of reservoirs. In this regard, we acknowledge that lifetime net revenues *for particular storage sites* likely will be dependent on the geologic characteristics of the formation and the quantity of CO_2 that can be injected, and there is a role for further research on the economies of scale for individual formations. We assume that economies of scale are identical across strategies.[22]

To compare total revenues across strategies, we focus on a lifetime net-revenue analysis in recognition of the different lifetimes of EOR and GS operations. The lifetime of an EOR operation could be as short as 10 years, whereas a GS project may continue for hundreds of years before monitoring is complete. In this regard, we do not discount future cash flows.

We assume that capture costs are equal across all strategies, and we set these costs to zero. Depending on the policy instrument(s) used to price CO_2 emissions, capture costs could vary significantly and be absorbed or passed through at different points by various emitters.[23] We have no reason to believe that sophisticated site operators would experience different capture costs across strategies, because all strategies use CO_2 from anthropogenic sources.[24]

---

[21] By way of illustration, to optimize the operational purposes of the Afterthought and Indifferent strategies with the same amount of CO_2 injected, the Afterthought strategy (*i.e.*, oil recovery, then CO_2 storage) likely would exist in a much smaller reservoir than the Indifferent strategy (*i.e.*, oil recovery alone). If we invert this approach—*i.e.*, by fixing reservoir size and varying the amount of CO_2 injected across strategies—a sophisticated site operator likely would inject more CO_2 under the Afterthought strategy than under the Indifferent strategy, to both (a) yield the same amount of oil as the Indifferent strategy; and (b) store CO_2 in the formation.

[22] Bielicki (2008) states:

> Each segment of the CCS chain – capture at source, transportation in pipeline, and storage in reservoir – can benefit from increasing returns to scale, but the coupling of the technological cost structures over space determines the returns to scale for the overall system.

He finds further that capture costs typically are the largest cost component of integrated CCS systems (Bielicki 2008). Because our analysis compares strategies after the point of capture, we find that our analysis is more sensitive to the revenues than to the costs of each strategy. We found that results generally were not sensitive to even large shifts in the range of transportation, injection, and monitoring costs across strategies.

[23] Patiño-Echeverri et al. (2007) contains a detailed discussion of power-plant capture technology options.

[24] Although several EOR operations currently use naturally occurring pockets of CO_2 instead of anthropogenic sources, this is not necessarily a requirement for all EOR operations (Anderson and Newell 2004).

For strategies that recover oil, we assume that the injected CO_2 is not recycled.[25] EOR operations in the past have recycled CO_2 returned to the surface with oil recovery in order to save on CO_2 costs (White et al. 2004).[26] In this regard, we assume that any return of injected CO_2 to the surface occurs only as a result of leakage across the lifetime of the project.[27]

5. Model Results: Transitions from EOR to GS

Each strategy yields separate lifetime net revenues based on the different ORRs, LLRs, and total costs outlined in Section 4. As would be expected, all four strategies yield different lifetime net revenues under various scenarios of oil and CO_2 prices. Several figures in this section present particular combinations of ORRs, LLRs, and total costs. These combinations include (a) "Best-Case EOR"; (b) "Best-Case GS"; and (c) "Best-Case Hybrid EOR-GS."[28] Each named combination highlights particular combinations of ORRs, LLRs, and total costs that are most favorable to EOR operations, GS operations, or hybrid EOR-GS operations, respectively, under most scenarios of oil and CO_2 prices.

We illustrate the results of this model in two ways. First, we present results for these particular combinations under scenarios of oil prices up to 100 USD/barrel and CO_2 prices up to

---

[25] Because we assume that CO_2 is not recycled in the EOR process, we assume further that the energy costs (and related CO_2 emissions) associated with injection and re-injection proceses are not included in the analysis.

