ISSUES RELATED TO SEISMIC ACTIVITY INDUCED BY THE INJECTION OF CO_2 IN DEEP SALINE AQUIFERS

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Abstract

Case studies, theory, regulation, and special considerations regarding the disposal of carbon dioxide (CO_2) into deep saline aquifers were investigated to assess the potential for induced seismic activity. Formations capable of accepting large volumes of CO_2 make deep well injection of CO_2 an attractive option. While seismic implications must be considered for injection facilities, induced seismic activity may be prevented through proper siting, installation, operation, and monitoring. Instances of induced seismic activity have been documented at hazardous waste disposal wells, oil fields, and other sites. Induced seismic activity usually occurs along previously faulted rocks and may be investigated by analyzing the stress conditions at depth. Seismic events are unlikely to occur due to injection in porous rocks unless very high injection pressures cause hydraulic fracturing. Injection wells in the United States are regulated through the Underground Injection Control (UIC) program. UIC guidance requires an injection facility to perform extensive characterization, testing, and monitoring. Special considerations related to the properties of CO_2 may have seismic ramifications to a deep well injection facility. Supercritical CO_2 liquid is less dense than water and may cause density-driven stress conditions at depth or interact with formation water and rocks, causing a reduction in permeability and pressure buildup leading to seismic activity. Structural compatibility, historical seismic activity, cases of seismic activity triggered by deep well injection, and formation capacity were considered in evaluating the regional seismic suitability in the United States. Regions in the central, midwestern, and southeastern United States appear best suited for deep well injection. In Ohio, substantial deep well injection at a waste disposal facility has not caused seismic events in a seismically active area. Current technology provides effective tools for investigating and preventing induced seismic activity. More research is recommended on developing site selection criteria and operational constraints for CO_2 storage sites near zones of seismic concerns.

Introduction

Concerns about global warming have prompted investigation into the disposal of carbon dioxide (CO_2) into deep saline rock formations. This option is attractive, since there are regionally extensive aquifers capable of accepting large volumes of CO_2 from power plants without the need for long pipelines. There is also a substantial amount of research available on the subject from projects on enhanced oil recovery and deep well injection of liquid wastes. However, application of the technology to populated areas may involve seismic hazards if the injection facilities are not properly sited and operated. The objective of this paper is to review induced seismic activity as it

relates to the injection of CO_2 into deep saline aquifers in the United States. Basic theory, regulation, monitoring and testing methods, and special considerations on induced seismic activity are addressed. A case study on seismic practices in Ohio is also presented to outline typical procedures followed to monitor seismic activity during deep well injection. Related DOE funded work on geologic storage of CO_2 in saline formations conducted at Battelle includes compositional reservoir simulations (Gupta et al., 2001), evaluation of geochemical aspects through modeling and experiments (Sass et al., 2001a and Sass et al., 2001b), and assessment of economic and engineering aspects (Smith et al., 2001).

Seismic activity was first linked to deep well injection activities near Denver, Colorado, in 1962. Since then, seismic activity triggered by injection wells has been noted at locations worldwide. Due to the uncertainty associated with deep subsurface investigations, an understanding of the lithology, structural geology, and hydrology of the site is critical to determining if injection will induce seismic events. To this end, regulation on injection wells exists to ensure that a site is properly investigated and monitored for seismic vulnerability. In addition, several distinctive processes related to CO_2 injection must be considered for the option of CO_2 disposal. Ramifications of induced seismic events go well beyond the traditional image of earthquake activity. While most seismic events triggered by deep well injection are too small to be noticed, moderate earthquakes have occurred due to injection activity. Most notably, two earthquakes with Richter magnitude of 5.1 and 5.2 were triggered in Denver, Colorado, in 1966. Seismic activity may also affect the injection system itself. In the worst-case scenario, a fault or fracture causes the rupture of the injection well casing and containment is lost. Fractures may also occur in overlying rock units providing a pathway for upward migration of the injection liquid. Continual seismic activity may result in the gradual weakening of the well casing. In addition, formation alteration may affect the performance of the injection system by reducing or increasing the pore space in the injection system. However, through proper siting and operation procedures, seismic events may be prevented. In fact, current technology has provided very effective tools for investigating potential seismic activity induced by deep well injection.

Overview of Induced Seismic Activity

In general, deep well injection weakens the strength of a fault, triggering movement and the resulting seismic event. Wesson and Nicholson (1987) note that deep well injection usually triggers activity in a seismically unstable area rather than causing an earthquake in a seismically stable area. Conceptually, the fluid in a fault is pressurized and assumes the stress of the overlying rock and water. Since the fluid has little shear strength, the frictional resistance along the fault declines and the fault blocks slip, causing a seismic event. These processes are best represented by a stress/strain relationship at very high pressures. Other processes involved in the triggering of seismic activity may include transfer of stress to a weaker fault, hydraulic fracture, contraction of rocks due to the extraction of fluids, subsidence due to the saturation of a rock formation, mineral precipitation along a fault, and density-driven stress loading. Figure 1 shows a conceptual model of processes involved in triggering seismic activity by underground injection wells. Most of these processes are site specific and can be evaluated through site investigations or formation testing.

