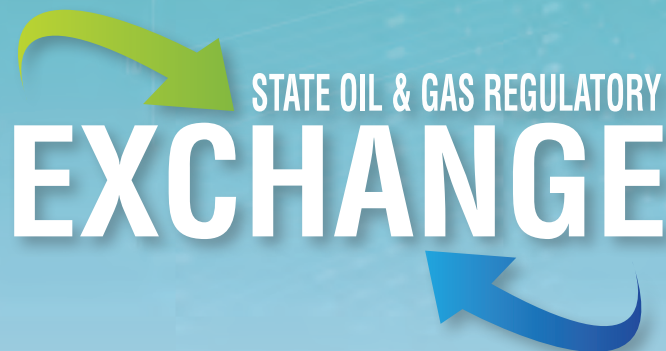

2021 UPDATE

Potential Induced Seismicity Guide

A Resource of Technical & Regulatory Considerations Associated with Fluid Injection



Potential Induced Seismicity Guide: A Resource of Technical and Regulatory Considerations Associated with Fluid Injection

Disclaimer

This is an informational document and is not intended to offer recommended rules or regulations. The Induced Seismicity Workgroup (ISWG), an effort of the State Oil and Gas Regulatory Exchange (Exchange) recognizes that management and mitigation of the risks associated with induced seismicity are best considered at the state level with specific considerations at local, regional, or cross-state levels, due to significant variability in local geology and surface conditions (e.g., population, building conditions, infrastructure, critical facilities, seismic monitoring capabilities, etc.).

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Preface

While seismicity induced by a variety of human activity has been observed and documented for decades, induced seismicity related to underground injection activities was only first recognized in the 1960s at the Rocky Mountain Arsenal near Denver. With the dramatic increase in seismicity in the southern mid-continent of the U.S. starting in 2009, followed by a significant decreasing trend since 2015, attention has been renewed on the potential hazards posed by earthquakes induced by fluid injection. The science required to understand the process and predict its impacts is ongoing.

This Guide is the third edition of what was previously entitled “Potential Injection-Induced Seismicity Associated with Oil & Gas Development: A Primer on Technical and Regulatory Considerations Informing Risk Management and Mitigation.” The previous editions focused on induced seismicity associated with the underground disposal of oil and gas produced fluids in Class II wells. The purpose of this edition of the Guide is to update the science surrounding induced seismicity since 2017 and to expand on the topic of induced seismicity related to hydraulic fracturing. The Guide consists of four chapters and 12 appendices. A new topic, induced seismicity due to carbon capture and storage (CCUS), is also briefly described in Appendix H.

This Guide is designed to provide state and provincial regulatory agencies with an overview of current technical and scientific information, along with considerations associated with evaluating fluid injection-induced seismicity, managing the associated hazard and risk, and developing response strategies to mitigate the occurrence and severity of the events. It is not intended to offer specific regulatory recommendations to agencies but is intended to serve as an information resource. Also, unlike prior studies by the National Research Council (NRC), U.S. Environmental Protection Agency (USEPA), Stanford University, and others, this document is not intended to provide a broad literature review.

This Guide was developed by the State Oil and Gas Regulatory Exchange (Exchange), an initiative of the Interstate Oil and Gas Compact Commission (IOGCC) and the Ground Water Protection Council (GWPC). The effort was led by the Induced Seismicity by Injection Work Group (ISWG), composed of representatives of state and provincial oil and gas regulatory agencies and state and provincial geological surveys, and subject matter experts from academia, industry, federal agencies, and environmental organizations.

Management and mitigation of the risks associated with induced seismicity are best considered at the state level, with specific considerations at local or regional levels. A one-size-fits-all approach is infeasible, due to significant variability in local geology and surface conditions, including such factors as population, building conditions, infrastructure, critical facilities, and seismic monitoring capabilities. Appendix G includes summaries of approaches that various states have taken to address risk management and mitigation. Although important, the issues of insurance and liability are not addressed in this Guide because each state or province has unique laws that render general consideration of these topics impractical.

Although earthquakes can be either natural (tectonic) or human-induced, this Guide uses the term “earthquake” to refer to an induced seismic event due to fluid injection. All induced seismic events of engineering and environmental relevance are earthquakes that are the result of displacement or slip on pre-existing geologic faults. Although such events are more accurately considered to be triggered, the terms “induced” and “triggered” are often used interchangeably to refer to seismicity related to human activity. “Microseismic” events due to hydraulic fracturing are generally the result of fracturing of intact rock but can be also fault-related slip events. Microseismic events are observed to be generally smaller than moment magnitude (**M**) 1.0.

Throughout this Guide moment magnitude is used to denote the size of an earthquake unless otherwise noted. For a more complete description of moment magnitude and its relevance to the size of earthquakes, see Earthquake Magnitude in Appendix A.

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Executive Summary

Introduction

The fact that some human activities can cause seismicity has been known for decades. The vast majority of earthquakes are tectonic (due to natural causes), but under some circumstances human activities can trigger seismicity. Induced seismicity has been documented since at least the 1920s and attributed to a broad range of human activities, including underground injection, oil and gas extraction, impoundment of large reservoirs behind dams, geothermal projects, mining extraction, construction, and underground nuclear tests.

This Guide discusses the potential for seismicity induced by the underground injection of fluids related to the development of oil and natural gas resources and identifies some strategies for evaluating and addressing such events. The State Oil and Gas Regulatory Exchange (Exchange), a collaborative effort between the Ground Water Protection Council (GWPC) and the Interstate Gas and Oil Compact Commission (IOGCC), recognizes that the science surrounding induced seismicity is undergoing significant changes and that any published document will need to be updated routinely to provide readers with the most up-to-date information available. To this end, the Exchange through the ISWG has committed to a process for updating this information in a manner consistent with science, technology, and regulation.

The principal focus of the first and second versions of this document was seismicity induced by injection of fluids in Class II disposal wells. In this third edition we have addressed with equal attention seismicity induced by hydraulic fracturing. We have also expanded the geographic coverage of the Guide to include the Canadian provinces of British Columbia and Alberta. We have added updates to the case studies and summaries of how states and provinces are addressing induced seismicity, and provided the latest available information concerning induced seismicity, and an extensive discussion of induced seismicity due to Carbon Capture, Use and Storage (CCUS).

The Guide focuses on the following topics:

- Understanding induced seismicity;
- Assessing potential injection-induced seismicity;
- Risk management and mitigation strategies; and
- Considerations for external communication and engagement.

Understanding Induced Seismicity

The majority of well operations (both injection for disposal and hydraulic fracturing) in the United States (U.S.) do not pose a hazard for induced seismicity, but under some geologic and operational conditions, a limited number of injection wells and hydraulic fracturing operations have been determined to be responsible for induced earthquakes with felt levels of ground shaking. To evaluate the need for mitigation and management of the risk of induced seismic events, it is important to understand the science.

Understanding induced seismicity requires knowledge about the relationship between injection activities and the activation or reactivation of faults, including the effects of pore pressure increases from injection and the spatial and temporal relationships between injection and optimally oriented, critically stressed faults. Because the same basic physics govern tectonic and induced earthquakes, it is possible to apply much of established earthquake science to understanding induced seismicity.

The frequency of earthquakes increased in the Mid-continent Region of the U.S. beginning in 2009, peaked around 2014 to 2016, and has been declining since then. Most of this activity could be linked to underground injection in Class II wells. Some earthquakes occurred in areas that previously had not experienced noticeable seismicity, creating an increased level of public concern. Some of this increase may be attributed to the greater ability to detect earthquakes smaller than M 3.0 as well as expanded seismic monitoring of seismicity.

Induced seismicity generally is confined to the shallow part of the earth's crust, often in the vicinity of the formation where the injection is occurring. For example, while natural earthquakes in the central and eastern U.S. can occur throughout the Earth's crust to maximum depths of 25 to 30 km, the majority of induced earthquakes in Oklahoma are occurring in the top 6 km. The largest injection-induced earthquakes and those events that may have the potential to be felt and potentially damaging have generally occurred in the Precambrian basement and not in the overlying sedimentary rock.

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. The largest induced earthquakes observed to date are due to fluid injection from disposal wells as compared to hydraulic fracturing operations. In the U.S. there have been four induced earthquakes of **M** 5.0 and greater all due to disposal wells with the largest event a **M** 5.8 in 2016 near Pawnee, Oklahoma. The largest North American induced earthquake associated with hydraulic fracturing is a **M** 4.6 event in British Columbia. An approximate **M** 5.7 earthquake occurred in China in 2018 reportedly due to hydraulic fracturing. There are clearly differences between the two processes with hydraulic fracturing operations being of shorter duration and lower volumes albeit with higher pressures.

Earthquake hazards can include ground shaking, liquefaction, surface fault displacement, landslides, tsunamis, and uplift/subsidence for large events (**M** > 6.0). Because induced

earthquakes, in general, are smaller than **M** 5.0 and short in duration, the hazard of greatest concern is ground shaking. Ground motion models can be used to estimate the ground shaking at a given site and to determine if it creates anxiety, hazards, or neither. New ground motion models for injection-induced earthquakes have been developed because of the recent availability of seismic data from induced earthquakes in Oklahoma, Kansas, Texas, and Alberta.

Assessing Potential Injection-Induced Seismicity

At present, it is very difficult to differentiate clearly and uniquely 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. Stakeholder collaboration is often essential to develop and characterize the broad data sets needed.

Historical seismicity data are needed to establish the background rate of naturally occurring events in a particular area over many decades or centuries, which, in turn, may indicate whether recent increases in seismicity are likely to be due to natural causes or are anomalous and perhaps induced by human activity. Increased monitoring and detection also influence the background seismicity rate. Significantly more seismic monitoring instruments are employed today than in the years prior to 2010.

Evaluating causation can be a complicated and time consuming process that entails 1) accurately locating the earthquake(s); 2) locating critically stressed faults that can be reactivated; 3) identifying the detailed temporal and spatial evolution of earthquakes where fault slip first occurs and of any associated aftershocks; 4) characterizing the subsurface stress near and on the fault; and 5) developing a physical geomechanics/ reservoir engineering model to evaluate whether an induced change (subsurface pore pressure change) could move the fault.

As stated by Davis and Frohlich (1993), in evaluating causation, seismologists typically explore potential spatial and temporal correlations with injection operations. They proposed a screening method using seven questions that address not only spatial and temporal correlations, but also injection-related subsurface pore pressure changes near the fault:

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

If all seven screening questions were answered no, the observed earthquakes were judged not to be induced by injection; conversely, if all 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 analyses could be conducted to better assess factors that may be contributing to causation. Additional causation studies might include:

- Deploying temporary seismic monitoring networks;
- Reviewing available seismological archives and records;
- Identifying the range of potential anthropogenic sources that may be leading to subsurface stress perturbations;
- Reviewing all available pressure data for injection wells in proximity to the earthquakes; and
- Fully considering and characterizing other relevant data, such as subsurface fault mapping, including 2D and 3D seismic imaging data and fault interpretations; available geologic, seismologic, and depositional history; and available geologic and reservoir property data.

Risk Management and Mitigation Strategies

If a state or provincial regulatory agency makes a determination of injection-induced seismicity, the regulator may employ strategies for mitigating and managing risk. Given the broad geologic differences across the U.S. and western Canada, a one-size-fits-all regulatory approach for managing and mitigating risks of induced seismicity would not be appropriate. Consequently, states and provinces have developed diverse strategies for avoiding, mitigating, and responding to potential risks of induced seismicity in the siting, permitting, and seismic monitoring of Class II disposal wells and hydraulic fracturing operations.

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. For a risk to exist there must be exposure to the hazard and a mechanism for harm from the exposure. For example, earthquake hazard exists anywhere there is a fault capable of producing an earthquake. However, the risk of damage from an earthquake is low if that fault is far from people and property.

With respect to hazard and risk relative to injection-induced seismicity, two questions must be addressed:

- How likely is an injection operation to pose an induced-seismicity *hazard*?
- What is the *risk*—the probability of harm to people or property—if seismicity is induced?

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 characteristics**, taking into account the geological setting and formation characteristics, including tectonic, faulting, and soil conditions along with historical baseline seismicity levels from U.S. Geological Survey (USGS), state and provincial geological surveys, universities, and industrial array data;

- **Built environment**, including local construction standards as well as the location of public and private structures, infrastructures such as reservoirs and dams, and historical construction or significant architectural elements;
- **Operational scope**, including existing or proposed injection fluid volumes or hydraulic fracturing design;
- **Estimations of maximum magnitudes** of potential induced earthquakes; and
- **Estimations of potential ground motions** from potential induced earthquakes.

Because the risk from induced seismicity depends on the characteristics of the locations and operations where injection is occurring, many states use site-specific, flexible, and adaptive response actions when an incident of seismicity occurs that may be linked to injection. States may determine that different types of response strategies are “fit for purpose,” depending on whether an event of potentially induced seismicity resulted in damage or felt levels of ground motion or was detected using seismic monitoring, with no damage or felt levels of ground motion.

Based on the assessment of risk from induced seismicity, a state or provincial regulatory agency may determine whether operations may be altered or resume at the well. When mitigation actions are determined to be appropriate, options might include supplemental seismic monitoring, altering operational parameters (such as rates and pressures) to reduce the ground motion hazard and risk, permit modification, partial plug back of the well, controlled restart (if feasible), suspending or revoking injection authorization, or stopping injection and shutting in a well.

State and provincial oil and gas regulatory agencies consider a variety of factors in determining if, when, and where seismic monitoring related to underground injection is appropriate. Screening protocols can help determine if seismic monitoring is warranted. If so, the state or province may include in a plan the method of seismic monitoring, equipment, reporting of data, thresholds for reporting changes in seismicity, steps to mitigate and/or manage risk by modifying operations, and thresholds for suspension of injection activity.

Although state and provincial regulatory agencies typically do not have the resources or expertise to undertake detailed seismic monitoring or investigations, they often partner with other organizations such as the USGS, state or provincial geological surveys, research institutions, universities, or third-party contractors to assist states in designing and installing both permanent and temporary seismic monitoring networks and in analyzing seismic monitoring data.

Considerations for External Communication and Engagement

Because of the increasing occurrence and detection of earthquakes potentially linked to underground injection, public entities involved in responding should be prepared to provide the public with information and respond to inquiries. The messages should be direct and clear.

It is important to develop a communication plan and response strategy as early as possible and before it is necessary to respond to an incident. While common approaches can be considered,

each state and province has a unique regulatory and legal structure that must be taken into account in any communication plan and response strategy.

Prior to any event the state or provincial regulator should consider developing a strategy that focuses on the following goals and objectives:

- **Public surveys:** The goal is to understand the concerns of the public so that the educational and communications components of the strategy can address the issues that are important to the public;
- **Education:** The goal is to present information in a manner that can be understood by the audience. The process originates with the presenter and flows to the audience, using feedback to determine if the message was received and understood; and
- **Communication:** An effective communication process begins with listening to the perceptions, concerns, ideas, and issues of the audience of the communication. If the intended receiver does not, for whatever reason, regard the response or message as germane to his or her personal concerns, effective and productive communication may not take place.

The regulator could develop a strategy that includes methods of communicating with stakeholders, other agencies, the public, and legislators and within the agency itself before, during, and after the event. Once an induced earthquake has occurred at a threshold level, the regulator would implement its communication and response plans. Identifying early on which state or provincial employees will publicly represent the state or province allows the regulator to appropriately respond to public inquiries with a consistent message and the most current information and updates. This protocol will indicate who is responsible to address questions based on the entity asking and questions being asked. Even if no physical damage has occurred, responding to an earthquake can be very similar to an emergency response.

The regulator should be prepared to issue statements and respond to questions and concerns. The regulator could consider holding stakeholder meetings, as appropriate. As they should with all issues, the regulatory representatives should speak clearly and plainly and choose language carefully. Certain words may cause unnecessary concerns or mischaracterize the situation or, stating conjecture or hypotheses without substantiating the facts can mislead the public. For example, it is important to convey that even if an agency such as the USGS issues a report that an earthquake occurred, this does not mean that it can accurately be linked to a source. Information needs to be verified by the appropriate state or provincial agency prior to making any conclusive statements. When reporting epicenter locations, one consideration is to include explicit listing of the location uncertainty, so that the public is clear about where the source of the earthquake may possibly be. After or between earthquakes the regulator should consider following up with internal and external stakeholders about what was done well and what needs to be improved. With any follow up communication, the regulator should not make promises or definitive statements concerning avoidance of future events. The key goal is to show the agency's involvement and ongoing commitment to addressing an evolving concern. Also, it may be important to designate

someone who can respond to ongoing inquiries about the status and conclusions of state or provincial efforts and investigations. Finally, it is important to view the before, during, and after sequence not as linear process but rather as part of an iterative process of continually modifying and improving communication plans and strategies.

Key Message

Induced seismicity is a complex issue for which the base of knowledge changes rapidly. State and provincial regulatory agencies that deal with potential injection-induced seismicity should be prepared to use tools, knowledge, and expertise, many of which are offered in this Guide, to prepare for and respond to any occurrences.

Chapter 1: Understanding Induced Seismicity

Chapter Highlights

This chapter discusses the following:

- Key concepts of earthquake science, such as magnitude, ground motion, and hazard;
- The magnitude and depth of induced earthquakes relative to natural earthquakes, including the relevance of shallow versus deep earthquakes and the ranges of magnitude for natural and induced events;
- The hazards related to induced seismicity with an emphasis on ground shaking;
- Unlike earlier versions of this report, we now give equal attention to injection-induced seismicity due to hydraulic fracturing. The increasing number of cases of hydraulic fracturing induced earthquakes and the increasing magnitudes of such events requires additional research and mitigation;
- The ways in which fluid injection might cause earthquakes, including the concept that the main physical mechanism responsible for triggering injection-induced seismicity is increased pore pressure on critically stressed faults, which decreases the effective normal stress, effectively unclamping the fault and allowing slip initiation (Hubbert and Rubey 1959; Ellsworth 2013);
- The research on induced seismicity, including the evaluation of temporal and spatial correlations of disposal operations over broader geographic regions to earthquakes in those specific geographic areas;
- Ground motion models (GMMs) currently being used and the need to develop models specific to injection-induced earthquakes;
- Decreasing seismicity rates since 2015 in Oklahoma have been attributed to regulatory responses including stopping injection at problematic wells (Langenbruch and Zoback 2016); and
- Future research needs, including approaches for better identification of the presence of seismogenic faults in proximity to injection sites and whether injection-induced earthquakes are different from natural earthquakes.

Introduction—Key Concepts and Earthquake Basics

While Appendix A contains a more detailed guide to earthquake science and Appendix J a glossary, the following key concepts, observations, and terms are useful in understanding this report:

1. Earthquake basics:
 - Magnitude quantifies the size of an earthquake, while ground motion is a result (hazard) of the event;
 - Magnitude scales are logarithmic—earthquake amplitude increases exponentially with scale;
 - Ground motion resulting from the earthquake rupture process depends on magnitude,

- distance, depth of event, properties of the intervening earth, and local geologic conditions;
 - Ground motion is the most significant impact of an earthquake—how seismicity affects people and structures;
 - Rates of earthquakes for a given magnitude are logarithmic—the number of individual events increases exponentially with decreasing magnitude (the so-called Gutenberg-Richter relationship);
 - When a segment of a fault ruptures, the slip and release of built up strain energy can occur over an extended time period (e.g., weeks and months); there may be many smaller “foreshocks” and “aftershocks” associated with the “mainshock”; while hundreds (or even thousands) of separate earthquakes may be recorded during this process, these events are generally associated with a single fault or fault patch undergoing movement;
 - The size of the fault patch affected will impact the amount of seismic energy released which will limit the magnitude of any earthquakes;
 - The epicenter is the location of an earthquake at the earth’s surface;
 - The hypocenter is the location of the earthquake at depth or where the rupture begins;
 - Earthquakes greater than moment magnitude (**M**) 2.5 are typically in the felt range; and
 - Detection and location are not the same. An earthquake can be detected by a single seismic station, but you need a minimum of three stations, located around the earthquake, to estimate the location horizontally and vertically. The denser the network is in terms of seismic stations, the better the earthquake can be located.
2. Where seismic stations are not present or are inadequately spaced, it often impairs the ability to detect or analyze events properly.
 - Low magnitude earthquakes can occur almost anywhere;
 - Seismic station coverage across the U.S. since the 1970s is believed to be adequate to detect all earthquakes of **M** 3.0 and above, although locations and depths may be highly uncertain; and
 - Installing more seismic stations may result in detection of more earthquakes.
 3. Improved detection at an early stage can lead to a more confident determination of the causation of seismicity.
 4. It often takes in-depth analysis of data, some of which may not exist, to differentiate between natural and induced earthquakes.
 5. Most cases of induced seismicity have occurred on previously unknown faults:
 - The large majority of faults which produce smaller induced earthquakes are below the resolution of commonly used seismic imaging tools; and
 - With respect to vertical or near vertical faults, detection is problematic with current seismic imaging tools.

The vast majority of earthquakes are natural due to tectonic forces, but under some circumstances, seismicity can be triggered by human activities. Induced seismicity has been documented since at least the 1920s and attributed to a broad range of human activities, including underground fluid injection of both wastewater and hydraulic fracturing, oil and gas extraction, the impoundment of

large reservoirs behind dams, geothermal projects, mining extraction, construction, and underground nuclear tests.

Industrial activities that involve injection of fluids into the subsurface can create induced earthquakes that can be measured and felt. In many cases, felt injection-induced seismicity has been the result of direct injection into Precambrian basement rocks or injection into overlying formations with permeable avenues of communication with basement rocks.

In one of the first comprehensive looks at induced seismicity, researchers at the USGS (Nicholson and Wesson 1990) described potential earthquake hazards associated with injection. Their report discussed known cases of injection-induced seismicity and explored probable physical mechanisms and conditions under which the triggering is most likely to occur based on the state of stress, injection pressure, and the physical and hydrological properties of the rocks into which the fluid is being injected. The report described that, under certain circumstances, the increased pore pressure resulting from fluid injection, whether for waste disposal, secondary recovery, geothermal energy, or solution mining, can trigger earthquakes. The report established criteria to assist in regulating well operations to minimize the seismic hazard associated with fluid injection.

The frequency of earthquakes has increased in the Mid Continent beginning around 2008. Some of these events occurred in areas that previously had not experienced felt earthquakes, creating an increased level of public concern. Figure 1.1 shows the earthquake distribution for events $M \geq 3.5$ in the U.S. from 1980 through 2019. Figure 1.2 shows the annual number of recorded events of $M \geq 3.0$ in the central U.S. from 1973 through 2019. The increase in seismicity, particularly in the Mid Continent in 2008, shared a temporal and spatial correlation with increased oil and gas activity, and studies indicated a connection with the disposal of wastewater in Class II wells. Decreasing seismicity rates since 2015 in Oklahoma have been attributed to regulatory responses including stopping injection at problematic wells (Langenbruch and Zoback 2016).

In addition, seismicity associated with hydraulic fracturing has become increasingly more significant in terms of the magnitudes of the events and hence their potential for being felt and damaging (Chapter 2). Because the same basic physics govern tectonic (natural) and induced earthquakes, it is possible to apply much of the established earthquake science to understanding induced seismicity. Background on relevant earthquake science is provided in Appendix A.

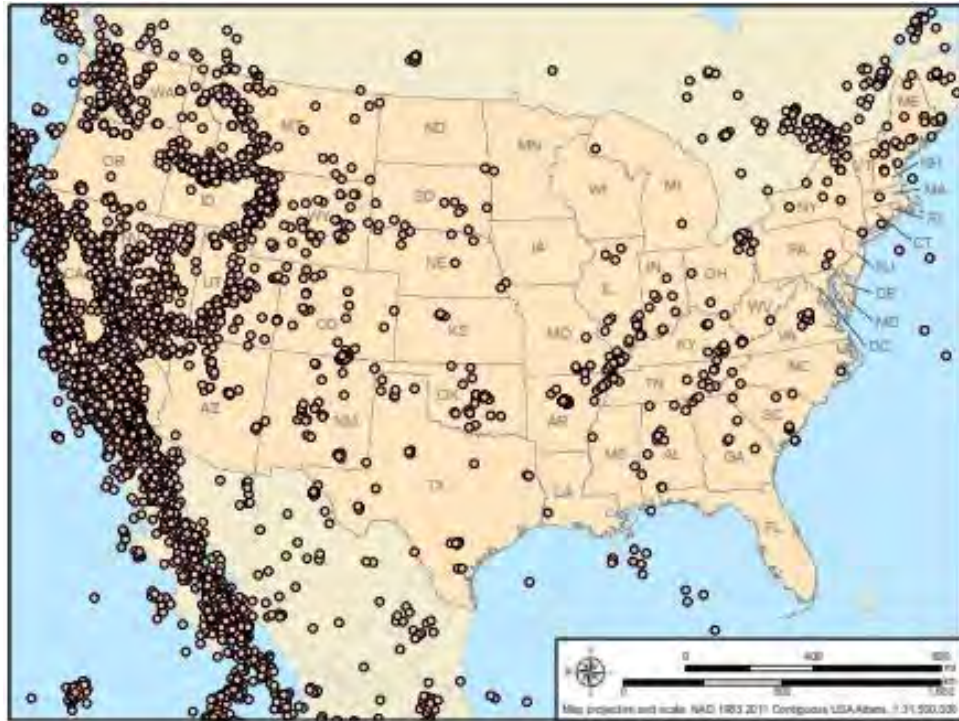


Figure 1.1. U.S. earthquakes $M \geq 3.5$ and greater, 1980–2019. Data from the USGS ANSS catalog. Source: LCI, 2020.

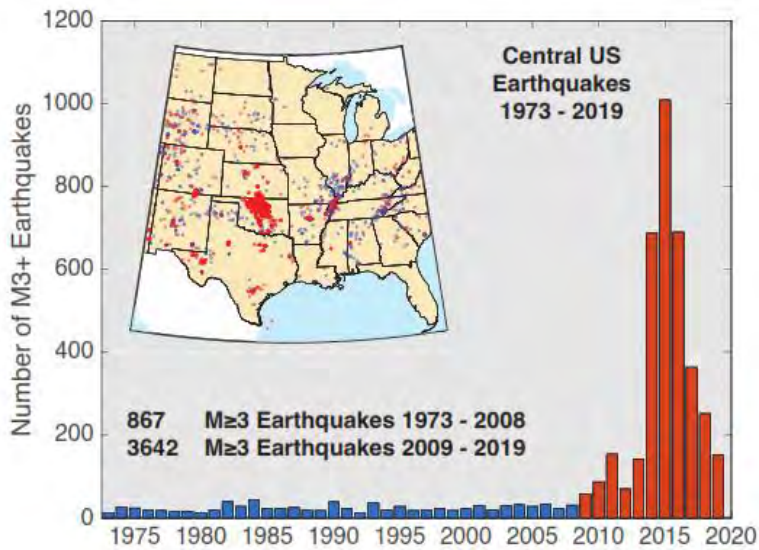


Figure 1.2. The number of earthquakes $M \geq 3.0$ and greater in the central United States, 1973–2019. Source: J. Rubinstein, USGS

Magnitude and Depth of Induced Earthquakes

As discussed in more detail in Appendix A, magnitude is a parameter that quantifies the size of an earthquake. There are several magnitude scales although the moment magnitude scale (**M**) is preferred and used in this document. There can be significant differences in magnitude estimates for a given earthquake between the different scales and even among different institutions using the same scale because of source, path, and site effects on the recorded ground motions. As illustrated in Figure 1.3, induced earthquakes, because of their typically smaller size, possess substantially less energy than major tectonic earthquakes. Although the amount of energy released is usually smaller than with natural earthquakes, induced earthquakes can still be damaging or create anxiety (see following discussion).

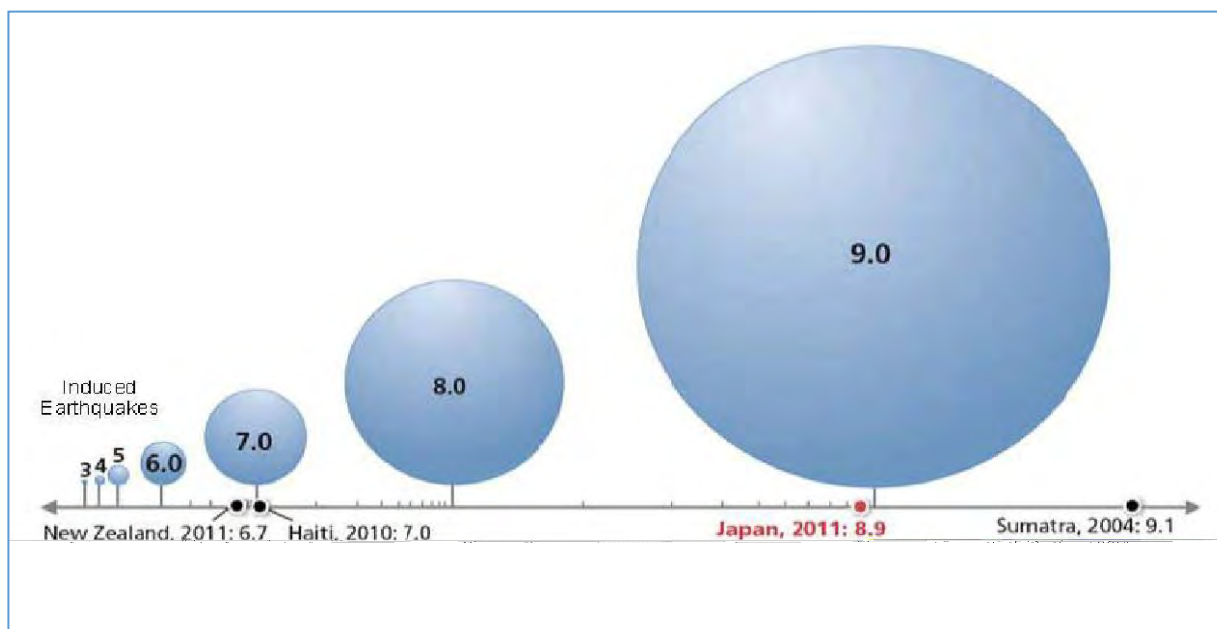


Figure 1.3. Schematic illustration of the energy release associated with earthquakes of various magnitudes. Image courtesy of ISWG.

The September 3rd, 2016 **M** 5.8 Pawnee, Oklahoma seismic event is the largest injection-induced earthquake to occur in the U.S. This event occurred in Osage County where underground injection is under the purview of the USEPA and not the Oklahoma Corporation Commission that controls such activity in the rest of the state. The depth of this event was reported as 5.4 km putting it well into Precambrian basement rock. A case history synopsis for this and related events can be found in Appendix C of this document. The largest induced event due to hydraulic fracturing in the U.S. was a **M** 4.0 earthquake in 2018 in the Eagle Ford play in Texas (Fasola et al. 2019).

In general, natural earthquakes occur deeper in the Earth's crust while induced earthquakes generally occur at shallower depths. The larger potentially injection-induced earthquakes have almost always occurred in Precambrian rock, where the rock is sufficiently strong to store larger amounts of tectonic strain energy.

For example, the 2011 Youngstown, Ohio, earthquakes (largest event **M** 3.9) occurred at depths of 3.5 to 4.0 km in the Precambrian basement (Kim 2013). Also, while natural earthquakes in the central and eastern U.S. can occur at maximum depths of 25 to 30 km, the majority of potentially induced earthquakes in Oklahoma are occurring in the top six km, well into the shallow crystalline basement (McNamara *et al.* 2015). This shallow depth often explains why induced earthquakes as small as **M** 2.0 can be felt. In general, natural earthquakes occurring in the central and eastern U.S. are not felt at that small of a magnitude unless they are very shallow.

Hazards and Risks of Induced Seismicity

Earthquake hazards can include ground shaking, liquefaction, surface fault displacement landslides, and tsunamis, and uplift/subsidence for very large events (**M** > 7.0). Because induced earthquakes, in general, are smaller than **M** 5.0 with short durations, the primary concern is ground shaking. Ground shaking can result in structural and nonstructural damage to buildings and other structures and can result in human anxiety.

- **Damage to structures:** It is commonly accepted that structural damage to modern engineered structures happens only in earthquakes larger than **M** 5.0. Very few cases are known in which injection-induced earthquakes have caused significant structural damage because they generally are smaller than **M** 5.0. However, older structures or those not designed to meet current earthquake resistance standards could be susceptible to structural damage in earthquakes of this magnitude or lower. In rare cases, nonstructural damage has been reported in earthquakes as small as **M** 3.0.

In the U.S., moderate to significant damage to buildings has been documented in several induced earthquakes including:

- The 2016 Pawnee, Oklahoma **M** 5.8 earthquake which damaged brickwork and cracked sheetrock at a number of structures;
 - The 2011 **M** 5.7 Prague, Oklahoma, earthquake, which damaged some local homes, broke windows, cracked masonry, and collapsed a turret at St. Gregory's University (Earthquake Engineering Research Institute 2011);
 - The 2011 **M** 5.3 Trinidad, Colorado, earthquake, which caused structural damage to unreinforced masonry as well as nonstructural damage, including cracked masonry, fallen chimneys, broken windows, and fallen objects;
 - The 2016 **M** 5.0 Cushing, Oklahoma event which resulted in cracks to buildings and fallen bricks and facades on City Hall and the Lions Club; and
 - The 2012 **M** 4.8 Timpson, Texas, earthquake, which caused fallen chimneys and damage to masonry walls (Morgan and Morgan 2011; Frohlich *et al.* 2014).
- **Human anxiety:** Anxiety refers to the human concern created by low level ground shaking. Because injection-induced seismicity is generally of a small magnitude and short duration, human anxiety is often the primary impact associated with most felt events.

Ground Motion Models (GMMs) for Induced Seismicity

GMMs are used to estimate the ground shaking at a given site to determine if it poses a hazard. Ground motion recordings of earthquakes from strong motion and broadband stations in Oklahoma, Kansas and Texas have become available in the past few years and have been used to develop GMMs. Appendix A discusses the threshold of damage with respect to ground shaking.

A significant issue that still remains controversial is whether ground motions from injection-induced earthquakes differ from those from natural earthquakes, whether they change (scale) with magnitude and distance in the same way, and, if so, whether this scaling is a function of tectonic regime as with natural earthquakes. Some researchers suggest that the stress drops of induced earthquakes appear to be lower than those for natural earthquakes. Smaller stress drops will give smaller ground motions. This issue is a topic of active research.

Examples of Current Models

Figure 1.4 shows three GMMs that have been developed for induced earthquakes primarily for Oklahoma but also southern Kansas and Texas (Zalachoris and Rathje 2019, Novakovic *et al.* 2018, and Wong *et al.* 2019). The three GMMs are for peak horizontal ground acceleration (PGA) for a firm rock site condition (V_{s30} [time-averaged shear wave velocity in the top 30 m] of 760 m/sec) and they are compared against recorded data for M 4.0 to 4.25. As observed in strong motion data, the scatter about the mean GMM estimates can be significant.

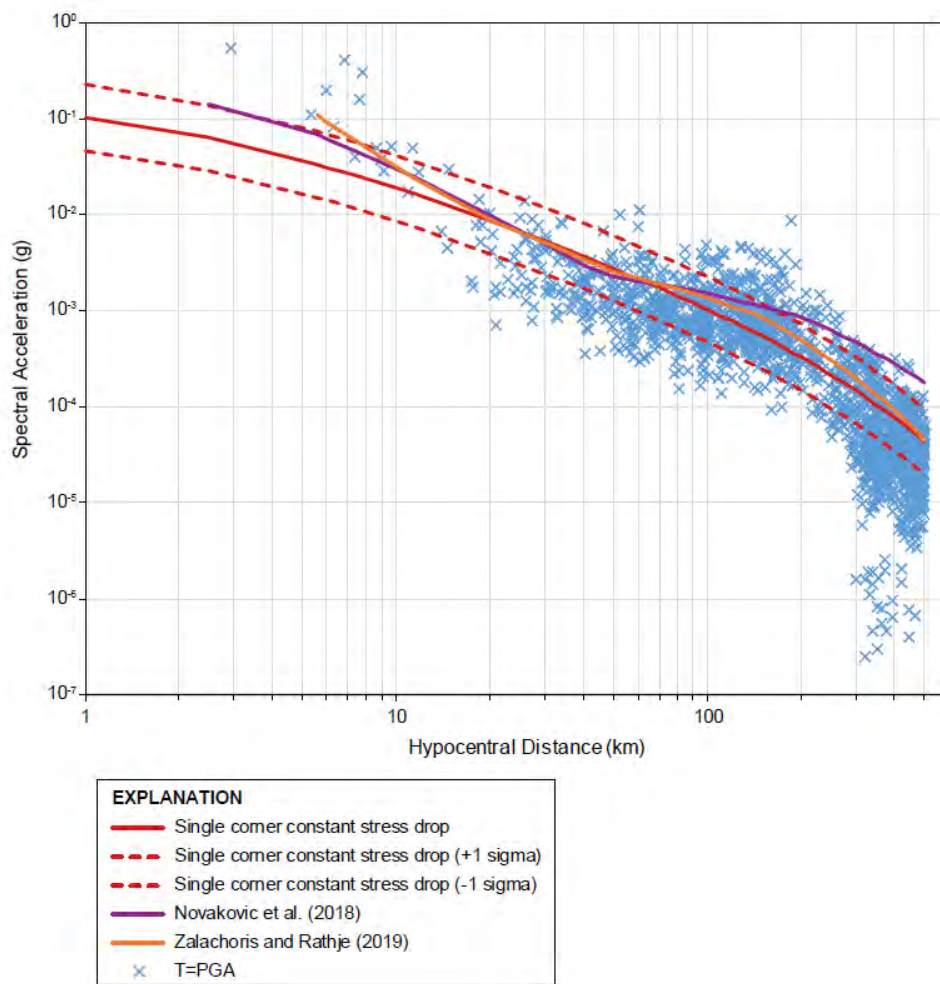


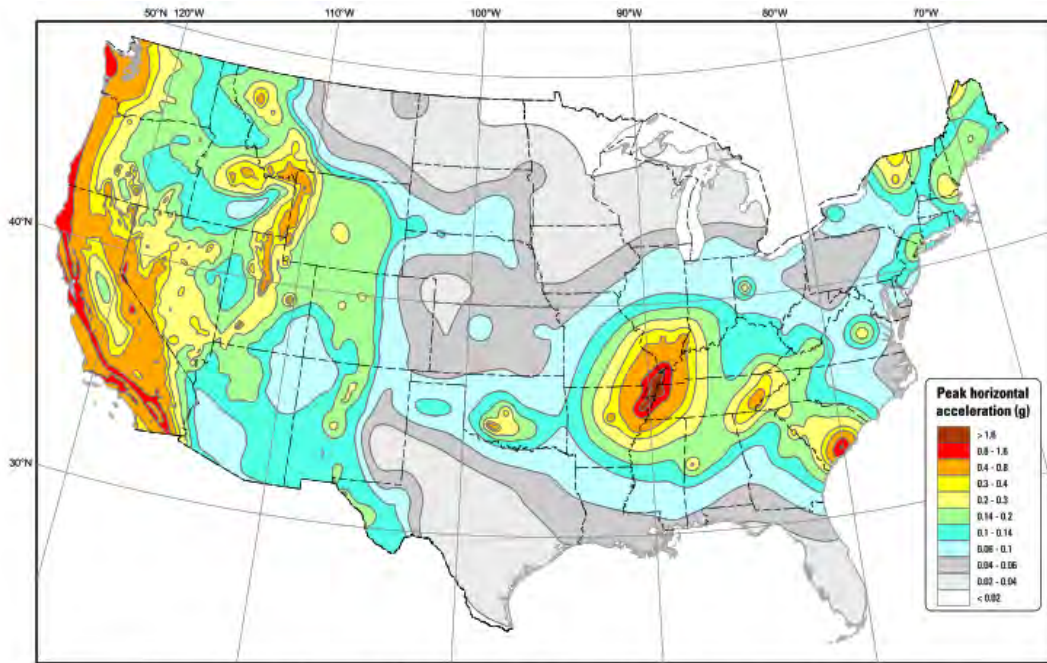
Figure 1.4. Comparison of three GMMs for M 4.0 to 4.25 on firm rock (V_s 30 760 m/sec). Peak horizontal ground acceleration (PGA) in terms of factors of gravitational acceleration (g 's) is predicted as a function of distance from the earthquake hypocenter. Source: LCI, 2020.

USGS Hazard Maps

The USGS has characterized ground shaking in the U.S. through the development of the National Seismic Hazard Maps (NSHM), which are based on long term seismicity records and geologic activity rates (Figure 1.5). These maps form the basis of the International Building Code (U.S. building code), earthquake insurance ratings, and risk assessments.

For the years 2016, 2017, and 2018, the USGS developed one-year seismic hazard forecasts for the central and eastern U.S. that includes the hazard from both induced and natural earthquakes (Petersen *et al.* 2017; 2018; 2019) (Figure 1.6). The hazard maps drawn from these efforts assume that the non-stationary process of induced seismicity is stationary at least for a one-year period. The maps are based on inputs that include alternative earthquake catalog durations, maximum magnitudes, and ground motion models. The intent of the alternative models is to capture the uncertainties in the model parameters and the range of models in the scientific community.

In the 2018 forecast, the same methodology and logic trees were used as for the 2017 forecast with an updated earthquake catalog being incorporated into the model. The seismic hazard forecast for 2018 was lower than for 2017 as seismicity rates declined in 2017 due to the decline in wastewater injection. Although seismicity rates have declined, the short term hazard for damaging ground motions across much of Oklahoma remains high because the rates of small events are still the highest in the history of the state (Peterson *et al.* 2019).



2018 National Seismic Hazard Model for the conterminous United States
Peak horizontal acceleration
with a 2% probability of exceedance in 50 years
NEHRP site class B/C ($V_{s30} = 760$ m/s)

Figure 1.5. An example of the 2018 National Seismic Hazard Maps (excluding potential induced seismicity) from the recent USGS report. Source: Petersen *et al.* 2020.

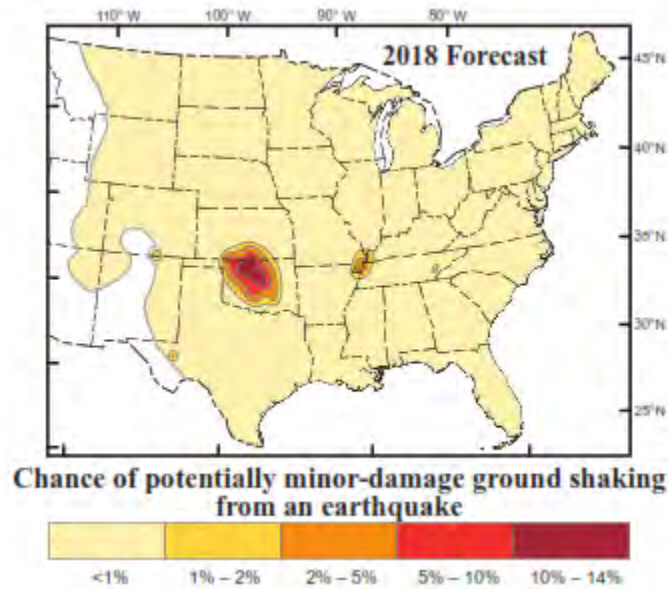


Figure 1.6. Short term Induced Seismicity Models – 2018 One year Model, Source: USGS Earthquake Hazards Program.

The USGS concludes that induced earthquakes are difficult to include in probabilistic seismic hazard analysis because the hazard is: 1) highly variable spatially and temporally, 2) dependent on human economic or societal decisions about when to initiate or terminate wastewater disposal and how much fluid (volume) would be injected or extracted, 3) conditional on understanding differences between source and ground-shaking characteristics of induced and natural earthquakes, and 4) dependent on the length and depth extent of the causative faults, which generally are unknown. Many decisions are critical to the analysis, including modeling decisions about earthquake catalogs, rates, locations, maximum magnitudes, and ground motions.

Estimated Number of Induced Seismicity Locations

The report by the NRC, “Induced Seismicity Potential in Energy Technologies,” published in 2013 and providing information only through 2011, is a detailed summary of induced seismicity of all types, principally in the U.S. (Appendix E). The NRC had identified 156 global locations where induced seismicity was suspected to be caused by energy technologies (during the last ~80+ years). Geothermal projects and reservoir impoundment projects (e.g., dam construction and hydroelectric power generation) accounted for a significant portion of these cases (69 locations). In the U.S., the report notes 60 energy-development sites where earthquakes were caused by or likely related to energy development activities. The report identifies sites in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas. Undoubtedly the number of induced seismicity cases have substantially increased since 2011. The NRC report is available at http://www.nap.edu/catalog.php?record_id=13355.

As stated earlier from 2008 to 2015, there was a significant increase in the number of induced earthquakes reported and studied in the published literature. It is believed that a significant portion

of the seismicity increase in Oklahoma is associated with widespread disposal of wastewater in the Arbuckle Group. Seismicity in Oklahoma tracked by the Oklahoma Geological Survey showed a downward trend starting in 2016 and continuing to this day. Similarly, in Texas, researchers are studying the potential for induced seismicity associated with disposal of wastewater into the Ellenberger Formation. The increase in the number of cases of moderate seismicity attributed to hydraulic fracturing operations in Oklahoma, Ohio, Pennsylvania, and particularly in western Canada has garnered attention among researchers and regulators. Comprehensive regulations have been introduced in these regions with transparent technical exchanges between stakeholders including regulations, researchers, and industry enabling development of techniques to effectively mitigate induced seismicity.

How Fluid Injection May Induce Earthquakes

Class II wastewater disposal and hydraulic fracturing typically involve injection into porous and permeable formations. The majority of disposal wells in the U.S. do not pose a hazard for induced seismicity, but 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.

An earthquake occurring on an optimally oriented and critically stressed fault after injection of fluids is considered a triggered earthquake because a relatively small amount of stress perturbation or pore pressure change caused the release of stress. The stress accumulates in the Earth's crust through natural tectonic processes and can be stored for millennia before being released in an earthquake or earthquake sequence (Zoback and Gorelick 2012).

The main physical mechanism responsible for triggering injection-induced seismicity is increased pore pressure on the fault surface, which decreases the effective normal stress, effectively unclamping the fault and allowing slip initiation (Hubbert and Rubey 1959; Ellsworth 2013). 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.

Factors that may increase the probability of triggering an event include the magnitude and the spatial extent of stress perturbation or pore pressure change, which is tied directly to the balance of the fluid being injected and withdrawn, the presence of critically stressed faults that are well oriented for failure (faults of concern), the *in-situ* stress condition, and any hydraulic connection between the injection zone and the critically stressed fault (Townend and Zoback 2000). See Chapter 2 for a detailed discussion of factors indicating whether an earthquake is induced.

For the most part, injection-induced earthquakes, particularly those larger than **M** 1.0, are relieving tectonic stress stored along preexisting faults, but their occurrence has been accelerated by a triggering mechanism such as pore pressure increase due to injection. In other words, natural

earthquakes may have occurred eventually in an area of induced earthquakes, although not necessarily in the exact same manner or time frame. This latter point is somewhat controversial, and it is not possible to assess how much longer it would have taken for the tectonic stresses to be relieved naturally in the absence of a triggering mechanism because fault reactivation strongly depends on *in-situ* stress conditions and how close to failure the causative faults were initially.

Research has been under way to explore the physical links between the recently observed increase in Mid Continent seismicity and oil and gas activities. Of particular note is the evaluation of possible temporal and spatial correlations of disposal operations over broad geographic regions in Oklahoma to earthquakes in those specific geographic areas (Walsh and Zoback 2015). Walsh and Zoback (2015) proposed a conceptual model for the increased seismicity in Oklahoma based on their analysis of the available disposal well data and injection volumes and the correlations to observed patterns of seismicity. With the observation that many of the earthquakes in Oklahoma occur in the Precambrian basement underlying the Arbuckle Group, Walsh and Zoback (2015) hypothesized that the Arbuckle Group (the disposal zone) may be in hydraulic communication with the underlying crystalline basement over broad areas. They add that significant growth in disposal of produced water increases pore pressure in the Arbuckle Group that then spreads out away from the injection wells with time, eventually triggering slip on critically stressed faults in the Precambrian basement.

Researchers continue to advance development of integrated technologies and approaches to evaluate the potential for fluid injection to induce fault slip. One such example is the publicly available “Fault Slip Potential” software tool; Rall Walsh of Stanford University recently developed this integrated reservoir geomechanics software modeling tool to estimate the chance of a fault slipping in these circumstances, given stress, pore pressure, and injection conditions (Appendix F).

Additional research (Langenbruch and Zoback 2016) is focused on developing predictive models to better forecast potential seismicity based on statistical model of injection-related seismicity in Oklahoma that links changes of wastewater injection rates to seismicity rates. The Langenbruch and Zoback (2016) model is based on an approach developed to evaluate fluid injection–induced earthquakes at geothermal and hydrocarbon reservoirs that are usually associated with a single injection well and adapting this model to hundreds of large volume injection wells and thousands of injection-related earthquakes in Oklahoma. The model is first calibrated with the observed earthquakes and reported injection volumes in the areas covered by the directives and then goes on to predict how induced seismicity in Oklahoma will respond to the mandated injection rate reduction. These forecasts associated with the innovative models suggest seismicity should be reduced with the volume reductions that have been implemented in Oklahoma.

In a recent study by Zhai et al. (2019), they developed a physics-based earthquake forecasting model considering both pore pressure and poroelastic stresses. They applied their model to Oklahoma and were able to show that the regional-induced earthquake timing and magnitudes were controlled by fluid diffusion in a poroelastic medium, and that seismicity could be successfully forecasted using a rate-and-state earthquake nucleation model.

Potential for Seismicity Related to Hydraulic Fracturing

Incidents of felt seismicity associated with hydraulic fracturing occur far less frequently than those associated with Class II disposal wells and typically have smaller magnitudes than injection-induced seismicity. Within the U.S., the largest published earthquake that has been associated with hydraulic fracturing is a Richter local magnitude (**M_L**) 3.5 / **M** 4.0 on May 1, 2018 event in Eagle Ford play of Texas (Fasola et. al. 2019 reference (<https://doi.org/10.1029/2019GL085167>)).

In Oklahoma, there have also been several earthquakes attributed to hydraulic fracturing that have been measured up to **M** 3.5 (Skoumal et. al. 2018 reference (<https://doi.org/10.1029/2018JB016790>)).

Globally, the largest recorded earthquake to date, that researchers have associated with hydraulic fracturing operations, has been the 2018 **M_L** 5.7 South Sichuan Basin earthquake (Lei *et al.* 2019). This event is significantly larger than those in British Columbia and Alberta, where the largest earthquake has been a **M** 4.6 (Mahani et al. 2017).

Because the energy release associated with an earthquake is dependent on the size of the fault that slips, and the amount of fault slip, the fact that larger events have occurred outside the U.S. suggest the geologic conditions are significantly different; and ongoing research is focused on developing better understanding of the triggering release mechanisms associated with hydraulic fracturing.

The process of hydraulic fracturing is different from the process of waste disposal. The rate of fluid injected over the short term is generally higher than with a disposal well; however, the hydraulic fracturing process lasts only a short time compared to a long term disposal well. In hydraulic fracturing, the fluid is pumped into the well at high rates and pressures, with the intent of causing the target formation to fracture and stimulate permeability. Hydraulic fracturing will always produce very small earthquakes (Microseismic event) as part of the fracturing process which are commonly used to image and control the hydraulic fracture. Disposal wells are typically designed, operated, and regulated to prevent such fracturing.

Unlike disposal wells, hydraulic fracturing is a transient process in which the wellbore typically is subdivided into stages, isolating subsequent intervals so that extended fault contact is not likely. Fracturing of a stage lasts from one to several hours, depending on volumes and rates. The well, which may be produced soon after the fracturing operation, becomes a pressure sink, drawing fluids into it and decreasing pore pressure in the vicinity of the well. Chapter 2 contains additional information regarding induced seismicity potential relative to hydraulic fracturing.

Several states including Ohio, Oklahoma, and Pennsylvania have adopted procedures and action points for companies conducting hydraulic fracturing in order to limit the magnitude of any seismicity that may be associated with such operations. Research into the causes of such events is continuing.

Future Research

Induced seismicity has a long history with increased focus during the past decade, as evidenced by the recent scientific meetings and conferences on the subject. Although the basic mechanisms and contributing factors of injection-induced earthquakes are well understood, each case is a product of the local geology, including faulting, *in-situ* stress conditions, hydrologic regime, and the characteristics of the causative injection. Some of the questions of interest to researchers include:

- What new methods and techniques can be used to better identify the presence of critically stressed and seismogenic faults in proximity to injection sites?
- Are stress drops of injection-induced earthquakes smaller than those of natural earthquakes?
- Are ground motions of induced earthquakes different from those caused by natural earthquakes?
- Can the largest induced earthquake be estimated?
- Can we further develop induced earthquake forecasting on a regional and site-specific basis?
- Can advanced seismic waveform processing techniques be developed to offer higher sensitivity in detection and location of earthquakes to better illuminate faults as they undergo displacement?
- Can injection parameters and processes be changed to control seismicity?

Chapter 2: Assessing Potentially Injection-Induced Seismicity

Chapter Highlights

This chapter discusses the following:

- Assessing seismicity
 - Historic records – recorded by seismographs (instrumental), reported by humans, and observed impacts on the built and natural environment, and geologic evidence (non-instrumental); and
 - Contemporary and current and ongoing seismicity – recorded by seismographic networks, both regional and local, including seismic monitoring by states with regional and temporary local arrays.
- Injection well disposal zone conditions
 - Fluid data from one well, consideration of adjacent wells; and
 - Geologic and hydrologic data.
- Evaluating causation by injection wells
- Hydraulic fracturing fluids and target zone conditions
 - Fluid data;
 - Geological data;
 - Geophysical data;
 - Evaluating causation by hydraulic fracturing;
 - Well Design; and
 - Completion Details
- Understanding differences between hydraulic fracturing and wastewater disposal

Introduction

Assessing seismicity for whether it is related to injection, either saltwater disposal or during hydraulic fracturing operations, involves three activities:

1. Assessing historical and contemporary seismicity;
2. Assessing conditions in the injection zones; and
3. Assessing possible causes.

This chapter will discuss these areas; the data required and its inherent uncertainty, and the subsequent analysis to help determine causation.

Historical Seismicity: Historical seismicity data are needed to establish the background rate of naturally occurring events in a particular area. This baseline enables detection of changes in the seismicity rate, which, in turn, may indicate whether recent increases in seismicity are likely to be due to natural causes or human activity. A survey of past events includes data from non-instrumental and instrumental records.

- Non-instrumental records:** These can include academic reports, historical summaries of public reports, newspaper archives, and other historical accounts of earthquakes as well as paleoseismological observations (looking at the stratigraphic record of ancient earthquakes). These records are less complete and more qualitative than instrumental records. A primary reference is “Seismicity of the U.S. 1568–1989 (revised)” by Stover and Coffman (1993). This report documents felt and important instrumentally recorded earthquakes in each state. Paleoseismological observations sometimes offer direct evidence of past earthquakes, as in the case of the large surface deformation visible for the Meers Fault in Oklahoma (Crone and Luza 1990). More often, however, the evidence is indirect, particularly for past activity in the central and eastern U.S. For example, evidence for possible past earthquake activity in the New Madrid Seismic Zone (Tuttle et al. 2005) consists of observations of liquefied loose sands. State geological surveys can be a resource to help identify past earthquakes or geomorphic evidence of such hazards, as references can be difficult to identify or may not exist electronically.
- Instrumental records:** These are obtained from national, regional, and local seismic networks. The USGS maintains a searchable database of earthquakes dating back to 1973, available at <http://earthquake.usgs.gov/earthquakes/search/>. A more complete catalog for the U.S. covering 1568 through 2012 was used to develop the 2014 National Seismic Hazard Map (Petersen et al. 2014), which was updated in 2018 (Peterson et al. 2018) and can be downloaded at <https://www.usgs.gov/natural-hazards/earthquake-hazards/science/>. In some cases, state agencies maintain seismic networks that are not part of the USGS Advanced National Seismic System (ANSS). Some state seismicity catalogs are available online and, in most cases, will be more complete than those downloadable from USGS sources. For example, the Arkansas Geological Survey website (AGS 2014) provides information on station locations and events detected. Ohio, Oklahoma, and Texas have deployed permanent and temporary seismic networks for proactive seismic monitoring and reporting in order to monitor tectonic activity and also study potential induced seismicity. Similarly, some academic institutions operate seismic networks, either for permanent seismic monitoring (e.g., Oklahoma Geological Survey as part of the University of Oklahoma and the Bureau of Economic Geology as part of the University of Texas at Austin) or short- term projects, and may maintain archives of events of magnitudes lower than those detected by larger regional networks. Not all regional networks and short term research projects archive their results in the Comprehensive Catalog (ComCat) that is maintained by ANSS.

Care is needed when gathering earthquake catalogs, as biases exist within these datasets. For example, the Oklahoma Geological Survey joined ANSS in mid-2019 and their events become part of the USGS Comprehensive Catalog immediately upon review. With a lower magnitude of completeness than previous catalog entries from the limited seismographs that USGS utilizes for the national system, it would appear that earthquakes are occurring more frequently; however, smaller earthquakes are being reported than were otherwise previously detectable. Furthermore, as regional networks grow or shrink their operations due to fluctuations in resources, the catalog completeness may decline or increase, biasing the estimates of background seismicity. Instrumental records can offer much more information than non-instrumental records, but they

are potentially limited by their incomplete and short duration coverage (Schorlemmer and Woessner 2008) as well as limited location accuracy, particularly for event depth (Husen and Hardebeck 2010) and consistency in data collection, analyses and reporting methods. However, the earthquake catalog used to develop the 2014 National Seismic Hazard Maps (Petersen et al. 2015) is substantially complete for earthquakes with $M \geq 3.0$ in the central and eastern U.S. (Ellsworth 2013).

The historical seismicity record is incomplete for small magnitude events ($M < 3.0$) in most regions of the U.S. because most of the sensitive seismographic networks needed to monitor such events have been deployed during only the last few decades. Using historical seismicity records must account uncertainty in earthquake locations, magnitudes, depths, and incomplete records.

Contemporary Seismicity

Increases in seismicity, or seismic areas of interest, are evaluated with data from seismic networks. These can be regional or local, depending on the accuracy needed; whether mere detection is the objective or pinpointing the location of the events.

Regional seismic networks (inter-station spacing on order of tens of km or sparser) can detect earthquakes below the felt threshold ($M < 2.0$). Many networks detect and locate earthquakes well below this threshold, including earthquake with a negative magnitude. However, there is some uncertainty in the location of these earthquakes due to the wide spacing of seismic stations in these regional networks as well as uncertainties associated with velocity models used to locate earthquakes. Very local seismic networks (inter-station spacing on 1s of kms) can provide better epicentral location and hypocentral depths because of the density and proximity of the seismic stations.

A widely spaced network of seismometers operated by the USGS and other organizations covers the U.S. Earthquake locations initially reported by the national USGS network can have substantial uncertainty. The epicentral location uncertainty is $\sim 5\text{--}10$ km and depth uncertainty is ~ 10 km across most parts of the U.S. This location uncertainty is due to the small number of seismic stations used, the wide separation of stations (often more than 160 km), and the use of general models that do not reflect local variability in seismic velocities or geologic conditions. Depths are particularly problematic; for some events, the USGS usually fixes a default value and reports the depth at 5 km.

Table 2.1. Performance targets for the ANSS for different areas. Adapted from Advanced National Seismic Systems Performance Standards Version 2.8.

Seismic Monitoring/Strong Earthquake Shaking					
Metric	Units	High Risk Urban Areas	Mod-High Hazard Areas	National	Global
Magnitude Completeness Level	M	2	2.5	3	4.5
Epicenter Uncertainty	km	2	5	10	20
Depth Uncertainty	km	4	10	10	20

A more densely spaced but temporary network of seismometers was operated by an academic consortium, the Incorporated Research Institutions for Seismology (IRIS), that swept across the country in the past decade, with stations in place for several years before leapfrogging forward. This was part of a coordinated research program known as the EarthScope USArray. For example, from 2009 to 2011 the program deployed stations at 70 km spacing across Texas. This presented an opportunity to record earthquakes much smaller than usual and to locate them more accurately (Frohlich et al. 2015). The US Array data are available within the IRIS archive (<http://ds.iris.edu/ds/nodes/dmc/>) and may be a resource for screening of past seismic activity.

Seismic Monitoring by States

In some states, regional networks are operated by universities, state geological surveys, external partners, or state agencies. For example, the New Madrid network operated by the University of Memphis forms a core component of the broader ANSS. At the same time, University of Memphis is under subcontract with the Arkansas Geological Survey (AGS) to operate their permanent seismic network in Arkansas. Research is conducted from those generated data products and AGS is better able to provide technical assistance to their regulatory bodies. The recently (2017) created TexNet Seismic Monitoring Program (TexNet) at the Bureau of Economic Geology at the University of Texas at Austin (UT) has rapidly expanded across the state and is operating at full strength. The Oklahoma Geological Survey, Kansas Geological Survey, New Mexico Bureau of Geology and Mineral Resources, Colorado Geological Survey, and Kentucky Geological Survey also operate their own seismic networks and derived data is public, with most streaming raw datasets as well. Ohio seismic monitoring is conducted by the Department of Natural Resources, a state oil and gas agency. Several other states (e.g., North Dakota, West Virginia, Wyoming) with active hydrocarbon exploration lack any sort of enhanced ability to identify seismicity other than what is available through USGS monitoring. Seismic monitoring not only encompasses deploying seismographs, but also the analysis of recorded waveforms to populate an earthquake catalog. The earthquake catalog informs seismologists and other experts on the inherent seismic hazard of an area.

Because of the limitations inherent in the USGS National network (Table 2.1) some states have augmented their seismic monitoring capabilities. Local seismic monitoring of seismic activity near a disposal well may assist a state in managing risks through appropriate operational controls, while seismic monitoring at the state level may improve detection of earthquakes and assist in examining causes and informing regulatory action. Because catalogs of events stemming from state and local networks use different thresholds and processing methods than the USGS, data need to be reconciled for purposes of analysis and outreach. Data sharing, archiving, and dissemination are possible through a national repository managed by IRIS. If a state decides to augment available seismic data, it may deploy either a permanent or temporary network.

Permanent Networks: A permanent, statewide network can supplement national and other networks to improve the detection threshold of earthquakes and to provide better baseline data. Historic seismic activity, oil and gas activity, and other criteria can help determine network requirements. A permanent network operates on a continuous basis with automated analysis and near real-time notification. The network can be designed to target a detection level to record small earthquakes and provide a good estimate of the location. Ideally, the network would be designed for the best detection capability around active oil and gas areas. Four states (Ohio, Oklahoma, Kansas, and Texas) already have deployed state seismic networks. As the mid-continent is less active than California, some of these networks predate induced seismicity or were installed for test ban treaty and suitability studies for nuclear facility or storage site selection (e.g., New Mexico and Oklahoma). If networks are expected to expand into requiring operators to help fund the state seismic network could be added to well permitting fees in identified areas of potential induced-seismicity risk, such as those outlined in Petersen et al. (2015), or where injection is close to critical facilities, such as schools, hospitals, power plants, or airports.

Analysis/Reporting Capabilities: In addition to the hardware and telemetry costs associated with deploying field equipment there is a substantial cost associated with adding highly technical staff and centralized servers to ingest the data and produce an earthquake catalog. While several open-source software packages exist to support real-time processing, some require outside technical support or licenses to additional modules that assist with populating publicly accessible databases, web-based catalogs, or rapid alerting of stakeholders. For example, the OGS network requires ~\$80,000 per year to support servers in the private cloud, software licenses, and telemetry costs. These costs are in addition to the five staff members that fully or in part support the earthquake monitoring (some staff have percentages of their time devoted to research activities). The data is often served through web-based maps, which without existing organizational support, may require outside services.

Temporary Networks: Temporary networks serve to rapidly respond to an earthquake, a local increase in seismicity rates, or to proactively monitor areas of interest prior to planned activities. These dense networks typically record aftershocks of an initial event or sometimes a larger main event (such as in Youngstown, Ohio, on New Year's Eve 2011). They can help determine more accurate earthquake locations and depths, highlight active geologic faults, and help determine potential causes. Temporary networks also can be deployed to areas of interest and where baseline data is desired before disposal. For example, the U.S. Bureau of Reclamation began recording background activity six years before saltwater injection began at Paradox Valley, Colorado.

Generally, a temporary network could serve to identify many smaller events that would otherwise be missed by the state permanent network or broader national network. Temporary networks or sub-arrays consists of three or more seismic stations and is flexible to remain in place as long as needed because induced seismicity can continue to occur a year or more after injection ceases. Because the number of earthquakes increases exponentially with decreasing magnitude, target detection levels would need to be low enough to allow detection of a sufficient number of events to illuminate active geologic features. However, post processing of the data often may show such features. For example, if an **M** 3.0 has been detected by the National network, there may be on the order of 10 or more **M** 2.0 and on the order of 100 or more **M** 1.0 events associated with this sequence. In these cases, a local network designed to detect and locate **M** 1.0s with confidence (the magnitude of completeness [M_c]) is likely to see enough seismic activity to assess and guide potential mitigating steps. For example, that information can help guide a geomechanical assessment of the probable fault in question or could be used within a statistical model to assess likelihood of a felt earthquake. When possible, strong motion sensors (e.g., accelerometers) should be included in the network to measure actual surface ground motion (acceleration or velocity and frequency) resulting from the earthquakes to assess effects on people and infrastructure in higher risk areas (Appendix D).

Several states have deployed seismic networks, though the continued support for these requires significant investment that is often found at the state rather than federal level. For example, Ohio receives real time data from 95 stations, including data from other agencies and Universities. In Texas, TexNet installed 27 permanent stations that, when integrated with the existing 18 stations, now compose a backbone seismic network of 45 stations. TexNet also deployed 62 portable stations, with specific areas of interest in the Dallas-Fort Worth area, the Permian Basin in west Texas and the Eagle Ford play in south Texas. While the Oklahoma Geological Survey (OGS) operates ~90 seismic stations, it only owns ~20 of those as part of a backbone network with the remaining being borrowed from IRIS. OGS has proposed a three-year phased approach to upgrade the current seismic network consisting of 20 permanent seismometers. The proposal includes the installation of 72 permanent seismograph stations replacing the USGS and OGS temporary stations. The cost to install the new stations is estimated to be \$1.5 million with added ongoing staff and operations costs. TexNet was appropriated approximately \$1 million for equipment to densify the network in Texas and \$1.7 million per year to operate the network and conduct analyses on the data to understand the causes of the seismicity.

Kansas provides an illustrative example of the ad-hoc nature in which some networks have expanded. When Kansas began experiencing induced seismicity in the fall of 2013, the only seismic monitoring in the state was from two stations operated by USGS some distance from south-central Kansas where the seismicity was occurring. The Kansas Geological Survey (KGS) operated a seismic monitoring network from 1977 to 1989, giving it expertise in seismic monitoring (in spite of the lack of seismic activity prior to 2013). With the advent of seismicity in south-central Kansas, the USGS deployed a temporary network in the area in April 2014. The KGS then established a somewhat broader temporary eight station network in south-central Kansas that began operations in January 2015. That network, operated with support from the Kansas Corporation Commission, recorded more than 2,000 events, with a minimum magnitude of 0.3, in the first six months of operation. With funding from the Kansas legislature, the KGS established a statewide network of seven stations in 2017. The goal of the network was to have statewide coverage of events greater than **M** 1.5. In July 2017, the KGS established a seismic monitoring consortium (Kansas Consortium to Study Trends in Seismicity) with Class I well operators in the state. That led to the creation of a 12-station network focused mainly on central Kansas that aims to provide alerts within 24 hours for any seismic event of **M** 2 or greater within 30 miles of a consortium members facility. Data from those networks, an interactive earthquake mapper, and information about the Kansas Consortium to Study Trends in Seismicity is online at <http://www.kgs.ku.edu/Geophysics/Earthquakes/>

State regulatory agencies may need outside assistance and expertise to undertake detailed seismic monitoring or investigations. Entities such as USGS, state geological surveys, research institutions, universities, or private consultants can assist states in designing and installing seismic networks and in analyzing seismic data. For example, USGS currently has conducted research with state surveys in Kansas and Oklahoma and has collaborated actively on the deployment, operation, and maintenance of temporary seismic stations. State and private networks may request authentication, which would join ANSS as self-supporting participants. Networks need to meet strict ANSS policies, standards, and procedures listed at https://pubs.usgs.gov/of/2008/1262/pdf/OF08-1262_508.pdf.

In addition to public seismic arrays, the oil and gas industry also operates numerous independent arrays to record background seismicity. These arrays may be either temporary or permanent deployments and focused on a specific location or with more regional coverage. Regional arrays are sometimes operated such that the data can be obtained by a number of different industrial users. The industry arrays are normally intended to provide more sensitive and accurate seismic data to enable accurate assessments of seismicity in relation to injection operations.

Injection Well Disposal Zone Condition

Because of the potential causal link between fluid injection and induced seismicity, data specific to injection practices is needed. These data could include volumes, rates, and pressures, as well as details about the zone of injection. Injection zone targets are characterized in regard to induced seismicity by their geological and hydrological properties, proximity to basement rock and known faults, and the physical and chemical interactions between these features, the disposed fluid, and the injection zone.

Key data to understand subsurface conditions include:

- Fluid data:
 - Volumes, rates, pressures (downhole – average and maximum);
 - Physical properties: fluid density and temperature, compressibility, viscosity;
 - Fluid chemistry; and
 - In-situ fluid properties: physical and chemical, phases present (gas or liquid).
- Geological data:
 - Reservoir thickness and areal extent;
 - Reservoir porosity, permeability, and initial pressure;
 - Mechanical properties – elasticity, ductility;
 - Stratigraphy – especially presence of confining layers above and below;
 - Presence and orientation of faults and fractures; and
 - In-situ stresses, vertically and horizontally, due to rock mass and fluids.

Many of these data are available, in various forms and level of completeness, from state agencies (fluid data), operator records on file with state regulatory agencies (basic geologic data e.g., from well logs), or otherwise known to state geologic survey or research organizations. However, because different states require records to be submitted at different rates and with different information, some data are questionable and may be difficult to use. For instance, the pressure data most commonly recorded is surface (or well head) pressure, and often that may be just an instantaneous measurement. Surface data are rarely a good measure of downhole reservoir pressure are often affected by tubing friction, wellbore conditions and near wellbore damage. Downhole pressure gauges are not commonly employed but give more accurate representations, and some states are increasingly encouraging their use. Stress data can be inferred qualitatively from some well logs, but only in direction and relative magnitude and not quantitatively (except for overburden stress which can be calculated from rock density logs). Some relative stress orientations may be available from leakoff tests, lost return events during drilling, etc.

In Kansas, underground fluid disposal is accomplished primarily through Class I and Class II injection wells. Approximately 50 Class I wells dispose of industrial waste and are regulated by the Kansas Department of Health and Environment. About 5,000 Class II wells are used to dispose of oil-field brines and are regulated by the Kansas Corporation Commission. Most of these wells inject into the Arbuckle Group of rocks, a Cambrian-Ordovician unit that lies atop Precambrian basement rocks. The Arbuckle is heterogenous, highly porous in places, and capable of receiving large volumes of fluid, often under the force of gravity.

Beginning in 2009, south-central Kansas saw a dramatic increase in drilling, production, and water disposal from a Mississippian limestone play that produced large volumes of water. In the fall of 2013, the same part of the state began experiencing increased seismicity, much of it traced to oil-field brine disposal. At the time seismicity began to increase, Class II well operators were required to submit, on paper, monthly reports on volume on an annual basis. That data is now submitted digitally, and in some locations where the Corporation Commission limited disposal volumes, more

detailed data-reporting requirements are in place. Data from Class I wells has been approached differently. Volume and downhole pressure are measured monthly and reported annually. Because of the connection between small pressure changes and seismic activity, bottomhole pressure is extremely important in guiding seismic mitigation. In Kansas, downhole pressure is generally limited to Class I wells, most of which are located a significant distance from where induced seismicity initially occurred.