[26] Experience from the Weyburn reservoir has shown CO_2 recycling to return approximately 20% of the CO_2 originally injected for further use (White et al. 2004). Because CO_2 recycling currently is used at several EOR sites, we infer that recycling and re-injecting a unit of CO_2 is cheaper than aquiring a "new" unit of CO_2 from the source pipeline. Because this analysis ignores CO_2 recycling, we believe our cost estimates are conservative, as all CO_2 injected originates from the source pipeline. We also note that our ORR estimates are undisturbed, because the ORR is a function of CO_2 injected, regardless of whether that CO_2 came from the source pipeline or through recycling.

[27] This return of CO_2 to the surface would be the result of the leakage pathways described earlier. This assumption may appear inconsistent with current miscible EOR operations, in which CO_2 returns to the surface with the recovered oil (*i.e.*, we would underestimate the amount of CO_2 injected as part of a hybrid EOR-GS operation, because additional CO_2 would need to be injected to supplement the CO_2 returned to the surface as part of the EOR operation). However, we note that CO_2 recycling is ignored in this model (*i.e.*, we would overestimate the amount of CO_2 injected as part of a hybrid EOR-GS operation, because we do not account for the reuse of CO_2 for the EOR operation and ultimately stored as part of the GS operation). Taken together, these two assumptions may partially offset the bias that each introduces individually. However, we note in this regard that the particular impact of these assumptions may be subject to the variation in the site-specific characteristics of any formation.

[28] We do not identify any "worst-case" combinations. Instead we assume that the ORR, LLR, and total costs that are optimal for one combination are sub-optimal for other combinations.

250 USD/metric ton.[29] Second, we present results for these particular combinations under an expected long-term oil price and projected CO_2 prices under a climate-change policy over time. This second presentation method permits a temporal understanding of the shift from EOR to GS operations. We describe these results in the subsections below.

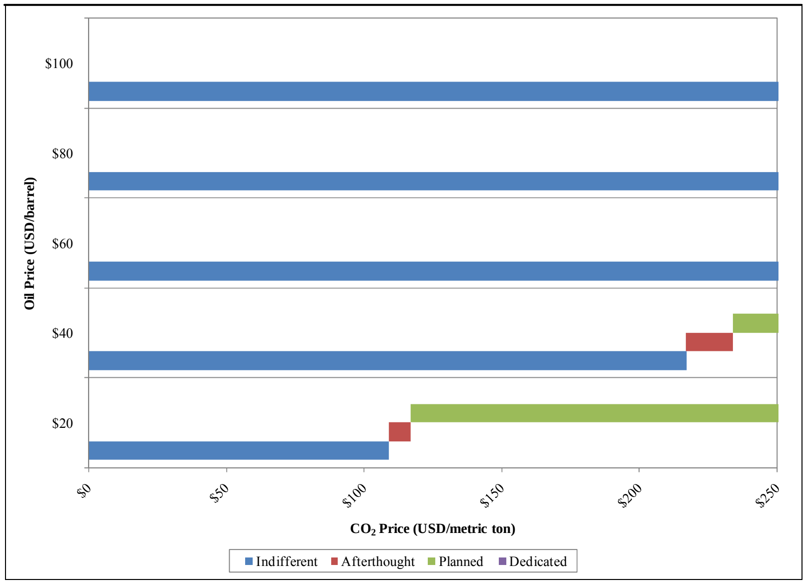
5.1 Model Results for Ranges of Oil and CO_2 Prices

This first set of results presents three combinations of ORRs, LLRs, and total costs, which we have termed (a) Best-Case EOR; (b) Best-Case GS; and (c) Best-Case Hybrid EOR-GS. In each figure, we present oil prices of 20, 40, 60, 80, and 100 USD/barrel, and CO_2 prices from zero to 250 USD/metric ton.

The Best-Case EOR combination is characterized by a high ORR, a high LLR, and low costs. This combination is illustrative of formations with generous oil recovery (where possible) and significant leakage across the board. The results for the Best-Case EOR combination are presented in Figure 2 below. It is apparent that any GS operation generates the greatest net revenues at low prices of oil (*i.e.*, less than 40 USD/barrel) and high prices of CO_2 (*i.e.*, greater than 100 USD/metric ton).

