Scientific Principles Affecting Protocols for Site-characterization and Risk Assessment Related to the Potential for Seismicity Triggered by Saltwater Disposal and Hydraulic Fracturing

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EXECUTIVE SUMMARY

In recent years, there has been a dramatic increase in the number of small-to-moderate size earthquakes in the central and eastern U.S. (and other parts of North America) apparently associated with injection related to saltwater disposal and, less often, hydraulic fracturing. To address this, regulatory agencies, private companies, and public interest groups have proposed an assortment of guidelines for reducing the risks associated with potentially triggered earthquakes. We present here a discussion of some of the scientific principles affecting guidelines for site characterization and risk assessment for only triggered earthquakes associated with saltwater disposal and hydraulic fracturing. In this context, this document is intended to define some of the scientific principles that could be considered by operators and regulatory authorities to address the risks associated with triggered earthquakes. We do not consider triggered earthquakes that might be associated with geothermal development, depletion of oil and gas reservoirs, mining or reservoir impoundment as each of which would be influenced by somewhat different scientific principles.

To the degree possible, we have based this work on the best available understanding of the underlying processes responsible for triggered earthquakes. The topics we address include 1) the geologic setting of a site and surrounding region, 2) the earthquake history of the area, 3) the hydrologic characteristics of the injection and adjacent formations, 4) a geomechanical characterization of the site that includes the existence of active faults, 5) the state of seismic monitoring and reporting, 6) current monitoring and reporting requirements for injection pressures, volumes, and rates, 7) seismic hazard and risk assessment, and 8) responding to potentially triggered events. Factors considered in the risk assessment protocol include the location and potential size of triggered earthquakes and the proximity (and vulnerability) of possibly affected population centers, structures, and facilities. We utilize a modified Probabilistic Seismic Hazard Analysis (PSHA) as the foundation for risk assessment prior to injection as well as to evaluate the change in risk in the event of apparently triggered earthquakes.

The recommendations presented here are intended to be goal-based, rather than prescriptive, and adaptable to local circumstances. They rely, to the degree possible, on established best practices drawn from existing procedures and recommendations. As a part of this effort, we have considered existing regulations for Class II injection wells for the states of
Arkansas (AOGC, 2011 and 2012), California (CDC, 2013), Colorado (COGCC, 2011), Illinois (IAC, 2011), Ohio (OAC, 2014), Oklahoma (OCC, 2013), and Texas (RCT, 2014), as well as recommendations from the American Exploration and Production Council (AXPC, 2013), the British Columbia Oil and Gas Commission (BCOGC, 2012 and 2014), the Canadian Association of Petroleum Producers (CAPP, 2012), scientists at ExxonMobil (Nygaard et al., 2013), the International Association of Oil and Gas Producers (OGP, 2013), the National Research Council (NRC, 2012), the Seismicity Expert Group Workshop (SEGW, 2014), the United Kingdom (DECC, 2013; Green et al., 2012; The Royal Society, 2012), the United States Environmental Protection Agency (EPA, 2014), several publications focusing on triggered earthquakes, and a published protocol developed for seismicity associated with Enhanced Geothermal Systems (Majer et al., 2012).

Through this report, we hope to inform and contribute to the development of rational and effective measures for reducing the risk from possible triggered earthquakes. Our plan is to update this report as new information, analysis, models, and an improved understanding of triggered earthquakes become available with time and is available online at https://pangea.stanford.edu/researchgroups/scits/publications.
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I. INTRODUCTION AND OVERVIEW

The technologies and regulatory context associated with saltwater disposal have been well established for decades. There are currently about 30,000 EPA Class II saltwater disposal wells operating in the United States (EPA, 2012), nearly all of which have been operating without negative consequences for many decades. It is imperative that both companies and regulators have best practice guidelines available to them that would allow them to characterize a proposed injection site and determine whether the risk associated with injection is appropriate to pursue a particular project. Moreover, in the event of unforeseen problems, such guidelines should provide the essential information that regulators and companies need to determine an appropriate course of action. The objectives of this document are to contribute to the body of existing documents and regulations that focus on reducing risks associated with potentially triggered seismicity in order to provide a comprehensive understanding of the key scientific principles and resulting recommendations.

As reviewed by the U.S. National Research Council (NRC, 2012), earthquakes apparently triggered by fluid injection have been observed in many parts of the world. Although injection-related seismicity is a well-known phenomenon, recent years have seen a dramatic increase in earthquake occurrence apparently associated with oil and gas development. This increase has been most notable in the central and eastern United States (Figure I-1, after Ellsworth, 2013). Although the central and eastern U.S. has a well-documented history of naturally occurring earthquakes, the increase in the rate of earthquakes over the past 10 years (and especially, the past five years), shown in Figure I-1, is quite remarkable and is not an artifact of enhanced seismic network coverage or other observational factors (Ellsworth, 2013). Of particular note in the central United States, an extended earthquake sequence near Guy, Arkansas culminated in February 2011, with an earthquake of magnitude 4.7 (Horton, 2012). In December 2011, several widely-felt events, up to magnitude 4.0, appear to have been triggered by saltwater disposal near Youngstown, Ohio (Kim, 2013). The magnitude 5.7 Prague event that occurred in November 2011 is the largest recent earthquake in Oklahoma, and may have been triggered by saltwater disposal (Keranen et al., 2013). Moreover, the increase in the seismicity rates in several parts of Oklahoma has been attributed to widespread increases in pore pressure due to extensive saltwater disposal (Keranen et al., 2014).
The physical processes responsible for injection-related seismicity are generally well known (see reviews by NRC, 2012; Suckale 2009). In the context of a critically stressed crust, relatively small pore pressure changes at depth can trigger earthquakes associated with the release of strain energy that has accumulated over time as a natural geologic process (this is discussed by Zoback and Gorelick (2012) in the context of the potential for CO$_2$ injection to trigger earthquakes). The increase in seismicity seen in Figure I-1 is apparently associated with the injection of fluids from three specific sources: i) increases in produced water, the non-potable water that accompanies oil production ii) the wastewater that flows back out of a horizontal well after hydraulic fracturing (King, 2012) and iii) hydraulic fracturing operations (NRC, 2012; BCOGC, 2012 and 2014). In this regard, it is noteworthy that the increase in the rate of earthquake occurrence seen in Figure I-1 is temporally correlative with increases in the number of horizontal wells being drilled for hydraulic fracturing operations.
Sources of Injected Fluids

**Produced water** - As noted above, approximately 144,000 EPA Class II wells have been operating for many decades. Figure I-2 shows the concentrations of the approximately 7,000 saltwater disposal sites that have been operating safely in Texas for many years, although there are several places where produced water injection may have triggered earthquakes (see NRC, 2012). Like some of the other regions shown in Figure I-1, there appear to be a marked increase in the triggered seismicity in recent years, including near Timpson, East Texas (Frohlich et al., 2014) and Cleburne, Texas (Justinic et al., 2013).

A recent large source of saltwater in Oklahoma and southern Kansas is associated with increases in production. Figure I-3 and I-4 (from Walsh and Zoback, 2015) shows the dramatic increase in seismicity in Oklahoma in recent years. As shown in Figure I-5, the average monthly volume of saltwater disposal in Oklahoma has roughly doubled in the past ~15 years with much

![Figure I-2. Map of Texas showing the density of the approximately 7,000 saltwater disposal well locations. Map revised from Murphy (2013) using data from the Texas Railroad Commission.](image)
Figure I-3. Statewide seismicity for Oklahoma showing historical earthquakes in yellow (1974-2008) and recent earthquakes in red (2009-present). Historical earthquakes are distributed relatively evenly across the state, whereas more recent earthquakes are clustered. Figure from Walsh and Zoback (2015).

Figure I-4. Cumulative number of earthquakes in Oklahoma since 1974. There has been a significant increase in the rate of earthquake occurrence in the past 5 years (2009-present). Figure from Walsh and Zoback (2015).
Figure I-5. Statewide saltwater disposal (SWD) injection volumes have roughly doubled over 15 years, and seismicity has increased significantly starting in 2009 for Oklahoma. Figure from Walsh and Zoback (2015).

larger relative increases in injection in the areas of pronounced recent seismicity. Walsh and Zoback (2015) show that in areas where the majority of earthquakes occur in north-central Oklahoma, there have been marked increases in the volume produced water injection.

**Flowback Water** - During hydraulic fracturing, fluid injection pressure in a section of a well is raised sufficiently to cause fractures to propagate in a direction normal to the minimum principal stress. Normally, this is the minimum horizontal stress such that the hydraulic fractures propagate in vertical planes away from the wellbore. As horizontal wells are typically oriented in the direction of the minimum horizontal stress, the hydraulic fractures propagate perpendicular to the well trajectory (King, 2012). Accompanying the hydraulic fracture propagation, numerous microearthquakes occur due to slip on small pre-existing faults in the reservoirs. The microearthquakes associated with hydraulic fracturing are generally extremely small events typically on the order of magnitude -2 (Warpinski et al., 2012). From Figure I-6, which summarizes the relationship between earthquake magnitude, the size of a fault that slipped in the earthquake and the amount of fault slip (see Appendix B), it can be seen that a magnitude -2 microseismic event is expected to occur on a fault about ~ 1 meter in size with a slip on the order of 0.1mm (or less).

It is important to note, most of the seismic hazard associated with potentially triggered earthquakes involves faults in crystalline basement rocks. The reason for this is that potentially damaging earthquakes require faults of relatively large size to slip, which means the faults are often located in, or extend into, the basement rock. For example, in order to trigger earthquakes of a size similar to the largest that occurred in the Guy, Arkansas (M 4.7) and Prague, Oklahoma (M 5.7) sequences (Figures I-7 and I-8) the faults that slipped clearly require faults extending down into crystalline basement, which they do. The M 5.7 Prague earthquake (Figure I-7, from Keranen et al, 2013) and M 4.7 Guy Arkansas earthquake (Figure I-8, from Horton, 2012) appear to result from slip on basement faults. Evans et al. (2012) examined 41 European case histories of fluid injection
Figure 1-6. Scaling of earthquake source parameters showing the relationship between earthquake magnitude, the size of the fault that slipped in the earthquake and the amount of fault slip See Appendix B for an explanation of the equations used to construct this figure.

into crystalline basement and found that, in general, injection in basement tended to result in more earthquakes than if injection occurred in sedimentary formations.

Hydraulic Fracturing - There have been a few places where hydraulic fracturing operations appear to have triggered events large enough to be felt. These cases include the over 200 events ranging from M1.0 to M4.4 at the Montney Trend, British Columbia between August, 2013 and October, 2013 (BCOGC, 2014), the 2014 M3.2 event near the Eagleton 1-29 in Oklahoma (Darold et al., 2014), the six M1.7-2.2 earthquakes that occurred in Harrison County, Ohio between October 2 and October 19, 2013 (Friberg et al., 2014), the 2011 M3.7 event at the Horn River Basin, British Columbia (BCOGC, 2012; NRC, 2012), the 2011 M2.8 event near the Eola Field, Oklahoma (Holland, 2011), and the 2011 Preese Hall, United Kingdom M2.3 earthquake (Green et al., 2012; Clarke et al., 2014), among others. In the case of the Ohio earthquakes, it was found that the events were located in the basement rock due to injection in the overlying formations (Friberg et al., 2014).
Figure I-7. Earthquakes located by the Oklahoma Geological Survey (frame A) and relocated by Keranen et al. (2013) (frames B-D) relating to the three $M \geq 5$ earthquakes that occurred on 5, 6, and 8 November 2011 (Events A, B, and C, respectively, also shown in frame A) near Prague, Oklahoma. Frames B-D show the depths of the earthquakes in relation to the depth of the basement rock which is represented as the white unit underlying the yellow unit (the Arbuckle). Figure from Keranen et al. (2013).

BCOGC (2014) described a case in which injection associated with hydraulic fracturing activated pre-existing faults. Figure I-9 shows how the events associated with pre-existing faults define lineations of orientations unexpected for hydraulic fractures given the orientations of the wells are perpendicular to the greatest principle stress. A somewhat similar case was noted by the British Columbia Oil and Gas Commission (2012) in a discussion of seismicity accompanying hydraulic fracturing operations in the Horn River Basin in northernmost British Columbia. The largest event in the region was $M_L 3.8$, the largest known event to be associated with hydraulic fracturing anywhere in the world until the BCOGC reported the occurrence of a $4.4$ $M$ earthquake triggered by hydraulic fracturing in the Montney Trend (BCOGC, 2014). After deployment of a dense array of seismometers in the vicinity of a pad with multiple wells being hydraulically fractured (left side, Figure I-10, modified from BCOGC, 2012), events spread out along a pre-existing fault as in the two cases noted above, but in this case, 69 earthquakes in range $M_L 1.5$-$3.1$ were detected during hydraulic fracturing of this pad. In another case (right side, Figure I-10, from BCOGC, 2012),
Figure 1-8. Earthquakes associated with the M4.7 Guy, Arkansas earthquake. A) Map view of the located earthquakes (dark and light gray filled circles), seismic stations (black squares), and UIC wells (gray diamonds). B) Cross-section showing event depths with respect to the Precambrian basement rock. Figures from Horton (2012).
Figure I-9. Map view of faults reactivated during hydraulic fracturing. Microearthquakes are mapped as colored spheres (events colored by fracture stage and size of sphere scaled by event magnitude). Events here range between 1.1 and 3.2 Mw. The hydraulically fractured well is the well labeled with the perforation locations. From BCOGC (2014).

Figure I-10. (A) Microseismicity and earthquakes as large as Ml 3.1 occurred during hydraulic fracturing of this pad. Again, the distribution of hypocenters indicates slip along a pre-existing fault that cuts across the pad. Modified from BCOGC (2012) (B). In another area, seismicity associated with hydraulic fracturing clearly extends down into basement rocks. As noted above, basement faulting is commonly associated with larger magnitude earthquakes. From the BCOGC (2012).
microearthquakes clearly indicate the downward propagation of pressure along a pre-existing fault into basement rocks. As will be discussed in Section IV, the pressurization of basement faults is particularly hazardous because of the potential for triggering relatively large magnitude earthquakes.