In terms of stress equations, deep well injection reduces both the principal and confining pressure in the injection formation while keeping the differential pressure constant, moving the system toward failure (Figure 2). Represented on a Mohr's circle, it is easy to see how the injection pressures may move the rock to the point of failure (Figure 3). With respect to deep well injection systems, the confining pressure and the principal pressure may be measured or estimated based on lithology and depth. Consequently, injection pressures may be analyzed to determine if

the changes in pressure may trigger fracture. Key parameters that affect injection pressures are formation permeability and porosity. Rock formations with high permeability and porosity are more receptive to injected fluids. Low permeability and low porosity rock formations will require higher injection pressures and be more susceptible to induced seismicity. Another factor which may influence the stress-strain system is formation pressure. Water trapped in a formation during deposition may reach very high pressures as sediments are deposited on top of the formation throughout time.

At very high injection pressures, rock formations may fracture in a process termed hydraulic fracturing. This process is often used by oil/gas companies to increase the transmissivity of a formation around the well. Hydraulic fracturing occurs when the injection pressure exceeds the intergranular strength of the rock, creating or expanding fractures. 1996 Joule II proceedings suggest that controlled hydraulic fracturing does not induce seismic activity above a magnitude of one. However, unmonitored hydraulic fracturing may produce rather extensive fractures several meters wide and hundreds of meters long which could possibly trigger more substantial seismic activity.

Seismic events can be correlated to injection activities in several ways. A seismic monitoring network is essential to collecting information on earthquakes. Most seismic events triggered by deep well injection are too small to be felt, but they are often precursors to larger events. The most obvious way to link earthquakes to injection wells is an increase in seismic events once injection begins. The frequency of seismic activity compared to previous seismic trends may be examined to reveal changes introduced by the injection practices.

The magnitude of the seismic events is another line of evidence to link earthquakes to injection wells. The seismic activity caused by the injection well may be either smaller or larger in magnitude than the previous trend in seismic activity. For example, numerous small seismic events may happen after injection starts. Trends in the magnitude of seismic activity may be recognized by comparing frequency-magnitude charts. The geographic location of the earthquake foci should be in the general area of the injection radius of influence. It should be noted that the radius of influence of the injection system may be kilometers to tens of kilometers from the injection wells. Similarly, the depth of the earthquakes may be in the affected injection interval; although, earthquakes have been triggered several kilometers below the injection well. More advanced analysis methods can determine the orientation of faults from the seismic response and compare the orientations to the location of the injection well to see if the two are somehow related.

Operations data on injection pressure at the wellhead and/or injection volumes can be valuable to studying seismic events. The frequency of the seismic activity over time is often related to the injection pressure or injection volume history over time. There may be a lag of days to years between the two events since an earthquake may be triggered by a propagating pressure wave. In addition, sudden pressure changes at the wellhead itself may result from an earthquake event.

Another method of linking earthquakes to deep well injection is the analysis of critical fluid pressures capable of causing failure along a fault. Based on formation pressures at depth and induced pressure, the Mohr-Coloumb failure criteria may be used to determine if conditions capable of triggering a fault would be created in the injection zone. However, these calculations involve several assumptions concerning fault strength and pressures. The method provides less certainty than direct evidence from monitoring instruments. For example, Davis and Pennington (1989) found that injection pressures at thousands of sites in the state of Texas were high enough to trigger seismic activity but do not exhibit seismicity. The value of stress analysis is that the

work may be performed in site selection and system design before any fluid is actually injected. Information for evaluation of critical fluid pressure may be obtained from compression tests, hydraulic testing, and analysis of the orientation of the stress tensors.

Reservoir modeling may be used to analyze the migration of injection pressure. Reservoir modeling uses the hydraulic properties of the injection formation with analytical or numerical equations to simulate the progression of pressure or liquid. These models are useful in determining whether deep well injection may have caused seismic activity a long distance from the injection well(s). Similar models are available to determine what pressures will trigger hydraulic fracture and the extent of the fracturing.

Seismic activity induced by deep well injection has been observed at locations throughout the world. However, only a few case studies have been well studied due to the large amount of monitoring and testing required to demonstrate a conclusive relationship between earthquakes and deep well injection. Table 1 summarizes documented case studies of induced seismic activity. Earthquakes were first linked to deep well injection in 1962 at the Rocky Mountain Arsenal near Denver, Colorado (Healy et al., 1968). This remains one of the best-studied occurrences of seismic activity triggered by deep well injection. Researchers suggest that these earthquakes were likely triggered by pressure waves that continued to propagate after injection was stopped. Hsieh and Bredehoft (1981) reassessed the Denver earthquakes with reservoir modeling. The authors found that they could use modeling to simulate the arrival of critical pressure levels in a faulted zone where earthquakes occurred. The modeling results were comparable to the earthquake control studies by Raleigh et al. (1976) that demonstrated that earthquakes could be controlled by monitoring injection pressure and seismic activity. Increased seismic activity has also been observed at numerous oil/gas drilling sites, due to either fluid extraction or injection. Motivated by the Denver earthquakes, the USGS conducted an experiment in 1976 to control earthquakes at a nearby oil well site in Rangely, Colorado (Raleigh et al., 1976). Injection pressures were increased to critical levels, then decreased. The frequency of earthquakes decreased after the initial pressures declined. Similar research was performed in Matsushiro, Japan.

