White Paper on
Induced Seismicity Related to
Oil and Gas Development

Environmentally Friendly Drilling Systems (EFD) Program

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Table of Contents

Introduction .................................................................................................................................... 5

Chapter 1: Injection-Induced Seismicity Overview................................................................. 7
  What Is Induced Seismicity? ........................................................................................................ 7
  Why Suddenly Induced Earthquake are an Issue? ................................................................. 8
  What Causes Induced Seismicity ............................................................................................. 9
  History of Induced Seismicity ............................................................................................... 10
  Natural vs Induced Earthquakes ....................................................................................... 13
  Induced Seismicity Hazards and Risks ............................................................................ 13
  Understanding the Differences between Hydraulic Fracturing and Salt-Water Disposal ...... 15
  Chances of a Damaging Earthquake in 2016 from Induced and Natural Earthquakes .......... 16
  Misconceptions and Facts about Fluid Injection Earthquakes ........................................... 17

Chapter 2: Basic Earthquake Science..................................................................................... 19
  Earthquake Process ............................................................................................................... 19
  Faults Classification ............................................................................................................ 20
  Earthquake Magnitude and Intensity ............................................................................... 20
  Seismic Waves and Estimating Earthquake Location ...................................................... 22
  Ground Motion Characterization ..................................................................................... 24

Chapter 3: Evaluating Injection-Induced Seismicity and Seismic Monitoring ...................... 26
  Distinguishing Between Induced and Natural Earthquakes ............................................ 26
  Seismic monitoring by States .......................................................................................... 27
  Causation Assessment of Specific Seismic Events ............................................................... 27
  Determining Criteria for Induced Seismicity ...................................................................... 28
  Evaluate Causation related to Injection-Induced Seismicity .......................................... 29

Chapter 4: Managing and Mitigating Induced Seismicity ...................................................... 30
  Seismic Risks and Hazards ............................................................................................... 30
  Understanding the Risk .................................................................................................. 30
  Framework for Managing the Injection-Induced Seismicity Risk ..................................... 31
  Considerations for Science-Based Risk Management ..................................................... 32
Mitigation and Response Strategies for Hydraulic Fracturing .......................................................... 34
Risk Management Protocols Proposed by Subject Matter Experts ................................................. 34
Traffic Light Systems (TLS) ............................................................................................................... 37
Risk Mitigation Options in Siting and Permitting of New Class II Wells ..................................... 40
Risk Mitigation Options Existing Class II Wells ............................................................................. 40
Chapter 5: Current Guidelines and Regulations Relevant to Injection Induced Seismicity .............. 41
Federal Regulations ....................................................................................................................... 41
State Regulations ......................................................................................................................... 42
Key observations: .......................................................................................................................... 47
Future Considerations .................................................................................................................... 47
Appendix A: Responding to Injection-Induced Seismicity ............................................................... 48
Who is concerned? .................................................................................................................... 48
What do they need to know? ........................................................................................................ 48
How to fill in the scientific understanding of induced seismicity? ................................................ 48
Communication Planning Process ............................................................................................... 48
Responding to an Injection-Induced Seismicity Event ................................................................. 49
Appendix B: Class II Injection Wells ............................................................................................... 50
Salt Water Disposal Wells ........................................................................................................... 50
Enhanced Oil Recovery (EOR) Wells ........................................................................................... 50
Hydrocarbon Storage Wells ........................................................................................................ 50
Appendix C: Other Sources of Induced Seismicity ......................................................................... 52
Geothermal Operations ................................................................................................................ 52
Reservoir Induced Seismicity (RIS) ............................................................................................. 52
Mining Induced Seismicity .......................................................................................................... 53
Appendix D: Glossary of Terms and Acronyms ........................................................................... 54
Terms ........................................................................................................................................ 54
Acronyms .................................................................................................................................. 55
Appendix E: References ................................................................................................................ 57
Introduction

It has long been understood that human activities such as impoundment of reservoirs, mining, withdrawal of fluids and gas from the Earth’s subsurface, and injection of fluids into underground formations can induce earthquakes. But the phenomenon has been brought to renewed attention by the rise in seismic activity across unusual parts of the central and eastern United States. That surge has become an important topic of discussion not only in North America, but also in Europe, and Canada, owing to the concern that oil and gas operations such as hydraulic fracturing could cause damaging earthquakes. In most cases, the earthquakes are not due to hydraulic fracturing itself, rather, the wastewater disposal, where high volumes of water extracted in oil and gas operations is reinjected into deep basement rocks.

The vast majority of wastewater disposal activities proceeds without incident, but the potential for some injections to trigger earthquakes is nonetheless has been reported. Scientists at the USGS and other institutions have tied earthquake surge in six states: Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas, to injection wastewater from oil and gas productions. Peer-reviewed literature suggests that earthquake risks can spread for miles beyond the original disposal sites and can persist for a decade or more after injection stops. Even though the biggest earthquake from wastewater injection was a 5.6 on the Richter scale, near Oklahoma City in 2011, scientists think that tremors enough to cause severe damage are possible, though unlikely.

This white paper is an informative document which aim to provide a clear and non-technical understanding of the induced seismicity with a focus on the disposal of wastewater by injection into deep wells and a set of general guidelines detailing useful steps to evaluate and manage the effects of induced seismicity. The aim was to provide most up-to-date information available to the readers. This was prepared by reviewing peer-viewed literature, documents produced by federal and state agencies, online databases and resources, and information requested and submitted by external sources.

The five main chapters of the whitepaper focus on the following topics:

- Injection-Induced Seismicity Overview
- Basic Earthquake Science
- Evaluating Injection-Induced Seismicity and Seismic Monitoring
- Managing and Mitigating Induced Seismicity
- Current Guidelines and Regulations Relevant to Injection-Induced Seismicity
More information on responding to an induced seismicity event, Class II Injection Wells, and other sources of induced seismicity are discussed in the appendices.

Induced seismicity is a complex issue for which the base of understanding has been changing rapidly. Although more studies are underway and significant uncertainties exist, regulators and industry can use the tools, knowledge, and expertise in this white paper and take steps to inform and protect the public.
Chapter 1: Injection-Induced Seismicity Overview

The extraction of hydrocarbons creates large volumes of wastewater that require disposal. With advances in drilling technology and engineering, these wastewater has been successfully injected into deep rock formations capable of accepting the wastes for permanent storage. In the recent years many claims have been made that injection related to various forms of energy production have led to increased rates of earthquakes that can be felt by the public. It has been shown that under some geologic and reservoir conditions a limited number of injection wells have been determined to be responsible for induced earthquakes with felt levels of ground shaking (Walsh and Zoback, 2015, McGarr, 2015, Ellsworth, 2013, and Frohlich, 2012). Therefore, to evaluate the need for mitigation and management of the risk of induced seismic events, it is important to first understand the basics of injection-induced seismicity. This chapter focuses on concepts and observations that are related to injection-induced seismicity. Chapter 2 includes more detailed information on understanding general earthquake process.

What Is Induced Seismicity?

Induced seismicity events or induced earthquakes is defined as the seismic events caused by human activities. This includes two relevant points: “induced” means attributed to human activities and the terms “seismic events” and “earthquakes” are comparable. Induced seismic events are attributed to a range of human activities such as:

- Oil and gas operations that involve injection or withdrawal of fluids from Earth’s subsurface:
  - Injection wells used for long-term disposal of produced water,
  - Hydraulic fracturing,
  - Enhanced oil recovery (EOR),
  - Enhanced geothermal energy, and
  - Carbon capture and sequestration (CCS),
- Impoundment of large reservoirs behind dams (reservoir induced seismicity or RIS),
- Mining explosions, and
- Underground nuclear tests.
Why Suddenly Induced Earthquake are an Issue?

A marked increase in earthquake rates have been observed in multiple areas of the Central and Eastern United State (CEUS), especially since 2009. According to Figure 1.1, before 2009, earthquake rates were relatively stable. After 2009, it shows a marked increase of recorded events of \( M \geq 3 \) in the CEUS. Here and throughout this document \( M \) is used to denote the size of an earthquake. Scientific studies, Ellsworth, 2013, Keranen et al, 2014, Walsh and Zoback, 2015; Weingarton et al, 2015, have linked the majority of this increased seismic activity to wastewater injection in deep disposal wells.


Figure 1.2. Active and associated class II injection wells in CEUS. Locations of active injection wells from the Weingarten, 2015 database are shown as blue circles. Injection wells associated with earthquakes are shown as yellow circles. (Modified from Weingarten, 2015 injection well database).
What Causes Induced Seismicity

Physical causes of induced seismicity includes either or both an increase in shear stress (e.g., mass change, thermal change, permeability barriers) or an increase in pore pressure (e.g., fluid injection). For example, seismicity can be induced by the increased pore pressure that effectively reduces the natural friction on a fault. Injection fluid does not need to travel to the fault to affect the fault’s behavior. The change in fluid pressure can be transmitted to greater distances. Figure 1.3 shows the schematics of two mechanisms for inducing earthquakes related to oil and gas operations.

Figure 1.3. Schematics (not to scale) of two mechanisms for inducing earthquakes related to oil and gas operations. Left: an increase in the pore pressure along a fault. Right: load changes on the fault (either through extraction or injection) (Source: Ellsworth, Science, 2013).