While there are many mapped faults in the region where relatively large earthquakes were triggered by hydraulic fracturing in the Horn River Basin, based on the three cases considered above, even when there have not been widely felt, or unusually large, earthquakes associated with hydraulic fracturing, the occurrence of unusual microseismic trends can be used to identify the presence of pre-existing faults in a region. Once this is noted in an area, care should be taken not to pressurize these faults during hydraulic fracturing operations.

**Current Guidelines and Regulations**

There are many guidelines, regulations, and studies related to the topic of triggered seismicity. Many are designed for specific sites, states, or countries, which are helpful in some settings but may not be transferable to all situations. As a part of this effort, we have considered existing regulations for Class II injection wells for the states of Arkansas (AOGC, 2011 and 2012), California (CDC, 2013), Colorado (COGCC, 2011), Illinois (IAC, 2011), Ohio (OAC, 2014), Oklahoma (OCC, 2013), and Texas (RCT, 2014), as well as recommendations from the American Exploration and Production Council (AXPC, 2013), the British Colombia Oil and Gas Commission (BCOGC, 2012 and 2014), the Canadian Association of Petroleum Producers (CAPP, 2012), scientists at ExxonMobil (Nygaard et al., 2013), the International Association of Oil and Gas Producers (OGP, 2013), the National Research Council (NRC, 2012), the Seismicity Expert Group Workshop (SEGW, 2014), the United Kingdom (DECC, 2013; Green et al., 2012; The Royal Society, 2012), the United States Environmental Protection Agency (EPA, 2014), several publications focusing on triggered seismicity, and a published protocol developed for seismicity associated with Enhanced Geothermal Systems (Majer et al., 2012).

Many publications relating to mitigating triggered seismicity associated with subsurface fluid injection focus on approaches to respond to seismic events after they occur (we discuss this issue in Section IX). We have reviewed these publications in order to offer a review of the scientific principles involved and suggestions that are both comprehensive and adaptable. Our suggestions are meant to reduce, as low as reasonably possible, the risks associated with triggered seismicity based on the best available scientific understanding of the responsible processes. We hope to help establish leadership principles to be considered for adoption by private industry and responsible
regulatory authorities. Continued communication among regulators, operators and the public will be required to incorporate site-specific knowledge based on local and regional information as well as site-specific issues.

In the sections below, we discuss many of the aspects of triggered seismicity in a site-adaptable format, focusing specifically on geological characterization, earthquake history, hydrologic characterization, geomechanical characterization, factors contributing to risk, the needs for seismic monitoring and reporting, plans for monitoring and reporting injection pressures, volumes, and rates, probabilistic seismic risk analysis, and how the occurrence of apparently triggered earthquakes changes the risk.

In the context of faulting theory, an increase of pore pressure at depth resulting from fluid injection can potentially induce fault slip by reducing the effective normal stress (the total normal stress minus the pore pressure) acting perpendicular to a fault that is well-oriented for slip in the current stress field. Because it acts in a direction perpendicular to a fault plane, the effective normal stress can be thought of as the stress that resists fault slip. By increasing pore pressure, the effective resistive stress might decrease sufficiently for fault slip (i.e., an earthquake) to occur releasing elastic strain energy in the rocks around the fault. Elastic strain energy accumulates in the crust as a result of natural geologic processes. In many regions, brittle rocks at depth are in a state of frictional failure equilibrium, such that only small perturbations of pore pressure would be sufficient to trigger seismicity (e.g., Zoback et al., 2002).

Please see Appendix A for a list of the acronyms and definitions used throughout this document.

II. GEOLOGICAL CHARACTERIZATION

Assessing the potential for triggered seismicity associated with saltwater disposal and hydraulic fracturing involves achieving a sufficient understanding of the geology of the area at both regional and local scales. Understanding the characteristics of the formations and the presence and orientation of faults and fractures that may be present enables a better understanding of the basic geological factors that may contribute to the level hazard in the area. The first step in geological site characterization is consulting available resources and collecting data to determine the current state of geological knowledge at the site.

At a regional scale, a great deal of information is usually available in the public domain. For example, in the United States, the United States Geological Survey (USGS) and the Association of
American State Geologists (AASG) maintain the National Geologic Map Database (NGMD, 2014). Operators can also consult the map catalog and collection of stratigraphic columns from the NGMD in a web-based format to gain overall knowledge of the regional geology. In the United Kingdom, it has been suggested that operators consult with the British Geological Survey to receive known information about specific sites and receive advice on well placement (Royal Society, 2012).

With respect to local geology, the information that is often requested of operators by regulators includes the names, descriptions, and depths of the geological zones or formations that would be used for injection (OAC, 2014; RCT, 2014; OCC, 2013; IAC, 2011) as well as any available well logs or completion data (BCOGC, 2012). In the United States, the main reason for these requirements is the Safe Drinking Water Act which was originally passed by congress in 1974 to protect drinking water and its sources (SDWA, 1996). Geophysical well logs offer the opportunity to better understand the formation depths and thicknesses as well as their rock properties. In cases where well logs are not available for a particular site, it would be reasonable to use well logs from a nearby well (RCT, 2014) with the understanding that it will likely introduce some amount of error into the analysis of the formation attributes, particularly in areas of high structural complexity.

While regional geology may not seem relevant to siting a specific injection well, an example associated with a recent earthquake sequence illustrates its importance. Hurd and Zoback (2012b) (Figure II-1) showed that the northeast trending alignment of epicenters associated with the fault that caused the M4.7 earthquake near Guy, Arkansas (Figure I-8) is compatible to the trend of one of the major faults associated with the New Madrid earthquake sequence of 1811-1812 (labeled AF, Figure II-1), located about 100 miles to the northeast (see Section V for an explanation of the importance of fault orientations). Thus, in siting injection wells in this area, the identification of and attention to the orientation of potentially active faults in the region was more important to consider.

**Identifying Subsurface Faults**

The identification of faults in the area surrounding a proposed saltwater disposal or hydraulic fracturing site is a critical step in determining the possible occurrence of triggered seismicity. Many current guidelines and publications suggest including all available or acquired geologic and geophysical data to characterize the geology and faults near a proposed injection site (Green et al., 2012). Making the locations of faults available to regulators and operators allows for the determination of potentially active faults in the current state of stress. At the time of writing, the
Figure II-1. Orientations of active faults in the New Madrid Seismic Zone (NMSZ) examined in Hurd and Zoback (2012b). The slip on the fault labeled AF is compatible to the alignment of epicenters associated with the fault that caused the M4.7 earthquake near Guy, Arkansas (Figure I-8).

Oklahoma Geological Survey is preparing an update fault map for the state of Oklahoma that will be a valuable resource for regulators and operators.

Currently, many regulations and guidelines include restrictions as to whether drilling and/or injection should be banned or strongly monitored when located within a specified distance of a potentially active fault. For example, according to the Arkansas Oil and Gas Commission, drilling should not occur within 1 mile of a regional fault or within 5 miles of a known active fault (AOGC, 2011). Meanwhile, Davis and Frohlich (1993) suggests that if faults are mapped within 20km of an injection site, that project is more likely to trigger or induce earthquakes. Regulations based on a specific distance between an injection site and a known fault may not be appropriate. Instead, each site needs to be considered on a case-by-case basis, especially with respect to whether a fault is potentially active. While regional geological studies may contain such information as noted above, one of the most valuable forms of data in determining the presence of faults in a region is 3D
seismic data. As noted in Section IV, hydrologic modeling would be of great importance in considering the location of projects with respect to local and regional faults.

Determining whether identified faults are potentially active can be a controlling factor for hazard. It is important to recognize that not all faults will be potentially active in the current state of stress and may, therefore, have relatively little importance in determining the earthquake hazard at a site. If a fault is considered potentially active, Nygaard et al. (2013) suggests avoiding perforating or completing any well to be used for hydraulic fracturing that is located adjacent to it. Zoback (2012) also argued that injection wells should not be located near potentially active faults. The identification of potentially active faults is discussed in Section V on geomechanical characterization. If it is found that a local fault is not potentially active in the current stress field, and would not be affected by a probable pressure perturbation, then no additional precautionary measures may be needed.

**Importance Of A Lower Sealing Formation**

A significant geological attribute that is an emerging potential factor is the importance of a lower sealing formation. In the case where fluid injected perturbs the pore pressure in sedimentary formations in direct contact with crystalline basement, injection-related pore pressure changes could directly affect potentially active basement faults (EPA, 2014). Sealing formations that separate saltwater disposal zones from the basement would limit the exposure of potentially active basement faults to pressure perturbations caused by fluid migration (See Section IV). SEGW (2014) and AXPC (2013) discuss the importance of the presence of basement faults when trying to understand the possibility of triggered seismicity. Figure I-6 illustrates that moderate size earthquakes (M 5 to M 6) require fault sizes on the order of 10s of kilometers in size, clearly involving slip on basement faults. The absence of sealing formations separating injection zones and basement could increase the chance of triggering on potentially active faults in the basement.

**III. EARTHQUAKE HISTORY**

The earthquake history of the region in which an injection site is located is an important consideration in evaluating the potential for injection-related seismicity. Regulations in some states require identification of known earthquake sources. Colorado, for example, requires the Colorado Geological Survey (CGS) to submit a review of seismicity that includes use of the CGS geologic maps,
the USGS earthquake database, and area-specific knowledge to provide insight into the seismic potential of a location (COGCC, 2011). In the case that seismicity is identified in the vicinity of the proposed well being considered as an injection site, COGCC requires the operator to define the seismic potential and the proximity to faults the geological and geophysical data prior to approval (COGCC, 2011). The state of Texas requires all historic earthquakes be reported that occurred within a 6 mile (~9.1 km) radius from a proposed injection well using data from the USGS (RCT, 2014). Similar regulations may be useful in other geographic regions, especially ones of relatively high historic seismicity. However, it is important to note that heterogeneities in the geology and hydrology of an area, among other things, often mean a specific radius is not the most robust factor to use for assessing whether earthquakes of particular locations are more suggest a higher risk than others (see Sections IV and VIII for further discussions). Figure III-1 shows recorded events of $M \geq 3.5$ in the continental United States from 1974 through 2003 (USGS, 2014a) and Figure III-2 shows recorded events of $M \geq 3.0$ in the state of Oklahoma from 1970 through June of 2014 (USGS, 2014b). Earthquake information such as this can give a baseline understanding of the relative rate of earthquake occurrence for certain parts of the United States.

Sources of information on earthquake activity range from catalogs of earthquakes developed with the benefit of instrumental records, through historical accounts of past earthquakes, to paleoseismological observations. Instrumentally recorded seismicity offers much more in the way of information, but it has issues of its own including non-uniform and highly time-dependent coverage (Schorlemmer and Woessner, 2008) as well as limited location accuracy, particularly for event depth (Husen and Hardebeck, 2010) and limited duration of coverage. The record of pre-instrumental seismicity is necessarily less complete and more qualitative. For much of the central and eastern US, for example, paleoseismological evidence for past earthquake activity is indirect such as for paleoliquefaction deposits associated with earthquakes in the New Madrid Seismic Zone (Tuttle et al., 2005). There are important exceptions, however, such as for the Meers Fault in Oklahoma (Crone and Luza, 1990). These limitations need to be accounted for when interpreting the earthquake history of a site.

**Earthquake Catalogs**

Resources that should be considered when investigating the earthquake history at a particular location include global, national, regional, and local seismic networks. For global catalogs, the magnitude of completeness may be larger than magnitude 4; whereas for dense local networks, the magnitude of completeness may approach 0. In some areas of the central and eastern
US, for example, detection thresholds have only been as low as magnitude 3.0 for the past couple of decades (Ellsworth, 2013).

The USGS Advanced National Seismic System (ANSS) works to provide continuous, accurate, and up-to-date earthquake locations. These are collected in the ANSS Comprehensive Catalog (ComCat), which contains earthquake locations, magnitudes, and other data and products produced by contributing seismic networks. A list of contributing networks is available at: http://earthquake.usgs.gov/earthquakes/map/doc_aboutdata.php. The ComCat database is scheduled for completion by the end of 2014. Ultimately, it will include digital catalogs of earthquake source parameters (e.g. Centennial Catalog, Global Centroid Moment Tensor Catalog). ComCat includes NEIC global PDE information since 1973, the ShakeMap Atlas from 1923-2011, the Centennial Earthquake catalog that dates back to 1900, as well as the global centroid moment tensor results.

Figure III-1. Earthquake map for the continental United States. Events mapped are of M3.5 and greater that occurred between 1974 and 2003. Figure from USGS (2014a).
that magnitudes can be highly variable. Due to the patchwork nature of many regional and networks, their own seismic networks, either for permanent monitoring or short-term projects, and may maintain archives of events of magnitudes lower than those detected by larger regional networks. Due to the patchwork nature of many regional and networks, the accuracy of locations and magnitudes can be highly variable.

Detecting an earthquake and determining the magnitude is obviously not enough to know whether an earthquake might be triggered or natural. Accurate earthquake hypocentral locations are critical for this purpose. Operating and maintaining a seismic network, and analyzing the data that results is a major undertaking. Thus, it would be sensible to leverage ongoing operations of existing state or national earthquake monitoring networks.

Figure III-2. Earthquake map for Oklahoma. Events recorded are M3.0 and greater that occurred between 1970 and mid-June 2014. Figure from USGS (2014b).

In some cases, state governments and academic institutions maintain seismic networks that are not part of the ANSS. These sources may have archives of events available on the web. For example, the Arkansas Geological Survey website (AGS, 2014) provides information on station locations and events detected. Additionally, some academic institutions own, install, and maintain their own seismic networks, either for permanent monitoring or short-term projects, and may maintain archives of events of magnitudes lower than those detected by larger regional networks.
For much of the US, where there is only a skeletal “backbone” network, horizontal location errors may reach 10 km, and the ability of existing seismic networks to constrain earthquake depth is poor. This results in often-unreliable analyses of spatial and temporal earthquake occurrences during injection operations and even contradicts efforts for mitigation that require earthquake reporting to regulators in areas smaller than the location errors. Thus, should suspected triggered seismicity occur, it would require enhanced monitoring to improve location accuracy and detection capabilities. This argues for a portable, temporary network deployment capability, such as the IRIS PASSCAL program operates for academic earthquake and Earth structure experiments (IRIS, 2014). Here again, it would be sensible to leverage the capabilities of existing organizations for maintaining and overseeing the use of such equipment.