With the increased attention to induced seismicity, more and better data will be acquired with subsequent improvement in models that could help regulators predict seismicity, or attribute causation, and inform its mitigation, as discussed below.

Evaluating Causation for Injection Wells

While most injection sites do not trigger earthquakes, induced seismicity can occur under certain conditions. The USEPA report (USEPA 2015) “Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches,” identifies three components as necessary for felt injection-induced seismicity:

1. Sufficient pore pressure buildup from disposal activities;
2. Faults of concern; and
3. A pathway allowing the increased pressure to communicate with the fault.

When these conditions are present, an induced earthquake may occur on the fault when the balance between the stresses on the fault and the frictional strength of the fault is disrupted. The fault will remain locked as long as the shear stress is less than the clamping forces as modified by fluid pressure. A rise in pore pressure of as little as a few psi or a shear stress increase of the same amount can be sufficient to initiate an earthquake on a critically stressed fault.

Assessing causation requires combining seismicity information and disposal conditions as listed above. At present, it still remains difficult to differentiate clearly and uniquely between induced and tectonic earthquakes using seismological methods. Integration of multiple technical disciplines and skill sets often is required to perform a causation assessment with collaboration among seismologists, reservoir engineers, geomechanical engineers, geologists, and geophysicists. Stakeholder collaboration also is often critical to obtain the broad data sets necessary.

The current primary evaluation is spatial and temporal correlation, proximity, and timing. Did earthquake events occur near an injection well, concurrent with or soon after injection? However, this alone is insufficient to prove causation because spatial and temporal correlation does not address other factors, such as geomechanical processes associated with induced seismicity.

Evaluating causation can be a significant and time-intensive process, entailing locating the seismic event(s) accurately, locating critically stressed faults that may have been reactivated, identifying the detailed temporal and spatial evolution of earthquakes where fault slip first occurred and of any associated aftershocks, characterizing the subsurface stress near and on the fault, and

developing a physical geomechanics/reservoir model that would evaluate whether an induced subsurface pore pressure change could initiate an earthquake. Other anthropogenic causes need to be considered also. Along with injection wells and production wells, other sources may include geothermal operations, reservoir impoundment, lake level fluctuations, and possibly other activities.

One possible route to consider is the screening criteria proposed by Frohlich, which asks several key questions related to location, timing, and volume of fluids being injected (Appendix I).

Uncertainty: The process described in this chapter involves significant challenges and uncertainty. For example:

- **Locating the seismic event(s):** Evaluating the possibility of induced seismicity requires a reasonably precise and accurate location of earthquake hypocenters. Often, in those states without statewide or regional networks, the first examination of the seismic data is the earthquake locations reported by the USGS. In general, the epicentral location uncertainty is ~5 to 10 km and hypocenter location uncertainty is ~10 km across the majority of the U.S. (Table 2.1) for events less than **M**3.0, but otherwise depending on the proximity of the hypocenter to the seismometer. Deploying additional seismic stations concurrent with an ongoing earthquake sequence provides a mechanism for reducing these location uncertainties.
- **Characterizing changes in subsurface stress:** A definitive assessment is difficult due to a lack of detailed knowledge of the subsurface stress conditions in proximity to the seismic activity. To evaluate whether fault reactivation is due to pore pressure increases from fluid injection versus dynamic tectonic forces requires reasonable knowledge of and estimates for fault friction, strength, and tectonic stress changes. In general, this information is not readily available. Some states, such as Kansas, require bottomhole pressure measurements in Class I wells, which yield insight into common storage zones also utilized for Class II disposal. Research is ongoing to find ways to determine the relationship between stress and fault reactivation.
- **Developing a physical geomechanics/reservoir engineering model:** While reservoir pressure modeling and geomechanics analysis may be useful for evaluating relative order-of-magnitude impacts of injection, the analysis generally will not provide definitive conclusions regarding causation but will assist risk mitigation. In particular, information needed to model fluid pressure diffusion in the crystalline basement (where most earthquakes occur) is largely unknown. Geologic, seismologic, geophysical, and geomechanical judgment often must be applied to the assessment, considering all the available information and analysis.

Hydraulic Fracturing Fluids and Target Zone Conditions:

Similar to the above injection zone conditions for disposal wells, proper assessment of hydraulic fracturing induced seismicity requires extensive knowledge of the geology and geophysics of the subsurface and target formation(s), proximity to critically stressed faults which intersect or nearly intersect the target formation(s), and the interplay between pore pressure and poroelastic stress disturbances induced by hydraulic fracturing activities. The contrast between disposal injection conditions and hydraulic fracturing conditions is primarily found in the availability of data from

operations. Detailed subsurface geophysics, fault mapping, reservoir characterization, and hydraulic fracturing operational data are collected prior to and during hydraulic stimulations. Details of the types of data recorded during the hydraulic fracturing process can be found in Appendix I.

Key data to understand subsurface conditions for hydraulic fracturing include:

- Fluid data:
 - Hydraulic fracturing fluid design (slickwater vs gel);
 - Fluid/slurry densities, proppant concentrations, friction reducers;
 - Pumping rates, max treatment pressure, average treatment pressure; and
 - Total fluid by foot of perforated length, by stage, by well, by pad.
- Geological data:
 - Reservoir thickness and areal extent;
 - Reservoir porosity, permeability, and initial pressure;
 - Mechanical properties – elasticity, ductility;
 - Stratigraphy – especially presence of confining layers above and below;
 - Presence and orientation of faults and fractures; and
 - In-situ stresses, vertically and horizontally, due to rock mass and fluids.
- Geophysical data:
 - 3D geophysical assessment of target formation(s) and underlying units;
 - Fault mapping from geophysical outputs; and
 - Fault intersection characterization with target reservoir(s).

The primary difference between data and information sharing considering hydraulic fracturing operations compared to disposal well operations is the level of detail obtained during hydraulic fracturing operations and the potential for much of that data to be considered confidential because of what it reveals about the well completion methods, procedures, and approaches. Different states, provinces, and countries have different rules about data reporting of well completion and hydraulic fracturing operations. As a result, there is likely to be wide variations in the type of information that can be gleaned from public sources or be routinely available for correlation with any seismicity. Given that information sharing remains a heavily debated topic, gathering the above data for hydraulic fracturing operations can be problematic.

Evaluating Causation for Hydraulic Fracturing

Causation of earthquakes with hydraulic fracture operations share many aspects with other forms of injection, including effects of pressure, stresses, fault orientation, and seismicity characteristics. However, hydraulic fracturing operations are fundamentally unique from other types of injection, especially given the relatively short duration and high injection pressures. Individual fracturing stages typically last a matter of hours, restricting the spatial impacted region around individual initiation points. Depending on the number of fracture stages, the entire operation may only last a matter of days to months. Therefore, the temporal and spatial aspect of causation is relatively limited to during, or closely following hydraulic fracturing and near the wells.

Evaluating causation for hydraulic fracturing suspected induced seismicity greatly benefits from the wealth of data collected during pre-planning and active hydraulic fracturing operations. The detailed information discussed in Appendix I gives researchers and regulators a framework for correlating the seismic data gathered during induced seismicity cases with the highly constrained spatial and temporal data gathered during hydraulic fracturing operations. Regulators can benefit from accurate pre-planning and reporting of hydraulic fracture activities by operators prior to well stimulations. The Oklahoma regulator (Oklahoma Corporation Commission) requires notice be given at least 48-hours prior to commencement of hydraulic fracturing operations in the state (OAC 165:10-3-10 (b) (2)). Through collaboration with the state seismological authority, the Oklahoma Geological Survey, the OCC maintains active well-seismic automated processes to establish causation for hydraulic fracturing seismicity occurring within the state. Automated alerts allow staff to proactively respond to suspected cases of hydraulic fracturing induced seismicity. This approach has been documented in other countries (Canada, China, and Great Britain) but remains limited in widespread use. A complete representation of the States' regulatory frameworks for hydraulic fracturing monitoring and response can be found in Appendix G.

Another example of available public hydraulic fracturing data is the FracFocus Database ([http://www.fracfocus.org/.](http://www.fracfocus.org/)) FracFocus is the nationwide system for disclosing the additives and chemicals used in the hydraulic fracturing process. Water volumes are also recorded in FracFocus. This reporting provides a retrospective for well completion activities back in time but cannot be used for monitoring/assessment in near real-time. Other additional information detailing hydraulic fracturing operations is usually required for assessment of causation in induced seismicity cases. Below are some examples of hydraulic fracturing well data useful for correlating injection activities to induced seismicity.

- Well and Completion Details (hydraulic fracturing specific):
 - Well completion (sliding sleeves or plug and perf);
 - Stage cluster/perf design;
 - Stage length;
 - Use of diverters, other in-wellbore rate reducers/limiters;
 - Well spacing and pad locations;
 - Injection sequence; and
 - Orientation of well with respect to critical stress direction.

Understanding the Differences between Hydraulic Fracturing and Wastewater Disposal

With respect to induced seismicity, hydraulic fracturing is different from wastewater disposal in many important ways. These include:

- Hydraulic fracturing operations are intended to fracture the rock while injection operations are not;
- The pumping operation only lasts for a short period of time; each fracture stage ranges from

one hour to several hours depending on volumes and rates; the entire well stimulation typically lasts several days to weeks, depending on the well completion type;

- The amount of fluid pumped in a fracture completion is orders of magnitude less than in a disposal operation over time. However, high-rate fluid injection during a hydraulic fracturing stage may be several times greater than traditional disposal well rates over short periods of time (minutes to hours). Longitudinally, the total energy put into the system is relatively small when compared to disposal operations (month to years);
- The fluids in a fracture completion are largely stored in the fractures; and some volume of the fracturing fluids is normally recovered soon after the treatment while the remaining fluid is imbibed in the reservoir. When considering a specific hydrocarbon reservoir where fracturing is performed, fracturing is very different from injecting into a permeable disposal zone where the fluid is stored in the porous and permeable formation; and
- In addition, the well will typically be produced relatively soon after the fracturing operations are completed. With flowback, the initially increased pressure associated with the hydraulic fracturing operation is relieved by the subsequent flowback. Then with longer-term production, the reservoir pressure is further reduced below original reservoir pressure due to depletion effects. Therefore, unlike disposal well operations, hydraulic fracturing operations followed by production operations generally results in lowering of reservoir pore pressure in proximity to the well.

Induced seismicity associated with hydraulic fracturing are relatively uncommon, given the large numbers of completions without seismicity (e.g., Skoumal et al. 2018). Oklahoma, Texas, Alberta, Ohio, and British Columbia have had cases of earthquakes triggered by hydraulic fracturing. In rare cases hydraulic fracturing has been associated with induced seismicity resulting in felt levels of ground shaking. Based on limited occurrences, there also appear to be similarities between disposal and hydraulic fracturing induced seismicity. A small percentage of hydraulic fracturing operations have reactivated old faults. The seismicity of concern may only occur on critically stressed faults; most other preexisting faults may not be reactivated.

Modeling

After acquiring the available seismic and reservoir data, it may be possible to develop computer models that attempt to predict the subsurface response to fluid disposal or hydraulic fracturing. These models typically start with a geologic characterization of the subsurface; what the reservoir conditions are like and how they vary laterally and vertically; what faults and fractures may be present and how are they aligned and how deep do they go; and what stresses and pressures are like in the subsurface. This information and data would then be used by a reservoir or hydraulic fracture model to determine how the addition of fluids would affect the subsurface, how pressure and stress would migrate, and to what extent would they increase over time. Finally, this understanding could inform a geomechanical model that would assess the effects of an increase in pressure; how the rock would accommodate the new fluids; whether resulting stress would be felt by nearby faults; and whether the stress would be sufficient to reactivate the faults and cause an earthquake.

In some cases, additional modeling can then be used to help forecast the potential for earthquake propagation and the possible ground motion at the surface. Hazard maps and models would use these data so that states could prepare risk scenarios and appropriate regulatory responses ahead of potential events, rather than reactively. Modeling should appropriately include sensitivity studies associated with the range of data uncertainties, and may point to additional data (e.g., bottomhole pressure and flow tests) that should be collected to better constrain the models. Indeed, one of the main advantages in creating models is to make clear the deficiencies in the available data and to help highlight where new information could be beneficial. The sensitivity studies help highlight which data are the most critical for predictive capability. Appendix F provides a discussion of available reservoir and geomechanics modeling approaches and their applications and limitations.

Key Messages from Chapter 2

Approaches to assess and manage seismicity risk from hydraulic fracturing operations should take into account the local conditions, operational scope, geological setting, and historical baseline seismicity levels and reflect reasonable and prudent consideration of local engineering and building standards. Reasonable and practical evaluation and response systems are best developed considering the actual level of risk associated with local conditions. Given the broad geologic differences and diversity that exist across the U.S., it would not be appropriate to adopt a “one-size-fits-all” regulatory approach for managing the risk. Local conditions must be considered (with the recognition that this could vary between states and within a given state at a more localized level for a given area of interest). Key observations and considerations made ahead of time can greatly inform the risk assessment needed to evaluate projects and the steps to undergo when seismicity is induced; this is the subject of the next chapter.

Chapter 3: Risk Management and Mitigation Strategies

Chapter Highlights

This chapter discusses the following:

- The difference between hazard and risk;
- The strategies for managing and mitigating the risk of induced seismicity; and
- The two basic questions risk assessment from induced seismicity addresses:
 - How likely is an injection or hydraulic fracturing operation to pose an induced-seismicity hazard?
 - What is the risk—the probability of harm to people or property—if seismicity is induced?
- Science-based approaches to assessing and managing induced seismic risk from injection and hydraulic fracturing including:
 - Characterizing the site;
 - Monitoring background seismicity;
 - Estimating maximum magnitudes; and
 - Predicting hazards from ground motion.
- Mitigation and response strategies:
 - Siting and permitting of new wastewater disposal wells;
 - Additional downhole testing requirements for such wells;
 - Pre-planning well design and hydraulic fracturing operations; and
 - Responding to earthquakes of concern.

Introduction

This chapter presents risk management and mitigation strategies for potential induced seismicity from Class II disposal wells and hydraulic fracturing. Further background on hydraulic fracturing methods and considerations are detailed in Appendix I. Risk management and mitigation strategies addressed herein rely on information discussed in Chapter 2. As discussed in Chapter 2, Class II disposal well operations and hydraulic fracturing operations are substantially different from each other, considering scope, time, injection pressure and volumes of fluids that are injected underground. Thus, in this Chapter, Class II disposal wells and hydraulic fracturing will be discussed in separate subsections.

States have developed diverse strategies for avoiding, mitigating, and responding to risks of induced seismicity in the siting, permitting, operations, and seismic monitoring of Class II disposal wells. In the case of hydraulic fracturing, specific guidelines have been established in the few regions where seismicity has been induced by hydraulic fracturing. Appendix G profiles examples of these strategies. In addition, stakeholders—including regulatory agencies, private companies, academics, and public interest groups—have proposed an assortment of tools and guidelines that can support states in this effort.

Given the broad geologic differences across the U.S., a one-size-fits-all regulatory approach would not be appropriate for managing and mitigating risks of induced seismicity. Conditions may vary

across states or within a given state at a more localized level for a certain area of interest or an area of concern. Cross-disciplinary expertise, as illustrated by Figure 3.1, may be needed to establish a framework for science-based risk management and mitigation. Because of the site-specific considerations and technical complexity of tailoring a risk management and mitigation strategy, many state regulators choose to work with multi-disciplinary experts on this subject.

Characterization of the potential presence of faults requires information and knowledge informed by interpretation and integration of geology, geophysics, and seismological data. Understanding the potential reservoir pressure and subsurface stress changes associated with injection requires interpretation and integration of reservoir, subsurface, and geomechanics data. Understanding the potential ground shaking and risk associated with an earthquake requires interpretation and analysis of the size of the fault that has slipped, and how the created waves propagate and attenuate through the subsurface. Further, the potential impacts from an earthquake depend on population density, local building design and construction standards, and local infrastructure.

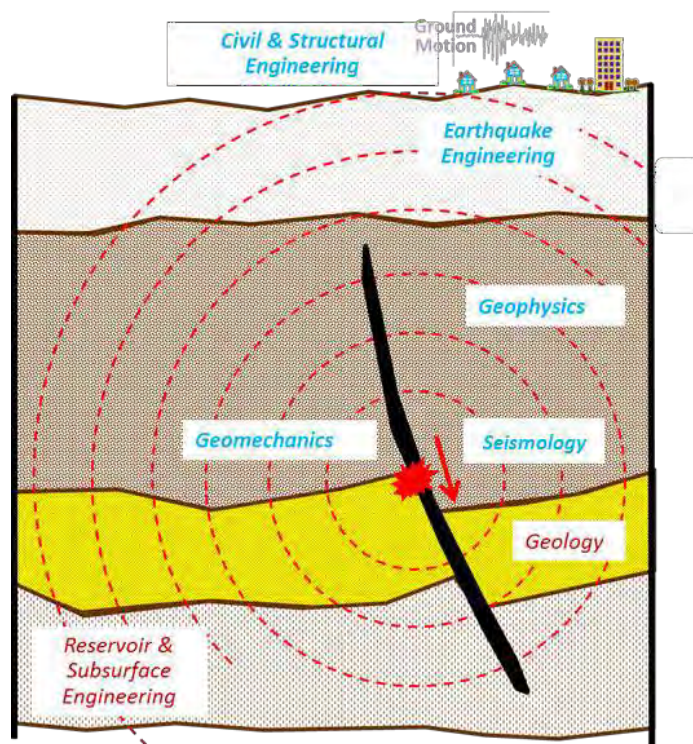


Figure 3.1. Schematic of types of multi-disciplinary expertise used to examine risk of induced seismicity (after AXPC SME 2012).

Data collection and analysis, which are fundamental elements in any risk management strategy, is addressed in Chapter 4.

Risks and Hazards

Understanding the distinction between seismic risks and hazards is fundamental to effective planning and response to induced seismicity.

- A **hazard** is any source of potential damage, harm, or adverse impact on something or someone; whereas
- A **risk** is the chance or probability that a person or property will be harmed if exposed to a hazard.

The presence of a hazard does not constitute a risk in and of itself. For a risk to exist, there must be exposure to the hazard and a mechanism for harm from the exposure. A high-risk activity is one that can frequently result in significant safety, health, environmental, or security consequences, while a very low-risk activity may result in minor consequences on a very infrequent basis, or even negligible consequences on a frequent basis.

More specifically, seismic risk assessment can be defined as a combination of seismic hazard and vulnerability. Considering buildings and infrastructure, seismic vulnerability is generally considered as the building's (or infrastructure element's) susceptibility to damage by ground shaking of a given intensity. Seismic hazard depends upon geology of the area under consideration and is, therefore, site-specific.

Seismic vulnerability generally depends upon the material of which the structure is made; the mechanical properties of construction materials; the geometry and layout of a building and its structural components; the detailing of structural components, as well as floor-wall connection details. Using these definitions, risk assessment regarding injection-induced or hydraulic fracture-induced seismicity addresses two distinct questions:

1. **How likely is an injection or hydraulic fracturing operation to pose an induced-seismicity hazard?** Preconditions for a hazard include an optimally oriented and critically stressed fault of concern, sufficient pore pressure build-up in the area of the fault related to injection or stimulation, and a potential connection between pore pressure or poroelastic stress changes and the fault and
2. **What is the seismic vulnerability and risk—the probability of harm to people or property—if seismicity is induced?** Considerations include the potential magnitude of the earthquake, its associated ground motion, and the proximity of people and structures that might be affected.

To date, the likelihood of induced seismicity associated with a particular injection site or a hydraulic fracturing operation has been very low and limited to specific regions, as has the risk of harm to people or property. In the majority of cases, fluid injection and hydraulic fracturing operations have no association with induced seismicity. While some incidents associated with injection are believed to have caused injuries requiring medical attention and a limited amount of structural or nonstructural damage to buildings, the most significant common consequence has been anxiety. Industries such as mining, construction, seismic exploration, and geothermal follow statutes or

guidelines with regard to ground motion and its effects. Damage and injuries are not believed to have been associated with seismicity induced with hydraulic fracturing, with the sole exception of China.

However, whether a given population considers detectable low levels of ground motion acceptable or unacceptable (and, therefore, perceived as harmful) is highly subjective and varies from site to site and region to region.

Science-Based Risk Management

Science-based approaches to assessing and managing seismicity risk associated with wastewater injection and hydraulic fracturing operations weigh both hazard and risk for a specific site.

Considerations may include:

- **Site characteristics**, taking into account the geological setting and formation characteristics, including tectonic, faulting, and soil conditions, along with historical baseline seismicity levels (from USGS, state geologic surveys, and private array data);
- **Built environment**, assessment of building and infrastructure seismic vulnerability, including local construction standards as well as the location of public and private structures, avoiding populated areas, infrastructures such as reservoirs and dams, and historical construction or significant architectural elements;
- **Operational scope**, including existing or proposed injection/stimulation fluid volumes, surface pressures, and density and types (e.g., zipper fracs) of hydraulic fracturing (note: hydraulic fracturing methods are described in detail in Appendix F “Considerations for Hydraulic Fracturing”);
- **Estimations of maximum magnitudes** of potential events; and
- **Estimations of ground motions** related to events, which would vary by the magnitude of the earthquake, the distance from the earthquake to a site, the depth of the hypocenter, and geologic site conditions.

Any available data on past operating experience and potential occurrence of seismicity may be considered as well, along with an assessment of public sensitivity to seismicity in the area.

Site characterization: In assessing the risk associated with an injection/hydraulic fracturing site, identifying faults of concern is of primary importance, along with characterizing any pathways for communicating pore pressures to the fault. Such pathways can occur in areas of complex structural history when strata beneath the injection zone may be fractured naturally. Also, faulting in the Precambrian basement rock can extend into overlying sedimentary strata, potentially providing for communication between the disposal/stimulation zone and the Precambrian basement (basement) rock. During hydraulic fracturing, initial fault activation can initiate around the target reservoir although they often appear to be associated with basement seated faulting.

A main consideration is whether the pore pressure increase from injection/stimulation can reach the crystalline basement rocks. In geology, basement and crystalline basement are the rocks below a sedimentary platform or cover, or more generally any rock below sedimentary rocks or

sedimentary basins that are metamorphic or igneous in origin. The basement rock is the thick foundation of ancient, and oldest, metamorphic, and igneous rock that forms the crust of continents, often in the form of granite. The basement rock is contrasted to overlying sedimentary rocks which are laid down on top of the basement rocks after the continent was formed, such as sandstone and limestone.

Avoiding or minimizing the potential for injection/stimulation communication with the basement can reduce the likelihood of induced seismicity associated with larger, optimally oriented, and critically stressed faults that may be present and unmapped in the basement rocks. Therefore, the vertical distance between an injection/stimulation formation and basement rock as well as the characteristics of strata below the injection zone are key factors in identifying any risk assessment. The potential hydraulic connectivity of the injection zone to the crystalline basement is a key factor related to transmission of pore pressure into the crystalline basement.

Historic seismicity is an important factor to characterize the potential of seismicity of a mapped fault since activation of a specific fault of concern may not actually result in induced seismicity. Background natural seismicity is a positive regional indicator of seismic potential. Historic cases of induced seismicity caused by earlier injection local to a fault of concern is a significant indicator of seismic potential. However, a fault may continue to have potential of generating future seismicity without association of past seismicity.

Built Environment: Evaluation of the localized building environment along with analysis of the infrastructure is important when assessing the potential hazards and risks associated with induced seismicity. Distances from structures, infrastructure, and densely populated areas are a critical factor in assessing the built environment. As highlighted earlier, building vulnerability generally depends upon the material of which the structure is made; the mechanical properties of construction materials; the geometry and layout of a building and its structural components; the detailing of structural components, as well as floor wall connection details.

Operational Scope: Operational history of disposal wells in regard to injection rates, surface pressures, and both surface and downhole treatment of injectate can be very important in an evaluation of the operational scope of a disposal well and the potential for injection-induced seismicity. For horizontal well hydraulic fracturing jobs, consideration and evaluation of Precambrian basement structures and faults should play a valuable role in assessing the number of completion stages and/or skipping of fracturing stages to avoid identifiable geologic structures that could potentially lead to induced seismicity.

Estimating maximum magnitudes: It is currently not possible to reliably predict the maximum magnitude of injection-induced earthquakes that could occur in an area (Appendix A). Because the size of the rupture area dictates the magnitude of an earthquake, the maximum-sized earthquake on that fault can be estimated if the dimensions of the fault are known. However, a given fault can produce earthquakes of different magnitudes depending on what portion of the fault is ruptured.

Empirical relationships between fault rupture length and rupture area have been developed (e.g., Wells and Coppersmith 1994) for tectonic earthquakes larger than **M** 5.0. These relationships are used in seismic-hazard evaluations when the dimensions of active faults are available, primarily from geologic studies, to estimate the maximum magnitude of an earthquake. However, in most locations of induced seismicity, particularly in the central and eastern U.S., very few active and critically stressed faults have been identified.

Geophysical techniques can be used to image faults at depth, but this requires extensive 2D or 3D seismic reflection investigations. These techniques reveal some but not all faults. In particular, existing geophysical techniques can be poor at imaging strike-slip faults and faults within the Precambrian crystalline basement, which are also the faults with the highest likelihood of producing an earthquake that could cause damage. Because most induced earthquakes are smaller than **M** 5.0, the rupture areas are small. Typically, small scale faults in the basement rock cannot be imaged by traditional oil and gas geophysical techniques.

Predicting hazards from ground motion: Several ground motion models can serve as a starting point for estimating the ground motion from injection-induced earthquakes and determining whether the ground motion would be likely to pose a hazard, result in anxiety, or neither (Chapter 1). Assessing the potential ground shaking hazard from injection-induced earthquakes typically requires the services of engineering seismologists and geotechnical and structural earthquake engineers.

Mitigation and Response Strategies for Class II Disposal Wells

Regulatory agencies consider a wide variety of strategies to mitigate risks of induced seismicity associated with a new or existing disposal well, particularly when:

- Significant seismicity (above historical baseline levels) has occurred, and a scientific assessment indicates that the seismicity is associated with fluid injection operations; or
- Technical assessment indicates the local area may possess significant risk associated with potential induced seismicity.

Risks associated with potential induced seismicity typically are determined based on a site-by-site evaluation and often can be mitigated by injection-site characterization/selection, injection well design and construction features, and control over well operational factors.

Regulatory screening protocols can help determine what mitigation and response strategies may be appropriate under different circumstances. Some states use an “if this, then that” screening process, which may be summarized as a decision tree, risk management matrix, or traffic light system (Appendix G). Traffic light systems describe the risk thresholds for taking varying levels of mitigation and response actions.

The publicly available “Fault Slip Potential” software tool is now being commonly used to qualitatively assess the potential for faults to slip when exposed to changing reservoir pressure and

stress conditions. Rall Walsh of Stanford University developed this integrated reservoir-geomechanics software modeling tool to estimate the chance of a fault slipping in these circumstances, given stress, pore pressure, and injection conditions (see Appendix F for further discussion of the FSP tool).

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. Thresholds may be determined by considering questions such as:

- Did a seismic event of specified magnitude occur within a specified distance of an injection/horizontal well?
- Did the seismic event occur within a particular area of interest, defined by historic seismicity?
- Did the seismic event exceed a specified ground motion or magnitude?
- Did an evaluation define a reason for concern (e.g., well location within a specified distance of an optimally oriented and critically stressed fault; spatial and temporal evaluation of well providing a potential link to seismicity; operational changes in injection pressure, injection volume, or reservoir pressure; or nearby population and infrastructure at risk given a specific level of ground motion)?

Siting and permitting of new Class II disposal wells: State approaches for addressing induced seismicity are further summarized and detailed in Appendix J “State Regulatory Approaches”. For proposed new disposal wells in areas of seismic concern, permitting protocols may include a review of key factors that can affect induced seismicity. Currently, these include an analysis of faulting in and/or seismic history of the area of a proposed disposal well, proximity to the Precambrian basement rock and potential pathways for pore pressure transmission into basement rock, reservoir conditions, completion methodology, and the proposed injection pressure and rate.

In areas where potential induced seismicity is a concern, the state regulatory agency may include, as part of each project’s operation permit, a mechanism for the well operator to be able to control, reduce, or eliminate the potential for felt earthquakes. Some regulatory agencies have implemented permit conditions that may include additional downhole testing requirements, and/or seismic monitoring and mitigation.

When an evaluation and response strategy is to be adopted to control operations that may cause unacceptable levels of induced seismicity, disclosure, and discussion of the adopted system prior to the start of operations may be considered, so that these safeguards are clearly known and understood by all concerned. Permitting regulations in some states require identification of known earthquakes and location of mapped faults.

Ohio was perhaps one of the first oil and gas regulatory states that implemented new permit conditions associated with deep disposal well operations. Per Ohio’s OAC 1501:9-3-06 located at <http://codes.ohio.gov/oac/1501%3A9-3> permit conditions can include additional geophysical logging requirements, radioactive tracer surveys, pressure fall-off testing, and installation of a local seismic monitoring network.

Colorado, for example, requires the Colorado Geological Survey (CGS) to conduct a review of seismicity at proposed injection sites that include use of CGS geologic maps, the USGS earthquake database, and area-specific knowledge to provide insight into the seismic potential at the location (COGCC 2011). If seismicity is identified in the vicinity of the proposed injection well site, the Colorado Oil and Gas Conservation Commission (COGCC) requires the operator to define the seismic potential and the proximity to faults using the geological and geophysical data prior to approval (COGCC 2011).

The Railroad Commission of Texas (RRC) requires reporting of all historic earthquakes that occurred within a 100-square-mile area, considering a 9.08-km radius, from a proposed injection well location using data from the USGS (RCT 2014). When establishing the historic seismicity in a local area, it is important to recognize the location error associated with reported events (~5–10 km) and how the error depends on the design and operational characteristics of the seismic monitoring network. Additionally, the RRC has implemented additional requirements for SWDs, particularly in the Permian Basin area, that may include reduced injection rates and possibly even seismic monitoring, if warranted.

The Pennsylvania Department of Environmental Protection (DEP) now requires any new Class II SWDs to submit a seismic monitoring and mitigation plan and establish a local seismic monitoring network that sends real-time monitoring data to IRIS, so it can be evaluated by Penn State University. Other states, like the New Mexico Oil Conservation Division, require SWDs injecting into the deeper geological formations (Devonian-Silurian) to be 1.5 miles apart in an effort to avoid well interference and potential induced seismicity and has prohibited injection into the deeper Ordovician Ellenberger Formation.

Similarly, the OCC reviews the location of known mapped faults and proximity to proposed deep SWD sites during the permitting process. The OCC, by practice, limits maximum injection rates for deep disposal well permits across Oklahoma (specifically those located near mapped optimally oriented and critically stressed faults) and prohibits Administrative Approval of deep SWD permits within a defined Area of Interest for Induced Seismicity.

Risk mitigation options in siting and permitting new Class II disposal wells in areas of concern may include:

- Obtaining local stakeholder input concerning risks (Chapter 4);
- Selecting a different location for new disposal wells;
- Avoiding injection into the crystalline basement or even into formations that directly overlies the basement;
- Locating faults in the vicinity of the proposed project area based on seismic reflection survey data or geologic mapping and placing the well outside the at-risk area where injected fluid may not significantly and adversely perturb the pore pressure/stress state; and
- Avoiding direct injection of fluids into optimally oriented and critically stressed faults of concern.

Permits for new or existing Class II disposal wells might include some conditions, such as:

- Proactive temporary (short term) seismic monitoring at specific sites and establishment of magnitude thresholds by incorporating baseline historic seismicity in the area;
- A procedure to modify injection operations (e.g., step increases in injection rates during start up or reducing rates as needed) if a specified ground motion/magnitude event occurs within a specified distance from the well;
- An administrative order to suspend injection operations if seismicity levels increase above threshold values for minimizing public disturbance and damage; and/or
- A mitigation plan to determine if SWD operations could be restarted and the procedure for establishing injection at safe levels.

Temporary and proactive seismic monitoring may be considered at the sites of proposed new disposal wells in local areas where induced seismicity is of significant risk. A seismic monitoring requirement with specific magnitude thresholds and location accuracy may be incorporated into the permit as a mitigation plan. Goals of seismic monitoring may include the ability to:

- Identify any seismicity that may be attributable to injection at a site;
- Indicate when any induced seismicity at a site has the potential to damage structures, be felt by the public, and/or cause serious disturbance to the public; and
- Use data to create appropriate site-specific actions to mitigate the risk of potential induced seismicity (Appendix E).

A seismic monitoring and mitigation plan might include the method of seismic monitoring, type of instrumentation required, reporting of data analysis, and an archive of the data in a public seismic database, thresholds for reporting changes in seismicity, steps to mitigate and/or manage risk by modifying operations, and thresholds for suspension of injection activity.

For example, Ohio developed a new seismic evaluation program in late 2012. The Ohio Department of Natural Resources, Division of Oil and Gas Resources Management (DOGGRM) created the OhioNET seismic monitoring network which now has 27 DOGGRM-owned seismic stations with an additional 68 maintained by operators, other agencies, and universities in place (Figure 3.2). DOGGRM has required seismic monitoring for disposal and hydraulically fractured wells based on proximity to documented seismicity and mapped faults. Seismic monitoring occurs prior to injection and continues for at least six months after injection operations have commenced. If no significant induced seismicity is detected, the seismic instrumentation may be moved to another location with the written approval of the division chief. This seismic monitoring program is implemented on a case-by-case basis in Ohio.

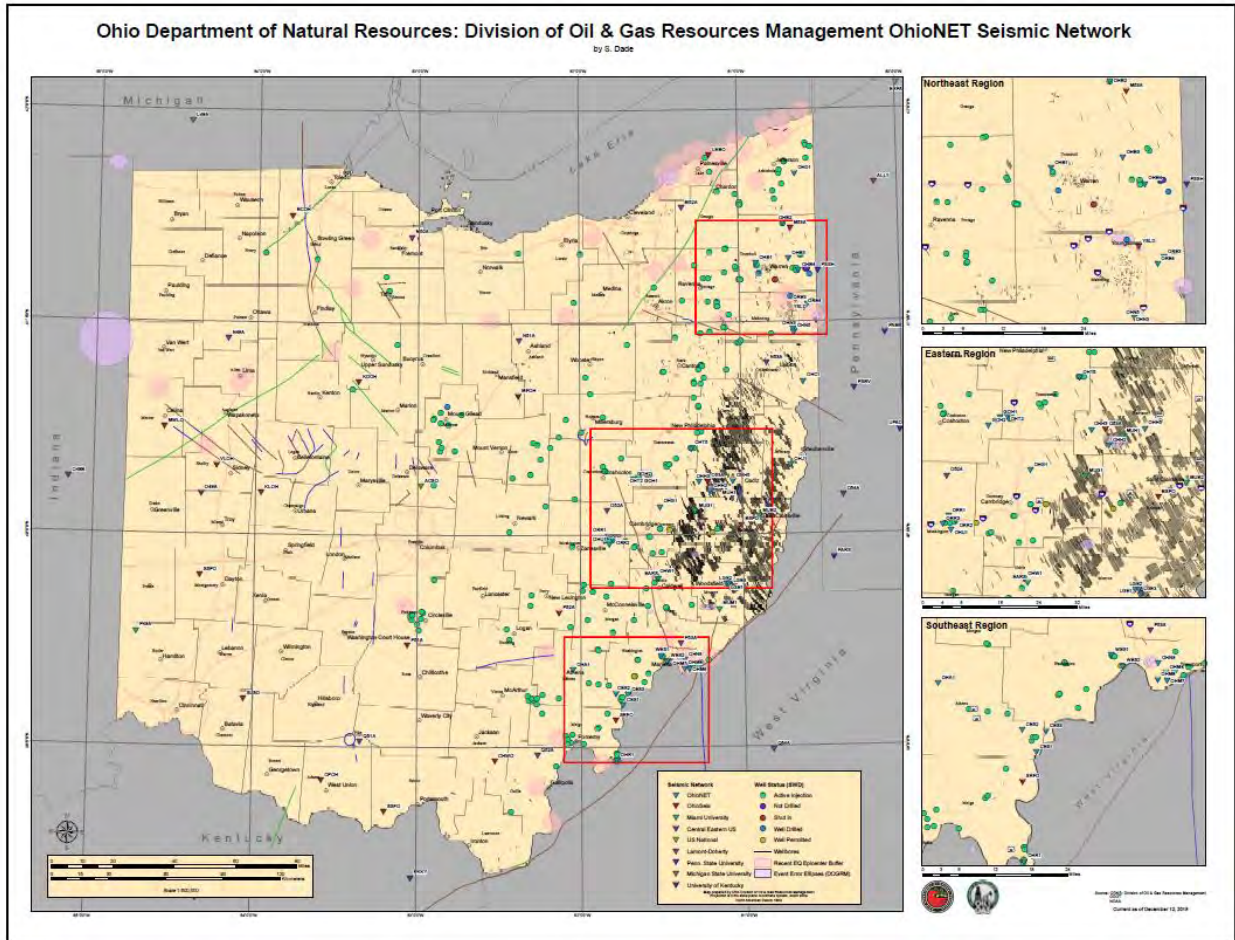


Figure 3.2. Map showing the OhioNET seismic monitoring network in Ohio (DOGRM 2019).

In some cases, state geological surveys have decided to install their own permanent or temporary seismic networks, as discussed in Chapter 2.

Planning for and responding to an event of potentially induced seismicity: Because the risk from induced seismicity depends on the characteristics of the disposal well locations and operations, many state regulatory agencies utilize site-specific, flexible, and adaptive response actions when an incident of seismicity occurs that may be linked to injection. Regulatory agencies may determine that different types of response strategies are “fit for purpose,” depending on whether an event of potentially induced seismicity resulted in damage or felt levels of ground motion or was detected using seismic monitoring, with no damage or felt levels of ground motion.

In a recent study of Oklahoma seismicity, Goebel et al. (2019) suggest that that rapid mitigation can affect earthquake rates over large areas and potentially reduce induced seismic hazard within days from fluid injection operations. The authors highlight that aftershock sequences in Oklahoma are generally more productive than comparable sequences in California, potentially caused by elevated ambient stress level due to fluid injection operations. Their models show that mitigation effects are

dominated by fluid pressure reductions near injection wells within the Arbuckle Group and elastic stress decreases at greater distances within the basement.

Generally, an initial step in developing a response strategy is to collect background and baseline information about the earthquake. As part of the collection of background information, all potential sources or causation of seismicity should also be considered, including understanding the historical background seismicity and naturally occurring seismicity.

In some cases, a regulatory agency or state geological survey also determines that the seismic evaluation of an event of potentially induced seismicity is warranted. Input from many technical disciplines may be involved in such evaluations, addressing geology, hydrology, geophysics/geomechanics, seismology, reservoir engineering, civil engineering, oil, and gas injection well operations, and permit conditions. Data that can be used to inform a seismic evaluation and reservoir/geomechanics modeling include:

- **Seismicity data** includes historic and current event recordings from USGS, State Geological Surveys, universities, and private networks; epicentral and hypocentral locations and magnitudes to conduct spatial evaluations; and ground motion data.
- **Well data** can include:
 - Well location to conduct spatial evaluations;
 - Daily injection rates to conduct temporal evaluations;
 - Cumulative volume over time to conduct reservoir evaluations,
 - Reservoir evaluations (e.g., Hall and Silin Plot[s]);
 - Daily maximum injection pressure, specific gravity of the injectate, and fluid level within the injection tubing to calculate bottomhole/reservoir pressure;
 - Bottomhole pressure (obtained from a downhole sensor);
 - Wellbore diagram showing construction of the well, injection depth (top and bottom of open-bore hole or location of perforations), the formation(s) into which injection is taking place, and the depth from basement;
 - Open hole geophysical logs including gamma ray, caliper, compensated density-neutron, and resistivity obtained when drilling the well that;
 - Seismic reflection surveys;
 - Mud log;
 - Log defining *in-situ* stress orientation;
 - Other imaging logs;
 - Temperature or noise logs;
 - Dipole sonic log;
 - Pressure transient tests;
 - Step-rate tests; and
 - Pressure Falloff test.
- **Geologic data** includes general stratigraphy of typical formations in the area showing their stratigraphy in relation to the basement, maximum principal stress information, hydrogeological data (for hydrogeological flow and pore pressure modeling, and location of known faults, best defined by 3D seismic, if available).

- **Local factors** include population, infrastructure, public and private structures, surface reservoirs and dams.

Based on the risk assessment of the potentially induced seismicity, a state regulatory agency may determine that operations can resume at the disposal well or site. When mitigation actions are determined to be appropriate, options might include supplemental seismic monitoring, altering operational parameters (such as rates and pressures) to reduce ground motion and risk, permit modification, partial plug back of the well, controlled restart (if feasible), suspending or revoking injection authorization, ceasing injection, and shutting in a well, or plugging and abandonment of the SWD.

Mitigation and Response Strategies for Hydraulic Fracturing

General risk management and mitigation approaches relevant to potential injection-induced seismicity also can be applied to large volume hydraulic fracturing operations in horizontal wells. However, any significant risk of induced seismicity associated with hydraulic fracturing is extremely rare, is quickly mitigated, and when detected at the surface generally has the lowest levels of surface impact. Hydraulic fracturing stimulations utilize temporary injections, in contrast to longer term disposal injections such that the risk is spatially and temporally limited to well stimulation operations. Therefore, evaluation and response systems should be tailored differently for hydraulic fracturing than for disposal.

Several jurisdictions have introduced guidelines for hydraulic fracture induced seismicity, including Ohio and Oklahoma, along with Alberta and British Columbia in western Canada. These guidelines have been introduced to avoid reports from local residents and are intended to mitigate felt seismicity, where for a small subset of well stimulations public reports of felt shaking have been reported near the operations. Many regulators work on these issues with the input of experts from government agencies, universities, private consultants, and industry. These guidelines often involve a traffic light system approach based on the magnitude of seismicity in the vicinity of hydraulic fracturing operations within a specific area of interest.

Considerations for Development of Risk Management Guidelines for Hydraulic Fracture Induced Seismicity

State regulatory agency risk management approaches have generally been developed based on public considerations and the perception of local risk exposures. These approaches have been framed around two key risk management concepts involving the use of “Traffic Light Systems” and/or “Areas of Interest.” Risk management systems should be designed and implemented to be responsive and mitigate potential risks independent of specific completion methodologies that are being employed. Whether a Traffic Light System and/or Area of Interest are implemented as the risk mitigation approach, the approach should be implemented considering the risk exposures for the local community. It is desirable for the system to enable flexibility in the implementation risk mitigation elements such that protocols and procedures may be specifically tailored and adaptable for each unique situation.

In areas where potential induced seismicity is a concern, the state regulator may include, as part of each project's operational permit, a mechanism for the well operator to be able to control, reduce, or eliminate the potential for felt earthquakes. Because of the proprietary nature of certain information related to hydraulic fracturing, regulators may need to work closely with the operators. Some regulatory agencies have implemented permit conditions that may include additional downhole testing requirements, and/or seismic monitoring and mitigation. When an evaluation and response strategy is to be adopted to control operations that may cause unacceptable levels of induced seismicity, disclosure, and discussion of the adopted system prior to the start of operations may be considered, so that these safeguards are clearly known and understood by all concerned.

If earthquakes are observed during simultaneous operations and application of zipper fracturing methods or concepts during fracturing of multiple wells on a single pad, a substantial range of potential mitigation steps exist and could be considered. The mitigation strategies depend on the configuration of the wellbores, and evaluation of available subsurface information and seismicity trends.

If an earthquake occurs near ongoing fracturing operations, various mitigation approaches could be considered that utilize the breadth of operational flexibility afforded by the presence of the multiple wells on the single pad. If these very rare events are encountered, careful evaluation and site-specific research is key to effectively inform the response strategy and align potential operational adjustments to mitigate potential future events in the local area.

Unlike data related to disposal well operations, much of the data obtained during hydraulic fracturing operations is likely to be considered confidential because of what it reveals about well completion approaches. Because rules about data reporting of well completion and hydraulic fracturing operations differ by state, wide variations can be expected in the types of information that can be gleaned from public sources or that would routinely be available for correlation with any seismicity. One public source of information is FracFocus, the nationwide system for disclosing the additives and chemicals used in the hydraulic fracturing process, which also records water volumes.

Traffic Light Systems

Traffic Light Systems typically specify earthquake magnitude thresholds that if exceeded, mandate an action, such as communication with the regulator, or a change to the scope of operations. For example, when a "yellow light" magnitude threshold for a seismic event is exceeded, the scope of operations may be modified in such a way to lower the potential for further seismicity. When a "red light" magnitude threshold for an earthquake is exceeded, the operation is suspended and further investigations are made by the regulatory agency and also possibly the operator(s),

Thresholds may vary based on local conditions and the risk management goals of a given agency. The thresholds are based on standardized earthquake magnitude measurements derived from ground motions recorded by a seismic monitoring network. When considering selection of traffic light thresholds, the equipment, procedures, and resource requirements for implementation of a

specific system can vary substantially depending on desired thresholds for taking action. Seismicity may also be detected associated with other nearby industrial operations (such as mining blasts, for example), and thunderstorms or natural tectonic activity. Local disposal well operations can also result in seismicity distinct from hydraulic fracturing operations.

Traffic light thresholds may also consider background thresholds associated with hydraulic fracturing and recognize that microseismic events are anticipated and may routinely observe recorded events of approximately **M** 1. Micro-seismicity are extremely small magnitude events that are routinely used to map hydraulic fracture growth and are an intrinsic characteristic of hydraulic fracturing. Typically, this type of seismicity is too weak to be detected by seismometers in the presence of background noise. Setting a traffic light threshold near the low magnitudes associated with microseismic events may result in traffic light scenarios unrelated to anomalous fault activation.

Areas of Interest

Another common approach used by regulators is to define an “Area of Interest”. If operations are conducted within the specific geographic Area of Interest, constraints on scope of operations are predefined or implementation of seismic monitoring may be required or enhanced. Areas of interest may be defined based on historical seismic activity and location of operations relative to known fault systems and/or known proximity to the deeper basement rock.

The larger earthquakes in Alberta have been associated by some researchers with basement rooted fault structures and their proximity to fossil reefs (Schultz 2016). Areas of interest (susceptible to induced seismicity) were also identified through multi-variant analysis of receptors and predictors for seismogenic wells (Pawley et al. 2018) The earthquakes in the Horn River and Montney plays in British Columbia have also been linked to faults that were interpreted to extended into the basement (BC Oil and Gas Commission 2012; Atkinson 2016).

In Ohio, investigations of earthquakes in proximity to hydraulic fracturing operations in Harrison County (**M** 3.1 event) and Poland Township (**M** 3.0 event) also suggested that hydraulic fracturing operations may have triggered movement of faults that extend into the basement structure (Dade 2017; Skoumal 2015).

More recently, Oklahoma Geologic Survey analysis of seismicity data and hydraulic fracturing operations in the South Central Oklahoma Oil Province (“SCOOP”) and the Sooner Trend in the Anadarko Basin located in Canadian and Kingfisher counties (“STACK”) has prompted the Oklahoma Corporation Commission to implement an area of interest and traffic light system to mitigate risk of hydraulic fracturing operations triggering surface-felt seismicity in the SCOOP and STACK plays (Oklahoma Corporation Commission 2016).

In Pennsylvania, an earthquake sequence (**M** 1.8 – **M** 2.3) that occurred in April 2016, was associated with nearby hydraulic fracturing operations. These events were not felt at the surface but were detected by the Pennsylvania seismic network (Pennsylvania Department of Environmental Protection 2017). Based on this information, the Pennsylvania Department of

Environmental Protection highlighted that hydraulic fracturing in the Utica shale was performed in proximity to Precambrian crystalline basement rock.

Specific Examples of Regulatory Risk Management Approaches

States and provinces have adopted a variety of strategies for risk management and response related to potential fracturing-induced seismicity. For example:

- In a proactive approach, the Oklahoma Corporation Commission's Oil and Gas Conservation Division (OGCD) and the Oklahoma Geological Survey (OGS), along with interested operators, have developed seismicity guidelines focused on the SCOOP and STACK plays. The OGCD maintains the following statement for actionable magnitudes between differing arrays within active plays:

"While the OGS Earthquake Catalog is the magnitude of record for all events, protocol action is to be initiated upon the first detected actionable magnitude. If the OGS magnitude is higher than the magnitude detected on the operator's private array, further protocol action will be required at the level appropriate to the OGS magnitude."

Expected statewide, but mandatory within an "Area of Interest" associated with the SCOOP and STACK plays, the OGCD will take the actions listed below following anomalous seismic activity within 5 km of hydraulic fracturing operations:

- If magnitude, as determined by the OGS (or an operator's private array whichever is greater), is greater than or equal to **M 2.0**: operators begin implementation of a Seismicity Response Plan;
- If magnitude is greater than or equal to **M 2.5**: OGCD contacts designated representatives for active completion operations within a 5 km radius of located earthquakes. A qualified pause of no less than six hours and discussion of mitigation procedures will commence if no prior actions have been taken. If prior actions have been taken additional mitigation may be requested;
- If magnitude is greater than or equal to **M 3.0**: Operator initiates a mandatory pause of operations for no less than six hours. Technical conference/call held between the OGCD staff and operator about operator mitigation practices. Upon agreement between operator and OGCD regarding mitigation practices and reduced seismic activity, operator permitted to resume with revised completion procedure; and
- If magnitude is greater than or equal to **M 3.5**: Operator suspends operations. Operators are required to meet with OGCD staff for a technical review of the operations and may be required to submit detailed information regarding the HF stimulation and seismicity. Operations may restart only once Induced Seismicity Department Manager has approved a new operational mitigation plan and seismicity has returned to baseline levels within 5 km.
- Currently, within certain areas of interest, Ohio Division of Oil and Gas Resources Management (DOGRM) has implemented permit conditions requiring seismicity monitoring for fracturing operations conducted within three miles of a known fault or within the error ellipse of the epicenter of a recorded seismic event recorded since 1990 with **M 2.0** or greater. If an event is

detected by any seismic network, DOGRM has developed the following response procedures. An event less than **M** 1.5 requires no action. An event between **M** 1.5 and less than **M** 2.0 requires notification (either by the DOGRM to the operator or the operator to the DOGRM). This threshold allows for initial discussion between the parties to possibly limit escalation of magnitude. An event between **M** 2.0 but less than **M** 2.5 will result in a temporary pause of fracturing operations on the well(s) of concern. During the pause, the operator should consider and may propose modifications to the completion design such as skipping stages, reducing job volumes and pressures and/or changing from zipper fracturing to stack fracturing. The DOGRM may authorize resumption of fracturing operations after discussions with the operator and if the proposed modifications are reasonable and appropriate. An event greater than **M** 2.5 will cause a temporary stop on the well(s) in question. The stop will not be lifted by the DOGRM until a complete assessment of the event including cause, location, and remediation has been fully vetted by the DOGRM and the operator. At this point, several operators have opted to discontinue fracturing operations altogether and instead move to place the stages completed to that point into production. The temporary stop only affects the well(s) being completed at the time of the event. Completion activity is allowed to shift to other well(s) on the pad not associated with the event.

- California’s well stimulation regulations are designed to ensure that well stimulation via hydraulic fracturing does not generate seismicity that causes public concern or damage to structures, and to provide assurance that fractures created during hydraulic fracturing do not encounter and activate a fault. Monitoring of the California Integrated Seismic Network is required during and after hydraulic fracturing. If an earthquake of **M** 2.7 or greater occurs within a specified area around the well, further hydraulic fracturing in the area is suspended until the Division, in consultation with the California Geologic Survey, determines that there is no indication of a heightened risk of seismic activity from hydraulic fracturing.
- In Pennsylvania, the Department of Environmental Protection (DEP) has implemented an approach following several low magnitude earthquakes that occurred in Lawrence County just west of New Castle on April 25, 2016. Epicenter locations for the earthquakes vary slightly based on the degree of data refinement, but in general are confined to Mahoning, North Beaver and Union Townships in Pennsylvania. Due to this relationship, DEP has put in place permit conditions for operators to monitor and respond to seismic activity associated with Utica Shale Formation gas wells within North Beaver, Mahoning, and Union Townships in Pennsylvania. Among various requirements, these permit conditions require the operator to notify the DEP of an “Event” above a ML1.0 and within a six-mile radius of a wellbore path; and further requires the operator notify the DEP of an “Event” equal to or above a ML2.0 and within a three mile radius of a wellbore path as well as suspend fracturing operations.
- Energy regulators in Alberta, Canada have established seismicity monitoring requirements, a pre-hazard assessment, and response plan for all fracturing operations in the Duvernay zone in localized area where potentially induced seismicity events were recorded coincident with fracturing. In one case a traffic light system is implemented that provides a “yellow light” condition established for **M** 2.0 events—requiring reporting—and a “red light” condition established for **M** 4.0 events. The Alberta rules 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. Traffic light thresholds vary from areas of interest with respect to their site-specific conditions and location to critical infrastructure. Alberta has also required setbacks from dams and operation within the Duvernay.

- Energy regulators in British Columbia, Canada have established a traffic light system associated with hydraulic fracturing (and injection or disposal operations) on a well, whereby the well permit holder must immediately report to the British Columbia Oil and Gas Commission any seismic event within a 3 km radius of the drilling pad that is recorded by the well permit holder or reported to the well permit holder by any source available, if the seismic event has a magnitude of **M** 4.0 or greater (**M** 3.0 or greater in Kiskatinaw region), or a peak ground acceleration of 0.008 g to 0.02 g or if felt on the surface by any individual within the 3 km radius.

Approaches to assess and manage seismicity risk from hydraulic fracturing operations should take into account the local conditions, operational scope, geological setting, and historical baseline seismicity levels and reflect reasonable and prudent consideration of local engineering and building standards. Reasonable and practical evaluation and response systems are best developed considering the actual level of risk associated with local conditions. Depending on the specific local area, thresholds could consider, or be set consistent with, established acceptable limits from other industrial activities, e.g., mining, blasting, geothermal, etc. (Siskind 1983).

Given the broad geologic differences and diversity that exist across the U.S., it would be inappropriate to adopt a “one-size-fits-all” regulatory approach for managing risk. Local conditions must be considered (with the recognition that this could vary between states and within a given state at a more localized level for a given area of interest).

Pre-Planning for Hydraulic Fracture Operations

Prior to the initiation of a hydraulic fracture operation, pre-planning can be used to mitigate seismic risk. The first step is to identify potential optimally oriented and critically stressed faults of concern that could be activated during hydraulic fracturing. Each regional regulatory guideline defines an area of interest around specific wells defining an effective outer limit where faults may be encountered. However, if expected hydraulic fracture dimensions have been determined using modeling or microseismic monitoring, faults of concern within these dimensions would be more likely to be activated.

Prior to drilling a new well expected to have elevated seismicity risk, various factors can be considered to lower the risk. These factors may include:

- Geological characterization and structural evaluation;
- Drill wells in a way to avoid faults;
- Adjust timing to coordinate activities adjacent to the fault;
- Pad layout to ensure operational options if seismicity experienced;
- Plan completions to minimize fault activation; and

- Response plan developed with a predefined mitigation plan.

Widely Felt Earthquake Events from Hydraulic Fracturing Are Extremely Rare

A limited number of earthquakes with sufficient size to be felt have been associated with hydraulic fracturing operations (Rubinstein 2015). The largest recorded earthquakes to date, that researchers have associated with hydraulic fracturing operations in horizontal wells. There have been magnitude **M** 4+ events that occurred in the Alberta and British Columbia regions of Canada (Atkinson 2016) and **M** 5+ plus events in China in December 2018 and January 2019.

In a review of localized seismicity occurring between 1985 through 2015 in western Canada, researchers (Atkinson 2016) examined over 12,000 wells. Based on time and space correlations of fracturing operations with **M** ≥ 3 earthquakes, the historic events data suggest that hydraulic fracturing may be associated with earthquakes in approximately 0.2% to 0.4% of the wells (e.g., 30 to 50 of 12,289 wells).

In a review of localized seismicity in Ohio (Skoumal 2015; Brudzinski 2017), research focused on approximately 1,500 hydraulically fractured wells. Based on time and space correlations of fracturing operations considering **M** 2 or greater earthquakes, seismic data analysis “template matching” techniques indicated that earthquakes were associated with less than 0.4% of the wells (i.e., six of over 1,500 wells).

During a review of OCC mitigation procedures and hydraulic fracturing data, regulators in Oklahoma generated a “Frac Notice—Seismicity Match Catalog” from late 2016 through mid-2019 (Shemeta 2019). The study found 826 unique well-seismicity matches, or approximately 19% of wells of the total 4,302 wells in the study area. Of those wells, 333 wells were uniquely associated (earthquakes associated with only the single closest well) with a least one or more earthquakes of **M** 2 or greater, or 7.7% of the total well stimulations. A total of 1,438 unique earthquakes were matched to completion operations during the study period ranging in magnitude from **M** 0.3 to **M** 3.9. “The catalog has 960 earthquakes with **M** ≥ 2 , and of these, 57 events have **M** ≥ 3 . The largest event occurred in July of 2019 in Kingfisher County, with the OGS listing the event as an **M** 3.9 and the USGS National Earthquake Information Center (NEIC) catalog assigning the event a magnitude of **M_w** 3.6.”

When considering most horizontal wells in Ohio may have 45 stages or more, the percentage of hydraulic fracturing associated events is very low indeed. Additional review by the DOGRM estimates that there have been over 75,600 fracturing stages associated with over 1,680 wells with twenty-nine **M** 2 or greater earthquakes which serves to firmly establish the rarity of such events (Simmers 2017) corresponding to ~0.04% of the fracturing stages.

Responding to a Hydraulic Fracture Induced Seismic Event

In the event of possible induced seismicity associated with hydraulic fracturing operations, the process of shutting down the pumping may result in a steady decrease in seismicity, both event number and size. This behavior has been observed in micro-seismicity using downhole geophone arrays and also in the few cases where induced seismicity has been observed at the surface.

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 (e.g., a plug that was set over a previous stage would not allow for flowback of that previous stage until the plug was drilled out).

If seismicity at actionable levels is experienced during operations, the hydraulic fracturing should be changed to reduce the seismic risk. Depending on local circumstances, well design, and specific geology and reservoir conditions, various mitigation options could include, but not necessarily be limited to:

- Delay of further pumping until seismicity subsides;
- Potentially redesigning the perforation clusters to allow pumping at lower rates and volumes;
- Change fracturing sequences to lower the activity per unit time near the fault;
- Reduce fracture stage volumes to lessen fault activation;
- Change hydraulic fracture factors such as rate and fluid viscosity;
- Change of proppant design schedules (concentration, proppant size, etc.)
- Avoid identified seismically active features by skipping stages;
- Change in the sequence of fracturing operations if “zipper-fracturing” is being performed; and
- Monitoring and use of real-time seismological “double-difference” techniques to identify potential propagation of fault lineaments.

As the observation of many hydraulic fracturing operations has shown, induced seismicity potentially related to hydraulic fracturing is generally rare. When it does occur, it is often quickly mitigated, and in the U.S. has had little direct impact.

Therefore, the evaluation and response systems such as the “Traffic Light” for hydraulic fracturing should be tailored differently than those for disposal. The fracturing of a stage is a very transient process, and the subdivision of the wellbore into stages isolates subsequent intervals so that extended fault contact is not likely.

Chapter 4: Considerations for External Communication and Engagement

Chapter Highlights

This chapter discusses the following:

- The communication planning process, including preliminary scans, stakeholder involvement, tying communication strategies to risk, conducting mock exercises and other training;
- Communication plan elements, such as scenario analysis, external and internal audience analysis, definition of key messages and communication strategies, communication team roles and responsibilities, materials and resources, and potential answers to frequently asked questions;
- Guidelines for responding to an earthquake include providing professional, clear, concise, and authoritative responses, listening, documenting, avoiding absolutes, and sharing only approved information;
- Incorporating lessons learned, which includes understanding how communication takes place, documenting how decisions were made, avoiding definitive statement or promises, and improving a communications plan; and
- A case example from the Oklahoma Secretary of Energy and Environment.

Introduction

Clear and direct communication with the public is an important responsibility of states that are managing the risks of induced seismicity. There are state oil and gas regulatory agencies that choose to take a proactive approach by working with state public affairs officers on communication plans that address a range of possible scenarios. Some also adopt outreach strategies that include proactive public education and media engagement to share current information on relevant science and technology and on risk management methodologies used by the state. This chapter provides general guidelines for developing and continuously improving communication plans as well as for responding to induced seismic activity.

There are several key aspects of communication relative to earthquakes:

- Earthquakes can come with no warning and in areas that have not had previous seismicity;
- Shocks may grow with time and activity may go on for days;
- Initial official reports of locations and magnitudes can be inaccurate;
- The USGS “Did You Feel It?” system and shake maps are good early indicators of intensity and location;
- Public anxiety levels can be high and significant to deal with regardless of damage levels; and
- Determining causes of earthquakes may be difficult and jumping to conclusions should be avoided.

Communication Planning Process

Any situation involving seismicity is likely to be fluid and evolving. Communication planning in advance of any earthquake equips state regulatory and public affairs officers to respond effectively when a dynamic situation arises. Planning allows agencies to designate key communication roles and responsibilities, revisit the plan when personnel change, evaluate and anticipate likely questions and concerns, draft key messages and activities based on scenarios, and maintain a library of up-to-date materials and resources that incorporate current research and knowledge.

While communication planning needs to reflect the specific regulatory and legal structure of each state as well as unique geologies and other local conditions, states may find it valuable to learn from and adopt common planning approaches. For example, in defining the process for communication planning, agencies may elect to:

- **Do a preliminary scan.** The scan can include gathering relevant communication case studies, information resources, and communication planning approaches from other states or agencies; reviewing current communication plans for the state as a whole and specific to the agency; and creating an inventory of communication media and outreach methods (social, print, electronic, community, etc.) available to the agency;
- **Involve stakeholders with multiple areas of expertise.** In crafting the plan, agencies have an opportunity to learn from industry, the research community, and emergency management officials regarding such topics as geology, seismicity, and earthquake response strategies;
- **Tie communication strategies to risk management thresholds.** Agencies may use the thresholds in their risk management plans as communication planning scenarios, defining the strategies along with roles and responsibilities specific to each scenario;
- **Conduct mock earthquake exercises and other training.** Once the communication plan is drafted, an agency may test its communication strategies with a mock earthquake and evaluate and improve the plan as appropriate. Training should include a drill for designated state employees who will publicly represent the state and clear instructions for communications; and
- **Develop, revisit, and revise the communication plans on a regular cycle (e.g., annually).** Updating and evaluating plans regularly enables agencies to respond to changing situations and knowledge and to ensure that key roles, responsibilities, messaging, and strategies are fully identified and understood.

The planning process may also define the actions to be taken after an earthquake to evaluate the effectiveness of the plan and make improvements to messaging and strategies. Guidelines on plan evaluation are described in the section, “Incorporating Lessons Learned.”

Communication Plan Elements

Even if no physical damage has occurred, responding to an earthquake can be similar to any emergency response. In communication planning, therefore, it is appropriate to consider a crisis communication model with clear roles, responsibilities, and procedures. Typically, elements of such a communication plan include:

- **Scenario analysis.** Scenarios may be related to thresholds established in the risk management plan. If these thresholds have not been defined, the planning team can review various scenarios that would merit different levels of communication responses;
- **External audience analysis.** This analysis considers the viewpoints, concerns, perceptions, misperceptions, and commonly asked questions for various external audiences. The agency can outline the likely expectations of different stakeholders (e.g., homeowners, public safety and political officials, businesses, media) and indicate which stakeholders receive notification and at what frequency. Proactive audience research, including public meetings and seismic monitoring media, can provide valuable insights on the unique concerns and needs of each audience. Media contacts for editors and reporters who are likely to be interested in the topic along with links to past coverage generally are maintained in a database by the public affairs office;
- **Internal audience analysis.** This analysis identifies leadership within the primary response agency, in other state agencies and offices, and in the legislature, who need current information and talking points. Generally, internal audiences include responsible parties in the public affairs office. Internal and interagency audiences may be identified using the RACI (Responsible, Accountable, Consulted, and Informed) model to ensure that all internal parties are appropriately informed and engaged in each scenario (<http://www.cio.com/article/2395825/project-management/how-to-design-a-successful-raci-project-plan.html>);
- **Definition of key messages and communication strategies.** Keeping in mind both the external and internal audiences, the planning team will define key messages and strategies to be used under different scenarios. Strategies typically will address liaisons to major internal audiences and stakeholders; outreach to media (including traditional and digital media) through press conferences, press releases, and other activities; use of online and social media assets owned by the agency or the state; use of a telephone notification system or other method for handling citizen calls; and engagement of appropriate third-party subject-matter experts. Messaging will anticipate the varying interests of each audience. Citizens may be most interested in how to respond to an earthquake and where to receive additional information or updates. Media may be more interested in specifics around the earthquake, the potential causes, and companies that might be involved. Finally, elected officials will likely be requesting information to respond to constituents' questions to determine whether there is adequate regulatory authority to address the issue or avoid future issues;
- **Definition of communication team roles and responsibilities.** Typical roles may include a response manager with overall responsibility for managing the entire response as well as the communication team; an internal liaison to keep agency leaders and public affairs officials up to the minute on events; a designated and trained external (media) spokesperson, who often will be a public affairs officer; and an issue manager, who will support the spokesperson with any needed research and drafting, document events as they unfold, and maintain a history over time. The plan will define roles and responsibilities for each person and define the methods to be used to coordinate the team. In addition, other employees should be able to refer the public to the appropriate agency staff for additional information; and

- **Definition of materials and resources.** The team will evaluate available communication and outreach materials and resources (e.g., media backgrounders, public education materials, and briefings for state and local government leaders), identify gaps to be filled, assign responsibilities for developing new materials, and define the process for keeping the library of materials and resources up to date (typically assigned to the issue manager). Materials and resources should include information about the purpose, roles, and authorities of the various agencies concerning seismicity, the purpose of wastewater injection wells, the process of wastewater injection, hydraulic fracturing, and other oil and gas processes; the rules and regulations regarding injection wells, hydraulic fracturing, and other oil and gas processes; and the general causes of induced seismicity. The effort to develop and maintain current information may involve other government entities, industry, public interest groups, and the research community;
- **Drafting responses to frequently asked questions.** A valuable planning exercise is anticipating and drafting responses to likely frequently asked questions (FAQs). For example, FAQs might clarify the differences between hydraulic fracturing and underground disposal and explain the current consensus view on the relatively low hazards of induced seismicity related to hydraulic fracturing in comparison to disposal. Another FAQ response might address the difference between produced water and flowback water; and
- **Outreach and education.** The agency also may plan its proactive outreach and education strategies as part of the planning process. Strategies may include public events and meetings, use of digital and social media, and other methods of educating and interacting with key audiences. Primary goals might include dissemination of information on what the state is doing to evaluate, avoid, mitigate, and manage the risk of potentially induced seismicity.

Guidelines for Responding to an Earthquake

If an earthquake occurs at or above a threshold level, the agency would implement its communication plan. The following are guidelines for the designated spokesperson and others on the team who are drafting press releases and briefing materials:

- **Be professional and objective.** Speak clearly and plainly and be careful not to mischaracterize, minimize, or dramatize the situation. Reflect the agency's respect for public concerns about potentially induced seismicity and its commitment to answering questions and concerns;
- **Listen carefully.** Ensure that stakeholders have opportunities to voice their specific concerns, carefully define the issues as the agency understands them, seek feedback to assure that understanding was correct, and tailor response messages accordingly. Use stakeholder issues as the guide for agency messaging;
- **Avoid speculation.** Avoid speaking in speculative terms regarding public safety and seismicity. Make it clear that there are uncertainties, the situation could change, and the agency is keeping abreast of the situation. Demonstrate that the agency is open to new information and be candid about what is and is not known at any one time (e.g., "to the best of our knowledge and based on the information that we have today..."). This response may not satisfy all stakeholders, but it is consistent and appropriate considering the evolving nature of the

knowledge base concerning potentially induced seismicity;

- **Review all information before release.** Be clear on what the agency considers fact, what it is evaluating or investigating, and what it does not know at the time of the questions. Avoid conjectures and hypotheses without substantiation of the facts. For example, even if a reliable agency such as the USGS issues a report that an earthquake occurred, it does not mean that it can be accurately linked to a source. Such information needs to be verified by the appropriate state agency prior to making any conclusive statements;
- **Monitor communications.** Keep track of media, social media, and stakeholder communications. Monitor what the research community is saying about the earthquake, what various media outlets are saying, and what other agencies are doing in response to the earthquake. Track which entities are asking specific questions (media, citizens, political officials); and
- **Document.** Designate a historian to document how decisions are being made and for what reasons throughout the event.

Incorporating Lessons Learned

All communication is personal and individual, regardless of medium or the size of the audience. If the intended receiver does not, for whatever reason, regard a response or message as germane to his or her personal concerns, the communication may not be effective and productive.

It is critical that the agency evaluate its response and communication plans in this light after an earthquake and appropriately modify and improve the plans based on what has been learned.

The agency should document how decisions were made and for what reasons during the event and then follow-up with internal and external audiences about what was done well and what needs to be improved. A set of follow-up questions can be developed for each audience to gauge how well communications addressed their needs and expectations, what they learned during the process, and what they wish they knew before, during, and after the earthquake.

With any follow-up communication, the agency should not make promises or definitive statements concerning avoidance of future earthquakes. The goal is to show the ongoing commitment of the agency to an evolving concern. Also, it may be important to designate someone at the state who can respond to ongoing inquiries about the status and conclusions of state efforts and investigations.

In the evaluation process, the agency should identify key stakeholders involved that can help educate and communicate with other communities.

Based on its follow-up, the agency can improve its communication plan by considering:

- What communication strategies were effective or ineffective, and why?
- What forms of mediated communication were effective or ineffective, and why?
- What message was misunderstood, and why?

- Have stakeholder concerns changed, and if so, how?
- What worked or did not work regarding intra-agency communication and cooperation?
- What other assets can be used to improve the communication plan?

Case Example: Oklahoma Secretary of Energy and Environment

By 2015 Oklahoma's response to the issue of induced seismicity included not only the Oklahoma Corporation Commission and the Oklahoma Geological Survey, but several other agencies as well. At the same time, public concern and questions over the increased earthquake rate continued to grow, not only regarding the oil and gas production connection, but also as related to insurance and concerns over possible damage to the state's infrastructure. What was needed was a one-stop approach to disseminating information about the state's response.

The Oklahoma Secretary of Energy and Environment's Office created an earthquake information website <https://ee.ok.gov/resource/earthquakes-in-oklahoma/>, that offers information on the state's response to induced seismicity, research, and other vital information. Participating agencies provide the Office with data and other information for the site, which is updated regularly. Among the features of the site is an interactive map that enables residents to look at seismicity rates and disposal well locations for their area.

The site has proven to be a valuable asset for providing comprehensive information to the public in a transparent manner and helping to dispel the misperception by some that the state government was ignoring the seismicity issue.

In 2014, Oklahoma Governor Mary Fallin formed the Coordinating Council on Seismic Activity and charged it with organizing state resources and related activities related to Oklahoma's recent increase in seismic activity. The council meets regularly to share data, studies, developments, and proposed actions related to Oklahoma's earthquakes.

Appendix A: Relevant Earthquake Science

This appendix provides background on how earthquakes are generated, and seismic waves propagated, the hazards they pose, and techniques used to estimate their magnitude, frequency, location, and intensity as well as associated ground motions, and risk.

