

Appendix 4.A

Earthquake Measurements

4.A.1. Earthquake Recording and Analysis

Seismic waves radiated by earthquakes are recorded by networks of seismometers placed on the earth's surface or deployed in boreholes. Seismic recordings are used to analyze earthquake source parameters, including location in space and time, magnitude, source type, and the direction and amount of fault slip, as well as to understand the properties of the rock layers along the propagation path between the earthquake and seismometer. Record fidelity is commonly referred to as “signal-to-noise,” the ratio of signal amplitude to background noise. Placing seismometers in boreholes greatly enhances signal-to-noise, often enabling recording of very small earthquakes (magnitude less than zero).

Earthquake detectability, the minimum magnitude that can be detected at a given location, depends upon several factors, including the spacing of seismic recording stations within the region and background noise conditions. Detectability is usually stated in terms of a threshold magnitude, M_c , above which a particular earthquake catalog is considered complete. Figure 4.A-1 shows a map of M_c for the U.S. Geological Survey (USGS) Advanced National Seismic System (ANSS) network deployed in California, estimated using the maximum curvature method of Wiemer and Wyss (2000). This method tends to underestimate M_c , typically by 0.2–0.3 magnitude units (Woessner and Wiemer, 2005; Werner et al., 2011). Figure 4.A-1 shows that, even allowing for this bias, the present completeness threshold is M1 or less in large areas of California, and less than M2 over most of the state. This is significantly better than in most other regions of the U.S., where the completeness threshold provided by the ANSS backbone array and regional networks is generally about M2.5 or greater (see the Figure on p.131 of NRC, 2013). Temporary arrays of seismometers are often installed at sites of particular interest to increase detectability and improve signal-to-noise, in order to enable detailed analyses of the spatial and temporal distributions and mechanisms of microearthquakes (e.g., Frohlich et al., 2011).

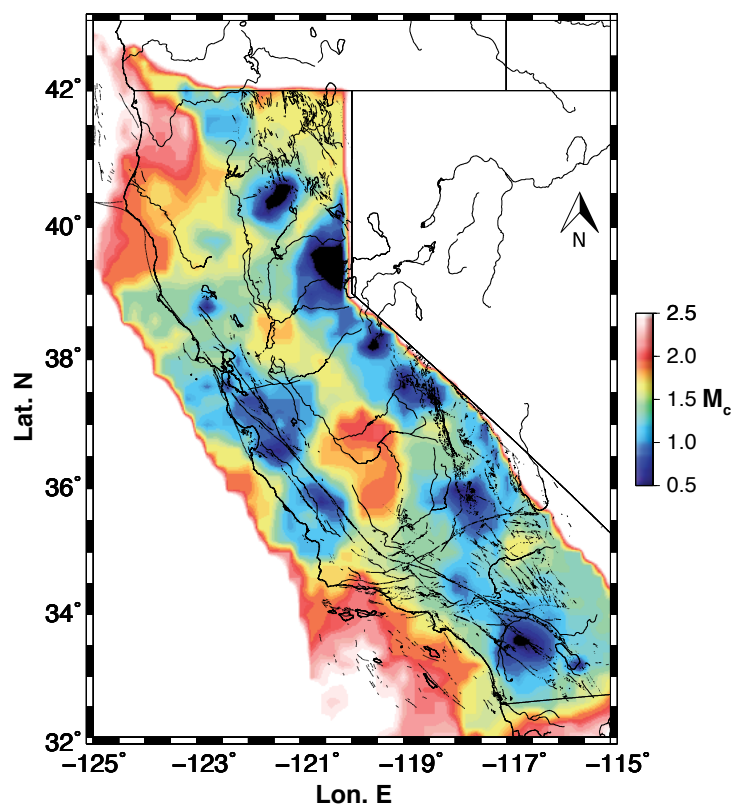


Figure 4.A-1. Earthquake detectability in California. The map shows the minimum magnitude of complete detection, M_c , for the USGS ANSS network currently deployed in California calculated using the maximum curvature method of Wiemer and Wyss (2000). Values have not been adjusted to account for the tendency of the method to underestimate M_c (see text).