**Considering Past Events**

Once event archives have been collected for the region of interest to an injection project, it is useful to consider the particular locations and magnitudes of those events. Are there clusters or alignments of events that suggest the presence of a fault? Are some of the events large enough to cause concern? Even events of very small magnitudes (<M2) might define the presence of a relatively large fault that could pose a significant hazard. It is also important to consider past or current projects that may have triggered seismic events in an area. Do events in the catalog coincide with other area operators in both space and time? If so, this is important because it means that events have the potential to be triggered in the area even if they weren’t initially correlated to specific injection projects. Adjustments in the choice of injection site or operational procedures may need to be made to accommodate this.

In some cases, the earthquake history provided by existing catalogs may be insufficient to determine the level of background seismicity in an area. In this case, it is possible for background seismic data to be collected to estimate the natural earthquake activity in an area. This may require the deployment of enhanced local seismic networks (such as those discussed in Section VII). As based on Majer et al. (2012), the length of time that operators should plan to acquire data to determine the baseline seismic activity for an area depends on the detection level of the network of stations being used. In the case where the network is able to detect all events down to a very low magnitude data may only need to be recorded for a short amount of time. Whereas, in cases where the array used is only able to detect larger events, the baseline data may need to be collected for significantly months. Majer et al., 2012 suggests that monitoring should begin as soon as an injection site has been chosen.
IV. HYDROLOGIC CHARACTERIZATION

Hydrologic characterization of the region in which fluid injection is planned will allow operators and regulators to predict the migration of fluids in the subsurface and determine whether those fluids, and the accumulation of fluids from previous or concurrent injection projects, have the capacity to perturb the state of stress and trigger earthquakes. Factors such as the pressure increase controlled by cumulative injected fluid rates and volumes, the presence of hydrologic seals, and the effects of faults on fluid flow should all be considered. In some cases, 3D hydrologic modeling may be needed to determine the risk associated with the cumulative effects of injection in the area and the local geology.

It was well documented for the past five decades that injection pressures and rates could affect earthquake occurrence (Evans, 1966, Healy et al., 1968 and Rayleigh et al., 1976). From March of 1962 to September of 1963 and August 1964 to February 1966, saltwater disposal took place at the Rocky Mountain Arsenal near Denver, Colorado and was ceased due to the apparent correlation between the injection volume and earthquake occurrence (Figure IV-1, Healy et al., 1968). The largest event triggered near the site during injection was between M 3 and M 4, while in 1967, post-injection, there were three earthquakes between M 5 and M 5.4. Healy et al. (1968) speculated that the reduction of the frictional resistance to faulting due to decreased effective normal stress was the mechanism by which failure was occurring. Shortly thereafter, in 1969, a field experiment aimed at exploring the relationship between triggered earthquakes and fluid pressure was carried out at the Rangely Oil Field in Colorado (Rayleigh et al., 1976). They confirmed the fact that changes in subsurface pressure due to fluid injection could literally turn earthquakes on and off (Figure IV-2).

In both the Rocky Mountain Arsenal and the Rangely Oil Field, the Mohr-Coulomb Failure Criterion was used to support the premise that earthquakes were being triggered. As discussed further in Section V, the Mohr-Coulomb Failure Criterion emphasizes the relationship between the shear and normal stresses on a fault and how increasing the pore pressure decreases the effective normal stress, thereby encouraging slip in the form of an earthquake (see NRC, 2012). More information about the Mohr-Coulomb Failure Criterion and triggered earthquakes is described in Section V.
Figure IV-1. Correlations between earthquake frequency and high-pressure fluid injection at the Rocky Mountain Arsenal, Denver, Colorado that led to the initial suspicions that earthquakes might be controllable. Figure from Healy et al. (1968).

Figure IV-2. Frequency of earthquakes at Rangely as shown in Raleigh et al. (1976). Stippled bars show earthquakes detected within 1km of the injection wells. Clear areas indicate detected earthquakes further than 1km from the injection wells. Pressure history of well Fee 69 shown by the heavy line. The predicted critical pressure is shown by the dashed line. Figure and modified caption from Raleigh et al. (1976).
State Of The Knowledge

For a list of the geophysical and geological properties that could be considered in carrying out a hydrologic characterization, we refer to the AXPC (2013) report. As a first step, it is beneficial to consider what is already known about the hydrology of an area and any previous injection practices. This could include consulting local geological surveys, studies, regulators, and other area operators to gather an initial set of information that may include the formation attributes, history of previous injection, the existence of faults and whether they are active, and the presence of any hydrologic seals in the area. Geophysical logs can be used to determine the injection zone thickness and porosity and to determine the scale of zonal isolation the bounding layers will provide (COGCC, 2011). Knowing other well locations, injection rates, and injection pressures, especially if there are many injection wells into the same formation, can lead to a greater understanding of what amounts are appropriate and how the reservoir, neighboring formations, and any local faults that were affected by fluid injection.

Pressure Perturbations

In the case of the Mohr Coloumb Failure Criterion, there is a clear association between pressure changes resulting from injection and triggered slip on a fault. Methodologies that could help avoid injection near potentially active faults are discussed in the following section. Obviously, when there are many injection wells in a local area, it is also important to consider how the cumulative effect of these wells can impact the pore pressure on a regional scale. The presence of a cumulative effect of pressure perturbations can make the correlation between seismicity and specific injection wells very difficult, particularly when injectors have been in operation for long periods of time or when high volumes are injected.

Keranen et al. (2014) included the use of a 3D hydrogeologic model of pore pressure diffusion associated with injection from 89 local wells, four of which were considered as anomalously high-rate injectors (Figure IV-3). The details of the modeling published in Keranen et al. (2014) are described in the supplemental material that accompanied the paper. Their study illustrates the possible effect of cumulative pressure perturbations in the Arbuckle formation, a saline aquifer used for saltwater disposal immediately above the basement rocks. In this regard, Keranen et al. (2014) illustrate the value of 3D hydrologic modeling in the context of triggered seismicity resulting from fluid injection. These models allow one to estimate the extent of pore pressure perturbations expected from the cumulative injection of multiple wells. Due to the
complexity of these models, it is important to note their limitations, including the permeability (as well as the initial pore pressure) in both the Arbuckle formation and basement in their model. In addition, there are no direct measurements of pore pressure changes at depth to constrain their modeling. From the cross-section in Figure IV-3, it is clear that their model assumes a fairly high and uniform basement permeability, which may not be representative of the actual basement rocks which likely has a very low matrix permeability with more permeable potentially active faults imbedded within it as discussed in the next section.

**The Effect Of Faults On Fluid Flow in Crystalline Basement**

Knowing whether there are permeable faults in crystalline basement can lead to a better understanding of where fluids may migrate as the result of saltwater disposal and hydraulic

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**Figure IV-3.** Fluid pressure migration as the result of fluid injection from 89 wells using a hydrogeologic model. The pressure increase is dominated by the four high-rate injection wells in the area. Figure from Keranen et al. (2014).
fracturing. According to Townend and Zoback (2000), the permeability in the crust results largely from hydraulically conductive, critically stressed faults. This means that faults that are active in the current state of stress are likely permeable and therefore channel fluid flow whereas those that are not potentially active are likely not permeable (Figure IV-4, Zoback and Townend, 2001). This means when injection formations are in hydraulic communication with basement formations (as is the case of the Arbuckle formation in Figure IV-3), one would expect pore pressure changes transmitted to potentially active faults to be significantly higher than in the basement, rather than in the basement rocks as a whole. In contrast, faults that are inactive in the current state of stress are not characterized by anomalously high permeability and not expected to affect subsurface fluid flow.

**The Presence Of Hydrologic Seals**

In addition to understanding the affects of local faults on fluid flow, it is also important to consider whether there are sealing formations located in the area of proposed injection. Many state regulations require the presence of an upper sealing unit in an attempt to protect shallow drinking

![Figure IV-4](image)

*Figure IV-4.* Shear and effective normal stresses on fractures and faults. When the shear to normal stress is close to what is required to cause fault slip (0.6) the faults are more likely to be permeable (large symbols), compared to faults and fractures where the shear to normal stress is lower than that required to cause fault slip (small symbols). Figure from Zoback and Townend (2001).
water resources (SWDA, 1996). In the context of the previous discussion, it is also important to consider whether there is a lower sealing formation present at the injection site to ensure the fluid pressure changes in a formation being used to saltwater disposal stays in the target formation thus avoiding possible pressure perturbations in the basement.

Zhang et al. (2013) constructed a suite of simulations that uses a simple hydrogeological-geomechanical model to determine what conditions promote or deter triggered earthquakes within crystalline basement rocks. Through their simulations, they found the single most important factor that helped to mitigate pressure perturbations in the basement was the presence of hydrologic seals between the reservoir and the basement rock (Figure IV-5F) (Zhang et al. 2013). Their study focused specifically on long-term injection, similar to what we would expect of saltwater disposal projects.

**Estimated “Radius Of Concern”**

In nearly every current state regulation and in many guidelines and studies, it is suggested that a “radius of concern” be defined for a proposed saltwater disposal or hydraulic fracturing project. The purpose of the radius of concern is to determine the area for which perturbations due to fluid injection are occurring. Rather than this “radius of concern” being prescriptive and generalized for all injection sites in a country or state, the radius of concern would be more accurate if it were based on the hydrologic properties of the formations of interest (including sealing properties between the injection interval and the basement – See Figure IV-5F), the presence of faults and fractures in the area, and the cumulative injection volumes, rates, and pressures for the proposed project and neighboring projects.

Davis and Frohlicher (1993) suggest using historic earthquakes of specific distances from the injection site to determine whether the planned injection would be likely to trigger or induce seismic events. For instance, they suggest addressing whether earthquakes of higher magnitude (greater than M5.5) have occurred in the region and used an example radius of several hundred kilometers as an appropriate distance (Davis and Frohlicher, 1993). While such a criterion may be useful for generally characterizing the overall level of earthquake activity in a region, it is difficult to apply such knowledge to the question of whether a planned injection activity might trigger seismicity. Their guidelines also suggest using a local radius of 20km between the injection site and smaller events in determining whether the project is likely to induce damaging seismic activity (Davis and Frohlicher, 1993). We hesitate to suggest a specific radii and magnitudes thresholds for
every injection operation because these values are very dependent on site-specific hydrologic characteristics and historical detection thresholds for earthquakes.

The radii operators and regulators use to determine which wells to identify prior to injection would be more accurate if they were based on the hydrologic characteristics and the locations of critically stressed faults and fractures at the site, and the proposed injection plan. In some cases, fluids may migrate a much greater distance than what is recommended in the current Texas and Oklahoma regulations, though this possibility may be difficult to identify. 3D modeling of how the injected fluid may flow through the subsurface and how pore pressure changes may interact with nearby injection operations can increase the operator’s ability to predict how the fluid may interact with local faults and fractures and the particular rock properties of each formation, though it is important to recognize that these models will also have limitations and may not be reliable with the available data.

As discussed earlier, it is difficult to predict how far fluids may travel as the result of injection, especially when there are uncertainties in data collected and uncertainties in the identification of faults and the hydrologic properties in the subsurface. Not fully understanding or not considering the extent of sealing formations may seriously affect the resulting fluid migration in the area. In the case where rather large volumes of fluids are injected over long periods of time, it would be possible for these fluids to create a cumulative effect with other area operations and potentially increase pore pressures several kilometers away potentially triggering or inducing earthquakes much further from the radius of concern required by many current state regulations. Davis and Frohlich (1993) and Keranen et al. (2013) both suggest that pressure perturbations relating to fluid injection may migrate further (20km and 30km, respectively) than most regulations consider. This doesn’t necessarily suggest that a radius of concern ought to be 10s of kilometers in length, but that the radius of concern needs to be considered site-by-site using the location’s geology, hydrology, earthquake history, and cumulative injection in nearby wells as guides.

V. GEOMECHANICAL CHARACTERIZATION

To first order, injection-related seismicity can be understood in terms of the Mohr Coulomb Failure Criterion. This faulting theory allows knowledge of stress orientation and relative stress magnitude to define which faults are optimally orientated for failure in the current stress field in a
Figure IV-5. Model output from Zhang et al. (2013) showing how hydrologic seals (horizons labeled C1 and C2) are effective at limiting hydrologic communication between relatively permeable intervals (horizons A1, A2, and A3) and the crystalline basement (CB). The model shows hydraulic head above reservoir conditions (in m) after 10 years of reservoir injection. Modeled normal faults are shown as blue lines. Orange regions show areas in the basement where total pressures are greater than the critical pressure. Frame (D) shows how injecting into a formation that overlays basement rock could allow pressure communication to basement faults. Frame (F) shows the value of a lower sealing formation to help limit the pressure communication between the injection formation and basement faults.
given area (SEGW, 2014; AXPC, 2013; Hurd and Zoback, 2012a and 2012b; NRC, 2012; The Royal Society, 2012) as well as the level of pore pressure perturbation could cause them to slip (e.g., Wiprut and Zoback, 2000; Chiaramonte et al., 2008). As mentioned above, studies of earthquakes triggered by fluid injection at the Rocky Mountain Arsenal near Denver in the 1960’s and later at the Rangely oil field in western Colorado demonstrated that fault slip occurs when the ratio of shear stress to effective normal stress on a pre-existing fault exceeds the coefficient of fault friction (Healy et al., 1968, Raleigh et al, 1976, Zoback and Healy, 1984, Hsieh and Bredehoeft, 1981).

It is obvious therefore that in attempting to avoid triggering earthquakes, it would not be wise to cite saltwater disposal wells near potentially active faults, nor would it be wise carry out hydraulic fracturing in the close proximity of potentially active faults. Only after the fact were the causative faults identified in the vicinity of the Guy, Arkansas and Youngstown, Ohio cases where injection appears to have triggered moderate size earthquakes. Had high quality 3D seismic reflection data been available and used to identify faults in these areas, the potentially active faults could have been identified (and avoided) prior to injection. As described below, it is relatively straightforward to obtain the data needed to identify potentially active faults, especially if the faults cut through the sedimentary rocks being used for saltwater disposal or hydraulic fracturing. However, there are scenarios in which faults may be difficult to identify using 3D seismic data. This is particularly true of high angle faults or basement faults with little expression in the overlying sediments.