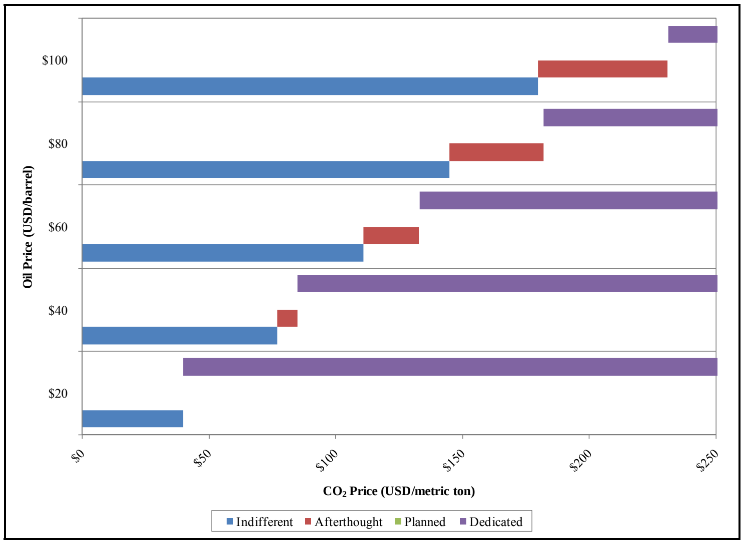
[29] Although in recent history oil prices have exceeded the 100 USD/barrel considered here, our analysis reveals that the Indifferent strategy is dominant for oil prices greater than 100 USD/barrel. Therefore, we limit our presentation and discussion of results to oil prices between 20 and 100 USD/barrel.

Figure 2: Best-Case EOR (high oil output, high leakage, low cost)



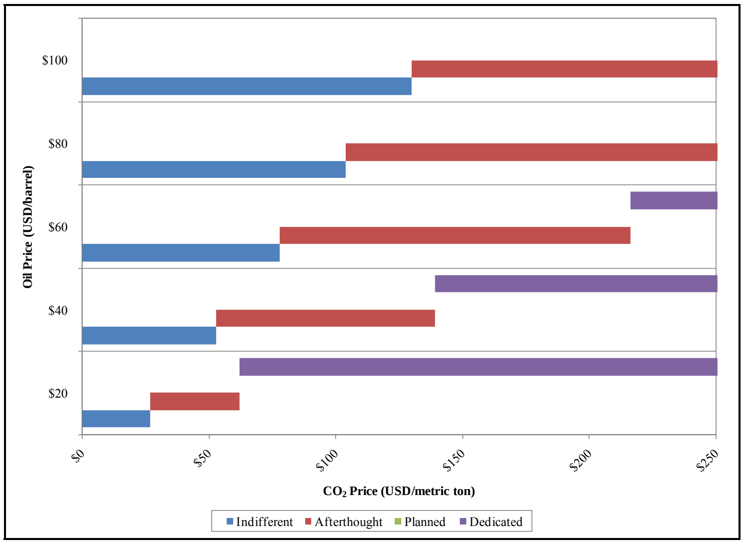
The Best-Case GS combination is characterized by low ORR, high LLR, and high costs. This combination is illustrative of formations with little oil recovery (where possible) and insignificant leakage across the board. The results for the Best-Case GS combination are presented in Figure 3 below. It is clear that GS operations in this combination generate the greatest net revenues at relatively lower CO_2 prices compared to the Best-Case EOR combination for a given price of oil. The Best-Case GS combination also demonstrates that it is possible to “skip” strategies—e.g., at an oil price of 20 USD/barrel, the most preferred strategy “jumps” from Indifferent to Dedicated near 50 USD/metric ton of CO_2.

