Probabilistic approach to evaluating seismicity in CO2 storage risk assessment

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Abstract

Risk assessment has been employed in management tool kits in a wide variety of projects not necessarily related to CO2 storage. Studies suggest these approaches are applicable to CO2 storage. The features, events, and processes (FEP) that affect CO2 storage have been compiled in a database (Quintessa online). A methodology is proposed in this study which utilizes the FEP database and a probabilistic approach. It is illustrated by applying common geomechanical techniques to a case study conducted using an oil field in the Williston Basin. The implications of incorporating such assessments into a larger projectwide risk management plan are also discussed here.

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1. Introduction

Stabilizing the concentration of anthropogenic greenhouse gases (GHG) in the atmosphere through carbon capture and storage (CCS) requires large-scale projects with up to gigatons of CO2 sequestered each year over the course of decades. Significant experience with natural gas storage, waste disposal, and enhanced oil recovery (EOR) provide natural analogues and a high level of confidence in the safety of geological injection and storage of CO2. However, because of the large amounts of the stored CO2 that will be necessary to make meaningful reductions in GHG emissions, it is essential to understand the probable risks involved in underground injection and the long-term fate of the CO2 in the subsurface. The risks pertinent to an individual project should be well understood even in the earliest stages of project development when making decisions regarding the feasibility of the storage project [1]. Such understanding can be difficult to gain, especially when information about the subsurface system is limited.

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Unfortunately, the acquisition of detailed geological information can be very expensive and difficult to conduct in the very initial stages of a project. Thus it is desirable to apply analytical approaches that can use readily available, previously generated data to understand and quantify the risks involved in an anticipated project.

Limited information and uncertainty are characteristic of the majority of risk assessment studies and our understanding of the geological conditions of the subsurface environment in general. One meaningful way of dealing with uncertainties is the probabilistic and statistical treatment of the risk factors. Although the statistical approach is the most straightforward one, its application for the problems of CO₂ sequestration can be complicated. The complexity stems from the fact that the number of large-scale CO₂ storage projects worldwide is very limited [2] and does not provide enough historical data for statistical analysis. However, valuable experience gained by the oil and gas industry can provide useful tools for statistical risk assessments. Although CO₂ has been utilized for EOR for over 30 years, the historical data are not readily applicable to storage projects because the objectives of storage projects are different from those of EOR. For example, when sequestering CO₂ in geologic formations, the intention is for the CO₂ to remain contained for timescales on the order of thousands of years, whereas EOR operations historically have not been concerned with containing the injected CO₂ for long periods of time. Thus the concept of risk needs to be treated differently. It is expected that with an increasing number of projects worldwide, the focus of risk assessments will shift toward employing statistical techniques. In the meantime, the lack of historical data limits the analysis to the application of deterministic [3, 4] and probabilistic approaches. While a deterministic approach provides a powerful tool for the prediction of system behavior, its application in the case of limited data is often impossible. To the contrary, a probabilistic approach to the quantification of risk is advantageous in that it utilizes a range of inputs and readily incorporates uncertainty into the calculations.

Although the concept of risk management and the methodologies behind it are routinely employed as part of management tool kits in a wide variety of projects, and studies suggest that these approaches are applicable to CO₂ storage, few comprehensive risk management plans have been produced for current CCS projects. A detailed examination and discussion of comprehensive risk management plans for CO₂ storage projects is beyond the scope of this paper. Therefore, this paper shows how individual risk events related to CCS can be assessed using probabilistic methods. This is illustrated by assessing the risk of induced seismic activity, an occurrence which has been thought, in some cases, to be caused by subsurface fluid injection [5]. A case study illustrating a quantitative assessment of induced seismicity using probabilistic methods was performed for an oil field in the Williston Basin of central North America. The study shows how readily available geophysical data can be used to assess technical risk events. A discussion addressing the implications of incorporating such assessments into a larger projectwide risk management plan is also presented here.

2. Methodology

Two groups of risks are involved in CO₂ storage projects: 1) programmatic risks and 2) technical risks. Programmatic risks can include the risk to such areas as project cost or time schedule [6] and are generally well understood as they are a part of nearly all subsurface operations. Thus the focus of this study is placed on the assessment of technical risks. These risks also can be divided into two groups, short- and long-term risks. Risks from both of these groups should be assessed in the stage of project planning [1]. Later in the lifetime of the project, when the storage site is thoroughly characterized, deterministic models should be built, history-matched, and used for the prediction of the long-term project performance. However, in the initial stages of a project, models are often unable to reliably describe processes in the systems because of the lack of data. This paper presents a methodology for assessing technical risks while avoiding time-consuming model building.