In the context of the Mohr Coulomb Failure Criterion, the primary information needed to develop a geomechanical model of an area where hydraulic fracturing or waste injection is planned includes the magnitude and orientation of the three principal stresses, and the pore pressure. Determining these parameters is well understood (Zoback, 2007). Often, we refer to the three principal stresses in terms of the maximum horizontal stress ($S_{Hmax}$), the minimum horizontal stress ($S_{Hmin}$), and the vertical stress ($S_V$) where the maximum horizontal stress is always greater than the minimum horizontal stress and the vertical stress can be the least, intermediate, or greatest principal stress depending on the tectonic setting. Figure V-1 illustrates the relative magnitudes of the relationship between stress states and faults that are well-oriented for failure. The center column of figures represents the three stress states as originally defined by E.M. Anderson (1951). In normal faulting stress states the vertical stress exceeds the magnitude of the horizontal stresses. Active faults normal faults strike sub-parallel to $S_{Hmax}$ and dip steeply in the direction of $S_{Hmin}$. In strike-slip faulting stress states the vertical stress is intermediate in value between $S_{Hmax}$ and $S_{Hmin}$. In such stress states, active faults are expected to be near vertical and strike $±30^\circ$ from the
direction of $S_{hmax}$. Reverse faulting corresponds to a stress state in which the vertical stress is the least principal stress. In this case, active faults strike in a direction parallel to the $S_{hmin}$ and dip in the direction of $S_{hmax}$.

The left side of Figure V-1 shows the limiting stress states. When the two horizontal stresses are equal but less than the vertical stress, normal faulting could occur on steeply dipping faults striking in almost any direction. Correspondingly, when the two horizontal stresses are approximately equal but much greater then the vertical stress, reverse faulting could occur on moderately dipping faults striking in any direction.

The right side of Figure V-1 shows intermediate stress states. For example, when the vertical stress and $S_{hmax}$ are approximately equal and significantly greater than $S_{hmin}$, both normal faults and strike-slip faults can be active at the same time. Similarly, when the vertical stress and $S_{hmin}$ are approximately equal and $S_{hmax}$ is significantly greater, both strike-slip and reverse faults can be active in a region simultaneously.

When earthquakes occur, the radiated seismic waves allow one to construct focal plane mechanisms that reveal the style of faulting and relative stress magnitudes. Focal plane mechanisms define two planes, one of which is the fault plane that slipped in the earthquake and provides approximate information about stress orientation. Figure V-2, modified from Zoback (2007) illustrates the relationships between normal, strike-slip and reverse faulting stress states, active fault orientations, stress magnitudes (utilizing Mohr circles) and earthquake focal plane mechanisms (the “beach ball” diagrams at the right).

Figure V-3 is a map of the central and eastern United States that shows relative stress magnitudes determined from earthquake focal plane mechanisms (from Hurd and Zoback, 2012a). Following the work of Zoback and Zoback (1980, 1989) and M.L. Zoback (1992a), Hurd and Zoback (2012a) showed that the style of faulting associated with a given earthquake is consistent with the stress state as revealed by independent stress indicators. The color scale shows the seven stress states illustrated in Fig. IV-1 using a continuous color scale from 0 to 3 following Simpson (1997). Note the systematic southwest to northeast increase in compressive stress going from north central Texas (where the two horizontal stresses are approximately equal and significantly less than the vertical stress) to high compression in New England and southeasternmost Canada.
The relationship between relative stress magnitudes and potentially active faults (see text). The numbers in parentheses next to the faulting styles correspond to the color scale shown in Figure V-3.

**Stress Data Acquisition**

In the context of the discussion above, knowledge of the presence and orientation of faults at depth and the orientation of the stress field and style of faulting in a region can be used to identify potentially active faults. A good starting place to start to evaluate available stress data in a region is the World Stress Map (Zoback, 1992) that is an online database of stress orientation and relative stress magnitudes

Figure V-2. Schematic illustration of the orientation of various types of faults with respect to the orientation of $S_{\text{Hmax}}$ and $S_{\text{hmin}}$. (a) Conjugate normal faults are expected to dip 60° (for $\mu \sim 0.6$) and strike parallel to the direction of $S_{\text{Hmax}}$. (b) Conjugate strike-slip faults are expected to be vertical and strike $\sim 30^\circ$ from the direction of $S_{\text{Hmax}}$ (for $\mu \sim 0.6$). (c) Reverse faults are expected to dip $\sim 30^\circ$ (for $\mu \sim 0.6$) and strike normal to the direction of $S_{\text{Hmax}}$. Because fractures and faults are introduced during multiple deformational episodes (depending on the age and geologic history of the formation) it is common for formations to contain numerous fractures at a variety of orientations. Figure modified from Zoback (2007).

While in many regions the World Stress Map database is sparse it is straightforward to augment the database with stress information from geophysical logs that are often already available in oil and gas producing regions (WSMP, 2014). An example of this is shown in Figure V-4 (from Alt and Zoback, in preparation) utilizing geophysical image logs made available by oil and gas companies. Over eighty high quality indicators of the direction of maximum horizontal stress (blue lines) have been added to the $\sim 10$ previously available high quality data points in the state. The extremely uniform N$\sim 85^\circ$E $S_{\text{Hmax}}$ direction, along with the consistent strike-slip style of faulting revealed by earthquake focal plane mechanisms in Oklahoma (Holland, 2011) enables one to identify potential active faults. Steeply dipping faults striking $\pm \sim 30^\circ$ from the direction of $S_{\text{Hmax}}$ are expected to be potentially active, such as the N$\sim 50^\circ$E fault that slipped in the largest of the Prague earthquakes (see Figure I-7) The stress data also can be used to argue that it is unlikely slip would be triggered on faults like the NNW striking Nemaha fault near Oklahoma City.
Figure V-3. Relative stress magnitudes determined from earthquake focal plane mechanisms in the central and eastern U.S. reveal compressive stress magnitudes systematically increasing from southwest to northeast in this region Hurd and Zoback (2012a).

The Royal Society (2012) suggests that the government should be involved in carrying out national surveys to characterize stresses and identify the orientations of faults. The Royal Society (2012) also suggests that operators be required to share stress data and fault data with the government to establish a national database. Sharing these government databases with the World Stress Map project would allow for the development of a comprehensive, greatly improved worldwide stress database in the public domain (WSMP, 2014).
Figure V-4. The direction of maximum horizontal stress in Oklahoma (except for the panhandle in northwest) obtained from a recent study of drilling-induced wellbore failures using image logs provided by private industry (blue lines) and high quality stress orientation data available in the World Stress Map (green lines) (WSMP, 2014). From Alt and Zoback (in preparation). The red lines are faults from the Oklahoma Fault Database.

**Identification of Potentially Active Faults**

The faults shown in Figure V-4 are those determined from subsurface well data, geophysical data and surface mapping. At this time, this map represented the best data available in the public domain. It is obvious that if potentially active faults are going to be avoided when siting waste injection wells, all faults present in the subsurface must be identified. With such data in hand, one can use stress, historical seismicity, geologic, paleoseismic and other information to identify the subset of faults that are potentially active today. One example of such work examined the probability of slip on a fault plane at Teapot Dome oil field in Wyoming due to CO₂ sequestration (Chiaramonte et al., 2008). From their work, the authors were able to estimate the pressure perturbation required to trigger fault slip. Although techniques to identify faults in the subsurface
are generally well known, compiling the necessary data can be a considerable challenge and may require proprietary geophysical data such as 3D seismic reflection surveys.

Another challenge with fault identification is that as described in the section on Geological Characterization (Section II), the potentially active faults of most concern associated with saltwater disposal are those in basement rocks. Such faults can be very difficult to identify if they have little expression in the overlaying sediments. The absence of obvious surface faults associated with much of Central and Eastern US seismicity testifies to the difficulty of identifying active faults.

A final challenge in the identification (and avoidance) of potentially active faults in the subsurface is that pore pressure changes from many saltwater disposal wells in an area over time can cause cumulative pore pressure changes that affect a significant area. One example of this effect is the suspected cumulative pressure perturbation in Oklahoma as modeled by Keranen et al. (2013) (Figure IV-3). Hence, the potentially activate faults that might be of concern could be 10s of km away from the nearest injectors. In this case, it would be important to consider a more large-scale approach to the question of how pressure changes from cumulative injection might trigger seismicity on distant faults.

Pore Pressure

In absolute terms, pore pressure data are necessary for the calculation of the effective state of stress and therefore which faults would be active in a given stress regime; however, over time, stress states in the brittle crust may reach a state of frictional equilibrium whether the pore pressure is hydrostatic, sub-hydrostatic or greater than hydrostatic (see examples in Zoback, 2007). In sub-hydrostatic pore pressure scenarios, the initial state of stress is assumed to be close to that at which well-oriented faults are near failure. This means a small pressure increase in pore pressure could trigger faulting on well-oriented faults but pore pressure could increase dramatically without any indication at the surface. In other words, large pore pressure changes can occur at depth without any increase of wellhead pressure potentially, and bringing pre-existing faults close to failure. In the case of fluid injection at the Rocky Mountain arsenal near Denver, the earthquakes that were triggered occurred in basement rocks that were significantly under pressured. When the pore pressure due to injection was sufficient to trigger seismicity, the pore pressure was still sub-hydrostatic (Zoback and Healy, 1984; Hsieh and Bredehoeft, 1981) and saltwater was being injected at zero surface pressure.
VI. MONITORING AND REPORTING PRESSURE, INJECTION VOLUMES, AND RATES

To date, there is a considerable difference between state regulations in the United States regarding the acquisition and reporting of injection pressure, volumes, and rates. According to the Ohio Administrative Code (OAC, 2014), before injection begins, operators are asked to develop a description of the method proposed for the completion and operation of a project, including the full stimulation program (OAC, 2014). Additionally, bottomhole pressures are required to be tested and recorded and the estimated average pressure to be used for injection and the method used to measure the actual daily injection pressure are required to be identified (OAC, 2014). The Arkansas Oil and Gas Commission (AOGC) requires operators to submit information on the proposed daily amounts to be injected, the source and type of fluid to be injected, and a standard laboratory report of the disposal fluids (AOGC, 2012). In Oklahoma, information such as the maximum injection rate, the maximum surface injection pressure, and the injection fluid must be reported prior to the start of injection at the site (OCC, 2013). In this section, we discuss how plans for monitoring and reporting injection pressure, volumes, and rates may be improved to help mitigate triggered earthquakes.

Relationships Between Injection Practices and Earthquake Activity

As the understanding of triggered earthquakes increases, conclusions can be drawn regarding the relationships between event magnitudes, depths, injection pressures, and injection volumes. In the case of hydraulic fracturing, microseismic data generally show a modest increase in triggered event magnitude with depth (Warpinski et al., 2012). This is attributed to some combination of higher pressures and larger in-situ stresses at depth leading to larger energy releases during earthquakes (Warpinski et al., 2012). In addition, higher injection pressures may lead to larger variability in the orientations of faults that are activated.

Data analyzed by Warpinski et al. (2012), which focused on hydraulic fracture data in the major shale basins of North America, suggests that the details of treatment conditions do not contribute induced or triggered seismicity, and that it is most affected by fault interactions caused by geological, structural, and stress conditions in reservoirs. This implies that seismicity can be minimized by avoiding areas that are structurally complex or by increasing monitoring and developing an appropriate mitigation plan. In the case that injection occurs in areas of structural
complexity, great care needs to be taken to ensure that seismic events of concern are recognized and that the injection and mitigation plan are rigorously monitored and adjusted. Nevertheless, injection pressure, rates, and volumes are often necessary for discerning temporal and spatial links between single injection wells and triggered earthquakes.

**Frequent, High Quality Reporting Of Injection Pressure, Volumes, And Rates**

Currently, many regulations require injection pressures, volumes, and rates be submitted on an annual basis. As suggested by the SEGW (2014), the EPA (2014), and encouraged by many others, more frequent and timely, high quality reporting of injection pressures, volumes, and rates should be standard practice because it will allow for a stronger analysis of the spatial and temporal correlation between particular saltwater disposal or hydraulic fracturing wells and potentially triggered earthquakes (SEGW, 2014). The ability to submit these daily records in real-time or near-real time would allow the operators and regulators to work efficiently. These data should be monitored, recorded, reported, and archived for the life of the well and for some time after.

Additionally, data related to fluid injection, such as well locations, injection depths, and injection volumes, pressures, and rates should be collected by the state and federal regulatory agencies in a common format and made accessible to the public through a coordinating body such as the USGS (NRC, 2012). This will allow other area operators to compare their injection strategies and earthquake occurrences to determine the best suitable practices, as well as inform interested parties about the injection practices in their areas.

**Injection Pressure Limits**

The purpose of the trial injection test is to establish the effective permeability and the capacity of the injection interval, which can be thought of as the porosity multiplied by the volume of the formation in question. In Colorado, a generalized fracture pressure gradient of 0.6 psi/ft is required and used to define the site unless the operator decides to do a step rate injection test to define whether a higher injection zone fracture gradient exists (COGCC, 2011). In the state of Texas, injection pressure perturbation is restricted to not exceed 0.5 psi/ft (RCT, 2014). In many cases, especially those with moderate to high risk, performing a step rate injection test may help constrain the fracture gradient prior to injection.

Injection pressure limits are inherently different for hydraulic fracturing and saltwater disposal. In the case of hydraulic fracturing, the goal is to increase formation permeability through
the creation of small fractures caused by injection pressures that rise above the least principle stress. In the case of saltwater disposal, the goal is to inject as much saltwater as possible without fracturing the formation. To benefit both types of projects, the SEGW suggests recording the initial bottom hole pressure once the well has been drilled (SEGW, 2014).