Faults and Earthquake Generation

A fault is a fracture or zone of fractures between two blocks of rock (USGS Faults 2012) where the blocks move relative to each other. This movement may occur rapidly, in the form of an earthquake, or slowly, in the form of the phenomenon called fault creep. Faults may range in length from a few millimeters to a few thousand kilometers. Most active faults produce repeated displacements over geologic time.

The fault plane can be horizontal or vertical or an angle in between. Geologists classify faults in three general categories, as shown in Figure A.1, using the angle of the fault plane with respect to the surface (known as the dip) and the direction of slip along the fault:

1. **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). This type of faulting occurs in response to extension and is commonly observed in the western U.S. Basin and Range Province and along oceanic ridge systems.
2. **Reverse fault:** A dip-slip fault in which the hanging wall moves up and over the foot wall. This type of faulting is common in areas of tectonic compression, such as western Oregon and Washington, Southern California, and regions of the central and eastern U.S. When the dip angle is shallow, a reverse fault is often described as a thrust fault.
3. **Strike-slip fault:** A fault in which the two blocks slide horizontally past each other. The San Andreas fault in California is an example of a right-lateral strike-slip fault. In a right-lateral strike-slip fault, the displacement of the far block is to the right when viewed from either side. In a left-lateral strike-slip fault, the displacement of the far block is to the left when viewed from either side.

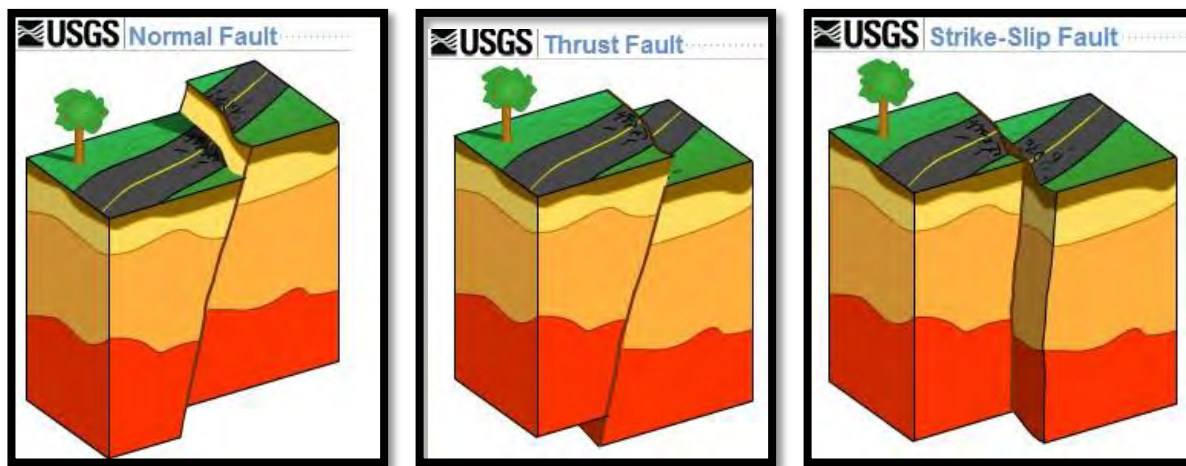


Figure A.1. Examples of a normal fault, reverse fault, and strike-slip fault. Image's courtesy of USGS.

Faults that show both dip-slip and strike-slip motion are known as oblique-slip faults.

As illustrated in Figure A.2, the location inside the earth at depth where the earthquake starts (rupture is initiated) is called the hypocenter, and the location directly above it on the surface of the earth is called the epicenter.

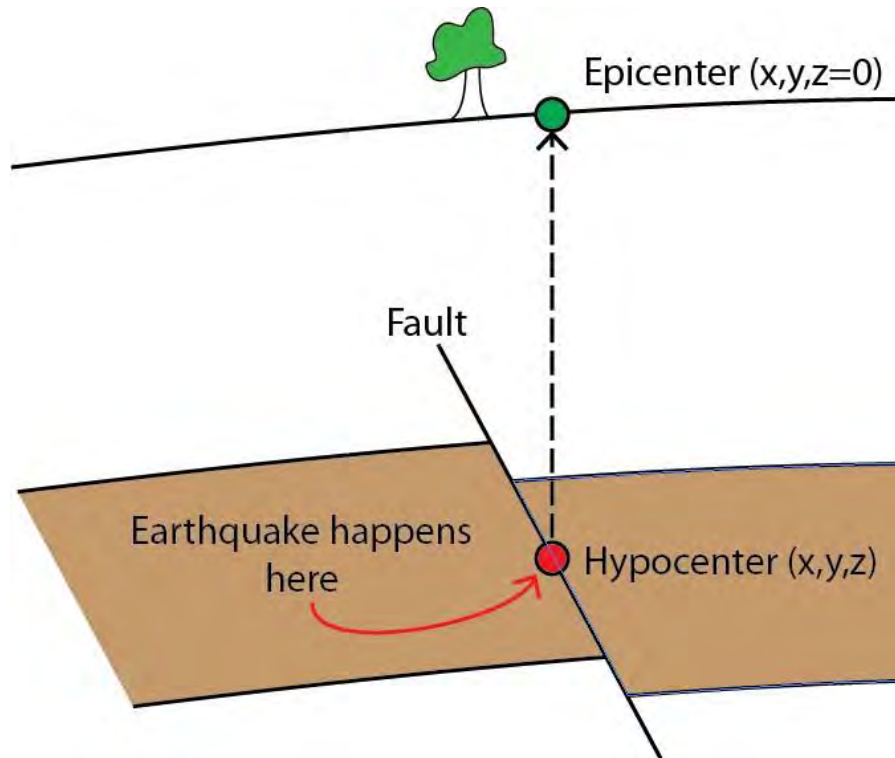


Figure A.2. Schematic illustrating the concept of epicenter and hypocenter locations of an earthquake. Source: ISWG.

As the fault slips, strain energy is expended by the crushing of rock within the fault zone, production of heat, and a release of a small percentage of energy as seismic waves. The relief of stress in one part of a fault may increase the stress in other sections, effectively transferring strain energy to those sections. Such stress transfers influence subsequent earthquakes (aftershocks).

An earthquake can present several types of hazards. Direct earthquake hazards include ground shaking, surface fault displacement, tsunamis, and uplift/subsidence for very large events ($M > 7.0$). Ground shaking, in turn, can introduce secondary hazards, such as liquefaction and slope failure (for example, landsliding). Impacts can include structural and nonstructural damage and human anxiety.

The modern concept of earthquake mechanisms began in the 1880s, when American geologist G.K. Gilbert theorized that earthquakes were the result of displacement along geological faults (Gilbert 1890). In 1910 geophysicist H.F. Reid suggested that earthquakes were the result of a phenomenon called elastic rebound based on observations of the 1906 M 7.9 San Francisco earthquake (Reid 1910). This theory states that an earthquake is generated by a rupture or sudden displacement along a fault

strained beyond its elastic strength. In the process of strain accumulation, the opposing sides of the fault are stressed until a sudden displacement occurs, releasing the stored elastic energy (accumulated strain), and then opposing sides rebound to a less strained state with some permanent displacement. Each cycle of strain accumulation along a fault results in an earthquake. Elastic rebound has become the accepted model for the generation of most earthquakes, although some types of volcanic and deep earthquakes may have different mechanisms.

Scientists have tried many ways of predicting earthquakes, but to date such efforts have not been successful. For any particular fault, scientists may be able to identify the possibility of another earthquake in the future and its size, but they are not able to identify when it will happen.

Faults of Concern

The Earth's crust is widely fractured and faulted. While the majority of faults are "inactive" and will not produce a significant earthquake, scientists attempt to identify "faults of concern" (USEPA 2015) that are optimally oriented for movement and are critically stressed and of sufficient size that a fault slip has the potential to cause a significant earthquake. A multi-disciplinary approach is often required to evaluate such faults, which may refer to a single fault or a zone of multiple faults and fractures. Faults of concern generally are not well identified or mapped.

The orientation of the fault and the stress distribution along the fault will help determine whether a fault may slip, as shown in Figure A.3. The NRC report, [*Induced Seismicity Potential in Energy Technologies*](#) (2012), contains a detailed discussion of the subsurface conditions that may contribute to fault reactivation.

There are cases in which a fault is able to host earthquakes even if it is not well oriented for failure (for example, the San Andreas fault in California [Hickman and Zoback 2004; Townend and Zoback 2000]). When weakening mechanisms become important at seismic-slip velocities, areas of a fault can slip even if it is not close to failure initially. For an earthquake to occur, however, a localized area must be close enough to failure that the stress perturbation due to injection can initiate it.

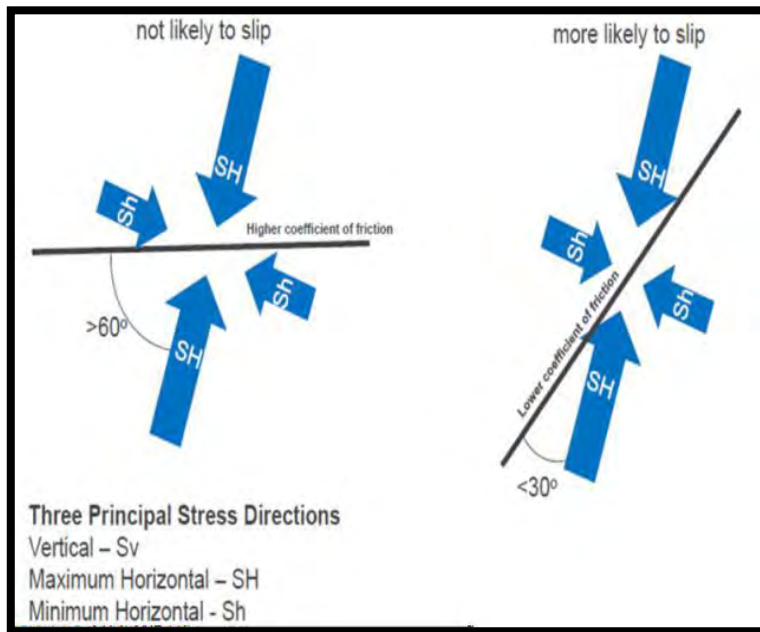


Figure A.3. Schematic showing conditions in which a fault may be more or less likely to slip. Source: ISWG.

Faults may be more prone to slip under certain stress conditions and geologic circumstances (Figure A.3). In a given stress field, the ratio of shear stress to resisting strength on a fault depends on the fault orientation.

Resisting strength depends on the stress acting perpendicular to the fault (i.e., the degree of clamping of the fault). While the two faults illustrated here have approximately the same shear stress, the fault on the right is more likely to slip; the fault on the left is less likely to slip because the larger stress, S_H , is more perpendicular to the fault (Figure A.3).

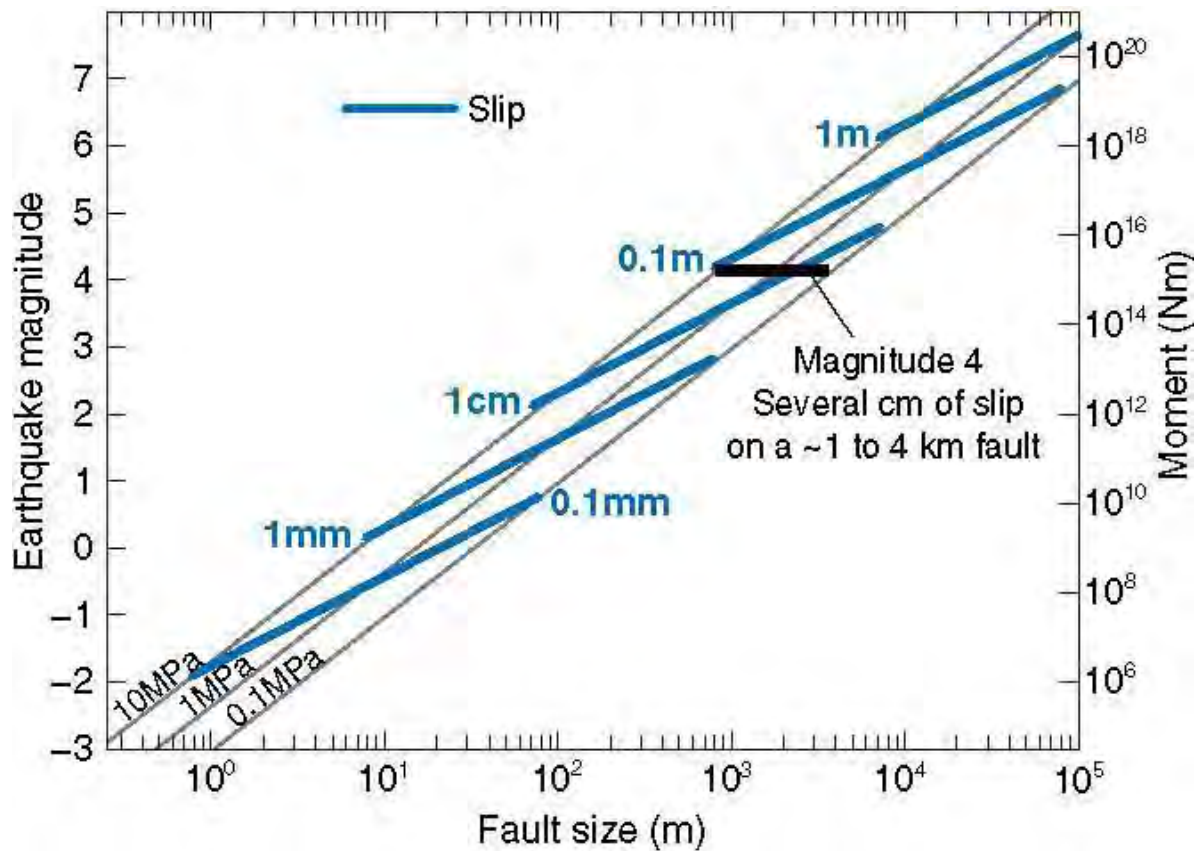


Figure A.4 Illustration of the relationships of fault size, fault slip, and stress drop relative to earthquake magnitude. Fault patch size is defined as the equivalent dimension of length in m, representing the diameter of a circular fault patch that has slipped in the model. The dotted lines show two stress drop levels of 0.1MPa and 10 MPa. For example, an earthquake of **M** 5 will have a fault patch size of several thousand m and will slip several centimeters. Figure courtesy of Mark Zoback, Stanford University

Earthquake Magnitude

The magnitude of an earthquake is related to the area of the fault that ruptures and the amount of displacement along the fault (Figure A.4). The larger the product of the rupture area and the displacement, the larger the earthquake and the more seismic energy released. Several measurement techniques and scales are commonly used to characterize the magnitude of earthquakes (Table A.1). All these techniques characterize the magnitude based on logarithmic scaling relationships.

Table A.1. Common scales used to characterize magnitude of earthquakes. Source: ISWG.

Scale	Abbreviation	Description
Richter local	M_L	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.
Moment	M or M_w	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.
Surface wave	M_s	Measured from recordings of 20 sec period surface waves.
Body wave	m_b	A common scale used in the central and eastern U.S. based on the recorded amplitude of body waves.
Duration or coda	M_D or M_C	A scale used for microseismic events ($M < 3$) based on the duration of the event.
Regional magnitude	m_{bLg}	A regional scale based on the amplitude of Lg surface waves.

Earthquake size can range from magnitudes less than zero, resulting from fault slippage of a millimeter or less, to the largest events, M greater than 9.0, with fault displacements of many m. The largest known earthquake was the 1960 M 9.5 Chile earthquake. Negative magnitudes are the result of more sophisticated measuring techniques because Richter set the magnitude scale with a “0” set at the smallest measurable event using 1930s technology.

Charles Richter developed the local magnitude (M_L) scale for southern California earthquakes in the early 1930s, allowing for the first-time precise quantification of the size of an earthquake based on instrumental recordings. Because M_L values were simple to calculate, the scale rapidly became a worldwide standard. Since then, several other magnitude scales such as moment magnitude (M), surface wave magnitude (M_s), and body wave magnitude (m_b) have come into use. Events recorded regionally often are characterized by the size of the largest arrival, the Lg surface wave and are designated as m_{bLg} . Although the M_L scale is still commonly used, seismologists prefer the moment magnitude scale because it is based on seismic moment, which is the best measure of earthquake size. The seismic moment is the product of the area of the fault that ruptures, the average displacement on the fault, and the shear modulus, a parameter related to the rigidity of the rocks in the fault zone.

The USGS estimates that globally there are more than one million naturally occurring (tectonic) earthquakes per year of **M** 2.0 or greater (USGS 2015). Earthquakes of about **M** 3.0 or less are called microseismic events as they commonly are not felt by people and generally are recorded only on local seismographs.

Sometimes an earthquake has foreshocks, smaller earthquakes that occur before the mainshock, generally along the same causative fault. Scientists cannot tell that an earthquake is a foreshock until the larger earthquake happens. The mainshock is commonly followed by aftershocks, which are smaller earthquakes in the same vicinity. Depending on the size of the mainshock, aftershocks can continue for weeks, months, years, and even decades (USGS Aftershocks 2012).

Earthquakes in a region generally follow the Gutenberg-Richter relationship (Richter and Gutenberg 1954), which describes the logarithmic increase in earthquake frequency as magnitudes decrease. The b-value quantifies the relative distribution of small and large earthquakes, and is observed to be around 1 globally, meaning that for an **M** 5.0 earthquake, there will be approximately 10 **M** 4.0 earthquakes and for each **M** 4.0 earthquake, there will be 10 **M** 3.0 earthquakes and so on. (A b-value of 1.5 means there would be about 30 **M** 4.0 events for each **M** 5.0 event, 1,000 **M** 3.0 events, and so on.) This relative distribution of small and large earthquakes is shown on a global scale in Table A.2. Note the b-value for induced earthquakes has been known to deviate significantly from 1.

Table A.2. Annual global earthquake frequency; estimates from USGS available at <https://www.usgs.gov/natural-hazards/earthquake-hazards/earthquakes>

Global Earthquake Frequency (from USGS Estimates)	
Magnitude	Annual Average
8 and higher	1 ^a
7 – 7.9	15 ^a
6 – 6.9	134 ^b
5 – 5.9	1319 ^b
4 – 4.9	13,000 (estimated)
3 – 3.9	130,000 (estimated)
2 – 2.9	1,300,000 (estimated)
Based on observations from 1900	
Based on observations from 1990	

Estimating Maximum Magnitude for Induced Earthquakes

No reliable technique currently exists for estimating the largest induced earthquake in an area. Attempts can be made to inventory and characterize active and potentially active faults in an area and assess their potential maximum earthquakes based on their dimensions. Commonly used empirical relationships by Wells and Coppersmith (1994) relate moment magnitude and fault dimensions for tectonic earthquakes ($M > 5$). Faults that are favorably oriented in the tectonic stress field (given pore pressure changes from injection) and critically stressed are likely to be potential sites for induced earthquakes. Factors such as the historical record of seismicity in an area may be considered. It is believed that the maximum magnitude of an induced seismic event cannot exceed the size of the maximum tectonic earthquake in the area; however, the maximum tectonic earthquake in the central and eastern U.S. is an issue of considerable uncertainty (Petersen et al. 2008).

Estimating Earthquake Location

To estimate the location of an earthquake, seismologists analyze the seismic waves it generates. Seismic waves can be classified into three basic types: compressional or primary (P) waves, shear or secondary (S) waves, and surface waves (Figure A.5).

- **P-waves and S-waves** are called body waves because they can travel through the interior of the Earth. The P-wave, which has the highest velocity and arrives first, causes particles in the Earth to move back and forth in the direction the wave is travelling. S-waves generate transverse particle motion perpendicular to the direction the wave is travelling and generally move at half to two-thirds the speed of the P-wave. Because S-waves generate horizontal ground motions at the ground surface and carry much more energy than P-waves, they are of greater concern for hazard.
- **Surface waves**, which are generated by shallow earthquakes, travel along the Earth's surface. There are two types of surface waves: Love and Rayleigh waves. Love waves, like S-waves, travel with transverse motions while Rayleigh waves result in both transverse and longitudinal motions. Surface waves can be damaging to long-period structures particularly when generated in sedimentary basins.

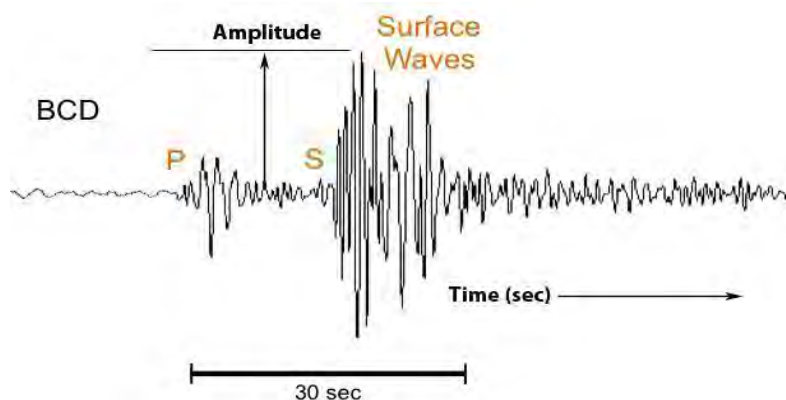


Figure A.5. Seismogram showing P-, S-, and surface waves (modified from http://akafka.files.wordpress.com/2012/10/maine_seismogram_bcd.png).

Using the time difference between when the P-waves and S-waves arrive, seismologists can estimate the distance of the earthquake from a seismic station. Figure A.6 shows a schematic of how the difference in P- to S-wave travel times is picked on a seismogram.

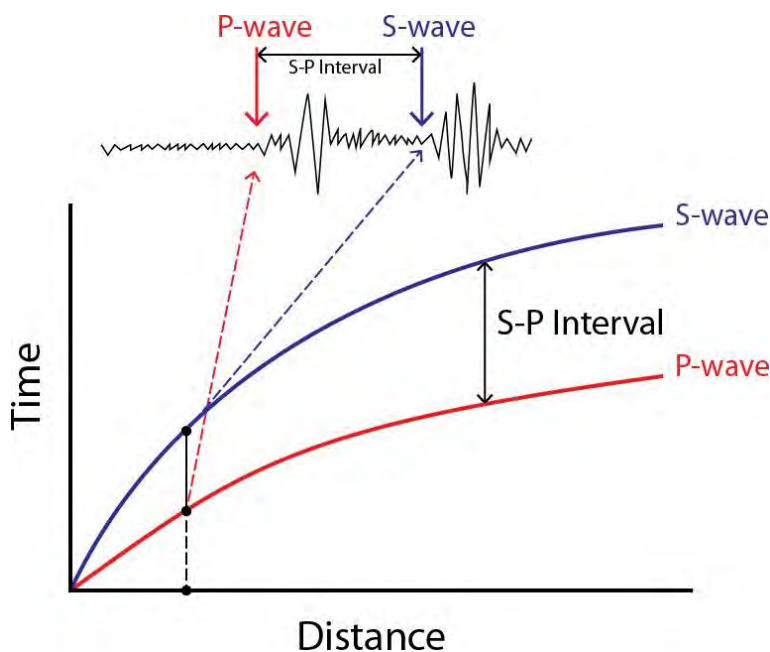


Figure A.6. Schematic illustrating the S-P travel time determination used in locating earthquakes.
Source: ISWG.

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 earthquake hypocenter 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.

Characterizing Ground Motions

The hazard associated with an earthquake is related primarily to the levels of ground shaking. Ground shaking levels are strongly influenced by earthquake magnitude, fault dimensions, orientation and type of fault, fault depths, and stress drop. The larger the earthquake, the larger is the rupture area, resulting in longer duration ground motions. Smaller earthquakes ($M < 5$) usually can be regarded as point sources of energy released when computing the hazard. If the earthquake is larger, then the finite dimensions of the rupture area can impact the level of ground shaking particularly at close-in distances (< 10 km). Stress drop, which is the difference in stress on a fault before and immediately after an earthquake occurs, controls the ground motions at high and moderate frequencies.

Distance has a very significant impact on ground shaking: the greater the distance from the earthquake location, the lower the ground motions. In addition, the properties of the Earth along the path the seismic waves travel have an impact because the Earth dampens (attenuates) the energy of the waves. Finally, geologic conditions at a site can influence ground motions. Observations of earthquake damage stretching back centuries indicate that ground shaking on soil generally may be greater than on rock because soil can amplify ground motions. If the soil is deep enough, however, it can both amplify and de-amplify depending on the frequencies of the seismic waves. Deep soils tend to dampen ground motions at moderate to high frequencies (> 1 Hz) and amplify at low frequencies (< 1 Hz).

The preferred approach to characterizing ground motions is to use quantitative measures, such as acceleration, velocity, or displacement. Prior to modern seismic instrumentation, ground motions were only estimated qualitatively using intensity i.e., Modified Mercalli Scale (see following discussion). Common ground motion measures (Table A.3) are peak ground acceleration (PGA) and peak ground velocity (PGV). PGA is the most commonly used measure in seismology and earthquake engineering, while PGV is used for structural and nonstructural building damage criteria and for human nuisance.

Table A.3. Ground motion parameters and their commonly used units. Source: ISWG.

Measure	Typical Units
Peak ground acceleration (PGA)	cm/sec ² , m/sec ² or g's, where 1 g = 980 cm/sec ²
Peak ground velocity (PGV) or peak particle velocity (PPV)	cm/sec, m/sec, in/sec
Peak ground displacement (PGD)	cm, m, inches

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 A.7 shows acceleration record of an induced earthquake in Timpson, Texas, from three seismic stations.

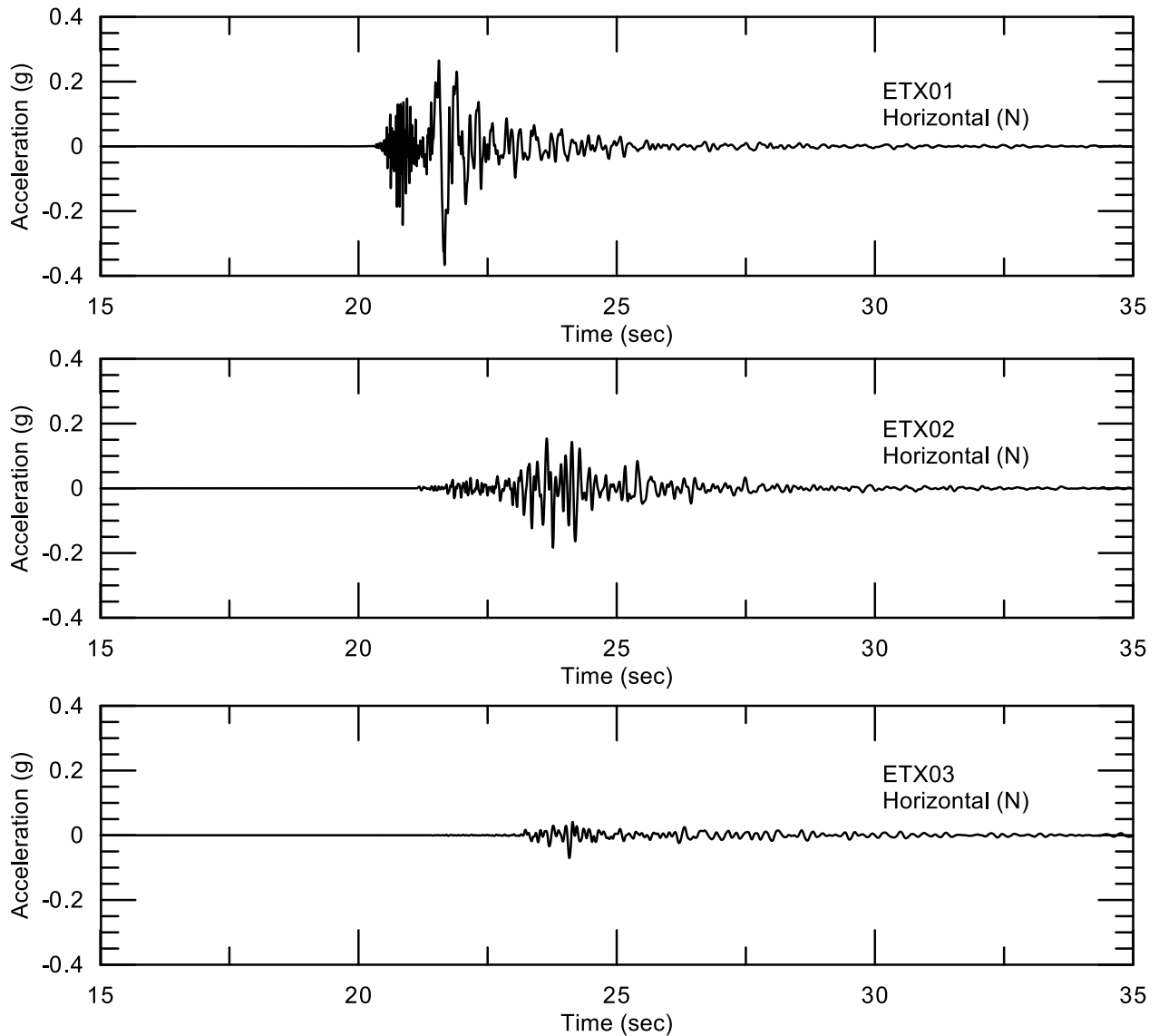


Figure A.7. Acceleration time histories of the 2013 **M** 4.1 Timpson, Texas, injection-induced earthquake. Source: ISWG.

Predicting Ground Motions

Estimating the severity and characteristics of earthquake ground motions has been one of the biggest challenges in earthquake engineering and engineering seismology. A fundamental tool used in seismic hazard analysis and other applications is the ground motion model. There are numerous models for tectonically active regions, such as the western U.S., and for the more tectonically stable central and eastern U.S. The models for the western U.S. rely on empirical motion data obtained from instrumental records of earthquakes or numerical modeling in the absence of adequate strong-motion data. Because there have been very few large earthquakes (**M** > 6) in the central and eastern U.S. in modern times, numerical modeling has been used for ground motion prediction in these regions.

A ground motion model relates a ground motion parameter, such as peak ground acceleration or peak ground velocity, to magnitude, distance, and site condition and, in some cases, other source and path parameters. Empirical models are developed by performing a statistical regression on a ground motion parameter from the recorded data to find the best-fitting model. Current ground motion models generally do not extend to magnitudes smaller than **M** 3.0. A considerable effort has been underway to develop models for induced earthquakes in Oklahoma, southern Kansas, and Texas.

Common inputs into a ground motion model include magnitude, distance, and site condition. The current ground motion models use moment magnitude. For small earthquakes generally less than **M** 4, hypocentral distance is an adequate distance metric. For larger events, a distance metric that accounts for the finite dimensions of the fault rupture area is desirable. For most models, rupture distance (the shortest distance to the fault plane) is used.

Site condition inputs also are required to accurately predict ground shaking, particularly at a soil site. The time-averaged shear-wave velocity (V_s) to a depth of at least 30 meters (m) needs to be characterized. This parameter is used in the U.S. building code (International Building Code) to classify site conditions. If the geology beneath a site is complex, a site-specific site-response analysis may be necessary, particularly if the site is or will be occupied by an important or critical facility. In those cases, a V_s profile down to rock or very firm soil is used to quantify the site and building foundation responses. This profile can be obtained through geophysical surveys, such as downhole and cross hole surveys, surface wave techniques, and microtremor surveys (for example, Stokoe and Wong 2011). For some areas of the U.S., the National Earthquake Hazard Reduction Program has developed maps that classify sites by six categories (called NEHRP site classes): hard rock, rock, very dense soil and soft rock, stiff soil, soft soil, and soft liquefiable soil. These maps are based on V_s data and, in some cases, the surficial geology.

Earthquake Intensity

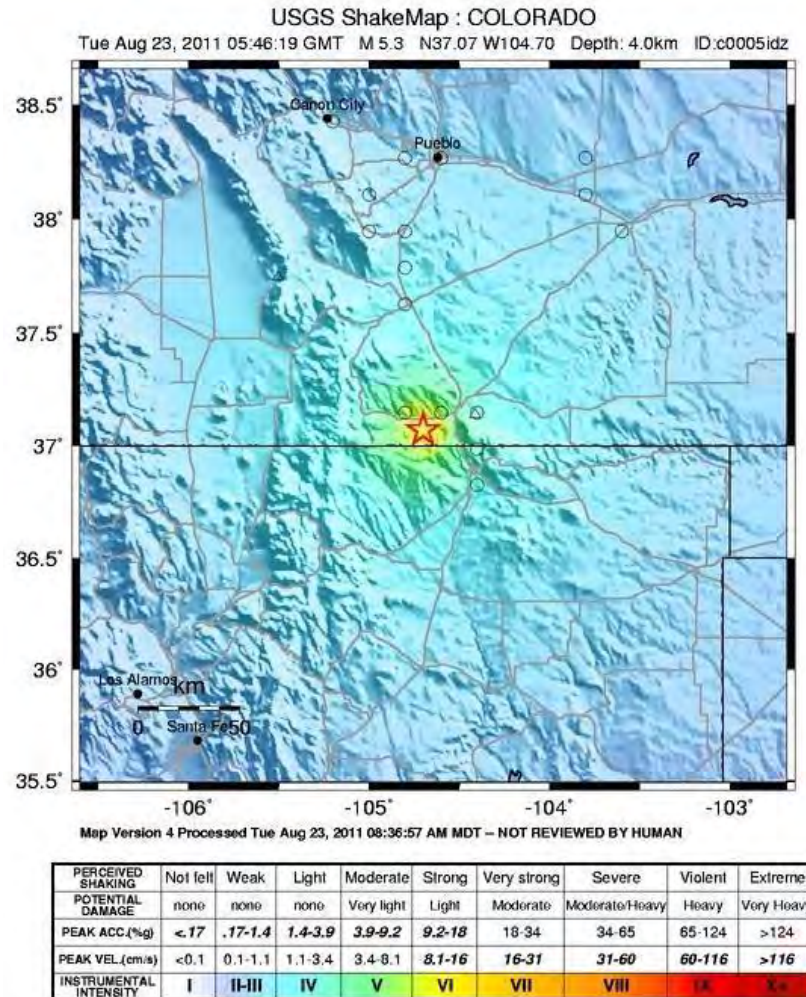
Intensity is a qualitative measure of the strength of shaking at a specific place and is characterized in terms of impact of this shaking on individuals as well as on objects and structures. It is not a measure of the size of the earthquake. The intensity scale most widely used today is the Modified Mercalli (MM) scale (Table A.4). Intensity is a useful measure for communication with the public and for providing a general sense of the ground shaking and impact.

Table A.4. Modified Mercalli intensity, peak ground acceleration, and peak ground velocity for the central United States. The MM scale has 12 levels but only eight are shown. Source: ISWG.

MMI	Description	PGA (g)	PGV (cm/sec)	Observations (Richter 1958)
I	Not felt	< 0.00007	< 0.003	Not felt except by a few under especially favorable circumstances.
II to III	Weak	0.0008	0.04	Felt by only a few people, often indoors. Hanging objects swing. May not be recognized as an earthquake.
IV	Light	0.01	0.5	Hanging objects swing. Vibration like passing of heavy trucks; or sensation of a jolt like a heavy ball striking the walls. Standing motor cars rock. Windows, dishes, doors rattle. Glasses clink. Crockery clashes. In the upper range of IV, wooden walls and frames creak.
V	Moderate	0.05	3.0	Felt outdoors; direction estimated. Sleepers awakened, liquids disturbed, some spilled. Small unstable objects displaced or upset. Doors swing, close, open. Shutters, pictures move. Pendulum clocks stop, start, change rate.
VI	Strong	0.09	6.5	Felt by all. Many frightened and run outdoors. Persons walk unsteadily. Windows, dishes, glassware broken. Knickknacks, books, etc., off shelves. Pictures off walls. Furniture moved or overturned. Weak plaster and masonry cracked. Small bells ring (church, school). Trees, bushes shaken.
VII	Very strong	0.15	14	Difficult to stand. Noticed by drivers of motor cars. Hanging objects quiver. Furniture broken. Damage to masonry D, including cracks. Weak chimneys broken at roofline. Fall of plaster, loose bricks, stones, tiles, cornices, un-braced parapets, and architectural ornaments. Some cracks in masonry. Waves on ponds; water turbid with mud. Small slides and caving in along sand or gravel banks. Large bells ring. Concrete irrigation ditches damaged.
VIII	Severe	0.27	30	Steering of motor cars affected. Damage to masonry; partial collapse. Some damage to masonry B; none to masonry A. Fall of stucco and some masonry walls. Twisting, fall of chimneys, factory stacks, monuments, towers, elevated tanks. Frame houses moved on foundations if not bolted down; loose panel walls thrown out. Decayed piling broken off. Branches broken from trees. Changes in flow or temperature of springs and wells. Cracks in wet ground and on steep slopes.
Masonry A		Good workmanship, mortar, and design; reinforced, especially laterally, and bound together by using steel, concrete, etc.; designed to resist lateral forces.		
Masonry B		Good workmanship and mortar; reinforced, but not designed to resist lateral forces.		
Masonry C		Ordinary workmanship and mortar; no extreme weaknesses like failing to tie in at corners, but neither reinforced nor designed to resist horizontal forces.		
Masonry D		Weak materials, such as adobe; poor mortar; low standards of workmanship; weak horizontally.		
<i>Note: MMI, description, PGA, and PGV from ShakeMap.</i>				

Displaying the distributions of earthquake shaking: Maps of the location and strength of earthquake shaking provide valuable information to emergency managers, first responders, media, and the public by identifying the areas likely to be or that have been affected by an earthquake. Such maps routinely produced by the USGS and other ANSS networks are known as ShakeMaps and display the intensity of shaking as MM intensity, PGA, and PGV (Wald et al. 1999) (Figure A.8). These maps may include measurements from accelerometers and reported intensities and predicted

intensities based on the earthquake epicenter and magnitude. For a particular earthquake, contours encompassing areas of similar intensity can be drawn. These isoseismal maps show that, generally, the larger the earthquake, the larger the felt area, and intensities decrease away from the epicenter. A ShakeMap is produced in near-real time minutes after most earthquakes of **M** 3.5 and larger in the U.S.



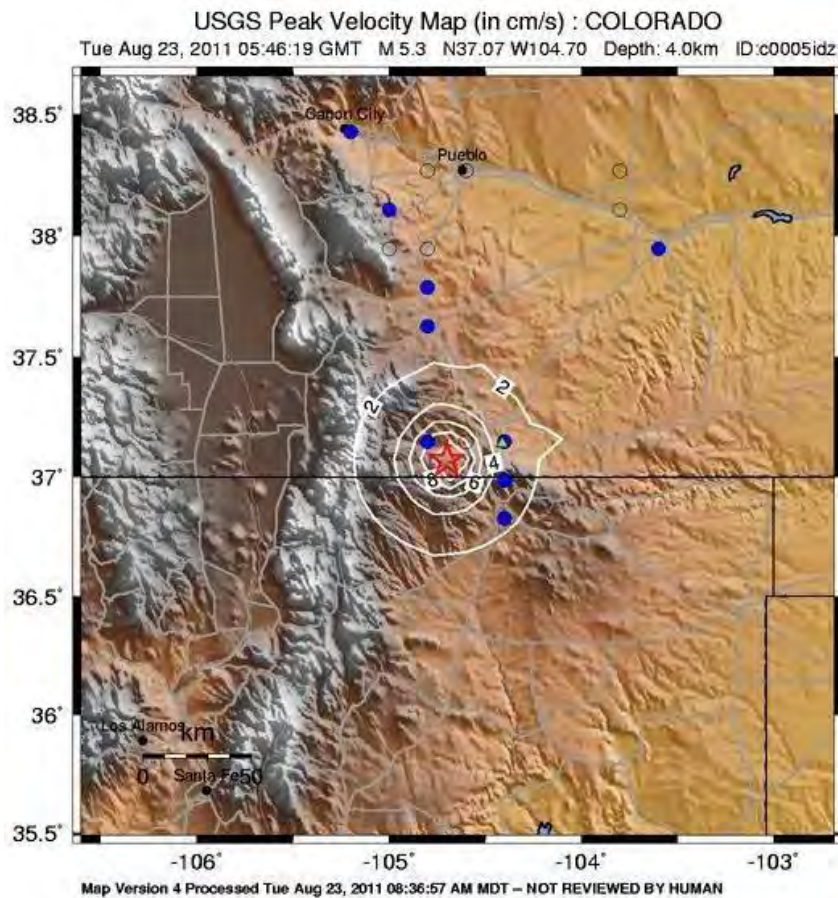


Figure A.8. Instrumental MM intensity (previous page), PGA (above), and PGV (bottom right) ShakeMaps of the 2011 M 5.3 Trinidad, Colorado, earthquake from the USGS. Source: ISWG.

Correlating intensity with PGV and PGA: A number of authors have developed relationships between MM intensity and PGV and PGA for tectonic earthquakes (Wald et al. 1999; Kaka and Atkinson 2004; Atkinson and Kaka 2007). The original relationship derived by Wald et al. (1999) was developed from eight California tectonic earthquakes of M 5.8 and greater. Because these earthquakes are much larger and occur much deeper than typical injection-induced earthquakes, there is considerable uncertainty regarding the use of this relationship for smaller magnitude induced earthquakes, particularly outside California. Because of this, assigning a PGA or PGV to MM intensity (or vice versa) may not be reliable. Kaka and Atkinson (2004) and Atkinson and Kaka (2007) computed similar relationships for PGV in central and eastern North America and concluded that relationships between MM intensity and ground motion are significantly different in central and eastern North America than in California, and that the California relationships under-predict intensities in central and eastern North America. All three models are shown in Figure A.9.

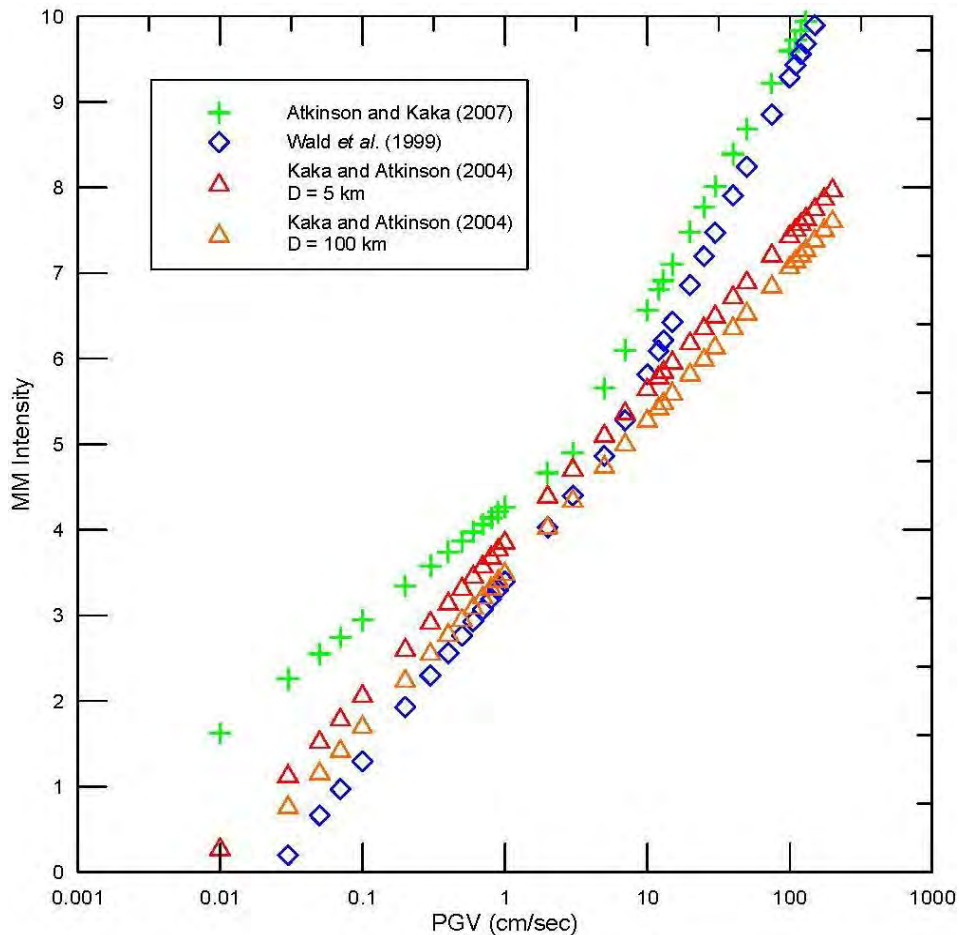


Figure A.9. Comparison of models of MM intensities versus PGV. Source: Wong et al. 2017.

Impacts of Ground Motions on Structures

Ground motion can cause structural and nonstructural damage to buildings as well as to civil structures, such as dams, bridges, highways, railroads, tunnels, pipelines, tanks, and airport runways. It is commonly accepted that structural damage to modern engineered structures generally happens only in earthquakes larger than **M** 5.0. For example, for the National Seismic Hazard Maps, which are the basis for the building code in the U.S. (International Building Code), the USGS uses a minimum magnitude of **M** 5.0 in the western U.S. and **M** 4.75 in the central and eastern U.S. in their hazard calculations (Petersen et al. 2014). Poorly designed or constructed buildings, such as unreinforced masonry (URM), for example, brick and adobe (Table A.4), and buildings built before modern building codes can be subject to nonstructural damage at magnitudes as low as **M** 4.0 and, in some rare cases, as low as **M** 3.0. Structural damage has been observed in very poorly designed and constructed buildings and in a few rare cases, in earthquakes smaller than **M** 5.0.

Structural damage can occur after several cycles of ground shaking, when resulting seismic loading induces strains resulting in failure of structural (load-carrying) components. Brittle structures, such as URM buildings, are particularly vulnerable. Maximum damage occurs when the predominant frequency of the larger amplitude seismic waves coincides with the natural frequency of a structure

(called resonance). Most ground shaking damage from earthquakes is attributed to S-waves because they generate horizontal ground movement as they approach the Earth's surface. Surface waves generally have larger amplitudes than body waves, but they have much longer wavelengths and frequencies much lower than 0.2 Hz. They generally will impact long-period engineered structures such as tall buildings and long bridge only at large distances when the body waves have become less prominent. As a rule, surface waves do not become prominent until distances are reached that are two times the thickness of the Earth's crust (Kramer 1996).

Building damage due to ground shaking can be classified into three categories (Dowding 1996):

1. **Threshold cracking** encompasses cosmetic damage due to cracking of stucco, plaster, or gypsum boards where cracks are closed.
2. **Minor damage** is superficial damage that does not cause a weakening of the structure and includes broken windows, loosened or fallen plaster, and hairline cracks in masonry.
3. **Major damage** includes any weakening of the structures as indicated by large cracks, shifting of the foundation, or bearing walls, or major settlement resulting in distortion or weakening of the superstructure.

In an early study Dowding (1985) indicated that threshold cracking occurred in older structures at peak particle velocities (or PGV) of about 8 cm/sec, minor damage at 11 cm/sec, and major damage at 20 cm/sec. The peak particle velocity level of damage is strongly correlated with the age and condition of the structure and the quality of construction. For example, unreinforced masonry structures are more prone to damage than modern reinforced masonry. Historical structures could be damaged at lower peak particle velocities than stated above.

It is generally believed to be difficult to establish general thresholds of damaging ground motions because of the many factors that can affect damage. From a structural engineering perspective, the damage a building sustains in an earthquake is very specific to that building, its building type (e.g., masonry, concrete, steel-frame, etc.), age, quality of design and construction, and the characteristics of the ground shaking.

A recent paper by Atkinson (2020) examines the issue of damage potential from induced earthquakes and intensity. She concludes that the damage threshold of MM VI (Table A.4) is commonly exceeded for events of about **M** 4.5 at close distances (< 10 km) and significant damage effects (MM VII) for events **M** 4.8 and greater within 10 km. Atkinson (2020) further states that MM VI can be roughly correlated with a PGV of 6 cm/sec and PGA of 0.09 g in the central and eastern North America.

While damage to the structural system is the most important measure of building damage because it could result in casualties and catastrophic loss of function (due to unsafe conditions), damage to nonstructural systems and contents tends to dominate economic loss (FEMA 2010).

Human Anxiety Created by Ground Motions

Human anxiety can occur from low-level ground shaking that does not necessarily cause physical damage to the built or natural environment (Majer et al. 2014). Although the ground motions can be of low amplitude, if repeated often enough they could impact the health and mental well-being of people.

Although difficult to quantify, there is substantial literature on the human response to ground vibration from the mining and construction industry. For example, ISO (International Organization for Standardization) 2631 (ISO 1997, 2003) is a standard for assessing human response to ground acceleration for people standing, sitting, or lying. Bommer et al. (2006) show a useful figure illustrating the levels of human sensitivity to blast vibrations, reference levels for vibration perception and response from traffic, and vibration thresholds for pile-driving (Figure A.10).

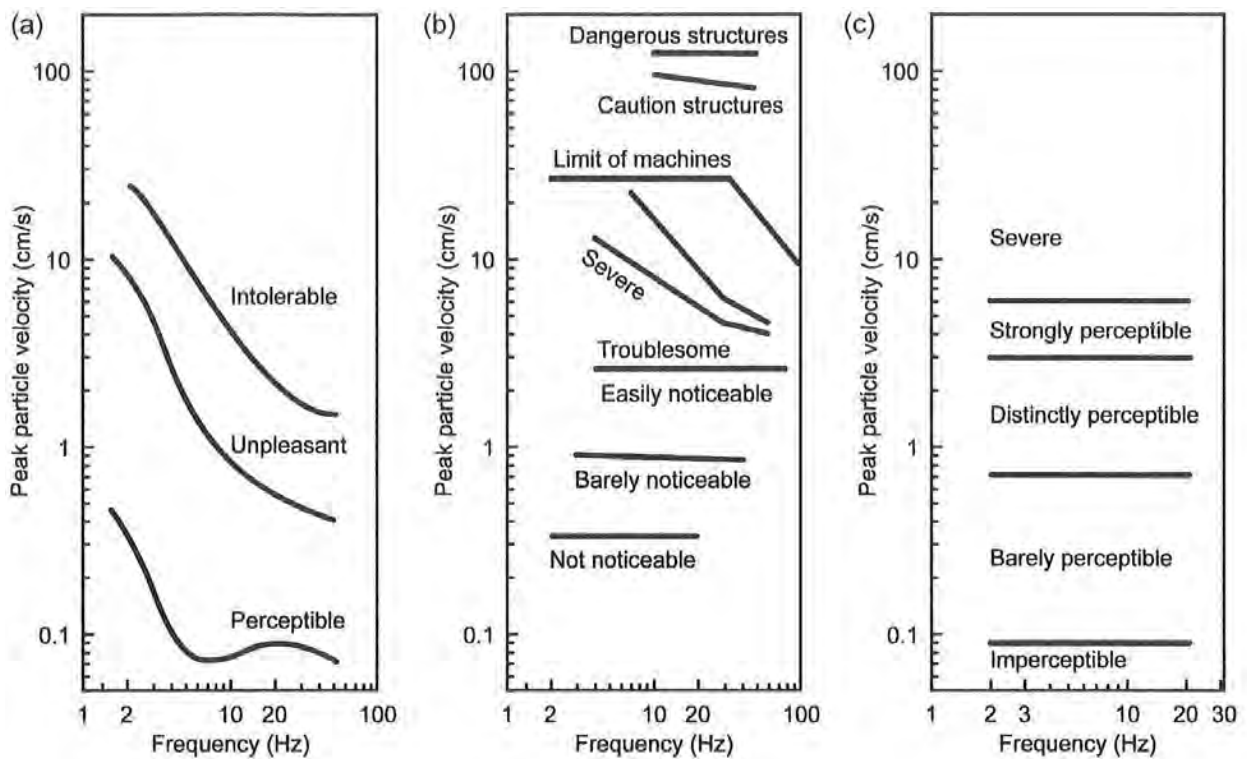


Figure A.10. Levels of human sensitivity to different sources of vibration, from (a) blasting, (b) traffic, and (c) pile-driving. Source: Bommer et al. 2006.

Figure A.11 is taken from Majer et al. (2014) and shows an example of a vulnerability function that describes the six possible states of human sensitivity: 1) comfortable, 2) a little uncomfortable, 3) fairly uncomfortable, 4) uncomfortable, 5) very uncomfortable, and 6) extremely uncomfortable. The curve gives the probability that a person would find a given level of ground shaking unacceptable. With this vulnerability function and knowledge of the impacted population (density and location), it would be possible to estimate the average number of people who would be inconvenienced and who would find the ground motion unacceptable (Majer et al. 2014).

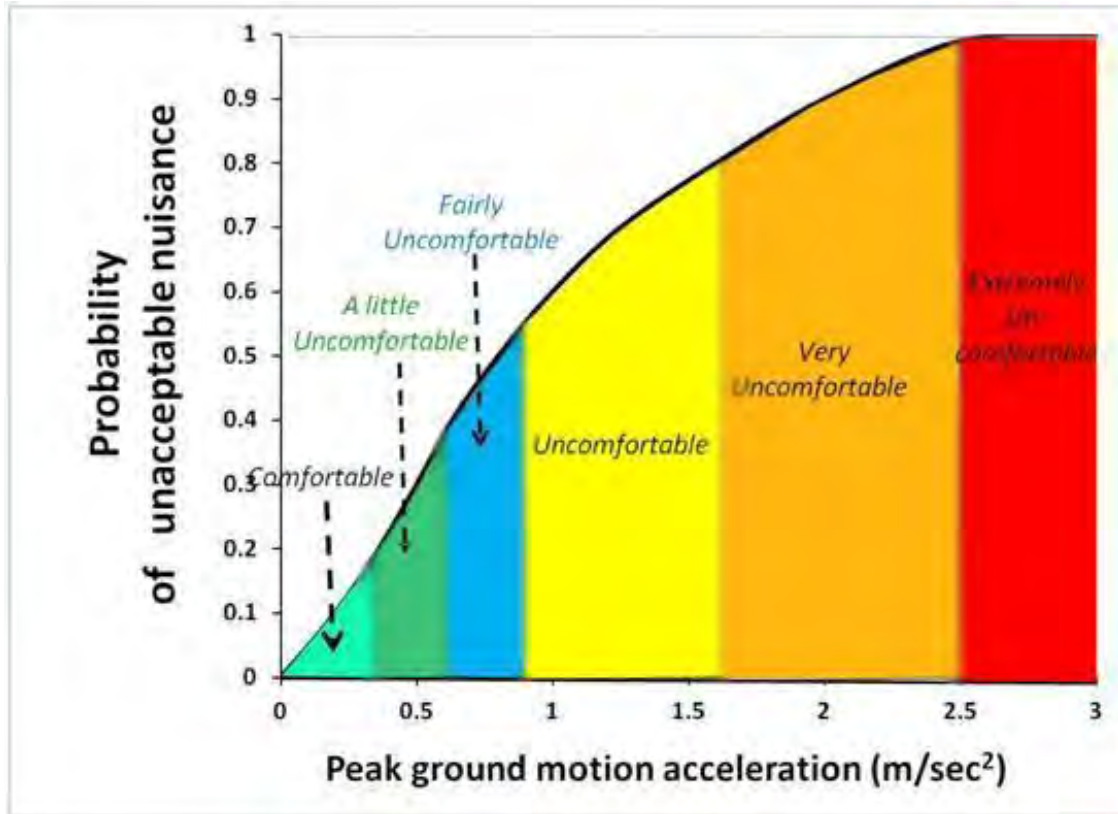


Figure A.11. Probability of unacceptable nuisance (after Majer et al. 2014).

Appendix B: Class I and II Injection Wells

Introduction

This appendix provides background on the Underground Injection Control (UIC) program, the types of Class I and II injection wells, and the construction criteria for and regulatory management of Class I and II disposal wells.

The USEPA UIC program considers six well types based on similarity in the fluids injected, activities, construction, injection depth, design, and operating techniques. Wells with common design and operating techniques are required to meet appropriate performance criteria. Extensive information on wells regulated under the UIC program is available at:

(<http://water.epa.gov/type/groundwater/uic/wells.cfm>). Table B.1 summarizes the typical uses for each class of well.

Table B.1. Summary of UIC wells and estimated inventory. Source: USEPA 2019.

Underground Injection Well Classification Chart		
Well Class	Purpose	Active Wells
I	Injection of hazardous, non-hazardous, and municipal wastes below the lowermost USDW	907
II	Injection of fluids associated with the production of oil and natural gas resources for the purposes of disposal or enhanced oil and gas recovery	160,211
III	Injection of fluids for the extraction of minerals	28,465
IV	Injection of hazardous or radioactive wastes into or above a USDW (USEPA prohibited the use of Class IV wells in 1984)	169
V	Injection into wells not included in other well classes but generally used to inject non-hazardous waste	552,574
VI	Injection of supercritical carbon dioxide for storage	3

Class I Protection of Underground Sources of Drinking Water

Class I wells allow injection far below the lowermost Underground Sources of Drinking Water (USDW). Injection zones typically range from 1,700 to more than 10,000 feet in depth. The injection zone is below and separated from USDWs by an impermeable “cap” rock called the confining layer. The confining layer may be associated with additional layers of permeable and impermeable rock and sediment to separate the injection zone from the USDW. Every Class I well operates under a permit issued by a regulatory agency. Each permit is valid for up to 10 years. Owners and operators of Class I wells must meet specific requirements to obtain a permit. These requirements address the siting, construction, operation, monitoring and testing, reporting and record keeping, and closure of Class I wells.

Types of Class I Wells

Hazardous waste disposal wells inject industrial hazardous waste. These wells are strictly regulated under the Resource Conservation and Recovery Act (RCRA) and the Safe Drinking Water Act (SDWA). These wells have stricter construction, permitting, operating, and monitoring requirements than for other Class I injection well categories. Approximately 15% of Class I wells in the U.S. are hazardous waste disposal wells. Most Class I hazardous waste wells are located at industrial facilities and dispose of waste generated onsite.

Non-Hazardous disposal wells comprise approximately 85% of the Class I inventory in the U.S. The disposal of non-hazardous industrial waste occurs at injection wells operating in 18 states. The majority of these wells are in Texas, California, Louisiana, Kansas, and Wyoming. They provide disposal for highly mineralized wastewater that is a product of industries such as petroleum refining, metal production, chemical production, pharmaceutical production, food production and municipal wastewater treatment. In Florida, Class I wells are used to dispose of municipal wastewater.

Class II Protection of Underground Sources of Drinking Water

Class II wells dispose of fluid produced in conjunction with oil and gas drilling, completion, and production operations. Extraction of oil and gas usually produces large amounts of brine and other fluid wastes. Often saltier than seawater, formation brines can contain toxic metals and sometimes Naturally Occurring Radioactive Materials (NORM). Deep underground injection of oil and gas brines in formations isolated from USDWs prevents soil and water contamination. All oil and gas producing states require the injection of oil and gas wastewater into the originating formation or other producing formation for Enhanced Recovery or into deep brine formations for disposal. Every Class II disposal well operates under a permit, while enhanced recovery wells may operate under an authorization or a permit. Permit length varies by UIC Program. Owners and operators of Class II wells must meet specific regulatory requirements concerning well construction, mechanical integrity and well operation to obtain a permit or authorization to inject.

Types of Class II Wells

Enhanced recovery wells inject brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and, in some limited applications, natural gas. The injected fluid thins or displaces small amounts of extractable oil and gas, which is then available for recovery. Enhanced recovery wells are the most numerous types of Class II wells, representing nearly 75% of the approximately 160,000 Class II wells in the U.S.

Disposal wells inject brines and other fluid wastes associated with the drilling, completion, and production of oil and natural gas or natural gas storage operations. As oil and natural gas are brought to the surface, they generally are mixed with wastewater. On a national average, approximately 10 barrels of wastewater are produced with every barrel of crude oil (GWPC 2013). The wastewater is segregated from the oil and gas and then injected into a deep formation which generally contains brine and is capable of receiving the injected fluid.

Disposal wells represent about 20% of Class II wells in the U.S. and have been used in oilfield related activities since the 1930s. Today, there are approximately 38,000 active Class II disposal wells used to dispose of oil and gas related wastes (USEPA 2019).

Hydrocarbon storage wells inject hydrocarbons, that are liquid at standard pressure and temperature, in underground formations (such as salt caverns) where they are stored, generally as part of the U.S. Strategic Petroleum Reserve. More than 300 liquid hydrocarbon storage wells are in operation in the U.S.

Construction of Class I and II Disposal Wells

As shown in the Figure B.1 and B.2, Class I and II disposal wells are designed and constructed to adequately confine injected fluids to the authorized injection zone and prevent the migration of fluids into USDWs. Injection wells are drilled and constructed with multiple steel casings cemented in place. Surface casing is typically cemented from below the protected groundwater up to the surface to prevent fluid movement into the groundwater or USDWs. Cement is also placed behind the long string (injection) casing at critical sections to confine injected fluids to the authorized zone of injection.

Typical Class I disposal wells have a minimum of two layers of concentric casing and cement, with all casing cemented to the surface. The tubing and packer design is based on well depth, disposal fluid characteristics, and injection rate. A packer is used to isolate the disposal zone from the annular space, preventing fluid migration out of the injection zone. An initial external mechanical integrity test is required to be performed to demonstrate mechanical integrity prior to commencement of injection operations. During construction, additional downhole tests are performed to ensure there is no vertical migration of fluid. Operational requirements also require permittees to continuously monitor the annulus pressure to detect leaks in the casing, tubing or packer, containment of the injection zone, and passing of an internal and external mechanical integrity test annually or once every five years depending on the state's regulatory requirements.

A typical Class II disposal well also has injection tubing set on a packer and through which the fluids are injected from the surface down and into the permitted geologic formations. A packer is commonly used to isolate the disposal zone from the space between the tubing and production casing above the packer. An initial external mechanical integrity test is required to be performed to demonstrate mechanical integrity prior to commencement of injection operations. Some states require continuous monitoring for mechanical integrity while other states require a five year mechanical integrity test.

Regulation of Class I and II Disposal Wells

The UIC program under the SDWA authorizes regulation of Class I and II disposal wells. Class I and II wells are regulated by either a state agency that has been granted primary enforcement authority over the program (primacy states) or by the USEPA, under direct implementation. Primacy programs are established under Sections 1422 and 1425 of the SDWA. Section 1422 requires primacy applicants to meet EPA's minimum requirements for UIC programs. Programs

authorized under this section, referred to as 1422 programs, may have primacy for Class I, II, III, IV, V, and VI wells. Section 1425 requires primacy applicants to demonstrate their standards are effective in preventing endangerment of USDWs. Section 1425 programs are not required to meet EPA's minimum requirements, provided applicants can show their standards protect USDWs. Section 1425 applies to Class II wells only.

These regulations address injection pressures, well testing, and in some states, pressure monitoring and reporting. Class I and II well operators in direct implementation states must meet regulatory requirements implemented and enforced directly by USEPA.

Regulators are responsible for reviewing disposal well permit applications, issuing permits, and overseeing existing disposal wells. The regulatory process requires a technical review to assure adequate protection of drinking water, USDWs, and an administrative review to define operational guidelines. The subsurface conditions at a proposed site are evaluated to make sure the formations will isolate the injected fluids to the permitted injection zone and out of USDWs. Through the permitting process, site-specific requirements are imposed to address any unusual circumstances. The regulations or the permits include limitations on factors such as the maximum allowable surface injection pressure and the maximum disposal volumes/rates as well as operational and reporting requirements.

Additionally, all Class I and Class II wells are required to perform an area of review (AOR) around each proposed injection well to ensure any wells within the AOR that penetrated into or through the proposed injection zone is properly isolated or properly plugged and abandoned. AORs can vary for state regulatory programs, but typically many Class II UIC programs use a ¼ mile AOR or allow for an AOR calculation using the Zone of Endangering Influence (ZEOI) equation. Class I wells can have a larger AOR radius as required by the Class I regulatory program.

Regulators evaluate well construction to make sure all components have both internal and external mechanical integrity. After UIC disposal wells are placed into service, periodic well testing and monitoring assures groundwater protection. Injection pressures and volumes are monitored as potential indicators of well performance. Effective monitoring is critically important for identifying well construction and performance problems. These practices vary among primacy programs and well classes.

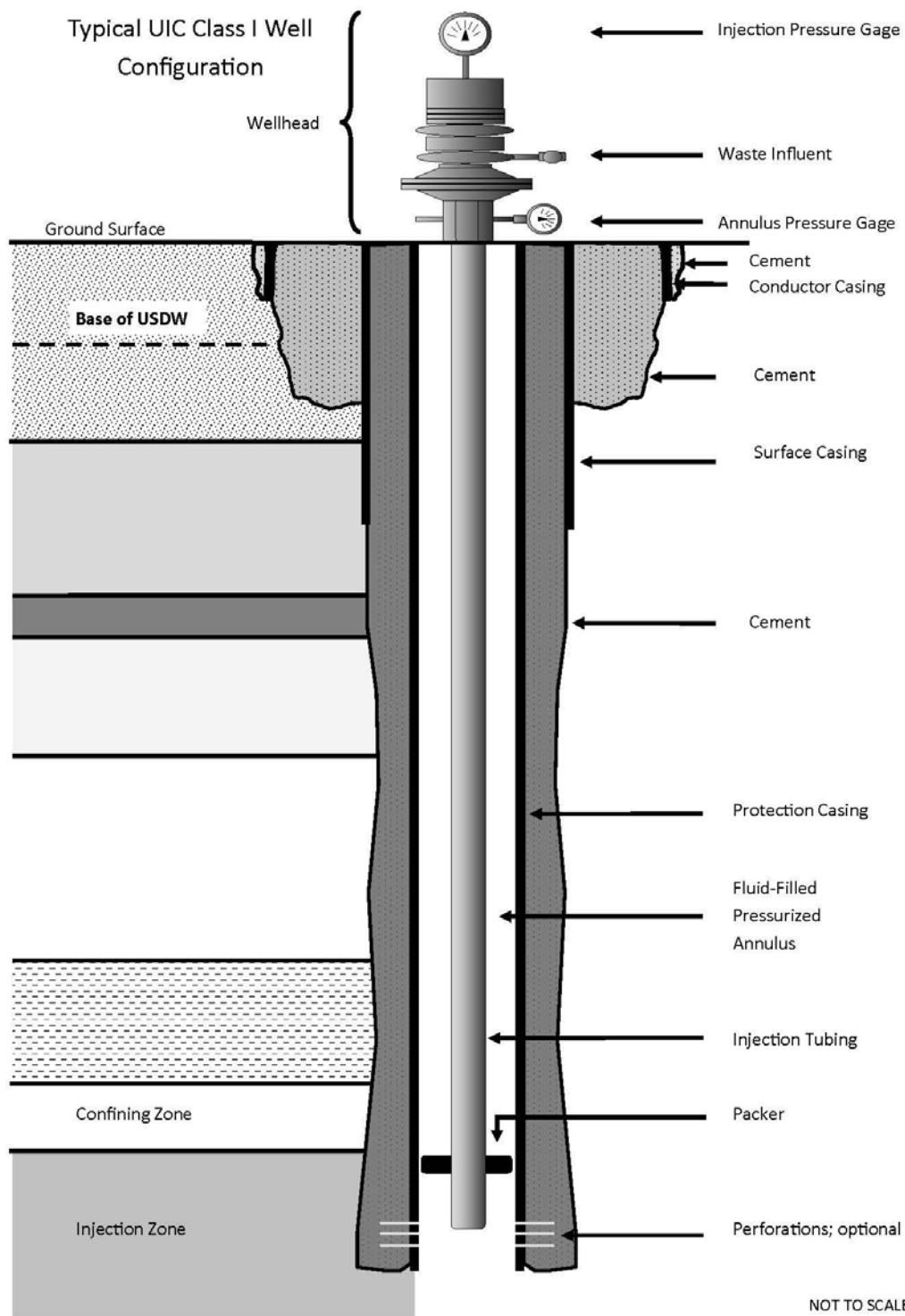


Figure B.1. Typical design of a Class I disposal well. Figure courtesy of KDHE.

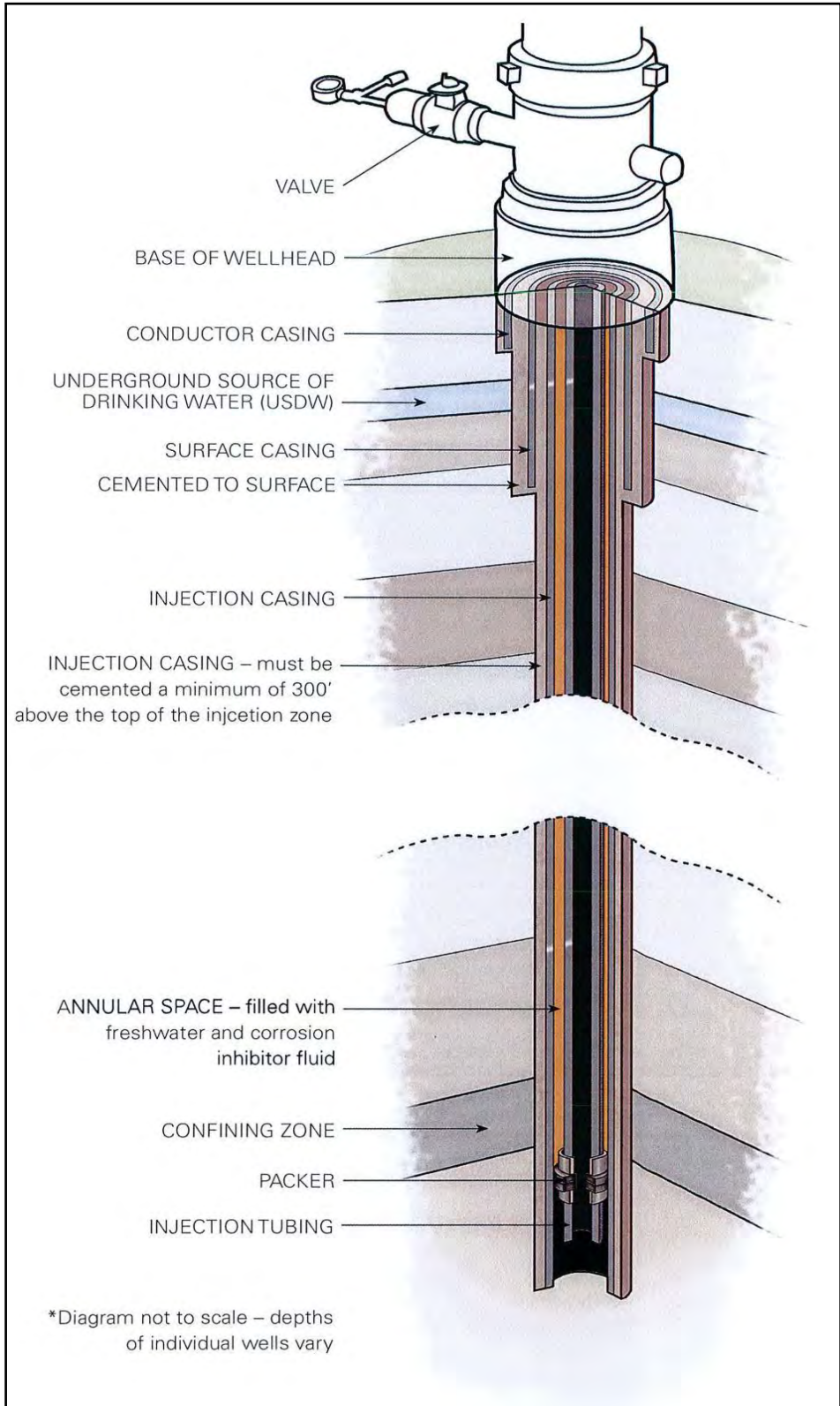


Figure B.2. Typical design of a Class II disposal well. Figure courtesy of ODNR.