Issues Related to Induced Seismic Activity

Regulation

Injection wells in the United States are regulated by the federal Underground Injection Control (UIC) program, which provides minimum rules for the siting, testing, installation, operation, monitoring, reporting, and abandonment of underground injection wells (Title 40 Code of Federal Regulation Parts 146 and 148). UIC rules are enforced by regional and/or state Environmental Protection Agency (EPA) offices, which dispense permits for UIC wells. Injection wells are classified according to the type of fluid injected and the injection interval in relation to underground sources of drinking water (USDW). CO_2 disposal wells have yet to be classified by the EPA. However, they will likely be held to the same type of seismic regulation as Class I wells because of depth considerations. The UIC program requires testing on formation materials to ensure that injection pressures will not fracture rock formations in the injection interval. The program also requires regular monitoring to retain injection permits.

Overall, UIC regulation does not extensively address induced seismic activity. However, two sections are fairly explicit in providing rules related to earthquake activity:

40CFR146.13 Except during stimulation, injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water.

This rule is aimed at preventing formation of transmissive faults and fractures which may allow injected fluids to migrate vertically and reach sources of drinking water. The CFR addresses the issue of seismic activity induced by deep well injection in 40CFR146.68. The UIC guidance provides the enforcing agency more than enough leeway to require extensive testing and monitoring:

40CFR146.68 The Director may require seismicity monitoring when he has reason to believe that the injection activity may have the capacity to cause seismic disturbances.

Testing and Monitoring

Many types of tests are available to detect faulting or fractures that could lead to induced seismic activity including down-hole geophysical tests as well as more traditional testing methods that may be performed within the borehole. Another type of testing is pressure fall-off/shut-in testing that involves monitoring pressure buildup in the well. Testing methods are summarized below:

- 2-D or 3-D seismic surveys
- Core sample collection from major units during drilling
- Down-hole caliper logging to detect fractures
- Down-hole resistivity logging to detect fractures and lithologic changes
- Down-hole spontaneous potential logs
- Down-hole gamma ray logging to detect formation changes
- Down-hole density testing
- Fracture-finder logs to detect fractures
- Compression tests on formation samples to determine rock strength
- Geotechnical tests on formation samples (porosity, density, permeability)
- Compatibility test of injection fluids with formation unit and confining unit
- Pressure fall-off/shut-in tests
- Radioactive tracer survey.

Monitoring is another important part of assessing induced seismic activity from an injection well. Table 2 summarizes typical monitoring requirements at an underground injection facility to aid in evaluating seismic activity. Monitoring at the well may include recording of injection volume, rate, and pressure, continuous monitoring of annulus pressure. Abrupt changes in these parameters may signal a seismic event. Well workovers to assure mechanical integrity and detect weakening of well casing may also suggest faulting at depth. Other monitoring methods may include reservoir pressure/ambient monitoring and groundwater monitoring to detect upward migration of injection fluids through fractures.

Seismic monitoring should be performed before injection activities start to obtain baseline conditions. Depending on the frequency of seismic activity at the injection site, months to years of monitoring may be required to achieve an adequate depiction of baseline seismic conditions prior to injection. This may involve the installation of several subsurface seismic sensors around the proposed injection site. Seismic monitoring considerations may also be integrated into well installation so that down-hole sensors can be installed while drilling. The Joule II report suggests that at minimum a network of subsurface sensors should be installed at the injection site. Another monitoring method to consider is measuring changes in elevation due to expansion, subsidence, or movement along fault blocks. Tiltmeters may also be considered to monitor changes in fracture orientation at depth. Monitoring should be continued once injection activities begin. Aside from the frequency of seismic events, the location, depth, and magnitude of the seismic events should be analyzed to determine if the events are related. Geophysical methods may also be used to determine the extent of injected fluid as proposed for the Sleipner Aquifer CO_2 Storage operation in the North Sea of Norway (International Energy Agency, 1998). Since seismic velocities vary according to the density of the material, the density contrast between the formation waters and injected CO_2 may provide evidence of the extent of the injected fluid.

Modeling can be a valuable tool in evaluating the potential for deep well injection to trigger earthquakes. Overall, modeling refers to making a simplified representation of actual conditions or processes. Reservoir modeling involves using numerical equations to simulate the migration of pressure and/or fluid from the injection well. With respect to seismic activity, modeling may be used to predict if and when critical pressures are reached in a seismically sensitive area. Modeling may also be used to address uncertainty regarding rock strength, formation pressure, and other factors to see if more testing is required to characterize the injection system. Simple one- or two-dimensional models as used by Hsieh and Bedehoeft (1981) to complex three-dimensional models like UTCOMP (Chang, 1990) may be used for CO_2 injection simulation. Davis and Pennigton (1989) modeled pressure buildup in the Cogdell oil reservoir and showed a correlation between earthquake epicenters and zones of high pressure.