For saltwater disposal projects, regulations generally require that saltwater disposal wells do not inject at pressures above the fracture gradient to minimize unintentionally hydraulically fracturing the formation (AOGC, 2012; COGCC, 2011). The State of Colorado Oil and Gas Conservation Commission (COGCC) currently requires a COGCC UIC engineer to calculate a maximum injection volume, based on thickness and porosity from the log data. According to COGCC policy, there are restrictions in place meant to constrain the total volume of injected fluids to a one-quarter mile radius during the life of the well. To achieve this goal, a COGCC UIC engineer calculated the total injectable volume by considering the thickness of the target formation and its porosity (COGCC, 2011). It is important to stress that implementing a distance, such as one-quarter mile, is highly dependent on the geology, local active faults, hydrology, and historic injection practices both at the injection site and nearby. In most cases, it will be difficult to assign a specific distance for the radial volume injected.

As with many aspects related to fluid injection and triggered seismicity, it is important to consider the dynamic conditions of the reservoir (SEGW, 2014). More specifically, operators and regulators would benefit from examining how bottom-hole pressures, volumes received, area of influence by injection, and how compounded affects from other area injection wells affect the possibility of triggered events occurring, particularly when the target formation is sub-hydrostatic (Section IV).

VII. EARTHQUAKE MONITORING AND REPORTING

High quality microseismic data is of fundamental importance when considering issues related to triggered seismicity. Microseismic data is useful during every stage of the injection process, including before, during, and after injection and provides insight into the seismic hazards present (The Royal Society, 2012) and the development of fractures (Warpinski, 2013). Monitoring can be carried out via many different methods and a site-specific plan should be developed based on the risk associated with the specific project.
The importance of increasing the number of permanent seismic stations

An often-overlooked issue regarding microseismic monitoring is whether adequate seismic network coverage is available to assess baseline microseismic earthquakes and to detect earthquakes associated with injection. As discussed before, state and national agencies own and operate permanent seismic networks, but these networks may not have a sufficiently low detection threshold to detect either natural, triggered, or induced micro-earthquakes. Obvious examples of regions where denser seismic networks would be beneficial are Oklahoma and parts of Texas. These regions have earthquake histories that suggest the potential for triggered earthquakes, but the current level of monitoring would not be able to detect events of small enough magnitudes for robust earthquake mitigation. Clear documentation of the detection threshold for existing networks is a necessary first step for developing a monitoring plan. In areas of sparse coverage, this issue provides the geoscience community and the oil and gas industry with a natural partnership to increase the number of permanent seismic monitoring stations to improve earthquake detection capabilities in areas where the oil and gas industry operates or may operate in the future.

There are several options that could be considered to increase the number of permanent seismic stations on the state and national level. The British Columbia Oil and Gas Commission suggests a requirement that installed networks need to be able to positively identify appropriately low magnitude seismic events (BCOGC, 2012). A first option requires operators to install and maintain one seismic station for the duration of injection at each well and make the data available to the public. This would be in addition to any high-density networks the operators may install based on the risk level of their project. Though this installation of one permanent, public station would increase the number of stations, the station spacing may not be ideal and the data may be noisier, particularly if it is located in close proximity to ongoing oil and gas activity.

A second option might require that for every injection well drilled, operators would pay a fee to the state or federal government that would underwrite the acquisition, installation, operation, and maintenance of existing seismic networks. This would require the state or federal government to accept the responsibility of choosing a location for the instrument, installing it, and maintaining it. Ideally the state or federal government would consider the optimal locations of stations to monitor potentially triggered seismicity in the most reliable, cost-effective way possible.

Regardless of how the stations are funded and where the stations are located, it is not only necessary to collect the data, but also to establish a system for the near real-time analysis of triggered earthquakes. While it may be common practice for operators to not include permanent microseismic monitoring as a part of their projects, should a triggered event occur, microseismic
monitoring could provide important information to guide a response. Having a site-specific permanent station or an array of stations could greatly enhance the operator’s ability to detect and analyze the development of microseismic events before they evolve into a situation of concern (see Section IX).

**When To Monitor For Events**

Monitoring for microseismic events in the oil and gas industry is relatively common only when fluid injection is occurring. It would be extremely beneficial for earthquake monitoring to be carried out before, during, and after injection to understand the possible relationship between earthquakes and injection. Monitoring for microseismic events before injection begins allows for the operators to identify the occurrence of natural earthquakes, including their rate, magnitudes and locations. Monitoring for events prior to injection will give the operator and regulators a glimpse into the background seismicity of the area and give the operator a better understanding of the increase in seismic activity once injection begins. Many current guidelines suggest the collection of baseline microseismic data at proposed injection sites, including Green et al. (2012), The Royal Society (2012), and the NRC (2012).

Monitoring during injection allows operators to be proactive in the detection of earthquakes and the determination of whether those events are reason for concern. There are particular features in the microseismic events that should be monitored for continuously and perhaps automatically, including whether the events are occurring at unexpected depths, are of magnitudes larger than expected, are defining a planar feature that may suggest the presence of an active fault, and are occurring further from the injection well than expected. Microseismic monitoring during injection may provide the added benefit of allowing the operator to estimate the extent of fluid migration based on the locations of the microearthquakes.

After injection has ceased, earthquake monitoring is still of importance. In the case of saltwater disposal where the fluids and pressure fronts will likely migrate to relatively great distances, the termination of injection will not immediately halt fluid or pressure front migration which means the occurrence of a triggered earthquake of a concerning size is possible for some time after injection has occurred. An example highlighting the importance of earthquake monitoring post-injection is the sequence of events following saltwater disposal in the Precambrian basement rock at the Rocky Mountain Arsenal, Colorado (Hsieh and Bredehoeft, 1981). At this site, three earthquakes, each with magnitudes greater than 5.0, occurred some time after injection.
ceased. The earthquakes are thought to have occurred within the naturally fractured Precambrian basement rock.

**Possible Monitoring Methods**

There are many monitoring arrangements that can be used to detect triggered seismicity, all varying in sophistication, price, sensitivity and reliability. These monitoring methods include human observation (CAPP, 2012), regional arrays (CAPP, 2012), accelerometer-based “strong motion” systems, local surface arrays, local near-surface buried arrays, and local borehole arrays.

One inexpensive, though less reliable, less sophisticated, and less sensitive, method of event detection is utilizing the presence of injection site employees to alert authorities in the event of an earthquake being felt at the surface. This technique should always be considered as a real-time detection capability, but it should only be considered as the primary earthquake detection method at sites that have extremely low risk. For instance, only sites with virtually no probability of a member of the public being disturbed and no structures or infrastructure being damaged as the result of any potential microseismic event triggered at the site.

If human observation is the only seismic monitoring method used at a site, then it would be beneficial for all on-site personnel to be trained to respond to felt ground motions as appropriate (CAPP, 2012). For very small earthquakes, whether a person is still or moving makes a substantial difference in their ability to detect an event. For this reason, every employee on-site needs to understand what to do if an earthquake is felt. For example, they must be trained to report felt events exceeding a particular intensity based on the Modified Mercalli Scale (Appendix C). Using this observation method is completely dependent on the detectability of human to level of ground shaking. Human detection generally isn’t possible until about a magnitude 2 to 2.5 and does not offer the ability to located the detected events.

Utilizing regional arrays to detect microseismic events is useful in cases where the risk is low. As discussed in Section III, regional arrays often have event detection thresholds too high to be of significant use in microearthquake analysis, meaning their catalogs are only complete for magnitudes higher than the level of concern for triggered microseismic events. If a regional array has a station located close to the injection site, it may still be able to detect whether there is a change in the occurrence of microseismic earthquakes.

Local surface arrays installed and maintained by operators have the benefit of being close to probable triggered events and appropriate instruments may be selected that would allow for the proper recording of very small, high frequency earthquakes. In this case, the operator may have
much greater control over the quantity and locations of any installed instruments. Surface instrumentation is susceptible to noise from atmospheric effects and cultural noise, but this can be reduced through careful site selection and vault construction.

Local buried near-surface arrays would have the same benefits of local surface arrays, including having the stations near the injection and providing a greater level of control to the operator with regard to the number of instruments and their locations. The most significant difference between local buried near-surface arrays and surface arrays is that the buried stations tend to have higher signal-to-noise ratio because they are removed from sources of noise at the surface, and they record waves before they propagate through the highly attenuating near-surface layers.

The most desirable, but often most expensive form of microseismic monitoring is the use of local borehole arrays. These arrays give the operator the sensitivity to record very small microseismic events occurring in the area of injection mainly due to the much reduced level of noise these stations record compared to local surface arrays, and even local buried near-surface arrays. However, there are limitations in determining focal mechanisms using borehole data due to their often poor focal sphere coverage.

The use of portable arrays that can be deployed if concern of triggered seismicity is rising or if a large event has occurred, offers an additional option for improved earthquake monitoring in areas of particular concern. Either operators or the local regulators and government can manage temporary portable arrays. In the case of British Columbia, the Oil and Gas Commission suggests studying the deployment of a portable dense array to selected locations where triggered seismicity is anticipated or has occurred (BCOGC, 2012). These arrays would be dense, temporary, and used to augment regional, permanent monitoring. Temporary monitoring would aid in focal mechanism determination, improved location resolution and lower magnitude detection. Enhanced monitoring is much easier to carry out if the data can be streamed with minimal latency into existing processing pathways at, for example, the US Geological Survey’s National Earthquake Information Center. Temporary monitoring capability has to be quickly deployable and could require as few as five stations. The British Columbia Oil and Gas Commission suggests it is their responsibility to seek funding for these portable arrays to be deployed as needed for triggered seismicity research and data collection (BCOGC, 2012).
Developing A Monitoring Plan

Based on the risk associated with the particular injection plan, each project should consider what earthquake monitoring method is most effective and appropriate. The more sensitive an array is, the clearer view the operators will have of seismicity and its possible relation to ongoing operations. For instance, higher quality data will lead to a greater ability to determine reliable earthquake locations, magnitudes, focal mechanisms, seismicity rates, and states of stress.

As suggested by Majer et al. (2012), in instances where seismic instruments are installed and maintained, it is most beneficial to use instruments suitable for collecting data in the frequency range of a few hertz to a several hundred hertz. Three component data should be collected in order to provide complete information with regards to the failure mechanism, wave propagation attributes, and an increased ability to determine accurate locations (Majer et al., 2012).

Before all injection projects begin, operators and/or regulators should consider the necessary earthquake detection threshold for their chosen monitoring systems at the injection site to allow for a proactive approach to mitigating triggered seismicity and to ensure that regulations and guidelines are being met. Green et al. (2012) suggests that hydraulic fracturing operations should have a monitoring system in place that would be able to provide automatic locations and magnitudes for seismic events in near real time. According to Green et al. (2012), these systems ought to include the necessary numbers and types of stations (specifically, near-surface sensors and borehole sensors) to ensure reliable detections, locations, and magnitudes for events -1ML and above with an adequate level of redundancy. We stress that, in the case of triggered seismicity, redundancy in monitoring only strengthens the ability to detect, locate, determine magnitudes, and calculate focal mechanisms of any earthquakes occurring.

Though it may not be appropriate to assign a baseline magnitude threshold (such as -1ML in the Green et al. (2012) example) to all injection operations, a similar magnitude threshold should be determined or identified for all projects to ensure a complete understanding of the sensitivity and redundancy of the proposed seismic network. It may be necessary to increase monitoring if it is clear there is not an adequate level of sensitivity or redundancy. For projects with low levels of risk, it may be more appropriate to establish magnitudes near 0ML as the goal detection threshold, whereas for projects that have been determined to have higher levels of risk, magnitude detection thresholds between -1ML and -2ML may be more appropriate.

In the case of the British Colombia Oil and Gas Commission, they suggest that the detection threshold for operations and reporting be at magnitude 2ML for the Horn River Basin (BCOGC,
2012). Though this may be reasonable for remote locations with very little risk, in general, it is likely too high of a threshold in areas of higher risk. The BC O&G Commission also suggests installing seismometers near selected communities to quantify the risk from ground motion and that The Natural Resources Canada experts should be consulted to determine equipment selection, location, installation, and operations of these sensors (BCOGC, 2012).

Additionally, Warpinski et al. (2012) considered earthquake data from several of the main shale gas operations in the United States where hydraulic fracturing is implemented and observed that many microseismic events were found to be of magnitudes less than -2.5Mw, while average magnitudes were approximately -3Mw. At these sites, the largest monitored microseismic events were less than magnitude 1Mw (Warpinski et al., 2012). This perhaps suggests that at these sites, events under this magnitude threshold are not of concern. However, we argue that it is not only the magnitude of the events that is of concern for injection operations and that magnitudes lower than 1Mw should be considered in order to observe whether the earthquakes are migrating at depths or distances that are unexpected, or if the events are occurring along a planar feature that may suggest the presence of an active fault.

Developing A Reporting Plan

Before injection, establishing a site-specific reporting plan would allow operators to communicate with the necessary authority in the event of a concerning earthquake or set of earthquakes and at regular intervals to help regulators keep a record of seismic activity. The shorter the length of the reporting intervals, the more engaged the operators and regulators would be. In British Columbia, they suggest a notification and consultation procedure between the British Columbia Oil and Gas Commission and area operators provides a means for the Commission to respond to triggered seismicity (BCOGC, 2012). If seismicity is detected on the Canadian National Seismic Network or an operator deployed dense array, then the Commission would contact the operator to investigate the occurrences and determine what appropriate mitigation options are necessary or required (BCOGC, 2012). In some cases, the government may not have such a proactive role in responding to possible triggered seismic events and it may be the responsibility of the operator to respond appropriately; however, we encourage an increase in involvement of many local governments in assisting area operators in detecting, reporting, mitigating, and responding to triggered seismic events as needed.
VIII. SEISMIC HAZARD AND RISK ASSESSMENT

Risk analysis is a concept used in many technical domains to facilitate decision-making in the presence of uncertainty. Risk is generally characterized by two factors: the consequences of possible adverse outcomes and the probability of occurrence of each of those outcomes. In the case of earthquakes, assessing risk requires a seismic hazard study to quantify the probability of experiencing strong shaking (the adverse outcome), complemented by other studies to quantify consequences such as shaking. This section will discuss basic concepts associated with seismic hazard and risk for triggered seismicity and presents a risk-based framework that includes several scientific principles affecting risk assessments that could be adopted by operators and regulators. Also included is a discussion of how such calculations would benefit operators and regulators in making decisions about new projects and seismic monitoring. When discussing adverse outcomes here, the focus is on consequences associated directly with ground shaking. Earthquakes can produce damage via other mechanisms (e.g. soil liquefaction or ground surface rupture), but the risks associated with those mechanisms from triggered seismicity are small and can likely be neglected in most cases.