Appendix C: Induced Seismicity Case Studies

Introduction

This appendix includes examples of how states and provinces have responded to instances of suspected induced seismicity through the use of local seismic networks. Each case presents a different situation, response, and observations that can be helpful for regulators, as well as technical details of seismology used. Multiple authors contributed to this section over multiple updates. Formats and vocabulary may not be uniform from one case study to the next. Please note that response needs are very site-specific and differences between the case studies indicates only that the conditions in each case may have required a unique response.

Contents and highlights:

1. Love County, Oklahoma: Benefits of USGS “Did you feel it?” reports, local network, disposal and earthquake correlation, and industry action;
2. Youngstown, Ohio: Early deployment of a local network, accurate locations, regulatory action;
3. Geysers, California: Permanent network around known induced seismicity, community outreach;
4. Decatur CCUS, Illinois: Compares two local arrays, surface and borehole, and differences in interpretations;
5. Greeley, Colorado: Local network, regulatory action; mitigation that may have resolved seismicity;
6. Pawnee, Oklahoma: Regulatory action to address a **M** 5.8 earthquake;
7. Harrison County, Ohio: Hydraulic fracturing caused felt seismicity;
8. Eagle Ford Shale Play, Texas: Hydraulic fracturing related seismicity in the Eagle Ford shale play;
9. Septimus, British Columbia: M 4.4 and aftershock earthquakes related to hydraulic fracturing the lower Montney formation in northeast B.C.;
10. Poland Township, Ohio: Communications related to hydraulic fracturing caused seismicity;
11. Tower Lake, British Columbia: Hydraulic fracturing induced seismicity near disposal induced seismicity; and
12. Alberta, Canada: Evidence of hydraulic fracturing influence on seismogenic faults.

Oklahoma Case Study — Love Disposal, Carter Co.

This case study follows incidence of earthquakes after initiation of disposal nearby. It illustrates the merits of the felt reports submitted to the USGS “Did you feel it?” system as a valuable tool in locating epicenters, in this instance more accurately than regional seismometer networks. Also, it is an example of voluntary action by an operator to mitigate the problem.

Background and Objectives: On September 17, 2013, earthquakes were detected in southern Oklahoma near Marietta. Residents reported felt earthquakes on the USGS “Did You Feel It” (DYFI) websites, many of which were not detected by the sparse OGS regional network. On September 23, two earthquakes of **M** 3.2 and **M** 3.4 occurred, which caused damage to chimneys, brick, and windows to homes near the epicenter. The damage associated with these small magnitude events suggested a shallow focal depth. Interestingly, the reports of damage were at least five miles north of the OGS epicenters and near a new commercial UIC well, Love County Disposal #1 (LCD-1), which had initiated water disposal into the Arbuckle September 3, two weeks prior to the felt event. It was clear that the nearest seismometers, located 40–100 miles north of the seismicity, would not be adequate for determining earthquake locations with the accuracy needed for correlating any causal relationship. A temporary network was deployed, and better locations were achieved, closely matching the ‘bull’s-eye’ of the DYFI reports.

Geology and Disposal: LCD-1 is a vertical well located in the Marietta Basin of southern Oklahoma, near a southwest plunging thrust fault that separates the Marietta and Ardmore Basins, just south of the Criner Uplift. Dips may be significant in this area. It was drilled to a depth of 6,342 feet, in the Arbuckle formation, several hundred feet above the basement, and completed over an interval of 4,366–6,273 feet.

LCD-1 began operations September 3. Disposal volumes rapidly increased to 5,000–7,000 bbl./day over two weeks (Figure C.1). Three days after the first detected earthquakes, volumes reached a peak of over 9,000 bbl./day. When the **M** 3.4 event occurred on September 23, the well operator voluntarily reduced volumes dramatically until the well was shut in three days later.

As injection volumes fell, the frequency and magnitude of earthquake events dropped rapidly. The local network operated during the last two days of injection. Earthquake locations clearly delineate a NESW zone of seismicity corresponding to the area of greatest MMI intensity. This orientation is consistent with the general stress field and active fault orientations observed in Oklahoma.

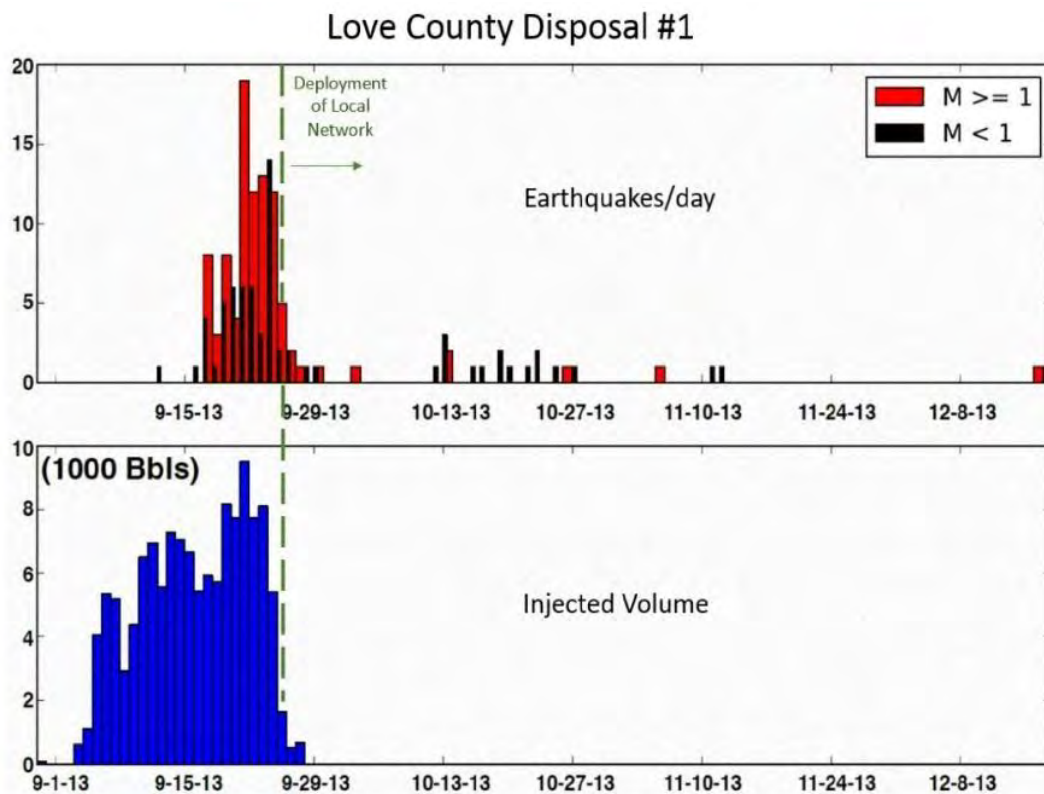


Figure C.1. Seismicity (top) recorded near and disposal histograms for the LDC-1. Source: Oklahoma Geological Survey.

Seismic Monitoring: Prior to the earthquake swarm, the regional network consisted of seismometers 40– 100 miles away, all located to the north of the seismicity. Event locations were calculated by OGS using the SEISAN software (Ottemoller et al. 2017). Uncertainty in locations was not only due to the sparse network described above but also to the use of a simple 1D velocity model to represent the complex geology of the Arbuckle Mountains, Ouachita Thrust Belt, and Washita Valley Fault system. The apparent shallow depths of the earthquakes could also cause inaccuracies due to waveform distortion and the complex shallow velocity structure. The magnitude of completeness (coda duration magnitude [M_c])—the lowest magnitude confidently located) was estimated to be no better than M_c 2.5.

To constrain the epicenter of the largest event (M 3.4) residents were interviewed, and damage observed to determine the Modified Mercalli Intensity (MMI). Figure C.2 is the MMI intensity map, which clearly shows that maximum MMI intensity (VII) was significantly north of the original epicenters. Moreover, strong intensities and damage levels suggest shallower focal depths than the estimated 6 km depth. Some improvement to locations was achieved using the more advanced HypoDD software (Waldhauser 2001) but significant scatter remained. Dozens of smaller earthquakes were found in the regional network data using cross correlation template matching techniques that improved the M_c closer to 1.0.

By September 25, a temporary local network of six continuous recording stations was deployed in the area closest to the strongest reported ground motion. These stations spaced three to five miles apart, were powered by solar panel and battery. Real-time data was transmitted to the OGS system from one station, while the others saved data on flash storage systems for manual download. The waveforms were processed manually by OGS analysts using SEISAN software (Ottemoller et al. 2017). The addition of the local network lowered the magnitude of completeness to nearly 0.5.

Results: Locations of the events seen by the regional network and the local network are indicated in Figure C.2, along with the MMI map after the **M** 3.4 event. Local network locations are tightly grouped and are near the center of shaking and the disposal well.

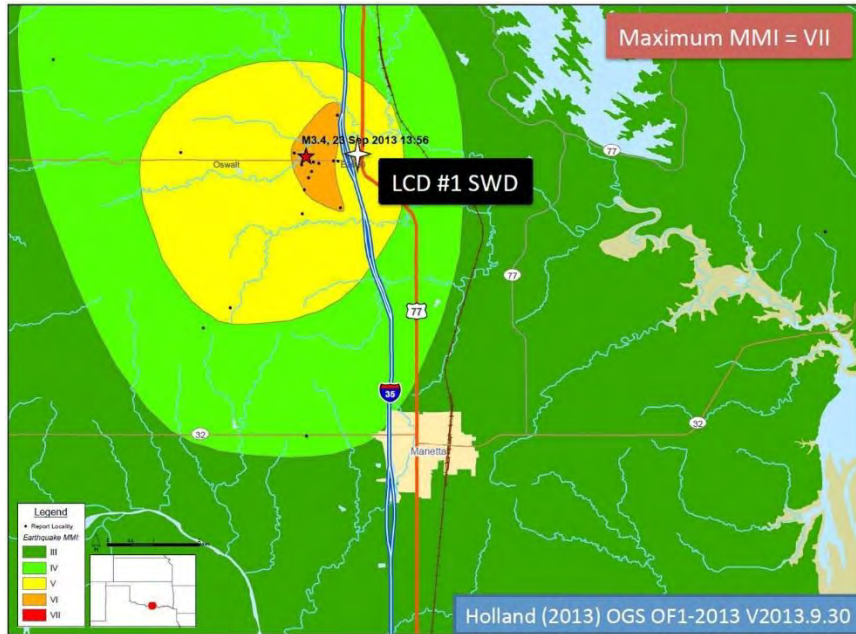


Figure C.2. Modified Mercalli Index map of seismicity around the **M** 3.4 event near Marietta, OK.

Discussion: The OCC has given the LCD operator approval to resume injection up to a maximum of 3,000 bbl./day and a pressure limit of 375 psi. To date the operator has chosen to leave the well shut in.

Conclusions: The successful deployment of the local seismometer network was necessary to understand the potential contribution of the LCD-1 well to the activation of nearby faults. The regional network locations had too much uncertainty to assess about cause and effect. Early DYFI reports accurately located the center of activity and were valuable in siting the temporary array.

Although the Love County swarm has similar characteristics to past swarms in the area, the temporal correlation of earthquakes relative to LCD-1 injection presents a reasonable case for induced seismicity. Spatially, events located using the regional networks were within five miles of the LCD-1 well. However, the distance between the LCD-1 well and the greatest impact caused by the two largest earthquakes was approximately one mile. This damage proximity, coupled with event locations recorded on the temporary network, make a very strong case for induced seismicity.

Ohio Case Study — Youngstown

This case study is an example of the integration of a state network with temporary networks and collaboration with academia. Early detection by the state network enabled deployment of a temporary array in time to detect the largest earthquakes, and thus to accurately determine their source locations, especially depth. This information helped the state take mitigating action and design further seismic monitoring, and to determine the presence and geometry of a previously unknown fault susceptible to reactivation.

Background and Objectives: Until recently, noticeable seismic activity in and around the Youngstown area had been relatively undocumented. Prior to the establishment of the ODNR Ohio Seismic Network (OhioSeis) in 1999, seismic monitoring in Ohio was sporadic. The OhioSeis network consisted of 29 one-component systems located across the state but concentrated in areas of known natural seismicity. The OhioSeis network currently consists of 19 three-component seismic stations distributed across Ohio. Before the establishment of OhioSeis, the Ohio Division of Geological Survey (ODGS) was unable to accurately detect any earthquakes below approximately **M** 3.0. The nearest OhioSeis station was located at Youngstown State University.

Geology and Disposal: The bedrock units underlying the Youngstown area are dipping gently to the southeast at about 50 feet per mile into the Appalachian Basin. The closest known mapped fault system is the Smith Township Fault, a NWSE-oriented fault, located in southwestern Mahoning County.

A number of geologists have identified the Mahoning River Valley as a geologic lineament that may be related to faulting in the area, but no evidence of the fault that resulted in the Youngstown earthquakes had been delineated at the time of the drilling and completion of the Northstar #1 well

(NS1). A 2D seismic reflection line reviewed after the NS1 was drilled identified a possible previously unknown fault zone in the Precambrian basement rock near the NS1.

The NS1 is located in an industrial district of northwestern Youngstown, Ohio. The well was drilled and completed as a stratigraphic test well in April 2010 to a depth of 9,192 feet, bottoming in the Precambrian basement rock. Following the evaluation of open-hole geophysical well logs, production casing was set and cemented in at a depth of 8,215 feet. The well was then completed as an open-hole injection well from the Knox Dolomite at 8,215 feet to the Precambrian at 9,192 feet. In July of 2010, a permit was issued to convert the NS1 to a Class II saltwater injection well. Injection operations commenced in late December of 2010.

Earthquakes were detected in the Youngstown area in March 2011. On December 1, 2011, at the request of the ODGS, Lamont Cooperative Seismographic Network (associated with Columbia University's Lamont Doherty Earth Observatory) deployed four, three-component portable seismic units around Youngstown to monitor seismicity at close distances. These portable units can accurately determine hypocenters of small earthquakes. The Lamont seismic monitoring network, along with the existing ODNR OhioSeis network, located earthquakes related to the NS1.

Seismic Monitoring: Since 2012, ODNR-DOGGRM and oil and gas operators have deployed seven three-component portable seismic units in and around two additional permitted injection wells within approximately 12 miles of NS1. ODNR-DOGGRM deployed three sets of digitizers and three-component sensors near the Northstar #4 injection well (NS4). The sensors are high frequency sensors with a range of 0.1 to 1,000 Hz, with a natural frequency of 2 Hz. The ODNR-DOGGRM stations are installed approximately three feet below the ground surface to reduce background noise.

One SWD well operator installed four portable seismic stations between July 2 and 4, 2013, in an urban setting east of Youngstown in Campbell, Ohio. Each of these seismic monitoring stations has a high frequency, 2 Hz, three-component sensor. Sensors were deployed at a depth of 60 feet below surface at each site in 4-inch diameter PVC-cased holes. A high-resolution data logger was installed to convert the analog data from the sensor to digital data. Channels were sampled at 200 Hz and backed up on a local compact flash drive. Communication was accomplished using cellular data modems. Power was provided by an 85-watt solar panel and two 100 amp-hour batteries, with charging controlled by a solar charge controller with a low voltage disconnect.

Data from the stations were run through manual triggering algorithms each night to detect earthquakes. Triggered earthquakes were broken down into three main types: earthquake, explosion, and noise. After triggering events were manually reviewed, earthquakes and explosions were picked, and noise deleted from the records. The data from stations were forwarded in real-time to ODNR-DOGGRM. The data from the three ODNR-DOGGRM stations were also displayed in real-time to a contracted data server.

Results: From March 2011 to July 2013, the area around Youngstown experienced numerous earthquakes, ranging from **M 2.1** to **M 3.9**, located along a previously unknown fault. Twelve of the earthquakes were detected on OhioSeis but could not be accurately located due to the sparse coverage of the seismic stations. With the addition of Lamont’s four portable seismic units, three earthquakes in late December 2011 and early January 2012 were more accurately located. The Lamont stations were installed within 2 to 6.5 km of the

seismic source area. Seismicity appeared to migrate gradually from the eastern end of the fault area close to the NS1 towards the west, away from the disposal well. Earthquakes were located in the Precambrian basement from depths ranging from 3.5 to 4 km below the surface and 4 km from the injection zone. Seismic activity was believed to be stimulated by increased pore pressure along a previously unknown fault, which is striking 265° ENE-WSW and dipping steeply to the north. Multiple earthquakes were relocated by Lamont to within 1 km of the disposal zone. Six earthquakes were felt locally. Figure C.3 shows the location of the NS1 and locations of some of the earthquakes.

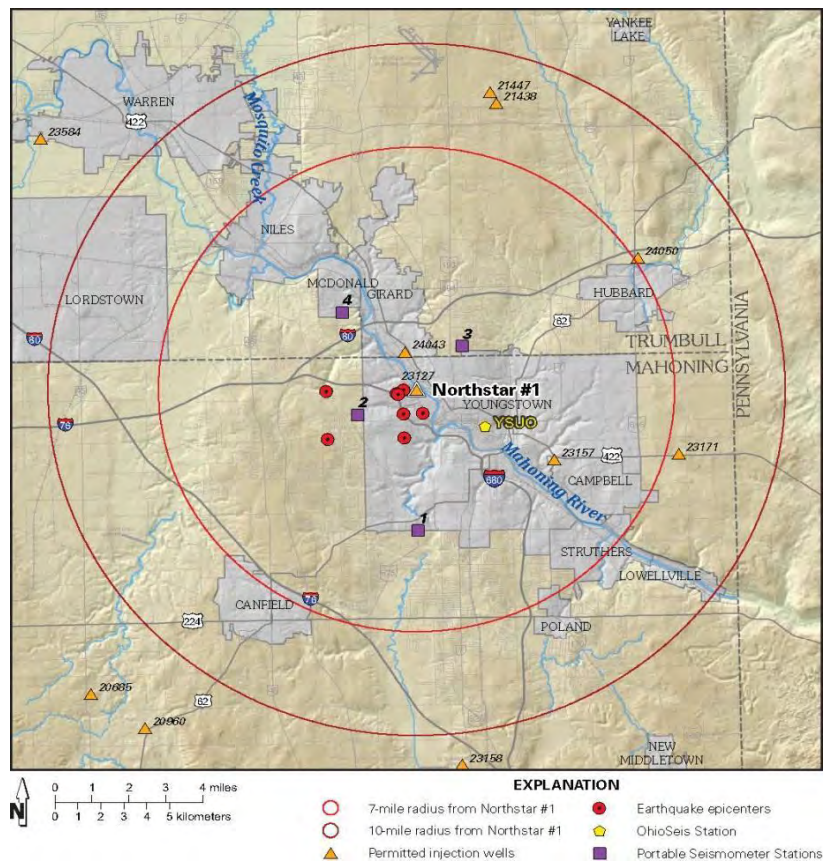


Figure C.3. Map of the Youngstown, Ohio, area showing the locations of permitted injection wells, earthquakes, and seismometers. Source: Tomastik, 2012.

The fault plane solution (focal mechanism), calculated by Dr. Won-Young Kim at Lamont-Doherty Earth Observatory for the December 2011 earthquake, indicates that the sense of movement of the fault was strike-slip (horizontal). The analyzed seismic data illustrates nodal planes striking at 265°

and 171° from north. These calculations agree well with those done independently by Dr. Robert Herrmann at St. Louis University based on data from regional seismic stations. Earthquakes relative to basement and the NS1 are shown in Figure C.4.

Shortly after the seismic monitoring network was installed, an **M** 1.3 earthquake was detected near NS1 on July 5, 2013. Figure C.4 shows the location of the July earthquake as detected by the operator's seismic monitoring network, in map view (upper left) and cross-section views.

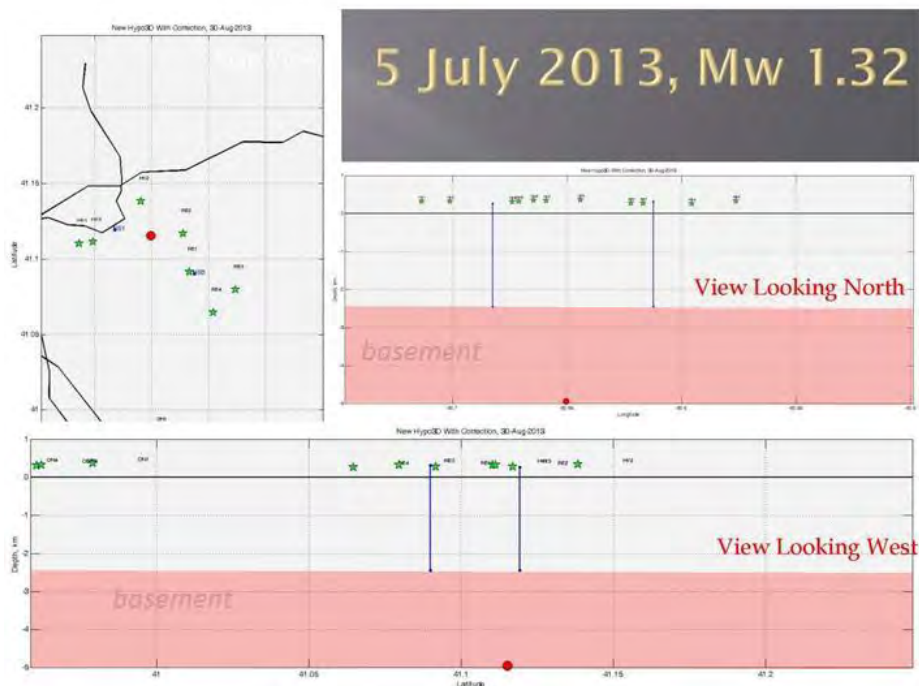


Figure C.4. The seismic monitoring network detection of a July 2013 earthquake near the NS1 well.

California Case Study — The Geysers Geothermal Field

This case study focuses on seismicity known to be induced by operations, and how a permanent seismic monitoring network enables the operations to continue while allowing mitigation and outreach to the local community. The study is derived from the geothermal industry, whose long history of managing induced seismicity offers useful lessons for UIC regulators.

Background and Objectives: Induced seismicity has been observed at The Geysers geothermal field since the mid-1960s, with the largest event an **M** 4.6 in the mid-1980s (Majer et al. 2007), although **M** 4 events have more recently begun occurring several times a year (Figure C.5). The events occur in the main injection zone, with depths between 1 and 6 km.

The area is lightly populated, with several communities of a few thousand people within a few miles' radius of the field and some inhabitants within less than a mile. The seismicity has grown as the amount of water injection has grown. Residents experience yearly events at rates of two to three **M** 4s, 30 to 40 **M** 3s, and 300 to 400 **M** 2s. Depending on the location, a few residents claim

to feel event magnitudes as small as **M** 1.5, but this would be highly unusual. Some local opposition of the geothermal development exists due to induced seismicity. Some minor damage has occurred from the earthquakes, as well as public annoyances, but no lawsuits have been filed.

The Geysers Geothermal Field is the largest geothermal field (990 Mw) in the world. It was started in the early 1960s by Magma Power Inc., followed by Unocal Geothermal, and is currently operated by Calpine Inc., Northern California Power Authority (NCPA), and few smaller operators. It produces steam from a deep (up to 10,000 feet) under pressurized steam reservoir at 240–260°C. Extensive water injection has increased the amount of produced steam. The water is derived from power plant cooling tower condensate, wastewater from nearby cities, and some local collected rainwater runoff.

Seismic monitoring at The Geysers was initiated in the late 1960s, a few years before injection began. Objectives are to detect low magnitudes ($>\sim\mathbf{M}$ 0.0) and locate events with an accuracy of \pm 400 m, sufficient to interpret geologic structure and water distribution (in time and space) as well as to help inform and guide injection practices for optimizing heat extraction. Analysis of seismic activity has aided mitigation activities designed to reduce the impact of induced seismicity on the community.

Geology, Disposal, and Velocity Model: The local geological structure has been interpreted from numerous drilling data, well logs, cuttings data and extensive geologic modeling performed by Unocal and Calpine. The system is bounded by two faults, the Mercuryville Fault to the southwest and the Collayami Fault to the northeast (EPRI 2014). The field itself has extensive small faults, dominated by the Big Sulfur Creek fault in the middle of the field. Depending on location within The Geysers steam field, wells may penetrate varying sequences of greenstone, serpentinite, chert (mélange), or greywacke at depths before entering the productive reservoir. Fractured greywacke sandstone is the characteristic rock in the producing reservoir throughout the geothermal field. The seismic activity stops at 4 km depth, corresponding to the start of the high temperature zone ($> 400^{\circ}\text{C}$).

Monthly injection data consisting of pressure recordings and volumes are gathered by the operator and sent to the state of California Geologic Energy Management Division (CalGEM). Most of these data can be accessed by the public.

Figure C.5 summarizes the rates of earthquakes detected versus the injection and production history of the wells. Injection volumes average about 25 million gallons per day (mgd) (\sim 600,000 Bbls/day)—more during the rainy season, less in the dry season. Before 1960, little or no seismicity was detected in the area of the current geothermal field. Earthquake activity increased soon after injection started in the late 1960s in an effort to decrease the rate of pressure decline of the reservoir and maintain the steam output.

Currently the operators move the injection points to optimize steam withdrawal as well as minimize the effect of induced seismicity on the nearby population.

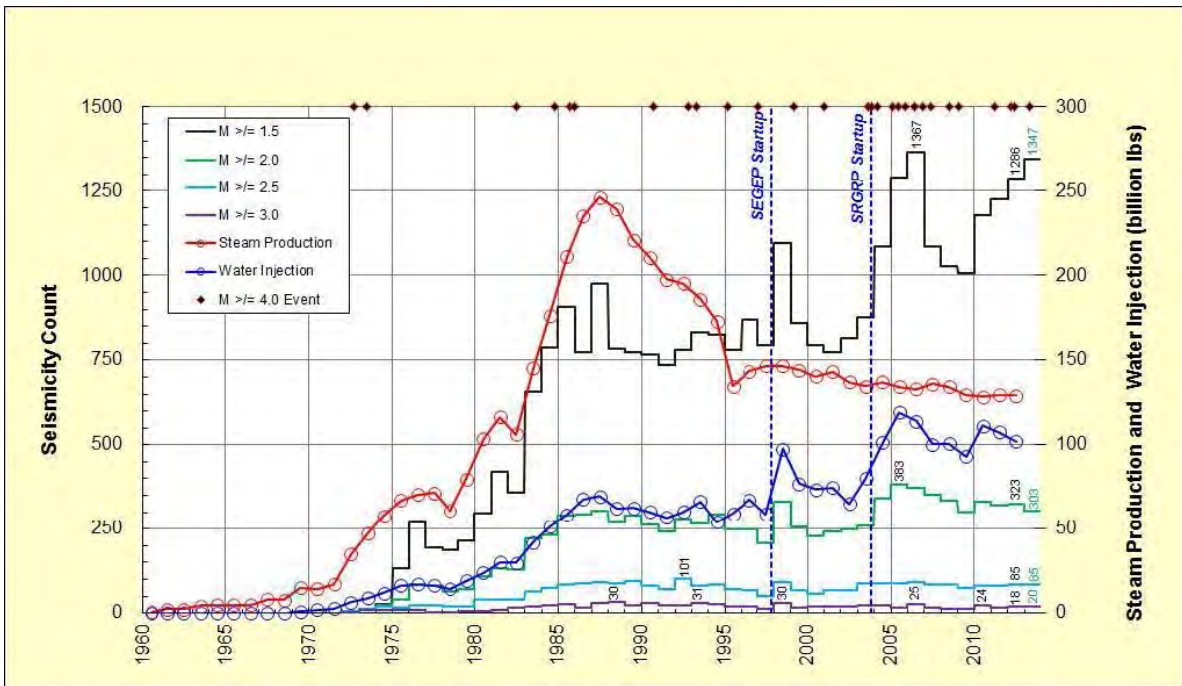


Figure C.5. History of seismicity at The Geysers for events of different sizes versus steam production and water injection volumes. Vertical dotted lines show the start of significant water injections (7 mgd in 1997 and 11 mgd in 2004) Source: from Craig Hartline, Calpine Inc.

The velocity structure of the field used to estimate event locations was derived from numerous inversion studies and tomographic velocity studies. However, the high temperature wells limit velocity logs. Velocity models were developed with incoming seismic event data and refined as more events accumulated.

Seismic Monitoring: Lawrence Berkeley National Laboratory (LBNL), funded by the U.S. Department of Energy DOE Geothermal Technology Office, installed, operates, and maintains The Geysers seismic array with support from Calpine. Currently, the MEQ array includes 32 surface stations (also five shallow borehole stations from 100 to 500 feet deep) with data telemetered in real time to a central site that detects events and reports them to LBNL for real-time location and magnitude determination. The data are then publicly displayed in plane and 3D views on the internet. Two strong-motion accelerometers are also in the area to detect ground motion.

Figure C.6 shows the stations (blue radio symbols) and injection wells (arrows).

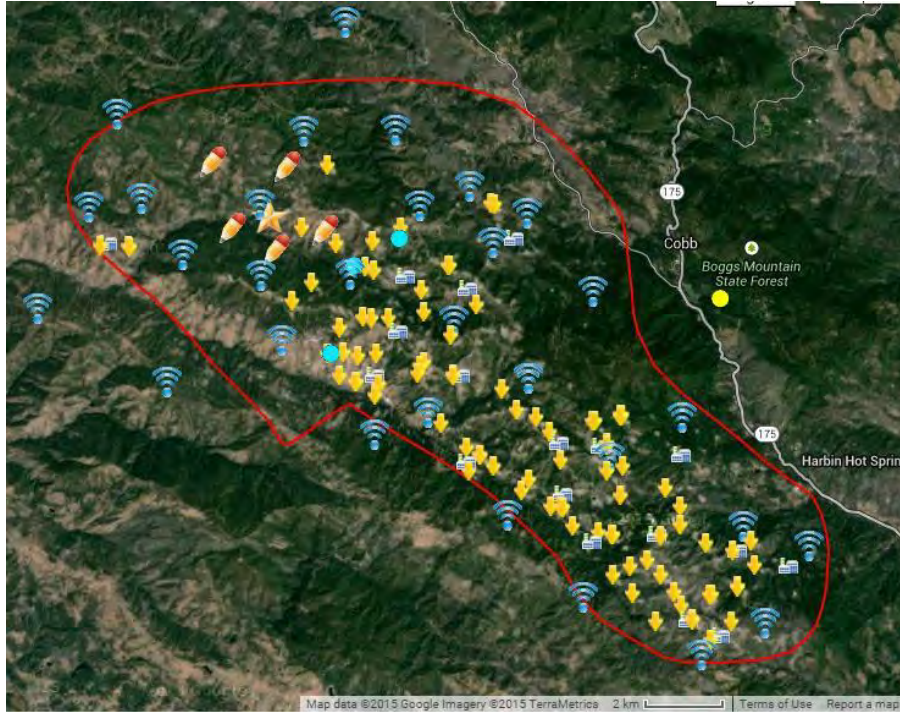


Figure C.6. Stations (blue radio symbols) and injection wells (yellow arrows) at The Geysers. The red line demarcates the production zone.

Each station has a three-component 4.5 Hz geophone, a digitizer (24-bit, 500 samples/sec) and two way spread spectrum radios. Spacing of the stations averages 1 to 2 km.

Processing is mainly automated for waveform picking, phase windowing, spectral analysis, location, and magnitude determination. The volume of data (40,000 to 50,000 events per year) prohibits manual picking, except for largest events ($M \geq 3.5$ events) and for selected injection experiments (often includes moment tensor analysis). Ultimately, the waveforms and processing results are sent to the Northern California Earthquake Data Center (NCEDC) operated by the USGS and the Berkeley Seismographic station and are available to the public. Real time data are available at <https://wellbore.lbl.gov/egs/geysers.html>

Results: Earthquakes occur throughout the entire production zone. In the early days of production before significant injection began, local monitoring did detect some seismicity. More events were detected soon after injection started, near the injection points in the subsurface. Clusters of seismicity were located, and their growth and migration were measured around the well and away (down as well as around) from it. As the field and injection points grew, the seismicity grew (Figure C.7). Magnitudes down to M 0.0 have been detected and located to an accuracy of +/- 500 m. Since 2000, over 500,000 events have been detected and located in The Geysers steam field.

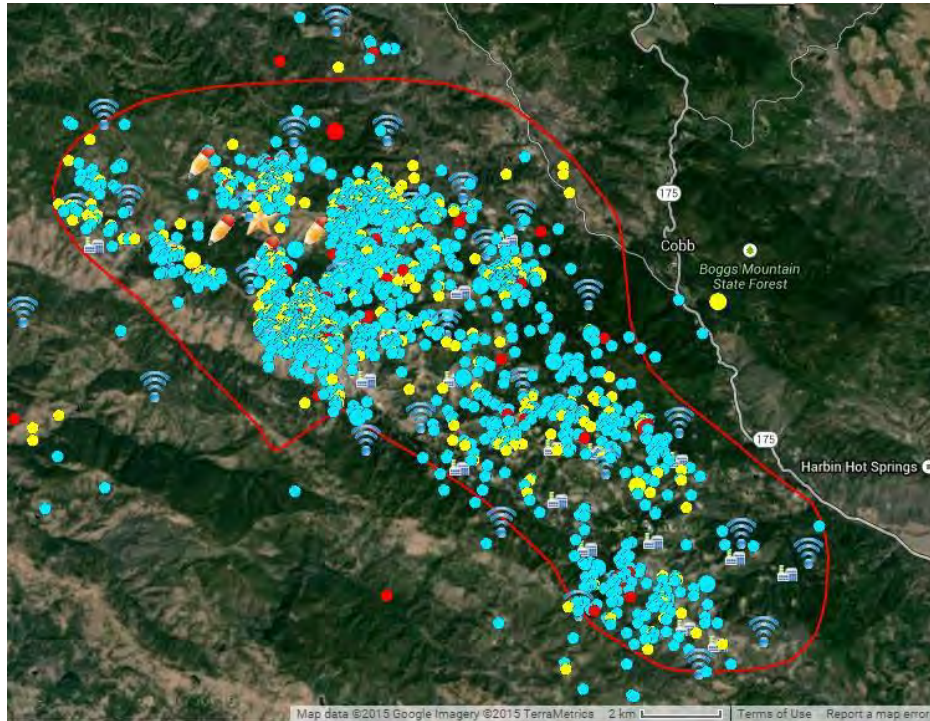


Figure C.7. A typical month of events (4,000 $M > 0$) at The Geysers steam field.

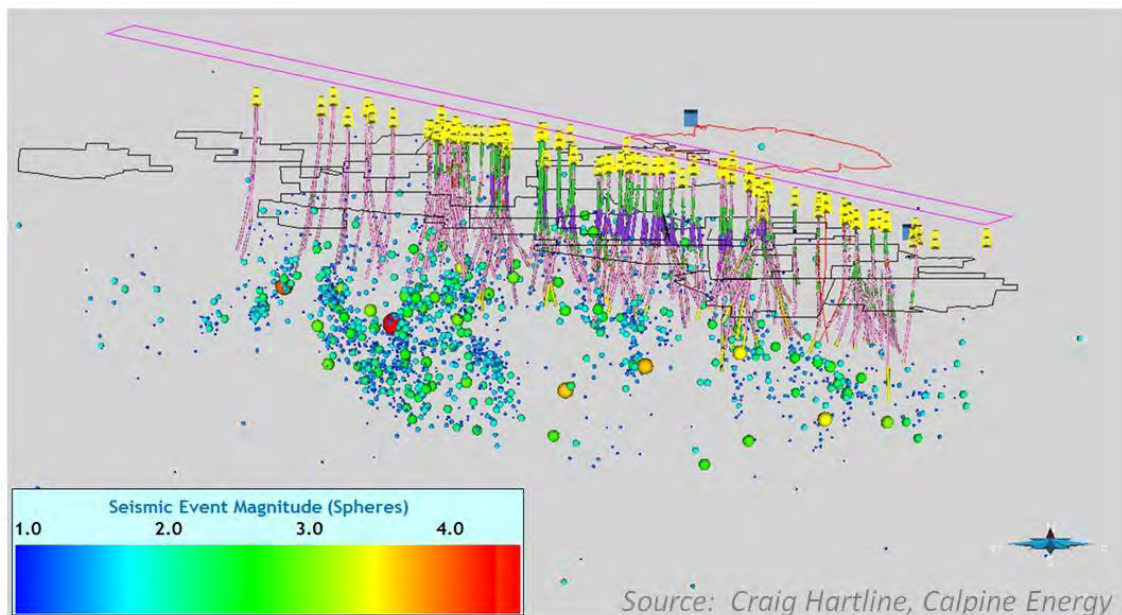


Figure C.8. Oblique cross-section view of The Geysers steam field with well trajectories and earthquakes, sized and colored by magnitude. Source: Calpine Energy.

Discussion: The Geysers seismic network has become a critical resource to the operators in order to optimize and understand the steam reservoir production, as well as for mitigating the impact of induced seismicity on nearby communities. Over the years, the operators, through proactive

communication and joint meetings, have formed an alliance with the community that is beneficial to all stakeholders.

Ideally, one could accomplish the same data quality and quantity with half the stations, by replacing the surface stations with 2 Hz shallow (300 feet) borehole stations. This would increase sensitivity and bandwidth. Mitigation efforts and data handling and processing have evolved over the course of the project, with all seismometers now being three-component broadband sensors.

All seismicity and injection data (seismicity in real time) are available to the public at the site mentioned above. Bi-annual meetings with all the stakeholders are open to the public and press. A hotline is also available to the public to voice any issues with the operators.

Many lessons can be learned from The Geysers experience. The information gained from studying induced seismicity is a valuable tool. This case illustrates that the more information one has on the causes of the seismicity, the better one can utilize that information as a tool to help mitigate the risk. Another lesson learned is that honest outreach and communication to the public regarding both known and unknown data and interpretations is critical to not only gain confidence from and acceptance by the public, but also for accurate risk assessment by the operator.

Illinois Case Study — Decatur Carbon Capture and Storage Project

This case study compares two separate local networks looking at the same earthquakes and illustrates some pitfalls and significant differences in locations and interpretations arising from different sensor geometries and velocity models. This study underscores the need for caution when relying on seismic data.

Background and Objectives: The Illinois Basin-Decatur Project (IBDP) is located in Decatur, Illinois, at an Archer Daniels Midland (ADM) facility. Carbon dioxide produced from agricultural products and biofuel production is stored deep underground through UIC Class VI disposal wells. This case study documents two parallel seismic monitoring efforts—one operated by ADM, with deep vertical arrays of geophones in boreholes near the injection point—and another operated by the USGS, a surface array nearby using surface and shallow borehole sensors. This study allows a comparison between a typical hydraulic fracturing seismic monitoring (borehole) system and a surface seismic monitoring system such as would be used to monitor a Class II disposal well, in an area without site-specific data to produce a detailed velocity model. The dataset comparison showed large differences in horizontal and vertical hypocenter locations. Surface sensor event locations were judged inferior due to the limited site information available, difficulties in analyzing waveforms produced by small microseismic events many kilometers away, and erroneous data created by noise typical of industrial areas.

Geology, Disposal, and Velocity Model: The CO₂ reservoir is thick, high porosity sandstone with injection occurring at a depth of 2.1 km (7,025-7,050 feet). Below this unit is less porous sandstone 30 m thick, which rests on the Precambrian crystalline basement. The site has been characterized

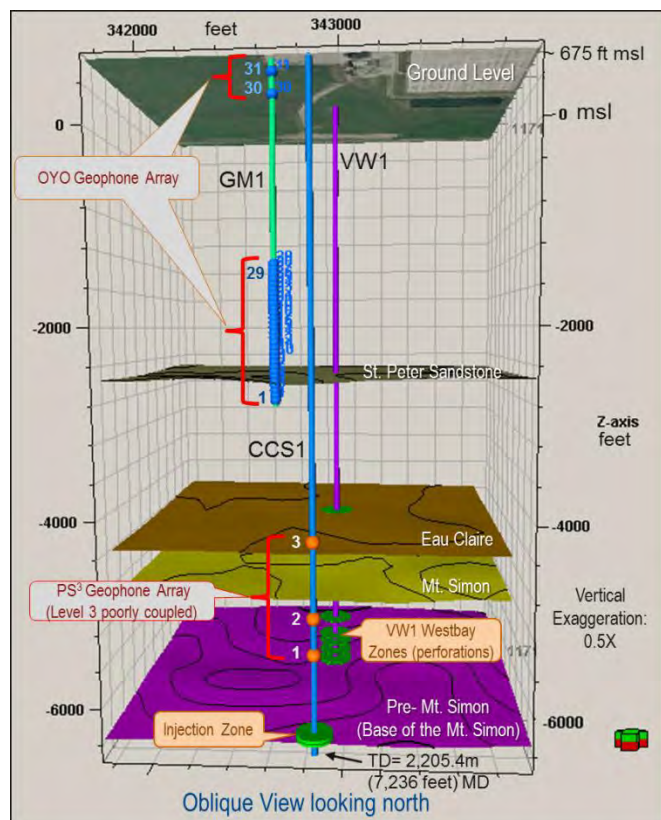
with surface seismic profiles and multiple deep boreholes with extensive geophysical testing. These data were used to develop detailed geologic and velocity models for the site.

Detailed geology and properties are provided by multiple boreholes penetrating the crystalline basement that have been geophysically logged, including sonic logs. The site has had 2D seismic lines and multiple 3D seismic surveys performed to characterize it. Near the surface is 115 feet of glacially derived material with varying sonic velocities.

Velocity data was derived from sonic logs in wells onsite and from seismic surveys to produce a velocity model. This model was checked with detected earthquakes from drilling a nearby borehole and perforation shots in that hole.

Seismic Monitoring:

Figure C.9. Map of well locations (below) and diagram (right) for vertical arrays showing configuration of borehole and monitoring equipment for the IBDP site in relation to stratigraphy: the WellWatcher PS3 geophone array in the CCUS1 well; the OYO, three-component, 31-level array in the GM1 well; and the Westbay system in the VW1 well for sampling and pressures readings at 11 levels. Source: from Will et al. 2014.



Vertical arrays: In 2010, two deep vertical arrays of geophones were installed 18 months prior to injection, which allowed for calibration as a nearby borehole was drilled and perforation shots were made. These vertical arrays consist of a four-component system within the injection borehole and a three-component system in another seismic monitoring well 200 feet away, with geophones closer to the surface providing some offset. Seismic monitoring started in 2010 and continues today in the post injection phase. The purpose of these instruments was to accurately locate

events in the proximity of the disposal well and to determine if seismicity was related to the very low injection pressure used to inject fluids into the high permeability formation.

The injection well (CCUS1 in Figure C.10) has a system consisting of 15 Hz geophones in a tetrahedral configuration, with four-component geophones at depths of 5,587 feet, and 6,137 feet. Because injection is also occurring in this borehole, geophones have picked up erroneous events associated with vibration within the tubing. The seismometer data is fed into recording system and put through a manual process to remove all the erroneous events. The second vertical array's geophones are much shallower, with 31 three- component 10 Hz geophones in an orthogonal configuration. The majority of these are between the depths of 2,062 and 3,460 feet, but two are at shallower depths of 152 feet and 372 feet, respectively. Calculated positions of several events were used to first orient these geophones relative to true north and then shots were used to orient the systems more accurately. All events were then realigned to true azimuths (NSEW).



Figure C.10. Map of USGS surface seismograph stations. CCUS1 is the injection borehole; the three “borehole” installations shown are 500 feet deep. Source: Hickman et al. 2014.

Surface array: Nearly two years into the injection process, the USGS network started seismic monitoring with nine surface and three shallow 500-foot-deep borehole installations. Later a fourth shallow borehole system was installed.

The surface installation consists of nine stations equipped with both a three-component broadband seismometer and a three-component force-balance accelerometer. The three borehole stations have the same accelerometer at the surface but have three-component, high-sensitivity geophones

in the boreholes. The aperture of this network is about three miles centered on the injection well (Kaven et al. 2014).

The surface seismic monitoring used a 1D velocity model developed from the borehole information supplied for the site permit and also P-wave logs from one of the 500-foot-deep boreholes. For event location, a constant ratio of P/S-wave velocities of 1.83 was used. The surface instrument analysis used Hypoinverse and Double Difference methods.

Results: Over the past five years and during the three years of injection, the IBDP network has recorded an average of four locatable events per day during injection. The network detects locatable events in the magnitude range from a little below negative **M** 2.0 to a few events a little above **M** 1.0. Ninety-four percent of the magnitudes fall below **M** 0.0. Most have occurred in clusters along what are presumed to be preexisting undetected planes of weakness that are oriented in the SWNE direction. Not all clusters followed an orderly progression in time with distance from the injection well as injection progressed. Some clusters—oriented closer to the critical stress conditions associated with the high horizontal *in-situ* stress—reacted sooner. The surface array located the events in the lower sandstones and into the upper part of the crystalline basement.

A comparison of the locatable events from the surface to subsurface arrays shows only about a six percent match in events over a four-month period. Comparison of locations nine months after surface installation showed a mismatch between the two systems, with the surface-defined event locations as great as two miles horizontally farther away and 1.3 miles deeper for small magnitude events near **M** 0.1. Events near **M** 1.0 had mismatches of about 0.6 miles in both horizontal and vertical directions. Analysis of data from the surface instruments placed events on a mile long NWSE linear feature, while the subsurface array plotted events in a tight cluster slightly beyond this feature. However, improvement of a velocity model for the surface instrument analysis has events approaching the subsurface array locations, with the linear trend collapsing to a cluster.

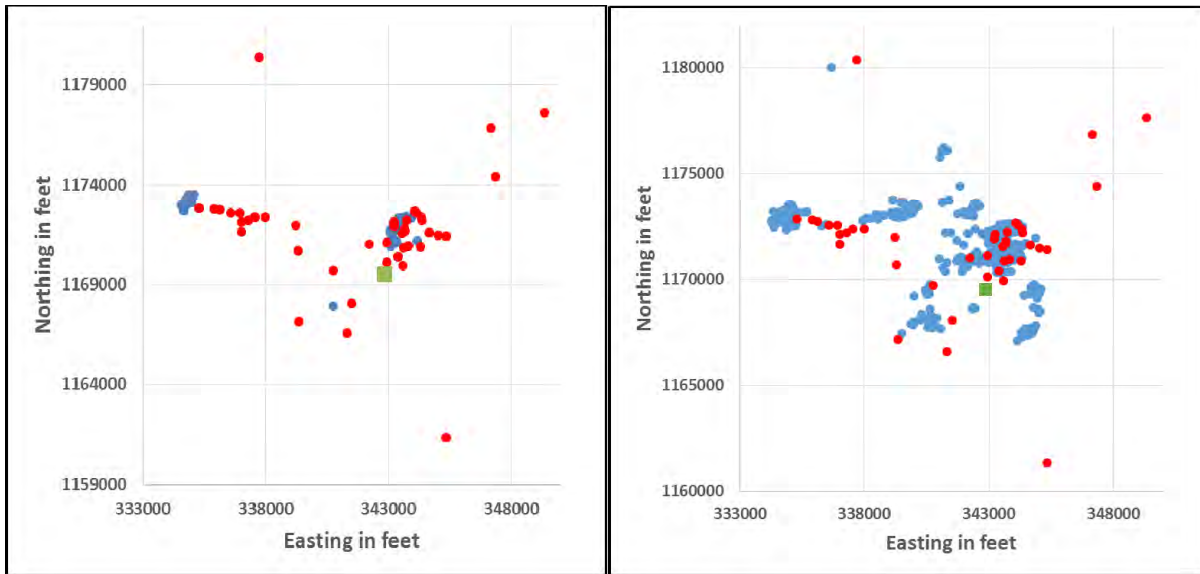


Figure C.11a. Comparison of the same four months of events located by the subsurface array (blue) to the surface array (red). Green is injection well and grid spacing is 5,000 feet.

Figure C.11b. Same time period as C14.a, but showing all 567 subsurface array located events (blue) to the 41-surface array located events (red). Green is injection well and grid spacing is 5,000 feet.

Discussion: After further refinements and analysis, the linear feature seen in early interpretations from surface instruments show that the linear feature is not present. Early interpretations could have been that a one-mile-long fault existed in this area.

This case study shows what large variations in locations can occur between surface and borehole data using reasonable velocity models. Areas with thick surface deposits that are extremely variable are a contributing factor for surface installations. Moreover, working with waveforms collected by surface seismic stations in a noisy industrial area, with low magnitude events occurring at 1.3 miles away or more, is challenging.

From a regulatory perspective, it is clear that caution is required before making decisions based on locations of microseismic events of roughly $M \leq 0.5$, given their distance from the injection well and alignment, and the availability of information to develop a velocity model to accurately locate events.

Colorado Case Study — Greeley

This case study is an example, like the Ohio one, of a regional network detecting events, and a temporary local network locating more events with better accuracy. It illustrates the use of advanced seismological methods to improve locations of prior events, and the use of a ‘Traffic Light’ system to help regulators with mitigation action. Finally, it is an example of where plugging back a disposal well seems to have been beneficial and allowed disposal to resume safely.

Background and Objectives: On May 31, 2014 at 9:35 PM, an **M 3.2** event was recorded by the USGS with an epicenter located six miles northeast of Greeley, Colorado in the proximity of the Class II UIC well NGL C4A (Figure C.12). The C4A injection well is located in the SWSE quarter-quarter of Section 26, Township 6 North, Range 65 West, in Weld County, Colorado. Though there is little historical earthquake activity in the region, there are well documented induced events related to the Rocky Mountain Arsenal injection well that occurred near Denver in the 1960s.

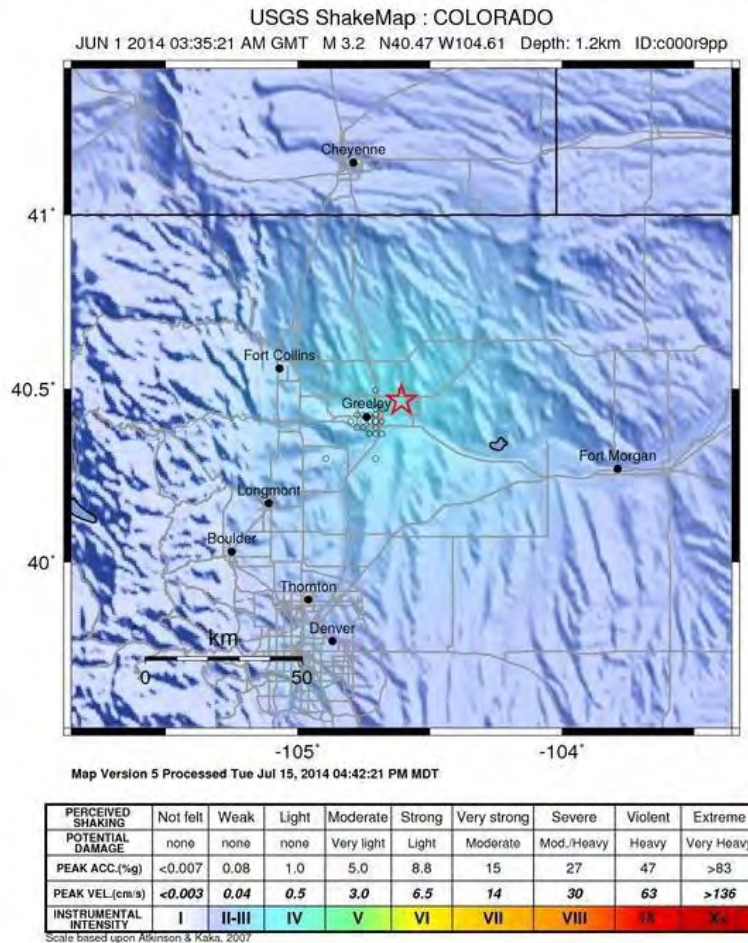


Figure C.12. Shake map of the **M 3.2** earthquake near Greeley, CO, May 31, 2014. Source: National Earthquake Information Center, USGS.

The region has a limited record of seismicity and is susceptible to a modest PGA of ~ 0.1 g for a fifty-year interval per the USGS National Earthquake Hazard Map. There is active oil and gas production and there are several Class II disposal wells in the region. And notably, this area is within the populated Denver–Ft. Collins metro corridor.

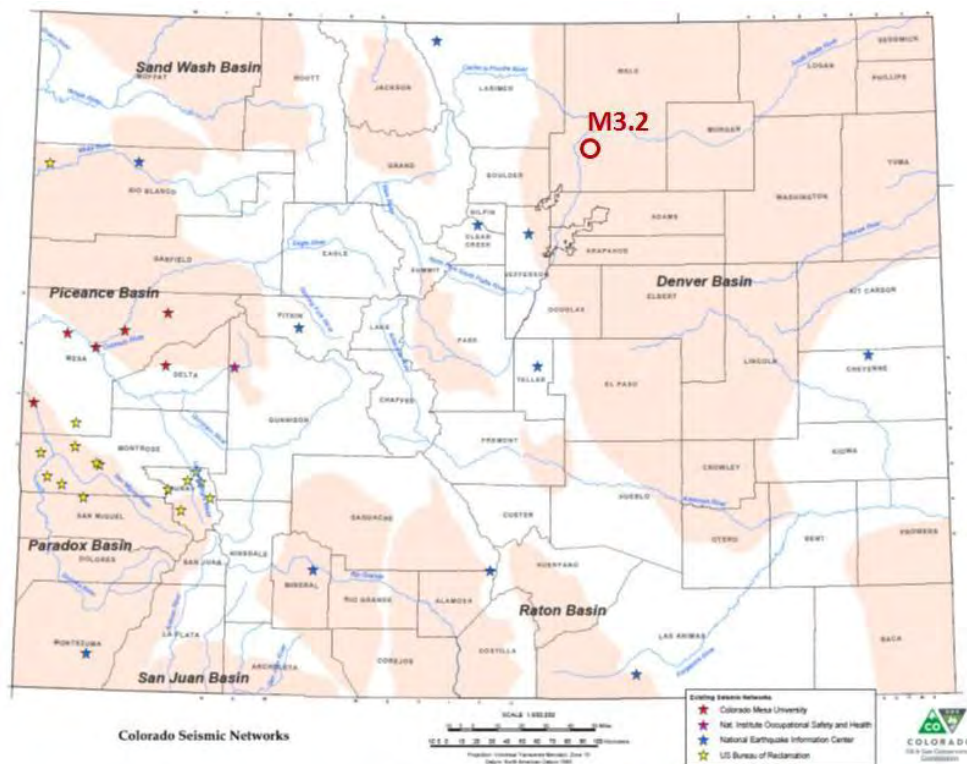


Figure C.13. Seismic stations in Colorado and the location of the **M** 3.2 earthquake of May 31, 2014. Source: Colorado Oil and Gas Conservation Commission (COGCC).

Colorado has an existing regional seismic network containing 11 stationary seismometers placed across the state (Figure C.13). The closest instrument at the time of the initial May 2014 event was the USGS ISCO station, located in Golden, Colorado, approximately 70 miles from the recorded epicenter. The initial event was detected by the regional network and reported by USGS. Subsequent seismic monitoring following the Greeley event was initiated by a geophysical research team at the University of Colorado, which deployed a set of portable short period seismometers in early June 2014 (Sheehan et al. 2014).

Geology and Disposal: The geologic setting is in the Denver-Julesburg Basin near the Greeley Arch, which separates the Denver Basin from the Cheyenne Basin. The disposal zone was in the Permian Lyons through Pennsylvanian Fountain Formations. The Fountain Formation sits on top of crystalline basement at a vertical depth of approximately 11,000 feet; zones of injection were initially less than 500 feet above the basement.

The published seismic data shows that the region has a variety of faulting styles from the deep reverse (wrench) faults, normal faulting, growth and listric faults. Generally, the faulting is a complex network of antithetic-synthetic faults originating from the basement. The faulting styles can be seen throughout the Upper Cretaceous section and into crystalline basement.

The C4A well was drilled to a depth of 10,818 feet. Disposal is through a slotted pipe liner with external casing packers, initially from a depth of 9,056 feet to total depth. Disposal data is gathered

by the operator regarding Natural Gas Liquids (NGL) and submitted to the COGCC as monthly injection volumes and maximum injection pressure. Injection began in April 2013 with higher rates of injection (>10,000 bpd) beginning in August 2013.

The USGS first reported earthquakes on May 31, 2014 with a second **M** 2.6 event on June 23, 2014, thirteen months after initial disposal. University of Colorado deployed portable seismometers in early June 2014. The C4A well was shut in for evaluation on June 23, 2014. The C4A well data, drilling logs, and well files were reviewed. The review of drilling logs indicated several lost circulation zones in the lower several hundred feet of the well. The operator conducted a spinner survey to characterize flow in the well with most of the well's flow in the bottom few hundred feet. As a result, the operator plugged back the well approximately 458 feet to 10,360 feet. The spinner survey was re-run. The results were an even injection profile throughout the well. Re-injection began at 5,000 bpd on July 19, 2014, with the injection increasing to 7,500 bpd in August 2014 and again in October 2014 to 9,500 bpd. These increased injection volumes were allowed with review of the seismic monitoring data, with little seismicity detected since resumption of disposal.

Seismic Monitoring: In addition to the regional seismometers already in place, a local seismic monitoring network was deployed at the location of the May event epicenter. The local seismic monitoring network consisted of portable short period seismometers and data recorders, which were on loan to the University of Colorado from the PASSCAL–IRIS Consortium.

By using a matched filter study, the University of Colorado retrospectively searched for waveforms at the ISCO station matching the **M** 3.2 event; that analysis suggests events associated with injection activity may have begun in November 2013.

Results: Event clusters located by the post-earthquake local network were observed to surround the NGL C4A injection well (Figure C.14) (Yeck et al. 2014).

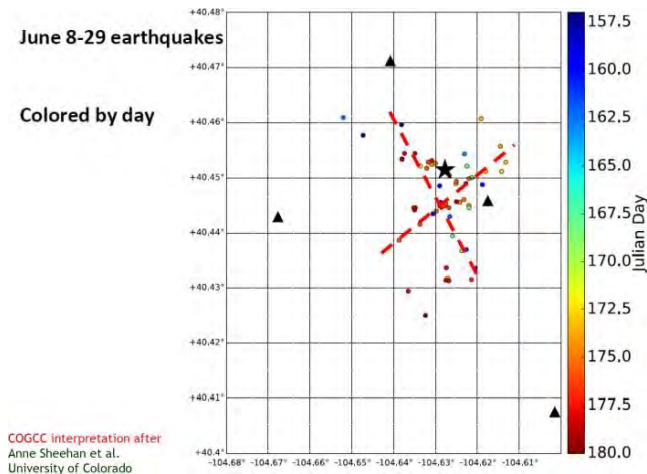


Figure C.14. Map view of temporary seismometer array (black triangles), the C4A SWD well, and events. Source: Colorado Oil and Gas Conservation Commission interpretation, after Anne Sheehan et al. 2014.

Discussion: The use of existing permanent and portable seismometers deployed around the C4A injection well provided the basis of seismic monitoring. The risk management plan AXPC/Industry induced seismicity Traffic Light scheme (NRC 2012) was implemented to monitor seismic activity. A base level of activity for magnitude and location was defined as a green light level. In this case, **M** 2.5 and a USGS epicenter location within 2.5 miles of the injection wells were defined as a green light limit.

Regional seismic networks allow for detection of **M** > 2.0 events but have limited capabilities in accurately locating these events. Further, a regional network is unlikely to detect the numerous smaller events that may be associated with injection activities. In this case, having access to a local seismic monitoring network operated by University of Colorado researchers allowed for more proactive seismic monitoring subsequent to the initial event. Managed injection was then possible as higher spatial and temporal resolution data became available.

It is suggested that a review of drilling logs for lost circulation zones, particularly in the lower portion of a well, can help identify flow migration outside the injection zone, which could migrate to crystalline basement. Furthermore, it is important to know the appropriate distance between the injection zone and crystalline basement because this interface may have bearing on earthquake susceptibility (Zhang et al. 2013). A regional seismometer network combined with a portable network allows the seismic monitoring of seismicity and risk management of induced earthquakes.

Oklahoma Case Study – Pawnee, OK

This case study focuses on the largest recorded magnitude earthquake to occur in Oklahoma in recent times. The expansion and improvement in the Oklahoma Geological Survey seismic network provided for quick resolution of the epicentral area that allowed the Oklahoma Corporation Commission and the USEPA to jointly take action and target selected underground injection wells for shut in and volume reduction.

Background and Objectives: On September 3, 2011, a **M** 5.8 earthquake was generated near Pawnee, Oklahoma and was reported as felt over a wide area of the central U.S. This was followed by a series of aftershocks ranging from **M** 2.6 to **M** 3.6 within four hours of the mainshock. The estimated hypocentral depth of this event placed it in Pre-Cambrian basement rock. Another series of events ranging from **M** 2.8 to **M** 4.5 were recorded in the same vicinity on November 2, 2016. Signs of ground settlement and soil liquefaction from the **M** 5.8 event were noted in a report by a Geotechnical Extreme Events Reconnaissance team (Clayton 2016). This team was dispatched by the Geotechnical Extreme Events Reconnaissance (GEER) Association which coordinates such visits under the sponsorship of the National Science Foundation. This team also noted that there was primarily non-structural damage to buildings in the area and that common observations included: façade failure, partial or full chimney collapse, and cracking of plaster and/or drywall. There were also reports of dishware falling off shelves and hanging picture frames falling to the floor. A follow up report put together by another GEER team focused on the geotechnical aspects of this major event. The extensive state-wide seismic monitoring network that had been installed by the Oklahoma Geological Survey assisted greatly in providing good location of the epicenter of this event.

Geology and Disposal: Saltwater disposal wells in the Pawnee area are primarily located in the Ordovician- age Arbuckle Formation which often lies on top of basement rock. Good information on the character of the Arbuckle is described in (Shelton 1985) and the following descriptions are primarily derived from such. The Arbuckle varies in thickness throughout its extent and is composed of carbonate mudstone, laminated dolomite, dolomitic limestone and interclast calcarenite with some sandstone beds. It is known to be vugular in many areas. In some parts of northeast and north central Oklahoma it is underlain by the Cambrian-age Regan sandstone. The distribution and thickness of the Regan sandstone is uneven across this area due to irregular paleo-topographic relief on the surface of the basement. The Arbuckle is known to be under pressured in much of the area but the reasons for such have not been definitively shown. Much of the produced water that is disposed in the Pawnee area is generated by dewatering of the Paleozoic Mississippi Limestone although some of the injected water comes from older producing wells also. Saltwater disposal wells within Osage County where the epicentral area was located are regulated under the auspices of the USEPA as this is the location of the Osage Nation Reservation. Saltwater disposal wells in the adjacent counties are regulated by the Oklahoma Corporation Commission (OCC).

Seismic Monitoring: The Oklahoma Geological Survey seismic monitoring network has grown substantially since 2009. Funding for additional seismic monitoring stations was provided by the Oklahoma Secretary of Energy and Environment and from a grant from the Research Partnership to Secure Energy for America (RPSEA). The USGS also funded a temporary localized dense array project in central Oklahoma.

The OGS has used the SEISAN earthquake package (Ottemoller et al. 2017) since 2010 and this is to calculate **M** and to determine focal mechanisms. A regional velocity model is used to help determine the locations of earthquakes.

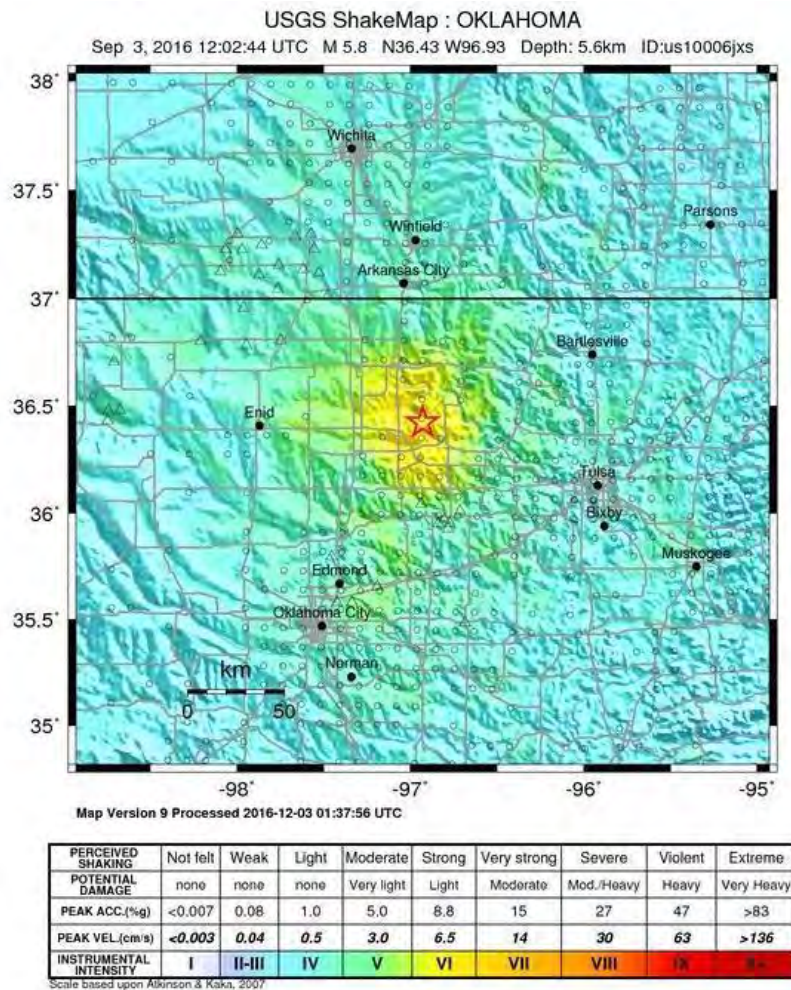


Figure C.15 USGS shake map of the Pawnee M 5.8 earthquake with values for peak ground acceleration and peak ground velocity. The shake map displays the area and severity of shaking generated by the event. Instrumental intensity values are calculated from the integration of the square values of spectral acceleration ordinates.

Discussion: Immediately following the M 5.8 event, the OCC ordered the shutdown of 37 saltwater disposal wells under its jurisdiction in areas adjacent to Osage County. On September 12, 2016, the OCC issued a directive modifying operations at 48 Arbuckle disposal wells with 32 wells being shut in and 16 additional wells being directed to reduce volumes. In addition, the USEPA who has jurisdiction for saltwater disposal wells in Osage County ordered five additional wells to shut down operations and 14 other such wells to reduce injection volumes as part of a coordinated response with the OCC. Following an M 4.5 event on November 2, 2016, on November 3, the OCC ordered four additional disposal wells to be shut in, 10 Arbuckle disposal wells had their allowable injection volumes reduced by 25% in volume and eight such disposal wells were limited in volumes to their last 30-day average (Skinner 2016).

Ohio Case Study — Harrison County

This case study is an example of the use of data from the state seismic network and additional broadband EarthScope Transportable Array stations to analyze the seismicity of a hydraulic fracture induced sequence. This information helped the state to take mitigating actions with the operators involved, to determine the extent of a previously unknown basement fault.

Background and Objectives: Some of the first reports of hydraulic fracture induced seismicity in the U.S. occurred in Ohio, beginning in October 2013 when a hydraulic fracture operation in Harrison County, Ohio was linked to inducing a series of small earthquakes (M 2.2 and below) on an unmapped basement fault (Friberg et al., 2014). This was followed in subsequent years by nearby seismicity correlated with hydraulic fracture completions on neighboring wells, with some earthquakes reaching magnitudes as large as M 2.9 (Skoumal et al 2016; Kozłowska et al. 2018; Brudzinski and Kozłowska 2019). The research objectives were to obtain a better understanding of the mechanism connecting hydraulic fracture and activation of the faults as well as to determine the extent of the basement fault structures.

Geology and Hydraulic Fracturing: Most of the shale gas exploration projects of the northeastern U.S. of the past few years have been done in the Marcellus shale in Pennsylvania, West Virginia, and parts of Ohio. However, only one case of well completions in this geological formation has been associated with seismicity (Skoumal et al. 2018). Instead, the older Utica-Point Pleasant shale has become the target for shale gas operations in eastern Ohio, leading to multiple instances of induced earthquakes (Skoumal et al 2015; Brudzinski and Kozłowska 2019).

Horizontal drilling and hydraulic fracturing completions are the primary technologies used to extract fluids trapped in the shale formations. As summarized in Appendix I below, hydraulic fracturing uses high pressure water and sand injected into wells to cause small fractures (which often manifest as microseismic events $-3 < M < -1$) in the formation to release the hydrocarbons. In some rare instances, the stress perturbations or pressurized fluids from hydraulic fracturing operations communicate with pre-existing faults that are critically stressed and optimally oriented, causing them to rupture as larger earthquakes ($1 > M < 4$). Since the Utica formation is in closer proximity to basement (< 1500 ft) completion operations in it have more potential to activate basement faults (Skoumal et al 2018; Kozłowska et al. 2018).

Seismic Monitoring: The EarthScope Transportable Array (TA) was deployed through Ohio from 2012 to 2014 with some retained for longer periods, providing a demonstrable increase in high quality observatory grade seismic stations. Since November 2013, ODNR-DOGRM and oil and gas operators deployed several stations as part of their OhioSeis monitoring program. Some of these stations were deployed in the vicinity of the first earthquake sequence in Harrison County to get a better handle on the locations of earthquakes in this region of Ohio.

A cross-correlation template-matching algorithm (Friberg et al 2014) was used to detect smaller earthquakes by finding similarities between the seismograms from larger earthquakes (templates) observed on the nearest EarthScope station against the continuous seismic records. This technique allows a researcher to detect earthquakes that are often two to three magnitude units lower than the original template earthquakes. In some instances, in Harrison County earthquakes, there were cases with over 3,000

smaller earthquakes coincident with completion operations on a well that led to larger earthquakes. In most cases, there was a precursory increase of activity as a larger earthquake was triggered on a tectonic fault.

Whenever there were earthquakes with clear seismic phases observed at four or more stations, they were manually analyzed to determine a more precise earthquake location and magnitude. A 1-D velocity model was used to locate the earthquakes within the network of seismic stations and achieved absolute location errors of less than 500m for some locations (Friberg et al. 2014). To further constrain the relative locations between earthquakes, an earthquake location algorithm that exploits the small-time differences of seismic phases on adjacent earthquakes, known as a double-difference earthquake location (Waldhauser et al 2001) was used. The double-difference earthquake location tightened up the clusters of earthquakes into linear features trending east west.

Results: Using the regional and local networks, several earthquakes attributed in time to hydraulic fracturing at multiple-lateral well pads in Harrison County, Ohio were observed (Friberg et al. 2014; Kozłowska et al. 2018). Figure C.17 shows the earthquake locations for the five largest seismic sequences refined with waveform correlation and double difference relation, which outlines a network of east-west oriented fault strands that were optimally aligned relative to SHmax. The waveform correlation also enabled the detection of smaller magnitude earthquakes, revealing more about the timing of the seismic sequences. Figure C.18 shows the timing of hydraulic fracturing stages for the five well pads and the magnitudes of seismicity over time. The onset of seismicity was well-correlated with the onset of hydraulic fracturing for all well pads, less than 2-3 hours in the case of two well pads, and there were many distinct bursts of seismicity that correlated with individual stages of hydraulic fracturing.