Mechanism for injection induced seismicity

In cases where wastewater injection continues over a long period of time, it will cause a cumulative rise in pore pressure on the fault surface. This will decrease the effective normal stress, effectively unclamping the fault and allowing slip initiation. The slip is triggered when the stress acting along the fault exceeds the frictional resistance to sliding. The common concept that injected fluids cause earthquakes by lubricating underground faults is not entirely accurate because fluids do not decrease the coefficient of friction. Rather, injected fluids (or extracted fluids) cause earthquakes by changing the stress conditions on and within faults, bringing these
stresses into a condition in which driving stresses equal or exceed resistive stresses, thereby promoting slip on the fault. But an increased pore pressure by itself does not necessarily induce earthquakes. According to Primer, 2015, necessary components for felt injection-induced seismicity includes:

- Sufficient pore pressure buildup from disposal activities,
- Faults of concern, and
- A pathway allowing increased pressure to communicate with the fault.

Faults of concern: The orientation of the fault and the local subsurface stress distribution may have significant impact on whether a fault may slip, as shown in Figure 1.4. Faults of concern are characterized by:

- a fault optimally oriented for movement,
- at or near critical stress, and
- sufficient size and accumulated stress/strain such that fault slip has the potential to cause a significant earthquake.

History of Induced Seismicity

There are two well-known cases of disposal wells injecting fluids other than produced water that contributed to induced earthquakes. Both of these examples are found in Colorado.
Rocky Mountain Arsenal (RMA)

Induced seismicity is a known phenomenon since the 1960s. In 1961, a chemical weapons plant known as Rocky Mountain Arsenal situated outside Denver, started pumping hazardous chemicals into a deep well. Shortly after, the residents started feeling tremors and more than 700 small to modest-size quakes shook the ground between 1962 and 1966. Though the U.S. Army shut down the disposal well the same year, the earthquakes continued and even grew stronger.

Key Observations:

- Prior to the injection wells use, the area was not recognized as a seismically activity region.
- The seismicity generally follows the injection pattern.
- Greatest seismicity often matches the greatest injection rates.
- Aftershocks in the region continued occurring for 20 years up to 16 km from the injection site.

Paradox Valley, Colorado

After a series of felt earthquakes in Paradox Valley due to brine injection, scientists began collecting more data and modified their injection strategy to reduce seismic risk.

Key observations:

- Seismicity appeared to be strongly related to injection rate.
- Seismicity for the region within ~2 km of the injection well appeared to be more sensitive to the changes in injection rates and shutdown periods.
- Seismicity dropped from 1100 events/year to 60 events/year.
- Changes in the injection strategy substantially reduced the seismic risk.
Figure 1.5: The RMA study confirming the connection between earthquakes and injector wells (Source: Hsieh and Bredehoeft, Journal of Geophysical Research, 1981).

Figure 1.6. Four phases of continuous pumping (1996-2003) superimposed on monthly injected volumes and induced seismic events per month versus time (Source: Aki et al., 2005).
Natural vs Induced Earthquakes

Although the basic mechanism for natural and induced earthquakes may be the same, induced earthquakes are usually smaller in size with less energy release than tectonic earthquakes (Figure 1.7). Largest potentially injection-induced earthquake almost always occur in Precambrian rock. Induced seismicity seems to be usually confined to shallow part of earth’s crust in the vicinity of injection. For example, while natural earthquakes in the CEUS can occur at maximum depths of 25 to 30 km, the majority of potentially induced earthquakes in Oklahoma are occurring in the top 6 km, well into the shallow crystalline basement. This shallow depth often explains why induced earthquakes as small as $M \geq 2.0$ can be felt. Active research is ongoing to understand how induced earthquakes might differ from natural events.

![Figure 1.7. A relative comparison of energy release associated with earthquakes of various magnitudes (Source: Primer, 2015).](image)

The main physical mechanism responsible for triggering injection-induced seismicity is the increased pore pressure on critically stressed fault surfaces, which effectively unclamps the fault and allows slip initiation. These faults generally are located in the Precambrian basement rock.

Induced Seismicity Hazards and Risks

A natural earthquake can present several types of hazards: ground shaking, liquefaction, surface fault displacement, landslides, and tsunamis. However, for induced seismicity events, the primary concern is ground shaking. The level and character of ground shaking is controlled by several physical factors:

- Rupture characteristics (dimension, geometry, orientation, type, and stress drop),
- Distance from a site to the fault,
• Magnitude of the earthquake,
• Rate of attenuation of the seismic waves, and
• Site factors (geology near surface, soil type).

Ground shaking can result in structural and nonstructural damage to buildings and other structures and can result in human anxiety.

**Structural damage:** Structural damage to modern structures happens only in earthquakes larger than M 5.0. However, historical or poorly constructed structures could be susceptible to structural damage in earthquakes of this magnitude or lower. One prominent case of structural damage due to induced earthquakes is the 2011 M 5.6 Prague earthquake, which damages some local homes, broke windows, cracked masonry, and collapsed a turret at a university.

**Nuisance:** Nuisance refers to the annoyance to humans due to low level ground shaking that does not necessarily cause physical damage. This is often the only hazard associated with injection induced seismicity due to its small magnitudes and short durations.

**Ground Shaking Characterization**

Ground shaking characterization can be done in terms of a quantifiable measure such as amplitudes of acceleration, velocity, or displacement. Common ground motion measures are peak ground acceleration (PGA in units of cm/sec2 or g’s where 1 g = 980 cm/sec2) and peak ground velocity (PGV). PGA is the most commonly used measure in seismology and earthquake engineering. PGV is used for structural and nonstructural building damage criteria and for human activity interference. The geologic conditions beneath a site can significantly influence the level and nature of ground shaking. In very general terms, soil sites will have a higher level of ground motions than rock sites due to site amplification. The parameter VS30 (the time-averaged shear-wave velocity in the top 30 m) is used in the U.S. building code (called the International Building Code or IBC) to classify six site classes: hard rock, rock, very dense soil and soft rock, stiff soil, soft soil, and soft liquefiable soil.

**ShakeMaps**

For the past decade, the USGS has been producing near-real time ShakeMaps for all earthquakes generally larger than M 3 to 3.5 in the U.S. ShakeMap illustrates the ground shaking produced by an earthquake (Figure 2-6). The maps are expressed in terms of instrumental intensity, PGA, or PGV. Instrumental intensity (based on the MM scale) can be correlated to expected damage. The ground motions are based on both actual recordings at selected sites in real-time and estimated ground shaking at other locations (where instruments are absent) using ground motion
prediction models. ShakeMaps are generally posted on the USGS website within a few minutes of an earthquake occurring. They are produced for both natural and induced earthquakes.

**Understanding the Differences between Hydraulic Fracturing and Salt-Water Disposal**

Hydraulic fracturing is performed since 1950s and the process is well understood. Felt-level seismicity incidents associated with hydraulic fracturing occur far less frequently than those associated with Class II disposal wells. When it does occur, it typically has a low magnitude, often quickly mitigated, and in the United States has had very little impact. To date, the largest hydraulic-fracturing induced earthquakes in the world have been confined to northeastern British Columbia where a few events have been slightly larger than $M_4.0$. Process of hydraulic fracturing is significantly different than disposal well operations, resulting in lower risk. Difference of hydraulic fracturing and disposal well operations are given in Table 1.1.

<table>
<thead>
<tr>
<th>Injection-induced seismicity</th>
<th>Hydraulic fracturing induced seismicity</th>
</tr>
</thead>
<tbody>
<tr>
<td>High volumes injected (&gt;100,000 m$^3$)</td>
<td>Low volumes injected per stage (500 – 2500 m$^3$)</td>
</tr>
<tr>
<td>Long duration (years)</td>
<td>Short duration (hours- days)</td>
</tr>
<tr>
<td>~35000 wells</td>
<td>~1M+ wells (check)</td>
</tr>
<tr>
<td>No flowback</td>
<td>Injected fluid flowed back to wellbore</td>
</tr>
<tr>
<td>Rarely intended to fracture the rock</td>
<td>Indented to fracture the rock</td>
</tr>
<tr>
<td>Injection through a single point</td>
<td>Multiple injection points along a wellbore</td>
</tr>
<tr>
<td>Inject into porous, permeable zone</td>
<td>Inject into a tight shale or slit</td>
</tr>
<tr>
<td>Distant fault movements can be triggered</td>
<td>Events usually within a 1 km of wellbore</td>
</tr>
<tr>
<td>Seismicity usually correlates to injection rate or volume</td>
<td>Seismicity does not correlate to injection rate or volume</td>
</tr>
<tr>
<td>Many felt earthquakes</td>
<td>Very few felt earthquakes in Canada</td>
</tr>
<tr>
<td>Several damaging earthquakes</td>
<td>No damaging earthquake’s</td>
</tr>
</tbody>
</table>

Table 1.1. *Difference of hydraulic fracturing and disposal well operations.*

The hydraulic fracturing process, however, is designed to create small-scale fractures or faults in a localized area around the well bore. When successful, the localized fracturing creates “mini” earthquakes called microseisms ($Mw<$1). These can be measured and located accurately by highly sensitive seismic equipment used to monitor and direct the process while it is occurring.
Chances of a Damaging Earthquake in 2016 from Induced and Natural Earthquakes

According to the USGS one year seismic hazard forecast released in March 28, 2016, approximately seven million people live and work in areas of the central U.S. that could experience a damaging earthquake in 2016 (Figure 1.8). Almost all the risk is linked to injection wastewater from gas and oil production into porous rock formations below ground. Only a small factor contributes to natural earthquakes. This is the first map from the USGS that included earthquakes induced from human activities. The forecast is only for a year as induced earthquake activity can increase or decrease with time and highly subjected to commercial and policy decisions.