As the issue of triggered earthquakes becomes more apparent, it is clear that it would be advantageous for an initial seismic risk assessment to be carried out for proposed and pre-existing fluid injection sites (The Royal Society, 2012). Earthquake hazard and risk assessments are well established but have historically focused on natural earthquakes and rarely anthropogenic earthquake triggering. Our work builds largely from previously published work, but differs in that we present a comprehensive framework that considers the scientific factors necessary for a hazard and risk assessment workflow in a format that is site-adaptable and can be updated as hazard and risk evolve with time. This changing hazard and risk may be due to a new geological understanding, updates made to the operational factors, changes in the exposure, or changes to the tolerance for risk at the site.

Hazard and Risk Analysis Workflow

Our proposed hazard and risk assessment workflow for earthquakes triggered by hydraulic fracturing and saltwater disposal is meant to be site-specific and adaptable (Figure VIII-1). It includes an analysis of the earthquake hazard at a site using what is known of the geology, hydrology, earthquake history, and geomechanics of the area and when used with a Probabilistic Seismic Hazard Analysis (PSHA) (e.g. McGuire, 2004) is the basis for determining the probable level
of natural seismic hazard. This is used in conjunction with operational factors that influence the potential for the occurrence of triggered earthquakes, including specific injection practices, the operating experience in the area and of the company responsible, and the formation characteristics. Once probabilities of experiencing various levels of natural ground motion have been computed, they can be combined with the associated likely consequences to evaluate risk. Consequences depend upon the level of exposure of the site and surrounding area, and the contributing operational factors. As such, risk assessment and planning needs to occur jointly with planning of operations that might affect risk. Both the operational factors and exposure are described further below.

The proposed workflow is intended to be implemented prior to injection operations and then used iteratively as new information related to the hazard and risk becomes available. While this process may be difficult in practice, it is important to reflect upon examples of injection operations where a risk tolerance assessment could have prevented triggered events, such as the earthquakes triggered by injection in Basel, Switzerland (Deichmann and Giardini, 2009). In cases where the risk is non-negligible, mitigation can include additional monitoring and data collection (Nygaard et al., 2013).

**Operational Factors**

Along with the earthquake history and geologic, hydrologic, and geomechanical characteristics of a site, a number of operational factors for saltwater disposal (Figure VIII-2) and hydraulic fracturing (Figure VIII-3) also contribute to the potential for triggered seismicity. The current scientific understanding suggests the potential for triggered earthquakes is not equivalent for saltwater disposal and hydraulic fracturing. The disposal of saltwater generally includes the injection of large volumes of water over relatively long periods of time at a single injection point, though, as we discuss below, cumulative affects from multiple disposal wells can have a large impact on risk associated with triggered earthquakes. Injection zones for these projects are generally of sufficient porosity and permeability to store large volumes of fluids which has the potential to result in triggered earthquakes that occur relatively large distances from the injection site.

The risk associated with triggering earthquakes from hydraulic fracturing is unique from saltwater disposal because the injected fluids are of lower volumes, higher pressures, and occur in injection stages (as opposed to a point source). The goal of hydraulic fracturing is to fracture the
Figure VIII-1. Hazard and risk assessment workflow. In concept, the hazard, operational factors, exposure, and tolerance for risk are evaluated prior to injection operations. After injection begins, the occurrence of earthquakes in the region and additional site-characterization data could require iterations of the workflow. As shown below, there are different risk tolerance matrices for different levels of exposure.
intended formations in order to increase permeability and retrieve hydrocarbons. In cases where earthquakes are triggered by hydraulic fracturing, the events are generally very close to the points of injection and occur where faults intersect injection wells. Historically, events triggered by hydraulic fracturing have been less common than events triggered by saltwater disposal.

It is the responsibility of the operators and regulators to determine the level of impact the operational factors have on the risk level of a project. Operational factors are specific to triggered seismicity and not included in standard seismic hazard and risk calculations. Since these operational factors are not included in current PSHA procedures, here we account for them separately in the formation of a project’s risk tolerance matrix. Conceptually, we would like to quantify factors that influence the likelihood of earthquake occurrence in terms of the seismic source model of the hazard analysis calculation. But, because it is currently difficult to link these operational factors in a quantitative or causative manner to earthquake occurrence, we take an indirect approach and consider operational factors as a separate metric to be used when assessing risk.

First, there are particular formation characteristics that may affect the risk at a site in addition to choosing injection well locations sufficiently far from potentially active faults. Specifically, examining whether the injection interval is in communication with the basement or an underpressured (sub-hydrostatic) environment. If the injection formation is located directly above the basement without the presence of a sealing formation or if it appears as though a permeable path may be connecting the injection formation with the basement, the earthquake risk for the project may increase significantly.

Second, the specific injection operations also have the potential to affect the level of risk associated with a project and site. The injection rates and volumes at single wells may be correlated with earthquake activity at a site. An increasingly significant operational consideration for saltwater disposal wells is the rate of injection of a well, or group of wells in close proximity. Moreover, high rates of injection in neighboring wells can cause a cumulative effect in the form of an unusually large pressure 'halo' that could trigger slip on potentially active faults in an area. Modeling by Keranen et al. (2014) showed that the pressure generated by four very high rate injection wells is expected to be significant in the vicinity of the wells. The diffuse seismicity now occurring in Oklahoma appears to be the result of increased pressure in the Arbuckle saline aquifer and underlying basement rocks as a result of the cumulative injection from many injection wells over a number of years (Walsh and Zoback, 2015).
### Saltwater Disposal Operational Factors

<table>
<thead>
<tr>
<th>Formation Characteristics</th>
<th>Injection Operations</th>
<th>Operating Experience</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection horizon likely in communication with basement, underpressured injection interval</td>
<td>High cumulative injection volumes and rates</td>
<td>Limited injection experience in region, past earthquakes clearly or ambiguously correlated with operations</td>
</tr>
<tr>
<td>Injection horizon potentially in communication with basement, slightly underpressured injection interval</td>
<td>Moderate cumulative injection volumes and rates</td>
<td>Moderate injection experience in region with no surface felt ground shaking</td>
</tr>
<tr>
<td>Injection horizon not in communication with basement</td>
<td>Low cumulative injection volumes and rates</td>
<td>Extensive injection experience in region with no surface felt ground shaking</td>
</tr>
</tbody>
</table>

**Figure VIII – 2.** Factors related to saltwater disposal operations that contribute to the level of risk at an injection site.

### Hydraulic Fracturing Operational Factors

<table>
<thead>
<tr>
<th>Formation Characteristics</th>
<th>Injection Operations</th>
<th>Operating Experience</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection horizon likely in communication with basement, underpressured injection interval</td>
<td>High fluid injection volumes and pressures near active faults</td>
<td>Limited injection experience in region, past earthquakes clearly or ambiguously correlated with operations</td>
</tr>
<tr>
<td>Injection horizon potentially in communication with basement, slightly underpressured injection interval</td>
<td>Moderate fluid injection volumes and pressures near active faults</td>
<td>Moderate injection experience in region with no surface felt ground shaking</td>
</tr>
<tr>
<td>Injection horizon not in communication with basement</td>
<td>Low fluid injection volumes and pressures remote from active faults</td>
<td>Extensive injection experience in region with no surface felt ground shaking</td>
</tr>
</tbody>
</table>

**Figure VIII – 3.** Factors related to hydraulic fracturing operations that contribute to the level of risk at an injection site.
Exposure

In the context of triggered seismicity, the exposure associated with a particular site depends on the number, proximity, and condition of critical facilities, local structures and infrastructure, the size and density of the surrounding population, and protected sites that have the potential to experience ground shaking as a result of fluid injection. Specific items to identify include populations, hospitals, schools, power plants, dams, reservoirs, historical sites, hazardous materials storage and natural resources (e.g. protected species) influenced by ground shaking (AXPC, 2013). If an injection project is proposed near one or more of these items, the risk for the project increases commensurately. It is important to consider whether nearby structures and infrastructure are capable of withstanding ground motion that could be caused by a triggered seismic event, keeping in mind that standards of construction vary widely depending on the year of construction, applicable building codes and other factors. Structures and infrastructure may include buildings, roads, pipelines, and electrical distribution systems (AXPC, 2013). Figure VIII-4 offers a summary of details relating to exposure to consider when determining the level of impact these parameters have on the overall risk.

![Exposure Table](image)

*Figure VIII-4. Technical factors that contribute to the level of exposure at an injection site.*
The area of concern for factors related to exposure will be site-dependent. The AXPC (2013) suggests considering populations that are within a 10-mile radius of the injection site. However, earthquakes can potentially be triggered at some distance away from an injection site and ground shaking from a moderate earthquake can be felt over a wide region. Determining this area of concern could be done in a way that incorporates the site-specific conditions of the geology, hydrology, geomechanical characterization, earthquake history and exposure to risk as well as whether injection from neighboring operators may have a cumulative contribution to the risk in the area.

Risk Matrices

Once the seismic hazard, exposure, and operational factors are determined for a given project, operators and regulators can aggregate the results using a risk matrix method. Figure VIII-5 shows how the results from the hazard assessment via PSHA (vertical axis), the operational factors (horizontal axis) and the exposure (top, middle or bottom figure) can be aggregated to perform such an evaluation, as expanded upon from concepts proposed by Nygaard et al. (2013). Figure VIII-5A shows generalized risk tolerance matrices for areas of low exposure, medium exposure, or high exposure. In our proposed risk tolerance matrices, the green regions would be considered favorable given appropriate operational practices, amber regions would be considered acceptable but may require enhanced monitoring, restricted operational practices and real-time data analysis, and red regions would require significant mitigating actions.

An understanding of the risk that exists for a particular project will allow the affected parties to determine the level of tolerance they have for the estimated risk. The tolerance for potential ground shaking will be shaped by the political, economic, and emotional state of the populations involved, making it inherently site-specific. In high-risk cases or for those who have a low tolerance for the determined risk, certain locations may not allow injection to proceed. Alternatively, in other areas, the tolerance for risk may be sufficiently high to not interfere with the proposed injection project. Of course, how one determines the exact levels of exposure, operational factors, hazard, and subsequent risk, to inform the specific risk tolerance matrix used for a particular project is somewhat subjective and requires collaboration among the stakeholders.

We consider several examples of actual injection operations to illustrate the use of the risk tolerance matrix in Figure VIII-5B. In each case, we have only performed a rough analysis to provide context based on the current scientific literature. When this workflow is implemented a more thorough analysis should be performed, including the use of PSHA to determine the probable
Figure VIII-5. Risk tolerance matrices. (A) Generalized risk tolerance matrices associating the level of shaking intensity (from PSHA), the operational factors (Figures VIII-2 and VIII-3), exposure (Figure VIII-4), and the tolerance for risk of a particular injection project. (B) Examples of projects being plotted on the risk tolerance matrices in light of what we know after events have occurred. Squares represent hydraulic fracturing projects and circles represent saltwater disposal projects.
hazard for a given project. For PSHA results to be utilized in this matrix, the ground shaking intensity with a given exceedance rate will need to be determined. Unlike building code applications, where the focus is on strong but very rare ground motion intensities, for triggered seismicity the interest is likely to be in more frequent (i.e., higher-exceedance-rate) but smaller intensity ground motions. We estimate the probable hazard in light of what we know after each of these earthquakes occurred (Figure VIII-5B). It is important to note that each project will have its own risk tolerance that will be determined by the public and stakeholders directly impacted. In order to reflect these differences in risk tolerance, the colored portions of the risk tolerance matrices should shift either up or down (to become more lenient or strict, respectively).

In addition to the Horn River Basin, we consider the possible placement of other projects onto the risk tolerance matrices, including the Guy, Arkansas saltwater disposal site (Horton, 2012), the Dallas-Fort Worth saltwater disposal (Frohlich et al., 2011), the Youngstown, Ohio saltwater disposal site (Kim, 2013), and the Bowland Shale (Preese Hall) hydraulic fracturing site (Green et al., 2012; Clarke et al., 2014). The Guy, Arkansas saltwater disposal project was placed in the red portion of the low exposure risk tolerance matrix because of it being located in an area with a low population density and few structures and infrastructure, but the occurrence of a M4.7 earthquake with an extended lineation of earthquake epicenters in 2011 (Horton, 2012). The Dallas-Fort Worth saltwater disposal site experienced several earthquakes of M3.3 and below October 2008 and May 2009 (Frohlich et al., 2011). We considered the site to be of medium exposure because of the close proximity of the Dallas-Fort Worth airport resulting in the project being located in the amber portion of the medium exposure risk tolerance matrix. The Youngstown, Ohio saltwater disposal site was placed in the red portion of the high exposure risk tolerance matrix due to its proximity to the Youngstown, Ohio urban area and the occurrence of a M3.9 earthquake in December 2011 (Kim, 2013).

The Bowland Shale hydraulic fracturing project was placed in the green portion of the medium exposure risk tolerance matrix because the project used a fairly unaggressive injection strategy located in a moderately populated area that experienced a M2.3 earthquake in 2011 (Green et al., 2012; Clarke et al., 2014). However, it is clear the stakeholders involved in hydraulic fracturing operations in the United Kingdom have a very low tolerance for risk and might consider the medium exposure risk tolerance matrix to not be strict enough as shown here. Therefore, they may produce risk tolerance matrices for their sites that show the transitions between the green, amber, and red portions occurring at lower possible shaking intensities.
Rapidly Changing Risk and Traffic Light Systems

Traffic light systems are a risk management tool that can be used to address the possibility of seismic risk changing with time due to the occurrence of unexpected seismicity in an area of saltwater disposal or hydraulic fracturing. Traffic light systems have historically been used in enhanced geothermal settings and have been based on ground shaking or magnitude thresholds to signify whether the injection project should continue as planned (green), modify operations due to heightened risk (amber), or suspend operations due to severe risk (red) (Majer et al., 2012; NRC, 2012; DECC, 2013). These systems have the potential to provide an excellent means of communication between the operating companies, regulators, the media and the public. They allow private companies and responsible State and Federal Agencies to communicate 1) the possible significance of the unusual seismic activity, 2) the steps that should be taken to understand better the risk associated with the seismicity and 3) the conditions under which remedial action might be taken.