Figure 3: Best-Case GS (low oil output, high leakage, high cost)



The Best-Case Hybrid EOR-GS combination is characterized by low ORR, low LLR, and low costs. This combination is illustrative of formations with little oil recovery (where possible) and insignificant leakage across the board. This combination also has low costs, as opposed to the high costs that characterize the Best-Case GS combination. The results for the Best-Case Hybrid EOR-GS combination are presented in Figure 4 below. It is interesting that hybrid EOR-GS operations in this combination generate the greatest net revenues at relatively lower CO_2 prices than the Best-Case GS combination.

Figure 4: Best-Case Hybrid EOR-GS (low oil output, low leakage, low cost)



Given the volatility and recent spikes in oil prices, low oil prices appear unlikely to be the norm in the long run. DOE projections show oil prices ranging from approximately 70 to 130 USD/barrel for the years 2010 to 2035 (DOE 2010a).[30] For this range of oil prices, the Afterthought strategy becomes most profitable at approximately 100 USD/metric ton of CO_2 in the Best-Case Hybrid EOR-GS combination. The Dedicated strategy becomes most profitable at approximately 150 USD/metric ton of CO_2 in the Best-Case GS combination. This first collection of results suggests that merely "putting a price on CO_2" likely will not provide a sufficient financial incentive to promote the widespread deployment of GS operations.[31]

5.2 Model Results for Expected CO_2 Prices under a Climate Policy

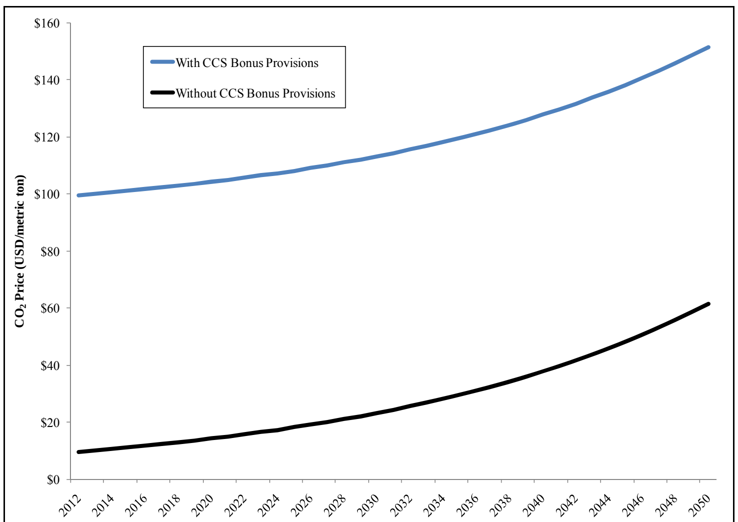
To focus our understanding of the transition from EOR to GS operations over time, we limited the analysis to oil and CO_2 prices estimated in governmental projections. Oil-price projections are based on DOE estimates, and the results for a long-term oil price of 70

[30] Projections are from the "Reference Case" and provided in 2008 USD.

[31] This finding is consistent with the capture-related findings contained in Patiño-Echeverri et al. (2007)—higher prices of CO_2 are required to incent the installation of CO_2 capture technologies on coal-fired power plants.

USD/barrel are presented here.[32] CO_2-price projections are based on EPA estimations of the American Clean Energy and Security Act of 2009 (ACESA).[33] In this second set of results, we provide results for two projections of CO_2 prices: (a) estimated CO_2 prices under ACESA;[34] and (b) estimated CO_2 prices with our inference on the CCS-specific bonus provisions outlined in ACESA.[35] These two CO_2 price projections are presented in Figure 5 below.

Figure 5: CO_2 Price Projection under ACESA with our Inference on CCS Bonus Provisions



Source: EPA 2009.

[32] DOE projections show oil prices ranging from approximately 70 to 130 USD/barrel for the years 2010 to 2035 (DOE 2010a). Based on the first set of results for ranges of oil and CO_2 prices, GS expectedly becomes less financially attractive as the long-term price of oil rises. Therefore, we present the projected oil price most favorable to GS, in recognition that anything greater makes the transition from EOR to GS less financially attractive for a given price on CO_2.