The USGS 2016 report concluded that, “Assessing hazard and potential damage from these events is difficult because induced earthquakes vary rapidly in time and space based on changes in industrial activity, which can be caused by economic or policy decisions; this variability also makes the induced earthquake hazard difficult to forecast.” Therefore, a forecast would have to address short intervals, such as one year, unlike the past hazard models which applied to a 50-year time period.

Figure 1.8. The hazard maps showing the USGS forecast for damage for the western United States and the central and eastern United States (CEUS) for 2016. As can be seen, the chance for damage in north-central Oklahoma and southernmost Kansas is similar to that of high-hazard sites in California (Source: Petersen et al., USGS).
Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas are the six states with the most significant hazard from induced seismicity listed in order from highest to lowest potential hazard. In developing this map, USGS has identified 21 zones (Figure 1.9) with increased rates of induced seismicity.

The new seismic hazard report can be used by both government officials to make more informed decisions and by emergency response personnel to assess vulnerability and provide safety information to those who are in potential danger. Engineers can use this product to evaluate earthquake safety of buildings, bridges, pipelines, and other important structures.

Figure 1.9. USGS map displaying 21 areas of rapid changes in seismicity that have been associated with wastewater injection together with earthquakes (both natural and induced) recorded from 1980 to 2015 in the central and eastern United States(Source: Petersen et al., USGS).

**Misconceptions and Facts about Fluid Injection Earthquakes**

(Source: J. Rubinstein and A. B. Mahani, Seismological Research Letter, 2015 and USGS)

**Misconception 1: Hydraulic fracturing causes all of the induced earthquakes.**

Hydraulic fracturing is directly causing a small percentage of the induced earthquakes observed in the United States. The primary cause for the recent increase in induced earthquakes is disposal
(wastewater) of fluids into deep injection wells. Disposal injection wells are more prone to induce earthquakes as they operate for a longer period of time and inject much more fluid compared to hydraulic fracturing. They can also raise pore pressure levels more than Enhanced Oil Recovery (EOR), thus increasing the probability of induced seismicity.

**Misconception 2: All injection wells induce earthquakes.**

Main fluid injection wells include hydraulic fracturing, wastewater disposal, and enhanced oil recovery. Though most of them do not cause felt earthquakes. Only a few dozen of injection wells from approximately 35,000 active disposal injection wells and 80,000 active EOR wells are known to induce earthquakes.

**Misconception 3: The wastewater injected into disposal wells is from hydraulic fracturing.**

Wastewater constitutes of not only spent hydraulic fracturing fluid but also produced water in the process of oil and gas extraction. This produced water is the brine water (salty water) trapped in the same pore space as oil and natural gas which comes up when oil and gas is extracted. Therefore the contents of wastewater can be highly variable. In some locations it can be spent hydraulic fracturing fluid (e.g., Arkansas and Ohio) while in other locations it consists of brine water (e.g., Oklahoma).

**Misconception 4: Seismicity is induced only close to the disposal injection well and at a similar depth as injection.**

Induced seismicity can occur at distances of 10 km or more away from the injection point. They can also occur at a greater depths than the injection point.

**Misconception 5: Induced seismicity does not occur where wells operating at zero injection pressure.**

Some disposal injection wells inject wastewater under gravity feed. (i.e., wells where you can inject liquid without added surface pressure at the wellhead). These wells can still increase the fluid pressure in the underground rock formation and induce earthquakes.
Chapter 2: Basic Earthquake Science

This chapter provides basic background information of earthquake process, seismic waves, magnitudes, and the intensity. Since same basic physics govern natural and induced earthquakes, it is possible to apply these establish earthquake science to understand induced seismicity.

Earthquake Process

Most earthquakes are typically the product of tectonic stresses that are generated at the boundaries of the Earth’s tectonic plates. Tectonic earthquakes can range in size from magnitude less than zero that results from fault slippage of a few centimeters, to a larger event of magnitude greater than nine where fault displacement are on the order of meters. The size of an earthquake is also a function of the fault plane ruptures. The larger the rupture area, the larger the earthquake. A $M_{7.0}$ earthquake ruptures a fault area of about 1000 km$^2$.

During a fault slip, tectonic strain energy is dissipated by the crushing of rock within the fault zone, producing heat and releasing a small percentage of energy as seismic waves. The point on the fault plane where the earthquake rupture is initiated defined as the focus or epicenter. The point on the Earth’s surface above the hypocenter is called the epicenter.

Figure 2.1. Schematic illustrating the concept of epicenter and hypocenter locations of an earthquake (Source: Primer, 2015)
Faults Classification

A fault is a fracture or zone of fractures between two blocks of rock that allows the blocks to move relative to each other. This movement may occur rapidly, in the form of an earthquake, or slowly, in the form of fault creep. The fault plane can be horizontal or vertical or an angle in between. As shown in Figure 2.1, depending on the angle of the fault plane with respect to the surface (dip) and the direction of slip along the fault, fault can be classified into three categories.

**Normal fault**: A dip-slip fault in which the hanging wall (block above the fault) has moved downward relative to the foot wall (lower block).

**Thrust fault**: A dip-slip fault in which the hanging wall moves up and over the foot wall.

**Strike-slip fault**: A fault in which the two blocks slide horizontally past each other. The San Andreas Fault is an example of a right-lateral fault.

Figure 2.2. Examples of normal fault, thrust fault, and strike-slip fault (Source: USGS).

Earthquake Magnitude and Intensity

The severity of an earthquake can be expressed in terms of both intensity and magnitude.

**Magnitude**: related to the amount of seismic energy released at the hypocenter. It is based on the amplitude of the seismic waves recorded on instruments and represented by a single, instrumentally determined value.

**Intensity**: based on the observed effects of ground shaking on people, buildings, and natural features.
Commonly used earthquake magnitude characterizing techniques and scales are shown in Table 2.1. All these techniques characterize the magnitude in logarithmic relationships.

<table>
<thead>
<tr>
<th>Scale</th>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Richter local</td>
<td>( M_L )</td>
<td>The original magnitude scale based on the amplitude of the seismic waves as recorded on a Wood-Anderson seismograph or instrument with the same response at local distances.</td>
</tr>
<tr>
<td>Moment</td>
<td>( M ) or ( M_w )</td>
<td>Measured from recordings and related to the earthquake seismic moment. Seismic moment is equal to the area of the fault surface that slips, the amount of slip and the shear modulus of the material.</td>
</tr>
<tr>
<td>Surface wave</td>
<td>( M_s )</td>
<td>Measured from recordings of 20 sec period surface waves.</td>
</tr>
<tr>
<td>Body wave</td>
<td>( m_b )</td>
<td>A common scale used in the central and eastern U.S. based on the recorded amplitude of body waves.</td>
</tr>
<tr>
<td>Duration or coda</td>
<td>( M_o ) or ( M_c )</td>
<td>A scale used for microearthquakes events (( M &lt; 3 )) based on the duration of the event.</td>
</tr>
<tr>
<td>Regional magnitude</td>
<td>( M_{lg} )</td>
<td>A regional scale based on the amplitude of Lg surface waves.</td>
</tr>
</tbody>
</table>

Table 2.1. Commonly used earthquake characterizing techniques (Source: Primer, 2015).

The local magnitude scale or \( M_L \): developed by Charles Richter in 1930, allowed precise quantifications of the size of an earthquake based on instrumental recordings. This scale rapidly became a worldwide slandered as it was based on the amplitude of the largest wave recorded in a seismogram and was simple to calculate. Although \( M_L \) is commonly used, the

Moment magnitude scale \( M \) or \( M_w \): is preferred by seismologists as it is based on seismic moment and the best measure of earthquake size. The seismic moment is a function of the area of the fault that ruptures, the average displacement of the fault and the shear modulus, a parameter related to the rigidity of the rocks.
The most widely used intensity scale today is a modified version of one originally developed by G. Mercalli. This 12-value Modified Mercalli Index (MMI) scale uses the observations of people who experience the earthquake and is shown in Table 2.2. It is a useful measure for communication with the public and to provide a general sense of the ground shaking and impact.