A commonly referred to example of a traffic light system was used during the 2003 hydraulic stimulations at a geothermal field in El Salvador, Central America (Bommer et al., 2006). In this case, the traffic light system was based on peak ground velocity (PGV) and the authors assigned the thresholds using ground motions levels (Figure VIII-6). In this case, the goals of the traffic light thresholds were based on whether the exposed population could perceive ground shaking (transitioning to amber) or whether damage might occur (transitioning to red).

An additional example of a traffic light system comes from the United Kingdom. This system was illustrated as a result of the Preese Hall events and includes the decision that future operations be halted and remedial action instituted if events of magnitude 0.5 $M_L$ or above are detected (Green et al., 2012; Clarke et al., 2014). Figure VIII-7 shows the traffic light system proposed by the United Kingdom’s Department of Energy and Climate Change (DECC, 2013). Compared to many other traffic light systems, the UK system is relatively sensitive and this is arguably the result of the low tolerance for risk of the stakeholders in that region. Alternatively, due to a difference in the level of risk and tolerance associated with injecting in parts of British Columbia, Canada and Alberta, Canada (Figure VIII-8, after Alberta Energy Regulator, 2015), the threshold used for transitioning an injection project into the red portion of the traffic light system is an earthquake of 4.0 $M_L$ or greater.
Figure VIII-6. Traffic light system made by Bommer et al. (2006) for use during the 2003 hydraulic stimulations at the El Salvador, Central America geothermal field. This traffic light uses peak ground velocity for the thresholds.

Figure VIII-7. Traffic light system instituted in the United Kingdom after the occurrence of triggered earthquakes near Preese Hall. In this case, the transitions between the levels of the traffic light are determined by magnitude thresholds. We encourage the addition of other earthquake observations as discussed in the text in the decision to move from one traffic light category to another. Figure modified from DECC (2013).
Figure VIII-8. Traffic light system instituted in Alberta, Canada for use during hydraulic fracturing. Figure made by Alberta Energy Regulator (2015).

The standards used by individual projects for s would be most effective if they were tailored to a site-specific and dependent on the risk assessment, rather than fixed for all circumstances. The systems could be developed with guidance from regulators and the local geologic surveys taking into account all aspects of hazard and risk (CAPP, 2012; Nygaard et al., 2013). Early in the development of the traffic light system it is important to use the outcome of the risk tolerance assessment to decide whether earthquake monitoring is necessary and, if so, how the seismic data will be observed and analyzed. It may be beneficial to consider not only earthquake magnitude thresholds and ground shaking but also particular geological observations in an attempt to be more proactive in mitigating triggered earthquake risks. In cases of high risk, this may include the continual performance of in-depth, real-time analysis of microseismic data that would aim to identify particular event characteristics that could foreshadow felt or damaging earthquakes, as discussed below.

Traffic light systems are dependent on the level of monitoring used at the site, which is determined by the outcome of the risk assessment. Earthquake monitoring is beneficial and appropriate at injection sites with sufficiently high risk. This monitoring could be done using data from regional or local arrays, or operational arrays specific to the injection site. How frequently data is requested and collected from the local arrays or acquired from operational arrays and then analyzed will be based on the seismic hazard and risk assessment. In cases of significantly high risk, it may be necessary to have a real time telemetry system in place that allows for the constant delivery of data to an automated event analysis system. An automated system that detects, locates, and estimates the magnitude of the earthquakes in the region would allow for an efficient means of
determining if any events have characteristics such as events highlighting faults and determining if the events have a larger spatial coverage and faster migration rate than expected. In the case of low risk, it may not be necessary to have a real-time automated system, but instead a system that allows the data to be requested or collected on an as needed or periodically.

The traffic light systems we present here for saltwater disposal (Figure VIII-9) and hydraulic fracturing (Figure VIII-10) encourage a site-specific, risk-informed, real-time risk management system that could be increasingly effective when updated as new data becomes available. The level of risk at a site informs the level of the seismic monitoring network used and any necessary operational adjustments. Our proposed system incorporates often subtle but potentially diagnostic geological and geophysical characteristics that may indicate a potentially larger event to come. This is done by focusing on specific observations that suggest the presence of a fault large enough to host a significant triggered earthquake. For the two project types, different observations may cause operators to transition between the green and amber zones of the traffic light; however, we suggest that the same observations may cause injection operations for both saltwater disposal and hydraulic fracturing to move into the red zone of the traffic light.

Of particular concern, and a key observation in mitigating risk, is whether there is the potential for triggered earthquakes to occur on relatively large, critically stressed, pre-existing basement faults. Over the life of an injection project, it is thought that pore pressure perturbations have the potential to migrate toward critically stressed, permeable faults in the crystalline basement. A relatively simple conceptual model involving the migration of pressure perturbations from injection horizons in Oklahoma to active basement faults has begun to evolve that shows how long-duration fluid injection has the potential to trigger slip on relatively large faults (Keranen et al., 2013; Zhang et al., 2013).

Figure 1-6 illustrates well-documented earthquake scaling relationships of relatively large triggered earthquakes based on their reported magnitudes (as summarized in Stein and Wysession, 2009). From these scaling relationships, we can see that a M4.7 earthquake, the largest magnitude event that occurred at Guy, Arkansas (Horton, 2012), suggests slip on a fault that is a kilometer in length. Fault patch sizes this significant are often larger than the thicknesses of the formations in which fluids are being injected, suggesting that fluids are migrating toward other formations (i.e. crystalline basement) capable of hosting such faults.

Faults large enough for potentially damaging triggered earthquakes may be identifiable using observations outlined in the proposed traffic light system. These observations include...
Saltwater Disposal Traffic Light System

**Observations:**
- Unacceptable ground motions and/or magnitudes
- Events define a fault capable of producing a potentially damaging earthquake, especially when located in the basement rock

**Actions:**
- Limit injection and consider well abandonment
- Continue earthquake monitoring and analysis
- Report observations and actions to area regulators and neighboring operators

**Observations:**
- Unexpected event(s) occurring

**Possible Actions:**
- Increase real-time earthquake monitoring and analysis
- Decrease injection rates and volumes

**Observations:**
- No seismic events detected

**Actions:**
- Operations and monitoring continue as planned

**Figure VIII-9.** Traffic light system applicable to saltwater disposal. The green, amber, and red panels represent the levels of heightened awareness frequently represented in traffic light systems. Within each panel we suggest what observations might be considered and possible actions to take.

Considering whether event locations highlight faults (either previously identified or not), whether those faults are preferentially oriented for shear failure in the current state of stress, whether the events have a larger spatial coverage and migrate faster than expected, or whether the events have higher magnitudes than expected.

As fluids are injected into the subsurface and microseismic events are monitored, there are two observations that may indicate the presence of active faults. First, events may migrate farther from the injection zone than expected, indicating that fluid is potentially migrating through a permeable, active fault. Second, small earthquakes may illuminate a planar feature suggesting the presence of a potentially active fault. Further analysis and a degree of caution would be appropriate, either through a continued examination of historical seismic data, microseismic data, or any available 3D seismic data. If an illuminated feature is preferentially oriented for failure then the seismic hazard may increase and the operational factors may need to be adjusted accordingly, with the option of well abandonment considered in severe cases.
Figure VIII-10. Traffic light system applicable to hydraulic fracturing. The green, amber, and red panels represent the levels of heightened awareness frequently represented in traffic light systems. Within each panel we suggest what observations might be considered and possible actions to take.

Ideally, all injection operations will begin in the green zone of the risk tolerance matrix and the traffic light system, where operations and monitoring would be carried out as planned based on the outcome of the initial risk assessment. For saltwater disposal, as long as no earthquakes are detected, the project remains in the green zone. For hydraulic fracturing, we would expect to observe very small magnitude earthquakes, but if an anomalous seismic event(s) was detected the project may transition to the amber zone. Anytime a project moves out of the green zone and into the amber or red zone, it would be beneficial to quickly evaluate to what extent operation practices might be adjusted or halted and what analysis might be performed (CAPP, 2012; AXPC, 2013; NRC, 2012). Operators and regulators may then work together to do a preliminary analysis of the event(s) and maintain open communication with each other and nearby operators (CAPP, 2012).

If a project begins in the amber zone of the risk tolerance matrix and traffic light system, or moves into it due to the occurrence of unexpected events, then caution should be exercised at all
times in the form of heightened awareness, enhanced monitoring and/or the real-time data analysis. We stress that the amber zone of the traffic light may not necessarily be interpreted as a disadvantageous phase nor should it be thought that a project would inevitably move to the red zone of the traffic light. Example actions are slightly different for saltwater disposal and hydraulic fracturing. In the case of saltwater disposal, it may be reasonable to decrease injection rates, volumes, and pressures, while for hydraulic fracturing, avoiding pre-existing faults during individual fracture stages and utilizing 3D seismic data to identify faults in the subsurface may be considered.

Observations that may cause a project to move into the red zone of the traffic light system for both saltwater disposal and hydraulic fracturing projects include the detection of unacceptable levels of ground shaking or magnitudes, events defining a fault capable of producing a potentially damaging earthquake, and events migrating into the basement rock. Actions that could be considered if any of the above observations occur include limiting injection and considering well abandonment, continuing earthquake monitoring for the duration of the examination or, in severe cases, sometime after the injection has ceased, and reporting observations and operational practices to area regulators and neighboring operators.

It is important to note that after a project moves to amber or red it may be possible to transition back to a lower risk level after a thorough evaluation of changes to the hazard and risk at the site. This may include engaging engineers and subsurface geological and geophysical experts to review available subsurface data and, if necessary, to design and conduct engineered trials to adjust operating procedures as appropriate with respect to injection volumes, rates, and locations (CAPP, 2012). It would be critical to re-evaluate the tolerance for risk at the site in light of the observations that caused the project to transition to the amber or red portion of the traffic light system.

If triggered events occur, all area operators and regulators have the opportunity to increase their understanding of the potential to trigger or induce events in the future and update their current understanding of the risk in their area (Bommer et al, 2015). Sharing information such as the time, location, magnitude, the focal mechanism (if the operator is able to calculate this information given their monitoring), and the injection history leading up to this event with regulators and other area operators may be necessary. Enhancing the seismic monitoring at a particular site, even if a project moves into the amber or red zone of the traffic light or if a project is abandoned, allows for a more detailed evaluation of any future events (SEGW, 2014; AXPC, 2013).
SUMMARY

To date, there are many different guidelines, regulations, and studies that have been published or put into practice. Many of these are ad hoc, prescriptive, and reactionary. We present here a framework for risk assessments for triggered seismicity associated with saltwater disposal and hydraulic fracturing and offer systematic recommendations for factors to be considered. This framework includes an assessment of the site characteristics, seismic hazard, operational factors, exposure, and tolerance for risk. The process is intended to be site-specific, adaptable, and updated as new information becomes available. We describe factors that are not currently included in standard earthquake hazard and risk assessment procedures, including considering the necessary anthropogenic factors that are inherent in fluid injection operations. We use risk tolerance matrices as a means for including all aspects that influence the tolerance for risk regulators, operators, stakeholders, and the public have for triggered earthquakes. The hazard and risk assessment workflow includes the use of a traffic light system that focuses on geologic and geophysical observations, rather than only earthquake magnitudes or ground motions, as the determining factors for whether a particular site needs to consider enhanced monitoring and decreased injection practices or possible injection well abandonment.

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APPENDICIES

A. Acronyms and Definitions

Acronyms

AASG  Association of American State Geologists  
AGS  Arkansas Geological Survey  
ANSS  Advanced National Seismic System  
AOGC  Arkansas Oil and Gas Commission  
AXPC  American Exploration and Production Council  
BC  British Columbia  
BCOGC  British Columbia Oil and Gas Commission  
CAPP  Canadian Association of Petroleum Producers  
CDC  California Department of Conservation  
CEUS  Central and Eastern United States  
CGS  Colorado Geological Survey  
COGCC  State of Colorado Oil and Gas Conservation Commission  
ComCat  ANSS Comprehensive Catalog  
DECC  Department of Energy and Climate Change  
EPA  Environmental Protection Agency  
GMPE  Ground Motion Prediction Equations  
IAC  Illinois Administrative Code  
IM  Intensity Measure  
IRIS  Incorporated Research Institutions for Seismology  
NEIC  National Earthquake Information Center  


NGMD  National Geologic Map Database
NMSZ  New Madrid Seismic Zone
NRC  National Research Council
NRCAN  National Resources Canada
OAC  Ohio Administrative Code
OCC  Oklahoma Corporation Commission
OGP  International Association for Oil and Gas Producers
OK  Oklahoma
PASSCAL  Program for Array Seismic Studies of the Continental Lithosphere
PDF  Probability Density Function
PGA  Peak Ground Acceleration
PGV  Peak Ground Velocity
PSHA  Probabilistic Seismic Hazard Analysis
RCT  Railroad Commission of Texas
SCITS  Stanford Center for Induced and Triggered Seismicity
SDWA  Safe Drinking Water Act
SEGW  Seismicity Expert Group Workshop
SSHAC  Senior Seismic Hazard Analysis Committee
SWD  Saltwater Disposal
TX  Texas
UIC  Underground Injection Control
USGS  United States Geological Survey
WSMP  World Stress Map Project

Definitions

\( f_M(m) \)  Probability distribution of earthquake magnitudes at the source
\( f_R|M(r|m) \)  Probability distribution of earthquake source-to-site distance
\( i \)  An earthquake source
\( M \)  Magnitude
\( M_i \)  Random magnitude for source i
\( M_L \)  Local Magnitude
\( m \)  Earthquake of given magnitude
\( m_{\text{max}} \)  Largest magnitude that can be observed from a source
\( MMI \)  Modified Mercalli Intensity
\( M_o \)  Seismic moment
\( M_W \)  Moment magnitude
\( n_{\text{sources}} \)  Number of seismic sources considered
\( R \)  Radius of the rupture path
\( r \)  Source-to-site distance
\( R_i \)  Random distance for source i
\( S_{\text{Hmax}} \)  Maximum horizontal stress
\( S_{\text{Hmin}} \)  Minimum horizontal stress
\( S_v \)  Vertical stress
\( x \)  A defined ground motion
\( \Delta \sigma \)  Stress drop
\( \lambda_m \)  Rate of earthquakes larger than magnitude \( m \)
B. Earthquake Scaling Relations

The relationships between earthquake scaling parameters have been well studied for the past several decades. In order to relate these parameters, we must employ a few assumptions, including the shape of the earthquake rupture patch, a reasonable range of stress drops, and that earthquakes exhibit self-similarity. We assumed a circular rupture patch and that the range of reasonable stress drops for earthquakes varies between 0.1MPa and 10 MPa. Last we assume the earthquakes exhibit self-similar behavior. This means the scaling, and therefor the physics, of large and small earthquakes are similar or that large earthquakes are essentially small earthquakes, just scaled by some factor. Aki (1967) was the first to propose earthquake self-similarity and it has been supported by more recent studies (Baltay et al., 2010; Allmann and Shearer, 2009). Abercrombie (1995) discusses the idea of earthquake self-similarity and specifies how some earthquake source parameters exhibit self-similar behavior (source dimension, stress drop, and seismic moment), while other parameters do not appear to exhibit self-similar behavior (apparent stress and seismic moment). Abercrombie (1995) speculates that this discrepancy in the theory of self-similarity may either be the result of an actual change in the energy radiated with seismic moment or the result of problems in estimating the seismic energy.

