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Risk Assessment for future CO₂ Sequestration Projects Based CO₂ Enhanced Oil Recovery in the U.S.

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Abstract

This paper is the first of a series that attempts to assess the possible health and safety risks associated with large scale CO₂ sequestration in deep brine reservoirs. The approach is based on analysis of available data on the operational track record from CO₂ transportation and injection associated with enhanced oil recovery (CO₂-EOR) in the US. This paper is particularly concerned with identification of the main business risks facing a company engaged in geological sequestration. Such risks include both the operational risks of capturing, compressing, transporting and injecting CO₂, as well as the risk of accidental, rapid CO₂ release from wells (including an analysis of blow out data from CO₂ injection wells, worked over wells as well as abandoned wells). Observations of the outcomes from accidents in real pipelines and CO₂ injection wells in CO₂-EOR projects provide the most concrete basis to predict the future safety of the above ground operations of CO₂ sequestration in deep brine reservoirs.

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1. Introduction

Climate change concerns are driving attempts to lower the carbon intensity of global energy production. The US has more energy resources in coal deposits than the Middle East has in oil. Coal can be extracted at low costs, and can play a major role in the future energy portfolio if cost effective separation and sequestration of CO₂ emissions can be developed. The aim of geological CO₂ sequestration is to attempt to moderate climate change by effecting long-term subsurface CO₂ storage to decrease the rate of CO₂ growth in the atmosphere. To capture and put CO₂ into long term storage in deep-brine reservoirs, oil reservoirs, and/or depleted gas fields. Most risk studies of geologic carbon sequestration have either focused on the probability that leakage could result in safety or health issues or have attempted calculate general leakage probabilities. Although safety and health issues are always of paramount concern, the excellent safety and health record of the CO₂ industry in the Permian Basin of West Texas may suggest that these issues are not a major component of the business risk faced by a putative carbon sequestration industry.

This paper is particularly concerned with identification of the main business risks facing a company engaged in geological sequestration. Such risks include: (1) the operational risks of capturing, compressing, transporting and injecting CO₂; (2) the risk of blowouts or very rapid CO₂ release from wells; (3) the risk that CO₂ put into long term geologic storage will leak into shallow aquifers and contaminate potable water by lowering pH and increasing dissolved metals and other components; and (4) the risk that sequestered CO₂ (and possibly associated methane gas) will leak into the atmosphere reversing the climate change benefits of sequestration and perhaps requiring repayment of CO₂ sequestration credits. Of these risks the first two can be directly

addressed by looking at the track record of the CO₂-EOR industry. The technology and practices used by the CO₂-EOR industry in handling and injecting CO₂ is a valuable resource for future CO₂ sequestration projects.

The CO₂-EOR industry has more than 35 years of experience in successfully transporting and injecting CO₂. In the US alone the industry operates thousands of CO₂ EOR wells, over 3,500 miles of high pressure CO₂ pipelines, has injected over 600 million tons of CO₂ (11 trillion standard cubic feet) and produces about 245,000 barrels of oil a day from CO₂ EOR projects. Few risk studies have looked at the pragmatic problem of how to evaluate the absolute (or relative) risk of sequestration projects in specific sites. The initial stage of planning a large-scale carbon storage project requires evaluation of the relative risks associated with specific alternative sequestration sites. A risk assessment will likely be required before corporations can finance such projects and such a study is also the first step in setting up risk management strategies.

The risks associated with CO₂ sequestration in brine reservoirs have been addressed in an EU funded study of geological CO₂ sequestration (Holloway [1]). It has also been analyzed in some detail in the environmental impact assessments completed for the four competing sites for the ill-fated FutureGen project. An important aim of designing large scale pilot injection programs such as Phase III of the Carbon Sequestration Partnership should be to gather information that will help companies to better evaluate the business risks associated with geologic CO₂ sequestration. The identification of optimal sites for large-scale demonstration projects provides a challenging test for the utility of available risk models and approaches.

This paper assesses the possible health and safety risks associated with large scale CO₂ sequestration in deep brine reservoirs based on analysis of available data from CO₂ injection for enhanced oil recovery (CO₂ EOR) in the US. This paper is the first of a series that will make a systematic review of all accident and blowout data associated with CO₂ pipeline transport and injection available in the US. These papers will then use this data to examine the pragmatic problem of how to evaluate the absolute (or relative) risk of sequestration projects in specific sites. The initial stage of planning a large-scale carbon storage project requires evaluation of the relative risks associated with specific alternative sequestration sites. A risk assessment will be required before corporations can finance such projects and such a study is also the first step in setting up risk management strategies.