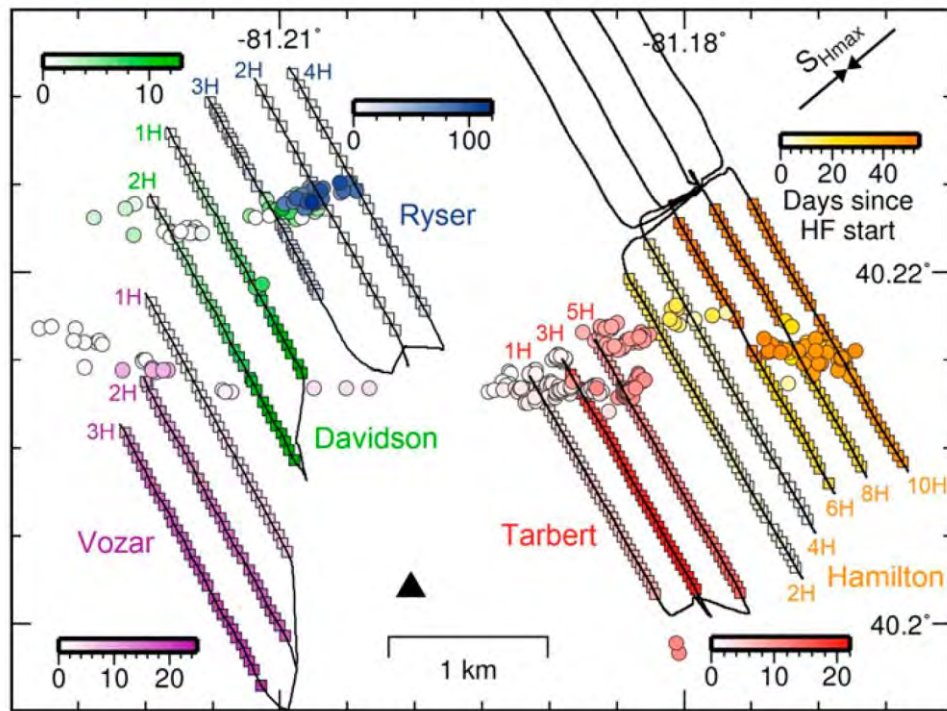


Figure C.16. Map showing five major sequences in Harrison County from 2013 to 2015 analyzed in Kozłowska et al. (2018). Curved lines indicate horizontal well drill paths. Stimulation stages (squares) and double difference relocated seismicity (circles) are shaded using a time scale since the start of hydraulic fracturing, with a different color for each well pad. Circle diameter shows mean horizontal location uncertainty. Nearest seismic station is shown as a triangle.

Activity of some stages was higher than others, indicating preferential communication of those stages with the underlying fault. For the Hamilton well pad, there was a noted increase in the number and magnitude of earthquakes prior to the largest earthquake observed (M 2.9). After the end of hydraulic fracturing, the seismicity only halted at shut-in for the Tarbert and Vozar well pads, while seismicity continued for over a month after the Ryser and Hamilton pads shut-in. This seismicity that continues after shut-in occurred at lower seismicity rates than during hydraulic fracturing and decayed over time, but the magnitude ranges were similar to that during hydraulic fracturing. Intriguingly, the wells with post shut-in seismicity also tended to have more larger magnitude earthquakes than average, while the wells without had more smaller magnitude earthquakes than is typical.

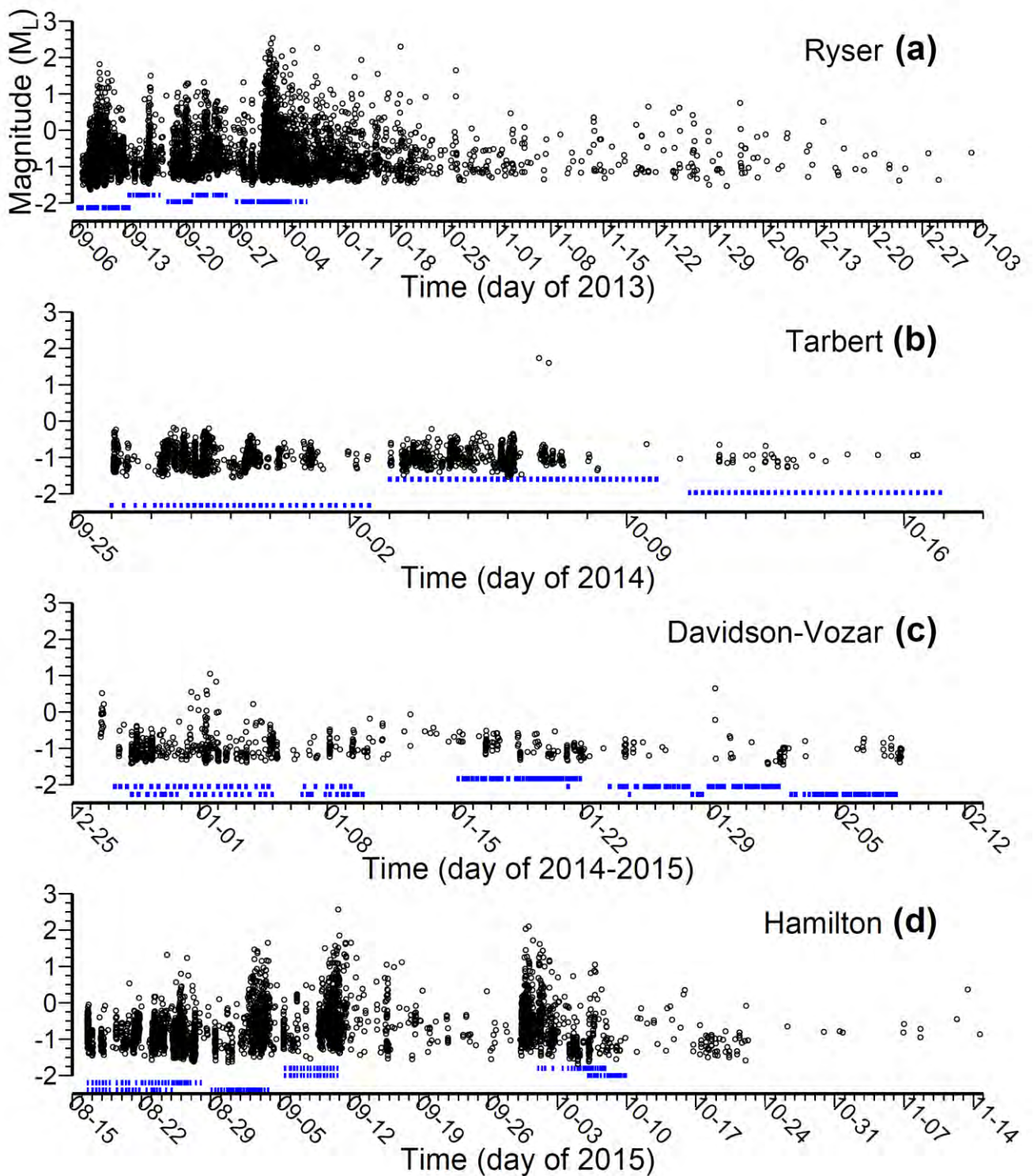


Figure C.17 Temporal distribution of hydraulic fracturing induced seismicity for the 5 cases in Harrison County, Ohio shown in Figure C.16 (Kozłowska et al. 2018). Magnitudes of earthquakes (circles) are shown together with timings of hydraulic fracturing stage stimulations (blue bars).

These two different frequency-magnitude patterns appear to be explained by the depth of the seismicity. The wells inducing shallower earthquakes in the Paleozoic sediments resulted in the group with more

smaller magnitude earthquakes and no post-shut-in earthquakes. The wells inducing deeper earthquakes in the Precambrian basement cause the group with more larger magnitude earthquakes and extensive post-shut-in sequences. These findings were consistent with prior geologic history, laboratory experiments, and fault modeling that indicate the deep seismicity represents slip on more mature faults in older crystalline rocks and the shallow seismicity is slip on immature faults in younger sedimentary rocks (Figure C.19).

Discussion: The occurrence of seismicity did not influence the hydraulic fracturing operations except for the Hamilton well pad, where communication between the operator and regulator resulted in stimulation being halted on well laterals 6H and 8H (Figure C.18) for over two weeks following the strongest earthquake and the injection pressures and volumes were decreased afterward. It is important to note that only 2.7% of hydraulic fracturing stimulations out of some nearly 2,000 wells in the Utica formation have induced seismicity to date (Brudzinski and Kozłowska 2019), although the prevalence is over 20% wells in this area of Harrison County. None of the earthquakes in this case study incurred any known damage, and only a few were felt at the surface. However, a subsequent earthquake in nearby Noble County was an order of magnitude larger (M 3.7), indicating the potential for larger and damaging earthquakes cannot be ruled out.

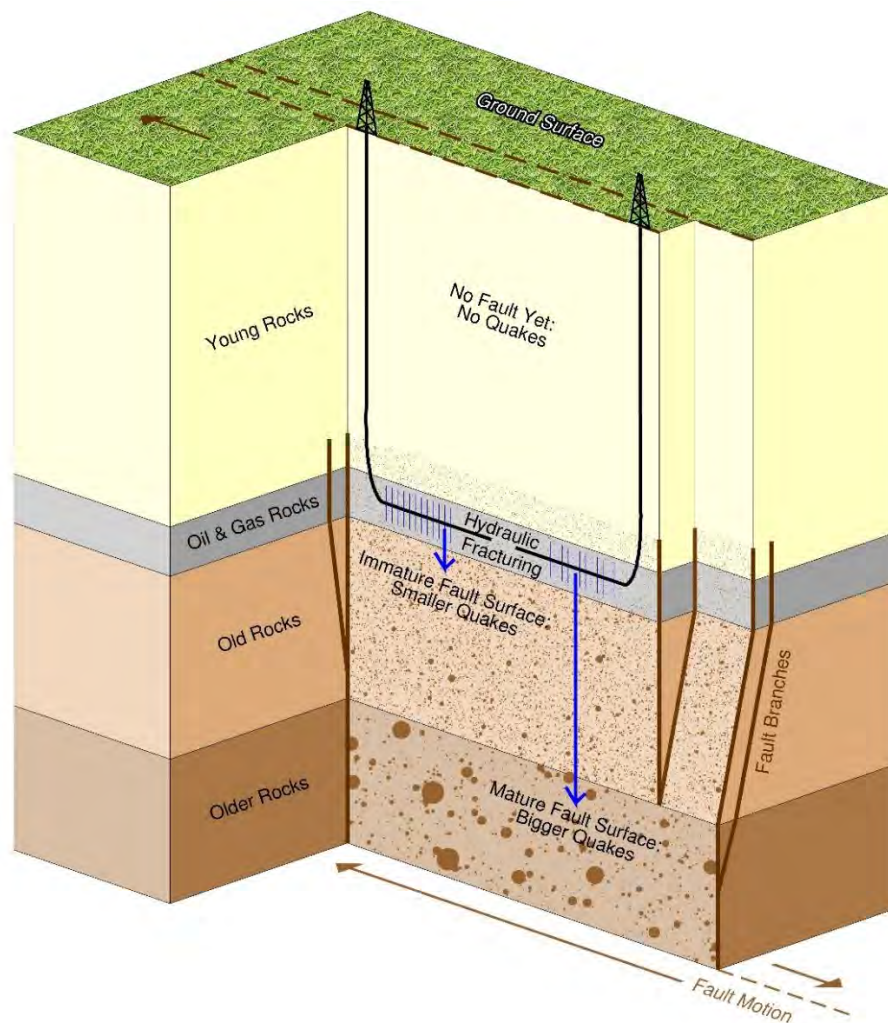


Figure C.18. Schematic cross-section illustrating differences between the shallow seismicity in the Paleozoic sedimentary rocks and the deep seismicity in the Precambrian basement rocks. Circles show seismic rupture areas synthetically computed from the frequency magnitude patterns, utilizing a magnitude to circular slip area approximation. Circle locations are randomly assigned in the depth range observed for illustration purposes. Curved black lines show example well paths. Straight brown lines illustrate potential fault branching associated with a positive flower structure seen for a similar strike-slip system in eastern Ohio (Currie et al. 2018). Figure modeled after Kozłowska et al. (2018).

Texas Case Study – Eagle Ford Shale Play

Background: Beginning in 2008, the rate of seismicity significantly increased across the southern Mid Continent of the U.S., including parts of Texas. Between 1975 and 2008 there were, on average, one to two earthquakes per year of magnitude greater than **M** 3.0. Between 2008 and 2016, the rate increased to about 12 to 15 earthquakes per year on average (The Academy of Medicine, Engineering and Science of Texas 2017). The previously existing (pre-2016) network of 18 operating seismic monitoring stations, irregularly distributed across Texas, was insufficient to detect, locate, and properly characterize

seismicity at a level of accuracy necessary to understand either what caused earthquakes or if any actions could be taken to reduce the recurrence of such earthquakes.

Current Development of TexNet: In 2015, the Texas State Legislature appropriated funds to design, acquire, install, and operate a seismic monitoring network, which now includes more than more than 100 stations (Appendix D). Along with the hardware and data collection program, TexNet works with a technical advisory committee which is composed of representatives from higher education with seismic or reservoir modeling experience, experts from the oil and gas industry, and a Railroad Commission seismologist. Data from the TexNet seismic stations streams in real time to the TexNet Data Hub for analysis and subsequent distribution to IRIS and the U.S. National Earthquake Information Center (NEIC), operated by the USGS.

Eagle Ford Shale Play: South Texas has a history of active oil and gas production, hydraulic fracturing, wastewater disposal, and seismicity, some of which occurs within or near areas of pervasive faulting (Figure C.19a) (Ewing 1990; Frohlich et al. 2016). With the advancements in horizontal drilling and hydraulic fracturing, the Eagle Ford shale play has focused on hydrocarbon production of the Upper Cretaceous Eagle Ford Formation and the Austin Chalk Formation directly above since 2008 (Frohlich & Brunt 2013; Martin et al. 2011; RRC 2019). Since 2012, the Eagle Ford has produced the second largest amount of oil in the US, averaging 1.3 million barrels per day (0.2 million m³/day) (EIA 2019). Up to 2019, there have been more than 19,000 hydraulically fractured wells completed in the Eagle Ford Shale play (www.fracfocus.org).

Eagle Ford seismicity has been largely attributed to increases in hydrocarbon production with a few cases related to wastewater disposal since 1973 (Frohlich & Brunt 2013; Frohlich & Davis 2002; Pennington et al. 1986). The largest earthquake in south Texas (4.8 Mw) occurred in 2011 and has been interpreted to be induced by fluid extraction (Frohlich & Brunt 2013). In 2018, the rate of Richter local magnitude [M_L] ≥ 3.0 earthquakes in the Eagle Ford grew to 33 times higher than background levels (3 per 10 years during 1980-2010, Figure C.19b inset).

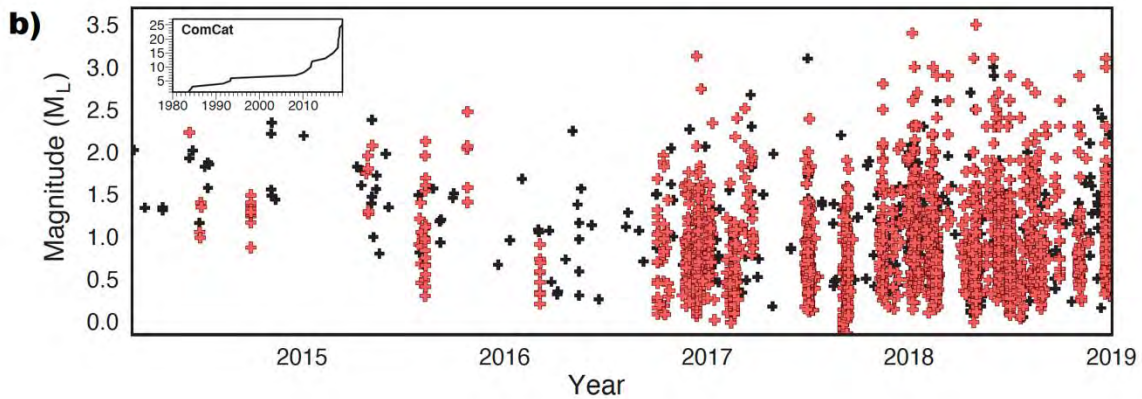
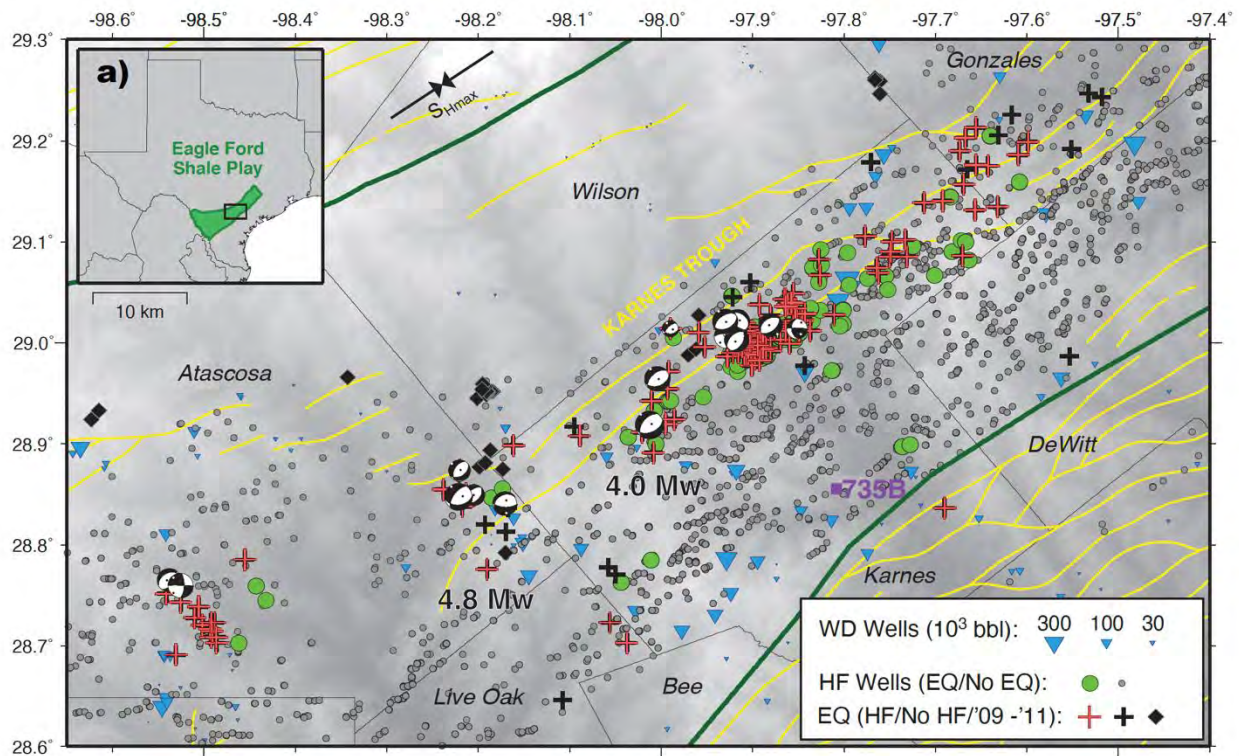


Figure C.19 Locations and timings of Eagle Ford HF induced earthquakes. a) Map showing earthquakes (crosses) and focal mechanisms (beach balls) since 2017 from the Texas Seismological Network. Hydraulically fractured wells are indicated by black circles (FracFocus). Correlated earthquakes and hydraulically fractured wells are red and green, respectively. Black diamonds show 2009–2011 earthquakes (Frohlich & Brunt 2013). Purple square shows the seismic station (735B) used for template matching. wastewater disposal wells are teal triangles sized by median monthly volumes. Arrows show regional SHmax orientation (Lund Sneek & Zoback 2016). Faults (Ewing 1990) are in yellow. b) Magnitude versus time for earthquakes (crosses) detected in the area shown in a). Earthquakes are colored when correlated with hydraulic fracturing. Inset shows cumulative number of earthquakes ($M \geq 3.0$) for this area from the USGS Comprehensive Catalog. Figure from Schultz et al., (2020).

Correlation of Hydraulic Fracturing and Seismicity: Fasola et al. (2019) investigated seismicity from 2014 to 2018 and identified how hydraulic fracturing contributed to seismicity by comparing times and locations of hydraulic fracturing with a catalog of seismicity extended with template matching. In this study, only a single regional station was within 150 km of the seismicity, so this station was used to detect additional earthquakes in time (Figure C.20b), but the high correlation coefficients indicated the additional detections were spatially consistent with the catalog locations. More than 85% of the detected seismicity was spatiotemporally correlated with hydraulic fracturing, and there were 94 $M_L \geq 2.0$ earthquakes correlated to 211 hydraulically fractured well laterals (Figure C.20a). There was no spatiotemporal correlation between wastewater disposal and seismicity, with few wastewater disposal wells having injection rates more than 300,000 barrels per month (47,700 m³/month).

As of yet, the 4.0 Mw May 1, 2018 earthquake is the largest hydraulic fracturing-induced earthquake documented in the U.S. (as opposed to other earthquakes induced by the wastewater disposal process). It appeared to occur on a mapped Karnes Trough normal fault (Figure C.20), which also hosted the largest regional earthquake (4.8 Mw) in 2011 that occurred ~10 km away (Figure C.19a). This indicates operational activities in this area are capable of producing felt and potentially damaging earthquakes. Considering all of the correlated cases, the effective injection rate (volume per day per area) had the strongest influence on the probability a well correlated with seismicity (Fasola et al. 2019). Cases where multiple laterals were stimulated concurrently (e.g., alternating stages between laterals) tripled the probability of seismicity relative to a single lateral stimulated in isolation.

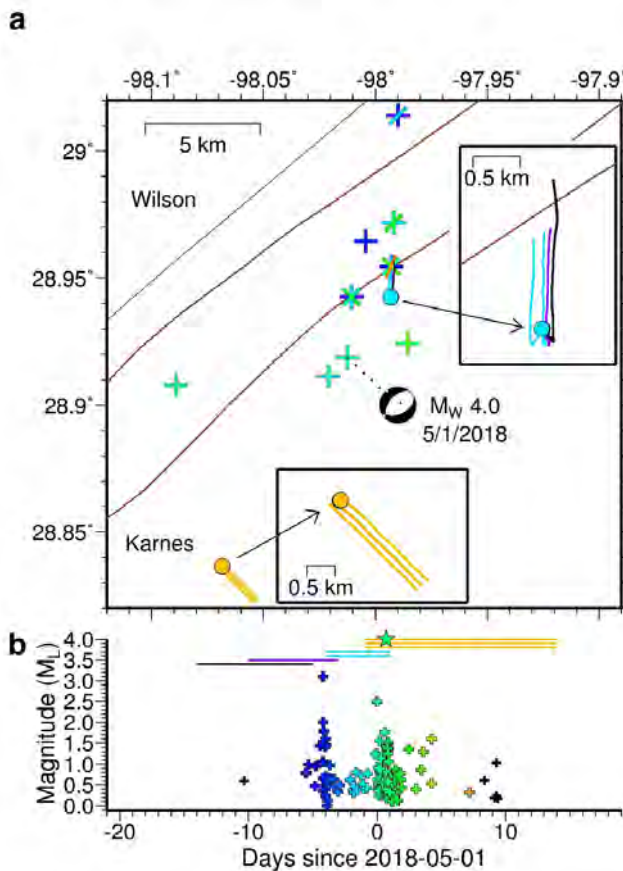


Figure C.20. Examples of hydraulic fracturing - induced seismicity from simultaneous (zipper) lateral stimulation. a) Map of a key sequence in Karnes County resulting in a M_w 4.0 (M_L 3.5) earthquake showing hydraulically fractured well pads (circles), digitized hydraulically fractured well laterals (lines: RRC), earthquakes (crosses), focal mechanism (Texas Seismological Network), and mapped faults (thin NE-SW oriented curves). Hydraulically fractured well pads, laterals, and seismicity are colored by time when correlated, otherwise they are black. Earthquakes have multiple colors if more than one hydraulically fractured well triggered that template earthquake over time. Insets show zoomed in views of well pad areas. b) Magnitude-time distribution for matched earthquakes (crosses). Reported hydraulic fracturing times (FracFocus) are shown as thin lines at the top of the graph.

Discussion: Fasola et al. (2019) used logistic regression on the Eagle Ford data set to examine the influence of several factors on the probability of induced seismicity. Larger injection volumes have been identified as a key influence on seismicity in Alberta, Canada (Schultz et al. 2018), and Fasola et al. (2019) also found there is a relationship between total volume injected into a lateral and the probability of seismicity in the Eagle Ford (Figure C.21a). However, this relationship does not occur for isolated wells (Figure C.21a) (Ries et al. 2020), indicating that the cumulative volume of multiple laterals is a key reason for the overall trend with volume. This is supported by the increased probability of seismicity as the number of laterals on a pad increased (Figure C.21b). The strongest increase in earthquake probability was found with daily effective injection rate, which accounts for injection into multiple laterals simultaneously (e.g., zipper; Figure C.21c). Fasola et al. (2019) found 12% of well laterals stimulated simultaneously, 7% of wells stimulated sequentially, and 4% of isolated laterals produced seismicity. The largest earthquake (**Mw 4.0**) occurred when two well pads were performing simultaneous lateral stimulations (Figure C.20).

As of yet, no regulatory controls on HF induced earthquakes have been implemented in the Eagle Ford Shale play, or anywhere in Texas. However, industry groups sought to learn about the research quickly, and indications are that the seismicity rate has decreased in 2019-2020 due to proactive management.

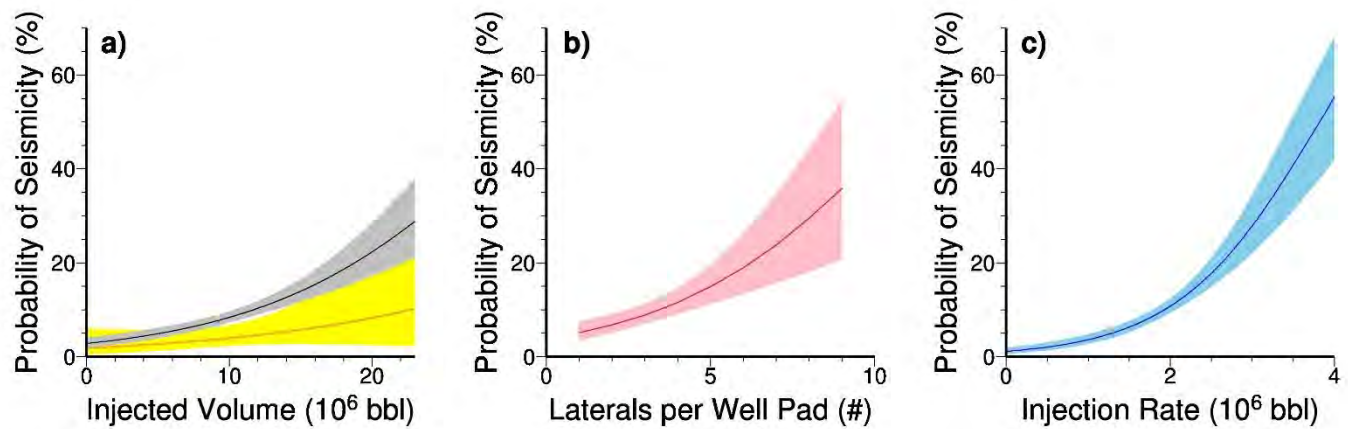


Figure C.21. Predicted probability of seismicity from logistic regression of Eagle Ford data for (a) injected volume, (b) number of laterals per well pad, and (c) daily effective injection rate. In (a), gray is for all wells, yellow is for isolated wells only. Lines show best fit, and shading shows 95% confidence interval. Figure modified from Fasola et al. (2019) and Ries et al. (2020).

British Columbia – Septimus

This case study reviews details of a significant (**M 4.4**) induced earthquake which occurred while hydraulically fracturing the lower Montney Formation in the Septimus area of northeast B.C. It illustrates the major differences in seismicity observed in the upper Montney and lower Montney strata and the heightened seismic hazard associated with reactivated faulting in the Fort St. John graben complex.

Background and Objectives: Between May 10 and June 7, 2018, seven horizontal wells within the upper Montney formation were completed via multi-stage hydraulic fracturing from a common pad. During that time, no earthquakes larger than **M** 2.0 were detected. An additional two wells were drilled from the same pad into the lower Montney during October and November 2018. In late November 2018, the two lower Montney wells on this pad were undergoing zipper fracturing completion operations, though the wells are 1,500 m (~one mile) apart laterally. On the third day of hydraulic fracturing operations, a non-damaging, widely felt **M** 4.4 earthquake occurred with several smaller aftershocks. Completion operations were halted immediately following the initial 4.4M earthquake in accordance with B.C. regulations. A subsequent investigation by the British Columbia Oil and Gas Commission (BCOGC) analyzed the occurrence of the earthquake and evaluated the potential for seismicity should further lower Montney completions operations occur on the pad. A detailed manual review of available waveform data uncovered 63 previously undetected precursor earthquakes between magnitude 0 and 2.

Geology and Reservoir: The Triassic Montney formation is approximately 200 m thick in the Septimus region and the upper and lower Montney wells on the subject well pad have a vertical offset of approximately 150 m. The Montney is a shallow marine, low energy sandstone deposit and, primarily in the lower Montney, there can be turbidite deposits. The Montney, in the subject area, is influenced by the Fort St. John graben complex. Prior to the deposition of the Montney, the Fort St. John Graben complex formed during the Carboniferous-Permian. The effects and basic shape of the graben can be outlined by contouring the Permian thickness (Figure C.22). From South to North, there is a gradual slope into the graben complex. Near the subject wells, the faulting becomes larger with more vertical offset into the deepest portion of the graben. Originally, during the formation of the Fort St. John graben complex, the faulting would have been normal down to the basement; however, subsequent reactivation during the Laramide orogeny, has altered the faulting to strike-slip and reverse.

There are significant pressure differences between the upper and lower Montney, as well as different hydrocarbon products. The upper Montney is primarily dry gas, whereas the lower Montney wells are wet gas and qualify as oil wells. The pore pressure within each formation varies vertically and can vary laterally, and this is the case in the subject lower Montney wells. The north well on the subject pad had a pressure of approximately 24MPa (3,500 psi), while the southern well had a pressure of 34 MPa (4,900 psi). These wells are 1.5 km (0.9 miles) apart laterally.

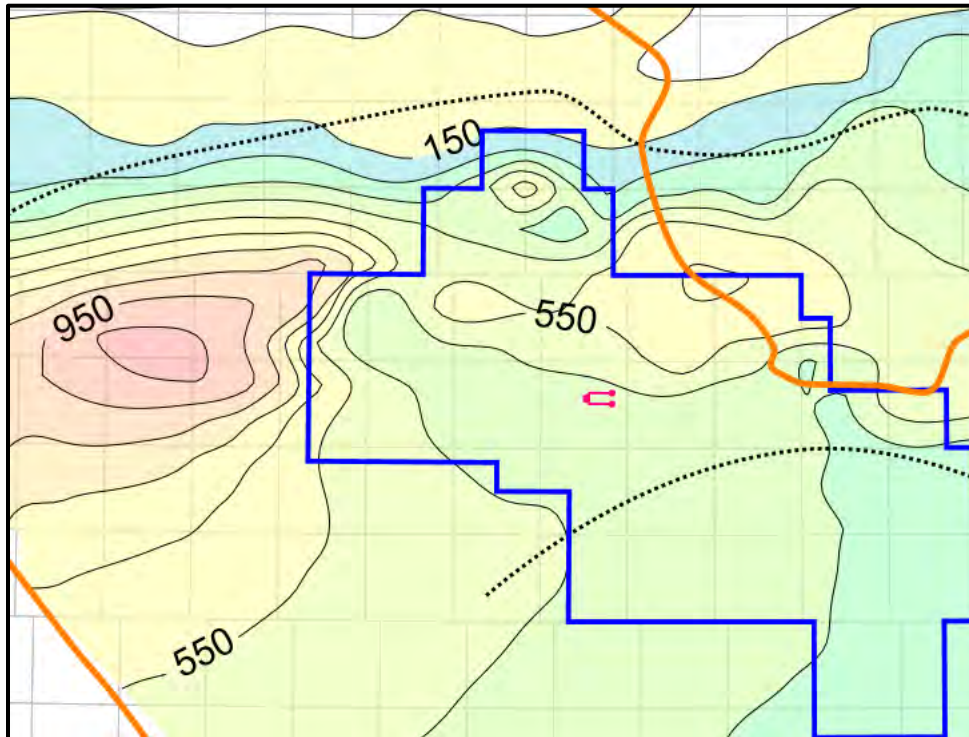


Figure C.22: The northern and southern outlines of the Fort St. John Graben complex are shown with the dashed black lines. The thickness (in m) of the Permian section is shown in the map (50m C.I.). The thickness increases gently from south to north before the basin rapidly thickens due to increased fault offset into the deepest portion of the graben. The two subject wells are shown in pink and the blue polygon outlines the Kiskatinaw Seismic Monitoring and Mitigation Area (KSMMA) Special Project. Light grey boxes are 6 miles x 6 miles.

Seismic Monitoring: The region where the subject wells are located is referred to as the Kiskatinaw Seismic Monitoring and Mitigation Area (KSMMA). It is a localized area where the BCOGC has implemented a Special Project with enhancements to the province-wide induced seismicity regulations. This area has shown a greater susceptibility to earthquakes with a much greater propensity for earthquakes when hydraulic fracturing occurs in the lower most portions of the Montney formation. As such, it has been a focal point for the BCOGC, academia and industry for seismic monitoring. The BCOGC has deployed, through various partnerships, a nine-station array in the KSMMA that is further bolstered by a 15-station array that is run by McGill University. By regulation, industry must also have access to a real-time array to operate within the KSMMA, so there are additional private stations throughout the KSMMA. Operators must also deploy an accelerometer within three km of their well pad.

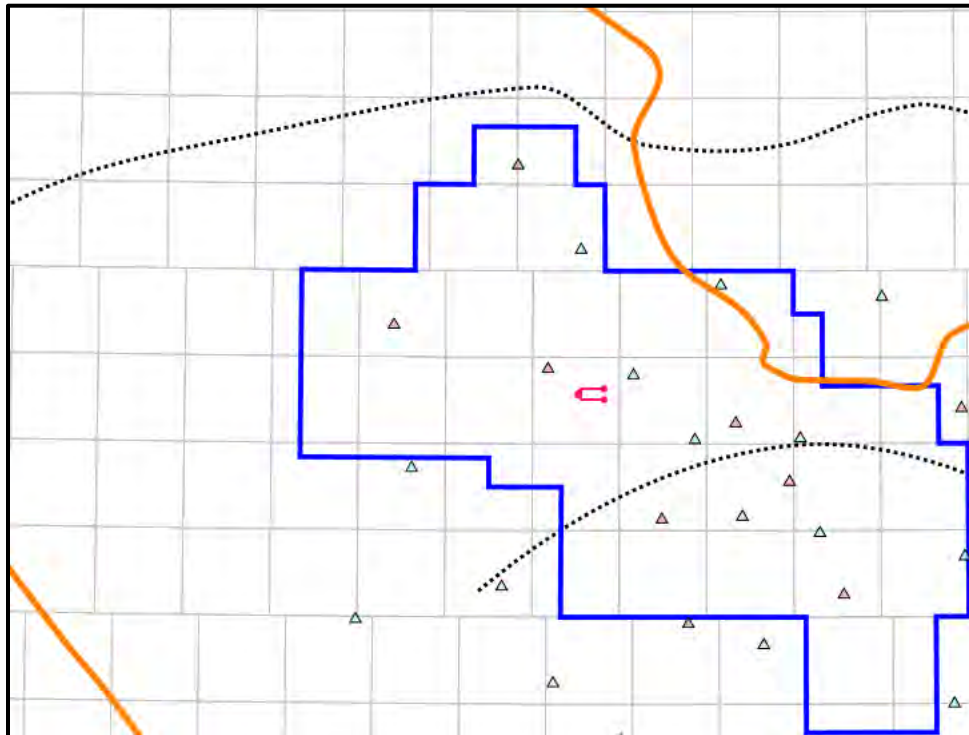


Figure C.23 The BCOGC maintains a nine-station array in the KSMMA with various partner agencies and the array is augmented through access to the McGill University research array. Operators have various private stations in the region and an accelerometer must be deployed within three km of a well pad during fracturing operations.

Result: From Nov. 27, 2018 to Dec. 9, 2018, a total of 273 earthquakes were located in the region around the subject wells (Figure C.24). Of these, 64 earthquakes were precursor events with the largest earthquake being a **M 2** earthquake. This earthquake was initially reported to the BCOGC by the operator as a **M 1.7**

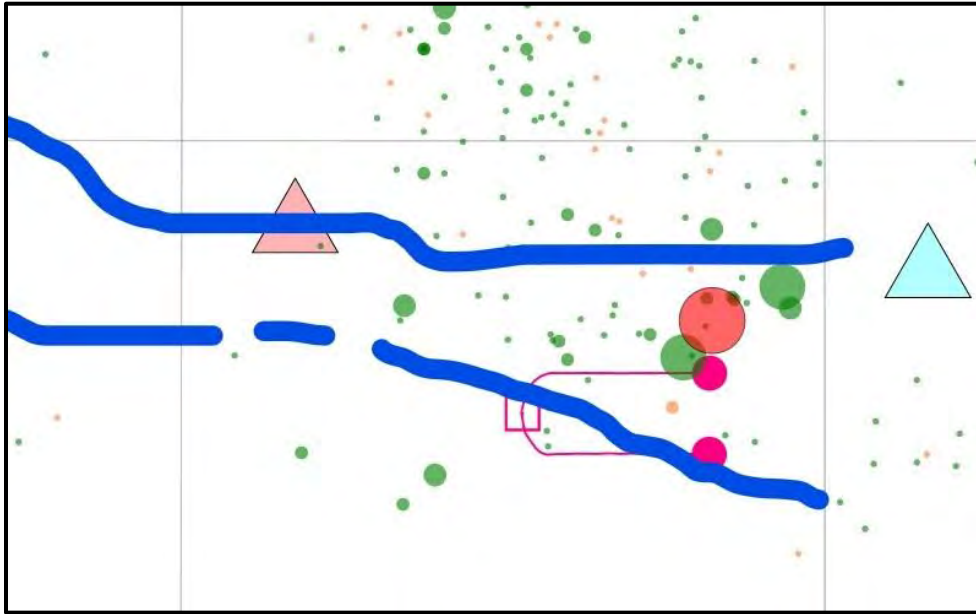


Figure C.24: Earthquakes shown from a map view with precursor earthquakes shown in orange and aftershock earthquakes shown in green. **M** 4.4 earthquake shown in red. Blue lines indicate fault structure below the Montney formation.

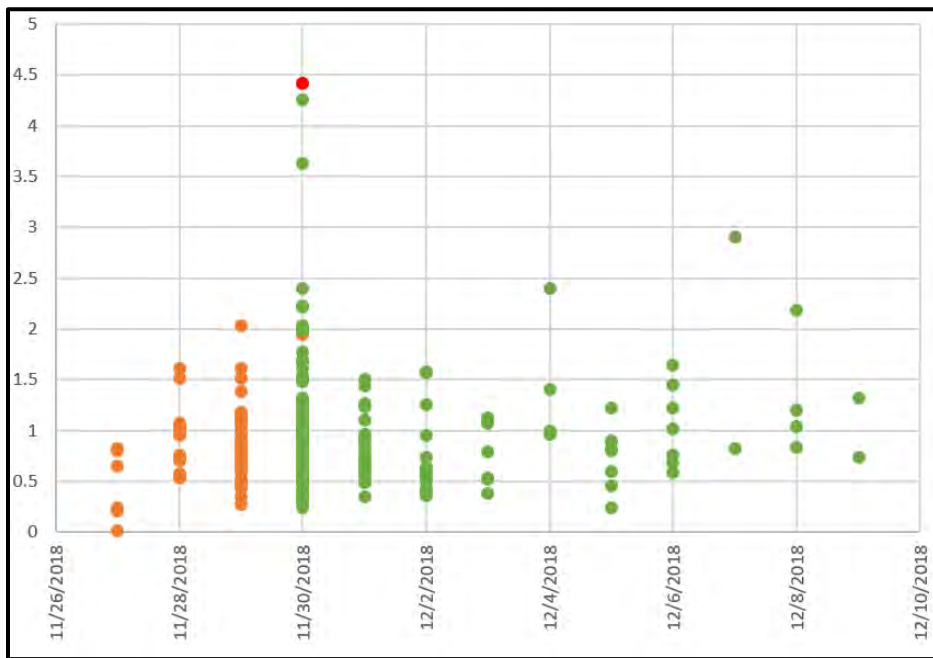


Figure C.25. Earthquakes show a magnitude vs. date plot. Precursor earthquakes are in orange. The **M** 4.4 earthquake is shown in red. Aftershock earthquakes are shown in green.

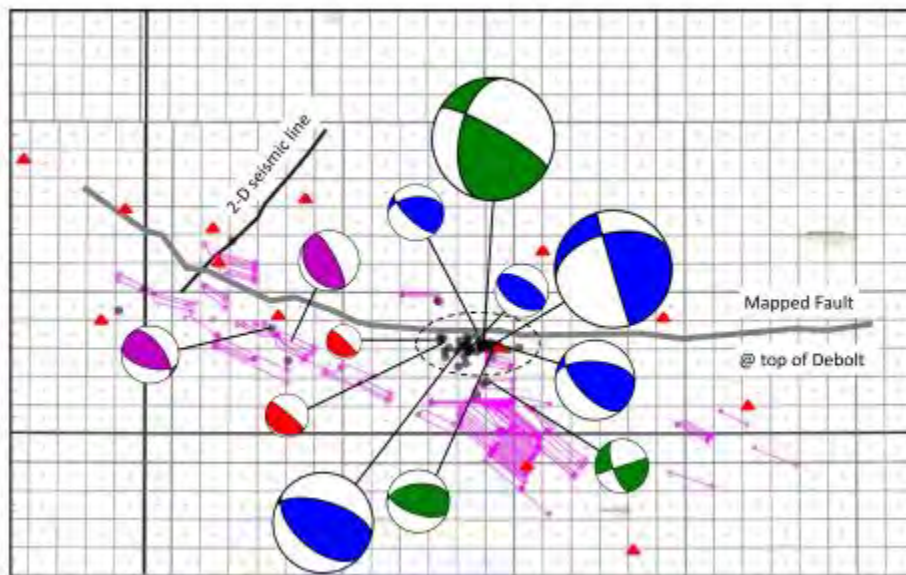


Figure C.26. Map of the study area, showing horizontal wells (magenta lines), seismicity (grey dots) detected using a local industry seismograph array (red triangles), along with focal mechanisms (scaled by magnitude); location of the southern bounding fault of the Fort St. John graben complex (grey line) and location of a 2D seismic line made available to researchers. Grey dots enclosed by the dashed ellipse show the distribution of aftershock earthquakes. Focal mechanisms were calculated by Nanometrics; corresponding beachball colors represent earthquake clusters, determined as part of the focal-mechanism analysis. Seismicity data and waveforms were provided by ESG/Spectraseis. Small squares represent one section (1.6 x 1.6 km).

Discussion: As a result of the **M** 4.4 earthquake, the well pad with two wells being completed were immediately suspended. The **M** 4.4 earthquake was widely felt by residents up to 100km away and felt reports were communicated to the BCOGC and via the federal NRCAN Did You Feel It portal. Routine analysis in the area for the BCOGC maintained array picked up the initial **M** 1.7 earthquake (later revised to **M** 2.0) prior to the **M** 4.4 earthquake; however routine analysis did not record the additional 63 precursor earthquakes. These earthquakes were confirmed during the post-earthquake analysis. The operator followed protocol by reporting the initial **M** 1.7 earthquake, which is a requirement under the KSMMA. There is no definitive method for determining that mitigation based upon the escalation in frequency of low magnitude earthquakes would have prevented the resulting **M** 4.4 suspension earthquake.

A comprehensive review of the earthquakes determined that further lower Montney completions could resume in the southern portion of the pad which is furthest from the major fault and exhibited 10,000 kPa lower pressure. Stricter monitoring thresholds and fluid viscosity changes were added to the well permit. The additional permit conditions will apply to the southern subject well should the operator decide to return and finish fracturing this well. Only seven of a planned 55 stages were completed prior to the suspension earthquake.

Ohio Case Study — Poland Township

This case study details a successful induced seismicity communication strategy. One of the earliest known examples of hydraulic fracturing induced seismicity occurred in Poland Township, Ohio. Concise, accurate, and understandable messaging to people with a variety of backgrounds is critical to successful communication. The Ohio Department of Natural Resources recognized this and developed a message, designated communicators, acquired expert input, and offered clarification as needed by monitoring ongoing media coverage.

Background: On March 10, 2014, the USGS identified four earthquakes ranging from **M** 2.2 to **M** 3.0 with a number of felt reports in Poland Township, Ohio. The earthquakes correlated with a hydraulic fracturing operation. The ODNR-DOGDM dispatched an oil and natural gas inspector to the site and requested the company halt operations while ODNR investigated. After reviewing all the data, the investigation concluded that there was a probable connection between the hydraulic fracturing and the seismic activity caused by a previously unknown fault.

Geology and Seismic Research: Some researchers have recently attributed hydraulic fracturing operations as possibly inducing earthquakes in the Utica shale or Point Pleasant formation, where hydraulic fracturing operations may be performed in closer proximity to the basement than typical Marcellus shale operations. Skoumal, Brudzinski, and Currie (2015) studied the earthquakes in Poland Township. During hydraulic fracturing operation along segments of two laterals, a sequence of 77 earthquakes on one fault (ranging from **M** 1 to **M** 3) was detected using cross-correlation with regional EarthScope seismometers. These earthquakes grew in magnitude and frequency between March 4 and 12, 2014 and then halted after the Ohio Department of Natural Resources issued a shutdown. The seismicity occurred during six stimulation stages along two horizontal well legs that were located ~0.8 km away from the fault (Figure C.27). Nearly 100 stimulation stages in the same or nearby wells at greater distances did not produce detected (**M** > 1) seismicity. The seismicity appears to have outlined a ~600-meter linear feature at the top of the Precambrian basement along an azimuth ~30° from the regional maximum stress. The left-lateral strike-slip focal mechanism for the largest earthquake was consistent with the seismicity distribution and suggests a possible mechanism of hydraulic fracturing for induced slip along a preexisting fault/fracture zone optimally oriented in the regional stress field. The focal mechanism, orientation, and depth of the seismicity were similar to earthquakes previously potentially induced by wastewater disposal in Ohio.

Communication Strategy: Because this incident was only the fourth time hydraulic fracturing had been linked to seismic activity (and the second time in the U.S.), the agency knew it would draw media attention. The ODNR staff worked to develop a plan, determined the appropriate message, established talking points for the team, and determined how information would be disseminated to the stakeholders. They established the appropriate spokesperson and identified available resources.

The regulatory agency focused its message on more stringent permit conditions and actions by the regulators to address and monitor seismicity across the state. The ODNR drafted a release and worked with both local and national media to share the message. The agency proactively identified third-party

validators to quote in the release and serve as an outside source for media, which was helpful in solidifying the credibility of their response and findings.

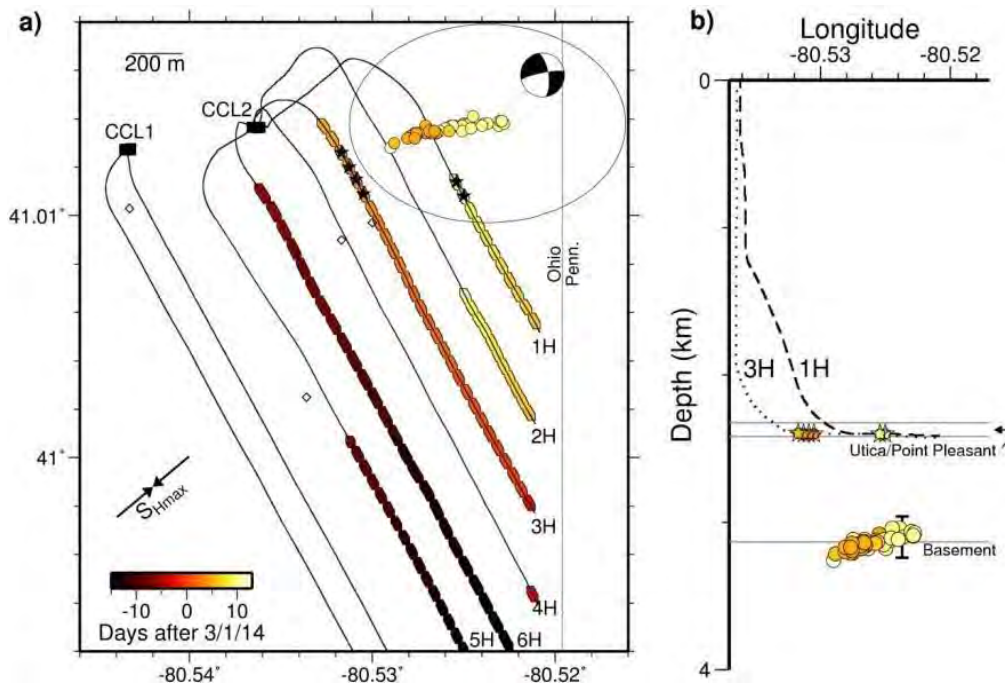


Figure C.27. Potentially induced seismicity during hydraulic fracturing near Poland, Ohio. Image a) is a map of well paths (curved lines), with hydraulic fracturing stages shaded according to time. Stars indicate only the closest stages produced seismicity (circles, shaded by time). Focal mechanism is from the **earthquake**, with a left-lateral fault plane that matches the linear seismicity, $\sim 30^\circ$ from the maximum horizontal stress (S_{HMAX}). Image b) is an east-west cross-section with no exaggeration showing well paths (dashed and dotted) and stages (stars) that produced seismicity (circles). Source: Skoumal, Brudzinski, and Currie (2015).

The Office of Communications was designated to handle media calls and monitor media coverage. The director and legislative staff called legislators when the announcement was imminent to ensure they were kept in the loop. The oil and natural gas subject matter experts taped a 30 second sound bite on a cell phone explaining the details of the announcement. The agency was then able to offer those sound bites to television stations across the state and country. They developed a fact sheet with frequently asked questions, which could be forwarded to stakeholders and media and put on their website.

Results: Seismic monitoring stories in mainstream and social media allowed the agency to determine the effectiveness of their message and make corrections, or clarifications, as necessary. Overall, the messaging rollout was successful as ODNR was able to provide key points to several media outlets and avoid much of the misunderstanding that often takes hold following an earthquake.

British Columbia – Tower Lake

This case study involves fracturing induced seismicity in an area with recent disposal induced seismicity. Many earthquakes were felt by local residents. Fracturing and disposal activities in the study area are at different stratigraphic depths, but the operator's local seismic array was not dense enough during initial activities to determine depth with accuracy. The British Columbia Oil & Gas Commission (BCOGC) required the operator to densify the array near the suspected disposal well, which led to certainty in the cause of each earthquake. Subsequently, the disposal well injection pressures and volumes were voluntarily reduced by the operator.

Background and Objectives: The map (Figure C.28) shows the number of wells in this area. Commonly, well spacing of ~250 m per stratigraphic horizon and 35 to 50+ fracturing stages per well results in many low magnitude earthquakes that are often felt. Horizontal disposal wells were added to this area in 2018 in a shallower Cretaceous horizon. Felt reports in summer 2019 occurred when there was no fracturing in this area. The regulator (BCOGC) ordered the operator to densify the local array in the vicinity of the disposal well to ensure depth of the earthquakes could be determined. By December 2019, it was confirmed the disposal well was causing seismicity.

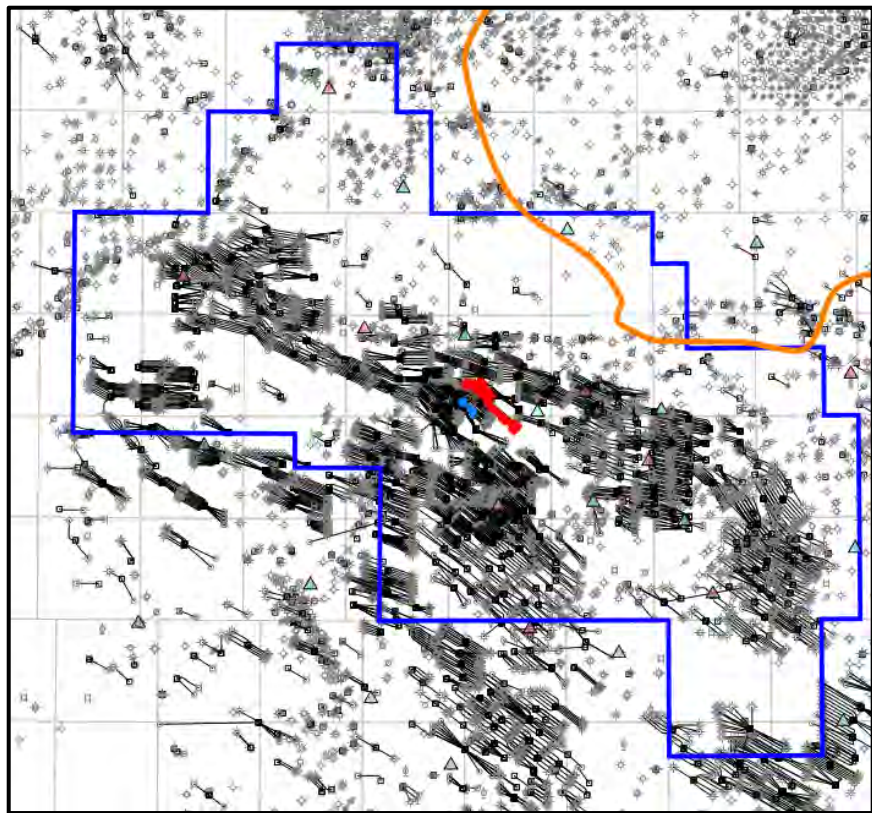


Figure C.28: Study area map showing subject fracturing wells in red, disposal well in blue and area wells in black. There are 13 of the subject fracturing wells. Eight wells have a NW dominant direction (north bank), and five wells have a SE dominant direction (south bank). The blue polygon is the outline for the Kiskatinaw Seismic Monitoring and Mitigation Area (KSMMA) Special Project.

Geology: The Triassic Montney formation is approximately 250 m thick in the Tower Lake region and the upper and lower Montney wells on the subject well pad have a vertical offset of approximately 200 m. The Montney is a shallow marine, low energy sandstone deposit. Turbidite deposits can be found in the lower Montney interval. The Montney in the subject area is influenced by the Fort St. John graben complex, which formed as a series of en-echelon normal faulting during the Carboniferous-Permian period prior to the deposition of the Montney. Subsequent fault reactivation during the Laramide orogeny has altered the faulting to strike-slip and reverse. The graben morphology in Tower Lake exhibits a gentle south to north slope. North of Tower Lake the faulting becomes larger with more vertical offset into the deepest portion of the graben.

The dominant faulting in the case study area is strike-slip. The strike-slip faults have minimal vertical offset, which makes them difficult to resolve ahead of activities using 3D seismic. Strike-slip faults in the area, when affected by fracturing activities, tend to cause numerous low magnitude earthquakes ($M < 2$). However, due to the surficial geology in the study area, local residents can feel earthquakes as low as M_L 1.8. The faulting appears to sole out in the base of the Montney, thus fracturing activities in the lower Montney tend to cause most, if not all induced earthquakes. The risk of induced earthquakes is reduced for fracturing activities occurring higher in the Montney Formation.

Disposal in the case study area occurs in the Cretaceous Cadomin Formation at 511.3m subsea (1311m TVD). Fracturing activities in the Triassic Montney formation occur at a range of 1125 to 1425m subsea (1925m to 2225m TVD).

Reservoir and Disposal: In B.C., prior to approval, operators of disposal wells must conduct testing to determine the minimum horizontal stress and initial reservoir pressure. This collection of data is used to determine the allowed maximum injection pressure and maximum reservoir pressure. Once per month, the operating wellhead pressure and the disposal volume must be reported. Once per year, the disposal reservoir pressure must be measured and reported. Knowing if pressure is increasing ensures the disposal fluid is contained, but also provides insight for the fault slip minimum effective stress. The disposal history for this well is shown in the chart below (Figure C.29) and the two earthquake clusters caused by disposal are shown in Figure C.30.

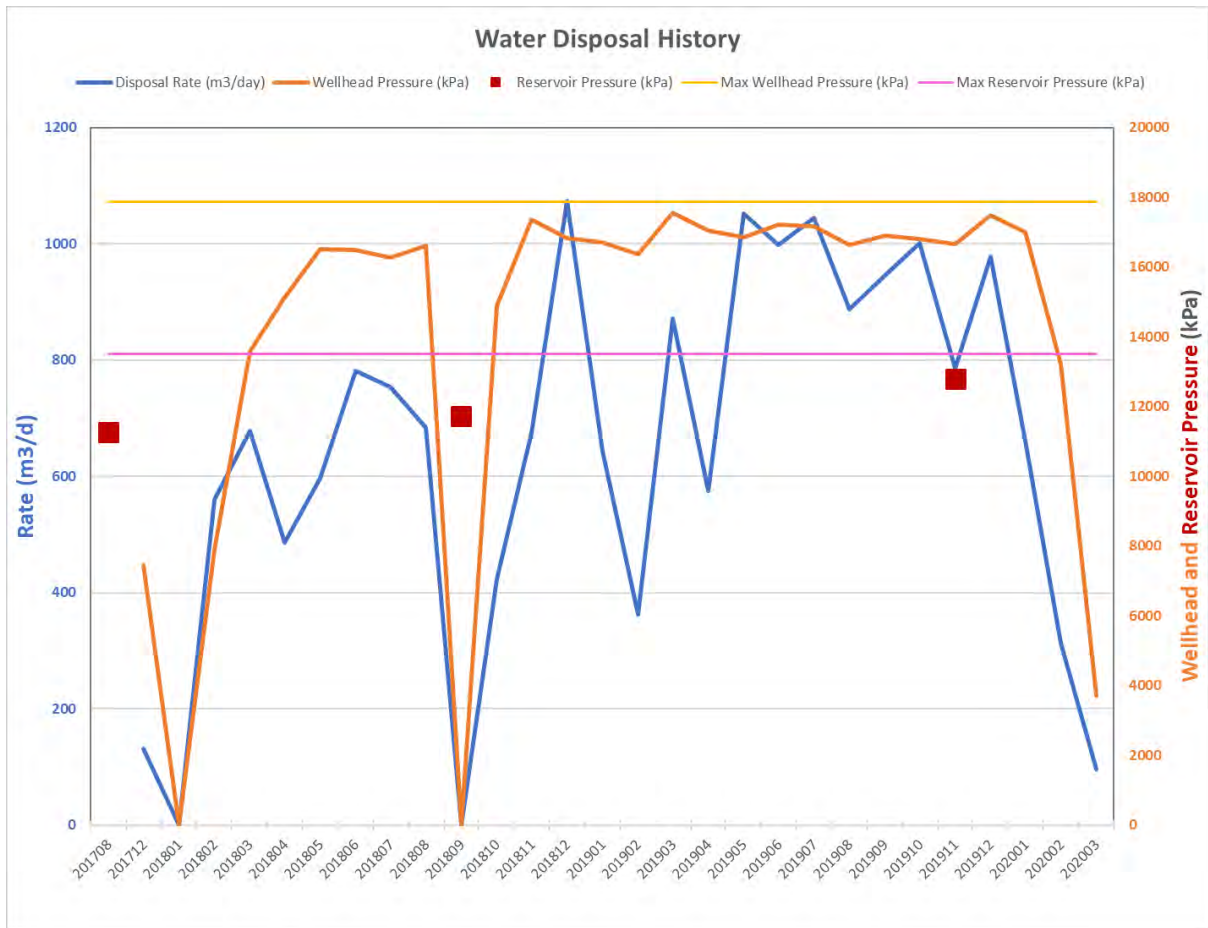


Figure C.29: Disposal well history. Red squares are annual pressure tests.

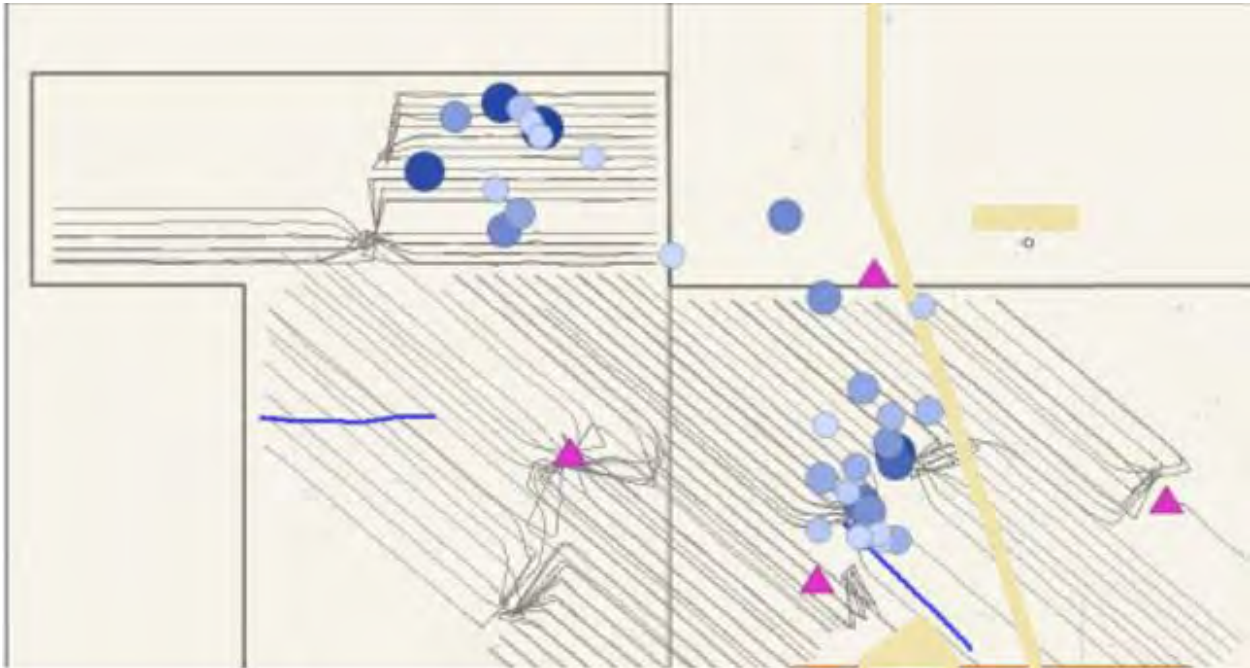


Figure C.30: Earthquake Map showing two clusters caused by disposal activities. The north cluster is predominantly thrust faulting while the eastern cluster shows as strike-slip. Blue lines are horizontal disposal wells. Pink triangles are industry deployed seismometers.

Seismic Monitoring: The BCOGC has deployed, through various partnerships, a nine-station array in the Kiskatinaw Seismic Monitoring and Mitigation Area (KSMMA) which encompasses Tower Lake. The array is further bolstered by a 15-station array operated by McGill University. By regulation, industry must also have access to a real-time array to operate within the KSMMA, so there are additional private stations throughout the KSMMA. Operators must also deploy an accelerometer within 3 km of their well pad. Water disposal wells that cause seismicity require depth accuracy, so typically employ three to five seismometers within 3 km of the disposal well. In this case, the increased density of monitoring equipment deployed near water disposal wells has had the added benefit of enabling the accurate depth determination of nearby fracturing related earthquakes. Fracturing and disposal stopped in the case study area early in 2020, due to reduced commodity price. Not surprisingly, the cessation of fracturing and disposal activities has nearly eliminated all seismicity in the area, with only a sparse count of earthquakes since March 2020 and all below **M** 1.5.

Results: Using the BCOGC array in consultation with industry, the BCOGC was able to allocate earthquakes and locations to specific activities (Figure C.31). Having an open dialogue with industry during activities is essential to accurately allocate earthquakes to activities in conjunction with an array that can provide accurate X-Y earthquake locations. This is particularly the case with concurrent operations in close proximity that have seismic potential.

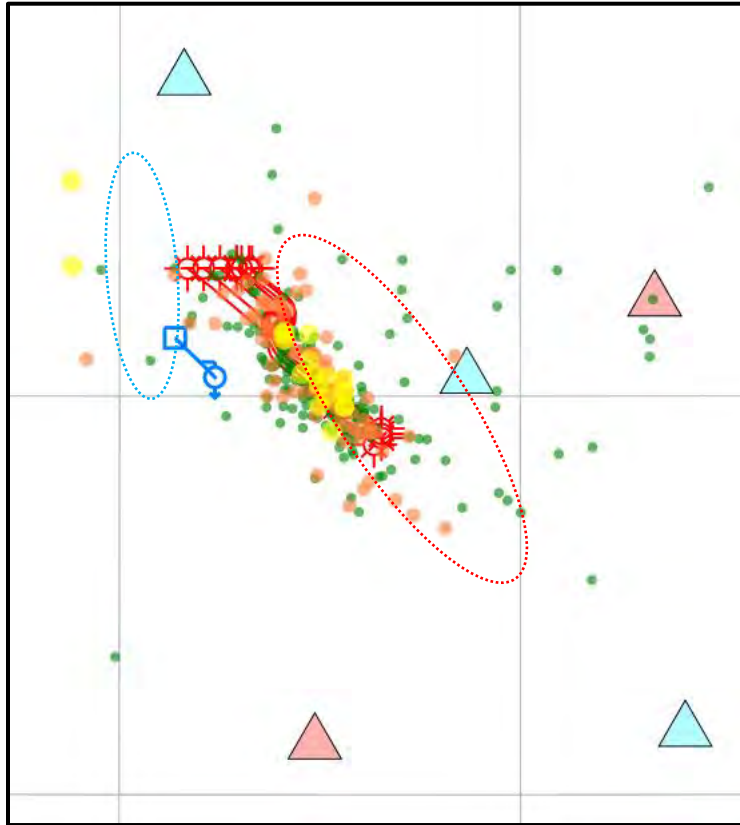


Figure C.31: Earthquakes during fracturing of subject wells. Fracturing wells in red and disposal well in blue. Green dots are earthquakes below ML1.5. Orange dots are earthquakes between ML1.5 and less than 2. Yellow dots are earthquakes greater than ML2. The blue dotted oval outlines disposal related earthquakes and the red dotted oval outlines fracturing related earthquakes. Triangles are the locations of public (red) and research (blue) seismic stations. Grey boxes are six miles by six miles.

Discussion: The operator of the subject fracturing well pad undertook several pre operation steps to alleviate residents' concerns. An open house was held prior to fracturing operations to provide information and solicit feedback. As required by regulation, they notified residents within three km of the wellbore trajectories to be fractured but did so by implementing a 'three door knock' approach, in that they would attempt three different times to hand deliver information packages, so that they had an increased opportunity to meet and answer additional questions.

The operator had planned the drilling program so wells were located in both the northward and southward dominant directions and within several distinct strata in the Montney. This provided the operator with operational flexibility to focus fracturing activities on less seismicity prone strata of the Montney (such as the upper or middle Montney) and provide additional relaxation time for the lower Montney. The operator also used a high viscosity friction reducer (HVFR) fluid program in the lower Montney, to reduce overall fluid requirements when stimulating the lower Montney, in an effort to proactively reduce the rate of seismicity. The operator began operations with two separate fracturing spreads. Each fracturing spread was focused on the north and south bank of wells, respectively.

Just ahead of operations, there was a local magnitude 2 earthquake on January 27, 2020. This was attributed to the subject disposal well and there was a single felt report from a resident north of the disposal well.

Event			Component H1		Component H2		Mitigation(s) taken	Mitigation intention
Date (UTC)	Time (UTC)	Magnitude (ML)	PGA (%g)	PGV (cm/s)	PGA (%g)	PGV (cm/s)		
2/4/2020	13:02:32	1.84	0.57	0.07	0.64	0.08		
2/9/2020	3:04:39	2.15	0.48	0.08	1.00	0.18	Lower Montney wells on south side removed from one completion cycle	Increase reservoir relaxation time to at least 6 hours
2/9/2020	4:06:28	2.4	1.40	0.20	2.22	0.38	Increase to two completion cycles after second event.	Increase reservoir relaxation time to at least 12 hours
2/9/2020	23:49:17	2.24	1.90	0.23	2.33	0.31	Increase stage spacing on lower Montney wells on south side and decrease tonnage by 20%.	Reduce intensity and speed up operations
2/10/2020	11:48:41	2.21	1.41	0.18	1.47	0.18	Cut stage short and went to flush. Skipping next stage and increasing perf clusters	Disconnect from seismogenic feature and reduce intensity
2/10/2020	16:55:24	2.1	0.71	0.09	0.80	0.09	Release north frac crew	Increase operational flexibility
2/10/2020	21:55:12	2.17	1.16	0.16	0.84	0.12	Frac spread reconfiguration	Allows Lower Montney wells to be taken out of completion cycles
2/11/2020	5:25:57	2.3	1.91	0.24	1.81	0.26	Latent event - frac spread reconfiguration on-going	Operations will take longer, but with more flexibility
2/12/2020	22:07:14	2.2	0.72	0.09	0.78	0.08	Lower Montney well being completed at time of event taken out of next cycle rotation	Increase reservoir relaxation time
2/13/2020	11:55:15	2.22	0.58	0.11	0.62	0.09	Reduce cycles for completion of mid and lower Montney wells on the south side	Reduce completions in seismogenic zone to once per day per well
2/16/2020	2:52:38	1.83	1.01	0.12	0.26	0.03		
2/16/2020	13:50:23	2.06	0.51	0.06	0.47	0.06	Reduce cycles for completion of mid and lower Montney wells on the south side	Continue with reduced daily operations on seismogenic zones
2/17/2020	18:30:28	1.95	0.26	0.04	0.10	0.02		
2/17/2020	21:16:40	1.99	0.32	0.06	0.28	0.05	Latent event from the M1.95 event earlier. Take well out of cycle	Increase reservoir relaxation time
2/19/2020	13:15:47	1.88	0.30	0.03	0.78	0.09		
2/19/2020	18:02:12	1.8	0.35	0.04	0.29	0.03		
2/20/2020	2:44:47	1.85	0.83	0.09	0.29	0.03		
2/21/2020	1:57:33	1.94	0.20	0.02	0.19	0.03	Ops complete - These are latent flowback events	
2/21/2020	2:55:15	1.92	0.40	0.05	0.38	0.05	Ops complete - These are latent flowback events	

Figure C.32: Felt reports received during fracturing.

During operations, the operator implemented several mitigation steps to avoid seismicity including increasing fluid viscosity to keep fracks close to the well, stage skipping, increasing relaxation time between stimulating stages and reducing total volume. Social engagement was also implemented by the operator during operations to answer additional resident questions and concerns. Mitigation and downhole issues reduced the total scope of the operations by over one-third on the south bank of wells. The open dialogue between the regulator and the operator allowed each entity to fully understand the impact of their programs and to properly allocate earthquakes to activities, ensuring additional mitigation measures were not applied unnecessarily. Several earthquakes were felt by local residents, which, when above M_L 2, had a consistent description as “being like a truck hitting the side of the house”. These non-damaging earthquakes were nonetheless startling to local residents and mitigation measures were largely focused on reducing the frequency of earthquakes above M 2. For this well pad, a total of 10 earthquakes above M 2 were recorded with the largest earthquake being local magnitude 2.4. Figure C.32 provides the accelerometer measurements from the felt reports, along with mitigation measures employed by the operator when a M_L 2+ earthquake occurred. Although some earthquakes had a peak ground acceleration (PGA) that surpassed 0.02g, which would be widely felt, the coinciding peak ground velocity (PGV) did not exceed 0.4cm/s, which is well below any measure for potential onset of damage.

Measuring the overall effectiveness of the mitigation plans is difficult, but overall, there were in excess of 400 stages completed with 10 earthquakes above M_L 2 and no earthquakes above M_L 3, which is the regulatory threshold at which suspension of hydraulic fracturing activities must occur within the KSMMA. Mitigation will continue to be the focus of research for the BCOGC, with the goal of reducing the frequency and effect of earthquakes to local residents.