<table>
<thead>
<tr>
<th>Potential Damage</th>
<th>Modified Mercalli Intensity</th>
<th>Perceived Shaking</th>
<th>Approximate Magnitude*</th>
<th>Peak Acceleration (g)</th>
<th>Peak Velocity (cm/s)</th>
<th>Description of Intensity Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>None</td>
<td>I</td>
<td>Not Felt</td>
<td>1.0 - 3.0</td>
<td>&lt;0.17</td>
<td>&lt;0.1</td>
<td>Not felt except by a very few under especially favorable conditions.</td>
</tr>
<tr>
<td></td>
<td>II</td>
<td>Weak</td>
<td>3.0 - 3.9</td>
<td>0.17 - 1.4</td>
<td>0.1 - 1.1</td>
<td>Felt only by a few persons at rest, especially on upper floors of buildings.</td>
</tr>
<tr>
<td></td>
<td>III</td>
<td>Strong</td>
<td>5.0 - 5.9</td>
<td>9.2 - 18</td>
<td>8.1 - 16</td>
<td>Felt by all, many frightened. Some heavy furniture moved; a few instances of fallen plaster. Damage slight.</td>
</tr>
<tr>
<td></td>
<td>IV</td>
<td>Severe</td>
<td>6.0 - 6.9</td>
<td>34 - 65</td>
<td>31 - 60</td>
<td>Damage slight in specially designed structures; considerable damage in ordinary structures; partial collapse. Damage great in poorly built structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned.</td>
</tr>
<tr>
<td></td>
<td>V</td>
<td>Very Strong</td>
<td>7.0 - 7.9</td>
<td>65 - 124</td>
<td>60 - 116</td>
<td>Damage considerable in specially designed structures; well-designed frame structures; substantial buildings, with partial collapse. Buildings shifted off foundations.</td>
</tr>
<tr>
<td></td>
<td>VI</td>
<td>Severe</td>
<td>&gt;7.0</td>
<td>&gt;124</td>
<td>&gt;116</td>
<td>Damage total. Lines of sight and level are distorted. Objects thrown into the air.</td>
</tr>
</tbody>
</table>

*Magnitudes correspond to Intensities that are typically observed at locations near the epicenter of earthquakes of different magnitudes.

Table 2.2. Modified Mercalli intensity, peak ground acceleration, and peak ground velocity for the central United States (Source: Nygaard et al, 2013).

**Seismic Waves and Estimating Earthquake Location**

There are three basic types of seismic waves as shown in Figure 2.3.

**P- (compressional or primary) waves:** First to arrive as they travel the fastest. Sound waves. Travel through all types of media.
**S- (shear or secondary) waves:** Travel slower than P-waves. Unable to propagate through air or gas. Much of the damage close to an earthquake is the result of strong shaking caused by shear wave as most of the seismic energy is contained in the S wave.

**Surface waves:** Include Love and Rayleigh waves. Travel along the earth’s surface. Generally not damaging.

---

Figure 2.4: *Seismogram showing P-, S-, and surface wave arrivals and amplitude measurements (Source: Primer, 2015).*

Figure 2.3: *Types of seismic waves (Source: Lay and Wallace, 1995).*
Using the fact that P- and S-waves travel at different speeds, one can measure the time interval between the onset of P-wave and the onset of S-wave shaking on the seismogram. This can be used to estimate the distance of the earthquake from a seismic station. Locating earthquakes accurately is a complex problem and requires an accurate velocity model of the earth, as the velocity model determines the travel times of the P- and S-waves. Earthquake location is an inverse problem, whereby the hypocenter and origin time of the earthquake are determined from the arrival times of waves at multiple stations. The origin time is then solved for by finding the point in the earth and origin time that most closely matches the observed P- and S-wave arrival times.

**Ground Motion Characterization**

Most damage during an earthquake is caused by ground motion. A commonly measured ground motion is peak ground acceleration (PGA), which is expressed as a percentage of the acceleration of gravity (g). The larger an earthquake’s magnitude, the stronger the ground motion it generates. The level of ground motion at a site depends on its distance from the epicenter: the closer a site is to the epicenter, the stronger the ground motion, and vice versa. Strong ground motion could also induce secondary hazards such as ground-motion amplification, liquefaction, and landslide under certain site conditions.

<table>
<thead>
<tr>
<th>Measure</th>
<th>Typical Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak ground acceleration (PGA)</td>
<td>cm/sec, m/sec, or g’s where 1 g = 980 cm/sec²</td>
</tr>
<tr>
<td>Peak ground velocity (PGV) or peak particle velocity (PPV)</td>
<td>cm/sec, m/sec, in/sec</td>
</tr>
<tr>
<td>Peak ground displacement (PGD)</td>
<td>cm, m, inches</td>
</tr>
</tbody>
</table>

Table 2.3. *Ground motion parameters and their commonly used units.*

**Ground-Motion Amplification:** The local geology and soil also play very important roles in earthquake damage. Soft soils overlying hard bedrock tend to amplify the ground motions -- this is known as ground-motion amplification.

**Liquefaction:** Soft sandy soils can be liquefied by strong ground motion -- a process called liquefaction. Liquefaction can result in foundation failure.
Earthquake-Induced Landslide: Strong ground motion can also trigger landslides -- known as earthquake-induced landslides -- in areas with steep slopes.

Instrumental recordings or time histories of ground shaking commonly are measured in terms of acceleration or velocity. A seismograph that measures ground acceleration is called a strong motion instrument or accelerograph. Figure 2.5 shows acceleration recordings of an event from three seismic stations.

Figure 2.5: Acceleration time histories of the 2013 M 4.1 Timpson, TX injection induced earthquake recorded by three strong motion sites (Source: Wong et al, 2015).
Chapter 3: Evaluating Injection-Induced Seismicity and Seismic Monitoring

Currently, it is very difficult to uniquely differentiate between induced and tectonic earthquakes using long-established seismological methods. An assessment of potential induced seismicity may include the integration of multiple technical disciplines and skill sets, with collaboration among seismologists, reservoir engineers, geotechnical engineers, geologists, hydrogeologists, and geophysicists. This chapter focuses on distinguishing between induced and natural earthquakes, detection and location, seismic monitoring by states, evaluating causation of specific seismic events, and determining criteria for induced seismicity.

Distinguishing Between Induced and Natural Earthquakes

To determine whether particular clusters of earthquakes were natural or induced, one can rely on published literature and discussions with state officials and the scientific and earthquake engineering community. Typically, scientists look at the following factors to evaluate an induced seismicity event.

General review:

Reflect a change in seismicity rate: A statistically significant rate change of earthquakes or an occurrence of earthquakes in areas that historically have not experienced seismic activity.

Instrumental records: USGS database, seismic hazard maps, and information from seismic arrays, and non-instrumental records: published reports, newspaper archives, and other historical documents can be used to evaluate the historic seismicity.

Specific review:

- Spatial correlation: Earthquakes located within a few kilometers and synchronize with and at depths consistent with injection
- Temporal correlation: Injection continuing or recently ceased at the time of the earthquake

Evaluating temporal and spatial behavior can be challenging as they need detailed geologic, seismologic, and geophysical studies.
Seismic monitoring by States

To determine the earthquake location (latitude, longitude, and depth) and origin time, at least three or more seismographs are required and their placement with respect to the earthquake is critical in determining an accurate location. For highest location accuracy, multiple arrival times from seismographs distributed evenly around the earthquake are desirable. Earthquake depth, another critical parameter for discriminating between induced earthquakes and natural tectonic events, is hard to constrain without a seismograph being within the distance equivalent to the earthquake focal depth. In practice, accurate focal depths are hard to determine without a closely spaced array of seismographs, particularly for shallow events.

The USGS and other organizations operate a widely spaced network of seismometers in the United States. Therefore, earthquake locations initially reported by the national USGS network can have substantial uncertainty. The uncertainty in epicenter location is ~5–10 km and in depth is ~10 km across most parts of the United States. This location uncertainty is due to the small number of seismic stations used and the wide separation of stations. If a state decides to augment seismic monitoring with improved accuracy, it may consider

- Deploying either a permanent or temporary network.
- Deploying closely spaced regional stations to provide better location identifications
- Incorporating results from local networks rapidly into the USGS Advance National Seismic System (ANSS) Program
- Long term monitoring near high risk that has active seismicity.

Seismic monitoring by state may help in:

- Public safety
- Managing and mitigating risk
- Public and stakeholder response and education

Causation Assessment of Specific Seismic Events

Evaluating causation can be a complicated and time-intensive process. This process involves significant challenges and uncertainty such as:

- Locating the seismic event(s)
- Locating critically stressed faults that can be reactivated
- Identifying temporal-spatial behavior and characterizing changes in subsurface stress where fault slip first occurs and of any associated aftershocks
- Characterizing the subsurface stress near and on the fault
• Developing a physical geomechanics/reservoir engineering model: model that would predict whether induced pressure change could initiate earthquake.

**Determining Criteria for Induced Seismicity**

In 1993, Davis and Frohlich proposed an initial screening method using seven questions that address the physical process of seismicity. If all of the seven questions were answered yes, then it is reasonable to conclude that the earthquakes may have been induced by injection.

1. Initial screening questions:
2. Are the events the first known earthquakes of this character in the region?
3. Is there a clear (temporal) correlation between injection and seismicity?
4. Are epicenters near wells (within 5 km)?
5. Do some earthquakes occur at or near injection depths?
6. If not, are there known geologic features that may channel flow to the sites of earthquakes?
7. Are changes in well pressures at well bottoms sufficient to encourage seismicity?
8. Are changes in fluid pressure at hypocentral locations sufficient to encourage seismicity?