2. Operational Risks in CO₂-EOR

Holloway [2] suggested that risks related to the “transport and injection of carbon dioxide” are “reasonably well understood and already borne by the enhanced oil recovery industry in the USA”. This conclusion was supported by Heinrich et al. [3] who noted that such risks have been “successfully managed” for decades in the context of commercial EOR operations. Similarly de Figueiredo [4] has asserted that the risks associated with CO₂ injection into a brine reservoir has been “successfully managed” for decades in EOR operations. Recently this conclusion has been echoed by Robertson et al. [5] who asserted “Operational liability [for CO₂ sequestration in brine reservoirs] is similar to that already dealt with in the oil and gas industry and therefore few new issues should arise when applied to CCS”. Although the assertions of these authors may well be correct there are little published data or analysis to support them. In fact Connolly [6] has declared that “There is relatively little experience worldwide in managing the risks associated with CO₂, compared with oil and gas”.

Gale and Davidson [7] have suggested that the transportation of CO₂ pipeline is analogous to that of natural gas transport. They also suggest that although accident rate for CO₂ pipelines is similar to that for natural gas pipelines, the amount of damages associated with incidents for natural gas pipelines is much higher than for CO₂ pipelines. Significantly no serious injuries or deaths have been caused by accidents associated with CO₂ pipelines. In the Permian Basin pipeline complex the accident records started in the mid-1970s. Svensson et al. [8] have suggested that statistical data on pipeline safety for CO₂ pipelines used by the CO₂-EOR industry demonstrate that the risks for pipeline leakage “are lower than for natural gas or hazardous pipelines”. Barrie et al. [9] noted that the CO₂ pipelines constitute a smaller statistical sample compared to natural gas pipelines. They further suggest that it is “reasonable to suggest” that statistically of the projected number of CO₂ pipeline incidents “should be similar to those for natural gas transmission”. The risk associated with natural gas production and transportation is well known. Before a quantitative analysis can be made comparing the risks associated with CO₂ injection and transportation with natural gas it is desirable to get an improved understanding of CO₂-EOR industries safety record.

3. Risk associated with transport of CO₂ by pipelines

Case Study One: The Dakota Gasification Company Pipeline

This pipeline, operated by the Dakota Gasification Company, is 328 kilometers long and has a capacity of 5 million tons a year. The gas stream averages 95.95% CO₂ with an average 0.80% H₂S (occasionally as high as 2% H₂S). The pipeline system has a number of safety systems including leak/rupture detection and automatic block valve closure along the pipeline route. The entire pipeline and compression operations are monitored by telemetry giving 24-hour real-time measurements of pressures, temperatures and flow rates. This telemetry system provides the capability for early detection of potential problems.

In the event of a pipeline leak, block valves are used to isolate the affected section and limit the volume of CO₂ released. Any significant leak results in a pressure drop of a large leak that activates the shut-off valves. The spacing of such control valves is set by U.S. Department of Transportation (USDOT) safety regulations and safety considerations. The pipeline has been designed to be inspected by instrumented internal inspection devices designed to detect corrosion or other defects that may impact pipeline integrity. Since it started operating in 2000 the system has had only one very minor leakage incident caused by a component failure.

Case Study Two: Denbury Pipeline Complex

Denbury Resources, based in Plano, Texas, owns and operates 562 kilometers of CO₂ pipelines (Table 1) radiating from the Jackson Dome, a large source of natural CO₂ in Central Mississippi. The longest segment (the NEJD pipeline) built by Shell in the mid 1980's extends from the Jackson Dome to east central Louisiana. Safety monitoring of Denbury's pipelines is based on 24/7 real-time data transmission by satellite, monitoring of critical flow parameters including moisture level, flow rate, pressure, and temperature at strategic locations. These systems enable operators to balance the flow of CO₂ in and out of the pipeline, thus ensuring the integrity of the pipelines and reducing the response time for field personnel to respond on those rare occasions when a problem is detected.

Table 1. Some characteristics of selected CO₂ pipelines

Pipeline	Location	Operator	CO ₂ Capacity [Mt/year]	Length [km]	Construction Year	Origin of CO ₂
Cortez	USA	Kinder Morgan	19.3	808	1984	McElmo Dome
Sheep Mountain	USA	BP	9.5	660	-	Sheep Mountain
Bravo	USA	BP	7.3	350	1984	Bravo Dome
Val Verde	USA	Petrosource	2.5	130	1998	Val Verde Gas Plants
Bati Raman	Turkey	Turkish Petroleum	1.1	90	1983	Dodan Field
Weyburn	USA & Canada	North Dakota Gasification Co.	5	328	2000	Gasification Plant
NEJD	USA	Denbury	11.5	293	1986	Jackson Dome
Free State	USA	Denbury	6.7	138	2005	Jackson Dome
Delta	USA	Denbury	7.7	49	2008	Jackson Dome
Cranfield	USA	Denbury	2.88	82	1963	Jackson Dome
Total			73.48	2,928		