4.A.2. Earthquake Magnitude

The size of an earthquake is most commonly expressed as a magnitude, which is a measure of the amount of energy released by slip on the fault. In general terms, the magnitude depends on the size of the area on the fault that undergoes slip. Several magnitude scales are in common use (see http://eqseis.geosc.psu.edu/~cammon/HTML/Classes/IntroQuakes/Notes/earthquake_size.html), most of which (e.g. local magnitudes, M_L , and body-wave magnitudes, m_b) are defined based on trace amplitude or signal duration measured on recorded seismograms. However, the moment magnitude (M_w) scale is preferred by most seismologists, because M_w is calculated from seismic moment (Hanks and Kanamori, 1979), a more fundamental measure of earthquake size (and energy) that is directly proportional to the product of slip and slipped area. The other magnitude scales are generally useful only for a limited range of magnitudes, where they roughly correspond to M_w . To give an idea of how magnitude relates to slip area, M_w 4.5 and M_w 3.5 earthquakes rupture fault areas of about 2.5 and 0.2 km² (618 acres and 49 acres), respectively.

Appendix 4.B

State of Stress in the Earth's Crust

To assess when a fault will slip according to the Coulomb criterion, it is necessary to know the local state of effective stress. The *in situ* effective stress state is fully described by pore pressure and three orthogonally directed principal stresses, which are related to the resolved normal and shear stresses on a fault by the fault orientation (Jaeger et al., 2007, Chap. 14). Within the Earth, the load of the overburden at a given depth usually leads to a compressional state, with one principal stress oriented vertically (σ_v) and having a magnitude equal to the weight per unit area of the overlying rock. This simplifies the problem of determining the complete stress state to estimation of the minimum (σ_h) and maximum (σ_H) horizontal stresses and the azimuth of one of them. However, determining the *in situ* stress state is still a challenging problem, because often only approximate stress directions and the type of stress regime—normal, strike-slip or thrust faulting—are known (e.g., Heidbach et al., 2008). Stress parameters are inferred from available, often sparse measurements in a region, such as earthquake focal mechanisms, wellbore breakouts and drilling-induced fractures (Zoback and Zoback, 1980; Heidbach et al., 2008). In principle, the relative magnitudes of the principal stresses and the stress azimuths enable identification of the faults that are most favorably oriented for slip and calculation of the normal and shear stress acting on them (Jaeger et al., 2007). However, the scarcity of stress measurements usually permits estimation of resolved stresses acting on faults only with significant uncertainty (e.g. NRC, 2013).

In contrast, Townend and Zoback (2000) proposed that, in general, the ambient pore fluid pressure is near-hydrostatic throughout the brittle, upper crust of the Earth in the interiors of tectonic plates. In this case, pre-injection pore pressures can be estimated relatively reliably just from the thickness of the overburden. Townend and Zoback (2000) used deep crustal permeability data over nine orders of magnitude acquired from six different regions to suggest that faults within the brittle crust are constantly in a state of critical stress; i.e., an incremental increase in shear stress or increase in pore pressure can lead to rupture. However, the difficulty in accurately estimating the shear and normal stress components often prevents determination of how near the state of stress of a particular fault is to failure. Exceptions to commonly assumed hydrostatic pressures occur in some deep basins, such as the Raton Basin in Colorado, where Nelson et al. (2013) showed (using drillstem tests) that deep formations are underpressured. If the crust within these basins is also critically stressed, then an increment in pore pressure less than that required to reach hydrostatic could bring favorably oriented faults to failure.

Appendix 4.C

Fluid Injection-Induced Seismicity Case Histories

4.C.1. Criteria for Classifying an Earthquake as Induced

The following criteria proposed by Davis and Frohlich (1993) have been commonly used to determine whether an earthquake sequence was induced by fluid injection or occurred naturally:

- Are these events the first known earthquakes of this character in the region?
- Is there a clear correlation between injection and seismicity?
- Are epicenters near wells—within 5 km (3.1 mi)?
- Do some earthquakes occur at or near injection depths?
- If not, are there known geologic structures that may channel flow to sites of earthquakes?
- Are changes in fluid pressure at well bottoms sufficient to encourage seismicity?
- Are changes in fluid pressure at hypocentral locations sufficient to encourage seismicity?