If all of the above seven questions were answered yes, then it is reasonable to conclude that the earthquakes may have been induced by injection. Both yes and no answers result in an ambiguous interpretation. In these circumstances, more detailed analysis could be conducted to better assess factors that may be contributing to causation. Therefore, in 2016, Frohlich et al introduced an improved five question test to assess how strongly the evidence suggests an earthquake is induced. Each of the five questions concerns a different category of evidence supporting the assertion than an earthquakes is induced.

1. QT. Timing: In this location, are earthquakes of this character known to begin only after the commencement of nearby petroleum production or fluid injection operations that could induce seismic activity?
2. QS. Spatial correlation: Are the epicenters spatially correlated with such production or injection operations (i.e., within 5 km for well-determined epicenters or within 15 km otherwise)?
3. QD. Depth: Is information available concerning focal depths of earthquakes at this location, and does this suggest some depths are shallow, probably occurring at or near production of injection depths?
4. QF. Faulting: Near production or injection operations, are there mapped faults or linear groups of epicenters that appear to lie along a fault? Here, “near” within 5
km if the earthquake or earthquake sequence of interest has well-determined epicenters, or within 15 km otherwise.

5. QP. Published Analysis: Is there a credible published paper correlating linking the seismicity to production or injection operations?

Scoring the answers “Yes”, “Possibly”, or “No” with 1.0, 0.5 and 0.0 respectively and summing the scores can suggest how likely the earthquake is induced.

If sum = 0.0-1.0, then earthquake is tectonic (T)

If sum = 1.5-2.0, then earthquake is possibly induced (Psl)

If sum = 2.5-3.5, then earthquake is probably induced (PrI)

If sum = 4.0-5.0, then earthquake is almost certainly induced (ACI)

Evaluate Causation related to Injection-Induced Seismicity

- Reviewing all available pressure data for injection wells in proximity to the seismic events:
  - injection well pressure data with the initial and current reservoir pressure conditions, and
  - historical injection well operational data (e.g., daily, weekly, or monthly injection rates, pressures).
- Characterizing other relevant data:
  - subsurface fault mapping including 2D and 3D seismic imaging data and fault interpretations,
  - available geologic and reservoir property data,
  - stress field orientation, and stress magnitude, and
  - data derived from measurements made in wells and borehole-imaging well logs.
Chapter 4: Managing and Mitigating Induced Seismicity

As we broaden our scientific knowledge regarding the variables that control induced seismicity, understanding them also offers a window into mitigation strategies that can help manage the associated risks. However, given the broad geologic differences across the United States, a one-size-fits-all regulatory approach for managing and mitigating risks of induced seismicity would not be appropriate. In other words, that mitigating the risk of induced seismicity requires a site-by-site assessment. This chapter discusses the factors related to risk and risk management and mitigation strategies developed by agencies to reduce the risk of potential induced seismicity from Class II disposal wells.

Seismic Risks and Hazards

Understanding the distinction between risks and hazards is fundamental to effective planning and response to induced seismicity. The presence of a hazard does not constitute a risk in and of itself.

**Seismic Hazard:** any source of potential damage such as fault rupture, ground motion, ground-motion amplification, liquefaction, and induced-landslide that is generated by an earthquake.

**Seismic Risk:** the probability that humans will incur loss or their built environment will be damaged if they are exposed to a seismic hazard.

In a more detailed definition, risk can be defined as Risk = hazard x vulnerability. The likelihood that an earthquake will strike is the earthquake hazard. Vulnerability means the consequences of that damage. Together, hazard and vulnerability make up risk. The hazard at a given location cannot be changed, and every building is subjected to earthquake hazard all the time. However, the amount of vulnerability to that hazard is controllable and can be used in managing the risk.

Understanding the Risk

Understanding your own risk is important, as it can help you decide what steps to take towards safety if seismicity is induced. Factors to be considered in understanding the risk are,

**Vulnerability**

- Structures
• Non-structural systems: This includes gas lines, electrical lines, or even something as simple as ceiling tiles.
• Contents: The contents of a home or business. This includes supplies, inventory, operating equipment and valuable processions in a home.

Performance

• Building performance during an earthquake
• Continued operation (hospitals and other critical facilities)

Regional Vulnerability

• Lifeline facilities: Water supplies, firefighting equipment, telecommunication lines, power lines, fuel delivery systems. Slow response from them can lead to economic recovery in the longer term
• Building stock: unreinforced masonry buildings (historic buildings)
• Economy: Region is heavily reliant on an industry

Framework for Managing the Injection-Induced Seismicity Risk

1. Evaluate the historical baseline seismicity in the region to assess if seismicity has been tectonic, or suggests abnormal seismicity that may have been induced due to human activity.

2. Review regulations related to underground injection operations and induced seismicity in the area to ensuring compliance with all regulations.

3. Collect information regarding the proximity to any known faults to injection location, volume of fluid to be injected, formation characteristics, tectonic/faulting environment, operating experience, and local construction standards.

4. Develop a preliminary injection plan based on the technical objectives that consider the initial understanding of the local geology, operating experience in the region, public sensitivity/tolerance to nuisance seismicity, and awareness of local construction standards and historical architecture designs and structures.

5. Screen to evaluate the potential risk factors in the region.

6. Based on the potential risk factors, perform an initial screen to identify the risk level for the injection operation.
7. Depending on the risk level, a fit-to-purpose “Traffic Light System” could be considered, defining the monitoring procedures and the seismicity thresholds based on local conditions where operations may be modified or suspended if anomalous seismicity is encountered in proximity to the operations.

8. Finalize an injection plan and any monitoring and mitigation requirements for potential induced seismicity.

9. Educate and train site personnel on induced seismicity risk, and in the operation and implementation of the Traffic Light System if increased levels of seismicity were to actually be observed.

**Considerations for Science-Based Risk Management**

Science-based approaches for assessing and managing seismicity risk associated with injection operations weigh both hazard and risk for a specific site and may consider:

**Site Assessment:** Identify and evaluate specific site characteristics that can trigger seismicity.

- Evaluate local and regional geological setting and formation characteristics (soil conditions, faulting, and historical baseline seismicity levels) to assess the likelihood of activating the faults.
- Estimate the initial static pressure and potential pressure build up in the reservoir
- Determine the proximity to the basement rock to the disposal zone
- Determine historical baseline seismicity levels Seismicity data: historic and current event recordings from USGS, State Geological Surveys, and private array data

**Built Environment:**

- local construction standards
- Lifeline facilities
- location of public and private structures,
- infrastructures such as reservoirs and dams, and
- historical construction or significant architectural elements

**Operational scope:**

- Conduct pressure transient testing in suspected disposal wells to cause seismicity
• Perform periodic static bottomhole pressure monitoring to assess current reservoir pressures
• Modifying injection parameters as needed to manage or minimize induced seismicity
• Operating wells below fracture pressure to maintain the integrity of the confining zone
• Perform annular pressure tests
• Injection well data including:
  o Well location to conduct spatial evaluations
  o Daily injection volume to conduct temporal evaluations
  o Cumulative volume over time to conduct reservoir evaluations
  o Daily maximum injection pressure to calculate bottomhole/reservoir pressure;
  o Injectate specific gravity to calculate bottomhole/reservoir pressure
  o Bottomhole pressure (calculated or data from a downhole sensor)
  o Wellbore diagram showing construction of the well, injection depth (top and bottom of open-bore hole of location of perforations), and the formation(s) into which injection is taking place, and separation from basement
  o Log obtained when drilling the well that defines the locations of the formations penetrated
  o Mud log, gamma ray log
  o FMI log
  o Dipole sonic log
  o Pressure transient tests
  o Step-rate test
  o Falloff tests

Estimations of ground motion:
• the distance from the earthquake to a site
• the depth of the hypocenter

Improve Seismic Monitoring:
• Increase frequency of monitoring of injection parameters
• Monitor Static reservoir pressure to observe pressure buildup
• Install seismic monitors in areas of concern
Mitigation and Response Strategies for Hydraulic Fracturing

In the event of possible induced seismicity associated with hydraulic fracturing operations, depending on local circumstances, well design, and specific geology and reservoir conditions, various mitigation options could include, but not necessarily limited to:

- Pumping of successive stages at reduced volumes,
- Skipping a next stage,
- Delay of further pumping until seismicity subsides, and
- Potentially redesigning the perforation clusters to allow pumping at lower rates and volumes.

In an extreme case, immediate flowback would rapidly decrease the downhole pressure and alleviate the induced seismicity source mechanism. But exact potentialities for flowback would depend on both the type of completion and timing of the seismicity relative to staging.

Risk Management Protocols Proposed by Subject Matter Experts

Several state agencies, as well as research groups, have begun compiling factors that should be considered when developing risk management protocols and tools to assist with mitigating potential seismicity.