Denbury has had very few safety issues related to unintentional releases on its major cross-country CO₂ pipelines. Through a combination of good mechanical and cathodic protection design, sound construction practices, diligent surveillance, regular maintenance, and continuous monitoring of critical parameters (moisture, pressure, temperature, flow rate), Denbury's pipeline systems have been relatively trouble-free. The single biggest threat to the integrity remains to be involuntary shut downs due to third-parties damaging the pipeline (during activities such as trenching), loss of power and communications caused by weather events, for which precautionary measures are taken to minimize the impact. Five accidental releases of CO₂ have occurred since the pipeline operations resumed. The volumes of CO₂ released are difficult to measure during these events, but the leaks were fairly short in duration due to closing block valves and/or safety shut down systems.

On the Free State pipeline, two leak incidents occurred soon after pressurizing the line and were caused by manufacturing imperfections in welds. Both these leaks were too small to be detected by the flow measurement imbalance. A landowner called the toll-free number on the pipeline signage to alert the control room of unusual white smog emerging from the ground where the

pipeline was located on his property, triggering a response from Denbury's Operations group. The third incident on the Tinsley 8" line, occurred when an excavator accidentally cut the line. Company personnel were onsite for immediate dispatch to isolate the system. On the Barksdale 6-3 #1 flowline incident (cement lined pipe rupture due to inadequate weld pre-heating), automatic shut-downs and alarms worked as designed. In the fifth incident at a pump station was minimal and observed by on-scene personnel. On the Free State pipeline, each leak caused minimal release but a controlled release of ~75 MMCF (each) was required to depressurize the pipeline segment for repair.

4. CO₂ well blowouts

The blowout of a well occurs when the operator of the well loses control of the pressure in the well resulting in fluid flow out of the well. Damen et al. [10] have suggested that the largest risk associated with CO₂ injection for sequestration in deep brine reservoirs is well failure. Such failures result from a failure to adequately control pressures in the injection system. This is typically due to mechanical failure of a component or an external event directly affecting the well. This results in temporary loss of control of the process and the pressure of the reservoir drives CO₂ and other entrained fluids upwards out of the well. Four types of blowouts have occurred associated with CO₂-EOR activities:

1. Blowouts of production wells drilled into natural CO₂ reservoirs
2. Blowouts of CO₂ injection wells
3. Blowouts of active oil production wells that are an integral part of the CO₂-EOR project
4. Blowouts of inactive or plugged and abandoned wells within the area of increased pressure associated with CO₂ injection wells

In the US experience with CO₂ well blowouts can be traced back to March, 1982, when a blowout occurred in the Sheep Mountain CO₂ field (one of three large natural reservoirs of CO₂ serving the Permian Basin's EOR activities), located in the Colorado Plateau area of southern Colorado. In this context, a well blowout occurs when the drilling crew fails to contain the subsurface pressure. In most cases blowouts are caused by mechanical failures beyond human control, for example the failure of a back-flow preventer. This loss of containment immediately results in the pressure release vaporizing the supercritical CO₂.

In this context a blowout is driven by the high expansibility of the released gas resulting in a vigorous eruption of the vapor up the well bore (with the likely entrainment of particles of solid debris). If this occurs during drilling into a CO₂ reservoir the rapidity of this phenomenon may make it a challenge to activate manual Blowout Prevention devices (BOPs) in time to prevent a blowout. Adiabatic cooling of CO₂ during this rapid expansion leads to the gas being cooled below the freezing point (the triple point for CO₂ being at -63°F and 76 psi). This results in the nucleation of dry ice and/or solid ice-like CO₂-hydrates. These solids can result in a blowout becoming a spray of solid particles. Such icy particles could damage pipes and other infrastructure in the path of the spraying particles. Whether this phenomenon is less risky than the CO₂ erupting as a fountain of dense CO₂ remains to be determined. If much of the CO₂ in a large blowout is in a frozen form then the risks posed by the initial blowout to the local are probably lowered.

The blowout at the Sheep Mountain Field occurred March 17-April 3, 1982, during the drilling of a CO₂ production well on the west slope of Little Sheep Mountain (Lynch, et al. [11]). The reservoir containing the CO₂ is at depths of 1000 to 1800 m depth in sandstones of Cretaceous and Jurassic age, sealed by fine grained marine sediments of Cretaceous age (Allis et al.[12]). A contractor called in to "kill" the blowout initially had problems related to the high flow rate of CO₂ (estimated at 200 million standard cubic feet/day) out of the well. The CO₂ was blowing out the brine-based "kill fluid" (and entrained drilling mud and debris). The well came under control the next month through the injection of drag-reduced brine followed by mud (Lynch, et al. [11]). The industry now has an increased understanding of handling CO₂ wells.