Although not all of these criteria need to be satisfied at once, they provide a basic foundation for establishing whether or not a given earthquake sequence has been induced, and have been employed in several cases to establish a clear link between seismicity and injection operations. However, in other cases, they have proven inadequate to establish conclusively that sequences were induced. It is often very difficult to prove causality for the following reasons: (1) In some cases—including some of those for which the evidence from in-depth scientific study is generally regarded as being conclusive—there is no clear temporal and/or spatial correlation between injection and the occurrence of specific earthquakes, the largest events having occurred several years after fluid injection began (e.g., Prague, Oklahoma) or ended (e.g., Ashtabula, Ohio), or up to ~10 km (6.2 mi) from the injection well (e.g., Rocky Mountain Arsenal and Paradox Valley in Colorado); (2) Regional seismic network coverage is often too sparse to locate the earthquakes with sufficient accuracy—particularly in depth—to investigate in detail their relationship to the injection well; (3) Even if detailed scientific studies are carried out, they are often

hampered by lack of densely sampled volume and pressure data and adequate site characterization; subsurface pressure measurements in particular are rarely available; (4) While it is relatively straightforward to apply the first criterion to initially identify suspected cases in regions of low naturally occurring seismicity, such as the central and eastern U.S., discrimination is much more difficult in active tectonic regions like California, where the rate of naturally occurring seismicity is much higher.

Table 4.C-1 summarizes observations of reported $M > 1.5$ events that are known or suspected to have been caused by well stimulation and wastewater injection operations. Only the largest event of each earthquake sequence is shown. For completeness, the table includes observations, marked by an asterisk, of wastewater injection-induced seismicity not related to oil and gas well stimulation activities, but these are not discussed further below.

4.C.2. Induced Seismicity Attributed to Hydraulic Fracturing Operations

Table 4.C-1 lists six published cases of known or suspected hydraulic fracturing-induced seismicity in which the magnitude of the largest event was greater than $M_{1.5}$. These cases are briefly discussed below in chronological order.

Love County, Oklahoma, 1977-1979: Nicholson and Wesson (1990) discussed two series of earthquakes in Oklahoma that occurred in June 1978 and May 1979. The largest event was $M_{1.9}$, and two of the events were felt. In each case, nearby hydraulic-fracturing operations correlated with the seismic events, but a lack of local seismic recording resulted in large location uncertainties and precluded a definite determination that the events were induced.

Blackpool, United Kingdom, 2011: Two felt seismic events of magnitude $M_{2.3}$ and $M_{1.5}$ occurred on April 1 and May 27, 2011 near Blackpool, England (de Pater and Baisch, 2011). Each of these earthquakes occurred approximately 1 day after a period of maximum-rate hydraulic fracturing in the nearby Preese Hall 1 well (Clarke et al., 2014). A 3-D seismic reflection survey conducted around the well to investigate the earthquake source mechanism defined the geometry of a preexisting fault favorably oriented for slip at 2 km (6,560 ft) depth, about 300 m (984 ft) below the well perforations (Clarke et al., 2014). Slip on this fault is believed to have resulted from hydraulic connection beyond the anticipated zone of fluid injection. The $M_{2.3}$ event on April 1 was preceded by several smaller events that were not initially detected automatically by the regional seismic monitoring system (all $>M_{0.2}$ events were subsequently detected through waveform cross-correlation analysis). The first event occurred 40 minutes after fluid injection started. On the day of this event, the injection volume increased more than 100% from $\sim 1,900 \text{ m}^3$ ($\sim 500,000$ gal) to $\sim 4,500 \text{ m}^3$ (~ 1.189 million gal) and the bottom hole pressure was 48 MPa ($\sim 7,000$ psi).

Garvin County, Oklahoma, 2011: In January 2011, a sequence of earthquakes (maximum M_L 2.9) occurred in close proximity to a hydraulic fracturing operation in Picket Unit B Well 4-18 in the Eola Field, Garvin County, Oklahoma. Several of the earthquakes were reported felt by a local resident. Initial reporting was unable to establish a conclusive link between the events and the well stimulation (Holland, 2011). Only after the operator released detailed pumping data, including injection rate and pressure records, were the times of the events shown to be closely correlated with fluid injection (Holland, 2013). The first earthquake occurred approximately 24 hours after injection started, when the wellhead pressure was ramped up from 21 MPa (~3,000 psi) to 35 MPa (~5,000 psi) and the fluid injection rate reached 900 m³/hr (237,755 gal/hr)—equivalent to a daily injection volume of 21,600 m³ (5.7 million gal). Eighty-six earthquakes located approximately 2 km (6,560 ft) away from the well and at the depth of injection (~2.5 km; 8,200 ft) occurred during the following week.