Stanford Center for Induced and Triggered Seismicity (SCITS)

Walters, Zoback, Baker, and Beroza (SCITS) have recently compiled a report with a comprehensive review of the processes responsible for triggered earthquakes, in addition to broad scientific principles for site characterization and risk assessment (Walters et al. 2015). This report is publicly available at: https://scits.stanford.edu/researchguidelines. A conceptual hazard and risk assessment workflow is presented as part of this work is shown in Figure 4.1 below. SCITS has also developed an example of a Traffic Light System (Figure 4.2 and Figure 4.3). Traffic light systems describe the risk thresholds for taking varying levels of mitigation and response actions. Thresholds can be defined based on magnitude or level of ground motion detected and the risk management goals of the agency and may vary based on local conditions.
Figure 4.1. Hazard and risk-assessment in concept, the hazard, operational factors, exposure, and tolerance for risk are evaluated prior to injection operations and reflected by shifting the green to red color spectrum in the risk tolerance matrix. After injection begins, the occurrence of earthquakes in the region and additional site-characterization data could require additional iterations of the workflow (Source: Walters, Zoback, Baker, and Beroza (SCITS)).
Figure 4.2. Traffic-light system applicable to saltwater disposal. The green, amber, and red panels represent the levels of heightened awareness frequently represented in traffic-light systems (Source: Walters, Zoback, Baker, and Beroza (SCITS)).

Figure 4.3. Traffic-light system applicable to hydraulic fracturing. The green, amber, and red panels represent the levels of heightened awareness frequently represented in traffic-light systems. (Source: Walters, Zoback, Baker, and Beroza (SCITS)).

American Exploration and Production Council (AXPC)

AXPC has developed an approach combining an “If This ... Then That” methodology into a flow chart, along with three tool boxes to be used in evaluating the potential for induced seismicity.
U.S. Environmental Protection Agency

A recent USEPA report, “Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches,” also provides insight on tools to help UIC regulators address injection-induced seismicity and describes the current understanding of potentially induced seismicity within the existing regulatory framework for Class II disposal (USEPA 2015). The report is available to the public at http://www.epa.gov/r5water/uic/ntwg/pdfs/induced-seismicity-201502.pdf.

Traffic Light Systems (TLS)

Traffic Light Systems were first developed and implemented risk management protocols associated with geothermal induced seismicity. The same principle and observations are now been also implemented in injection-induced seismicity. The specific design and operation of the TLS would be appropriately considered in the context of the risk level and local conditions.
associated with a specific injection operation. Key elements to consider when establishing the TLS:

- Monitoring methods/equipment,
- Monitoring frequency,
- The threshold parameters for the “yellow” and “red” trigger points where operations would be modified or suspended, and
- Reaction time needed to implement operational adjustments if required.

The purpose of a TLS is to assist in guiding decisions on injection operations as related to all forms of injection-induced seismicity. The threshold levels of TLS taken from Department of Energy’s (DOE) “Protocol for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems (EGS)” are given below.

- **Green**: The green zone is defined by levels of ground motion that are either below the threshold of general detectability or, if at higher ground motion levels, at occurrence rates lower than the already-established background activity level in the area which requires no response: Pumping operations proceed as planned.

- **Amber**: The amber zone is defined by ground motion levels at which people would be aware of the seismic activity associated with the stimulation, but damage would be unlikely and prompting the following response: Pumping proceeds with caution, possibly at reduced flow rates, and observations are intensified.

- **Red**: The lower bound of the red zone is the level of ground shaking at which damage to buildings in the area is expected to occur, prompting the following response: Pumping suspended immediately.

Options for the monitoring approach to use with the TLS

- **Human-observation of ground-shaking at site**: Can be easily implemented but would not provide hypocenter or epicenter event location.

- **Regional monitoring arrays**: USGS has available a free real-time monitoring service that sends automated notification emails when earthquakes happen in a local area.

- **Accelerometer-based “strong shaking” systems**: Can be easily implemented, can adjust the sensitivity of detector for local conditions and slightly perceptible ground shaking levels, relatively moderate cost, but would not provide hypocenter or epicenter event location.
• Local surface arrays: Can be easily implemented but requires high level technical expertise for event location and on-site staffing continuously for operations
• Local buried near-surface receivers
• Local borehole installed systems

Examples of TLS

Oklahoma: The Oklahoma Corporation Commission (OCC) has required TLS on a number of selected wells in Oklahoma but has no statewide regulation. The TLS thresholds range from a ML 1.8, which is the smallest event that has been felt in south-central Oklahoma, to as high as ML 3.7 and not based on real-time seismic monitoring. If a M 4.0 or larger occurs in the state, a 10-km “area of interest” is defined around the epicenter and a yellow light status is issued. Those operating in the area are required to report weekly daily volumes and pressures. A red light is issued if significant seismicity is deemed to be due to a particular well.

Alberta and British Columbia, Canada

Energy regulators are required to monitor in particular local areas that are exhibiting potentially fracturing-induced seismicity. A yellow light is triggered at M 2.0 events and a red light at M 4.0. The order requires sufficient seismometers to detect any potentially induced seismicity within 5 km of the wells being fractured. The operator is responsible for fielding an array, analyzing the seismicity data, and reporting any seismicity above M 2.0. Figure 4.6 indicates the traffic light system instituted in Alberta, Canada to use during hydraulic fracturing.

Figure 4.6. Traffic light system instituted in Alberta, Canada to use during hydraulic fracturing (Source: Alberta Energy Regulators).
Risk Mitigation Options in Siting and Permitting of New Class II Wells

Effectively addressing induced seismicity from injection wells requires a site-specific approach, taking into account the fact that geological conditions are not uniform and similar wells in different areas may or may not have any nearby seismicity. Such an assessment should be based on downhole pressure, volumes, and location, including in particular the orientation of any nearby faults. Source: Primer, 2015.

- Obtaining local stakeholder input concerning risks
- Selecting a different location for new wells
- Avoiding injection into the crystalline basement
- Locating faults in the vicinity of the proposed project area based on seismic survey data or surface expressions and placing the well outside the at-risk area where injected fluid may not significantly and adversely perturb the pore pressure/stress state
- Avoiding direct injection of fluids into known faults of concern.

Risk Mitigation Options Existing Class II Wells

- Temporary seismic monitoring at specific sites
- Seismic monitoring during drilling for the presence of any previously unidentified faults
- A procedure to modify operations (e.g., step increases in flow during start up or reducing flow) if a specified ground-motion/magnitude event occurs within a specified distance from the well
- A procedure to suspend operations if seismicity levels increase above threshold values for minimizing public disturbance and damage
- A metric to determine if operations could be restarted and the procedure for establishing injection at safe levels.
Chapter 5: Current Guidelines and Regulations Relevant to Injection Induced Seismicity

Many states have taken initiatives to design guidelines and regulations relating to induced seismicity which are specific to sites, states, or even counties. This appendix summarizes the efforts that have been made by both federal and state agencies to establish regulations relating to induced seismicity. They can be helpful in specific settings but may not be transferable to all situations.

Federal Regulations

Safe Drinking Water Act: The U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) program regulates the underground injection of fluids (water, waste, CO₂) under the Safe Drinking Water Act (SDWA). In some cases, federal law allows room for additional conditions to be added in individual permits as needed to protect underground sources of drinking water. Individual states have been granted primacy for regulating injection wells under the guidance of EPA. Underground injection regulations were designed to protect fresh groundwater and aquifers through a permitting or licensing process. Typically the permitting process requires:

- Evaluation of fundamental scientific information regarding the geology of a proposed injection site and
- Technical specifications pertaining to well integrity, injection pressures, and the location of injection zones deep below the zone of fresh water.

Currently EPA considers six well types based on similarity of the fluids injected, injection depth, design, and operation techniques injection wells (Table 5.1). The injection of oil and gas waste fluids is handled by Class II injection wells. More information on wells regulated under the UIC program can be found at https://www.epa.gov/uic/underground-injection-control-well-classes. In February 2015, the Environmental Protection Agency (EPA) released a management tool that provides a framework for addressing induced seismicity risks on a site-specific basis.
### Underground Injection Control Well Classification Chart*

<table>
<thead>
<tr>
<th>Classes</th>
<th>Uses</th>
<th>Inventory</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class I</td>
<td>Injection of hazardous, nonhazardous, and municipal wastes beneath the lowermost USDW</td>
<td>680 wells</td>
</tr>
<tr>
<td>Class II</td>
<td>Injection of brines and other fluids associated with the production of oil and natural gas resources for the purpose of disposal or enhanced oil and gas recovery</td>
<td>172,068 wells</td>
</tr>
<tr>
<td>Class III</td>
<td>Injection of fluids associated with solution mining of minerals beneath the lowermost USDW</td>
<td>22,131 wells</td>
</tr>
<tr>
<td>Class IV</td>
<td>Injection of hazardous or radioactive wastes into or above USDW</td>
<td>33 sites</td>
</tr>
<tr>
<td>Class V</td>
<td>Injection into wells not included in the other well classes but generally used to inject nonhazardous waste</td>
<td>400,000 to 650,000**</td>
</tr>
<tr>
<td>Class VI</td>
<td>Injection of supercritical carbon dioxide for long-term storage, also called geologic sequestration of CO₂.</td>
<td>6-10 commercial wells expected to come online by 2016***</td>
</tr>
</tbody>
</table>

* Source: Water.epa.gov.