Blowouts of oil production wells within CO₂-EOR reservoirs are a known hazard (Lynch et al. [11]; Skinner [13]). In 2003, Skinner in a paper in "World Oil" focusing on blowouts in the CO₂-EOR industry in the US suggested that there had been an "increased frequency of CO₂ blowouts in injection projects". Four of the five blowouts presented in the case studies of Skinner [13] occurred during remediation (or work-overs) of wells. Well work-overs are commonly done to reuse pre-existing wells for use in CO₂ EOR projects. For commercial CO₂ sequestration projects it is highly unlikely that old wells would ever be reused as injection wells.

Case Study One: Blowouts CO₂-EOR Operations of Company A

Company A utilizes several safety and preventive measures monitor and mitigate potential blowouts. Company A uses alarms, automatic shutdowns, and human monitoring. Recently Company A has been converting sites to 24 hour manned operations in order to detect and respond to any abnormal conditions and to promote more effective mitigation.

As noted by Skinner [13] the greatest danger for loss of well control is during work over operations. During such operations, Company A uses standard industry safeguards on the rigs. As part of their blowout prevention strategies Company A does daily monitoring of tubing, production casing and surface casing. Automatic reports are sent out if the pressure measured for production casing or surface casing is greater than zero.

Over the last five years of operation Company A has experienced 7 blowouts, incidents where they have temporarily lost control of wells. One of these incidents was associated with a CO₂ production well at when coiled tubing packing failed during well work. Two other incidents were associated with CO₂ injection wells. One was caused by leaking gasket at a well head. The other was not a problem with well itself but rather occurred when a mechanical seal was blown on HP booster pump. The other three incidents were associated with production wells. One incident occurred when a casing valve was accidentally left open during work-over operations. Another production well unexpectedly started to flow CO₂ before it was converted to and EOR producer. In the third incident, a problem occurred during the installation of a Blow-Out-Preventer stack during workover operations. There were no deaths or injuries associated with any of these event.

It is very difficult to determine with precision the amount of CO₂ that was released in each of these incidents due to the nature of the events. Company A engineers have estimated that the release rates ranged from <1 mmcf per day to 10 mmcf per day. The largest event in one of the production wells, occurred over 4 days and Company A engineers have estimated that approximately 40 MMcf of CO₂ (an average of 10 MMcf per day was vented over four days).

Company A has begun to deploy fixed monitors strategically placed throughout their CO₂-EOR facilities. These monitors measure CO₂, O₂, LEL, and H₂S. The accuracy of the new monitors described is +/- 1000 ppm (0.1%). The blowout events discussed above were at wells not at the time equipped with fixed CO₂ monitors. CO₂ measurements were conducted during the accidental release at one of the producers was monitored by portable sensors. Two hundred feet from the release maximum concentrations recorded were approximately 4750 ppm (0.475%). The elevated concentrations dissipated quickly (within 30 minutes). This type of data will be extremely valuable in validating modelling of risks associated with accidental CO₂ releases.

Case Study Two: Blowouts CO₂-EOR Operations of Company B and Company C

Over the last five years of operation Company B has experienced five blowouts, incidents in which they have temporarily lost control of wells. No injuries or deaths have resulted from any of these accidents. Four of these incidents were apparently caused by the failure of mechanical components (two due to valve failures, two due to failure of nipples). The fifth failure was not related to the well itself but rather was caused by failure of a pump component related to corrosion. None of the five incidents appear to have been caused by human error.

Over the past ten years Company C has experienced twelve well blowouts involving temporary loss of control of CO₂ wells. Six of these incidents were associated with failure of physical components such as valves. One blowout occurred during the installation of a blowout preventer. One incident that was clearly related to human error was caused by a truck backing over an injection well. Another blowout occurred when CO₂ reached a planned production well before a well work over could be completed. Again one of the “blowout” incidents was caused by the failure of a pump component.

5. Conclusions

The thirty seven plus years of history of CO₂ injection involved in CO₂ based Enhanced Oil Recovery in the US represent the most tangible evidence available for understanding the risks of CO₂ sequestration in deep brine reservoirs. In the case of both pipeline incidents and blowouts; component failure rather than corrosion or human errors have resulted in the leakage of CO₂. The rarity of corrosion related incidents reflects the industries success in implementing anti-corrosion measures. In the case of blowouts, incidents related to CO₂ production wells from natural reservoirs and those that occurred during work over of production wells, resulting from unexpectedly early CO₂ breakthroughs are not directly relevant to understanding the risk of CO₂ sequestration in deep brine reservoirs. The CO₂-EOR industry has an excellent safety record.

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