Table 4.C-1. Reported seismicity $M > 1.5$ associated with hydraulic fracturing and water injection.

| Site/Location | Country | Date | Magnitude | Proximate Activity | References |
|----------------------------|---------|-------------|-----------|-----------------------|--|
| Rocky Mountain Arsenal, CO | USA | 09 Aug 1967 | 4.8 M_w | Wastewater injection* | Healy et al., 1968; Herrmann et al., 1981 |
| Matsushiro | Japan | 25 Jan 1970 | 2.8 | Wastewater injection* | Ohtake, 1974 |
| Rangely, CO | USA | 1962 – 1975 | 3.1 M_L | Water injection* | Nicholson and Wesson, 1990 |
| Love County, OK | USA | 1977 – 1979 | 1.9 | Hydraulic Fracturing | Nicholson and Wesson, 1990 |
| Perry, OH | USA | 1983 – 1987 | 2.7 | Wastewater injection* | Nicholson and Wesson, 1990 |
| El Dorado, AR | USA | 09 Dec 1989 | 3.0 | Wastewater injection* | Cox, 1991 |
| Ashtabula, OH | USA | 26 Jan 2001 | 4.3 m_b | Wastewater injection* | Seeber et al., 2004 |
| Dallas/Fort Worth, TX | USA | 16 May 2009 | 3.3 m_b | Wastewater injection | Frohlich et al., 2011 |
| Cleburne, TX | USA | 09 Jun 2009 | 2.8 m_b | Wastewater injection | Justinic et al., 2013 |
| Garvin County, OK | USA | 18 Jan 2011 | 2.9 M_L | Hydraulic fracturing | Holland, 2013 |
| Guy-Greenbrier, AR | USA | 27 Feb 2011 | 4.7 | Wastewater injection | Horton, 2012 |
| Blackpool | UK | 01 Apr 2011 | 2.3 M_L | Hydraulic fracturing | Clarke et al., 2014; de Pater and Baisch, 2011 |
| Prague, OK | USA | 05 Nov 2011 | 5.7 M_w | Wastewater injection | Keranen et al., 2013 |

| Site/Location | Country | Date | Magnitude | Proximate Activity | References |
|----------------------|---------|-------------|-----------|-----------------------|---------------------------------|
| Youngstown, OH | USA | 31 Dec 2011 | 3.9 M_w | Wastewater injection | Kim, 2013 |
| Horn River Basin, BC | CAN | 19 May 2011 | 3.8 M_L | Hydraulic fracturing | BC Oil and Gas Commission, 2012 |
| Raton Basin, CO | USA | 23 Aug 2011 | 5.3 M_w | Wastewater injection | Rubinstein et al., 2014 |
| Timpson, TX | USA | 17 May 2012 | 4.8 M_w | Wastewater injection | Frohlich et al., 2014 |
| Paradox Valley, CO | USA | 24 Jan 2013 | 4.0 M_w | Wastewater injection* | Block et al., 2014 |
| Harrison County, OH | USA | 5 Oct 2013 | 2.2 M_w | Hydraulic fracturing | Friberg et al., 2014 |
| Poland, OH | USA | 3 Oct 2014 | 3.0 M_L | Hydraulic fracturing | Skoumal et al., 2015 |

* Fluid injection not related to oil and gas well stimulation activity

Horn River Basin, British Columbia, 2009-2011: To date, the largest magnitude earthquakes attributed to hydraulic fracturing occurred between April 2009 and December 2011 as a result of hydraulic fracturing operations conducted in several (at least six) wells in the Horn River Basin in British Columbia (BC Oil and Gas Commission, 2012). The largest event was M_L 3.8. Twenty earthquakes in the series were larger than M_L 3.0, and 69 larger than M_L 1.5. Nearly all events occurred in the depth range 2.80–2.87 km (9,186–9,416 ft), within 200 m (656 ft) of the perforation interval. There are numerous north-south trending subparallel faults in the region, which the induced seismic event locations effectively imaged as linear swarms crosscutting the hydraulic fracture target zone. Average total fluid volume injected per well was 61,612 m³ (16.276 million gal), with an average daily injection rate of 18,720 m³ (4.945 million gal). Although this volume was injected over (on average) 27 stages per well, according to the BC Oil and Gas Commission (2012) report, 18 events occurred no more than 24 hours after a fluid injection rate of 5,000 m³/hr (1.321 million gal/hr) was sustained for a period of one to two hours.