Special Considerations

Supercritical Liquid Properties

For deep well disposal, CO_2 is generally injected in a supercritical phase at pressures above 6.9 MPa (1,000 psig) to minimize the injected volume. Consequently, injection formations must be deeper than approximately 1,000 m to ensure that CO_2 will remain in a supercritical state. Supercritical CO_2 has a density of about 0.60 to 0.75 g/cc while the density of saline formation fluid ranges from 1.0 to 1.2 g/cc. Supercritical CO_2 is also less viscous than saline waters, resulting in more uniform flow migration. Czernichowski-Lauriol, et al. (1996) note that about 50 g of CO_2 will dissolve in 1 kg of typical formation water. Consequently, the injected CO_2 must be addressed as a multiphase system. Special considerations for underground disposal of CO_2 are mostly related to the unique properties of supercritical CO_2.

Formation Dissolution/Weakening

Supercritical CO_2 has the potential to dissolve, weaken, or transform the minerals in the injection formation. In the supercritical state, CO_2 becomes a “supersolvent.” Thus, there is potential for the fluid to dissolve and weaken the rocks in the injection formation. If the rock formation is weakened, the potential for hydraulic fracturing increases. Dissolution of minerals precipitated

along a fault will reduce the strength of the fault, possibly moving the fault to frictional sliding conditions where failure is more likely to occur.

Another aspect of deep well CO_2 disposal is the compatibility of the injected fluid with the formation waters and the formation rocks. There is potential for the injected fluid to precipitate out minerals. Mineral precipitation has the potential to significantly decrease formation porosity and permeability (Melcer and Gerrish, 1996). These changes may result in unexpected pressure buildup and formation faulting or fracture. Minerals may also bond along a previously aseismic fault. Thus, stress is increased and builds. The ensuing failure event is much larger than would have occurred without precipitation.

With respect to induced seismic activity, mineral dissolution and precipitation may have the greatest potential to affect a fault. Mineral precipitation in the pore space may cause a decrease in permeability, resulting in the buildup of pressure and hydraulic fracturing or pressure-induced faulting. Many shallow injection wells experience clogging due to similar processes as fine sediments accumulate in pore space around the well. Mineral precipitation or dissolution along fault planes may affect the stress regime of a fault system. Precipitation along a fault could "lock up" a previously aseismic fault. As stress accumulates, the potential for a more significant fault becomes greater. Conversely, mineral dissolution along a previously bonded fault may reduce the strength of the fault.

Radius of Influence

Deep well injection activities commonly affect a formation far beyond the location of the injection well(s). The earthquakes may occur after injection activities are stopped, as shown by the Denver earthquakes which occurred over one year after injection activities were stopped. Finally, earthquakes may be induced in formations well below the injection formation. For these reasons, the effective radius of influence must be examined for the injection well(s). Injecting 200 million tons of CO_2 into a formation 20 m thick with a porosity of 15% and a storage efficiency of 6% will require a radius of influence of approximately 22 km. Thus, it must be demonstrated that there are no faults of fractures within the radius of influence that might be susceptible to earthquakes. Simple calculations or modeling methods may be used with site characterization data to estimate the radius of influence. The radius of influence for the pressure front created by the injection practices may be even larger than the injection capacity indicates. Therefore, modeling may be necessary to evaluate this aspect of the injection process.

Density Driven Flow

Most other waste disposal wells attempt to match the density of the injection liquid with the formation fluids. However, the density of supercritical CO_2 is 0.60 to 0.75 g/mL while the density of most deep saline formation waters ranges from approximately 1.0 to 1.2 g/mL. Consequently, this density contrast may produce density-driven flow as the lighter, injected fluids migrate upward. Given the large volumes of fluid involved in CO_2 disposal operations, the impact of the density contrasts could be capable of influencing stress conditions at depth. Conceptually, the less dense fluid will migrate upward until it reaches a confining layer/cap rock. Once at the caprock, the upward force exerted by the lighter fluid could weaken the caprock or transfer stress to overlying faults. Stress transfer due to deep well injection was identified as a potential cause of seismic activity in Cogdell, Texas (Davis and Pennington, 1989). Similarly, injected CO_2 may produce seismic activity related to density-driven flow of free-phase CO_2 at depth. It should be noted that when the CO_2 is injected, much of the fluid will mix and dissolve into the formation

waters. Whether density-driven flow will pose a significant seismic threat is best addressed with multiphase modeling and chemical experiments.