The methodology utilizes the approach of features, events, and processes (FEP). Currently, FEPs in CO₂ sequestration projects are well understood and summarized in databases like that by Quintessa Ltd. (2008). The database provides a useful tool for selecting FEPs characteristic of a particular project. However, knowing the potential risk events does not solve the problem completely: the problem of risk quantification arises. It is suggested here that the essential elements of the quantification of a risk event are:
Understanding the mechanism of the occurrence.
Choosing a simple numerical model describing the process and its development.
Ensuring that the parameters used in the model are easy to estimate with limited field data.
Understanding the severity of the consequences of the occurrence.

Risk $R_{FEP}$ can be evaluated as the product of the likelihood $L_{FEP}$ of occurrence and the severity $S_{FEP}$ of the consequences $R_{FEP} = L_{FEP} \times S_{FEP}$ [7]. A methodology was developed and applied to assess the risk of seismicity induced by underground injection into a carbonate oil reservoir in the Williston Basin. The method uses readily available geophysical data to determine the likelihood of a seismic event occurring in the case study region. Then, knowledge of the regional and global historic seismicity, as well as local structural characteristics, are used to determine the potential severity of an induced seismic event. Finally, the overall risk is calculated and evaluated on a risk scale. Figure 1 illustrates the above methodology in a flowchart. The methodology is further illustrated by a case study in which the risk of seismicity induced by underground injection into a carbonate oil reservoir in the Williston Basin is assessed.

3. Case study

Mechanisms causing the occurrence of seismic events have been studied in detail. Generally seismicity occurs because of slip on a discontinuity within a rock mass. In the case of underground injection, induced seismicity may be triggered by increased pore pressure which can reactivate geological faults. Thus the phenomenon can be described by a model establishing a relationship between tendency to slip $T_s$ and pore pressure $P_f$ [8]:

$$T_s = \frac{1}{\tau} (\sigma_n - P_f)$$  \hspace{1cm} (1)
where \( \tau \) and \( \sigma_n \) are shear and normal stresses on the discontinuity defined by the stress state and the angle of inclination of the discontinuity \( \theta \):

\[
\tau = 0.5(\sigma_1 - \sigma_3)\sin(2\theta) \quad \text{and} \quad \sigma_n = 0.5(\sigma_1 + \sigma_3) - 0.5(\sigma_1 - \sigma_3)\cos(2\theta),
\]

where \( \sigma_1 \) and \( \sigma_3 \) are maximum and minimum principal stresses respectively. Because the Williston Basin is located in one of the most tectonically stable regions in North America, for the purposes of this study, principal stresses were determined assuming that the maximum principal stress is the pressure of overburden and no tectonic forces are present in the system: \( \sigma_1 = 4.0 \cdot d \) and \( \sigma_3 = \nu/(1-\nu) \cdot \sigma_1 \) with \( \nu \) being the Poisson ratio and \( d \) being the depth of the reservoir. In the absence of cohesion, slip occurs along the discontinuity when \( T_s \) is equal to or exceeds the coefficient of static friction (\( \mu_s \)) for the rock faces.

### 3.1. Likelihood of occurrence

In reality, the value for \( \mu_s \) on a natural fracture is between \( 0.6 \leq \mu_s \leq 0.85 \) [8]. For the purposes of this study, it was conservatively assumed that slip occurs when the slip tendency is equal to or exceeds \( T_s \geq 0.6 \). According to Equations (1) and (2), slip tendency is a function of the discontinuity inclination angle. The analysis of the equations indicates that the probability of slippage on the discontinuity is equal to the probability that the discontinuity is inclined by an angle in the range limited by \( \theta_{\min} \) and \( \theta_{\max} \), which represent the interval over which \( T_s \geq 0.6 \). The latter probability can be estimated using field or core observations. In this study, the probability distribution function (PDF) for the angle of inclination was derived from a Formation Micro Imager (FMI) log recorded in a well located in an oil field in the southwestern North Dakota portion of the Williston Basin. The formation being evaluated at this location is carbonate rock of the Mississippian Lodgepole Formation. The log is publicly available on the North Dakota Industrial Commission Web site (API 33-089-00467) [9]. Figure 2 shows the PDF generated from the oil field data and the best-fit function, which was found using a Cauchy distribution, \( f(\theta) = \frac{1}{\pi s \cdot \sqrt{1 + ((\theta - \theta)/s)^2}} \) with \( s = 11 \) and \( t = 26 \).