[33] Also informally known as the "Waxman-Markey" climate bill.

[34] The price path from EPA's IGEM model of EPA Scenario 2 of the bill (EPA 2009).

[35] Section 786 of the bill outlines provisions for bonus allowances related to CCS operations (S. 1 2009). For the first six gigawatts (GW) of CCS projects deployed under the bill, operators can receive a bonus of up to 90 USD/metric ton of CO_2. If operators capture less than 85 percent of the emitted CO_2, the bonus is adjusted downward. The bonus also can be adjusted downward if the captured CO_2 will be used for the purposes of EOR as opposed to GS. To incorporate the CCS bonus provisions into our analysis, we add 90 USD/metric ton to the CO_2 prices estimated by EPA for all years, with the understanding and caveat that this is a generous interpretation of the CCS bonus provisions regarding CO_2 prices.

For these two CO_2 price projections, we present results for the years 2012 to 2050 for each of the Best-Case combinations, which include (a) Best-Case EOR; (b) Best-Case GS; and (c) Best-Case Hybrid EOR-GS. Results for all three Best-Case combinations under the two CO_2 price projections are presented in Figure 6 below.

Figure 6: Results for Best-Case Combinations for CO_2 Price Projections under ACESA

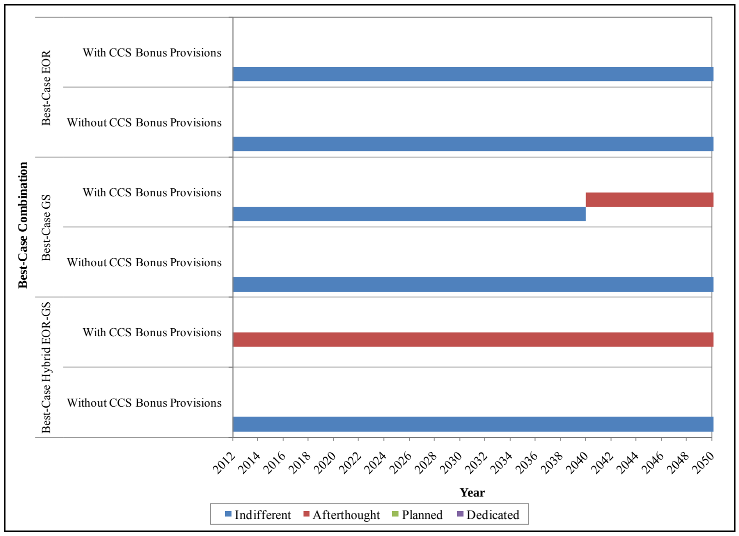


Figure 6 illustrates the challenge associated with designing appropriate incentives for GS deployment. Given a price on CO_2 without CCS bonus provisions, the Indifferent strategy is dominant across all three Best-Case combinations. Given a price on CO_2 and CCS bonus provisions, the Indifferent strategy remains dominant for one of three Best-Case combinations (*i.e.*, Best-Case EOR). The Afterthought strategy dominates in only the Best-Case GS and Best-Case Hybrid EOR-GS combinations with CCS bonus provisions. Further, the Afterthought strategy dominates only the Best-Case GS combination for the later period of the CO_2 price projection. The Planned and Dedicated strategies are not dominant for any period of the CO_2 price projections under any Best-Case combination.

The timing of these transitions under our optimistic interpretation of the ACESA CCS bonus provisions suggests that GS-related strategies might require substantial incentives to support near-term deployment. As Figure 6 illustrates, lower prices of CO_2 are unlikely to spur widespread investment in GS. Instead, CO_2 prices must reach levels much higher than the prevailing prices in current carbon markets like the ETS (PointCarbon, Inc. 2008). This finding suggests that CCS bonus provisions are a critical component of any climate and/or energy policy that seeks widespread GS deployment. This finding also is consistent with the relationship of the largest GS projects currently in operation (*e.g.*, the Sleipner, Weyburn, and In Salah operations) to oil or gas extraction.