** An inventory range is presented because a complete inventory is not available.

*** Source: Interagency Task Force on Carbon Capture and Storage.

Table 5.1. *Summary of the six classes of injection wells and their estimated national inventory (Source: The Geological Society of America).*

### State Regulations

The EPA has granted some states primacy to regulate Class II wells, including states where there has been an increase in seismic events. Some of these states have implemented regulations and policies aimed directly at reducing the risks associated with induced seismicity, while others have either proposed similar regulations, established heightened monitoring requirements or issued area-wide moratoriums.

**Oklahoma:** Oil and gas activity and Class II injection wells in Oklahoma are regulated by the Oklahoma Corporation Commission (OCC) through its Oil & Gas Division. OCC started amending the regulations in September 2014 to require, for injection in to Arbuckle formation, operators must:
• Monitor and record injection volumes and pressures on a daily basis,
• Keep the records for at least three years, and
• Provide the records to the OCC upon request.

Since then, OCC has issued several directives to the identified disposal well operators in so-called “areas of interests” (AOI) to reduce injection rates. Initially such areas were defined to include all locations within 10 kilometers of the epicenter or an earthquake with a magnitude 4.0 or greater but later expanded to include:

• All locations within 10 kilometers of a “swarm,” which is defined for purpose of the rule as two earthquakes, at least one of which has a magnitude of at least 3.0, that are located within 0.25 miles of each other;
• All locations within 3 miles of a seismically active fault, and
• All locations within 3 miles of a stressed fault, whether or not there has been seismic activity.

In 2013, the Oklahoma Corporation Commission (OCC) adopted a "traffic light" system whereby the agency reviews existing and proposed disposal well permits for proximity to faults. The traffic light system is communicated to well operators via a series of "directives" or area-wide plans typically requiring operators to shut in UIC wells or otherwise reduce the volume of produced water that is injected into a well.

March and July 2015: OCC issued directives affecting more than 500 wells, prohibiting operators from injecting wastewater below the Arbuckle formation, and requiring operators to reduce well depths if they were injecting below the Arbuckle formation.

August 2015: OCC began taking steps to address seismicity issues in northern Oklahoma County and southern Logan County.

February 2016: OCC announced its largest volume reduction plan for wells in western Oklahoma, covering approximately 5,281 square miles and 245 disposal wells injecting into the Arbuckle formation, ordering a 40% reduction in daily disposal volumes.

March 2016: OCC expanded the AOI, covering about 118 more disposal wells in the central part of the state which covered more than 5,000 square miles and more than 400 Arbuckle disposal wells. By expanding this area, the central Oklahoma response plan seeks to reduce total disposal volumes to 40% below 2014 levels.

The directives can be found at,

Oklahoma Administrative Code, OAC 165:10 (2014)
Oklahoma Corporation Commission’s directive on wells located within Areas of Interest for Induced Seismicity (2015)
Oklahoma Corporation Commission’s Oil and Gas Disposal Well Volume Reduction Plan (2015)
Oklahoma Corporation Commission’s Regional Earthquake Response Plan for Western Oklahoma (2016)
Oklahoma Corporation Commission’s Regional Earthquake Response Plan for Central Oklahoma and Expansion of the Area of Interest (2016)

**Texas:** Oil and gas activity and Class II injection wells in Texas are regulated by the Railroad Commission (RRC). On October, 2014, RRC adopted revisions to Texas’ existing fluid injection regulations to address and minimize the risk of induced seismicity. According to the new amendment:

- Applicants must include information from the USGS seismic database regarding historical earthquake activity in a 100 square mile area around the proposed injection well (a circle with an area of 100 square miles would have a radius of approximately 5.64 miles or 9.08 kilometers),
- Allows the RCC to require that an applicant for a new injection permit submit information not otherwise required for a permit application, (e.g., logs, geologic cross sections, pressure front boundary calculations, and/or structure maps), to demonstrate that fluids will be confined,
- Clarifies Commission’s staff authority to modify, suspend or terminate a disposal well permit, including modifying disposal volumes and pressures or shutting in a well if scientific data indicates a disposal well is likely to be or determined to be contributing to seismic activity, and
- Allows Commission staff to require operators to disclose the current annually reported volumes and pressures on a more frequent basis if staff determines a need for this information.

The amendments are available at

Amendments to 16 Tex. Admin. Code § 3.9, relating to Disposal Wells, and § 3.46, relating to Fluid Injection into Productive Reservoirs (2014)

**Ohio:** Oil and gas activity and Class II injection wells in Ohio are regulated by the Department of Natural Resources Division of Oil & Gas Resources. After a series of earthquakes in 2011 near Youngstown Ohio, the Department set forth geographical areas of review based on the average volume to be injected and require evaluations of a proposed injection. Examples of tests that may be required by an operator include but are not limited to:
• Pressure fall-off testing,
• Geological investigations of potential faulting within the immediate vicinity of the well location,
• Submittal of seismic monitoring plan,
• Testing and recording of original bottomhole injection interval pressure,
• Minimum geophysical logging suite: gamma ray, compensated density-neutron, and resistivity logs,
• Radioactive tracer or spinner survey, and
• Any other tests the chief deems necessary.

Every application for a new injection well must:

• State the estimated average and maximum quantities and pressures of brine to be injected daily,
• Outline the methods for measurement,
• Continuously monitor the injection and annulus pressures to maintain mechanical integrity, and
• Must include a shut-off device installed on the injection pump set to the maximum allowable injection pressure.

The amendment of rules are available at,

Executive Order 2012-09K an emergency amendment of the Ohio Administrative Code
Emergency amendments of rules 1501:9-3-06 and 1501:9-3-07

Arkansas: Oil and gas activity and Class II injection wells in Arkansas are regulated by the Oil & Gas Commission. In response to a large number of earthquakes, the Commission issued an order in early 2011, placing a moratorium of approximately six months on the issuance of new Class II injection well permits for a particular area. The order also required that operators of existing Class II wells within the area begin submitting biweekly reports to the Commission to report the daily injection volumes and the maximum daily injection pressure. After further consideration, the Commission issued an order placing a “permanent moratorium” on the issuance of new Class II permits in the area covered by the temporary moratorium issued earlier. Class II permit applicants must also require:

• information relating to the location of any Moratorium Zone Deep Fault within five miles—or a Regional Fault within two miles—of the proposed location of the disposal well.
• Installation of flow meters or other approved measuring devices on all Class II disposal wells to submit information on injection volume and pressure.
The amendment of rules are available at,

Final Rule H-1 – Class II Disposal and Class II Commercial Disposal Well Permit Application Procedures (2012).

- **Colorado**: Oil and gas activity and Class II injection wells in Colorado are regulated by the Oil and Gas Conservation Commission. In 2011, the Colorado Oil and Gas Conservation Commission (COGCC) issued a policy requiring the Colorado Geologic Survey to review all Class II injection permits for any indicators that might result in seismicity due to injection. The COGCC’s permit process aimed at reducing the possibility of induced seismicity considers:
  - Imposing caps on injection volume,
  - Mandating maintenance of pressure below the fracture gradient, and
  - Input from the Colorado Division of Water Resources and the Colorado Geological Survey.

The COGCC also maintains the Colorado Oil and Gas Information System (COGIS) online database, which contains all records from wastewater injection wells across Colorado. The COGCC permit process involves the submission of information pertaining to operation of the proposed well, such as:

- Well construction,
- Ground water and injection zone isolation,
- Fracture gradient,
- Maximum injection rate, injection volume, and injection pressure, and
- Injection zone water quality.

The rules and regulations are available at,

COGCC Rules 303, 324B, 325, 326, 706, 707, and 712.

**Kansas**: Oil and gas activity and Class II injection wells in Kansas are regulated by the Kansas Corporation Commission (KCC). In response to an increase in seismic events, Kansas established a task force in to develop a “Kansas Seismic Action Plan” to address the issue. With the recommendation, KCC requires operators of injection disposal wells located in certain areas to:

- Measure daily injection volumes and pressures,
- Report each month on the daily figures for the prior month,
- Provide additional information, including pressure front boundary calculations,
• Measure and report the true vertical depth of their disposal wells,
• Plug back any wells that have penetrated beneath the Arbuckle formation in order to confine fluids to that formation, and
• Conduct a search of the USGS seismic database for historical earthquakes within a circular area of 100 square miles around a proposed, new disposal well.

The monitoring period and injection limits, which were set to expire in September 2015, were extended to March 2016. In February 2016, the KCC staff recommended expanding the volume reductions schedule to cover wells not previously identified in the March 2015 Order. Since the order, the number and magnitude of earthquakes has dropped substantially.

Key observations:

• After restricting wastewater injection in areas of interest, Oklahoma and Kansas are starting to see decreased seismic activity compared with same time previous years. Some of it can be market-driven, due to the decrease in drilling across the states due to lower oil and gas prices.
• To gather more data Oklahoma, Pennsylvania and Texas are expanding their seismic monitoring systems, placing permanent stations across the states and moving temporary stations to new hot spots.
• Oklahoma and Texas have hired more staff and contracting with scientists to study the geology of areas the details of the quakes and the oil and gas activity that may be associated with them.
• Oklahoma has created a group to study how the wastewater could be recycled or reused https://www.owrb.ok.gov/2060/pwwg.php

Future Considerations

• Be cautious about restrictions as it can cause major reduction in revenue when the oil prices recover.
• Consideration for improving building codes.
• Considerations for induced-earthquake insurance.
Appendix A: Responding to Injection-Induced Seismicity

This appendix is focused on understanding the communication planning process, communication plan elements, and guidelines responding to an event. Because of the increasing occurrence and detection of seismic events potentially linked to underground injection, it is important to be prepared to provide the public with information and respond to inquiries.