Alberta, Canada Case Study – Cardston

This case study provides evidence that slip on seismogenic faults are a response to pore pressure increases, due to hydrologic communication from hydraulic fracturing operations. This case study was a multi-disciplinary investigation of the earliest known case of induced seismicity multi-staged horizontal fracking in Canada. Although it is difficult to identify seismogenic faults, this study provides a proxy (karsting features) that could help identify zones of susceptibility.

Background and Objectives: The Alberta Geological Survey (AGS) is a branch within the Alberta Energy Regulator (AER) that monitors earthquakes throughout the province of Alberta. AGS maintains a regional seismometer network and earthquake catalogue for the province (Stern et al. 2013; Schultz & Stern 2015). Through this network they provide induced seismicity research and regulatory compliance monitoring for all traffic light protocols used for induced seismicity risk management (AER 2015). Regulatory development for induced seismicity within Alberta receives guidance and maintenance from AGS and other government as well as academic stakeholders.

Within the Western Canadian Sedimentary Basin (WCSB) there are two hydraulic fracture target formations that are responsible for the majority of induced earthquakes: the Duvernay and Montney Formations (Atkinson et al. 2016). In British Columbia (B.C.), the majority of induced earthquakes occur in the Montney Formation in northwest B.C. (Babaie Mahani et al. 2017). Alberta has yet to experienced induced earthquakes from operations within the Montney Formation; it has predominantly experienced earthquakes from operations in the Duvernay Formation (Schultz et al. 2015; 2017). While Alberta and B.C. have experienced disposal and secondary-recovery related induced seismicity, the majority of concern is focused on multistage horizontal fracturing (MSHF) induced seismicity. The first reported case of MSHF induced seismicity occurred in B.C. in 2012.

In 2012 the British Columbian Oil and Gas Commission (BCOGC) reported the first case of MSHF related induced seismicity in Canada within the Horn River Basin (BCOGC, 2012). Operators were required to monitoring and report within 30 days of completion MSHF operation of a any M_L 4 earthquake (reported by Earthquakes Canada) within 3 km of a hydraulic fracturing operation would be considered a “red light” stopping operations (BCOGC 2014). In December 2013, Alberta experienced a cluster of induced earthquakes 30 km to the west of town of Fox Creek, Alberta (Schultz et al. 2015). Alberta experienced induced earthquakes as well, and in February of 2015 a traffic light protocol was introduced to help manage induced seismicity for particular zones of occurrence (AER 2015). The Alberta regulatory tool required operators engaging in MSHF within the Duvernay Formation to monitor earthquakes, report earthquakes “yellow” M_L 2, stop operations “red” M_L 4, do a pre-hazard assessment, and have a response plan.

December 2011 - March 2012 a cluster of more than 60 small earthquakes (M_L 0.7-3.0) were detected north of the town of Cardston, Alberta (Figure C.33). Historically this part of the WCSB has not recorded many earthquakes, so these were seen as anomalous. At the time there was not widespread recognition of induced seismicity related to MSHF, so the realization that this was induced earthquake did not happen until years later. The AGS has published two studies for this cluster of induced earthquakes (Schultz et al. 2015; Galloway et al 2018). This case study will review both studies and their findings.

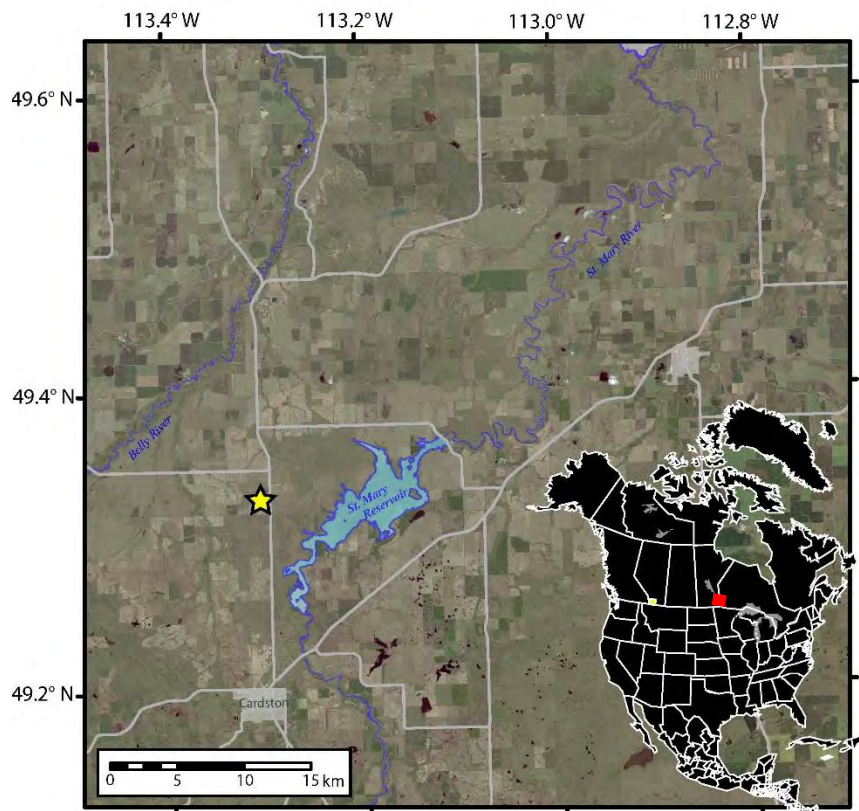


Figure C.33. The yellow star indicates the location of the cluster earthquakes, north of the town of Cardston, Alberta, Canada, map location indicated by the orange square (modified from Galloway 2018).

Geology: The WCSB is comprised of Cambrian to Paleocene sediments deposited in a foreland basin. This asymmetric basin is deeper toward the mountain front and thinner toward the east. Sediment thickness varies between ~5,000 m deep on the western portion and thins to the east. The Devonian-Mississippian age Exshaw Formation (2,845 m deep), which was the target of the seismogenic well. This zone was targeted due to overthickened portion (11 m thick). Cores collected near other areas of overthickened Exshaw and near the overthickened section by the well, have shown brecciation with dolomitization as cement (Galloway et al. 2018). Subsurface imagery (3D seismic for the area) exhibits evidence of a basement rooted fault below the area of the cluster earthquakes and associated with the overthickened Exshaw.

Seismic Monitoring: Earthquakes were detected, and information was collected from seismologists within the AGS as part of the AGS earthquake catalog. The catalog included monitoring from AGS's RAVEN network (Schultz & Stern 2015) and publicly available data. The area was sparsely monitored at the time, and so a matched-filtering search algorithm was used to extend the detection threshold. The magnitude of completeness at the time of the incident was $M_L \sim 2.5$ (Schultz et al. 2015a). Using HypoDD (Waldhauser 2001) and a statistical distribution examination, a robust hypocenter relocation providing a better relative geometry of the earthquakes in the subsurface (Figure C.34).

Operations: The seismogenic well in question was drilled into the 11 meter over thickened Exshaw Formation at ~ 2,845 m depth. The treatment for this well was completed in 10 individual stages, with average mean pressure (73.9 MPa), pumping rates (5.5 m³/min), total pumped fluid volume (716m³),

and proppant weight (150 tons). The well bore trajectory changes from vertical above the target Exshaw Formation, then transitions to horizontal at 320 azimuth for 1.6 km. Earthquakes only began after the fifth stage of completion.

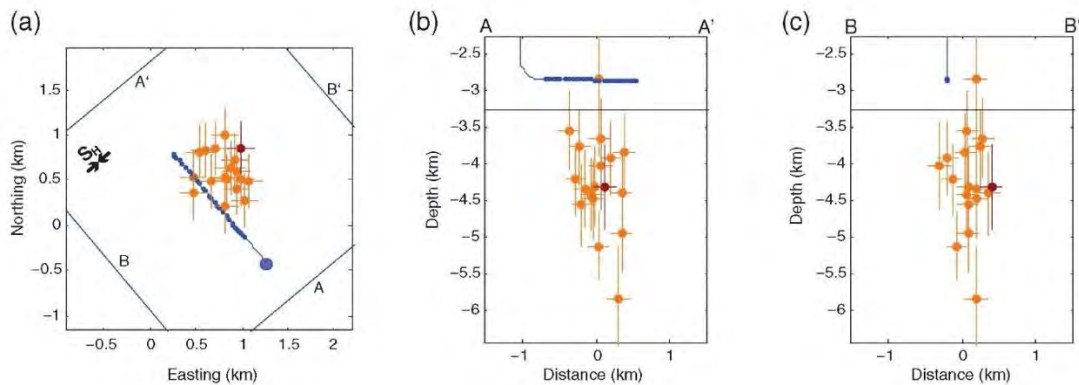


Figure C.34. Robust double-difference relocations of earthquakes; cross hair span indicates error ellipses. (a) Map view of epicenters (circles with cross hairs) in relation to the surface location (larger circle) of measured earthquakes related to the activity. The blue line represents the well bore and perforation intervals (smaller circles). (b) Depth cross section trending approximately southeast to northwest, from A to A'. (c) Depth cross-section trending perpendicular to wellbore azimuth (and parallel with regional maximum horizontal stress S_H). The majority of well-relocated earthquakes are within the Precambrian (denoted by horizontal line)(modified from Schultz et al. 2015).

Results: The cluster of earthquakes north of Cardston, Alberta was correlated to the operations of the nearby MSHF and deemed induced. This was demonstrated through temporal and spatial matching of the operations and earthquakes (Schultz et al. 2015b). The brecciated zones surrounding the overthickened Exshaw Formation have been interpreted as evidence of paleokarsting, which explained the areas of overthickened Exshaw as the subsequent deposit infilled the karst. The observed karsting is proposed to be genetically related to a basement rooted fault, that hosted paleo fluid-flow and produced the karst. The basement rooted fault penetrates into the overlying sediment and are reactivated during the hydraulic stimulation. This proposed scenario supports communication of hydraulic fracturing fluid pathways through preexisting faults.

Appendix D: Design and Installation of Seismic Monitoring Networks

Introduction

A seismic monitoring network consists of field equipment sensors, data loggers, data communications, power sources, and enclosures and off-site computers to store data for processing and archiving, installed in discrete locations across a particular area for a particular length of time. Network designs require specialized work to determine appropriate locations, based on substrate into which the sensors are installed, availability of communications, acceptably low background noise, etc. (See Savvaidis et al. 2019 for an example). Research groups, universities, consultants and/or vendors can provide the specialized knowledge needed to design and install seismic monitoring networks. This appendix provides a primer for interested regulators. Figure D.3 shows a fully installed station, this one located at the University of Texas in Dallas.

Equipment and Operation

Sensors are deployed as part of an array of seismic monitoring stations within the network. Seismic sensors come in three basic types: 1) broadband sensors, 2) short-period or high frequency geophones, and 3) strong motion sensors or accelerometers (see discussion below). Modern sensors measure motion in the vertical direction and two orthogonal horizontal directions.

Data loggers are on-site units (e.g., field computers without monitors), which are linked to the seismometer or other sensors, and that record and process data for transmission. For data quality, seismologists recommend at least 24-bit resolution and a capability of recording waveform data at a sampling rate of 100–1000 Hz. Data loggers usually communicate in real time with a central computer for data processing and state-of-health seismic monitoring, but also store data onboard in case communications are disrupted.

Data communications can be provided through cellular modems in most regions of the U.S., enabling flexibility and low cost. Where this method is not possible, options such as spread-spectrum Ethernet or low-power VSAT satellite transceivers enable station placement anywhere within North America.

Power may be provided by available AC sources or using off grid options such as solar or wind. Care should be taken to ensure that the power source, whether wind turbines or solar panels do not cause vibration that the seismic sensor may pick up.

Enclosures protect surface equipment against weather elements and vandalism. One popular solution is the use of steel job site tool chests with double locks, secured to the ground if possible. In some cases, a security fence around the site may be required. It is advisable to inform local authorities of the location and purpose of the equipment.

Data storage and processing: Seismic data recorded by a network and transmitted to a central site, or brought back to a central site, needs to be processed and analyzed for event detection and cataloging. Preliminary results for earthquake location, depth, and magnitude can be made available via automated systems within a few minutes of an event occurring, depending on the proximity of a sufficient number of sensors to the event, filtering of background noise, etc. In some cases, data should be in a format that is readily integrated with other systems (e.g., the USGS Advanced National Seismic System, or ANSS). Depending on the quality of the data and network, the Incorporated Research Institutions for Seismology (IRIS) can archive data for use in the public domain. All data, whether continuous or manually downloaded, should be archived, and backed up depending on how the data are used, archiving and multiple backups are required. Meta-data, which includes details of the site, instrumentation, and installation, should also be retained for each station for reprocessing as needed.

Network Installation: For simple background seismic monitoring networks, sensors can be deployed in “post-holes” with depths of 1 to 3 m below surface to avoid surface noise. In general, deeper deployments yield better results as they are both away from surface noise and can be better coupled with bedrock motion. These “borehole seismometers” can be installed in purpose drilled or existing wellbores. Depths for borehole type of deployments can be anywhere in depth from 100 m to over 1 km and require more rugged cabling and instrumentation. Where posthole or borehole sensors cannot be deployed, a surface deployment can be used, but will often be accompanied by more noise and poorer coupling to Earth, which reduces detection of smaller earthquakes. Regardless of the type of emplacement, the sensor should be placed as far away as possible from sources of cultural or electrical noise (e.g., roads, pump jacks, windmills, or other equipment).

Operations and Maintenance: Seismic monitoring stations do occasionally fail, so redundancy and regular state-of-health checks are suggested. Most seismic data loggers record state-of-health parameters (e.g., battery voltage, data transmission checks, etc.) and transmit these data to the acquisition computer in near real-time, enabling network operators to remotely monitor network performance and schedule operations and maintenance (O&M) trips to solve problems that could affect data quality and reliability. Basic O&M including cleaning of solar panels, checking electrical connections, and upgrading firmware should be performed on a station regularly (e.g., quarterly). Occasionally, data transmission interruptions may require site visits to recover data from local storage in the data logger. A typical O&M site visit takes about 20 or 30 minutes, but longer depending on whether the sensor itself is faulty and needs to be replaced.

Network Design

Number of sensors: Seismic sensor data are used to estimate distance to the event, based on seismic “P” and “S” wave arrival times. Placing multiple sensors allows for the use of triangulation between multiple sensors and the hypocenter of the event (see Appendix A). Accuracy in determining earthquake location improves with the number of and proximity to sensors. A minimum of three stations is recommended, with a minimum of four to estimate earthquake depth location. It is not uncommon to deploy a dozen or more stations around areas of interest.

Distance: To record smaller earthquakes ($\sim M$ 0.5– M 3.5), such as those normally associated with induced seismicity, stations need to be close to the event. As a rule of thumb, the stations are set a separation distance of up to one to two times the depth at which the earthquake hypocenter might be expected to occur, but the best-case scenario is when the sensors themselves are installed atop the hypocenter, so that the energy moves vertically upward toward the sensor.

Types of sensors: Three component sensors measure motion in three orthogonal directions but vary chiefly in their design frequency range. The optimum frequency band depend on the event magnitude, distance of the sensor to the event, signal attenuation as it passes through the Earth, and other geologic conditions.

- *Broadband:* Regional and national networks usually employ broadband sensors because they cover a wider frequency range, are often deployed at greater distances, and can measure longer period signals. They are significantly more expensive and fragile than high-frequency geophones.
- *High-frequency:* Short-period, three component geophone sensors can be used for local networks, such as for cases of potentially induced seismicity, as the earthquakes tend to be small magnitude, close, and contain predominantly high frequency energy.
- *Strong motion sensors:* Strong-motion sensors (accelerometers) can complement the high frequency sensors. They are useful for characterizing the level of longer period ground motion or shaking caused by earthquakes, of particular concern to people, buildings, and infrastructure.

Background Noise directly affects the ability and effectiveness of analyzing seismic waveforms, especially for smaller events when the signal-to-noise ratio is very low. Signal to noise is the measure used by seismologists for the proportion of data related to the earthquake versus background noise. Stations are better placed away from known noise sources (e.g., roads, pumps, electrical lines, trees, water lines, gas lines, etc.). Deploying sensors in boreholes, even shallow boreholes, if coupled to bedrock, can significantly reduce noise, and provide clearer earthquake signals, often to lower magnitudes. Networks should be designed to maximize the signal-to-noise ratio.

Velocity model: As mentioned earlier, distance from the hypocenter to the sensor is the most important outcome from analyzing seismic data. Calculating distance relies on the velocity of seismic waves through the Earth. An accurate velocity model, often in units of km/sec is the primary determinant of location accuracy; minor variations in velocity through different geologic strata can cause large errors in hypocenter location and depth. Surface “check shot” and seismic refraction surveys can often provide excellent “P” and “S” wave velocities and ground truth information. Sonic logs from local oil and gas wells can provide supplemental data but are naturally limited to the depth of the wells. The extent to which a local velocity model is needed, versus the regional velocity models used by the USGS National Earthquake Information Center (NEIC), depends on the goals of the network and need for lower magnitudes of completeness. Research continues on the optimum method of determining velocity models, whether by ground truth or advanced numerical techniques

(e.g., Huang et al. 2019). There is also significant discussion on the best ways toward accurately locating smaller induced events. One route uses local velocity models, derived from local velocity and geological information, and the other is to install more seismometers. Different geologic scenarios and ability to densify the networks will lead to different approaches.

Performance modeling is recommended as part of network design. Seismologists use these to predict the response of their instruments for earthquake magnitudes and locations (especially depth). The models account for the number of stations, the placement of those stations, and minimum magnitude detection threshold desired, and regional variations in the velocity model, attenuation properties, and site noise. Using these approaches, network designers can optimize locations to keep costs acceptable, while creating a network that satisfies the requirements of monitoring earthquakes at specific magnitudes thresholds.

Development of TexNet Seismic Monitoring Network

Beginning in 2008, the rate of seismicity significantly increased across the southern mid-continent of the U.S. In Texas, the rate of recorded seismicity increased from an average of one to two earthquakes per year of magnitude greater than **M** 3.0 between 1975 and 2008, to an average of about 12 to 15 earthquakes per year between 2008 and 2019 (Frohlich et al. 2016; The Academy of Medicine, Engineering and Science of Texas 2 017).

Pre-2016, the network of 18 operating seismic monitoring stations, irregularly distributed across Texas, was insufficient to detect, locate, and properly characterize seismicity at a level of accuracy necessary to understand either what caused events or if any actions could be taken to reduce the recurrence of such events. In mid-2015, however, the Texas State Legislature appropriated \$4.471M for fiscal years 2016-2017 under House Bill 2 (HB 2) of the 84th Texas Legislature for the purchase and deployment of seismic equipment, maintenance of seismic networks, research, and modeling of reservoir behavior for systems of wells in the vicinity of faults, and establishment of a technical advisory committee. This initiative, known as TexNet, is operated by the Bureau of Economic Geology (BEG) of the University of Texas at Austin (UT), which serves as the state geological survey. Since the 2015 biennium that created the program, two additional biennia have funded the program, including the 2020-2021 fiscal years, which directed funding through UT Austin.

TexNet is a network of stand-alone, broadband seismometers that are being installed in suitable locations throughout Texas in two configurations, permanent and portable. TexNet installed 24 permanent and three auxiliary stations that, when integrated with the existing 18 stations, compose the backbone seismic network of 45 stations, enabling BEG to monitor and catalog seismicity across Texas, at magnitudes to **M** 2.0, and lower in some local areas where seismometers are more closely spaced.

In addition to this backbone network, more than 60 portable seismic monitoring stations also have been acquired and deployed, allowing for detailed site-specific assessments of areas of active seismicity. These stations use broadband seismometers and are equipped with accelerometers to measure ground motion when earthquakes are relatively close. As of mid-2020, TexNet now consists of nearly 150 stations in total, with that number changing often to optimize the network to changes in seismicity (Figure D.1).

In October 2017, TexNet began posting all finalized (QA/QC'd) earthquakes detected with its network, dating back to January 1, 2017. The data collected from all seismometers in the network stream in real time to the

TexNet Data Hub, installed at the BEG, for analysis and subsequent distribution to IRIS and the U.S. National Earthquake Information Center (NEIC), operated by the USGS. In addition to the TexNet catalog at <http://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog>, data and analyses are also available to the public through IRIS and USGS.

The original enabling legislation called for the establishment of a technical advisory committee (TAC), which is composed of nine members appointed by the Governor, at least two of whom represent higher education institutions and have seismic or reservoir modeling experience, at least two of whom are experts from the oil and gas industry, and at least one of whom is a Railroad Commission of Texas seismologist. The TAC advises on the use of appropriated funds and on preparation of progress reports. A summary of all activities, in addition to many other papers and presentations, are published on December 1st, of each even year. Though the final state budget for the current (2020-2021) did not specifically mandate formation and operation of a TAC, BEG and the UT President's office have organized a TAC with essentially the same advisory and feedback activities.

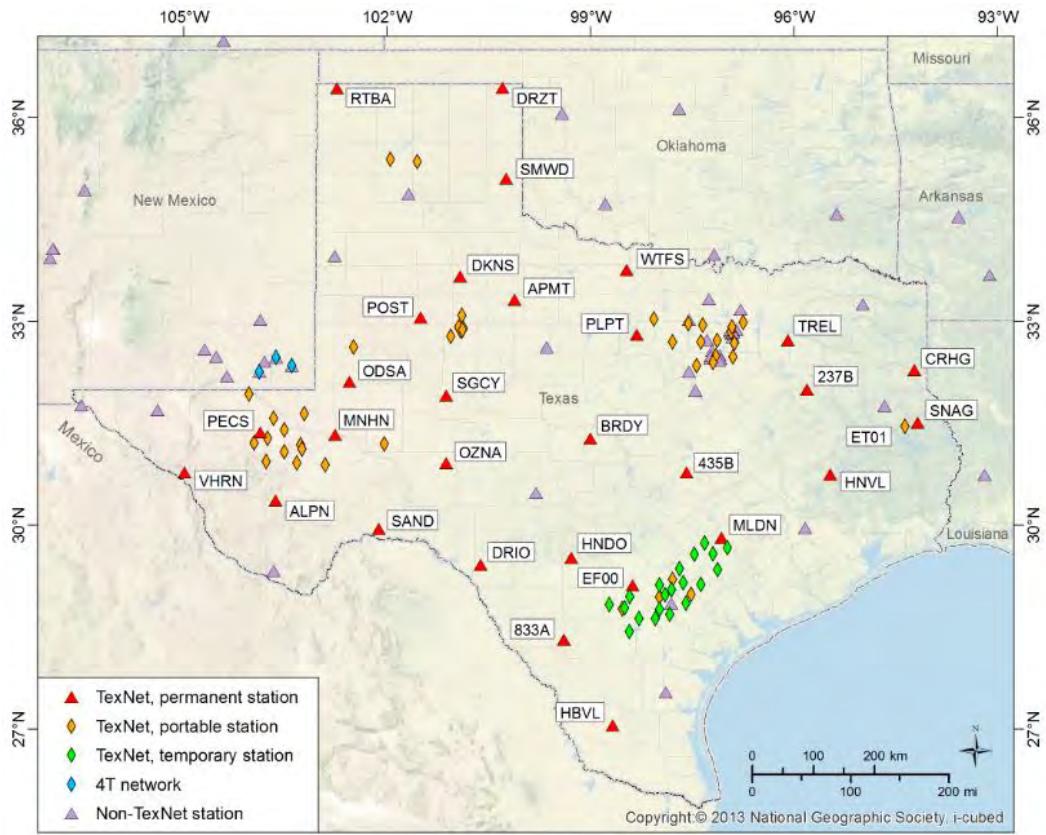


Figure D.1 Map of TexNet seismic network- Fall 2020.

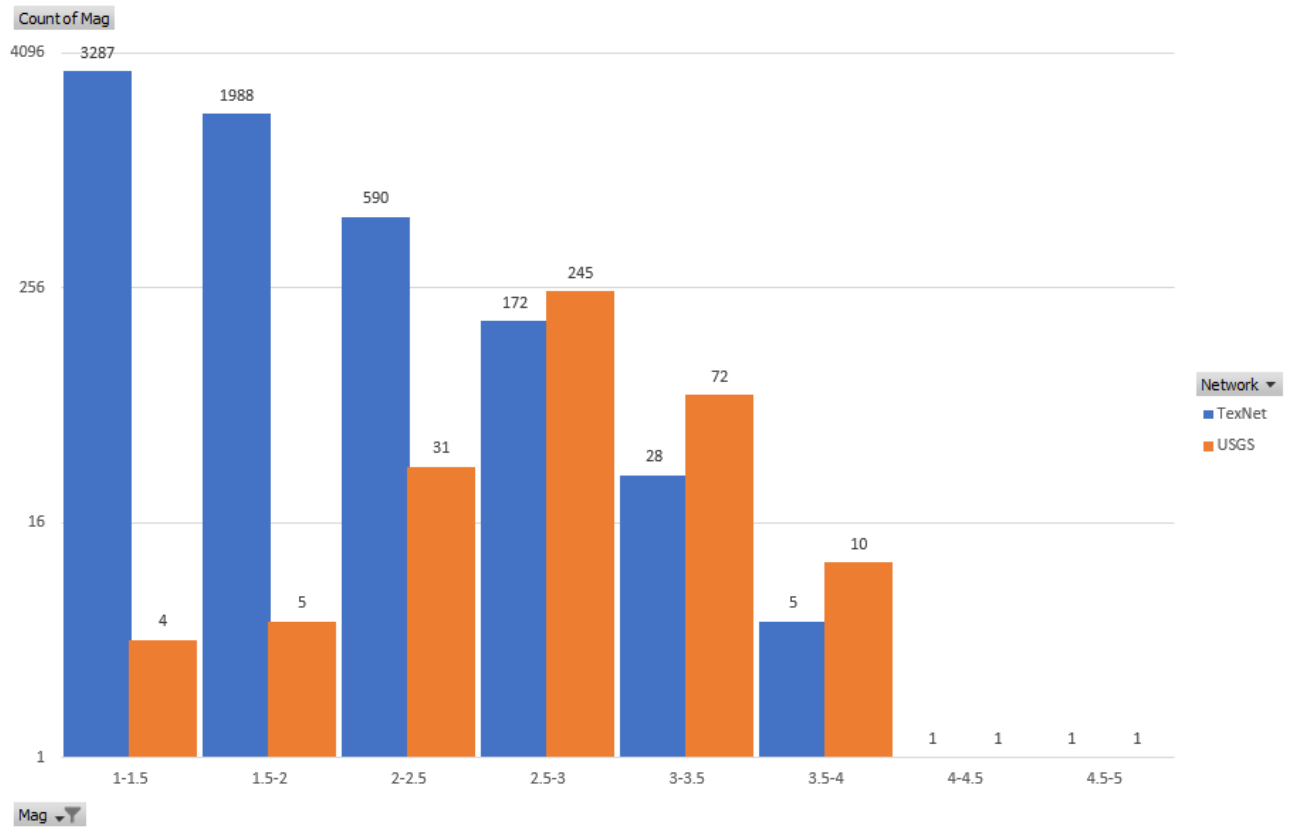


Figure D.2 A comparison of earthquakes posted by TexNet and the USGS. The larger number of events recorded at the lower end of the magnitude scale is due to what the USGS is reasonably able to post. Differences at the upper end of the magnitude bins is due to differences in how TexNet and USGS calculate moment versus local magnitudes.



Figure D.3 Example of fully installed seismological station, located on the campus of the University of Texas at Dallas. Credit: A. Savvaidis, 2017.

Appendix E: Methods for Estimating Reservoir Pressure Changes Associated with Injection

Introduction

A significant challenge associated with understanding whether injection may have triggered fault movement in a specific case is a substantial lack of detailed knowledge of the subsurface stress conditions in proximity to the fault that has slipped. To be able to evaluate whether the failure criteria was primarily met due to pressure increases from fluid injection versus changes to the stress field due to naturally occurring forces requires detailed knowledge of tectonic forces, fault friction, subsurface stress fields, and reservoir properties and structure. In general, this information is not accurately known or well characterized.

However, reservoir pressure modeling and geomechanics analysis can be very useful for evaluating relative order of magnitude impacts of injection and providing the supporting information and evidence to apply engineering and geotechnical judgment to a specific situation, considering all available information.

As described in many textbooks and articles on reservoir simulation, the tools of reservoir simulation range from the intuition and judgment of the engineer to complex mathematical models requiring use of advanced computing platforms. As highlighted by Coats (1987), generally the question is not whether to simulate but, rather, which tools or methods are most appropriate to use for the intended application, identifying the key assumptions that must be made in formulating the input data and calculation methods, and characterizing and appropriately accounting for the full range of uncertainty in the input data.

Over the last several decades, many techniques have been developed and applied for evaluating subsurface pore pressure changes from injection. These techniques include analytical reservoir engineering calculations, three-dimensional computational reservoir models, and integrated three-dimensional reservoir geomechanics computational models. An appropriate analytical or computational method should be selected based on the specific study needs, the technical questions to be considered, the complexity of the reservoir system and fault system under study, and consideration of available input data, data quality, and data uncertainty.

When generally considering evaluation of pore pressure changes in reservoirs associated with saltwater disposal, in most instances the reservoirs targeted for injection will not be homogenous and reservoir properties can vary spatially in all three dimensions (a non-isotropic system). Further the reservoir and geologic structure may not be very well characterized, and the reservoir and geologic model input data may be poorly constrained. Therefore, when considering the accuracy and limitations associated with pressure field calculations, it is important to consider the potential limitations of various modeling approaches and appropriately account for uncertainty in the analysis and when reporting the results (Coats 1969).

In choosing application of a specific calculation approach, the sophistication and complexity of the model may generally be chosen dependent on the level and quality of the data. There can be a natural evolution on the application of reservoir modeling. For example, the first pass modeling effort may be relatively simple and may offer certain insights. Depending on the study requirements and the availability of the data, the analysis may evolve into applying increasingly sophisticated approaches in the model to explore broader sensitivities and expand the parametric studies to further understand the range of possible modeling outcomes. Often advancing to the next level of modeling may require further acquisition and refined definition of geologic and reservoir properties.

This appendix is intended to provide a general overview of available methods and approaches for performing reservoir pressure calculations and the brief overview of general considerations associated with the various approaches. This appendix is not intended to provide a detailed listing of specific computational methods or models, nor is it intended to provide a comprehensive literature review of modeling approaches applied to study of injection related induced seismicity. Specifically, this appendix provides an overview of:

- Key technical items to consider in advance of model development when pursuing or performing pressure field calculations;
- General types of calculations and modeling approaches that are well known to reservoir engineering and geomechanical engineering experts;
- Key items that would generally be prudent to consider when selecting a specific modeling approach; and
- Key elements that stakeholders may generally desire to understand when modeling results are presented or reported.

Key Items to Consider When Embarking on Pressure Modeling/Reservoir Simulation

The reliability, accuracy, and inherent usefulness of any calculation or reservoir simulation of subsurface pressure are substantially dependent on a range of considerations and factors, including:

- Developing a clear understanding of the public, scientific, or business need, and selecting the calculation approach relative to the specific needs.
- Understanding the uncertainty in how the faults have been identified and characterized, especially considering the locations (as inferred from hypocentral locations and focal mechanisms where available) of any actual fault segments that have been reactivated or from interpretation of seismic survey data.
- Identifying and appropriately characterizing the available input data, including characterizing the uncertainty in input data.
- Identifying “missing” or “unknown” input data, and the assumptions and judgment that may be applied in model development accounting for the unknowns.
- Understanding the accuracy and uncertainty of modeling/calculating four-dimensional (time/space) evaluation of the reservoir pressure behavior compared to seismicity data

(including the temporal behavior and spatial locations of injection pressure changes relative to seismic event locations) in heterogeneous reservoirs.

- Evaluating the geologic and reservoir complexity, fault structure, stratigraphic layers, etc.
- Understanding whether a gas-phase may be present in the injection zone and evaluating how to address presence of multiple fluid phases if gas is present in the injection reservoir.
- Establishing the appropriate initial conditions for the simulations or calculations, or if initial conditions are not well described, understanding how to address uncertainty in the initial conditions.
- Establishing the appropriate boundary conditions (e.g., flow or no-flow) for the simulations or calculations, or if boundary conditions are not well described, understanding how to address uncertainty in the boundary conditions.
- Accounting for, as appropriate, the potential presence of other “sources and sinks” (i.e., production and injection wells) in the area of study that can affect the pressure calculations.
- Appropriately calibrating and validating the model with available data and information and considering what may or may not be possible to perform through model history matching to verify integrity of model approach relative to the intended application.
- Implementing and performing parametric sensitivity studies based on the available data and accounting for uncertainty in input data and various model assumptions (and alternative model assumptions).

Types of Models and Calculation Methods

In general, there are three types of approaches that could be considered when evaluating injection related pressure changes: analytical solutions of the pressure diffusion equation; (single-phase or multi-phase) reservoir models and coupled reservoir-geomechanics models.

In general, the required subsurface data to perform pressure calculations are typically estimated from available well logs, core data and well tests. Often, it is recognized that the available data may be limited, or not well characterized, in many instances; or there may be a high degree of reservoir heterogeneity, such that estimated input data values must also include the potential variability and uncertainty present in the reservoir characterization.

Calculated model results will also depend on model assumptions surrounding model size, flow or no-flow boundary conditions, description of faults (serving as permeable pathways or no-flow boundaries), vertical and lateral permeability estimates, use of single-phase flow or multi-phase flow, assumptions surrounding compressibility, etc. Since model input data is generally not well known, modeling typically involves sensitivity studies, using reasonable ranges for the required model input data.

Analytical Calculation Methods

As described in Appendix D of the recent USEPA Report (USEPA 2015), in some circumstances petroleum engineering analytical calculations can be performed and may provide insight relative to the three key components that must all be present for induced seismicity to occur. Different well

and reservoir aspects can be evaluated depending on the possible analytical methods used. These types of petroleum engineering methods typically focus on the potential for reservoir pressure buildup and the reservoir flow pathways around a well and at a distance and characterize reservoir behavior during the well's operation. The petroleum engineering analytical calculations will generally incorporate information typically collected from the well permit application and data on injection volumes and pressures reported for compliance purposes during operation of the well. These analytical calculations are generally based on single-phase fluid systems and assume generally homogenous reservoir conditions (e.g., single values of permeability, porosity, compressibility, fluid viscosity, etc.).

Well operational data can be analyzed using the steady state radial flow equation, while pressure transient tests are analyzed using solutions to the transient radial diffusivity equation. For best applicability, surface pressures should be converted to bottomhole conditions to account for friction pressure loss and the hydrostatic pressure from the fluid column must be added to the surface pressure as part of the bottomhole pressure calculation. The reporting frequency for injection rates can also impact the quality of the analysis.

Reservoir Computational Models

As described by Coats, in a broad sense, reservoir simulation has been practiced since the beginning of petroleum engineering in the 1930s. Before 1960, engineering calculations consisted largely of analytical methods, material balances, and one-dimensional calculations. Reservoir simulation (or reservoir computational models) became common in the early 1960s, as computing software and hardware enabled the solution of large sets of finite-difference equations describing 2D and 3D transient, multi-phase flow in heterogeneous porous media. As such, reservoir simulation methods and approaches are generally well known and well established for the study of simple to very complex reservoir situations.

In applying reservoir simulation methods, there are a range of technical factors and considerations to address as part of the overall model development. These factors and considerations are well known to reservoir engineering experts, and for general reference, a detailed description of fundamental practices and principles associated with reservoir simulation can be found in the Society of Petroleum Engineers Monograph on reservoir simulation (Dalton 1990). As discussed in detail in this monograph, in considering applications of reservoir simulation, there are several key steps associated with developing and running the model, including a) designing the model; b) identifying the reservoir-rock and fluid property data; c) selecting the numerical method, d) establishing suitable grid and time step sizes, e) establishing appropriate initial conditions and boundary conditions; and f) validating simulator with appropriate testing, history matching, and comparison to available well or field data.

Coupled Reservoir-Geomechanics Models

Over the last decade, many researchers have focused on developing models and simulation capabilities that couple reservoir fluid flow dynamics with the reservoir geomechanics behavior.

Coupled simulators are also now being used to investigate and study injection related seismicity. Coupled mechanisms play a significant role in understanding the potential for fault reactivation from pore-pressure changes due to fluid injection. From a fundamental physics perspective, the potential for fault reactivation is described by a coupled set of reservoir flow and geomechanics equations. Application of these types of coupled reservoir geomechanics models typically require extensive cross-disciplinary expertise and experience, a broad range of reservoir characterization data, and advanced computing resources.

An example of a simple coupled Reservoir-Geomechanics model is the Fault Slip Potential (FSP) tool developed jointly by Stanford University and ExxonMobil. This program uses fault location and orientation, injection well locations, rates, and reservoir characteristics, regional stress direction and magnitude, and natural pore pressure. It produces a probabilistic view of fault slip potential in these injection situations, which users can use as a screening tool in advance of siting disposal wells or before more advanced analysis is warranted. Figure E.1 shows an example view in the tool.

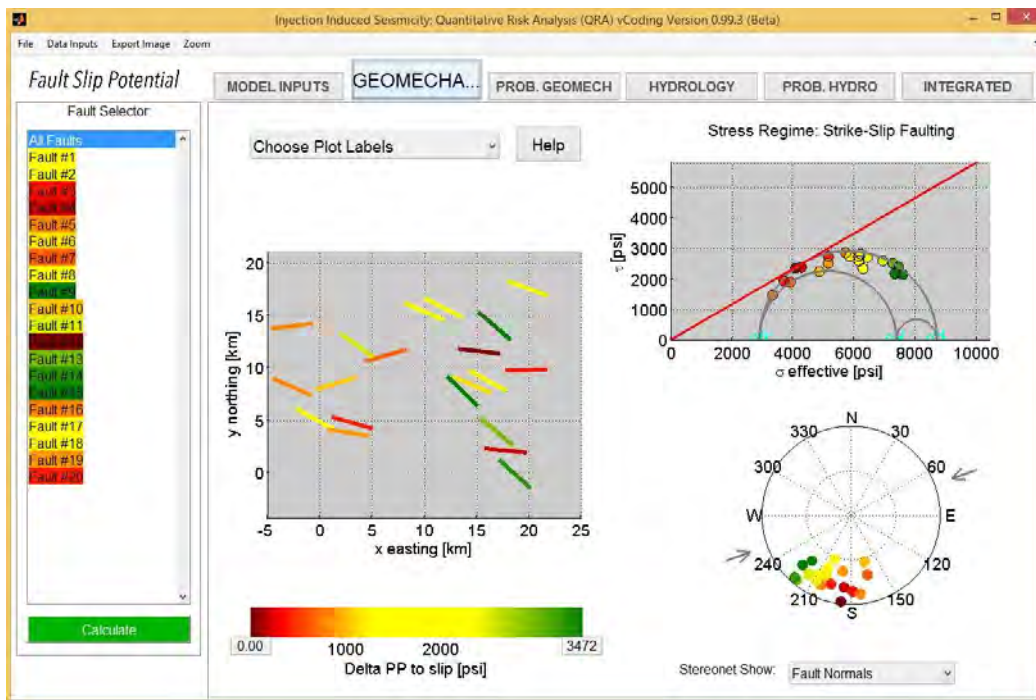


Figure E.1 A view of the Geomechanics tab within the Fault Slip Potential model, showing a map of faults colored by their likelihood of reactivation in a given injection scenario as input in separate tabs, with injection wells located within the faulted area. This evaluation tool can be accessed free, at <https://scits.stanford.edu/software>.

Source: F.R. Walsh, used with permission

Key Considerations for Selecting a Model

In choosing application of a specific calculation approach, the sophistication and complexity of the model may generally be chosen dependent on the level and quality of the data. In some areas, there

may be substantial subsurface characterization data that is available (such as in the case of The Geysers geothermal project). In other cases, there may be very limited subsurface and reservoir characterization data. The level of confidence in any calculation or simulation result is strongly dependent on the quality and accuracy of the available subsurface/reservoir characterization input data. Given this background, selecting a specific calculation or modeling approach or combination of approaches for a given application is then generally influenced by multiple considerations, including:

- The specific public, business, or scientific question or research to be addressed;
- The desired level of accuracy and “uncertainty” reduction to meet the public, business, or scientific question or research to be addressed;
- The desired level of accuracy and confidence necessary for making regulatory, business, or risk management decisions;
- The desired level of accuracy and confidence necessary to suitably test a hypothesis as plausible or implausible (or likely or unlikely);
- The available level of expertise, education, skills, and preferences of the individual modeler;
- The level of detail, availability, and complexity of the subsurface data and well operational data in proximity of the area of study;
- The number of injection wells in the area of study (and considering presence of other operations in area of study);
- The level of knowledge regarding fault locations, and potential fault slip locations, relative to the injection interval; and
- The available computational resources and software; considering available computing platforms (memory, CPU speed, etc.) and software (public open-source, commercial, O&G proprietary codes).

Key Considerations for Reporting Model Results

Many stakeholders may not be intimately familiar with reservoir engineering calculation methods and therefore may not be generally aware that the reservoir modeling calculations do not provide a “single” unique answer. Therefore, to aid stakeholder understanding of model results, it would generally be informative to describe the model approach, data assumptions, model assumptions, results, and result uncertainty considering the intended application of the results. Generally, various stakeholders would expect discussion of the following elements when presenting modeling work and any conclusions based on model results:

- Description of the modeling approach and simplifying assumptions;
- Description of input data available and used, and the uncertainties associated with the data;
- Description of input data that is not available, and how estimates were made in the absence of data;
- Description and characterization of the uncertainties in modeling results based on uncertainties in input data;
- Description and characterization of the range of sensitivity studies performed; and

- Description and characterization of the possible impacts that modeling assumptions have, or may have, on the presented results and conclusions.

Key Messages

Subsurface pressure calculations and reservoir modeling can provide very useful insights to inform the engineering and geotechnical assessments associated with risk assessment and causal assessments of potential injection-induced seismicity. It is important that the calculation and model approaches account for the data uncertainty considering the specific application and area of study.

The level of uncertainty in input data and the complexity of the specific situation will affect the scope of the modeling, the assumptions made in the model development, and the level of uncertainty in calculated results. For complex reservoirs, or situations where limited subsurface data may exist, modeling results may possess substantial uncertainty.

Calculation of reservoir pressure and stress changes due to subsurface fluid injection can be performed using engineering methods ranging from analytical solutions to coupled reservoir-geomechanics computational models. Selection of a specific calculation method(s) should consider:

- Which methods are most appropriate to use for the intended application and research, business, or regulatory purposes, considering the available data and resources;
- Identification of the level of accuracy desired for the intended application;
- Identification of the key assumptions used in formulating the input data and calculation methods; and
- Characterization of and accounting for the uncertainty in the input data.

It is important for stakeholders to understand that modeling results are generally “non unique” and will have a spectrum of possible solutions dependent on the uncertainty and variability of the model input data and assumptions associated with the model formulation.

In general, stakeholders and the technical community will desire that results are reported with description of key model assumptions and the potential impacts the assumptions and data uncertainties may have on model results and conclusions.

Advanced reservoir modeling tools and expertise may need to be accessed for specific studies in complex situations, where there may be a high degree of reservoir heterogeneity, the presence of multiple wells, and/or complex geologic or reservoir structure.

In general, collaboration across multiple stakeholder groups may be necessary to identify, develop, and characterize the input data necessary to perform pressure calculations and reservoir modeling in actual applications.

Appendix F: Data Collection and Interpretation

Introduction

Various categories of data are needed to determine whether the conditions are present for injection- induced seismicity: sufficient pore pressure buildup from disposal activities, a fault of concern, and a pathway for the increased pressure to communicate from the disposal well to the fault of concern. Such determinations are important for both risk management purposes and evaluation of causation.

Assembling and interpreting these data can be challenging, particularly because they may be distributed across many entities. Available data are limited in many categories, including:

- **Subsurface stresses.** Plate tectonics influence nearly all geologic processes (Kious 1996). Yet knowledge of subsurface stress conditions and the crystalline basement is limited for most of the U.S. While subsurface stress measurements may be obtained via well logs and injection tests, the data may be obtained only for limited geographic locations and reservoir depths and may not be publicly available. Additionally, subsurface stress conditions are continuously changing due to natural phenomena and may vary both geographically and with depth (Zoback 2002). Substantially improving the mapping of subsurface stress fields across the will require ongoing collaboration between researchers and oil and gas operators, with recognition that mechanisms need to be put in place for appropriate handling of confidential business data and information.
- **Injection well data.** The frequency of reporting and accessibility of injection well data may be variable between states.
- **Fault locations.** Access to seismic imaging and fault maps needed to identify faults and their locations and orientations may be limited, and detailed basement fault maps generally do not exist across broad regions of the U.S. Subsurface imaging and characterization of the deep basement geology is not routinely done, because this is not a prospective target for oil and gas resources, and seismic imaging can be problematic given basement depths and overlying formations.

Considering these challenges, collaboration across industry, researchers, and regulators is often critical in assembling and skillfully interpreting the necessary data. Recognizing data limits and constraints on information access is critical when evaluating a specific disposal well operation or suspected case of induced seismicity.

This appendix considers “raw data” collection as well as “interpretive data” based on the raw data. As an example, 3D seismic imaging waveforms are “raw data”, but expert interpretation is required to develop the “interpretive data” of identified faults and associated fault maps. Categories addressed are well data (raw), geologic and reservoir data (raw), fault maps (interpretive), basement maps (interpretive), subsurface stress maps (interpretive), and reservoir properties (interpretive). The appendix ends with data sharing considerations.

Well Data

Generally available Class II well data. The most common data available for Class II disposal wells are injection rates and volumes and injection tubing pressures. Such data are routinely reported as part of both EPA direct implementation and state UIC Class II program requirements. Bottomhole pressures (BHPs), which are more suitable for evaluating reservoir conditions, are not as readily available. BHPs either may be calculated based on surface pressure measurements and fluid engineering correlations, or directly measured with downhole pressure gauges. The frequency for reporting injection volumes and pressures varies among regulatory agencies and depends on site circumstances. Although less common, pressure transient test data are occasionally available.

Table F.1. Commonly available UIC data and pressure test measurements. Source: ISWG.

Commonly Available UIC Data	Pressure Test Measurements (Less Commonly Available)
Injection rates or volumes	Falloff/injectivity test for reservoir characterization and well completion condition assessment
Surface tubing pressures	Step rate test to determine formation fracture gradient
Well construction details (tubing/casing dimensions and depth, cementing information, completion type and injection interval)	Static pressures to measure initial pressure and static reservoir pressure change during well operations
Reservoir information (gross and net injection zone thickness, porosity, name and description of disposal zone and overlying confining zones, bottomhole temperature, initial static BHP)	
Reservoir and injection fluids (specific gravity, fluid constituent analysis)	

The frequency of recording and reporting of surface pressure, injection rate, and volume data can vary depending on the regulatory agency requirements. UIC programs may require reporting of injection pressure a number of ways, such as a maximum value and a monthly average or as monthly minimum and maximum values. Recently, improvements in data availability have progressed under state initiatives, such as the Oklahoma Corporation Commission's rule authorizing requests for daily Arbuckle formation disposal well pressures and volumes in areas of seismic concern.

Well pressure measurements and formation pressure buildup: The formation pressure generally increases with injection of fluids in the disposal zone. The magnitude of pressure buildup depends on the reservoir properties and characteristics and the injection volumes and rates, among other things. The pressure buildup is transmitted as a pressure front through fluids in the receiving formation radiating out from the injection well.

Estimating the dynamic evolution of the pressure field due to disposal of fluids requires application of subsurface engineering and reservoir engineering analysis techniques (Lee 1996).

Depending on the reservoir and geologic data available, different modeling and calculation methods may be considered depending on the level of accuracy desired and understanding the data uncertainties that may be present. These analyses consider estimates of reservoir rock and fluid properties, and predict pressure field changes with time, considering injection rates and pressures. Detailed estimates of reservoir properties are required to perform this type of analysis. For the analysis to provide reasonable accuracy requires reasonable estimates for model input data; in many instances, there may be significant uncertainty in reservoir properties.

Analysis of disposal well operating data and information from well testing, such as pressure transient tests, can provide details about the disposal zone reservoir pathway and the condition of the well.

Operating injection rates and pressures are typically collected as part of the permitting compliance activity and consequently are more readily available than pressure transient tests. Completion conditions reflect conditions at or near the wellbore in proximity to the injection interval, while reservoir characteristics describe the disposal zone away from the well. Reservoir characterization assesses the injection formation flow patterns, the formation's capacity to transfer pressure responses dependent on the completion characteristics of a disposal well.

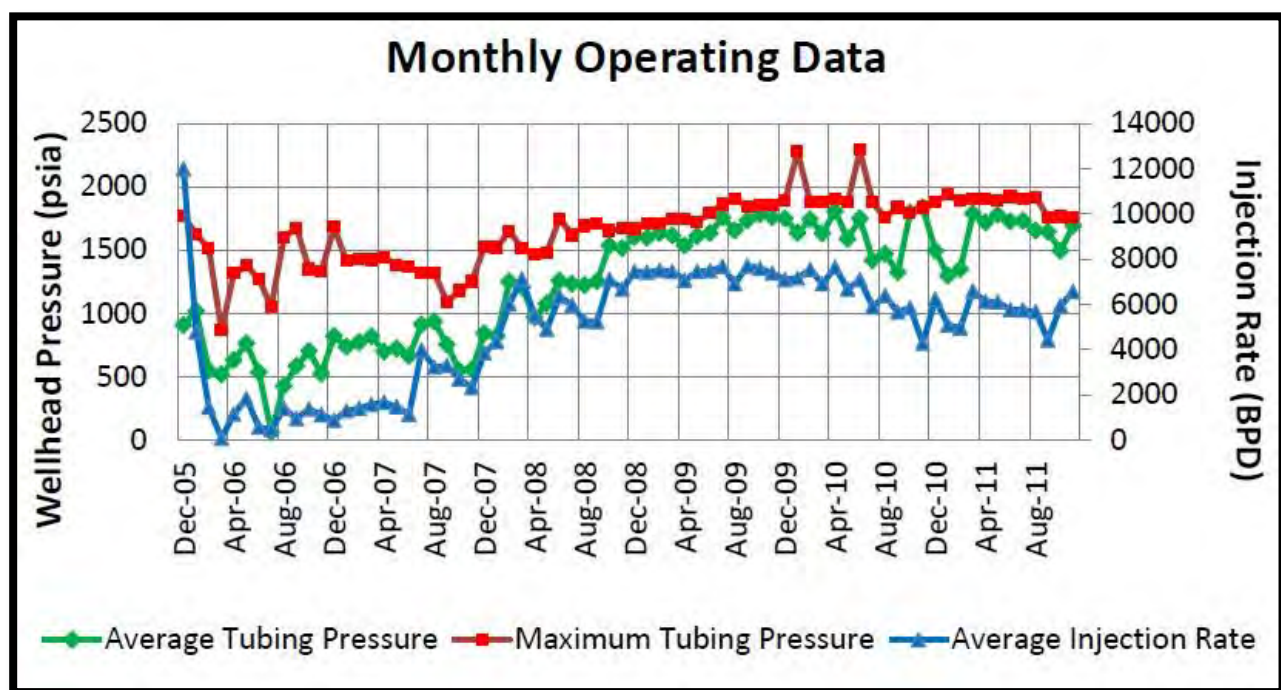


Figure F.1. Typical plot of monthly operating data from a Class II disposal well. Source: USEPA 2015. Identifying reservoir behavior through appropriate analyses and evaluation of the results in the context of the available geoscience data (e.g., presence of faults, etc.) may inform the possible relationships between injection well operations and suspected induced seismic activity.

BHP measurements generally may not be measured with downhole gauges in disposal wells. If BHPs are required, reasonable estimates can be made from the surface pressure and injection rate information.

Estimations require engineering calculations to account for friction pressure loss based on the tubing geometry and injection rates; the hydrostatic pressure from the fluid column must be added to the surface pressure as part of the calculation. In addition, the pressure losses associated with perforation friction and completion geometry effects should also be considered when considering injection well pressure boundary conditions if reservoir models are used to evaluate reservoir pressure changes associated with fluid injection. Using estimates of BHPs, reservoir modeling can be performed to evaluate temporal and spatial evolution of the pressure field throughout the subsurface formations and can provide higher fidelity results when disposal fluid densities change over time.

Geologic and Reservoir Data

Geologic and reservoir data consist of seismic surveys, well logs, and core data. Limitations of each data type are summarized in Table F.2.

Seismic surveys: Seismic surveys provide information on subsurface stratigraphy and structure as well as rock and fluid properties. Seismic data can provide broader understanding of the 2D or 3D subsurface structure as opposed to more localized data that may be available from well logs and core samples. In a seismic survey, seismic waves from a source (dynamite, air gun, or a vibrator truck) move downward into the subsurface. When acoustic waves hit an interface between two layers with different acoustic impedance, some wave energy reflects back to the surface (Figure F.2). How much energy is reflected depends on the change in acoustic impedance. Recording devices (geophones) at the surface or in a well record ground motion versus time. The basic data collected is amplitude of ground motion, polarity of ground motion, time, and spatial location of the geophone. This information must then be processed to produce a seismic section or 3D volume for interpretation. Seismic processing technology is often proprietary. It involves many steps and procedures that may focus on improving signal to noise, enhancing resolution, velocity analysis and migration (adjusting dipping reflectors into their correct orientation). For an interpreter, two key factors are whether the survey is in time or has been converted into depth and whether the survey has vertical exaggeration. Both factors impact whether the seismic image shows strata/structure in their true orientation.

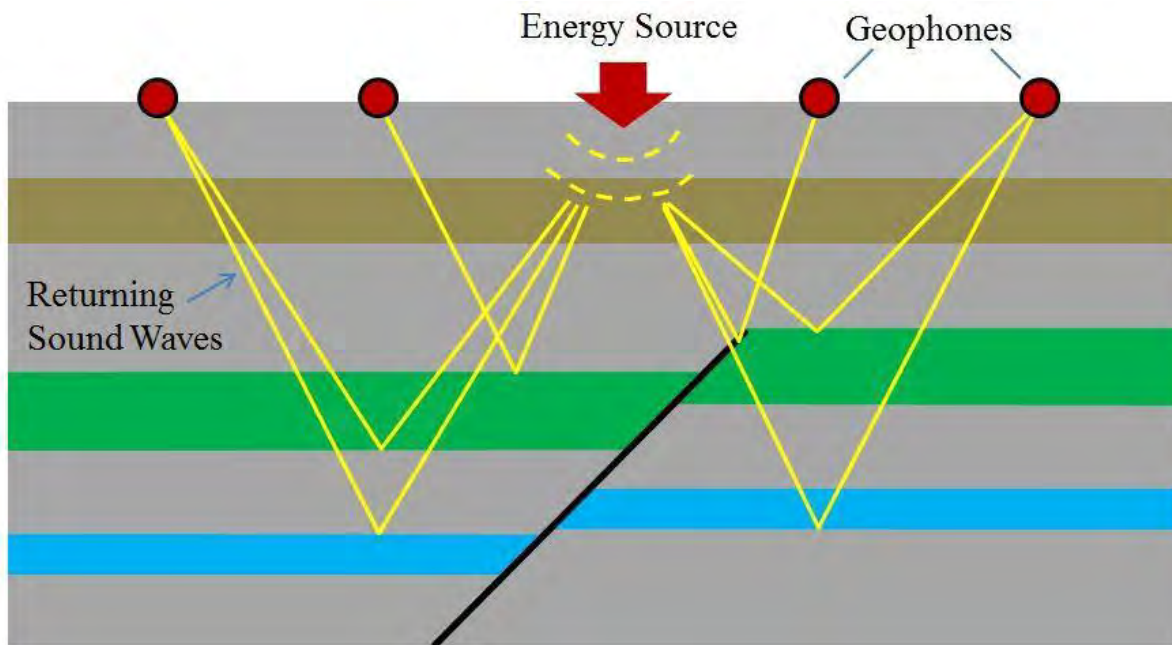


Figure F.2. Schematic representation of typical method used for performing a seismic survey. Source: ISWG.

Seismic interpretation can involve “picking” horizons and faults either with or without the aid of computer algorithms. Faults are usually interpreted by looking for bends, changes in dip, or truncation of reflectors. The visibility of faults on seismic surveys depends on their angle and how much they offset reflectors. Low angle normal faults and thrust faults with significant offset should be easy to interpret. However, high angle strike-slip faults with small offsets would be very difficult to see in seismic data (Figure F.3).

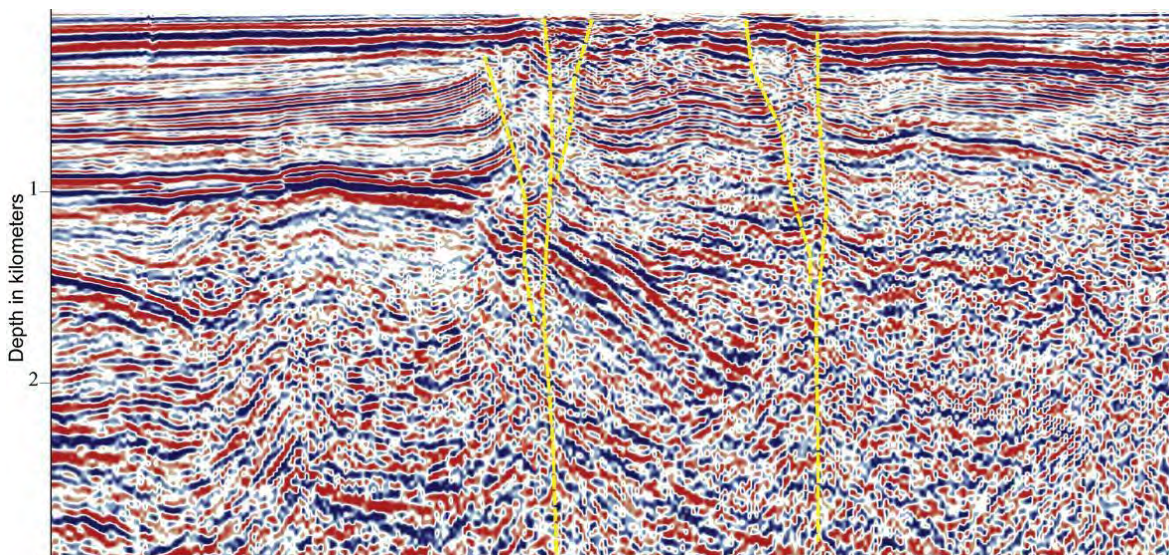


Figure F.3. Example seismic survey analysis illustrating interpretation of fault locations (yellow lines). Image courtesy of USGS. Source: USGS California Seafloor Mapping Program Data Collection 2014.

2D surveys are generally older and of lower quality. One advantage they may have is that many are regional lines that extend for tens of kilometers. With the advent of modern computers, 3D and even 4D seismic survey technologies and advanced processing capabilities have been developed. 4D seismic surveys involve repeating 3D seismic surveys a year or two apart. As the 3D and 4D surveys may target prospective acreage in exploration activities, they generally cover a relatively small area and often are proprietary.

Some acoustic wave energy may also refract at an interface and return to the surface. Refraction surveys were common in the first half of the 20th century but are relatively uncommon now. They have been used to detect crust/mantle boundary, depth to basement, and the top of the water table but are very useful in determining local velocity changes.

Vertical seismic profile (VSP) data are also sometimes available. In a VSP survey, the geophones are arranged vertically in a borehole rather than at the surface. VSP data are commonly used for velocity analysis. They may also be used to image vertical surfaces (salt dome-sediment interface). A “walk around” VSP moves the seismic source azimuthally around the borehole. Shear wave splitting in a “walk around” VSP can determine the orientation of subsurface fractures.

Well logs: Well logs record physical properties of the subsurface versus measured depth in a borehole (Figure F.4). Conventional wireline logging lowers instruments into a well on a wireline cable. Logging while drilling (LWD) or measurement while drilling (MWD) incorporates instruments into the drill string. Common logging tools are briefly discussed below. Many publications describe in detail various well log analysis techniques (Asquith 2004).

- **Gamma ray log:** measures the natural radioactivity of a formation in API units. This tool is useful for distinguishing lithology and changes in formation type with reservoir depth. Sandstones and carbonates typically are low in radioactive elements whereas shales and granitic basement usually contain higher amounts of radioactive elements.
- **Spontaneous potential log:** measures the natural voltage or potential difference between the surface and the borehole in mV. This tool is used to distinguish sandstone from shale and estimate clay content and formation water salinity. In general, shale has a low and consistent SP response, and permeable beds (sands) shift to the right if the clay content is low and/or the pore water salinity is high.
- **Resistivity log:** measures the ability of a formation to impede (resist) the flow of electrical current in ohm m. Resistivity depends on resistance, which is a material property and flow path. Resistivity varies with lithology and pore fluid content. Clay rich formations have lower resistivity than quartz/calcite/feldspar rich formations if the pore fluid content is the same. Hydrocarbons are poor conductors of electricity and water is a good conductor, so resistivity logs are also used to detect hydrocarbon bearing versus water filled (wet) sands (Figure F.4). Resistivity logs are plotted on a logarithmic scale because values vary by several orders of magnitude. If porosity is known from another log, then resistivity logs are used to determine water saturation (percentage of pore space filled with water as opposed to oil or gas).

- **Sonic log:** measures how long it takes acoustic waves to travel a fixed distance through a formation. Transit time varies with lithology and texture but primarily depends on porosity. Dipole sonic logs measure transit time using azimuthally oriented acoustic waves. Shear wave anisotropy from a dipole sonic log can be used to estimate the direction of maximum horizontal stress (Zoback et al. 2003); hence this log is particularly useful for determining stress field orientation. Sonic logs can also be used in converting seismic data from time to depth if other information (check shot or VSP) is not available.
- **Density log:** measures the bulk (grains plus pore fluids) density in g/m^3 of a formation by bombarding the formation with radiation from a known source and counting the resulting gamma radiation. Low gamma radiation implies a dense formation. Porosity as a fraction can be determined from bulk density. Estimating porosity is important for evaluating reservoir pressure response to injection.
- **Neutron porosity log:** measures the amount of hydrogen atoms in a formation, which is primarily contained in either water and/or hydrocarbons in the pore space. High concentration of hydrogen in clay minerals also may impact results. Estimated porosity is given as a fraction. Density porosity and neutron porosity are often plotted together. In many instances, they give consistent estimates of porosity. However, in gas filled sands the density porosity and neutron porosity estimates are significantly different resulting in a crossover of the curves; this log is then particularly useful for evaluating presence of gas in the reservoir.
- **Image log:** measures resistivity or acoustic impedance across the borehole wall with an azimuthal array of electrodes or a rotating transducer, respectively. These logs are used to identify rock fractures and their orientation as well as the dip direction of strata.
- **NMR log:** measures the nuclear magnetic resonance response of a formation to directly estimate its porosity and permeability. This log can be helpful to assess reservoir properties and variations of reservoir properties across the interval that was logged.

Walakpa 1

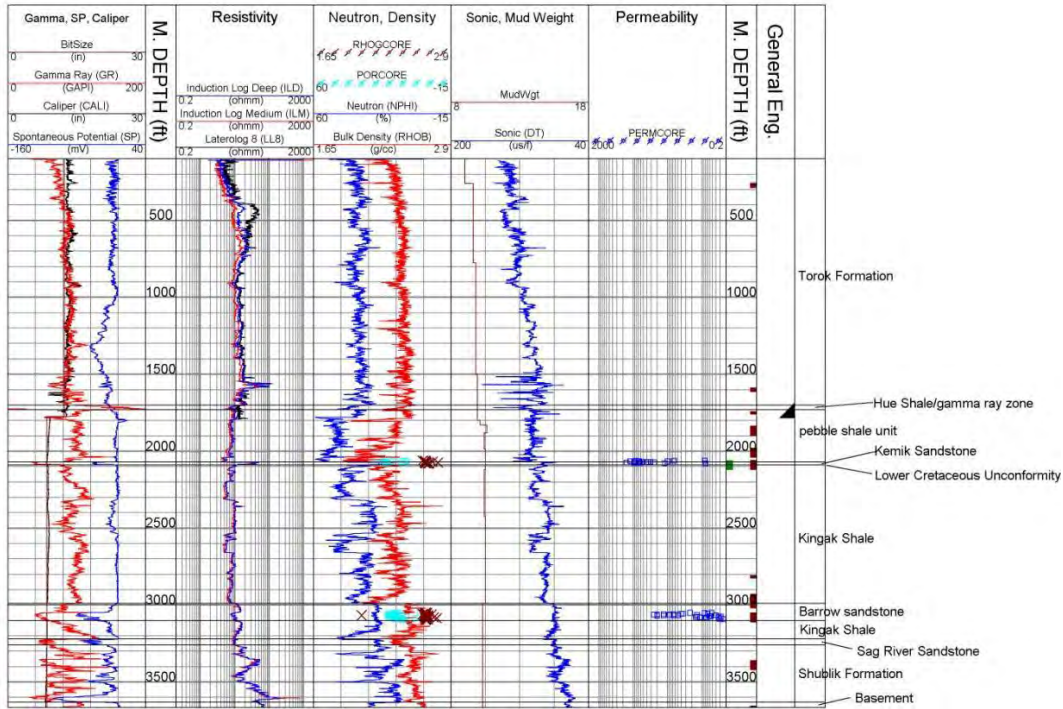


Figure F.4. Example of typical well log display. Source: USGS.

Core data: Physical and chemical properties of subsurface rocks are measured from samples retrieved from the wellbore. As these are direct laboratory measurements on subsurface rocks, core data are the most accurate and detailed measurements. Core sampling is less common than seismic or well log data. Core analysis and/or storage are typically done by a service company.

A conventional core is a four-five-inch diameter solid cylinder of rock extracted with a special drilling bit typically in 30-foot intervals (Figure F.5). Sidewall core is a one-inch diameter and one to two-inch-long sample taken from the side of a wellbore using either an explosive charge to fire a core barrel into the formation or a rotary core bit. Drill cuttings are small bits of rock material brought to the surface by drilling fluid. Core data are often used to calibrate log data (e.g., water saturation or acoustic velocities). Information derived from core analysis is briefly described below.

- **Biostratigraphy and petrography:** core samples can be used for thin sections, XRD, and SEM analysis, which may provide information on paleontology, palynology, mineralogy, grain size, and porosity. This information can be used to determine the age, depositional environment, and diagenetic history of the formation. Conventional and sidewall core can be CT scanned for detailed textural/structural analysis.
- **Fluids and fluid flow (petrophysics):** conventional and sidewall core samples can be used to estimate matrix permeability, relative permeability (water, oil, and gas), fracture permeability,

capillary pressure (force necessary for one fluid or gas to displace another in the pore space due to interfacial tension), water saturation, and wettability (preference of solid grains to contact one liquid or gas over another in the pore space). Water saturation, pore water salinity, and oil gravity also can be measured from core samples. Understanding the reservoir properties is important for reservoir modeling and subsurface pressure field calculations.

- **Geomechanical:** uniaxial and triaxial compression tests, thick wall cylinder tests and other analysis on conventional and sidewall core samples are used in conjunction with CT scans and visual inspection to determine geomechanical properties of the formation rock. Understanding the rock mechanical properties is important for geomechanical studies of fault reactivation.



Figure F.5. Image of core from Sag River Sandstone. Source: USGS. Core images can be found at https://www.google.com/search?q=usgs+sandstone+core+image&biw=1219&bih=836&source=Inms&tbm=isch&sa=X&ved=0CAYQ_AUoAWoVChMlybHdqoroxwIVAiWICH2qdAjl#imgrc=4iuaZVXbqASEkM%3A

Table F.2. Limitations of raw geologic and reservoir data. Source: ISWG.

Category	Limitations/Uncertainty
Seismic surveys	<p>Seismic interpretations are not unique. Different interpretations can be influenced by interpreter experience and bias. This is illustrated by a study in which several hundred geologists were asked to interpret a 2D seismic section (Bond 2007). Eight distinct interpretations were possible, but only a handful of interpreters correctly interpreted.</p> <p>Errors can be introduced by large vertical scale exaggeration and depth conversion problems.</p> <p>Resolution of seismic data depends on the frequency and velocity of the acoustic waves. Resolution is typically ~100 feet so small beds or faults are not resolvable. Resolution depends on the type of seismic survey and numerous seismic data acquisition input parameters.</p> <p>While seismic data can be used to infer a lot about the subsurface, it does not directly measure either lithology or fluid content. This information must be supplemented with well log or core data.</p>
Well logs	<p>If the borehole is not vertical, then measured depth is greater than the true vertical depth (TVD).</p> <p>Drilling muds invade the formation immediately around the borehole, changing its properties.</p> <p>Some log analysis requires bottomhole temperature.</p> <p>Well logs only measure physical properties within a short radial distance of the borehole, typically centimeters to (cm) to meters (m) depending on the tool.</p> <p>Some log analysis requires bottomhole temperature corrections and understanding the resistivity of the drilling mud filtrate.</p> <p>As the tool averages properties over a portion of the borehole, thin units may have a muted impact (e.g., a thin, water-wet sand will have a smaller reduction in resistivity than a thick water-wet sand).</p> <p>Some logs (e.g., resistivity) have high frequency noise.</p>
Core data	<p>Drilling muds invade the formation, changing its properties.</p> <p>Changes in temperature and pressure from <i>in-situ</i> conditions (e.g., depressurization expansion) and/or the retrieval process may damage the core sample and change its properties.</p> <p>Core samples can dry out during storage, which can change their physical properties.</p> <p>Core samples only measure physical/fluid properties within a small volume, which may not be representative of the larger reservoir (e.g., core may not sample fractures or deformation bands, which largely control fluid transport on a reservoir scale).</p>

Fault Maps (Interpretive Data)

Most faults pose no or very little seismic hazard. Faults of concern depend on the characteristics of the in-situ stress field and fault orientation which determine which faults are active and could potentially move. Fault maps have been traditionally used by the USGS to produce the national seismic hazard maps of the U.S. Fault maps could be coupled with regional stress maps to identify potentially active faults; faults that are aligned perpendicular to the maximum stress component in the subsurface are unlikely to be active and will have little importance in determining earthquake hazard at a site (Walters et al. 2015). Site-specific characterization of injection sites using fault maps is suggested in many current guidelines and publications (Walters et al. 2015b).

Major faults in the crust of the U.S. have been mapped using traditional geologic methods over the past hundred years, but these methods by no means capture all potential faults of concern. Many faults remain unidentified or unmapped. In the absence of identified or mapped faults, the regulatory agency may use additional tools to make decisions relative to injection operations. As larger magnitude earthquakes require larger fault slip, identification of the largest fault locations and siting injection wells away from these locations can reduce the likelihood of large, induced earthquakes. Determining “how far away is far enough” may require reservoir characterization and reservoir modeling work to identify the distance over which pore pressures may be increased from the injection.

There is long term need for improved identification and mapping of potentially active faults systems to better manage potential risks of induced seismicity (NRC 2012). Industry, academia, and government researchers are now working collaboratively to characterize and map faults and subsurface stress fields.

Several recent studies around fault slip characterization have been carried out in Oklahoma (Alt et al. 2017, Schoenball et al. 2018), Texas – Ft. Worth Basin (Hennings et al. 2019) Permian Basin (Lund Snee and Zoback 2016, Lund Snee and Zoback 2018) and across the greater North American Hemisphere (Lund Snee and Zoback 2020).

Data collection: One way to map active faults is to use precisely relocated earthquakes including data from higher accuracy deployable seismic monitoring arrays. Beyond seismicity measurements, examination of lineaments (linear features on the surface) obtained from satellite imaging enable geologists to identify regional faults over large swaths of land (Jacobi 2002). These can be ground-truthed by examining outcrops of formations that are intersected by the lineaments and by identifying fracture intensification domains that often surround faults.