6. Conclusions and Policy Implications

This analysis illustrates the challenge of designing policies for GS given the diversity of project types and risks associated with the option. Although EOR operations can serve as a technical foundation for GS in many respects, foregoing oil recovery to store CO_2 in deep saline aquifer formations can be costly. Our dominant-strategy approach indicates that oil prices have a far greater impact on total net revenues than both project costs and the storage integrity of the site (*i.e.*, the LLR). In the absence of very high prices of CO_2 (*i.e.*, greater than 200 USD/metric ton), our analysis indicates that GS operations likely may co-exist with EOR operations for some time, even under more favorable conditions to dedicated GS operations.

These results suggest that a price on CO_2 is needed for any deployment of GS, although early prevailing prices of CO_2 likely will incent only hybrid EOR-GS operations, if that. Generous bonus provisions for CCS are needed to encourage dedicated GS operations. Even with the CCS bonus provisions as proposed in ACESA, the near-term GS deployment likely would consist primarily of hybrid EOR-GS operations. Higher oil prices further diminish the financial motivation to forego oil recovery completely for a dedicated GS operation, making stand-alone GS operations unlikely to dominate the investment decisions of sophisticated site operators in the near term.

These results have serious implications for risk management and regulatory design. Near-term deployment of mostly hybrid EOR-GS operations may require more stringent regulations due to the potentially greater risk of leakage associated with storage in depleted hydrocarbon reservoirs. Similarly, a regulatory framework designed to address all GS projects must address the different probabilities and/or potential types of leakage associated with different storage formations. This suggests a need for tiered standards or targeted regulation based on the storage formation and/or the operational goals of the project, both to reduce investment uncertainty and to address varying long-term liabilities associated with different project types. (With regard to the current EPA UIC proposal, reapplication as a Class VI well should be required for any well that initially was permitted as a Class II well in order to begin GS operations.) At minimum, these findings warrant caution in merely extending the regulatory framework of EOR operations to GS operations without careful scrutiny.

Widespread deployment of GS currently is difficult, for several reasons beyond reaching various “trigger” prices of oil and CO_2. For example, other barriers include (a) the uncertainty surrounding the long-term behavior of injected CO_2 underground; (b) related geophysical, health, and environmental risks to underground CO_2 migration; and (c) ambiguity over long-term stewardship of the site. Regardless, an understanding of the transition from EOR to GS operations is essential for designing effective regulations that ensure both investment in and long-term public acceptance of GS as a major climate-change mitigation option. Our analysis addresses this potential co-evolution of EOR and GS projects, demonstrating how profit maximization under different strategies and various price scenarios may shape the deployment of an emerging technology in an uncertain regulatory environment.

References

American Clean Energy and Security Act of 2009, S. 1, 111th Cong. (2009).

Anderson, S. and R. Newell. 2004. "Prospects for Carbon Capture and Storage Technologies," *Annual Review of Environment and Resources*, November *29*: pp. 109-142.

Benson, S.M. 2005. "Lessons Learned from Natural and Industrial Analogues," in *Carbon Dioxide Capture for Storage in Deep Geologic Formations—Results from the CO_2 Capture Project, Vol. 2: Geologic Storage of Carbon Dioxide with Monitoring and Verification*. London, UK: Elsevier Publishing.

Benson, S.M. and D.R. Cole. 2008. "CO_2 Sequestration in Deep Sedimentary Formations," *Elements*, October *4*(5): pp. 325-331.

Benson, S.M., E. Gasperikova, and M. Hoversten. 2004. "Overview of Monitoring Techniques and Protocols for Geologic Storage of CO_2," IEA Greenhouse Gas R&D Programme.

Bielicki, J.M. 2008. "Returns to Scale for Carbon Capture and Storage Infrastructure and Deployment," Kennedy School of Government, Harvard University. Belfer Center for Science and International Affairs Discussion Paper 2008-04.