Case Study: Seismic Aspects of Deep Well Injection in Ohio

Deep well injection practices and seismic activity in Ohio were examined to determine the potential for induced seismicity in the state. All five active deep well injection systems in Ohio have been investigated for seismic hazards to some extent. Of the operational facilities, BP Chemical injects the most, with a cumulative injection volume of over 20 million metric tons. Most deep well injection in Ohio is into the Mt. Simon formation, a fine-grained sandstone with a relatively high porosity and permeability. The formation overlies Precambrian basement rock, with a top depth of approximately 800 m in northwestern Ohio to over 3,000 m below ground surface in eastern Ohio. The unit is generally less than 100 m thick throughout the state and thins toward the northeast. Rock formations overlying the Mt. Simon are generally less permeable shale, limestone, dolomite and sandstone. However, permeable layers exist at various depths in certain areas. In eastern Ohio, many oil and gas wells penetrate the Clinton sandstone 1,000 to 1,100 m below the surface. In general, there are several intervals of rocks which may be suitable for deep well injection in Ohio. The depth intervals and hydraulic properties of the receptive formations appear to vary throughout the state, but are fairly constant within the anticipated radius of influence of an injection facility.

Most faults in Ohio are associated with Precambrian basement rocks at depths over 1 km below land surface. Several faults have been identified in northwestern Ohio, while relatively few faults have been identified in the rest of the state. The Anna Seismogenic Region is one of the most active seismic zones in Ohio (Figure 4). The zone is located in west-central Ohio. While many faults have been proposed in the area, only a few are well accepted. The faults are mostly northeast-southwest or northwest-southeast oriented. Analysis of seismic effects in that area suggests that the faults are steeply dipping with strike-slip movement. Seismic activity in the Anna area is generally deeper than 10 kilometers. Other major faults southeast of Ohio are related to the Kentucky River Fault Zone. Faults have also been proposed in various other areas throughout the state, most notably the Ashtabula fault in northeastern Ohio.

The seismic history of Ohio dates back to 1811 when a series of earthquakes with epicenters near New Madrid, Missouri, were felt in Cincinnati. Since then, many seismic events have occurred in Ohio. The largest earthquakes have had a Richter magnitude in the range of 5.0-5.5, or a Mercalli Modified Index of VII-VIII. In general, most seismic activity indicates strike-slip movement along steeply dipping faults. Based on the USGS Seismic Hazard mapping project, there is a low probability for damage from earthquakes for Ohio, except in the Anna Seismic Area, which has a moderate hazard.

The Anna Seismic Seismogenic Region in west-central Ohio has been identified as one of the most active seismic areas in the Midwest. The area has a substantial history of seismic activity dating back to the mid-1800s. The largest earthquake observed in the area had a Modified Mercalli intensity of VIII in 1937. In general, seismic activity indicates northeast-southwest strike-slip movement oriented perpendicular to the predominant stresses in the area. Analysis of the seismic activity indicates foci in Precambrian bedrock at depths of over 10 km below ground surface. A number of faults have been proposed in the area, but most activity appears to occur near the trend of the proposed Anna-Champaign Fault. Overall, the Anna Seismic Area is considered a seismically active area. However, since most activity is well below potential injection formations, the potential for induced seismic activity is not likely. In fact, no substantial induced seismic activity has been observed at the BP Chemicals injection facility, which is

located 50 km northeast of the Anna Seismic Area. Based on the study of Ohio, a properly sited and operated injection facility may be located in a region with moderate seismic activity.

Conclusions and Future Work

The possibility for seismic activity induced by deep well injection must be considered when evaluating the disposal of CO_2 in deep saline aquifers. The potential for seismic events is greatest in seismically vulnerable locations with a history of faulting and earthquakes. Seismic activity may be prevented, through proper siting, installation, and monitoring. To this end, federal guidance exists to regulate underground injection facilities. Special considerations related to the properties of supercritical CO_2 may have seismic effects.

Future work on induced seismic activity associated with disposal of CO_2 into deep saline aquifers should involve improving methods for detecting seismic activity induced by injection activities, integrating seismic monitoring with the evaluation of the migration of the injected CO_2, characterization of regional seismic suitability for injection activities, and the assessment of fractured rock formation injection capacities and limitations.