Harrison County, Ohio, 2013: A series of 10 earthquakes greater than M_w 0, including 6 in the range M_w 1.7–2.2, was recorded in Harrison County by the Ohio regional seismic network between October 2 and 19, 2013. The first of these events occurred 26 hours after the initiation of hydraulic fracturing operations in one of three nearby wells (Friberg et al., 2014). No felt seismicity was reported. Rates of injection were between 160 – 635 m³/hr (42,000 – 168,000 gal/hr) during hydraulic fracturing treatments. Waveform cross-correlation exposed over 150 additional microearthquakes. The entire event sequence occurred at a depth of 3.0–3.6 km (9,842–11,811 ft) below the surface, and delineated an

approximately 500 m long basement fault. The seismicity was located approximately 0.5–1.0 km (1,640–3,280 ft) below the bottom of the perforation interval (2.4 km; 7,874 ft) and outside of the target formation, which was expected to confine all stimulated fractures.

Poland, Ohio, 2014: Skoumal et al. (2015) located 77 M_L 1-3 earthquakes that occurred close to a hydraulic fracturing operation in Poland Township, Mahoning County, Ohio between 4 and 12 March 2014. The events coincided in time with six hydraulic fracture stages located between 750 and 800 m (2,461 and 2,625 ft) away from the zone of seismicity. No previous seismicity had been detected in the area before hydraulic fracturing began, and none occurred during almost 100 more distant fracture stages. The seismicity rate decayed rapidly after the well was shut down on March 10, with only 6 events during the following 12 hours and then only one over the next two months. Relative hypocenter locations sharply define a 500 m (1,640 ft) long vertical plane that was assumed to be a pre-existing fault. The focal mechanism solution for the M_L 3 event is consistent with the fault strike and dip and with the regional tectonic stress orientation.

4.C.3. Induced Seismicity Attributed to Wastewater Disposal

There are many cases in which disposal of wastewater related to hydraulic fracturing via Class II wells is the most likely explanation of seismicity. These include seismic events in Dallas-Fort Worth, TX; Guy, AR; Youngstown, OH; Prague, OH; and Raton Basin, CO. In other cases (Cleburne, TX; Timpson, TX), wastewater injection represents one possible explanation, but it has not been possible to rule out that the earthquakes may have been of natural origin.

Dallas-Fort Worth, Texas: Typical of the low rates of natural seismicity in Texas and most other states east of the Rocky Mountains, there are no records of local felt earthquakes in the Dallas-Fort Worth area between 1850 and 2008. In October 2008, seven weeks after wastewater injection began in a disposal well in the area, m_b 2.5–3.3 earthquakes began to be felt. In response, Frohlich et al. (2011) deployed a local seismic recording array, which enabled the eleven earthquakes it recorded to be located with an uncertainty of ± 200 m (0.125 mi), compared with ± 10 km (6 mi) using only regional network data. All of these events were located about 200 m (656 ft) north of the disposal well, and within 1 km (0.6 mi) of a northeast-striking normal fault favorably oriented for slip in the regional stress field. The average daily brine-injection volume was 950–1,310 m^3 (252,000–346,500 gal) during the period covered by the temporary array, which is typical for disposal wells in this and neighboring counties. The injection depth, 3100–4100 m (10,100–14,400 ft), was about 1,000 m (3,300 ft) above the average depth of the seismicity. Felt seismicity continues to occur in the area more than two years after injection ceased.