In the central U.S., where the majority of induced seismicity is occurring, it appears that most earthquakes are associated with buried and deep fault systems. Generally, the only way these deep buried faults may be identified is through seismic imaging. Traditional approaches like geologic mapping and even aerial photography and satellite imagery are unlikely to be helpful when faults are buried and do not have surface expression.

A recent example of improving regional fault maps by combining high-resolution proprietary data with traditional maps are being performed by the Oklahoma Geological Survey (Holland 2015), which is collaborating with industry in a way that preserves the proprietary nature of the data. Figure F.6 shows the Oklahoma Geological Survey’s preliminary fault map as compiled from oil and gas industry data and published literature. This preliminary version identifies surface and subsurface faults on one map. The fault database continues to grow as more faults from published literature are being identified and added to the database nearly every day. A preliminary compilation of the fault database was made available as an OGS Open File Report OF3-2015 titled, “Preliminary Fault Map of Oklahoma,” with digital files and references available on the Oklahoma Geological Survey website. Combining operator data and public data enables development of more robust products to aid in identification of the potential locations of faults of concern in proximity to potential injection sites. Additional reports with digital images and GIS files for “Preliminary Oklahoma Optimal Fault Orientations” were published in OF4-2015 by the OGS. Value has been added by identification of optimally oriented faults derived from local focal mechanism characterizations. “Identifying optimal fault orientations (those likely to have an earthquake within the contemporary stress field, N 85°E) is important for determining the potential earthquake hazard of both naturally occurring and triggered seismicity” (OF4-2015 Darold and Holland).

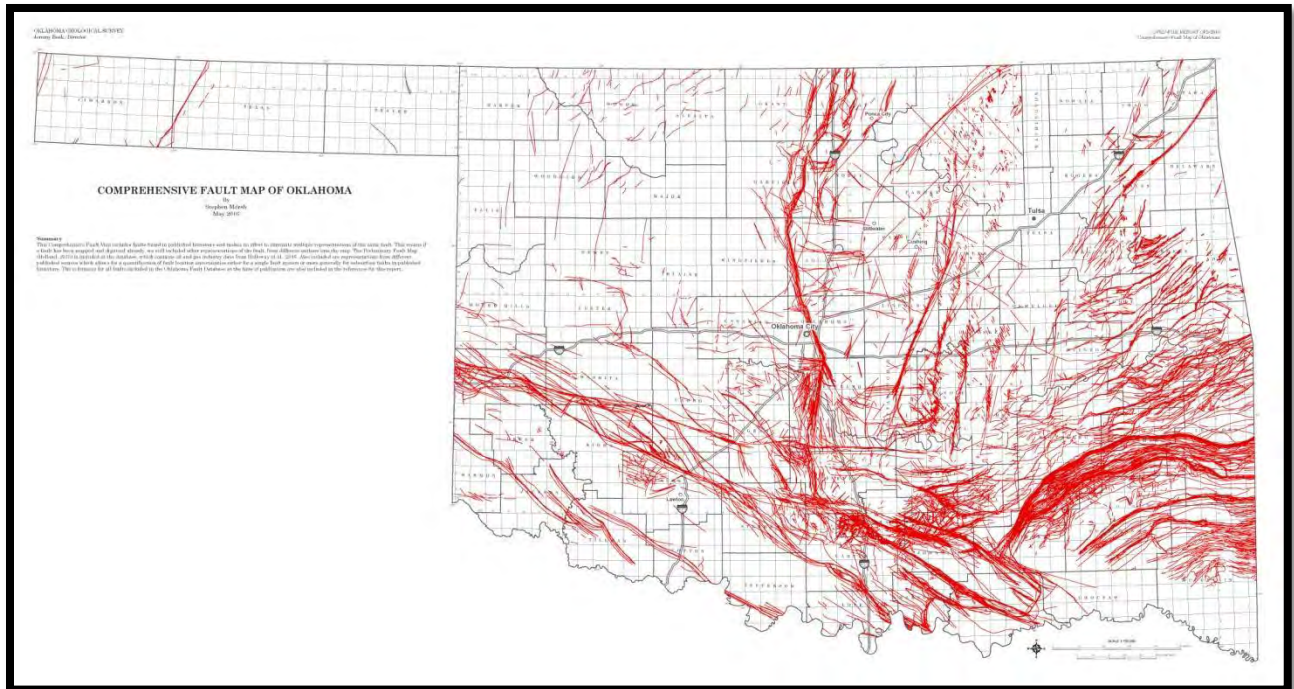


Figure F.6 Oklahoma fault map (preliminary). Source: Oklahoma Geological Survey Open File Report OF2- 2016.

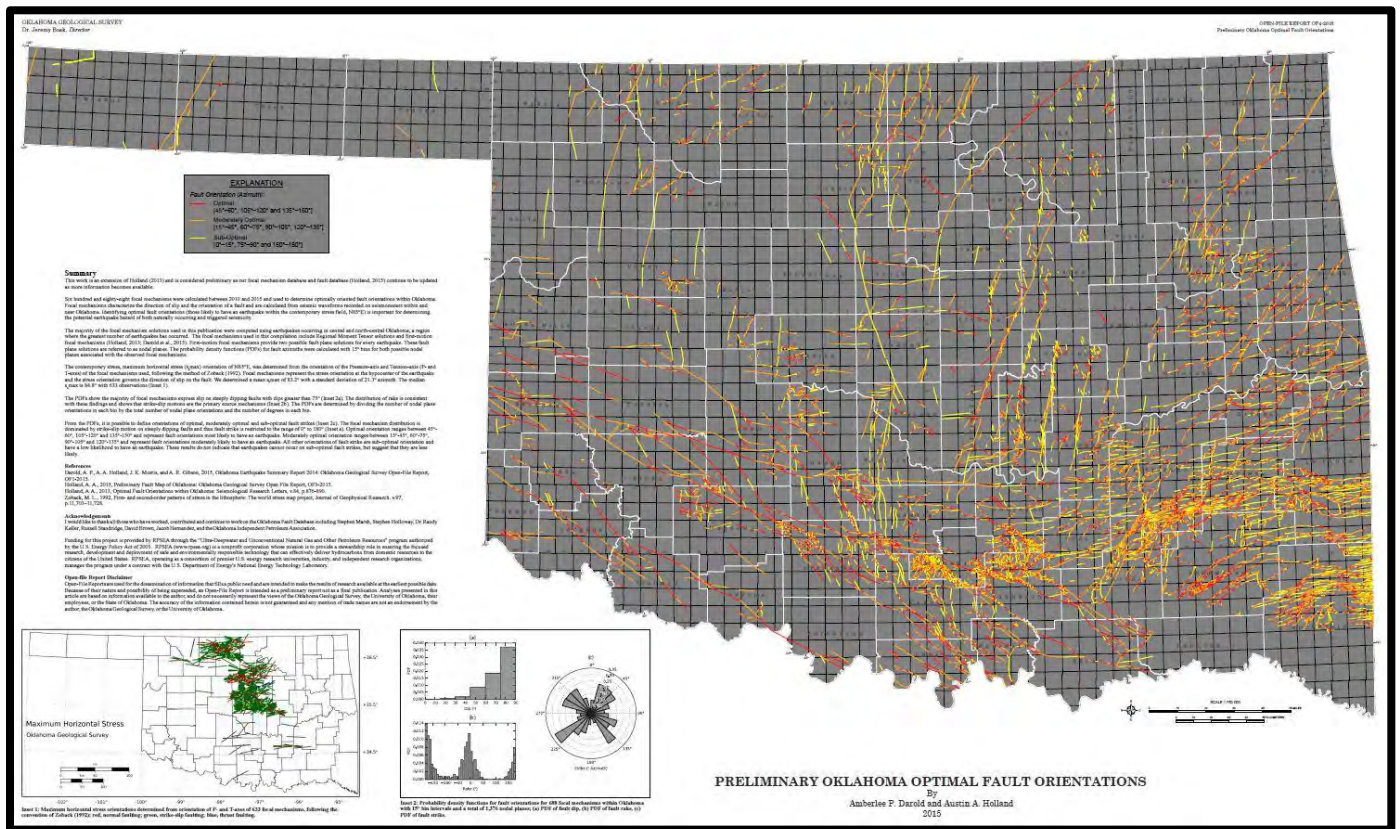


Figure F.7 Oklahoma Optimal Fault Orientations (preliminary). Source: Oklahoma Geological Survey Open File Report OF4-2015.

The USGS maintains a fault and fold database for some faults active in the Quaternary period, but it does not include all the faults that could be reactivated. Figure F.7 shows the USGS Quaternary period fault map (USGS 2015), which clearly does not identify many known faults across the broad mid-continent of the U.S. Additional data on faults may be available through state, industry, and academic institution sources.



Figure F.8. USGS Quaternary Fault and Fold Map. Source: USGS 2015.

Limitations of fault maps and other interpretive data are summarized in Table F.2.

Basement Fault Maps (Interpretive Data)

Knowledge of basement faults can provide important information regarding the potential for induced seismic activity. These deeper faults are in the less ductile crystalline rocks below shallow sedimentary rock and are less likely to plastically deform when critically stressed. Basement fault maps have not typically been used to characterize specific sites for oil or gas production; however, the influence basement faults exert on overlying formations may be useful for the characterization of field sites.

Data collection: The depth of basement faults complicates their detection and mapping. While many of the same techniques used to map crustal faults can be used for basement rocks, fewer wells penetrate the basement rock, making ground-truthing of suspected fault locations via core logs difficult. Lineaments can still be used to identify fault locations, but the hundreds of m to several km of rock above these faults may obscure some surface features. Fewer outcrops of continental basement formations exist as well. Mapping of the estimated basement depths for the broad U.S. has been developed by some researchers (Mooney 2010); and several state geologic agencies maintain their own basement depth and fault maps based on more detailed state and local data. As an example, (Figure F.9), the Ohio Department of Natural Resources Geological Survey has published maps portraying deep faults and other structures identified by a variety of geologic studies (ODNR 2015). Some faults are well known, whereas others are speculative. Very few are visible at the surface.

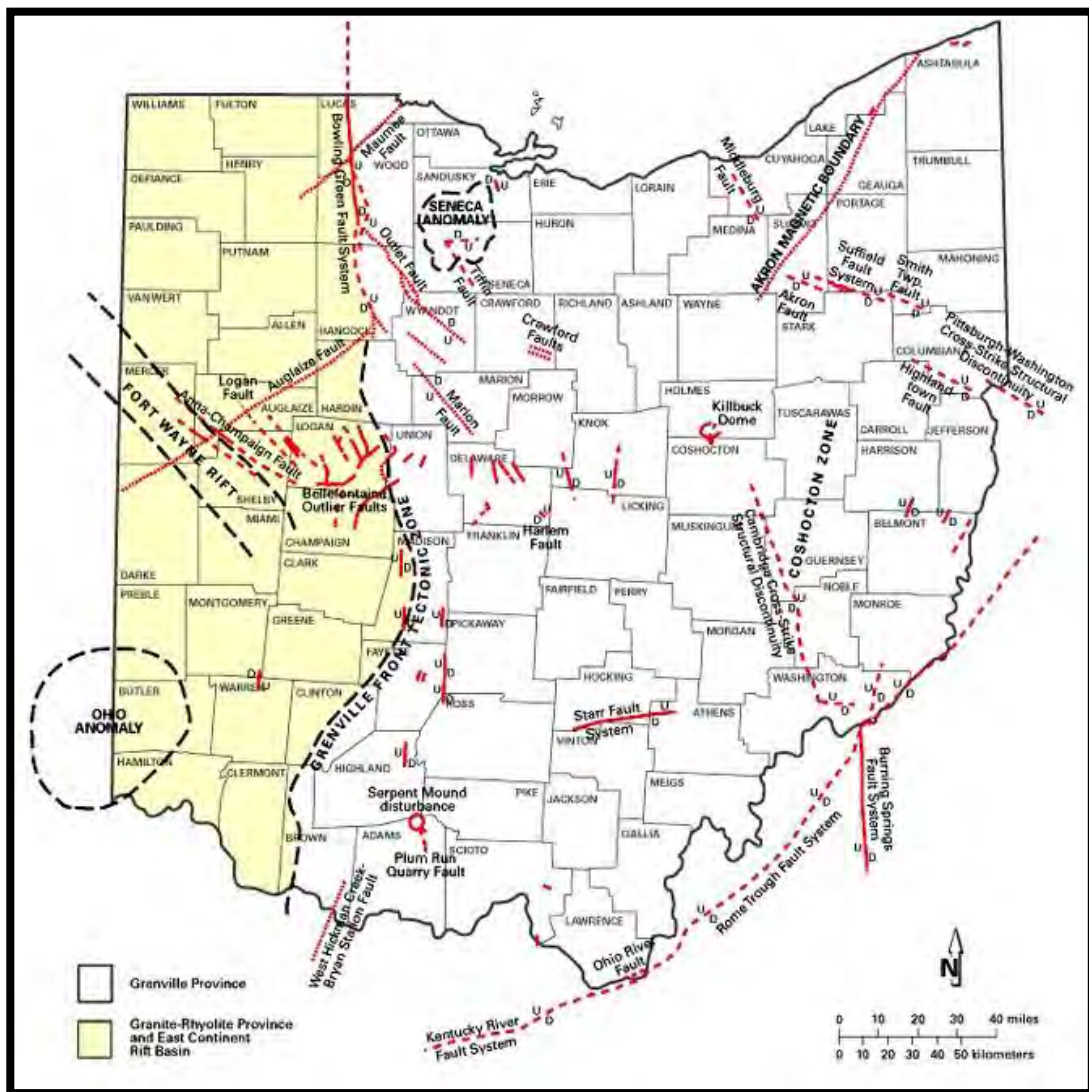


Figure F.9. Ohio map of deep faults and basement faults. Source: Ohio Geological Survey 2015.

While seismic surveys can be used to identify basement faults, they are typically sparse in areal extent and proprietary in nature. In addition to seismic measurements, magnetic and gravity anomaly measurements can assist in locating basement structure. Gravity anomaly measurements provide insight into crustal thickness and changes in values can indicate an offset due to a deep fault. Magnetic anomaly measurements can indicate changes in the subsurface chemistry or magnetism influenced by changes in basement depth. Faults interpreted from gravity and magnetic anomaly surveys are low resolution and placement is inferred from modeling. Limitations on basement fault mapping are summarized in Table F.2.

Subsurface Stress Maps (Interpretive Data)

Determination of the *in-situ* state of stresses in the subsurface is both complex and often expensive and possesses a large degree of uncertainty due to the sparseness of data. While the oil and gas industry occasionally collects borehole and well log data that can be used to estimate subsurface

stresses, this information is not readily or broadly available as part of injection well planning or permitting.

Generally public information on the *in-situ* stress in the earth is too fragmentary to allow confident estimates of the actual stresses acting on a fault. In most cases, the only reliable information available is the magnitude of the vertical stress, as it can simply be estimated from the average density of the overlying rock and the depth. Estimating the general fault types and configurations as well as the broad orientation of the maximum and minimum horizontal stresses at a scale of tens or hundreds of kilometers is also sometimes possible, based on a variety of stress indicators. One such example can be found at <https://doi.org/10.1038/s41467-020-15841-5> (Lund Snee and Zoback 2020), which presents one dataset associated with mapping of maximum horizontal stress data in North America.

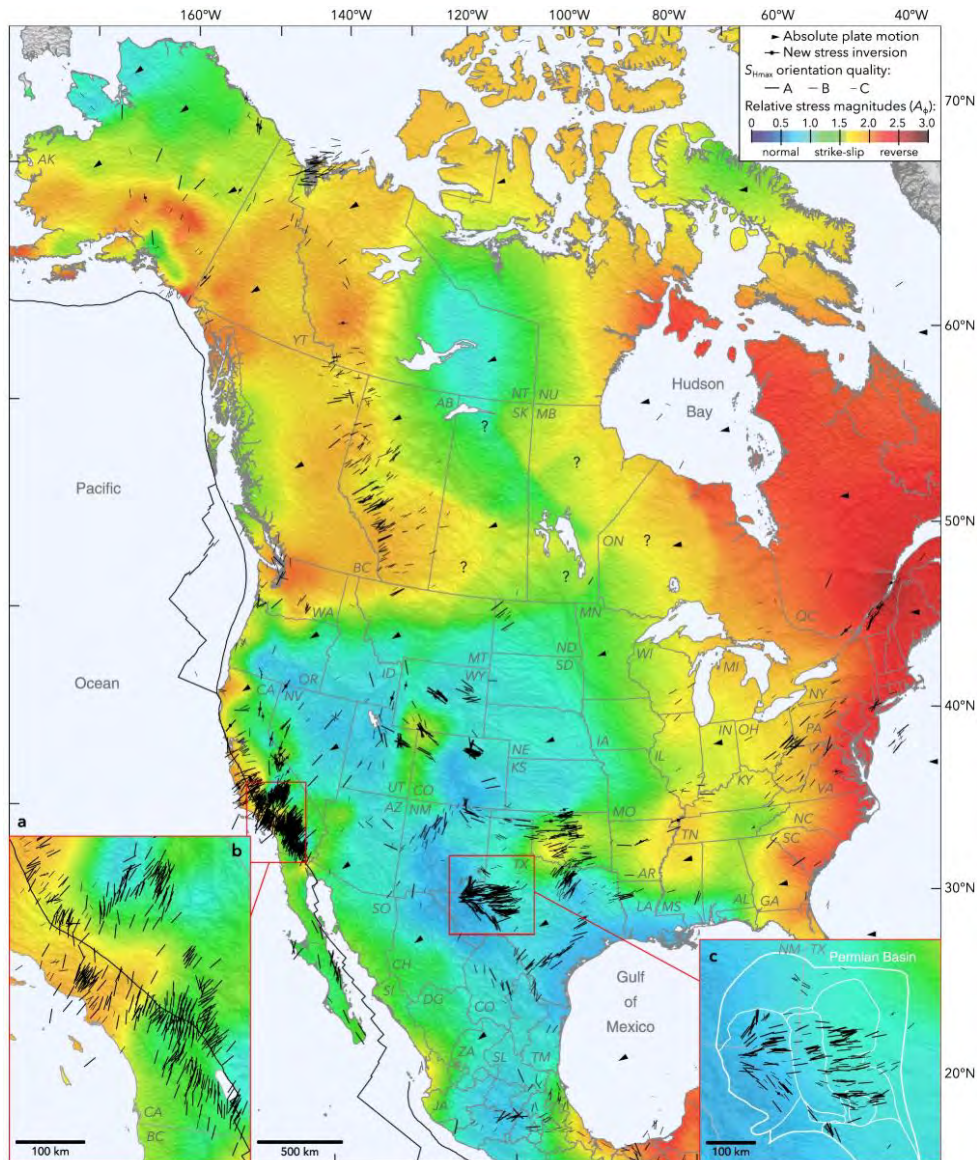


Figure F.10. Figure from Lund Snee, J., Zoback, M.D. Multiscale variations of the crustal stress field throughout North America. *Nat Commun* 11, 1951 (2020). <https://doi.org/10.1038/s41467-020-15841-5>

Although the conditions for initiating slip on a preexisting fault are well understood, it is difficult to make reliable estimates of the various quantities in the Coulomb criterion. Lacking these estimates, predicting how close or how far the fault system is from instability and slip is essentially impossible, even if the orientation of the fault is known. The implication is that the magnitude of the increase in pore pressure that will cause a known fault to slip generally cannot be calculated. Therefore, generally, it is not possible to uniquely predict the conditions (changes in pressure/stress) that would actually lead to fault slip. Further, when anomalous seismicity occurs, the lack of accurate subsurface stress information also substantially complicates understanding of whether naturally occurring stress changes or pore pressure changes associated with fluid injection may be primarily responsible for the observed fault slip.

Nonetheless, understanding how different factors contribute to slip initiation is valuable because it provides insight about whether fluid injection or withdrawal may be a stabilizing or a destabilizing factor for a fault (in other words, whether fluid injection or withdrawal causes the difference between the driving shear stress and the shear strength to increase or decrease). Any perturbation in the stress or pore pressure associated with an increase of the shear stress magnitude and/or a decrease of the normal stress and/or an increase of the pore pressure could be destabilizing; such a perturbation brings the system closer to critical conditions for failure.

Researchers are currently undertaking efforts to improve the quality of stress maps. An example of a regional stress map is shown in Figure F.11 (Lund Snee and Zoback 2018) utilizing geophysical image logs made available by oil and gas companies. Over 300 new high-quality indicators of the direction of maximum horizontal stress have been added to the map above. Such an approach can help assess the potential existence of faults that may be more prone to reactivation if they are preferentially oriented relative to the current-day stress state (at fault depth location). Accurate stress mapping is essential for site risk assessment, both at the basin scale and smaller. Recent studies have increased the knowledge base for current crustal stress regimes across active oil and gas plays in the U.S. (Lund Snee and Zoback 2018, 2020). *Oklahoma. Source: Alt 2015.*

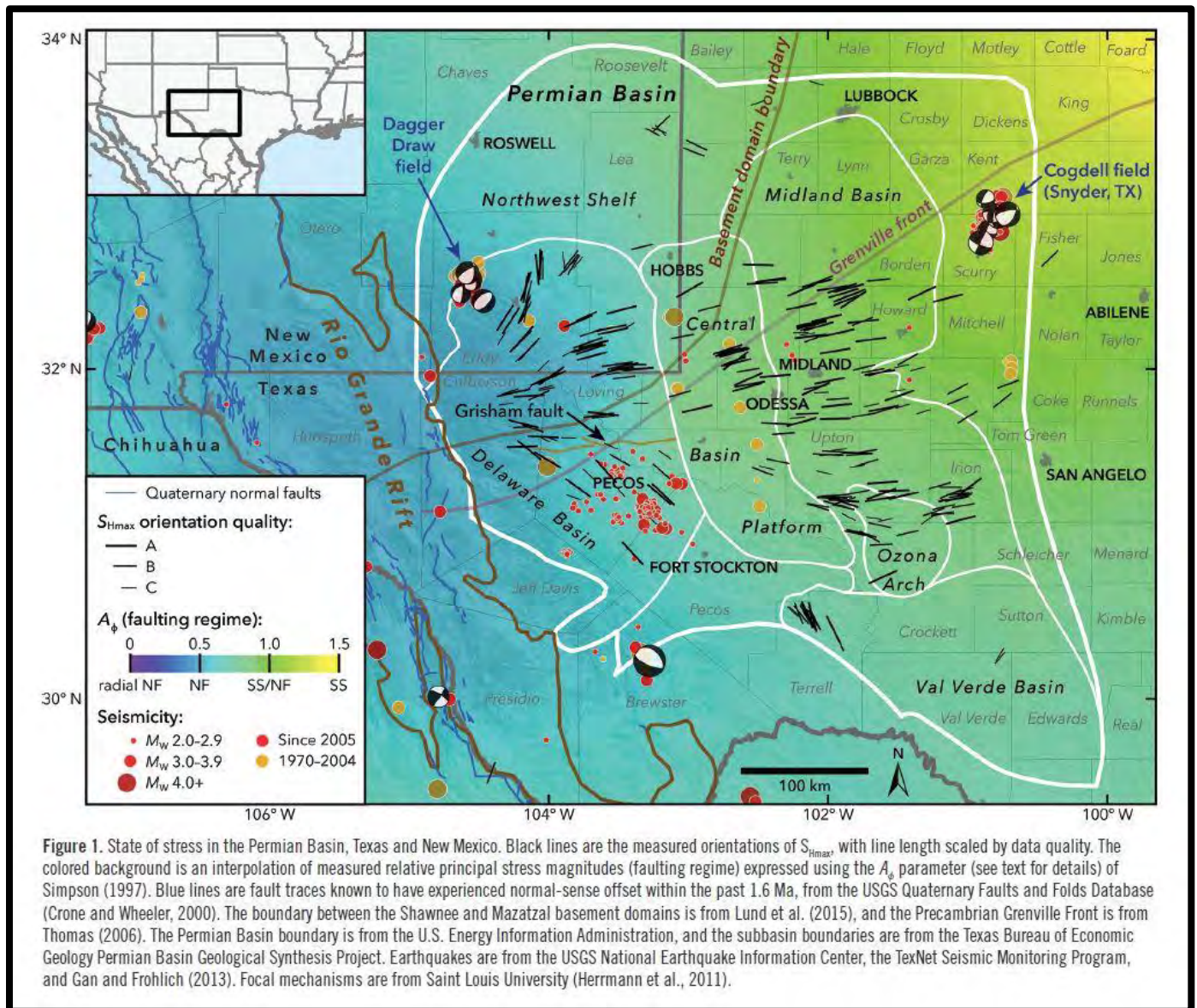


Figure F.11. Figure illustrating state of stress at regional scale in Permian Basin, Texas. Source: Lund Sneek and Zoback 2018.

Developing stress maps such as this requires reliable estimates of 3D stress components from well logs and reservoir property measurements. The equations and methods for measuring and calculating subsurface stresses and pore pressures are available in the reservoir and geomechanics literature (Zoback et al. 2003).

Reservoir Properties (Interpretive Data)

As discussed in “Well Data” above, the most commonly available information for injection wells is well head pressure and injection volume versus time. In addition, bottomhole pressure can be measured directly or estimated. Other tests sometimes conducted in wells to determine reservoir properties include:

- **Leakoff Test (LOT)** measures the fracture pressure of a formation. The well is shut in and fluid is pumped into the well bore until fluid enters the formation or leaks off.
- **Pressure Fall Off (PFO)** monitors pressure change with time after the well is shut in. After sufficient time, the pressure levels off and indicates a measure of the average reservoir pressure. How long it takes for the well to approach this leveling (or asymptotic) value measures the permeability of the surrounding formation as well as the “skin effect.” If successive PFO tests take appreciably longer to reach the asymptotic value, this may indicate buildup of skin or material plugging up the borehole. Pressure Buildup (PBU) is a similar test for a producing well.
- **Repeat Formation Tester (RFT)** can be repeatedly set and retracted into the formation at different depths. Pressure and temperature are measured with a gauge. The tool can also take two fluid samples.
- **Modular formation Dynamics Tester (MDT)** is similar to an RFT but has newer quartz gauges to measure pressure and temperature and can take more fluid samples.
- **Diagnostic Fracture Injection Test (DFIT)** a small volume of water is pumped into the formation until it fractures. The valve is then closed and pressure in the well is allowed to fall off over one to two days. A quartz transducer measures the pressure transient. This test is also known as a Data Frac, Mini-Frac, or Mini Fall-off (MFO).
- **Interference test** is a multiple well test. A pressure transient is introduced in one well while the pressure is measured in an adjacent shut-in well. This test determines whether there is communication between the two wells. It also can be used to determine permeability and hydraulic diffusivity.
- **Production data** in producing fields, oil rate, gas rate, gas oil ratio, and water rate are also measured often on a daily basis.

Limitations of reservoir properties data are summarized in Table F.3.

Table F.3. Limitations of interpretive data. Source: ISWG.

Category	Limitations/Uncertainty
Fault maps	<p>Faults may be too small to identify with traditional fault mapping techniques.</p> <p>Surface features used to map faults may be obscured by vegetation, slump, or fissile lithologic units.</p> <p>High resolution data are often propriety.</p> <p>Identification of faults by itself is not enough to know if the seismic hazard due to injection nearby to this fault is increased; stress state of the fault is required in order to understand if the fault is active.</p>
Basement fault maps	<p>Fewer deep wells and basement outcrops mean there are fewer opportunities to validate the locations of suspected basement faults.</p> <p>Because of the depth and lack of reflectivity in the basement, seismic surveys and traditional detection techniques are less likely to capture faults in the basement.</p> <p>Variances in reflectivity and formation acoustic differences can also impact the results.</p> <p>Basement stress regime may not be as well understood from limited data.</p> <p>The basement geology in general is poorly understood due to its older age. This is due to the limited data increased depth, and because it has a longer, more extensive, and complex geological history than horizons within the sedimentary section.</p>
Reservoir properties	<p>Pressure readings are subject to temperature drift.</p> <p>Older RFT tests may not have penetrated into the formation.</p> <p>Pressures measured by RFTs and MDTs may not be very representative if insufficient sampling time is used, and/or measurements made in lower permeability formations.</p> <p>Leakoff tests have to start below fracture pressure and have sufficient test points. This may not be possible with shallow wells and available equipment.</p> <p>Pressure fall off tests must have sufficient points recorded, as well as a steady injection rate prior to the test. Most regulations prohibit fracturing an injection well to avoid loss of injection confinement to the intended disposal zone.</p> <p>Highly deviated and lateral wells will not show the same character as wells that are essentially vertical.</p>

Data and Information Sharing Considerations

Injection well operating data (injection rates and volumes, well design, etc.) are not typically considered confidential business information. They are reported as required by the UIC program regulations and are publicly available. Data tabulation, reporting frequency, database formats, and record keeping methods may differ by each state with delegated UIC primacy. Currently, many regulations require annual submission of injection pressures, volumes, and rates as measured throughout the year. More frequent reporting of injection pressures, volumes, and rates could be considered to provide more timely data access and enable improved analysis of potential spatial and temporal correlations between particular injection wells and observed seismicity. Additionally, use of a common data format and database that is accessible to the public would improve transparency and enable interested stakeholders to be informed of injection practices in their specific areas of interest.

In contrast, subsurface and reservoir data associated with hydrocarbon-bearing reservoir intervals are broadly considered as confidential business information due to their importance in making commercial business decisions regarding field and reservoir development. Detailed well logs and reservoir property measurements typically are associated with production activities. Substantially less detail is available for injection wells; for example, stress measurements, advanced well logs, and seismic surveys are generally not performed for injection wells.

Development of improved stress maps and fault maps generally must rely on confidential business information supplied by industry. Agencies can put in place appropriate mechanisms that would allow industry to preserve confidential business information while providing sufficient data to assess subsurface stress fields and the potential presence of faults of concern. Such mechanisms could involve confidentiality agreements and/or specific relevant data provided based on geographic basis, without reference to operator or well name. Sharing of “raw” data and “interpretive” data may drive the agreement structure or data sharing approach. One recent example of broad stakeholder collaboration is the development of enhanced stress and faults maps in Oklahoma via the collaborative efforts of the Oklahoma Geological Survey, Oklahoma Corporation Commission, Stanford University, and various industry companies. Confidentiality provisions and data-handling agreements enable operators to provide well logs, stress data, and fault interpretations without public release of confidential business information.

Key Messages

Given the geologic diversity across the U.S., differences associated with the location and volumes of subsurface injection of saltwater, diversity and scope of operations, and allocation of state resources, there clearly is not a “one-size-fits-all” best practice for data and information collection, reporting, and sharing. Rather, best practices at the state and local levels may be developed based on the local geology, environment, and risk levels, considering state and local stakeholder discussions and engagement.

Development of improved stress and fault maps requires collaboration across multiple stakeholder groups. For specific local situations, data requested from industry should be handled in a manner that reflects consideration of confidential/proprietary business information and other potential

contractual obligations that may be in place. Also, because, interpretive data may be subject to revision and updates as new information becomes available, consideration should be given to the potential uncertainty and associated with these data when they are applied in specific regulations or permit conditions. Regulators may wish to consider how to mediate and broker information and data collection and sharing, so that the most effective and appropriate datasets are considered, and appropriate expertise is brought together to conduct studies and investigations.

Finally, industry stakeholders may want to evaluate the data collection and archival capability of regulatory agencies that hold injection well data, along with the companies that supply this data, and to identify opportunities to improve data collection and reporting capabilities with advanced computing systems, enabling more timely access to relevant injection well data.

Appendix G: State and Provincial Regulatory Summaries

The following State and Provincial Summaries are a snapshot of the dynamic regulatory framework in each respective jurisdiction and are provided to help with general understanding of oil and gas rules for induced seismicity. Consistent with this entire Induced Seismicity Guide. These summaries are not intended to provide specific operational, regulatory, or legal advice. As additional States and Provinces complete additional summaries, they will be added to this Appendix G online collection.

Ohio

Do Conditions Exist that Merit Regulatory Action? (1)

Yes. Though Ohio is often considered not very seismically active, there are areas where geologic and tectonic stresses are conducive for both natural and anthropogenic earthquakes.

Statutory or Regulatory Authority for Induced Seismicity Rules (2,3,4,5,6)

The Ohio Department of Natural Resources (ODNR): Division of Oil & Gas Resources Management (DOGRM) has the sole authority over oil and gas activities with regulations found in the Ohio Revised Code (ORC) Title 15: Chapter 1509 and Ohio Administrative Code (OAC) 1501. Specific rules for Class II storage and disposal of fluids by the underground injection control (UIC) program are found in OAC Chapter 1501:9-3 and ORC 1509.22. Additional DOGRM instructions on induced seismicity occur through permit conditions and administrative orders.

The Division helps protect Ohio's general public health, safety, and groundwater resources by regulating the disposal of brine and other wastes produced from the drilling, stimulation, and production of oil and natural gas in Ohio. These regulations follow national requirements adopted under the federal Safe Drinking Water Act regarding protection of underground sources of drinking water. Primacy of the Underground Injection (UIC) Program was received from USEPA in 1983. Ohio's Class II disposal wells include conventional brine injection wells, annular disposal wells, and enhanced oil recovery injection wells.

In 2012, the Division enhanced well construction guidelines; saw the implementation of updates designed to deal with horizontal shale drilling; enacted new rules regarding underground injection control; and increased our staff to better regulate the state's growing oil and gas industry. This expansion included the addition of the OhioNET seismic section, which continuously monitors for seismic activity in real-time across Ohio to determine if any recorded earthquakes may be related to oil and gas well completion (hydraulic fracturing) or injection activities.

In March 2014, these enhanced regulations and continuous seismic monitoring helped identify and mitigate seismicity associated with a well site in Poland Township, Ohio during its completion operations. A case study on this seismicity is found in Appendix C.

1. UIC Class II wells

a. Permitting (3,6)

Permitting is one of the most fundamental regulatory activities done by the Division of Oil & Gas Resources Management (DOGRM). Geologists perform a thorough review of every application

for oil and gas, brine disposal, solution mining, gas storage and enhanced recovery permits in Ohio. Detailed examinations of each application verify that all legal requirements are met prior to issuance of a permit. Additional terms and conditions are applied to each permit to ensure site-specific conditions of each proposed well location are addressed. Permits issued by the DOGRM are regulated under provisions of Chapter 1509 of the ORC and rules established in Chapter 1501:9 of the OAC. Class II and Class III applications are reviewed by the Underground Injection Control (UIC) Section. UIC staff review proposed construction specifications, engineering information, and geological data as part of the application review process. It is during this process that specific permit conditions may be applied to an eventual permit to address site-specific circumstances. The Division also regulates brine hauling. Brine haulers in Ohio are required to be registered, bonded, and insured prior to operation. Registered brine haulers must also report annually on each shipment of brine including pick up location, disposal location, and volumes.

b. Area of Review (AOR) for Permitting (6)

In Ohio, the area of review (AOR) for Class II SWD and EOR injection wells is determined based on volume. If the well is being permitted for 200 barrels/day or less, the AOR is a radius of $\frac{1}{4}$ mile. If the well is permitted for volumes greater than 200 barrels/day, then the AOR is a radius of $\frac{1}{2}$ mile. Operators must undertake corrective action for any artificial penetration of concern in this area. If a well or wells are identified for corrective action in the AOR, the approved corrective action becomes part of the permit conditions. The permit holder is required to complete corrective actions prior to initiating injection operations.

c. Operational Reporting (6)

UIC well operators are required to submit the Well Construction Report (form 8), mechanical integrity test results, cement tickets, cement evaluation logs, surface hole drilling fluid additives report (form 8A), well stimulation additives report (form 8B), and all geophysical logs. This typically includes at least a gamma ray, density neutron and resistivity log. The logs are all stored in paper and electronic form.

All UIC well operators are required to monitor injection pressure and injection volumes for each well on a daily operational basis with average and maximum pressures and volumes compiled monthly. The operators must file this information annually on forms supplied by the Division. Since 2014, new operations have been required to continuously monitor injection and annulus pressures as a result of rule revisions.

d. Action Levels and Notification Thresholds (also known as the Traffic Light System) (1)

A specific regulatory decision depends on factors in addition to seismic event magnitude, such as elastic properties of the near surface, proximity to population centers, critical structures, and other factors. In the future, the Division plans to include ground motion calculations as an additional way to monitor induced events. This will provide even more accurate evaluations of experienced shaking and a better understanding of how induced events affects the surface and whether damage to a structure is possible or likely.

e. Operational Mitigations Considered (1)

Operational mitigations may include additional monitoring, rate and pressure reductions, and well construction modifications.

2. Hydraulic Fracturing “HF” for New and Existing Wells (1,2,3,6)

a. Permitting (1)

Division personnel review construction specifications, engineering, geological data, and issue permits for horizontal wells. It is during this process that specific permit conditions may be applied to the application. Conditions may be placed on wells drilled near faults or areas of known seismic activity, in which seismic monitors must be installed for a specified time period, generally 60 days, prior to completion operations. Once the completion operation has been concluded, the operator may submit a request to the Division for a release of the seismic monitoring requirement. It is at the full discretion of the Division Chief as to whether the release is acceptable.

b. Area of Interest for Permitting (6,7)

DOGRM’s permitting program maintains a three-mile buffer zone around Precambrian faults and historical earthquakes that have been recorded since 1999 from the Ohio Geological Survey’s (OGS) OhioSeis seismic catalog, along with DOGRM’s current OhioNET seismic catalog. The OGS’ Precambrian basement fault map contains both known and inferred Precambrian faults that are used during the area of review permitting process. Buffers around each of these features dictate whether seismic monitoring conditions will be applied to a permit. Wells drilled in urbanized areas are subject to additional conditions due to the increased risk factors associated with operating in higher density population centers.

c. Operational Reporting (2,3)

Ohio law requires well owners to submit information regarding completion of the well, including fluids used to stimulate the well. The law allows owners to submit information through a chemical disclosure registry called. Quarterly production reporting is also required for horizontal wells once the well is completed. ORC 1509.10 states that “any person drilling within the state shall, within sixty days after the completion of drilling operations to the proposed total depth or after a determination that a well is a dry or lost hole, file with the division of oil and gas resources management all wireline electric logs and an accurate well completion record on a form that is prescribed by the chief of the division of oil and gas resources management.”

d. Action Levels and Notification Thresholds (also known as the Traffic Light System) (1)

Below are the current threshold magnitudes used to regulate cases of induced seismicity along with their respective regulatory action:

- $M_L \geq 1.5$ – Direct communication starts between operator and Division;
- $M_L = 2.0-2.4$ – Work with operator to modify operation;
- $M_L \geq 2.5$ – Temporary halt completions on lateral, approval plan needed by operator to resume completions on lateral.

However, one size does not fit all. A specific regulatory decision may depend on various risk factors, similarly, addressed in section 2d.

e. Operational Mitigations Considered (1):

- Mitigation techniques when induced seismicity occurs during hydraulic fracturing:
 - i. Change from zipper fracking to stack fracking;
 - ii. At least 20% reduction in volume and/or pressure; and
 - iii. Skipping stages may be necessary, especially if earthquakes indicate a lineament or fault structure near a lateral of the operation.
 - iv. Switch to a smaller sieve size.
- Switch to smaller sieve sizes for proppant.

Footnotes

1. AGI: State Responses to Induced Earthquakes
<https://www.americangeosciences.org/webinars/state-responses-induced-earthquakes>
2. Ohio Revised Code Chapter 1509: Division of Oil & Gas Resources – Oil and Gas
<https://codes.ohio.gov/orc/1509>
3. ODNR: Division of Oil & Gas Resources
<https://ohiodnr.gov/wps/portal/gov/odnr/discover-and-learn/safety-conservation/about-odnr/oil-gas/oil-gas>
4. OAC: Chapter 1501:9-3 Saltwater Operation
<http://codes.ohio.gov/oac/1501%3A9-3>
5. ORC: 1509.22 Storage or disposal of brine, crude oil, natural gas, or other fluids.
<https://codes.ohio.gov/orc/1509.22v1>
6. State of Ohio Class II UIC Program Peer Review
https://www.gwpc.org/sites/gwpc/uploads/documents/publications/2017OhioClassIIPeerReviewFinal_0.pdf
7. Structure contour map of Precambrian unconformity surface in Ohio
<https://ohiomemory.org/digital/collection/p267401ccp2/id/473>

Oklahoma

Do Conditions Exist that Merit Regulatory Action?¹

Yes. Oklahoma’s geology and tectonic stress conditions predispose the state to seismic activity, both from natural and anthropogenic causes.

Statutory or Regulatory Authority for Induced Seismicity Rules

The Oklahoma Corporation Commission, “OCC,” has sole authority to regulate all oil and gas activities under Oklahoma Administrative Code Title 52:3-139. Most oil and gas rules can be found in OAC 165:10. Additional OCC instructions for induced seismicity exist in the form of Directives and Notices. The following statute was signed into law in 2016 to address emergency situations, specifically where expeditious action is required, like seismic hazards:

“For purposes of immediately responding to emergency situations having potentially critical environmental or public safety impact and resulting from activities within its jurisdiction, the Corporation Commission may take whatever action is necessary, without notice and hearing, including without limitation the issuance or execution of administrative agreements by the Oil and Gas Conservation Division of the Corporation Commission, to promptly respond to the emergency.” 17 O.S. § 17-52 (D)(1) (2019)

1. UIC Class II Wells

Researchers working in Oklahoma have definitively linked certain Class II UIC well operations to historical and ongoing induced seismicity issues. In particular, the wells of interest for induced seismicity under Class II are Saltwater Disposal (SWD) wells. Other Class II wells, such as Enhanced Oil Recovery (EOR) injection wells, have not been identified as significant contributors to current or past induced seismic hazards in Oklahoma. The text presented here is generally applicable to SWD wells, as defined by the USEPA in its administration of the Clean Water Act, and no other type of injection wells.

a. Permitting

The permitting process to drill a new injection well or to convert a producing well to an injection well is found in OAC 165:10-1 and 10-3. This permitting process includes all of the typical SWD well permitting requirements to protect underground sources of drinking water (USDW); the environment; correlative rights, and to prevent waste. If concerns exist for induced seismicity, additional SWD well permitting information required could include an historical analysis of earthquakes, additional geophysical and geological investigation, and/or reservoir modeling. Language regarding seismic hazards and additional permitting conditions of the well may be added to any order to inject issued through the OCC’s Administrative Law Court. Orders containing seismic considerations are not issued administratively by the UIC Department, but rather through the agency’s court system. The following is a current example of the language that may be added to an order issued by the courts:

“SEISMICITY: Pursuant to 17 O.S. § 52 and 52 O.S. § 139, the Commission has jurisdiction over the subject matter of this cause. Applicants’ authority to operate this disposal well is subject to the provisions of 17 O.S. § 52(D).”

Prior to the above language (law passed in 2016) the seismicity clause added to Orders was specific to the authorization being requested; example:

- “(a) In the event that the frequency or magnitude of background seismicity increases to a point where the Director of the Oil and Gas Conservation Division or designee is concerned about the potential for triggered seismic activity, the Director of the Oil and Gas Conservation Division or designee shall determine whether injection operations are to be temporarily and immediately limited or suspended.
- (b) Resumption of injection operations may resume when, and under appropriate restrictions if any, as determined by the Director of the Oil and Gas Conservation

Division or designee.

- (c) Any action by the Director of Oil and Gas Conservation Division or designee to suspend or restrict operations shall be based upon the scientific analysis of all available data to determine and manage the risk of triggered seismicity.”

b. Area of Review “AOR” for Permitting

For SWD permitting in aseismic areas, a ½-mile radius is the typical Area of Review (AOR) for a new or converted SWD. For SWD permitting in areas where induced seismicity concerns exist, up to a 10 mile radius AOR may be used. In addition, specific geologic intervals linked to seismic hazards may be denied for injection, such as the Arbuckle Group, or any interval in close proximity to basement. Any proposed well location that may exacerbate an existing seismic hazard may be denied by the OCC.

c. Operational Reporting¹

For aseismic areas, injection volumes and pressures are recorded monthly and reported to the OCC annually via an electronic form. Mechanical Integrity Tests in aseismic areas are reported on an interval ranging from annually to every five years at the discretion of the UIC Manager. Exceptions must be made in writing to the UIC Department for consideration. In areas where seismicity concerns exist, injection volumes and pressures are recorded daily and reported to the OCC weekly, and in some cases, reported daily via an electronic form. For areas of concern, additional mechanical integrity testing may be requested at any time.

d. Action Levels and Notification Thresholds¹

The OCC’s Induced Seismicity Department responds to induced seismic hazards with spatially defined Directive Areas or Areas of Interest (AOI), curtailing SWD operations when large earthquakes (**M** 4.0+) or “swarms” of **M** 3+ or smaller events, occur. Directives the Induced Seismicity manager issues for widely felt single earthquakes or swarms typically consist of restrictions or shutdowns for wells located within radii extending from three to 20 miles from the seismic event(s). Action levels for individual Directives are generally commensurate with proximity to the earthquakes: an inner zone (3 to 5 miles), typically requires a gradual, managed SWD shut in; an intermediate zone (up to 7 additional miles), typically requires an injection volume reduction; and an outer zone (10-20 miles from the earthquakes), where wells are limited to their past disposal volumes or are put on notice of potential actions. Before a Directive is issued, potential impacts to SWD operations and the spatial organization of SWDs are analyzed and accounted for in the Directive orders.

The OCC’s Induced Seismicity Department defines regional Areas of Interest (AOI) for induced seismicity related to SWD operations over broad areas of concern. The AOI regions identified for Directive actions in Oklahoma were based on scientific considerations of previous seismicity, local geology and other regional structural boundaries derived from consultations with the Oklahoma Geological Survey and Stanford University. OCC Seismicity Department staff initiated the first regional reduction in early 2015 (~800,000 BPD) to curtail seismicity within the first regional AOI staff defined. Subsequent revisions to regional AOIs for SWD operations were made

in 2015 and 2016. In 2016, additional reduction of SWD well volumes in the AOI resulted in a >40% reduction in allowable injection compared with the maximum reported injection volumes in 2014.

Initial notification, following a Directive or AOI issuance, is typically a call from Seismicity Department staff to all affected SWD operators, requesting immediate operational mitigation. If an operator refuses to honor the staff's Directive or OCC's Order, an Emergency Order can be used to achieve compliance or the well can be shut-in immediately by OCC's Oil and Gas Conservation Division staff, citing the Oklahoma Statute created in 2016 to protect public safety.

e. Operational Mitigation Procedures¹

Depending on frequency and magnitude of earthquakes any of the following operational changes may be requested:

- SWDs are shut-in using a gradual, managed approach;
- SWDs are ordered to plug or plug back to increase distance from crystalline basement rock;
- Injection volumes and/or pressures are reduced;
- Radioactive Tracer Surveys or other diagnostic tests are required to prove injectate remains within the target permitted zone (this is especially important to establish injection rates for multiple injection intervals); and
- Operators are put on notice that reductions will be required if seismicity does not subside.

f. Hydraulic Fracturing "HF"

g. Permitting²

The permitting process for hydraulic fracturing (HF) for new or existing wells is found in OAC 165:10-1 and 10-3. This permitting process includes all of the typical well permitting requirements to protect underground sources of drinking water (USDW); the environment; correlative rights, and to prevent waste. Additional procedures specific for seismicity are discussed below under the Operational Reporting section.

h. Area of Interest for Permitting²

For induced seismicity potentially caused by HF operations in specific plays (e.g., the SCOOP-STACK in central Oklahoma), the OCC has additional seismicity requirements for well completion operations (e.g., active monitoring). The OCC's Well Completion Seismicity Protocol (issued December 2016 and revised February 2018) details the additional requirements and considerations for HF operations throughout the state. Although not specifically defined in the Protocol, operators are expected to complete a thorough pre-planning seismic investigation of the area in which proposed HF operations are to be completed. During preplanning, operators may review geophysical data, geological data, and/or historical seismicity to understand the seismic hazard in the vicinity of their proposed operations. During active HF operations, Induced Seismicity Department staff monitor the operations using automated GIS applications and

expect Operators to notify the OCC of events occurring within 5 km in any direction of the stimulated section of a well². Therefore, a horizontal well with a 2-mile-long lateral (3.2 km) has an area for monitoring that extends 13.2 km “long” and 10 km “wide.”

i. Operational Reporting²

In addition to reporting all the normal information for well completions to the OCC defined in section a., operators are required to submit a Form 6000NHF - Notice of Hydraulic Fracturing to the Oil and Gas Conservation Division no less than 48 hours prior to commencement of completion operations (OAC 165:10-3-10(b)). Included on the Form 6000NHF are additional actions the Operator has planned to minimize the chance of felt levels of induced seismicity during hydraulic fracturing operations, including an operator’s certification for access to a seismic monitoring array capable of detecting earthquakes down to a magnitude of completeness range of **M 2.0** to **M 2.5** and adoption of a Seismicity Response Plan. At any time, Division staff may ask for detailed completion information including, but not limited to, the operator’s Seismicity Response Plan and preplanning data should seismicity occur during HF.

j. Action Levels and Notification Thresholds²

Should seismicity occur within the prescribed monitoring area surrounding a well completion operation, the Oil and Gas Conservation Division’s Well Completion Seismicity Protocol² defines the additional active monitoring requirements. One important distinction listed in the current Protocol deals with differing magnitudes in various seismic catalogs maintained by private operators and service companies versus the public catalog maintained by the OGS. In the Protocol, the OCC requires the following: “While the OGS Earthquake Catalog is the magnitude of record for all events, protocol action is to be initiated upon the first detected actionable magnitude. If the OGS magnitude is higher than the magnitude detected on the operator’s private array, further protocol action will be required at the level appropriate to the OGS magnitude.” OGCD Division staff require operators conducting HF operations in SCOOP-STACK have access to a monitoring array that provides real-time data to inform field operations and to respond to detected events, as follows:

- **M 2.0** - operators begin following their own Seismicity Response Plan
- **M 2.5** - qualified pause for no less than six hours, discuss mitigations with Induced Seismicity Department staff by phone, email or other approved method.
- **M 3.0** - mandatory pause for no less than 6 hours, discuss mitigations with Induced Seismicity Department staff by phone email or other approved method. Operators must take additional mitigation measures for multiple events and/or other mitigating circumstances. Operations cannot proceed after the mandatory pause without Induced Seismicity Department staff approval.
- **M 3.5** - operations cease immediately. Operators are required to meet with the Induced Seismicity Department staff for a technical review of the operations and may be required to submit detailed information regarding the HF stimulation and seismicity. Operations may restart only once Seismicity Department manager has approved a new operational mitigation plan and seismicity has returned to baseline levels in the area of concern.

k. Operational Mitigation Procedures³

Operational mitigation procedures are determined by the operator on a case-by-case basis, but generally include the following options, in any combination:

- Pausing, or no pressure pumping for 6 to 24 hours depending on the situation
- Reducing fluid volumes per foot of lateral and/or pump rates for subsequent stages
- Changing fluid design for subsequent stages
- Reducing the length of subsequent stages and the total fluid volume proportionately
- Other operational changes on multi-well pads to limit energy input into same rock volume (no zipper operations, moving to offset operations or operational pauses between stages on different laterals)
- Skipping subsequent stages along the lateral

l. Public Outreach

Public outreach is an important consideration of induced seismicity as regulatory policies are created to protect the general public. The OCC's Office of Public Information (OPI) serves as the center for outreach to the public and other federal, state and local entities. OPI staff also provide support to the Induced Seismicity Department by interfacing with the public and receiving induced seismicity reports. Public reports contribute to OCC's knowledge of how residents perceive seismicity correlated with industry activities the agency regulates. OPI department staff strive to achieve transparency by immediately responding to the public's questions and rapidly disseminating information regarding induced seismicity.

Footnotes

1. OCC's Earthquake Response Summary May 30, 2018
2. OCC's News Release and Directive dated February 27, 2018
<https://oklahoma.gov/content/dam/ok/en/occ/documents/og/02-27-18protocol.pdf>
3. Industry Led Induced Seismicity Mitigation Workshops 2018

Texas

Do Conditions Exist that Merit Regulatory Action?¹

Yes. In specific regions of Texas, geologic and tectonic stress conditions are such that seismic activity can occur from natural and anthropogenic causes.

Statutory or Regulatory Authority for Induced Seismicity Rules^{2, 3, 4}

The Railroad Commission of Texas (RRC) has sole authority over oil and gas activities with regulations found in Texas Administrative Code (TAC) Title 16 Part I Chapter 3. Specific rules for UIC Class II wells exist in the form of RRC Statewide Rules 9 and 46, as well as various Field Rules. Authority over underground injection of fluids associated with oil and gas exploration and production activities has been delegated to the Commission by the USEPA. Regulations and procedures follow national requirements adopted under the federal Safe Drinking Water Act regarding protection of underground sources of drinking water. The RRC's Underground Injection Control (UIC) program features regulations specifically tailored to protect underground sources of

drinking water from harm resulting from injection or disposal of oilfield waste and oilfield fluids into underground formations.

In accordance with [16 TAC §3.9 and §3.46 (Statewide Rules 9 and 46)], the RRC grants injection and disposal wells permits for UIC Class II wells (injection wells associated with oil and gas production) when they meet the requirements of the RRC's UIC Program. The UIC permitting process features numerous requirements and safeguards including notice to the public [16 TAC §3.9(5) and §3.46(c)]; hearing opportunities; a review of area geology; and required areas of review [16 TAC §3.9(7)(A) and §3.46(e)(1)] near the proposed wells to determine if there are other wells penetrating the same geologic horizon proposed for disposal.

1. UIC Class II wells, also known as Saltwater Disposal (SWD) wells, also known as Injection wells⁵

a. Permitting

When permitting injection and disposal wells, the RRC reviews the application and related data to:

- determine whether an operator is eligible for a permit (has no past due franchise taxes, has the required financial assurance, and has no outstanding compliance problems applicable to the proposed injection or disposal operation);
- determine whether all required entities have been properly notified (RRC rules require that for non-commercial wells, the surface owner and nearby oil and gas well operators be notified, and for commercial wells that adjacent surface owners also be notified) [See 16 TAC §3.9(5) and §3.46(c)];
- in the event a protest is filed, notify the operator that the application cannot be approved administratively, and advise the operator of their right to a hearing on the application;
- determine whether the proposed injection well is properly constructed to protect groundwater with required surface casing and cement to the base of usable quality water as determined by RRC's Groundwater Advisory Unit and with long string casing and cement to ensure that the fluid is confined to the proposed injection or disposal interval [16 TAC §3.13 (Statewide Rule 13)] and determine that the proposed injection interval is not a USDW; and
- determine that there are no known improperly completed, improperly plugged or unplugged and abandoned oil and gas wells within at least a ¼ mile radius of the proposed injection well (This is known as the area of review 16 TAC §3.9 (7) and §3.46 (e) and may be expanded up to one-mile radius or more in some circumstances). In addition to the UIC permitting process, the RRC's requirements for proper well construction and completion, injection procedures and monitoring ensure that USDWs are not impacted by the injected fluid.

In May 2014, the RRC hired a seismologist to assist UIC staff with the review of seismic activity.

In October 2014, the Commission adopted rule amendments to 16 Texas Administrative Code §3.9 and §3.46 (Statewide Rules 9 and 46) designed to address disposal well operations in areas of

historic seismic activity. The main components of the rule amendments, effective November 17, 2014, are:

- requiring applicants for new disposal well permits to conduct a search of the USGS seismic database for historical earthquakes within a circular area of 100 square miles around the proposed, new disposal well;
- clarifying RRC'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;
- clarifying RRC staff's authority 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; and
- clarifying RRC staff's authority to require an applicant for a disposal well permit to provide additional information, including pressure front boundary calculations, to demonstrate that disposal fluids will remain confined if the well is to be located in an area where conditions exist that may increase the risk that the fluids may not be confined.

In further response to emerging seismicity in the Permian Basin, in 2019 RRC developed and implemented "Guidelines for Permitting Saltwater Disposal Wells in the Permian Basin"; key elements of these RRC guidelines include the following:

- Guidelines apply to the Permian Basin for **M** 2.0+ events on a well-by-well scoring basis, intended to provide flexibility.
- Guidelines are based on an initial seismicity screen, which looks at USGS data and TexNet data for **M** 2.0 or greater and creates a 100 square mile (9.08 km) circular area of review (AOR). A seismic event of **M** 2.0 or greater within the AOR will trigger further RRC review.
- A positive seismicity screen will require the submission of supplemental information to allow RRC to assess the state of the disposal zone and adjacent strata.
- If the seismic review is triggered by the initial seismicity screens, there are 3 possible well classifications that could result – Category A, Category B, and Category C – each with specific daily barrels per day (BPD) maximums (Category A providing for the highest maximum allowed at 30,000 bpd); daily record keeping; initial static bottomhole pressure test; and a step rate test and additional conditions as necessary (directed toward the more stringent Category C with maximum allowed at 10,000 bpd). In RRC Districts 7C, 8 and 8A that cover the Permian Basin, UIC Class II operators may receive higher operating limits under an RRC approved Seismic Monitoring Plan and an Earthquake Response Plan.

Considerations for induced seismicity during UIC Class II well permitting include an analysis of historical events, geologic, geomechanical and reservoir factors, plus a confidence level on data used. These considerations specifically include identification of nearby events > **M** 2.0 in the USGS or TexNet catalog, injection zone proximity to basement, injection well proximity to known faults, possible analysis of the relative potential of nearby faults to slip using Stanford's Fault Slip Potential tool, cumulative injection volumes given other injection wells in the same zone within 2.82 miles (equivalent to 25 sq mi) around the injection well, proximity to other injectors in the same zone.

Conditional permit approval may reflect lower injection rates and pressures, daily recording of injection rates and pressures, required bottomhole pressure and step rate tests.

The Seismic Monitoring Plan could include the potential for adding stations to the TexNet array with minimum requirements for quantity, location, equipment used and data sharing. The Earthquake Response Plan includes the operator's commitment to monitor the TexNet array, respond to detected events using operational mitigations and to communicate with the RRC within 24 hours if a **M** 3.5+ event occurs within the AOI. Within 30 days of an earthquake trigger, the operator will file a report with the Commission documenting the event.

b. Area of Interest (AOI) for Permitting

For new or amended UIC Class II well permits, the AOI is defined by a radius of 5.64 miles or 100 sq mi around the injection well.

- Operational Reporting
Additional reporting for induced seismicity may include more frequent injection well pressures and volumes, bottomhole pressures, step rate test results.
- Action Levels and Notification Thresholds (also known as the Traffic Light System)
The RRC has not established specific thresholds for a traffic light system and maintains flexibility to take actions dependent on the characteristics and location of a specific event. Operators are encouraged to take proactive mitigation steps if they become aware of the potential that their operations may be contributing to increased or anomalous seismicity in proximity to their operations.
- Operational Mitigations Considered
Operational mitigations may include additional monitoring, rate and pressure reductions.

Footnotes

1. Seismicity Observations and Research in Texas
<https://www.beg.utexas.edu/texnet-cisr>
2. RRC rules for Oil and Gas Operations
[https://texreg.sos.state.tx.us/public/readtac\\$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y](https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y)
3. RRC Statewide Rule 9
[https://texreg.sos.state.tx.us/public/readtac\\$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=9](https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=9)
4. RRC Statewide Rule 46
[https://texreg.sos.state.tx.us/public/readtac\\$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=46](https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=46)
5. Summary for RRC permitting UIC Class II wells in Areas of Seismicity
<https://www.rrc.texas.gov/oil-and-gas/publications-and-notice/manuals/injection-disposal-well-manual/summary-of-standards-and-procedures/seismicity-review>

Appendix H: Carbon Dioxide Geologic Storage and Induced Seismicity

Introduction

To achieve the Paris Agreement goal of limiting global temperature rise to 2⁰ C above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5⁰ C, drastic and rapid reduction in greenhouse gas emissions is needed. CO₂ emissions being the major contributor to this mix, Carbon Capture and Storage (CCUS) technology is expected to play a significant role in this effort.

According to the International Energy Agency (IEA) as well as various emissions trajectories developed by the Intergovernmental Panel on Climate Change (IPCC), the net-zero CO₂ emissions goals needed to stop further global temperature increase may be impossible and extremely expensive without the use of CCUS to mitigate direct emissions. This will especially be true in hard to mitigate sectors like air travel, freight, and heavy industries (Luderer et al. 2018). As per the IEA, in the 2⁰ C scenario, CCUS should help mitigate about 90 gigatonnes of cumulative CO₂ emissions by year 2050 (IEA 2019). The role of CCUS (used in conjunction with bioenergy and direct air capture) will be even more critical to deliver negative emissions in the second half of the century to limit future temperature increase to below 1.5⁰ C.

At time of writing, about 38 MTA (million tonnes per annum) of CO₂ is stored in the subsurface by the 19 ongoing CO₂ storage projects worldwide (GCCUSI 2019). To meet the 2⁰ C goal recommended by IPCC, CO₂ storage would need to operate on a much larger scale, potentially storing about 4 GTA (gigatonnes per annum) by year 2050. Such a rapid ramp up, from 38 MTA to 4 GTA in 30 years, may pose many challenges, including the possibility of induced seismicity. The connection between produced water injection and induced seismicity has gained attention in recent years and similar concerns exist for CO₂ injection operations.

Understanding induced seismicity potential due to CO₂ storage is a key requirement to evaluate the feasibility of such larger scale future CO₂ storage projects. Induced seismicity events related to geologic CO₂ storage projects and EOR projects to date have generally been limited to small magnitude events and generally have not caused any widespread surface felt ground shaking.

Felt induced earthquakes could hamper public acceptance of CCUS. In a worst-case scenario, seismic fault slip could compromise the seal integrity. Thus, the success of CCUS lies with minimizing such induced seismicity events. Similarly, there have not been demonstrated instances of significant felt seismicity attributed to CO₂ Enhanced Oil Recovery (EOR) projects (National Academies 2013). One reason for the apparent lack of felt seismicity with EOR projects is that the injection is generally intended to maintain reservoir pressure near pre-production pore pressure levels. It is noted that recently some studies have attributed one potential instance of felt seismicity to

CO₂ EOR injection operations. The specific causal relationships are complex as this area has had saltwater disposal operations and long term oil and gas production (White and Foxall 2016).

This appendix first discusses various types of geologic CO₂ storage options, key requirements for safe and secure CO₂ storage, and current well permitting frameworks. Then pertinent information from various currently ongoing geologic CO₂ storage projects is presented, which can help in understanding the potential for induced seismicity with future geologic CO₂ storage projects. In addition, several induced seismicity risk management options are discussed.

Geologic CO₂ Storage

Geological CO₂ storage includes emplacing CO₂ in:

- Oil reservoirs in association with EOR
- Depleted oil and gas reservoirs
- Deep saline formations
- Basalts and coal seams

During geologic CO₂ storage in depleted hydrocarbon reservoirs or saline formations, CO₂ from anthropogenic sources is compressed and injected at the supercritical state, with the density of CO₂ ranging from 600 to 800 kg/m³. For CO₂ storage in saline aquifers, the site depth is chosen such that it is deep enough to keep the CO₂ in the supercritical state (usually 1000 m or more). Alternatively, CO₂ can also be stored in association with EOR operations which results in increased recovery of oil or gas. During CO₂ EOR, the injected CO₂ facilitates recovery as oil is released and produced but a large percentage of the CO₂ gets trapped in rock pores and replaces the in-situ oil. This form of geologic storage is also known as associated storage since the primary purpose of CO₂ injection is oil recovery and the trapping and long term retention of CO₂ is incidental.

Figure H.1 shows a typical flow diagram for CO₂ EOR process. When CO₂ is injected into an oil reservoir in the supercritical state, depending on the pressure conditions, some fraction of the CO₂ will dissolve into the hydrocarbon-rich phase (oil). As it does, it lowers the interfacial tension and viscosity of the trapped oil (reduces capillary forces) thereby increasing the ease with which it is released and flows through the rock pores. This displaced oil is then produced at the production well. The CO₂ that is produced along with the oil is then separated and replenished with new CO₂ and reinjected into the reservoir thereby forming a closed loop system. In each cycle, a fraction of the injected CO₂ gets trapped in the reservoir, and the total volume of trapped CO₂ increases with the number of cycles.

Field data shows that for every million barrels of oil produced in CO₂ EOR operations, approximately 0.3 million tonnes of CO₂ is trapped in reservoirs (Science of Carbon Storage in Deep Saline Formations 2019). CO₂ EOR operations were first tried in 1972 in Scurry County, Texas; and CO₂ injection has been used successfully throughout the Permian Basin of West Texas and eastern New Mexico, and is now being pursued to a limited extent in Kansas, Mississippi, Wyoming, Oklahoma, Colorado, Utah, Montana, Alaska, and Pennsylvania (DOE website 2020 <https://www.energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery>). During the last 40 years, CO₂ EOR operations in the U.S. have injected more than 1 gigatonne of CO₂, and mass balance analysis suggests that more than 99% of CO₂ is trapped in the subsurface.

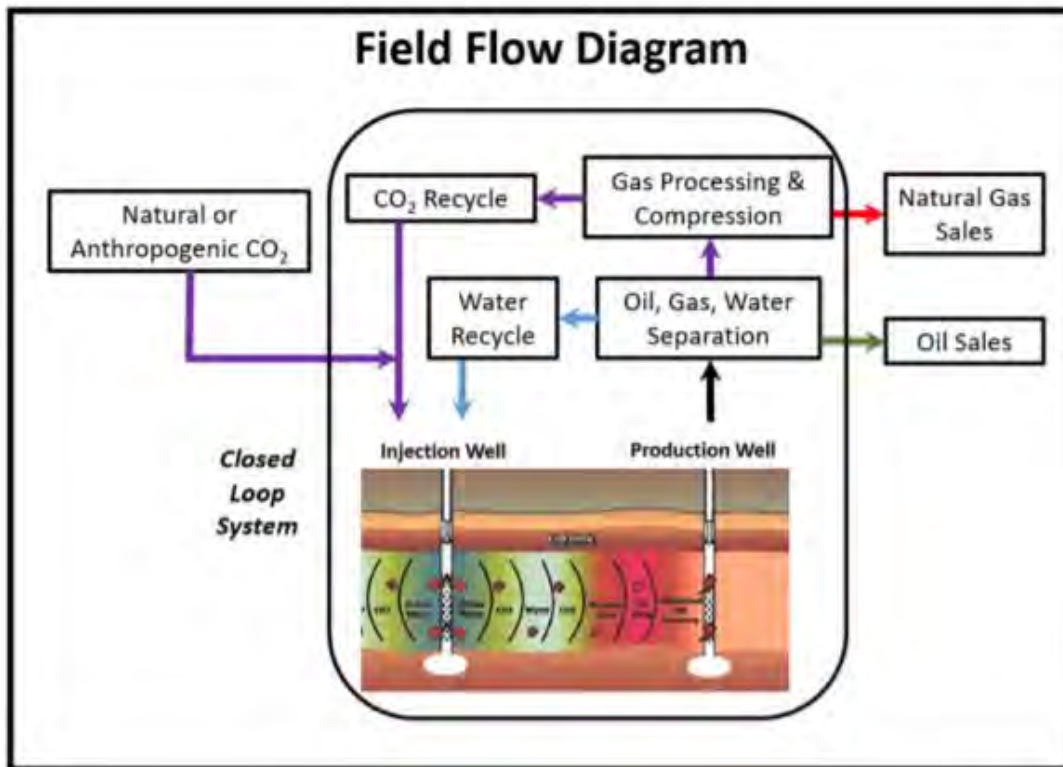


Figure H.1 Typical flow diagram for CO₂ EOR process (Source: NPC Report 2019)

Storing CO₂ in deep saline formations began in 1996 with the Sleipner CO₂ storage project in Norway, where the project operator has been injecting about 1 MTA. A more recent example is the Gorgon CCUS project in Western Australia, which began operation in late 2019 and is capable of injecting about 4 MTA into a deep saline formation.

Safe, secure, and permanent storage of CO₂ in deep saline formations requires reservoirs (called injection zones or injection intervals) with suitable thickness, permeability and porosity to easily inject large volumes of CO₂, overlain by a low permeability, high capillary entry pressure rock (called a seal, cap-rock, or confining zone) to keep the CO₂ from escaping. It also requires that projects be well designed, operated and managed.

Although CO₂ is in the supercritical state because its density is lower than brine, CO₂ that is not quickly trapped through dissolution into the brine will migrate upwards driven by buoyancy. Figure H.2 shows a schematic of the movement and trapping of CO₂ post injection. The secure storage of CO₂ in the subsurface relies on various trapping mechanisms (Benson et al. 2015):

- 1) Stratigraphic and structural trapping, where the buoyant CO₂ is trapped beneath an impermeable seal or cap-rock. The high capillary entry pressure cap-rock will prevent further vertical migration of the CO₂. In addition, sedimentary basins have closed, physically bound traps or structures, which are occupied mainly by saline water, oil, and gas. Structural traps include those formed by folded or fractured rocks. Faults can act as permeability barriers in some circumstances and as preferential pathways for fluid flow in other circumstances.

Stratigraphic traps are formed by changes in rock type caused by variation in the setting where the rocks were deposited. Both of these types of traps are suitable for CO₂ storage. At short timescales, this becomes the principal trapping mechanism and is a primary factor while screening potential storage sites.

- 2) Residual or capillary trapping, where the CO₂ is immobilized as isolated bubbles or “blobs”. This occurs during the post injection migration of the CO₂ plume when the displaced in-situ brine reinvades CO₂ filled regions at the tail of the plume resulting in the disconnected CO₂ blobs. This is similar to residually trapped oil.
- 3) Dissolution trapping, where the CO₂ dissolves into the in-situ brine resulting in a denser CO₂ rich brine. The dense CO₂ laden brine sinks deeper into the formation triggering a convective flow which in turn increases the dissolution rate.
- 4) Mineralization, where the dissolved CO₂ precipitates to form carbonate minerals or the CO₂ rich brine reacts with the rock minerals.

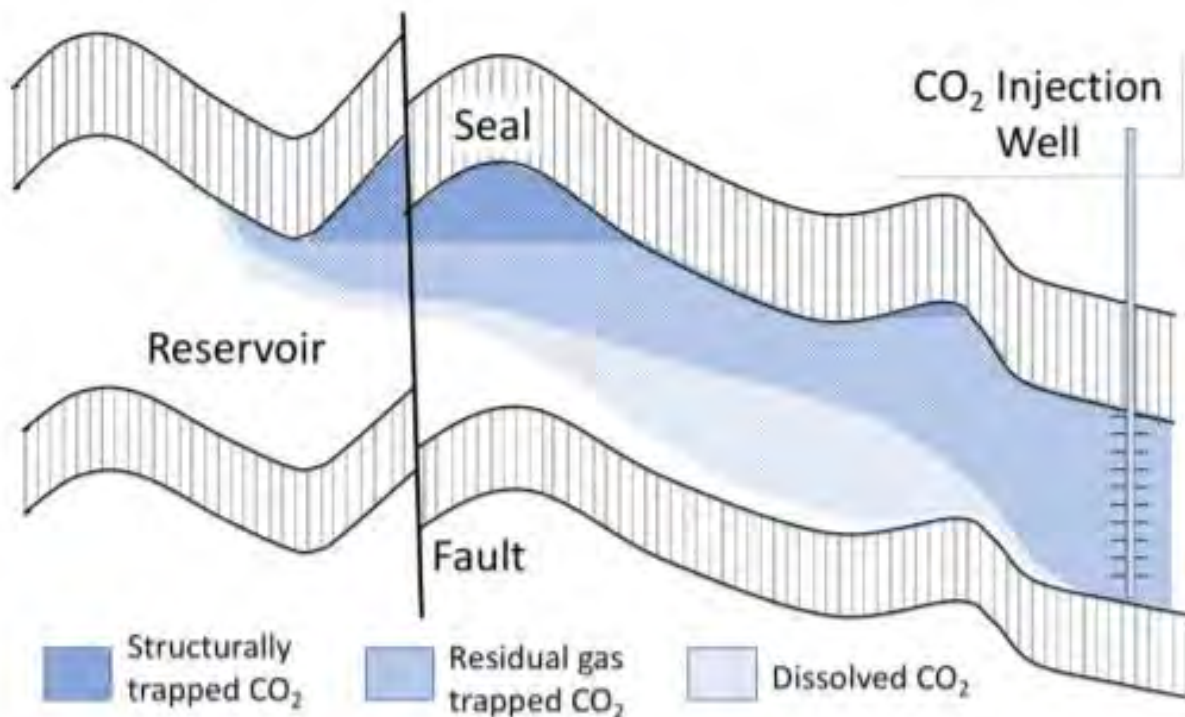


Figure H.2 Generalized flow patterns and trapping behavior of CO₂ post injection. Once injected, the buoyant CO₂ migrates upwards and eventually is trapped beneath a sealing-cap rock (Source: NPC Report 2019).