Who is concerned?

- Industry: Producers, Service Providers, Wastewater disposers
- Regulators: Oil and Gas regulators, local land use jurisdictions, seismic safety regulators
- Public: Anyone potentially at risk, critical, lifeline facility owners, builders

What do they need to know?

- Industry: Clear requirements for operations
- Regulators: Solid Scientific basis of requirements
- Public: Assurance that regulation are sufficient and being followed, Information to understand the induced seismicity hazard, Information to mitigate risk

How to fill in the scientific understanding of induced seismicity?

- Improve fundamental understanding of process
- Predictive understanding of conditions that may induce seismicity
- Scientific basis for is risk assessment
- Probabilistic hazard assessment

Communication Planning Process

- Preliminary scan to gather relevant information
- Involve stakeholders with multiple areas of expertise
- Tie communication strategies to risk management thresholds
- Conduct mock event exercises and training
- Develop, revisit, and revise the communication plans on a regular cycle
Responding to an Injection-Induced Seismicity Event

- Contact operators triggering problematic seismicity
- Keep up with operations Notice of Intent
- Request dense array monitoring
- Discuss mitigation options with operators

Permit conditions:

- Report M4.0 and greater events within 3km operations
- Report felt events within 3 km
- Suspend causal operations triggering M4.0 or greater events
- Resume operations with approved mitigation plan

Class II Wells

- Order cutbacks in injection or suspension operations
- Review for induced seismicity risk
- Limits on injection and reservoir pressure
- Continuous monitoring and recording of tubing and casing pressure
- Monthly reporting of disposal volumes, pressure and operating hours
- Annual reservoir pressure and packer isolation testing
Appendix B: Class II Injection Wells

According to EPA, Class II injection wells are categorized in to three subclasses.

Salt Water Disposal Wells
Inject wastewater consists of high salt content, as well as chemicals, heavy metals, and other fluids associated with the production of oil and natural gas or natural gas storage operations. On a national average, approximately 10 barrels of brine are produced with every barrel of crude oil (GWPC 2013). The brine is segregated from the oil and then injected into high-permeability formations, usually deeper than the production reservoirs.

Enhanced Oil Recovery (EOR) Wells
Inject brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and, in some limited applications, natural gas. Used to increase production and prolong the life of oil-producing fields. Secondary recovery or water–flooding is an EOR process that reinjects the coproduced saltwater into the oil-producing formation to drive additional oil into pimming wells. Tertiary recovery is an EOR process that injects gas such as carbon dioxide, water with special additives and steam to maintain oil recovery when previous methods become in efficient or uneconomical. Approximately 60% of the salt water produced with oil and gas onshore in the USA is injected into EOR wells.

Hydrocarbon Storage Wells
Inject liquid hydrocarbons in underground formations (salt caverns or rock formations) where they are stored, generally as part of the U.S. Strategic Petroleum Reserve. The wells are designed for both injection and removal of the hydrocarbons.
Figure B.1. A schematic of a typical injection well construction (Source GWPC, 2013).
Appendix C: Other Sources of Induced Seismicity

Any process that involves either extracting earthen materials (e.g., coal) or fluids (e.g., hydrocarbons), or injecting large volumes of fluid is capable of significantly altering the in-situ subsurface stress field and can induce seismicity. Injection of wastewater from hydrocarbon production has been highlighted in this white paper as a major contributor, but other industrial, construction, and mining processes can induce seismicity.

Geothermal Operations

Geothermal projects are generally located in tectonically active areas where naturally occurring geothermal fluids circulate in fractured rock or sediments. Geothermal operations employ both injection and extraction. First, wells are drilled into a geothermal reservoir to bring high-temperature fluids to the surface, where they are used for direct heat (direct use) or to generate electricity (thermoelectric). Then, the cooled fluids are injected back into the hot rock reservoir to pick up heat and circulate it back to the surface. At some locations, such as the Geysers geothermal field in California, the temperature changes associated with injecting this cold water back into the hot reservoir has resulted in seismicity.

Some reservoirs don’t have sufficient natural fractures or permeability to allow natural geothermal fluid circulation to pick up and transfer the heat. When such hot, dry rocks (HDR) are closed to the surface, hydraulically fracturing a HDR reservoir is used to create an artificial or enhanced geothermal system (EGS) to enhance natural fractures and allow injected fluids to capture heat. High pressure hydraulic fracturing undertaken in some EGS projects has caused seismic events that are large enough to be felt.

Reservoir Induced Seismicity (RIS)

Seismicity can be induced by the loading of the earth’s crust with a large mass, such as a reservoir of water behind a large dam or reservoir impoundment. RIS is caused by the rapid stress change due to the water mass, but a more delayed response can occur due to the diffusion of elevated pore pressure. Several earthquakes around the globe, including large events in India and China, were the result of reservoir impoundment. This is not generally an issue for smaller dams since the amount of water in storage is not sufficient to induce seismicity.
Mining Induced Seismicity

When an excavation is formed on a rock, the pre-existing stresses in the rock are distributed. This redistribution of load is always resulted in damage to the rock resulting in vibrations felt on the surface. This is identified in literature as mining induced seismicity and it can occur from both underground and open-pit mining.
Appendix D: Glossary of Terms and Acronyms

Terms

Aquifer: A body of permeable rock or sediment that is saturated with water and yields useful amounts of water.

Earthquake – The shaking or vibrating of the ground caused the sudden release of energy stored in rock beneath the Earth’s surface.

Epicenter – The point on the surface of the Earth directly above the focus or hypocenter of an earthquake. The point directly above where an earthquake originates.

Fault - A fracture or fracture zone along which the two sides of rock layers have been replaced relative to one another.

Flowback water - The fracturing fluid that returns to the surface through the wellbore during and after a hydraulic treatment.

Focus (Hypocenter) - The initial point of rupture of an earthquake below the surface, the point within the Earth that is the origin of the earthquake.

Formation - A basic unit of rock layers distinctive enough in appearance, composition, and age to be defined in geologic maps and classifications; the identifying characteristics are laterally extensive, perhaps for up to hundreds of miles.

Fracture - A crack or break in the rock.

Hazard - Any sort of potential damage, harm, or adverse impact on something or someone.

Hydraulic fracturing - A process to propagate fractures in a subsurface rock layer with the injection of pressurized fluid through a wellbore, especially to extract oil or gas.

Hydrocarbon - An organic compound made of carbon and hydrogen, found in coal, crude oil, natural gas, and plant life.

Mercalli intensity scale (MI) - Used by scientists to measure the size of an earthquake in terms of effects at the earth’s surface (e.g., levels of damage to buildings and their contents).

Moment magnitude scale (Mw or M) - Used by scientists to measure the size of earthquakes in terms of the energy released. The scale was developed in the 1970s to improve upon the Richter
magnitude scale, particularly to describe large (M >7) earthquakes and those with an epicenter is over 370 miles away.

**Microseismic** - A faint earth tremor, typically less than Richter Magnitude zero, which was the detection limit in 1935.

**Permeability** - The capacity of a rock for transmitting a fluid. Permeability depends on the size and shape of pores in the rock, along with the size, shape, and extent of the connections between pore spaces.

**Produced water** - The naturally occurring fluid in a formation that flows to the surface through the wellbore, throughout the entire lifespan of an oil or gas well. It typically has high levels of total dissolved solids with leached out minerals from the rock.

**Richter magnitude scale** - A numerical scale previously used by scientists to measure the size of an earthquake, ranging from <0 to >9.

**Risk** - The chance or probability that a person or property will be harmed if exposed to a hazard.

**Seismic event** - An earth vibration, such as an earthquake or tremor.

**Strain** – The amount of any change in dimension or shape when subjected to deformation under applied stress.

**Stress** – The force per unit area acting on a surface.

**Tectonic** – Processes pertaining to either the force or the resulting structural features from those forces acting within the earth.

**Acronyms**

- ANSS – Advance National Seismic System
- AXPC – American Exploration and Production Council
- CEUS – Central and Eastern United States
- DOE – U.S Department of Energy
- EPA – Environmental Protection Agency
- EGS – Enhanced Geothermal Systems
GWPC – Ground Water Protection Council
IBC – International Building Code
ISWG – Induced Seismicity Working Group
KCC - Kansas Corporation Commission
M or MW – Moment Magnitude
MMI – Modified Mercalli Index
NRC – National Research Council
OCC – Oklahoma Corporation Commission
P - Primary
PGA – Peak Ground Acceleration
PGD – Peak Ground Displacement
PGV – Peak Ground Velocity
RRC - Railroad Commission
S - Secondary
SCITS - Stanford Center for Induced and Triggered Seismicity
SDWA - Safe Drinking Water Act
UIC - Underground Injection Control
USDW – Underground sources of Drinking Water
USGS - United States Geological Survey
Appendix E: References


Hough, S.E. (2014). Shaking from injection-induced earthquakes in the central and eastern United