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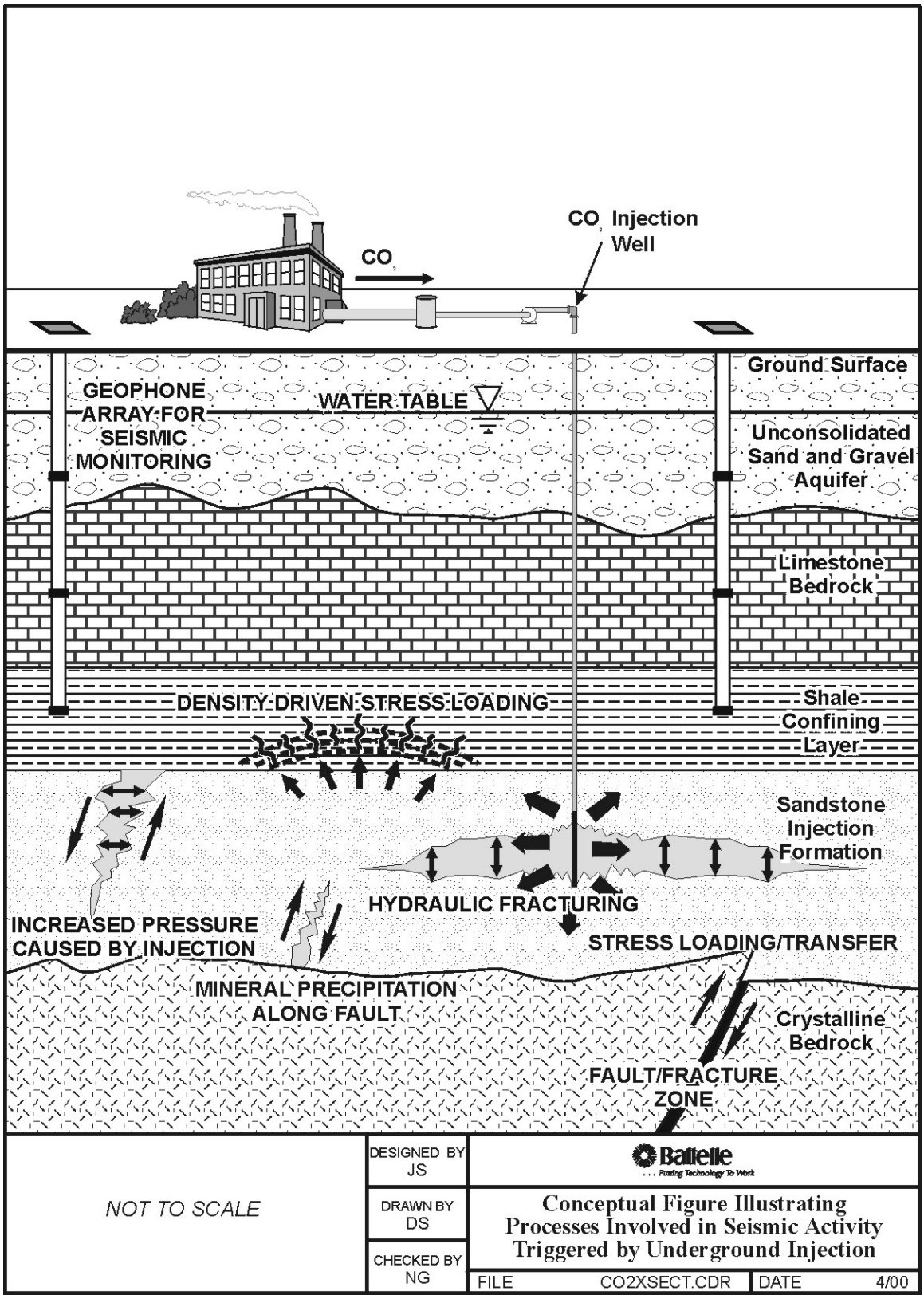


Figure 1. Conceptual figure illustrating processes involved in seismic activity induced by underground injection wells.