The relationships used to represent the scaling laws between different earthquake parameters are described below. In particular, we utilize relationships between earthquake slip, source dimension, seismic moment, and stress drop in an attempt to create a visual that acts as a useful guide when considering scaling relationships between different earthquake sizes (Figure 1-8). To construct this figure, we used two well-known equations in earthquake scaling studies. The first equation,

\[ M_w = \frac{2}{3} \log(M_0) - 6 \]

relates seismic moment, \( M_0 \), in Nm with moment magnitude, \( M_w \) (converted from Hanks, 1979). The second equation,

\[ M_0 = \frac{16}{7} \Delta \sigma R^3 \]
relates seismic moment with stress drop, $\Delta \sigma$, and the radius of the rupture path, $R$ (Singh, 1977). From these two equations and the assumptions described above, we are able to construct a visual representation of these earthquake scaling parameters for a range of earthquake sizes.

C. The Modified Mercalli Intensity Scale

The MMI scale was originally developed by Rossi and Forel (1885) and later modified by many scientists including Wood and Neumann (1931) and Richter (1958). We emphasize the use Modified Mercalli Intensity (MMI) Scale over earthquake magnitudes when determining whether a triggered event may be troublesome to an injection project because it emphasizes the felt effects of ground shaking as opposed to the energy released by the event (Figure C-1). For instance, in cases where the injection site is moderately close to a population center or critical facility, the level of ground shaking felt at those locations is the important factor, not the magnitude of the. It is equally useful to consider the intensity of ground shaking at the injection site if a project is using human observations as its only method of event detection. The use of the MMI scale does not remove the need for event magnitude determination, however. It is the event magnitude that can provide insight into the quantitative characteristics of an earthquake, including the energy released, the size of the slip patch, and the amount of slip that would have occurred.
D. Primer on Probabilistic Seismic Hazard

Seismic Hazard is defined as the rate of exceeding a certain intensity of ground shaking at a site. The concept is used extensively in the field of earthquake engineering to identify sufficiently rare ground motions to consider when designing buildings (Kramer, 1996; Baker, 2013). Probabilistic seismic hazard analysis (PSHA) is the most commonly used method to estimate seismic hazard. A variety of geological and geophysical data are considered in modern PSHA for natural seismicity, including the locations of known faults, the earthquake history on those faults, and site response (the effect of local geology).

PSHA incorporates uncertainties in location, size, and shaking intensity of future earthquakes to estimate the distribution of future shaking that may occur at a site. Figure D-1
illustrates the five basic steps of PSHA. Using PSHA, the rate of exceeding a certain ground motion level, \( x \) can be calculated as

\[
\lambda(IM > x) = \sum_{i=1}^{n_{\text{sources}}} \lambda(M_i > m_{\text{min}}) \int_{m_{\text{min}}}^{m_{\text{max}}} \int P(IM > x | m, r) f_{M_i}(m) f_{R|M_i}(r | m) dr dm
\]

(1)

where \( n_{\text{sources}} \) is the number of seismic sources considered, and \( M_i \) and \( R_i \) denote the random magnitudes and distances for source \( i \). An \( IM \), or Intensity Measure, is a metric to quantify the intensity of ground shaking. Peak ground acceleration (PGA) and Modified Mercalli Intensity (MMI) are two examples of IMs. \( P(IM > x | m, r) \) defines the probability of exceeding an IM value of \( x \) given an earthquake of magnitude \( m \) and source-to-site distance \( r \); in general, this probability depends upon additional factors such as style of faulting and site conditions, but the notation is simplified here for illustrative purposes. This probability is typically obtained through Ground Motion Prediction Equations (GMPE). \( f_m(m) \) denotes the probability distribution of earthquake magnitudes at a source. \( f_{R|M_i}(r | m) \) denotes the probability distribution of earthquake source-to-site distance, conditional upon the earthquake magnitude.

In aggregate, equation (1) accounts for uncertainties in earthquake occurrence and resulting ground motion to estimate the rates of exceeding various ground shaking levels at a site. PSHA does not estimate the maximum level of ground shaking that could be experienced at a site, but rather the rate of occurrence associated with a certain level of ground shaking. It should be noted that seismic hazard is defined as the rate of exceeding a certain ground motion level and not of exceeding a certain magnitude earthquake. Earthquake magnitude is an indicator of the seismic energy released at the source during an earthquake while the ground motion is the actual shaking felt at a site – the feature responsible for any damage that may occur.

The U.S. Geological Survey uses this methodology to compute seismic hazard for the United States (Petersen et al., 2014). Figure D-2 shows a map of hazard results produced using PSHA. Note that when computing Figure D-2, regions of potentially triggered earthquakes have been ignored. The authors of that study note, “Users of the current hazard information should consider that hazard might be higher in these zones of potentially triggered seismicity than are presently shown on the map.” The U.S. Geological Survey and others (e.g., Green et al., 2012), acknowledge the value of PSHA in the triggered seismicity context, though note the importance of developing accurate models for earthquake occurrence and ground motion. These issues are discussed further in the following sections.
Models of seismic sources are needed to quantify the $f_R(r)$ and $f_M(m)$ terms in equation (1)—loosely speaking, “where might earthquakes occur, and how big might they be?” In the case of natural seismicity in Central and Eastern U.S. (CEUS), earthquake occurrence rates mostly come from historical evidence (i.e., observed locations and sizes of past earthquakes). Because there are often not geologically well-defined seismic sources in stable continental regions like the CEUS (unlike plate boundary regions), seismic sources are often specified as areal regions from which earthquakes occur at random locations. If other information is available (such as geological indications of a critically stressed fault, or microseismicity on a well-defined structure), then a more precise model for a seismic source can easily be used within the same calculation. For a given earthquake source (whether an areal region or a specified fault plane), it is generally assumed that earthquakes will occur with equal probability at any location on the fault. Given this assumption, it is straightforward to identify $f_R(r)$, the distribution of source-to-site distances from the geometry of the source.

The size of earthquakes from a seismic source are described by a recurrence model. Gutenberg and Richter (1944) noted that the frequency of earthquake magnitudes in a region can often be quantified by the following equation

$$\log \lambda_m = a - bm \quad m < m_{\text{max}}$$

(2)

where $\lambda_m$ is the rate of earthquakes larger than magnitude $m$, $a$ and $b$ are constants, and $m_{\text{max}}$ is the largest magnitude that can be observed from the source. When the truncation at $m_{\text{max}}$ is used, this is termed a Truncated Gutenberg-Richter recurrence model, as the truncation was not part of the original model. A typical value of $b$ is approximately 1, indicating that each unit increase in magnitude is associated with an approximately 10-fold reduction in rate of exceedance. The value of the constant $a$ specifies the overall activity rate. This recurrence model can then be converted to a probability distribution for magnitudes for use in equation 1.
Figure D-1. Schematic illustration of the five basic steps in probabilistic seismic hazard analysis. (a) Identify earthquakes sources. (b) Characterize the distribution of earthquake magnitudes from each source. (c) Characterize the distribution of source-to-site distances from each source. (d) Predict the resulting distribution of ground motion intensity. (e) Combine information from parts a-d to compute the annual rate of exceeding a given ground motion intensity (Baker, 2013).
Figure D-2. Peak ground acceleration with a 2-percent probability of exceedance in 50 years (i.e., rate of exceedance of $\lambda = 0.0004$). Figure from Petersen et al. (2014).

For the case of triggered seismicity, the Truncated Gutenberg-Richter model appears to still be valid. The estimation of the model parameters requires careful thought, however. For induced seismicity from hydraulic fracturing, $b$ values can be much larger than 1, indicating that large earthquakes will be very rare (as discussed in NRC, 2012). Maximum magnitudes are a matter of some ongoing debate. For triggered earthquakes the maximum magnitude may be physically related to the total injected volume, via an energy balance relationship (McGarr, 2014). For triggered earthquakes, the maximum magnitude would simply be the maximum magnitude of a naturally occurring earthquake from the given source. Estimation of $a$ values is also challenging.
For natural seismicity in stable continental regions, $a$ values are typically estimated from observed historical rates of earthquakes in the region. For triggered seismicity this is unsatisfactory, as the rate may be changing in time with operational factors, and there is often a short period of time from which to estimate a new rate of triggered earthquakes. Several statistical methods have been proposed, however, to deal with these parameter estimation challenges (e.g., Convertito et al., 2012; Mena et al., 2013; Gupta and Baker, 2014).

**Ground Motion Intensity**

The intensity of ground shaking predicted at a site for a given earthquake is characterized by a ground motion prediction equation. These equations predict the probability distribution of ground motion intensity, as a function of many predictor variables such as the earthquake's magnitude, distance, faulting mechanism, sedimentary basins and near-surface site conditions. Figure D-3 shows observed ground motion intensities from the 1999 Chi-Chi, Taiwan earthquake, with results from a ground motion prediction equation superimposed, illustrating the model's decrease in predicted intensity at larger distances, and also showing the significant variability in predictions due to complexities in the earthquake rupture and seismic wave propagation process that are not captured by relatively simple predictive models.

The models are also developed for specific seismological conditions (e.g., there are separate predictive models for earthquakes in stable continental regions versus active shallow crustal regions). Ground motion prediction equations can be developed using a number of empirical and theoretical approaches (Douglas and Aochi, 2008). In the Central and Eastern U.S., models are often based on theoretical seismological predictions, further calibrated using observed ground motion data from the region.

An important question is whether intensity predictions from natural earthquakes can accurately predict ground motions from triggered earthquakes. The relatively shallow depth of triggered earthquakes and potentially smaller stress drops (Hough, 2014), have been postulated as reasons why these earthquakes may produce different ground motion intensities. A number of ground motion prediction equations for geothermal triggered earthquakes have been produced, due to the extensive monitoring and resulting extensive data sets associated with enhanced geothermal projects (e.g., Douglas et al., 2013; Sharma et al., 2013; Edwards and Douglas, 2013). It is unclear whether these models are accurate with regard to earthquakes from hydraulic fracturing.
Figure D-3. Observed one-second spectral acceleration values from the 1999 Chi-Chi, Taiwan earthquake. Spectral acceleration is one common measure of ground motion intensity. The spectral accelerations intensities decay with distance as the ground motions attenuate. Also shown in the figure are ground motion intensity predictions from the model of Campbell and Bozorgnia (2008).

and saltwater disposal, and it is challenging to build appropriate data sets from such events to calibrate the needed ground motion prediction equations.

**Epistemic Uncertainty**

The above models are all dependent upon interpretations of known conditions, and there are typically multiple credible interpretations. Uncertainty associated with lack of knowledge is often termed epistemic uncertainty, in contrast to the aleatory uncertainty considered above (which is associated with random variation in repeated observations of a phenomenon, such as the magnitude of an earthquake from a given source). We incorporate this uncertainty via logic trees, each branch of which has a set of input models and a corresponding ground motion hazard curve. The branches all have weights to represent the degree of belief that the given branch is the best model for the real world. For example, one branch of a logic tree could represent a seismic source as having a rate of earthquakes consistent with its long-term historical average. Another branch could represent the source as having an increased rate of earthquakes. The weighted branches, and their corresponding hazard curves, collectively represent our knowledge of seismic hazard at a given site, and the results can be aggregated to compute metrics such as a mean hazard curve (the
mean rate of exceeding a given ground motion intensity, where the mean is taken across the predictions from the logic tree branches). Consideration of epistemic uncertainties via logic trees is standard practice in seismic hazard analysis for natural seismicity (e.g., SSHAC, 1997; Hanks et al., 2009), and its extension to cases of triggered seismicity is conceptually straightforward; the challenge is with specifying and weighting the models that make up the logic tree.

**Model Updating**

Data from monitoring and operational factors can be used to update the above calculations and consider whether hazard is changing. If potentially triggered earthquakes occur after injection operations commence, the initial hazard assessment can be updated with the new information, which could suggest previously unidentified features that have been illuminated and should be considered in the analysis. Statistical methods can be used to assess whether observed events are consistent with observed long-term earthquake activity or whether they indicate an increase in seismic activity potentially associated with operations (Llenos and Michael, 2013; Gupta and Baker, 2014). Updating of seismic hazard calculations would preferably be done by updating the weights on the logic tree branches discussed in the previous section, reflecting that new knowledge has revised the relative likelihoods of the previously identified models being representative of reality. Sometimes, however, the new knowledge indicates that a likely representation of reality was not included in the initial logic tree, in which case a new seismic hazard calculation is needed that incorporates the new model.