The total likelihood (\( L_s \)) of slip occurring can be found by summing the individual probabilities together, which is equivalent to integrating the PDF of \( \theta \) from \( \theta_{\min} \) to \( \theta_{\max} \):

\[
L_s = \int_{\theta_{\min}}^{\theta_{\max}} f(\theta) d\theta \quad \text{(3)}
\]
It is obvious from Equation (1) that as soon as $T_s$ changes because of changes in pore pressure $P_f$, the values $\theta_{\text{min}}$ and $\theta_{\text{max}}$ change in response. The probability that a seismic event will occur on a discontinuity in response to pressure increase is determined by the difference of the probability of slippage at the initial pressure and probability of slippage at an increased pressure. To account for multiple fractures, it was supposed that the discontinuities were uniformly distributed in the reservoir with the frequency $\lambda = 0.69$ determined from the FMI log. For estimating pressure increase, a radial flow from the wellbore was assumed. For this Williston Basin oil field case study, a permeability of $3.00 \times 10^{-13}$ m$^2$, injection rate of 476.96 m$^3$/day, and reservoir thickness of 91.44 m (obtained from the FMI log) were used. A C++ program was written which served to calculate the total probability of an injection-induced seismic event occurring in the case study area. Using the above values, the resulting likelihood was $L_s = 6 \times 10^6$. A likelihood of $L_s = 100$ represents the occurrence of a single event; thus the likelihood determined from this formula represents the occurrence of $6 \times 10^4$ events. Initially this seemed unacceptably high; however, there is another component to quantifying risk that must be evaluated and can be considered a mitigating factor.

3.2. Severity of consequences

As mentioned above, the quantification of risk usually involves some combination of likelihood of occurrence and the severity of potential consequences. If a risk event has a high likelihood of occurrence, as may be the case in the case study oil field, but a low severity with negligible consequences, the total risk factor can be low. Thus, in order to fully assess the risk of induced seismicity, the potential severity of the events must also be quantified. A severity factor $S_f$ that incorporates global experience with earthquakes, as well as the historic seismic activity of the case study region, was needed.

The severity of a seismic event is usually characterized by its magnitude [10], which provides a good measure for understanding the severity of the damage at the surface. However, the damage to the formation is also of interest for the CO$_2$ storage applications. Formation damage can be partially assessed by estimating the displacement along a fracture during a seismic event. The amount of displacement along a fracture during a seismic event is related to the seismic moment ($M_o$) of the earthquake by the following equation:

$$M_o = \mu S <d>$$

(4)

where $S$ is the area of the fault, $\mu$ is the shear strength, and $<d>$ is the average displacement along the fault. The United States Geological Survey (USGS) uses moment magnitude ($M$) as its preferred way to describe the size of an earthquake. The moment magnitude has a logarithmic relationship with the seismic moment given by the following equation [11]:

$$M = 2/3 \log(M_o) - 10.7$$

(5)

It can be seen from these two equations that the movement along a fault and the magnitude of an event are related such that an increase in magnitude is marked by an increase in the amount of slip. Thus for seismic events of low magnitude, the displacement along the fracture will correspondingly be less than the displacement of a larger event. Knowledge of global historic seismic activity [12] indicates that earthquakes with $M < 2.9$ are generally not felt. Thus $M = 2.5$ was chosen as the conservative lower bound magnitude for negligible severity. Seismic events in the range of $3.0 < M < 5.0$ are usually felt but do not produce significant damage and, as a result, their severity remains relatively low. However, the occurrence of multiple events of such magnitude is probably unacceptable. For the purposes of this study, the occurrence of an event with magnitude greater than 5.0 is considered unacceptable. It is expected that the severity of induced seismic events will be negligible for $M < 2.9$ and will experience rapid growth for $M > 3.0$. This is illustrated in Figure 3a. This relationship was taken into consideration when the severity factor for the case study region was determined.

In order to understand the potential severity of an induced seismic event in a particular region, knowledge of the region’s seismic history is essential. By knowing how a region has behaved seismically in the past, inferences can be
made about how it might react to an induced seismic event. The USGS has compiled multiple databases which contain all recorded seismic events in the United States. By reviewing these databases, an understanding of the natural seismicity in the case study region can be obtained. This, along with the relationship between earthquake magnitude and severity (see above discussion), and local structural characteristics, makes it possible to assess the potential severity of an induced seismic event occurring in this region.

By searching seven earthquake databases [13, 14], it was discovered that only five recorded seismic events have originated in North Dakota. One had a magnitude of approximately $M = 5.5$ and occurred in 1909. The epicenter was located in the extreme northwest corner of North Dakota on the border of Montana. The reliability of this data is questionable, however, because of the limited use of early seismographs. Prior to 1973, epicenter placement was often estimated based on damage reports and thus may not accurately display the true location [15]. The second earthquake occurred in 1968 with a magnitude of $M = 4.0$ but, again, the accuracy of this data is questionable because of the unknown quality of the seismograph data. The final three earthquakes occurred in 1970, 1994, and 1998 with magnitudes of $M = 2.8$, $M = 2.9$, and $M = 3.5$, respectively. The $M = 2.8$ and $M = 3.5$ earthquakes originated on the southern and western borders, respectively. There is uncertainty associated with the data for these last three earthquakes because the data were from the National Earthquake Database of Canada, which has limited coverage outside of Canada.