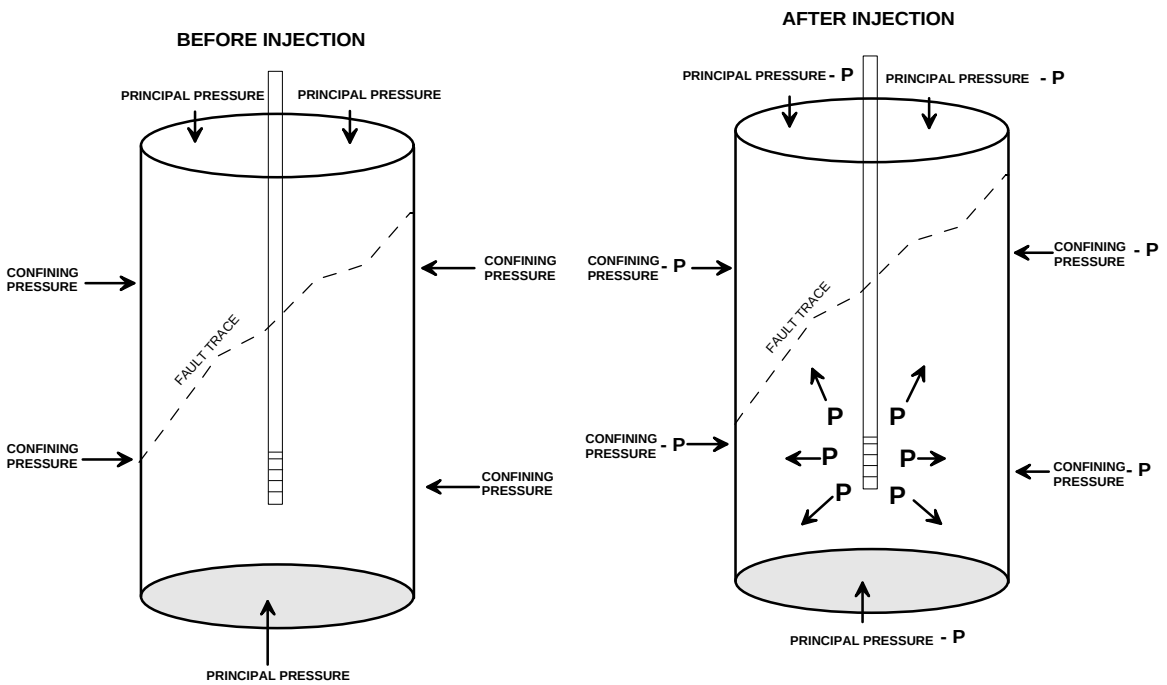


Figure 2. Diagram illustrating how injection pressures (P) reduce the effective confining and axial strength of a rock formation. Injection pressure counteracts confining and axial pressures, reducing the strength of the rock and causing fracture or faulting.

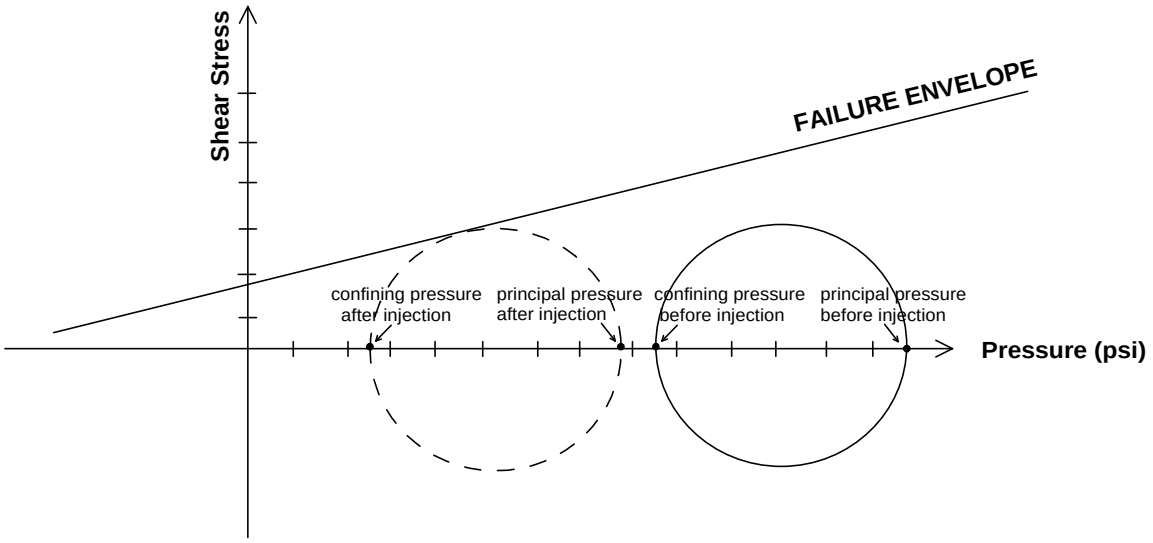
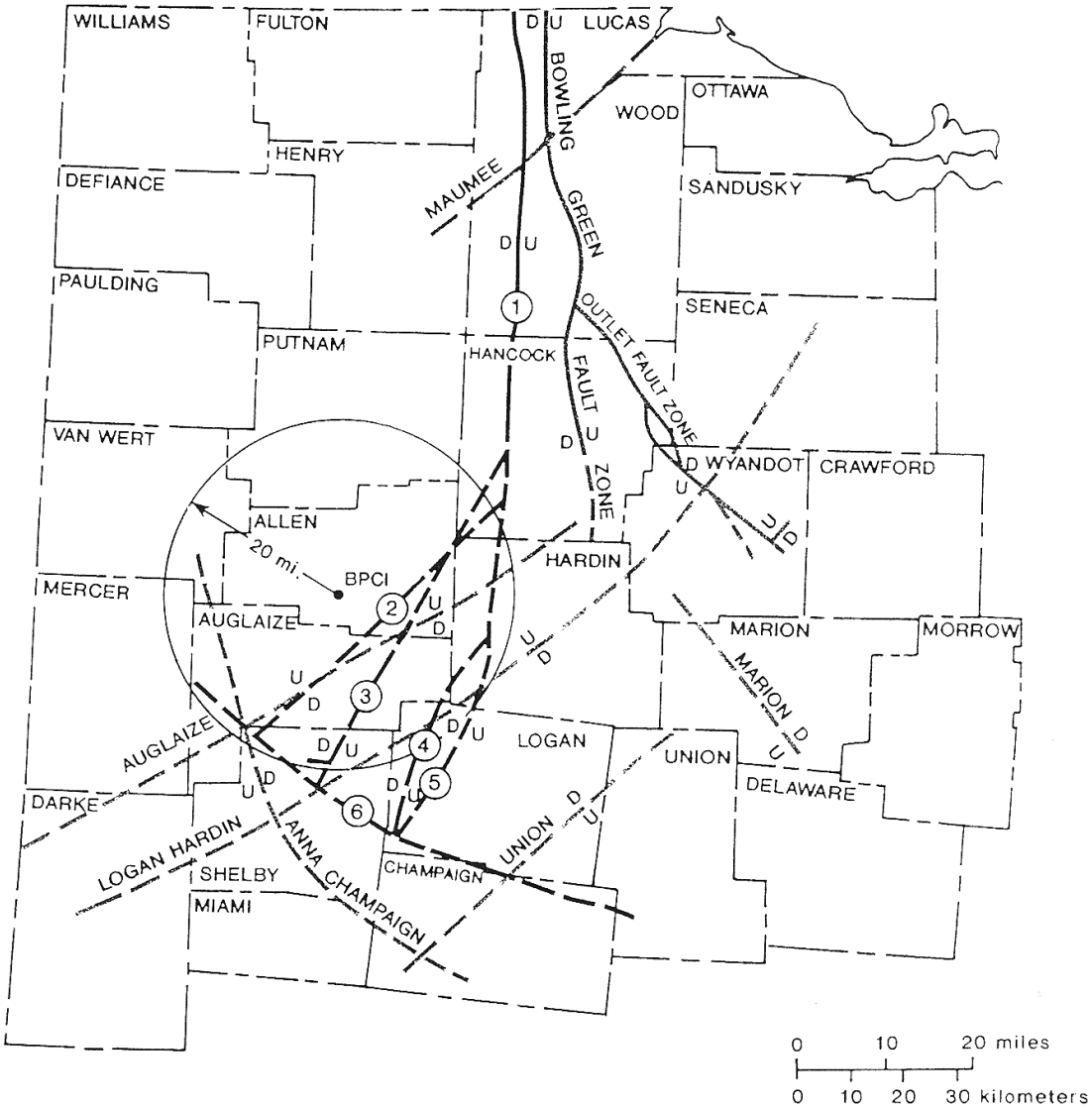