Bossie-Codreanu, D. and Y. Le Gallo. 2004. "A Simulation Method for the Rapid Screening of Potential Depleted Oil Reservoirs for CO_2 Sequestration," *Energy*, July-August *29*(9-10): pp. 1347-1359.

Dahowski, R.T. and J.J. Dooley. 2004. "Carbon management strategies for US electricity generation capacity: A vintage-based approach," *Energy*, July-August *29*(9-10): pp. 1589-1598.

Damen, K., A. Faaij, and W. Turkenburg. 2006. "Health, Safety and Environmental Risks of Underground CO2 Storage – Overview of Mechanisms and Current Knowledge," *Climate Change*, January *74*(1-3): pp. 289-318.

de Figueiredo, M. 2007. "The Liability of Carbon Dioxide Storage," Massachusetts Institute of Technology. Ph.D. dissertation.

DOE (U.S. Department of Energy). 2008. "DOE's FutureGen Initiative," *available at* www.fossil.energy.gov/programs/powersystems/futuregen/ (last visited May 10, 2010).

DOE. 2009. "EIA – Petroleum Basic Data," *available at* www.eia.doe.gov/basics/quickoil.html (last visited May 15, 2010).

DOE. 2010a. "Annual Energy Outlook 2010," *available at* www.eia.doe.gov/oiaf/aeo/ (last visited June 28, 2010).

DOE. 2010b. "International Energy Outlook 2010," *available at* www.eia.doe.gov/oiaf/ieo/ (last visited June 28, 2010).

DOE. 2010c. "NETL Carbon Capture and Storage Database," *available at* www.netl.doe.gov/technologies/carbon_seq/database/ (last visited June 2, 2010).

Dooley, J.J., R.T. Dahowski, C.L. Davidson, S. Bachu, N. Gupta, and J. Gale. 2004. "A CO_2-Storage Supply Curve for North America and its Implications for the Deployment of Carbon Dioxide Capture and Storage Systems," University of Maryland, College Park. Joint Global Change Research Institute.

Emberley, S., I. Hutcheon, M. Shevalier, K. Durocher, W.D. Gunter, and E.H. Perkins. 2004. "Geochemical Monitoring of Fluid-Rock Interaction and CO_2 Storage at the Weyburn CO_2-Injection Enhanced Oil Recovery Site, Saskatchewan, Canada" *Energy*, July-August *29*(9-10): pp. 1393-1401.

EPA (U.S. Environmental Protection Agency). 2008. "Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Proposed Rule," *Federal Register*, 25 July: pp. 43492-43541.

EPA. 2009. "EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the *111th Congress*," *available at* www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf (last visited June 20, 2010).

European Commission. 2006. "Sustainable Power Generation from Fossil Fuels: Aiming for Near-Zero Emissions from Coal after 2020," *available at* www.ec.europa.eu/energy/energy_policy/doc/16_communication_fossil_fuels_en.pdf (last visited May 10, 2010).

Ha-Duong, M. and D. Keith. 2003. "Carbon Storage: The Economic Efficiency of Storing CO_2 in Leaky Reservoirs," *Clean Technologies and Environmental Policy*, *5*(3-4): pp. 181-189.

Heinrich, J.J., H.J. Herzog, and D.M. Reiner. 2003. "Environmental Assessment of Geologic Storage of CO_2," Massachusetts Institute of Technology. Laboratory for Energy and the Environment.

Hepple R.P. and S.M. Benson. 2005. "Geologic storage of carbon dioxide as a climate change mitigation strategy: Performance requirements and the implications of surface seepage," *Environmental Geology*, March *47*(4): pp. 576-585.

Hovorka, S.D., S.M. Benson, C. Doughty, B.M. Freifeld, S. Sakurai, T.M. Daley, Y.K. Kharaka, M.H. Holtz, R.C. Trautz, H.S. Nance, L.R. Myer, and K.G. Knauss. 2006. "Measuring permanence of CO_2 storage in saline formations: the Frio experiment," *Environmental Geosciences*, June *13*(2): pp. 105-121.