Figure H.3 provides a simplified representation of the relative contribution of these trapping mechanisms towards total trapping capacity and the time scales over which each of these mechanisms act. While stratigraphic and residual trapping take effect starting at early times, dissolution and mineralization driven by slower mass transfer and kinetic processes are expected to occur over larger timescales (hundreds to thousands of years or more).

Residual trapping, dissolution and mineralization generally are more secure forms of trapping compared to structural and stratigraphic trapping which rely completely on the integrity of the seal. It should be noted that the relative importance of these secondary trapping mechanisms can be expected to vary substantially between sites of different characteristics (e.g., rock type, depositional setting, storage reservoir boundary conditions), and full physics based numerical simulation based on best available site information would be required to credibly forecast of long term trapping at any given site.

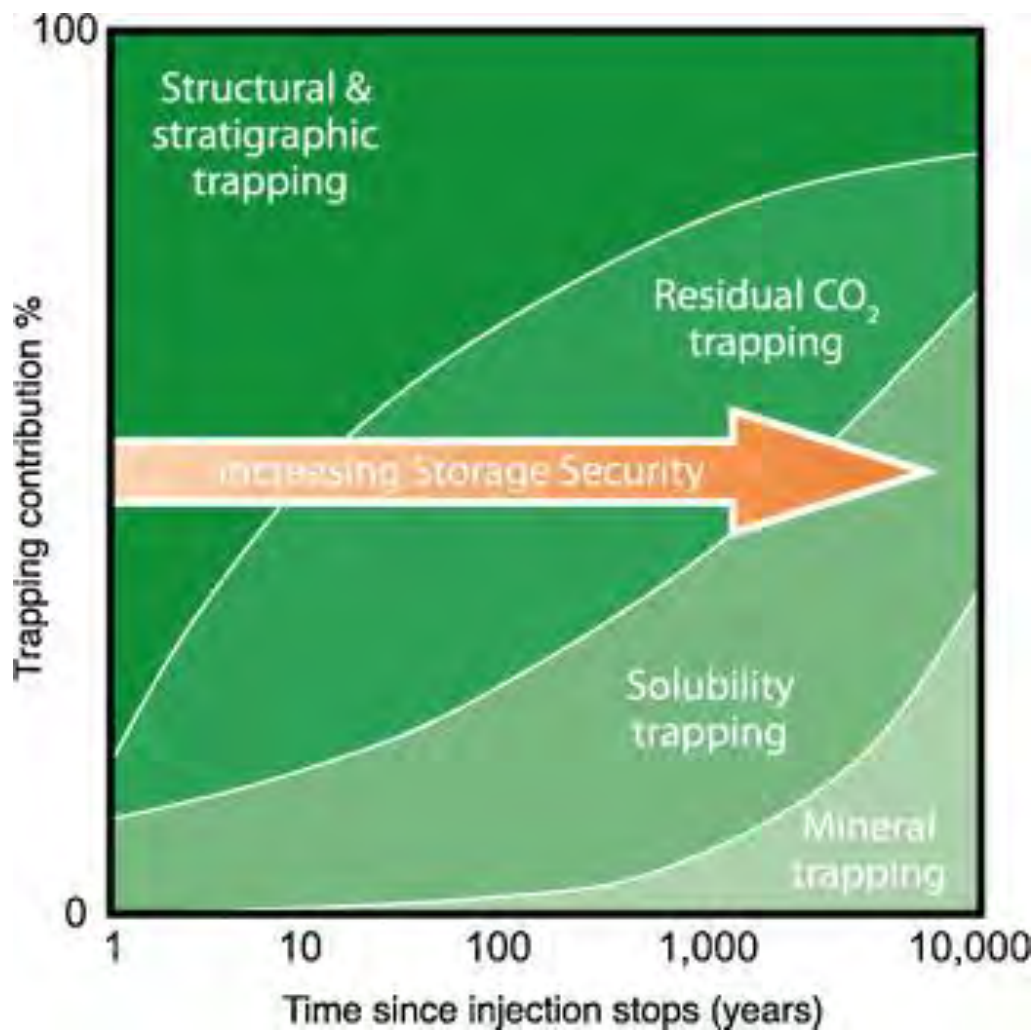


Figure H.3 Trapping mechanisms associated with geologic CO₂ storage. (Source: Benson et al. 2005 in Krevor et al. 2015, IJGGC)

Considerations for Safe, Secure and Permanent CO₂ Storage

Median estimates of total CO₂ storage capacity in the U.S., including storage in saline, depleted and unconventional reservoirs, range anywhere from 3000 to 8600 gigatonnes (NPC study 2019). Building upon the 20 years of commercial CCUS projects and almost half a century of CO₂ EOR projects expertise, the USEPA has published extensive guidance and criteria to consider for site selection, (e.g., Environmental Protection Agency 2012, Environmental Protection Agency 2013, Environmental Protection Agency 2016, Environmental Protection Agency 2018). Some of the key criteria to ensure safe, secure, and permanent storage during site selection are summarized in Table H.1.

Table H.1: Key considerations for safe and secure geologic CO₂ storage

Factor	Consideration and Requirements
Injection Interval or Zone	Highly permeable and porous formations with large lateral extent will favor higher injection rates (to positively impact project economics) and produce smaller increases in pore pressure (to minimize risk of induced seismicity). The injection formation should be sufficiently thick, regional in extent and well connected.
Overburden Seal or Confining Zone	Detailed characterization of cap-rock is vital. Low permeability and high capillary entry pressure rocks are essential. Failure of the cap-rock seal could possibly result in CO ₂ migrating into shallower formations. Choosing a site with multiple overlying sealing layers ('stacked reservoir-seal pairs') or a very thick regional seal will help reduce risk.
Initial Pressure	Initial pressure in injection interval and overburden seal conditions are such that the injection altered subsurface stress state remains away from critical conditions for fault activation.
Flow Barriers	Compartmentalized reservoirs or presence of flow barriers such as low permeability faults can result in injection-induced overpressure. Pressure monitoring is needed to avoid over pressurization due to compartmentalization.
Fault Seal	CO ₂ injection wells should be sufficiently far from the faults. The distance between a fault and CO ₂ injector should be evaluated taking into consideration pressure and CO ₂ plume size and fault reactivation potential. If faults are present, it is important to make sure that juxtaposition of low permeability rocks is present above the injection formation. Detailed characterization to determine juxtaposition geometries, sealing properties and stress state is essential and injection strategies must be designed to mitigate reactivation of faults.
Legacy Wells	Injecting in depleted reservoirs has advantages such as established characterization, production and geologic data, and the confirmation of reliable sealing mechanisms. But existing old wells might potentially act as leakage pathways and become a liability. Plans should be in place to understand the current status of wells and proper corrective action plans should be in place to mitigate potential issues in the area of review.
Induced Seismicity	Detailed characterization of storage sites is necessary to understand baseline stress and pressure conditions and to identify individual faults or fault zones that may be capable of generating seismicity of concern. Characterization of basement rock is advisable, especially if injection formation is close to the basement, (as larger faults at higher stress conditions could be present in the basement).
Monitoring	Seismic monitoring may be considered to track the CO ₂ plume movement. Microseismic sensor arrays and Interferometric Synthetic Aperture Radar ("InSAR") can help detect surface movement for land-based operations. Monitoring wells may be placed in the injection area, and if possible, above the storage formation to measure pressure, temperature and saturation and can help detect leakages and detect plume movement. These and other monitoring techniques, combined with modelling that has been shown to have predictive capacity, can demonstrate that storage is secure.

Additional considerations are provided in DOE's Best Practices manual for geologic sequestration operations. Recommendations relating to operations during injection include:

- Focus on monitoring and limiting risks;

- Monitoring includes the entire storage complex (the reservoir, confining layers, near subsurface environment, and surface environment) to ensure that the CO₂ is where it is supposed to be and there are no negative impacts to USDWs, human health or the environment;
- Monitoring data usually will be interpreted with the help of static and dynamic models; and
- All CO₂-handling pumps, pipelines and wells require frequent inspection and maintenance.

Regarding post-injection operations, the recommendations in the DOE Best Practices manual include:

- Continued monitoring of the storage complex, well closure and site closure; and
- Monitoring to continue, until the operator can demonstrate the integrity of the storage complex and stability of the CO₂ plume to the satisfaction of regulators.

As described in the National Petroleum Council report (2019) at

<https://dualchallenge.npc.org/downloads.php> geologically trapped CO₂ can be considered securely stored after an approved process is followed to determine that retention is demonstrated to be long-term. Standards for the monitoring, reporting and verification of injected CO₂ are critical to ensuring robust data can be collected on the containment and behavior of stored CO₂ to ensure long term secure geologic storage (also referred to as permanent storage, sequestration, or permanent sequestration). Such standards are detailed in 40 CFR Part 92, Subpart RR; 40 CFR Part 146, Subpart H; ISO 27914: 2017; and CSA/ANSI ISO 27916:19.

Well Permitting

Wells for CCUS and EOR are permitted under the underground injection control (UIC) program established by the Safe Drinking Water Act (SDWA). 42 USC § 300 et seq. Class II wells are used to inject fluids associated with oil and natural gas production.

As discussed in Appendix B, the USEPA has established regulations for the Class II wells used for CO₂ injection for CO₂-EOR or produced CO₂ disposal and Class VI wells used to inject CO₂ solely for geological sequestration (GS). Enhanced recovery wells are the most numerous types of Class II wells.

EPA Class V classification wells were used to permit the initial CCUS pilot and demonstration project wells. Class V wells are experimental projects whose primary purpose is to test new, unproven technologies. As these projects proved out the CCUS concept, EPA developed a new Class VI category for geologic sequestration wells to accommodate factors EPA considered unique to CO₂ injection for geologic storage, including the:

- Relative buoyancy of CO₂;
- Subsurface mobility;
- Corrosivity in the presence of water; and
- Large injection volumes anticipated at geologic storage (GS) projects.

In December 2010, the EPA published the Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells.

EPA developed specific criteria for Class VI wells:

- Extensive site characterization requirements;

- Injection well construction requirements for materials that are compatible with and can withstand contact with CO₂ over the life of the project;
- Injection well operation requirements;
- Area of review determined using a computational model;
- Comprehensive monitoring requirements that address all aspects of well integrity, CO₂ injection and storage, and groundwater quality during the injection operation and the post-injection site care period;
- Financial responsibility requirements assuring the availability of funds for the life of the project (including post-injection site care and emergency response); and
- Modeling, reporting and recordkeeping requirements that provide project specific information to continually evaluate Class VI operations and confirm USDW protection.

Induced Seismicity: Comparison of CO₂ Storage and Learnings from Produced Water Disposal

All geologic CO₂ storage projects to date have successfully stored CO₂ without any induced seismicity being felt at the surface but concerns about geomechanical response due to fluid injection volumes much greater than those performed to date remain a concern with some in the scientific community (Zoback and Gorelick 2012). When CO₂ is injected into a formation the associated pressure increase reduces the effective stresses on faults which could lead to their reactivation and result in induced seismicity (NRC Report 2013). Other reactivation mechanisms that might be considered are increased vertical stress from the mass injected or stress transfer from reservoir deformation and associated aseismic slip (Eyre, et. al. 2019).

Examining the history of produced water disposal volumes in the U.S. provides insight into whether it is feasible to store the 4 GTA of CO₂ the IEA suggests will be required by 2050 (globally). As discussed further below, disposal of such large quantities of saltwater into the subsurface, for over a decade, in the U.S. alone, provides some confidence in the technical feasibility of gigatonne scale CO₂ storage worldwide.

In the U.S., total annual produced water in year 2012 was about 20 to 21 billion barrels (Veil 2015), which is about 3.2 GTA of water or about 2 GTA of CO₂ by equivalent in-situ volume (assuming water density of 1000 kg/m³ and CO₂ density of 700 kg/m³).

In 2019, produced water in the Permian basin alone totaled about 10 billion barrels (S&P Global Platts 2019). Over the last decade, produced water in the U.S. averaged about 20 billion barrels per year (Platts 2019). About 45% of produced water is injected for reservoir pressure support and 46% of produced water is disposed into deep saline formations (Veil 2015). The portion of produced water disposed is more relevant to saline storage of CO₂ than is the portion injected for reservoir pressure management, thus, water volumes equivalent to 1.0 GTA of CO₂ have been disposed annually into the subsurface over the last decade in the U.S.

Produced water injection has not been induced seismicity free. Starting from the 1960s, several events with magnitudes ranging from **M** 2.9 to **M** 5.7 have been detected during produced water injection

(Verdon 2014). The geology of the disposal sites plays a crucial role. During CCUS, other than induced seismicity, there is also some risk of CO₂ leakage into the atmosphere or groundwater system. Knowledge gained from the decades of water injection needs to be incorporated during site characterization.

Table H.2: Produced Water, Water Injected, and Water Disposed in U.S. (source Veil 2015)

Year	Total Produced Water bbl.	Water Injected bbl.	Water Disposed bbl.	Water disposed GT	CO ₂ equivalent of disposed water GT
2007	20,995,174,000	9,447,828,300	9,657,780,040	1.53	1.07
2012	21,180,646,000	9,531,290,700	9,743,097,160	1.55	1.08

CO₂ injection has some advantages in comparison to water disposal in the context of induced seismicity, including a favorable pressure response and dissolution induced pressure dissipation (Vilarassa et al. 2019).

Increasing reservoir pressure, in response to injection, is one of the main triggering mechanisms. The pressure increase due to CO₂ injection will generally be lower than a corresponding pressure increase due to similar amounts of water injection. CO₂ is more compressible, less dense, and less viscous compared to water; such that the increase in pressure is lower for CO₂ injection compared to similar amounts of water injection. Though the magnitude of pressure increase is lower, the area of review, in which there is an appreciable increase in pressure, is the same as water injection.

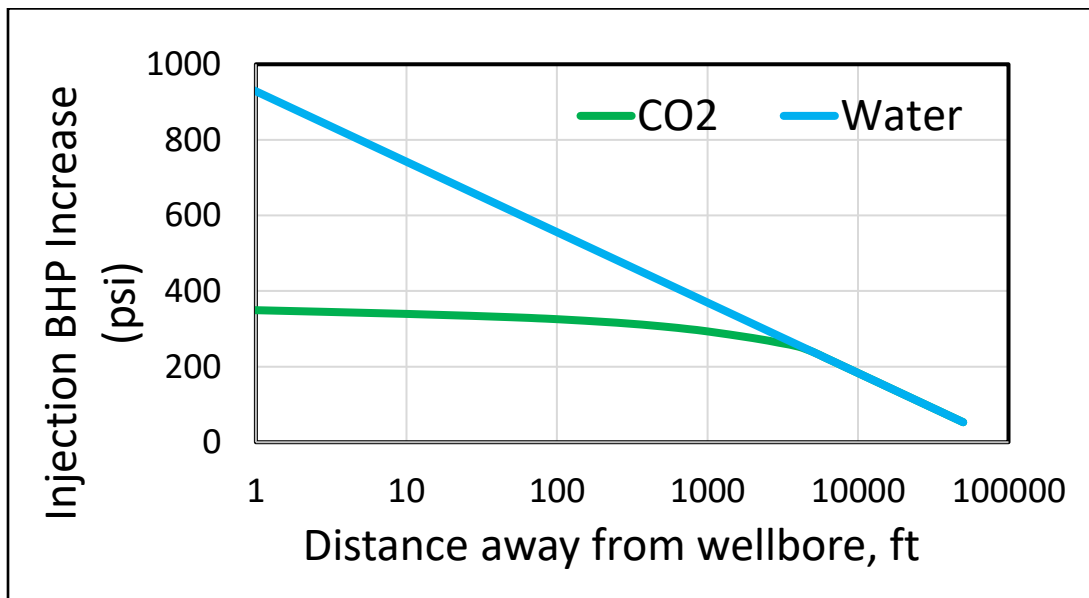


Figure H.4: An example scenario showing pressure increase plotted as a function of distance from the well after 15 years of injection of CO₂ and water at the same volumetric rate (3800 m³/day or 23860 bbl./day) at reservoir conditions into a saline formation 1000m deep. Formation permeability 250 mD and thickness 200 ft.

Figure H.5 shows another example of the injection well pressure increase as a function of time with injection volumes and reservoir properties similar to Figure H.4. In the case of water injection, the injection pressure generally, increases linearly with logarithmic time whereas for CO₂, the pressure increase is minimal. Vilarassa et al. (2019) describes such behavior, and it is mainly because of the lower CO₂ viscosity which offers low resistance to flow. The injection rate and associated pressure increase is one of the parameters that has been most correlated with initiation of seismicity (White and Foxall 2016) the evolution of pressure for CO₂ injection over time (Figure H.5) is favorable for geomechanical stability. Although CO₂ injection may lead to lower pressure increase which is favorable from an induced seismicity perspective, it is important to analyze induced seismicity with respect to real projects, which is addressed in the next section.

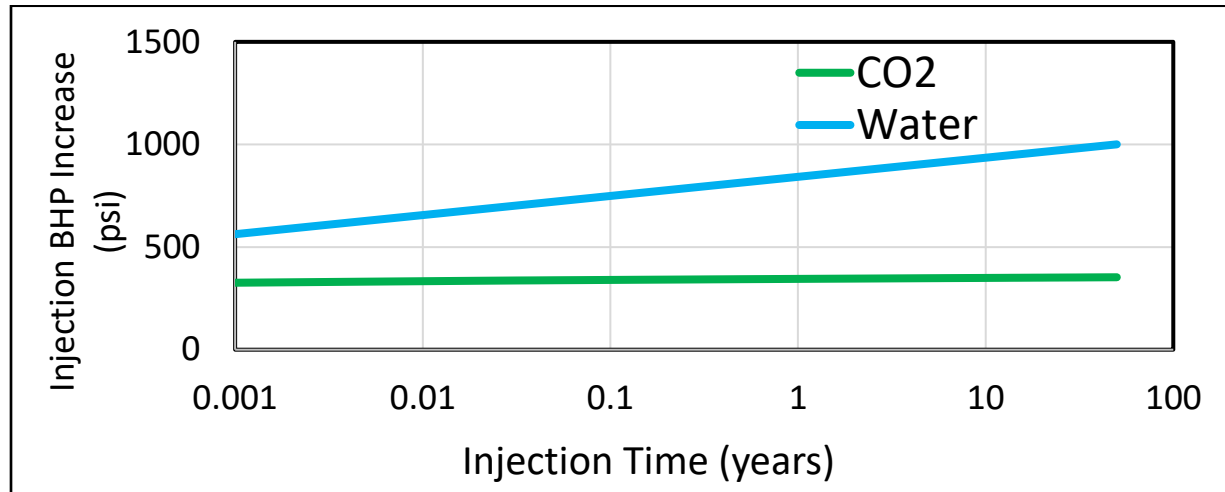


Figure H.5: An example scenario of injection pressure increase plotted as a function of injection time for CO₂ and water at the same volumetric rate (3800 m³/day or 23860 bbl./day) at reservoir conditions into a saline formation 1000 m deep. Formation permeability 250 mD and thickness 200 ft.

Ongoing Large-Scale CO₂ Capture Projects

Table H.3 provides a list of ongoing large-scale CO₂ storage projects worldwide, with a capture capacity at each project greater than 0.5 MTA. Out of the 19 ongoing projects, five projects store CO₂ in deep saline formations and the remaining 14 are CO₂ EOR projects. Out of the 19 large scale CCUS projects, the CO₂ source for 11 projects is natural gas processing. The remaining sources of CO₂ are from two power plants (post combustion), two hydrogen plants, two fertilizer plants, one ethanol plant and one iron and steel plant. The combined total capture capacity of all these projects is about 38 MTA.

Note that Appendix C of this Guide includes a detailed discussion of the Illinois Basin-Decatur Project (IBDP) and the Illinois Industrial CCUS Project. These projects are located in Decatur, Illinois, at an Archer Daniels Midland Company (ADM) facility. Carbon dioxide produced from agricultural products and biofuel production is stored deep underground through UIC Class VI wells. This case study documents two parallel seismic monitoring efforts—one operated by ADM, with deep vertical arrays of geophones in boreholes near the injection point—and another operated by the USGS, a surface array nearby using surface and shallow borehole sensors.

Table H.3: Details of large-scale ongoing CCUS projects (source Global CCUS 2019 report)

No	Name	Country	Project start year	CO ₂ capture capacity MTA	CO ₂ source	Storage type
1	Gorgon	Australia	2019	4	Natural gas processing	Deep saline formation
2	Jilin	China	2018	0.6	Natural gas processing	EOR
3	Illinois Industrial	USA	2017	1	Ethanol plant	Deep saline formation
4	Petra Nova	USA	2016	1.4	Post combustion	EOR
5	Abu Dhabi	UAE	2016	0.8	Iron and steel	EOR
6	Quest	Canada	2015	2	Hydrogen	Deep saline formation
7	Uthmaniyah	Saudi Arabia	2015	0.8	Natural gas processing	EOR
8	Boundary Dam	Canada	2014	1	Post combustion	EOR
9	Santos	Brazil	2013	3	Natural gas processing	EOR
10	Coffeyville	USA	2013	1	Fertilizer	EOR
11	Air Products	USA	2013	1	Hydrogen	EOR
12	Lost Cabin	USA	2013	0.9	Natural gas processing	EOR
13	Century	USA	2010	8.4	Natural gas processing	EOR
14	Snohvit	Norway	2008	0.7	Natural gas processing	Deep saline formation
15	Weyburn	USA	2000	1	Natural gas processing	EOR
16	Sleipner	Norway	1996	1	Natural gas processing	Deep saline formation
17	Shute Creek	USA	1986	7	Natural gas processing	EOR
18	Enid	USA	1981	0.7	Fertilizer	EOR
19	Terrell	USA	1972	0.5	Natural gas processing	EOR

Induced Seismicity Observations in CO₂ Storage Projects

Worldwide CO₂ storage in the future could be much as 4 GTA, which is orders of magnitude more than the current 38 MTA. Understanding induced seismicity potential due to CO₂ storage is a key requirement to evaluate the feasibility of such larger scale future CO₂ storage projects. Although, induced seismicity potential, in the context of uncertainty, may be assessed by numerical simulations and detailed geomechanical modeling informed by extensive geologic characterization, the discussion below summarizes seismicity as observed in the current ongoing projects.

Tables H.4 and H.5 below provide key information from some of the CO₂ storage projects that are currently ongoing from all over the world where seismicity is reported. Table H.4 shows publicly available data from CO₂ storage projects in deep saline formations and Table H.5 shows publicly available data from CO₂ EOR projects. Table H.4 includes five geologic CO₂ storage projects listed in Table H.3 as well as two additional small-scale projects geologic CO₂ storage projects (IBDP, Cranfield) with measured induced seismicity data.

The Quest, IBDP, Sleipner, Snøhvit, and In Salah projects were specially designed to store CO₂ in deep saline formations. The increases in bottomhole pressure at these five projects have varied from 0.1 MPa to 10 MPa. The inferred increased pressure, from 4D seismic, in Sleipner is very small as CO₂ was injected into a highly permeable and thick formation. The measured increase in pressure near wellbore in Quest and IBDP are 1.5 MPa and 2.4 MPa respectively. The higher bottomhole pressure of 8 MPa in Snøhvit is due to reservoir compartmentalization, which was rectified by recompleting the well in a shallower more permeable formation. Poor reservoir quality led to many unanticipated challenges in the In Salah project in Algeria. The In Salah project experienced earthquakes up to magnitude 1.7.

Not all the 19 major CO₂ storage projects shown in Table H.3 have a dedicated seismic monitoring network. However, any felt earthquakes would likely have been recorded by a regional seismic network. Based on available data, there have been no felt induced seismicity events in any deep saline CO₂ storage projects to date and only one EOR project (Cogdell) has been associated with induced seismicity at levels greater than magnitude 2.5.

Table H.4: CO₂ Storage in Deep Saline Formations

Project	Average injection rate MTA (No of wells)	Total Injected mass MT (project duration)	Injection bottomhole pressure increase MPa (psi)	Measured induced seismicity	Comments
Quest, Canada	1.1 (2 wells)	4 (2015-present)	1.5 (220)	-0.9 to 0.2	Large number of small earthquakes have been located in the underlying basement
Illinois Basin Decatur Project (IBDP), USA	0.36 (1 well)	1 (2011-2014)	2.4 (350)	-1.1 to 1.3	Earthquakes are observed along some small well-oriented faults in the underlying basement
Illinois Industrial CCUS Project (ICCUS), USA	1 (1 well)	1.7 (2017-present)	7.3 (1060)	-2.1 to 0.80	Earthquakes are observed along some small well-oriented faults in the underlying basement
Sleipner, Norway	0.85 (1 well)	17.8 (1996-present)	0.1* (15)	No dedicated local array, no felt events recorded on regional array	*average reservoir pressure increase calculated from seismic

Project	Average injection rate MTA (No of wells)	Total Injected mass MT (project duration)	Injection bottomhole pressure increase MPa (psi)	Measured induced seismicity	Comments
Snøhvit, Norway	0.7 (1 well)	5.8 (2008-present)	8* (1160) ~0**	No dedicated local array, no felt events recorded on regional array	Injection zone was changed after 3 years of injection from a deeper to shallower zone. *higher pressure increase was due to injection into the deeper compartmentalized reservoir. **pressure increase in the shallower non-compartmentalized reservoir was negligible
In Salah, Algeria	0.5 (3 wells)	3.8 (2004-2011)	10 (1450)	0.05 to 1.7	Low permeability and smaller thickness of storage interval led to significant pressure increase which resulted in notable earthquakes. Project involved use of horizontal wells for the CO ₂ injection.
Cranfield Saline Storage, USA	1.5 (1 well)	0.5 (2009-2010)	10 (1450)	No felt events recorded on regional array	Pressure increase was unexpectedly high

Currently, there are more than 150 CO₂ EOR projects (NPC Report 2019). Only a small number of projects have collected data to understand pressure changes and associated induced seismicity. Table H.5 shows data from three CO₂ EOR projects – Weyburn, Cranfield and Cogdell – where such data are available. Although the pressure increase is significant at Weyburn-Midale and Cranfield CO₂ EOR projects, the measured induced seismicity was not large. As mentioned previously, the Cogdell CO₂ EOR project has been associated with felt earthquakes. The seismicity in the Cogdell project has been attributed to the very high injection rates and the presence of faults in the reservoir (Gan and Frohlich

2013). The absence of similar magnitude earthquakes in the nearby fields undergoing similar CO₂ injection indicates that the events in Cogdell are an exception rather than the norm and highly dependent on the stress state and the geologic characteristics of the specific formation. It should be noted that out of the 150 CO₂ EOR projects, Cogdell CO₂ EOR project is the only project that has been associated with having earthquakes of low to moderate magnitude.

Table H.5: CO₂ Storage in Enhanced Oil Recovery Projects

Project	Average CO ₂ injection rate MTA (No. of wells)	Total Injected CO ₂ mass MT (project duration)	Injection bottom bole pressure increase MPa (psi)	Measured induced seismicity magnitude	Comments
Weyburn-Midale, Canada	2.5 (17)	38 (2000-present)	5 (725)	-0.5 to -3.5	Smaller earthquakes observed in overlying zones
Cranfield, USA	1.5 (24)	5.3 (2008-2015)	10 (1450)	No seismic activity. No felt events recorded on regional array	Pressure increase was unexpectedly high
Cogdell, USA	1.8	Not available	Not available	18 earthquakes of magnitude >3	A field with complex history of water injection since 1956. A combination of produced gas and CO ₂ has been injected from 2006-2011.

Seismicity Risk Management - Operations

The risks associated with induced seismicity at CO₂ storage sites can be reduced and mitigated using a systematic and structured risk management program. Site performance and management guidelines should be established prior to injection to optimize monitoring and mitigation programs; and establish control measures.

Key monitoring data that could be collected during operations can be derived from the use of techniques such as borehole microseismic and satellite InSAR measurements (if onshore, as InSAR cannot be used for offshore applications). InSAR data is inexpensive and valuable because measurement of

surface uplift can be used to indicate the scale of geomechanical deformation (Verdon et al. 2015). The deformation from InSAR can also be used to calibrate geomechanical models and compute fault slip, which in turn could be used to estimate the expected maximum seismicity. If InSAR is considered for a specific area, assessment of other factors (historic depletion, groundwater withdrawals, etc.) should be considered and their potential impacts on InSAR response evaluated.

The use of vertical wells versus the use of horizontal wells may have some influence on the level of risk of induced seismicity for a specific project, these different well types may yield different reservoir pressure changes, have different zones of influence, and different probabilities for intersecting or influencing faults that may be susceptible to activation and movement. Specific well plans and designs should consider the local geologic understanding and the potential for the pressure fields generated by different well types, with the goal of reducing the risk of induced seismicity.

CCUS project developers and operators that plan to do projects in the eastern part of the U.S. should be aware that seismicity in this region has a risk of being felt farther than in much of the rest of the U.S. due to the strata there being older and denser (USGS 2018). An example of such an event took place at the Northstar 1 Class II injection well site in Ohio (ODNR 2012).

The USEPA Class VI permitting process and rules governing operations include several elements that need to be considered as part of the overall risk management associated with Class VI well construction and operation that account for the unique nature of CO₂ injection for geologic sequestration. These elements include:

- Geologic site characterization to ensure that wells are appropriately sited;
- Requirements for the construction and operation of the wells that include construction with injectate compatible materials and automatic shutoff systems to prevent fluid movement into unintended zones;
- Requirements for the development, implementation, and periodic update of a series of project-specific plans to guide the management of CCUS projects;
- Periodic re-evaluation of the area of review around the injection well to incorporate monitoring and operational data and verify that the CO₂ is moving as predicted within the subsurface;
- Rigorous testing and monitoring of each storage project that includes testing of the mechanical integrity of the injection well, groundwater monitoring, and tracking of the location of the injected CO₂ using direct and indirect methods;
- Appropriate post-injection monitoring and site care to track the location of the injected CO₂ and monitor subsurface pressures until it can be demonstrated that USDWs are no longer endangered;
- Clarified and expanded financial responsibility requirements to ensure that funds will be available for corrective action, well plugging, post-injection site care, closure, and emergency and remedial response;
- A process to address injection depth on a site-specific basis and accommodate injection into various formation types while ensuring that USDWs at all depths are protected; and
- A discussion of key principles for permitting wells that are transitioning from Class II enhanced recovery (ER) to Class VI (EPA Memorandum 2015).

USEPA's Class VI regulations further require permit applicants to report on the seismic history of the project site, including the presence and depth of all seismic sources and a determination that seismic activity will not compromise subsurface containment of injected carbon dioxide (40 CFR 146.82(a)(3)(v)). Although the Class VI regulations include no explicit requirement for a seismic monitoring plan, in its Class VI Implementation manual for UIC Program Directors, USEPA states that concerns about seismicity or uncertainties about the seismic history of the site raised during site characterization may necessitate the inclusion of passive seismic monitoring (EPA Manual 2018).

The large net volumes of carbon dioxide injected and stored in large scale sequestration projects may have the potential to impact stress states and pore pressure, which may have potential to increase both the number and the magnitude of earthquakes. In addition, there is limited experience with fluid injection at these large scales and little data on seismicity associated with CO₂ pilot projects (NRC Report on Induced Seismicity Potential in Energy Technologies).

Seismic monitoring at the IBDP and the ICCUS project assisted in the identification of previously unknown faults and allowed identification of zones into which injection appeared to induce seismicity (Williams-Stroud, 2019). Verdon et al (2016) encouraged seismic monitoring at all future carbon storage sites to enable modeling to simulate the magnitude of the largest event.

In California, the California Carbon Capture and Storage Review Panel, recommended that seismic risks be considered during the operation and monitoring of CO₂ storage projects and stated that specialized seismic monitoring may be warranted as part of the overall monitoring, verification, and reporting (MRV) plan (California Institute for Energy and Environment 2010, p.2-8). Although the Panel itself did not make any specific recommendations regarding elements of an MRV plan for induced seismicity, the background reports make some specific recommendations. The Technical Advisory Committee to the Panel recommended that monitoring for induced seismicity should begin during the site selection and assessment phase to establish a baseline record of the natural background seismicity in the region encompassed by the project, using the state's existing seismometer network augmented by a local network. During operations, changes from the natural background should be observed and direct monitoring of fluid pressures should be performed. Microseismic events detected through seismic monitoring during operations may also be used as a tool for monitoring the movement of fluids in the subsurface.

The Committee recommended that the record of the natural background seismicity be compared to data collected after injection begins. Instrumentation for "real time" measurement and analysis should be employed to facilitate immediate response to significant events. The Committee recommended that the definition of what constitutes a "significant" event, as well as the mitigating actions that need to be taken in response to the event, should be part of the seismicity monitoring plan. The definition of "significant event" should consider geologic factors that affect the magnitude of shaking and the potential for damage of structures, as well as the sensitivity of the public to felt seismicity (California Energy Commission, Energy Research and Development Division, FINAL PROJECT REPORT, Investigation of Potential Induced Seismicity Related to Geologic Carbon Dioxide Sequestration in California, August 2017 | CEC-500-2017-028).

The California Air Resources Board protocol for CO₂ sequestration requires that the operator deploy and maintain a permanent, downhole seismic monitoring system to determine the presence or absence of any induced micro-seismic activity associated with all wells and near any discontinuities, faults, or fractures in the subsurface. The design of the array should consider the seismic risk. Location of small events can be helpful in risk reduction. Analysis of the micro-seismicity must consider if the risk of triggering an earthquake of Richter **M** 2.7, or greater, is significantly increased by injection. From commencement of injection activity to its completion, the operator must continuously monitor for indication of an earthquake of M 2.7 or greater occurring within a radius of one-mile of injection operations. If an increase in risk is detected, analysis of mechanical integrity and leakage must be performed, and the risk mitigated (California Air Resources Board, Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard, August 13, 2018).

Summary

Large scale (million tonnes per year per well) CO₂ storage in oil reservoirs through CO₂ EOR as well as in deep saline formation is technically feasible as demonstrated through about 150 CO₂ EOR projects and 5 large scale (>0.5 MTA) deep saline CO₂ storage projects worldwide. Induced seismicity events related to geologic CO₂ storage projects and EOR projects to date have generally been limited to small magnitude events and generally have not caused any widespread surface felt ground shaking.

The experience of large-scale produced water disposal in the U.S. provides insight into the technical considerations that should be accounted for as CCUS projects grow. Inferences suggest that the increase in reservoir pressure due to CO₂ injection would be about 40% of equivalent volume of water injection into the same formation. However, in some of the CO₂ storage projects, pressure increase can be as high as 1000 psi, mainly due to poor reservoir quality.

Careful considerations are required in site selection and execution of the projects to identify and manage hazards, including the potential for induced seismicity. This may involve geomechanical analysis of fault reactivation considering fluid pressure and stress state being conducted. If potential fault reactivation is of concern, a local seismic network deployed in advance of any industrial activity, would be helpful in monitoring for potential induced seismicity.

Appendix I: Understanding Hydraulic Fracturing

Considerations Specific to Hydraulic Fracturing

General risk management and mitigation approaches relevant to potential injection-induced seismicity also can be applied to hydraulic fracturing as discussed in Chapter 3. Induced seismicity of any significant risk associated with hydraulic fracturing is extremely rare, is quickly mitigated, and when detected at the surface is generally at the lowest levels of surface impact. Therefore, evaluation and response systems should be tailored differently for hydraulic fracturing than for disposal.

When considering systems such as the “Traffic Light” for hydraulic fracturing applications, “green-to-yellow” and/or “yellow-to-red” thresholds should be established based on the local conditions and geology and considering specific levels of ground shaking that are of local public concern.

Understanding the Hydraulic Fracturing Process

Recovering hydrocarbons from shale (and other tight rock formations) using horizontal drilling and hydraulic fracturing typically takes four to eight weeks for a single well – from preparing the site for drilling and completion of the well to production itself – after which the well may produce for 20 to 40 years. The hydraulic fracturing operation, which is a part of well completion, has a relatively short duration, typically a few days per well (King 2014).

If multiple wells are drilled from a single pad location, the duration of the drilling, completion and fracturing operations will increase correspondingly in time (e.g., a four well pad or eight well pad may take several months to complete the operations).

As illustrated in Figure I.1, a well can be a mile or more deep and thousands of feet below fresh groundwater zones before gradually turning from a vertical to a horizontal orientation. The horizontal portion of the well may extend more than 10,000 feet in length. A single well site (or pad) can accommodate a number of wells. Steel pipe known as surface casing is cemented into place at the uppermost portion of a well to protect freshwater aquifers.

As the well is drilled deeper, additional casing is installed and cemented in place to isolate geological formations between the surface and the reservoir prior to commencing hydraulic fracturing operations. Protective measures, such as containment equipment and spill response procedures are used and optimized to the local circumstances; these may include the use of liners under well pads, rubber composite mats under rigs, secondary containment measures for storage tanks, and barriers to control any potential surface runoff from the site (King 2012).

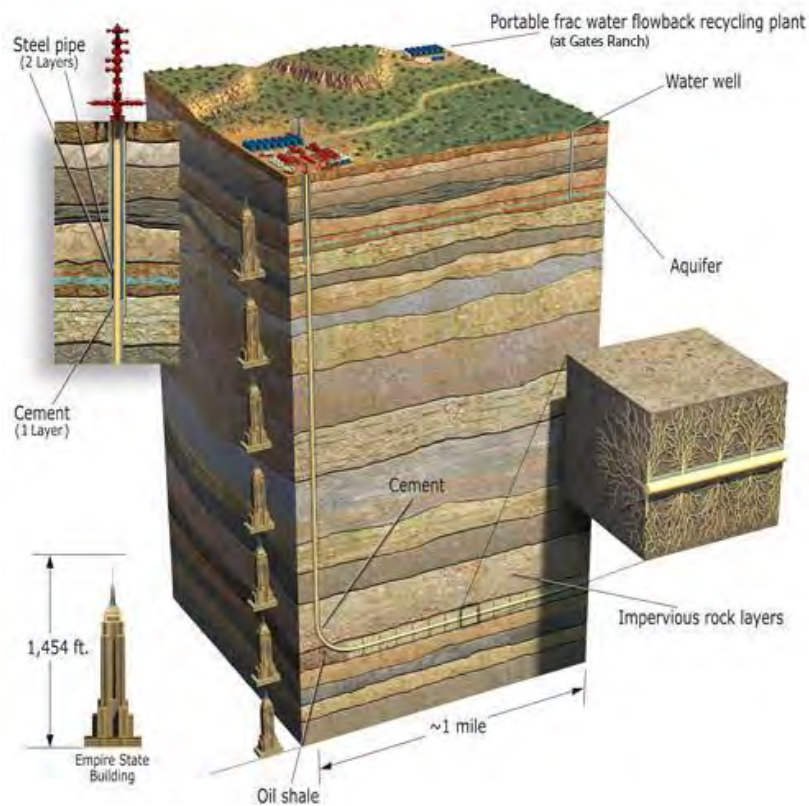


Figure 1.1. Illustration of hydraulic fractured horizontal well. Original source unknown: Reprinted from (Groundwater Protection Council 2010) URL <https://www.gwpc.org/topics/hydraulic-fracturing/hydraulic-fracturing-the-process/>

After the well(s) on a pad is drilled, cased, and cemented, it is necessary to connect the hydrocarbons in the reservoir formation to the wellbore so that it can flow to the surface. This is accomplished via multi-zone hydraulic fracturing operations, which can be done in several ways (Soliman 2012, Nygaard 2013). Currently, the “Perf and Plug” method is the most widely used method for multi-zone fracturing of horizontal wells.

In the Perf-and-Plug method, a mechanical device is placed downhole to perforate the horizontal part of the production pipe to make small holes in the casing, exposing the wellbore to the shale. Then a mixture consisting primarily of water, sand and a small percentage of chemicals is pumped into the well under high pressure to create fractures in the shale, enhancing the flow of oil and natural gas.

As illustrated schematically in Figure I.2, sand keeps the fractures open after the pressure is released. These fractures may be a few millimeters wide and extend horizontally several hundred feet to provide extended connection and flow-pathways in the oil or natural gas reservoir. The chemicals in the mixture are primarily used to reduce friction, prevent corrosion, and inhibit bacterial growth.

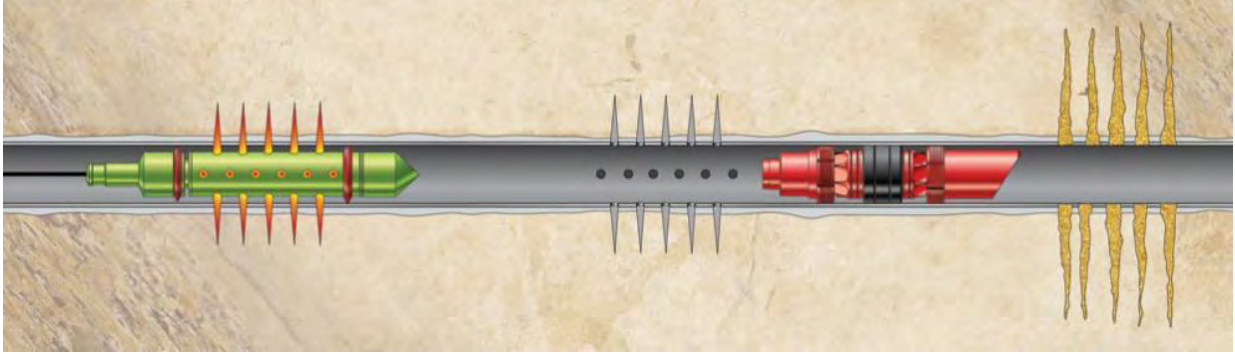


Figure I.2. Illustration of multi-zone hydraulic fracturing using the “Plug and Perf” technique (not to scale). Image source Re-printed from (Drilling Contractor 2012) URL: <http://www.drillingcontractor.org/self-removing-efdas-level-stimulation-access-14457> Image Source: Halliburton, Inc.

Understanding Hydraulic Fracturing on Multi-Well Pads.

Significant environmental benefits are realized by drilling multiple horizontal wells from a single surface location. This can result in as much as a 90% reduction in overall surface disturbance compared to drilling each well from its own surface location.

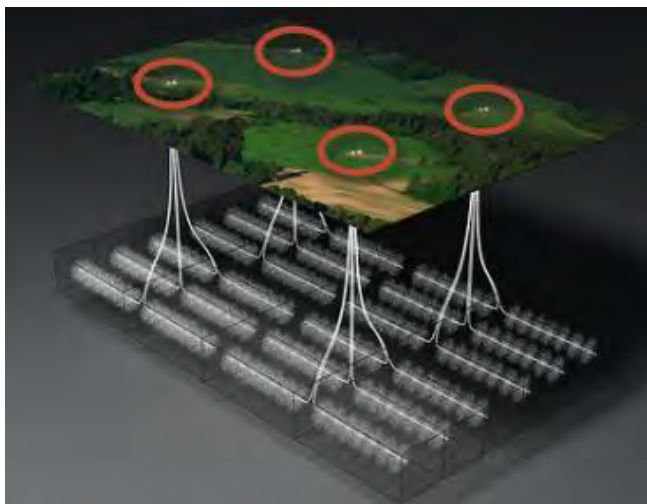


Figure I.3. In this graphic, six horizontal wells are drilled from each surface location highlighted by the red circles. Image source: US Energy Information Association (<https://www.eia.gov/todayinenergy/detail.php?id=7910>).

Figure I.3 illustrates the concept of using a single surface pad location to drill multiple horizontal wells. Multi-well pads improve safety performance and reduce hydraulic fracturing time, surface disturbance, and environmental impacts (Tolman 2009). By consolidating the wells and production to one pad site, companies can reduce the number of access roads and pipelines needed to service wells and can reduce truck traffic through the use of centralized water and sand delivery.

Understanding Alternating Well Hydraulic Fracturing (zipper method)

The term zipper is used to describe a completion methodology to more efficiently and effectively perform multi-zone fracturing when two or more wells are drilled from a single surface pad. The zipper method involves hydraulically fracturing a stage (i.e., a specific depth interval) in one well, while preparing the next stage in an adjacent well for hydraulic fracturing by running wireline and perforation operations. The next well is sequentially stimulated after completing the fracture treatment in the first well (Jacobs 2014). Thus, the method can be called zipper fracturing or more accurately alternating well hydraulic fracturing. The most common well design utilizing this method are cased and cemented horizontal wellbores that are fractured using the *Plug and Perf* method (Jacobs 2014). This allows completion operations to continue with minimal interruption and operational downtime.

Figure I.4 schematically illustrates this method for various well configurations and fracturing sequences. Figure I.4 (A) shows a traditional (non-zipper) sequential well fracturing operation, where the fracturing operations are completed in their entirety one well at a time. Figure I.4 (B) illustrates the zipper method where the hydraulic fracture stages are alternated between adjacent wells. This alternating well hydraulic fracturing procedure earned its name from the zipper like configuration of the fracture stages created between the two horizontal wellbores drilled parallel to each other.

Many different wellbore trajectories, other than directly offsetting parallel wellbores during the simultaneous operations, can be associated with zipper fracturing. As examples, Figure I.4(C) illustrates a two-well pad with parallel wellbores with fractures placed offset from each other across the wells; and Figure I.4 (D) illustrates an eight-well pad with parallel wellbores with fractures placed immediately adjacent across the wells. Spacing between wells is established considering state oil and natural gas regulations and specific local reservoir properties (e.g., permeability) that affect reservoir drainage and hydrocarbon recovery.

Optimization of well spacing, hydraulic fracture stage spacing, and the volume of water and sand used in fracturing operations is generally established through reservoir modeling studies, production test results, and well performance. In general, zipper fracturing only differs from sequential fracturing in the order of the fracturing stages in the wells.

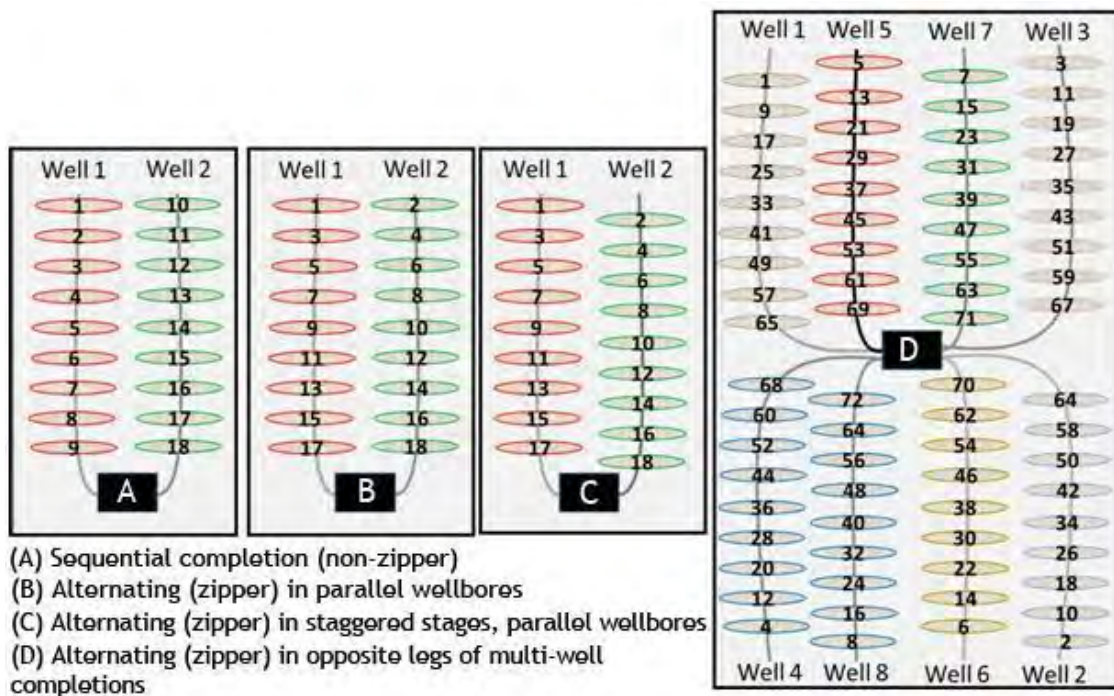


Figure 1.4. Examples of different horizontal well and multi-zone hydraulic fracture sequencing for simultaneous operations and application of concepts associated with zipper fracturing operational methods. The fracture sequencing is labeled numerically in each illustration. (Image after Patel 2016)

In addition to providing significant operational and financial efficiencies, simultaneous completion operations and the application of zipper fracturing methodologies, may improve stimulation effectiveness and increase oil and natural gas recovery from the reservoir (Sierra 2014, Patel 2016, Nagel 2011, and Pirayehgar 2016).

Understanding Microseismic Events Always Occur with Hydraulic Fracturing

Microseismic events are very weak seismic responses from the subsurface formation. Microseismic events are always expected to occur during hydraulic fracturing. They are not felt by people and do not cause damage at the surface. Microseismic activity provides information on the fracture behavior and its growth over time.

Microseismic monitoring, which is a fracture diagnostic tool used to determine geometric characteristics of hydraulic fracturing treatments for optimization and control, can also be used for assessing seismicity. Thousands of microseismic events may be detected during a single stage of a hydraulic fracturing operation. It is important to understand that microseismic events are routine and normal occurrences during hydraulic fracturing and are associated with the fracture propagation and the normal subsurface rock fracturing process. These microseismic events cause absolutely no identified hazard in normal operations. The risk associated with hydraulic fracturing is primarily associated with the very rare possibility that the subsurface pressure/stress potentially induced by the hydraulic fracture injection actually propagates the hydraulic fractures and directly communicates with a pre-existing critically stressed fault of concern.

A database of microseismic monitoring results was interrogated for the largest microseism detected in each stage of all monitored wells in six unconventional reservoirs, and a histogram of that data is shown in Figure I.5 (Warpinski 2013). The microseismic events are likely due to slippage along faults, natural fractures, and bedding planes, with the largest probably being fault interactions. For the several thousand fracture stages that were monitored in this study, none of the microseismic events exceeded M 1.0. The most frequently occurring microseisms are typically around M -1.0 to -1.5.

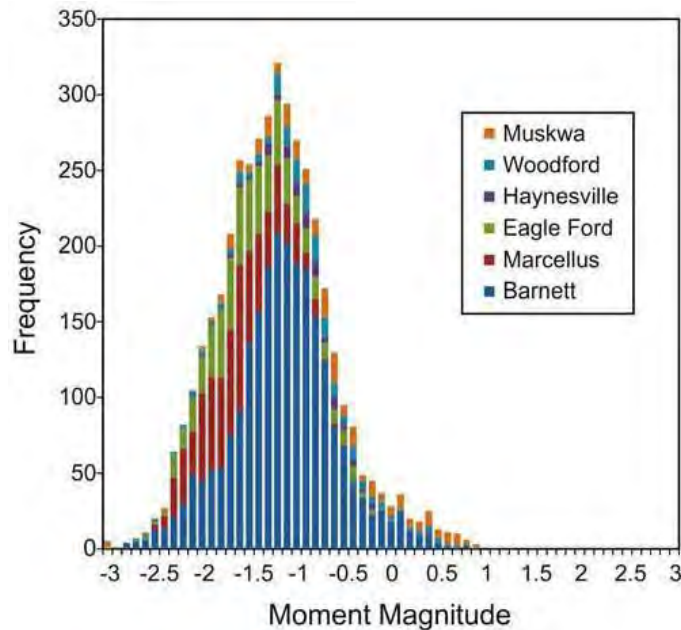


Figure I.5. Histogram of maximum magnitude microseismic events detected in six major unconventional reservoirs. Source: Warpinski 2013.

These results show that the typical magnitudes (**M**) of hydraulic fracturing microseismic events cannot be felt at the surface without the use of sensitive instruments that measure small subsurface vibrations (e.g., geophones and seismometers). Earthquakes greater than **M** 2.5, in general, may be felt by humans.

Earthquake magnitude scales, such as the Richter scale are logarithmic. Therefore, when comparing the smallest felt earthquakes (of approximately **M** 2.5) to hydraulic fracturing microseismic events (mean = **M**- 1), there is generally 10,000 times lower movement than a typical **M**-1.5, hence the reason why these microseismic events cannot be felt at the earth's surface.

Understanding Hydraulic Fracturing Data Availability

Detailed information on injection pressure, rate, and fluid and sand volumes are available for every hydraulic fracturing treatment. Detailed information is recorded, including surface pressure, flow rate, sand concentration, additive rates, and other parameters. In addition, because geologic controls are often highly resolved in hydraulic fracturing operations, operators will typically have detailed geologic information on the stratigraphy. Formation dip and faults with large vertical displacements can be correlated, which can be integrated with seismicity.

Though not routinely done, operators may monitor microseisms during hydraulic fracturing to diagnose geometric characteristics of the fracturing treatments for optimization and control. This microseismic data also can be used for assessing potentially induced seismicity by evaluating such factors as fracture height growth. Extensive publications in oil and gas technical journals discuss hydraulic fracture growth upward and downward, which may be useful to review when considering the potential for induced seismicity in hydraulic fracturing areas. For example, one database on fracture height growth (Fisher 2012) shows that height growth in the Marcellus shale is primarily upward and is not likely to contact basement features. In another example, although there are numerous cases of downward growth in the Barnett shale, it is from the basement and the hydraulic fractures propagating downward terminate in the thick Ellenberger formation. Finally, because the fractures created by hydraulic fracturing in the Eagle Ford Shale have very little height growth in any direction, they too are unlikely to induce significant seismicity.

Ground Motion

As with any seismic event, the amount and characteristics of the ground motion generated by the seismicity is the key factor in determining structural damage (Siskind 1983). There is very little ground motion data from the few incidences of seismicity associated with hydraulic fracturing. There is no documented damage and only a few cases of being felt. In the UK Bowland shale incident (de Pater 2011), at least one person apparently felt an **M** 2.3 earthquake. In the Poland, Ohio, incident, some people felt the **M** 3.0 earthquake and one of the smaller magnitude earthquakes. In the Horn River basin (BCOGC 2012) and the Montney trend incidents in Canada (AER 2015), numerous people onsite felt a number of earthquakes that were greater than **M** 4.

The best assumption, at this time, is that the ground motion associated with hydraulic fracturing may probably be very similar to that associated with the same size disposal-related seismic event. Some recent studies (Atkinson 2015) and (Hough 2014) suggest that both disposal well and fracturing may have lower shaking intensities than natural earthquakes.

Monitoring

Typical sources of seismic monitoring information related to hydraulic fracturing induced seismicity include:

- Downhole microseismic
- Surface microseismic
- Surface seismic network monitoring

Each of these provides different capabilities for monitoring seismicity associated with hydraulic fracturing:

1. Seismic monitoring that is able to record extremely small microseisms that occur during a hydraulic fracture job, which are typically **M** < 0.
2. Seismic monitoring for the potential for felt induced seismicity (**M** > 2). Although microseismic monitoring (**M** < 0) is a useful engineering tool for understanding hydraulic fracture geometry, it is performed on a minor portion of hydraulic fracturing procedures.

Downhole microseismic monitoring is used to analyze well stimulations. This technology has been available since about 2000. It is employed to provide diagnostic information for optimizing completions and fracturing treatments and may be used to better understand potential nearby faulting and hydraulic fracturing.

Downhole microseismic data are usually acquired with a 1,000 to 2,000 foot-long array of receivers placed in a nearby offset well at a depth relatively close to the depth of the fracturing treatments.

Microseismic data during hydraulic fracturing are also collected with large microseismic surface arrays consisting of hundreds or thousands of geophone or accelerometer stations. Some surface monitoring is done with low frequency geophones or accelerometers and can provide accurate magnitude information about the larger earthquakes recorded during a hydraulic fracturing. Surface earthquake monitoring capable of recording $M > 1-2$ earthquakes using permanent or transportable arrays have been used in several instances to provide information about possible hydraulic fracturing induced seismicity. Some researchers have leveraged the EarthScope transportable array, in combination with temporary arrays, to evaluate seismicity potentially associated with hydraulic fracturing (Friberg 2014).

In certain situations, when mathematically precise seismic event locations greater than $M 2.0$ may be required during hydraulic fracturing operations, at least four three-component portable seismic monitors should be considered, as three monitors would be required for effective triangulation and with one monitor within close proximity of the wellhead for more precise depth estimates of event location. The seismometers should be selected to achieve targeted performance specifications considering sensitivity, resolution, and accuracy and need to be designed to fit the local conditions.

It may also be appropriate to consider placement of additional seismometer(s) if measurement redundancy is desired. The seismometers should be deployed in an appropriate low-noise environment (relative to local ambient conditions and measurement requirements), to the extent possible distributed equidistant from the center of the well(s) to be hydraulically fractured and located to adequately sample variations in surface geology. The seismometers should be deployed at least a few days before fracturing operations begin to establish ambient noise levels and to determine if any pre-fracturing seismicity is occurring and should remain in place at least a few days after completion of fracturing operations.

Data and Information Sharing

The primary difference between data and information sharing considering hydraulic fracturing operations compared to disposal well operations is the level of detail obtained during hydraulic fracturing operations and the potential for much of that fracturing data to be considered confidential because of what it reveals about the well completion methods, procedures, and approaches.

Different states, provinces, and countries have different rules about data reporting of well completion and hydraulic fracturing operations. As a result, there is likely to be wide variations in the type of information that can be gleaned from public sources or be routinely available for correlation with any seismicity. For example, FracFocus at <https://www.fracfocus.org> is the nationwide system for disclosing the additives and chemicals used in the hydraulic fracturing process. Water volumes are also recorded in FracFocus.

Key Messages

Application of multi-well pad development techniques coupled with technological advances such as simultaneous operations and zipper fracturing have been effective in reducing local impacts. The use of multi-well pads have provided a significant environmental benefit by greatly reducing the overall surface area impacted by well operations as opposed to drilling each well from a single pad.

Approaches to assess and manage seismicity risk from hydraulic fracturing operations should take into account the local conditions, operational scope, geological setting, and historical baseline seismicity levels and reflect reasonable and prudent consideration of local engineering and building standards. Reasonable and practical evaluation and response systems are best developed considering the actual level of risk associated with local conditions. Given the broad geologic differences and diversity that exist across the U.S., it would not be appropriate to adopt a “one size fits all” regulatory approach for managing the risk. Local conditions must be considered (with the recognition that this could vary between states and within a given state at a more localized level for a given area of interest).

Appendix J: Glossary of Terms

Term	Definition
Amplitude	Measure of a parameter associated with a seismic wave or vibration (e.g., displacement, velocity); commonly refers to the maximum value of ground shaking or vibration. Can represent ground velocity or acceleration.
Average annual value	Amount of damage per causative event multiplied by the annual probability of occurrence of such events, summed over all possible earthquakes and all possible consequences of each earthquake.
Basement crystalline (basement)	The igneous and metamorphic rocks that underlie the main sedimentary rock sequence of a region and form the crust of the continents.
Class II Disposal Well	See Underground Injection Well.
Deterministic seismic hazard analysis	Estimation of the hazard from a selected scenario earthquake or seismic event.
Earthquake	Rapid slip or displacement on a geologic fault resulting in the release of seismic energy. Some earthquakes can be “induced” as a result of a man-made activity, e.g., by fluid injection.
Enhanced geothermal systems	Activities undertaken to increase the permeability in a targeted subsurface volume, via injection and withdrawal of fluids into and from the rock formations, intended to result in an increased ability to extract energy from a subsurface heat source.
Epicenter	The point on the earth’s surface vertically above the hypocenter (or focus) point in the crust where a seismic rupture begins. Epicenter coordinates in most earthquake catalogs are given in the WGS84 reference frame. The position uncertainty of the hypocenter location varies from about 100 m horizontally and 300 m vertically for the best located events, those in the middle of densely spaced seismograph networks, to tens of kilometers for events in large parts of the U.S. (USEPA)
Fault	A fracture or fracture zone along which there has been displacement of the sides relative to one another parallel to the fracture plane or planes.
Fault mechanism	Description of the rupture process of an earthquake, i.e., style of faulting, and the rupture fault plane on which it occurs.

Fault of concern	A fault optimally oriented for movement and located in a critically stressed region. The fault is also of sufficient size, and possesses sufficient accumulated stress/strain, such that fault slip and movement has the potential to cause a significant earthquake. Fault may refer to a single fault or a zone of multiple faults and fractures.
Focal mechanism	Graphic representation of the faulting mechanism of an earthquake, commonly described as slip on a plane specified by the strike, dip and slip angle (rake).
Ground motion prediction model	Mathematical formula that relates the magnitude of the earthquake, distance from the fault, and local site conditions to the amplitude of a specified ground motion parameter, e.g., peak ground acceleration (PGA).
Hydraulic fracturing	The process of fracturing rock with hydraulic pressure in order to increase permeability. High volume hydraulic fracturing refers to the larger amounts of fluids used to hydraulically fracture tight formations (usually shale) that are developed by horizontal drilling.
Hypocenter	The point within the earth of rupture initiation of an earthquake.
Human response curves	Graphic representation of a human’s sensitivity and response to vibration as a function of frequency.
Induced earthquake	Seismic event, e.g., an earthquake caused by human activities such as fluid injection, reservoir impoundment, mining, and other activities. The term “induced” has been used to include “triggered earthquakes” and so sometimes the terms are used interchangeably. See “triggered earthquakes” below and in this report.
Long string	String of casing that is typically used as a production or injection casing.
Moment magnitude	Preferred method to calculate the magnitude of an earthquake or seismic event based on its seismic moment. Seismologists regard moment magnitude as a more accurate estimate of the size of an earthquake than earlier scales such as Richter local magnitude. Moment magnitude and Richter local magnitude are roughly equivalent for magnitudes less than 7.0.
Normal force	The force that is oriented normal (perpendicular) to a given fault, fracture plane, or slip surface.
Normal stress	The component of stress oriented normal (perpendicular) to a given fault, fracture plane, or slip surface.

Paleoseismicity	Earthquakes recorded geologically, most of them unknown from human descriptions or seismograms. Geologic records of past earthquakes can include faulted layers of sediment and rock, injections of liquefied sand, landslides, abruptly raised or lowered shorelines, and tsunami deposits.
Peak ground acceleration	Maximum amplitude of the absolute value of the acceleration of the ground.
Peak ground displacement	Maximum amplitude of the absolute value of the displacement of the ground.
Peak ground velocity	Maximum amplitude of the absolute value of the velocity of the ground.
Peak particle velocity	Maximum amplitude of the absolute value of the velocity of an object or surface.
Probabilistic seismic hazard analysis	Quantitative evaluation of the likelihood (probability) of the ground motions that are expected to occur or be exceeded given a specified annual frequency or return period.
Precambrian basement	The igneous and metamorphic rocks that exist below the oldest sedimentary rock cover.
Probability of exceedance	Likelihood that the value of a specified parameter is equaled or exceeded.
Quad	Unit of energy equal to 10^{15} BTU, 1.055×10^{18} Joule, and 293.07 Terawatt-hours.
Rock permeability	Ability of a rock to transmit fluids (oil, water, gas, etc.).
Seismic hazard	The potential for the effects of an earthquake to result in loss or damage, such as ground shaking, liquefaction, and landslides.
Seismic hazard curve	A graphical representation of a probabilistic seismic hazard analysis. The probabilistic hazard is expressed as the relationship between some ground motion parameter, e.g., PGA and annual exceedance probability (frequency or return period).
Seismic moment	A quantitative measure of the size of an earthquake defined as the product of the area of the fault rupture, the average fault slip, and the shear modulus of the rock surrounding the fault.
Seismic risk	Probability of loss or damage due to exposure to a seismic hazard.
Shear force	The force that acts tangential to a given fault, fracture plane, or slip surface.
Shear stress	The component of stress that acts tangential to a given fault, fracture plane, or slip surface.

Shear-wave velocity profile	Relationship between the shear-wave velocity of the earth and depth. Shear-wave velocities of the near-surface (top hundreds of m) of the ground control the amplification of incoming seismic waves, resulting in frequency-dependent increases or decreases in the amplitudes of ground shaking.
Spectral frequency	Frequencies that constitute the ground motion record. They are the frequencies for which it is necessary to know the energy they carry to be able to reconstitute the full record in the time domain.
Strain	The amount of any change in dimension or shape of a body when subjected to deformation under an applied stress.
Strain energy	The energy stored in a body due to deformation.
Stress	The force per unit area acting on a surface within a body.
Surface casing	The casing string used to protect groundwater resources. This casing string is typically placed below protected aquifers, which vary from state to state, but may include potable water, usable water, USDWs, or other defined zones.
Tectonic	Pertaining to either the force or the resulting structural features from those forces acting within the earth; refers to crustal rock-deformation processes that affect relatively large areas.
Tectonic stresses	Stresses in the earth due to geologic processes such as movement of the tectonic plates.
Temperature gradient	Physical quantity that describes (in this context) the change in temperature with depth in the earth. The temperature gradient is a dimensional quantity expressed in units of degrees (on a particular temperature scale) per unit length (e.g., degree centigrade/km).
Thermal contraction	Contracting response of hot materials when interacting with cool fluids.
Tomography	Imaging by sections or sectioning, through the use of any kind of penetrating wave. A device used in tomography is called a tomograph, while the image produced is a tomogram.
Triggered seismic event	Seismic event that is the result of failure along a preexisting zone of weakness, e.g., a fault that is already critically stressed and is pushed to failure by a stress perturbation from natural or manmade activities.

<p>Underground Injection Well</p>	<p>An injection well is a device that places fluid deep underground into porous rock formations, such as sandstone or limestone, or into or below the shallow soil layer. These fluids may be water, wastewater, brine (saltwater), or water mixed with chemicals. Underground Injection Control (UIC) well classes:</p> <p>Class I – Inject hazardous wastes, industrial nonhazardous liquids, or municipal wastewater beneath the lowermost USDW.</p> <p>Class II – Inject brines and other fluids associated with oil and gas production, and hydrocarbons for storage. Most of the injected fluid is for disposal of saltwater (brine), which is brought to the surface in the process of producing (extracting) oil and gas. In addition, brine and other fluids are injected to enhance (improve) recovery of oil and gas.</p> <p>Class VI – Inject Carbon Dioxide (CO₂) for long term storage, also known as Geologic Sequestration of CO₂.</p> <p>For definitions of other UIC well classes, please refer to the USEPA UIC web site: http://water.epa.gov/type/groundwater/uic/wells.cfm</p>
<p>Underground Source of Drinking Water (USDW)</p>	<p>An underground source of drinking water is an aquifer or a part of an aquifer¹ that is currently used as a drinking water source for human consumption or may be needed as a drinking water source in the future. Specifically, a USDW is an aquifer or part of an aquifer that is not an exempted aquifer¹ and:</p> <p>Supplies any public water system², or</p> <p>Contains a sufficient quantity of groundwater to supply a public water system, and either currently supplies drinking water for human consumption or contains fewer than 10,000 mg/l total dissolved solids (TDS).</p> <p>¹ For definition of “aquifer” or “exempt aquifer,” refer to the USEPA UIC Glossary web site: http://water.epa.gov/type/groundwater/uic/glossary.cfm</p> <p>² For definition of “public water system,” refer to the USEPA Drinking Water web site: http://water.epa.gov/infrastructure/drinkingwater/pws/index.cfm</p>

Vibration	Dynamic motion of an object, characterized by direction and amplitude.
Vibration exposure	Person's exposure to vibrations, in this case ground motion vibration.
Vulnerability function	Function that characterizes potential damages in terms of a relation that gives the level of consequence (damage, nuisance, economic losses) as a function of the level of the ground motion at a particular location.

Appendix K: Glossary of Acronyms

Acronym	Meaning
ADM	Archer Daniels Midland
AER	Alberta Energy Regulator
AGS	Arkansas Geological Survey or Alberta Geological Survey
ANSS	Advanced National Seismic System
API	American Petroleum Institute
AOI	Areas of Interest
AOR	Area for Review
BCOGC	British Columbia Oil and Gas Commission
BEG	Bureau of Economic Geology
BHPs	Bottomhole pressures
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization, and Storage
CGS	Colorado Geological Survey
COGCC	Colorado Oil and Gas Conservation Commission
ComCat	Comprehensive Catalog
DEP	Department of Environmental Protection
DOE	Department of Energy
DOGRM	Division of Oil and Gas Resources Management
DYFI	Did You Feel It
EGS	Enhanced Geothermal Systems
EOR	Enhanced Oil Recovery
Exchange	State Oil and Gas Regulatory Exchange
FAQ's	Frequently Asked Questions
FEMA	Federal Emergency Management Agency

GEER	Geotechnical Extreme Events Reconnaissance
GIS	Geographic information system
GMMs	Ground Motion Models
GTA	Gigatons per annum
GWPC	Ground Water Protection Council
HF	Hydraulic Fracturing
IBDP	Illinois Basin-Decatur Project
IEA	Energy Agency
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Panel on Climate Change
IRIS	Incorporated Research Institutions for Seismology
ISO	International Organization for Standardization
ISWG	Induced Seismicity Work Group
KGS	Kansas Geological Survey
KSMMA	Kiskatinaw Seismic Monitoring and Mitigation Area
LBNL	Lawrence Berkeley National Laboratory
LWD	Logging While Drilling
M or M_w	Moment magnitude
M_c	Magnitude of Completeness
MDT	Modular Formation Dynamics Tester
MMI	Modified Mercalli Intensity
MRV	Monitoring, verification and reporting
MSHF	Multistage horizontal fracturing
MTA	Million tonnes per annum
MWD	Measurement While Drilling
NEIC	National Earthquake Information Center

NORM	Naturally Occurring Radioactive Material
NPC	National Petroleum Council
NRC	National Research Council
NSHM	National Seismic Hazard Maps
NTW	National Technical Workgroup
O&M	Operations and Maintenance
OCC	Oklahoma Corporation Commission
ODGS	Ohio Division of Geological Survey
ODNR	Ohio Department of Natural Resources
OGCD	Oil and Gas Conservation Division
OGS	Oklahoma Geologic Survey - Ohio Geologic Survey
OhioSeis	Ohio Seismic Network
P-Waves	Primary or Compressional Waves
PEER	Pacific Engineering Earthquake Research
PGA	Peak Ground Acceleration
PGD	Peak Ground Displacement
PGV	Peak Ground Velocity
PPV	Peak Particle Velocity
RCRA	Resource Conservation and Recovery Act
RFT	Repeat Formation Tester
RRC	Railroad Commission of Texas
S-Was	Shear or Secondary Waves
SCITS	Stanford Consortium for Induced and Triggered Seismicity
SCOOP	South Central Oklahoma Oil Province
SDWA	Safe Drinking Water Act
STACK	Sooner Trend in the Anadarko Basin Canadian and Kingfisher counties

SWD	Saltwater Disposal
TAC	Technical Advisory Committee
TVD	True Vertical Depth
UIC	Underground Injection Control
URM	Unreinforced Masonry
USDW	Underground Source of Drinking Water
USEPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey
Vs	Time-averaged shear-wave velocity USGS
VSP	Vertical seismic profile
WCSB	Western Canadian Sedimentary Basin
ZEOI	Zone of Endangering Influence

Appendix L: List of References

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