Figure 3. Mohr diagram showing how injection pressures bring a faulted rock to the point of failure.



BPCI = BP LIMA INJECTION FACILITY
1. BOWLING GREEN FAULT
2. TEAYS TRIBUTARY FAULT
3. AUGLAIZE FUALT
4. BOWLING GREEN EXTENSION FAULT
5. LOGAN-HARDIN FAULT
6. ANNA-CHAMPAIGN FAULT
(DASHED LINES INDICATE PROPOSED FAULTS)

Figure 4. Faults in Northwestern Ohio (Source: BP Chemicals, 1991)

Table 1. Documented cases of induced seismic activity.

Location	Type	Depth (m)	Injection Pressure (MPa)	Maximum Earthquake Magnitude
Denver, CO	Waste disposal	3,671	7.6	5.5
Fenton Hill, NM	Geothermal	2,700	20.0	<1.0
The Geysers, CA	Geothermal	3,000	(extraction)	4.0
Matsushiro, Japan	Research	1,800	5.0	2.8
Dale, NY	Solution mining	426	5.5	1.0
Central Michigan	Gas storage	320	1.5-4.3	NA
Germigny Reservoir, France	Gas storage	750	<3	<1?
Cogdell, TX	Secondary recovery	2,071	19.9	4.0
Rangely, CO	Secondary recovery	1,900	8.3	3.1
Gobles Field, Ontario	Secondary recovery	884	NA	2.8
Sleepy Hollow, NE	Secondary recovery	1,150	5.6	2.9
Snipe Lake, Alberta	Secondary recovery	NA	NA	5.1
Dollarhide, TX	Secondary recovery	2,590	13.8	~3.5
Dora Roberts, TX	Secondary recovery	3,661	43.1	~3.0
Kermit Field, TX	Secondary recovery	884	10.6	~4.0
Keystone Field I, TX	Secondary recovery	975	10.3	~3.5
Keystone Field II, TX	Secondary recovery	2,987	17.6	~3.5
Monahans, TX	Secondary recovery	2,530	20.7	~3.0
Ward-Estes Field, TX	Secondary recovery	914	11.7	~3.5
Ward-South, TX	Secondary recovery	741	13.8	~3.0

(after Wesson and Nicholson, 1986); NA = not available

Table 2. Typical Monitoring Requirements for a Class I Underground Injection Facility

Parameter	Monitoring Requirements	Reporting Requirements
Injection Pressure	Continuous	Monthly
Bottomhole Pressure	Calculated every 4 hours	Monthly
Annulus Pressure	Continuous	Monthly
Interannulus pressure	Continuous	Monthly
Temperature	Continuous	Monthly
Flowrate	Continuous	Monthly
Specific Gravity	Weekly	Monthly
PH	Weekly	Monthly
Composition of Injectate	Every 6 months	Monthly
Cumulative Volume	Daily	Monthly
Annulus Sight Glass Level	Daily	Monthly
Groundwater monitoring	Quarterly	Quarterly
Seismic monitoring (if required)	Continuous	Monthly