Cleburne, Texas: An m_b 2.8 earthquake was felt on June 9, 2009 in the Cleburne area, about 50 km (31 mi) south of Dallas-Fort Worth, close to two water-disposal wells (Justinic et al., 2013) located 1.3 km (0.8 mi) and 3.2 km (2 mi) from the epicenter. Like Dallas-Fort Worth, the Cleburne area had no previous history of felt earthquakes.

By the end of December 2009, over 50 smaller events, some of which were felt, had been recorded on a temporary microearthquake network installed shortly after the June 9 event. The earthquakes apparently occurred on a 2 km (1.25 mi) -long, pre-existing NNE-striking normal fault. Most of the events occurred within a 300 m (985 ft) thick zone centered at a depth of 3,800 m (12,550 ft), less than 1,000 m (3,281 ft) below the injection intervals in the two wells. The more distant well was active between 2005 and July 2009. The average monthly injection volume peaked at about 95,000 m³ (25 million gal) during the second half of 2008, and was close to 90,000 m³ (24 million gal) in June 2009. Injection in the closer well began in 2007. During 2009 the peak injection was about 16,000 m³ (4.2 million gal) in April. Although the Cleburne sequence fits several of the criteria for discriminating induced from natural seismicity discussed in 4.C.1, no pressure data were available to develop a detailed understanding of the correlation of the seismicity with injection, and hence to establish a definitive causal relationship.

Timpson, Texas: Another sequence of potentially induced earthquakes began on May 17, 2012, near Timpson (Frohlich et al., 2014). The sequence included five events having magnitudes of M_w4 and above; the largest event was M_w4.8. The earthquake epicenters fall along a mapped basement fault about 6 km (3.7 mi) long. Four active water disposal wells lie within about 3 km (1.9 mi) of the epicenters and near the largest magnitude event. Total injected volumes for the two largest volume wells were 1,050,000 m³ and 2,900,000 m³ (277 billion gal and 766 billion gal), with average injection rates exceeding 16,000 m³/mo (420,000 gal/mo). The injection interval for all four wells was 1.8–1.9 km (5,900–6,200 ft), and the top of the basement is at a depth of approximately 5 km (16,000 ft). Depths between 2.75 and 4.5 km (9,000 and 14,800 ft) were calculated for the five largest earthquakes by modeling waveforms recorded 25 km (15.5 mi) away from the epicentral area. Although the evidence favors the conclusion that these events were induced, Frohlich et al. (2014) could not rule out the possibility that they occurred naturally.

Guy-Greenbriar, Arkansas: Disposal of wastewater from hydraulic fracturing operations in the Fayetteville Shale has been correlated with 224 M > 2.5 earthquakes that occurred between 2007 and 2011. Three of the earthquakes had magnitudes of M_w4 and greater, and the largest event, M_w4.7, occurred on February 27, 2011 (Horton, 2012). In an area of otherwise generally diffuse seismicity, 98% of the recent earthquakes occurred within 6 km (3.7 mi) of three Class II disposal wells. One injection well appears to intersect the Guy-Greenbrier fault within the basement and was subsequently determined to be suitably oriented for slip within the regional tectonic stress field (Horton, 2012).

Prague, Oklahoma: The largest earthquake suspected of being related to injection of wastewater from well stimulation was an M_w5.7 event that occurred within a region of previously sparse seismicity near Prague, OK, on November 6, 2011 (Keranen et al., 2013; Sumy et al., 2014). This event, which is the second largest earthquake instrumentally recorded in the central and eastern U.S., destroyed 14 homes and injured two people. The hypocenter was located on the previously mapped NNE-SSW-striking Wilzetta fault system and was followed two days later by an M_w5.0 about 2 km (1.2 mi) to the west. Sumy

et al. (2014) proposed that the M_w 5.7 mainshock was triggered by an M_w 5.0 foreshock that occurred the previous day approximately 2 km (1.2 mi) from two active wastewater injection wells located within the Wilzetta North oilfield. One well injected into the previously depleted Hunton Limestone reservoir, while the other injected into two deeper formations. The zone of well-located aftershocks of this event extends along the strike of the fault to within about 200 m (656 ft) of these wells. Although injection into the first well began in 1993, the cumulative rate of injection was increased by starting injection into the second, deeper well in December 2005, accompanied by a tenfold increase in wellhead pressure; pressures at both wells averaged approximately 3.5 MPa (508 psi) between 2006 and December 2010, falling to 1.8 MPa (261 psi) in 2011. Keranen et al. (2013) also note that local earthquake activity began with an M_w 4.1 earthquake a few km from the 2011 mainshock in 2010, during the period of near-peak wellhead pressures, but they do not mention microseismicity before or after this event.