After reviewing the USGS [13] and Canadian databases [14], and considering the uncertainties associated with the available data as well as the previously discussed knowledge of the severity associated with global earthquake magnitudes, it was determined that there have been no earthquakes originating in North Dakota with significant severity in recorded history. These data provide evidence that the North Dakota portion of the Williston Basin is historically a seismically stable area. Although the probability of an induced seismic event occurring in the case study region is extremely high, the historic seismic data indicate that the majority of the events will most likely be microseismic in nature. Because of the relationship between magnitude and the movement along a fracture that was previously discussed, these microseismic events will have negligible displacement. Using this knowledge and the available historical data for global as well as regional earthquakes, a severity factor of $S_s = 10^{-8}$ was determined for the case study oil field. Figure 3a illustrates the function for determining the severity factor $S_s$ chosen for this study.
3.3. Risk factor

The risk factor was defined earlier as the product of the likelihood of occurrence and the severity of the consequences: \( R_{FEP} = L_{FEP} \times S_{FEP} \). By applying this equation to the previously computed value for likelihood and the estimated severity factor for the case study area, an overall risk factor of \( R_s = 6 \times 10^6 \times 10^{-6} \) is calculated.

In order to apply this methodology to multiple sites and make them comparable, a unified risk scale was needed. The scale was created based on knowledge of the historic seismicity of the Williston Basin case study region. The calculation of risk contains an element which is influenced by the perception of those affected by that risk [16]. This perception of risk can be taken into account when determining the risk scale for the region in question. The scale has a range of 50, with the lowest and highest risk factors equal to \( R_s = 0 \), \( R_s = 50 \), respectively. When assessed on this scale, a risk factor of 6 is extremely low. Figure 3b shows a visual representation of the risk scale.

It can be seen in this example that a high likelihood of occurrence alone does not necessarily result in a high overall risk factor; the overall risk can be negligible if the severity is very low. Thus while it has been estimated that the probability of an injection-induced seismic event is high, the severity of such an event is overwhelmingly likely to be very low, on the microseismic end of the magnitude scale. These two factors combine to result in a low overall risk for induced seismic activity in the case study region.

3.4. Risk management

The previous sections describe how individual FEPs can be assessed using probabilistic techniques. Alone these studies prove interesting, but they must be incorporated into a comprehensive risk management plan. In order to effectively manage risk, the following must be accomplished:

- Identify the risks
- Quantify the risks
- Response
- Control

A risk assessment similar to the one outlined here can aid in the development of response strategies and the implementation of controls to protect against future risk. It may be useful to develop a risk management plan that uses an FEP database to identify risk events and a detailed, probabilistic quantitative study performed for each identified FEP followed by the response and control processes. However, because of the lack of historical data and the fact that most large-scale CCS projects are in their early stages, the current methodologies for risk management of CCS projects use an “expert panel” approach. When using this process, a panel of experts in various fields ranging from engineering to financial analysis is created. This panel collectively assesses the individual risk events, usually assigning a likelihood of occurrence and severity to each event based on panel members’ expert opinions using the most current information available. This process allows a quick assessment of multiple risk events and can be readily applied to even the preliminary stages of a CCS project.

The development of individual probabilistic quantitative analyses for the long list of FEPs associated with CCS projects has the potential to be very time consuming. Therefore, the authors acknowledge that the benefit of the outlined approach over current risk assessment processes has not been determined. As the number of large-scale sequestration projects increases, the suitability of this methodology for preliminary site risk assessment may be better assessed.
4. Conclusions

A quantitative risk assessment should be used as a management tool to aid decision makers and inform stakeholders. In order for this to be accomplished, methods must be developed that allow the potential risks of CO2 storage to be assessed with data that is readily available even in a project’s early stages.

Experience with EOR, natural gas storage, wastewater disposal, and other analogues suggest that the risks associated with the geologic storage of CO2 can be effectively managed [17]; however, much work needs to be done to quantify potential risks. This paper describes a case study of the risk of induced seismic activity resulting from the injection of CO2 that was conducted for an oil field in the Williston Basin. This study illustrates how commonly available geophysical data could be used to perform a probabilistic quantitative analysis of the features, events, and processes relating to the geologic sequestration of CO2. The probability of injection-induced seismicity in the case study region was calculated to be \( L_s = 6 \times 10^6 \). When combined with the corresponding severity \( S_s = 10^{-6} \), the overall risk factor works out to be \( R_s = 6 \). A risk scale with a range from 0 to 50 was established for the case study region. When a risk factor of \( R_s = 6 \) was evaluated on this scale, the overall risk of injection-induced seismicity in the case study region was determined to be extremely low.

Although the proposed method may not be readily applicable to all potential storage sites, it is considered a first step toward the goal of creating a quantitative risk assessment methodology which can quickly and easily be applied to a wide variety of CO2 storage projects.

References