IEA (International Energy Agency). 2006. "IEA Energy Technology Essentials: CO_2 Capture & Storage," *available at* www.iea.org/textbase/techno/essentials1.pdf (last visited May 10, 2010).

IPCC (Intergovernmental Panel on Climate Change). 2005. *IPCC Special Report on Carbon Dioxide Capture and Storage*. Prepared by Working Group III of the IPCC, edited by Metz, B., O. Davidson, H.C. de Coninck, M. Loos, and L.A. Meyer. Cambridge, MA: Cambridge University Press.

Kallbekken, S. and A. Torvanger. 2004. "Can Geological Carbon Capture and Storage Be Competitive?" CICERO (Center for International Climate and Environmental Research Oslo). Working Paper.

Koottungal, L. 2008. "2008 Worldwide EOR Survey," *Oil & Gas Journal,* April: pp. 47-59.

Kovscek, A.R. and M.D. Cakici. 2005. "Geologic storage of carbon dioxide and enhanced oil recovery. II. Cooptimization of storage and recovery," *Energy Conversion and Management*, July *46*(11-12): pp. 1941-1956.

Martin, D.F. and J.J. Taber. 1992. "Carbon Dioxide Flooding," *Journal of Petroleum Technology*, April *44*(4): pp. 396-400.

McCoy, S.T. and E.S. Rubin. 2008. "An engineering-economic model of pipeline transport of CO_2 with application to carbon capture and storage," *International Journal of Greenhouse Gas Control*, April *2*(2): pp. 219-229.

Pacala, S. 2003. "Global Constraints on Reservoir Leakage," in J. Gale and Y. Kaya, eds., *Proceedings* of the *Sixth* International Conference on *Greenhouse Gas Control Technologies.* Amsterdam, the Netherlands: Pergamon Press.

Pacala, S. and R. Socolow. 2004. "Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies," *Science*, August *305*(5686): pp. 968-972.

Patiño-Echeverri, D., B. Morel, J. Apt, and C. Chen. 2007. "Should a Coal-Fired Power Plant be Replaced or Retrofitted?" *Environmental Science & Technology*, December *41*(23): pp. 7980-7986.

PointCarbon, Inc. 2008. "Carbon 2008: Post-2012 is now," *available at* www.pointcarbon.com/research/carbonmarketresearch/analyst/1.912721 (last visited June 20, 2010).

Safe Drinking Water Act of 1974. P.L. 93-523, Dec. 16, 1974, 88 Stat. 1660.

SPE (Society of Petroleum Engineers). 2010. "Glossary of Industry Terminology," *available at* www.spe.org/industry/reference/glossary.php (last visited May 10, 2010).

Stephens, J.C. and B.C.C. van der Zwaan. 2005. "The Case for Carbon Capture and Storage," *Issues in Science and Technology*, Fall *22*(1): pp. 69-76.

White, D.J., G. Burrowes, T. Davis, Z. Hajnal, K. Hirsche, I. Hutcheon, E. Majer, B. Rostron, and S. Whittaker. 2004. "Greenhouse Gas Sequestration in Abandoned Oil Reservoirs: The International Energy Agency Weyburn Pilot Project," *GSA Today*, July *14*(7): pp. 4-10.

Wilson, E.J., M.G. Morgan, J. Apt, M. Bonner, C. Bunting, M.A. de Figueiredo, J. Gode, C.C. Jaeger, D.W. Keith, S.T. McCoy, R.S. Haszeldine, M.F. Pollak, D.M. Reiner, E.S. Rubin, A. Torvanger, C. Ulardic, S.P. Vajjhala, D.G. Victor and I.W. Wright. 2008. "Regulating the Geological Sequestration of Carbon Dioxide," *Environmental Science & Technology*, April *42*(8): pp. 2718-2722.

Wilson, E.J., T.L. Johnson, and D.W. Keith. 2003. "Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage," *Environmental Science & Technology*, August *37*(16): pp. 3476-3483.