Keranen et al. (2013) concluded that the November 5, 2011 M_w 5 event was likely induced by a progressive buildup of overpressure in the effectively sealed reservoir compartment and on its bounding faults (part of the Wilzetta fault system) after the original fluid volume capacity of the depleted reservoir had been exceeded as a result of injection. However, this explanation apparently does not take into account injection into the deeper formations, which are separated from the reservoir by a (presumably relatively low-permeability) shale layer. An alternative explanation is that the triggering mechanism involved only the more recent injection into the deeper formations, the lowest of which directly overlays basement. McGarr (2014) proposed that the M_w 5.7 mainshock was induced directly by injection of much larger volumes into three wells located 10 to 12 km (6.2 to 7.5 mi) southeast of the epicenter. However, if, as asserted by Keranen et al. (2013), the faults of the Wilzetta system form barriers to lateral (SE-NW) flow that compartmentalize the oilfield, then it would not be expected that the wells discussed by McGarr (2014) would be in hydraulic communication with the westernmost fault of the system on which the earthquake apparently occurred. The occurrence of these events close to several high-volume injection wells strongly suggests that they were likely induced. However, the six-year delay between the significant increase in injection rate and pressure in the Wilzetta North wells and the conflicting hypotheses regarding the source and magnitude of the pressure perturbation mean that natural causes, as proposed by Keller and Holland (2013), cannot at present be ruled out.

Youngstown, Ohio: During a 14-month period in Youngstown, OH, an area of relatively low historic seismicity, 167 earthquakes ($M \leq 3.9$) were recorded in proximity to ongoing wastewater injection (Kim, 2013). Earthquake depths were in the range 3.5–4.0 km (11,482–13,123 ft) and located along basement faults. Given that relatively small fluid volumes ($\sim 700 \text{ m}^3$; $\sim 180,000 \text{ gal}$) were injected prior to the onset of seismicity, there is believed to be a near-direct hydraulic connection to a pre-existing fault. Periods of high and low seismicity tracked maximum and minimum injection rates and pressures. The total injected volume over this period was $78,798 \text{ m}^3$ (20.816 million gal), with an average injection volume of $350 \text{ m}^3/\text{day}$ (1,150 gal/day) at a pressure of 17.2 MPa (2,490 psi).

Trinidad, Colorado: Seismicity near Trinidad, Colorado within the Raton Basin of Colorado and New Mexico that occurred between August 2011 and December 15, 2011 is believed to have been caused by injection of wastewater near the southern extension of a local fault zone (Rubinstein et al., 2014). The sequence included three earthquakes $M \geq 4$, the largest of which was $M 5.3$. Between 2001 and 2013, 16 $M > 3.8$ earthquakes have been attributed to expanded wastewater disposal activity in the Raton Basin, which increased the median fluid injection rate from 75,000 to 191,000 m^3/mo (500,000 to 1.2 million bbl/mo). Prior to 2001, only one $M > 3.8$ earthquake was recorded in the Raton Basin. The 2011 earthquake sequence occurred within 10 km (6.2 mi) of five injection wells, four of which are high injection-rate, high-volume wells. At the end of August 2011, cumulative injection into these wells ranged from $1.8\text{--}2.68 \times 10^6 m^3$ (475–700 million gal).

Appendix 4.D

Induced Seismicity Protocols

The issue of induced seismicity is not new, and in the geothermal industry, potential risks from induced seismicity were recognized in the late 1990s. An effort was initiated in 2004 to develop a protocol and best practices for managing and mitigating induced seismicity that would allow development of geothermal energy to progress in a cost-effective and safe manner. The induced seismicity protocol described below was developed by the U.S. Department of Energy (DOE) to address induced seismicity issues related to enhanced geothermal systems (Majer et al., 2012; 2014), and is now being used as a blueprint by oil-producing states and several oil-and-gas-producing companies to develop induced seismicity protocols for fluid injection associated with well stimulation.

Most protocols adopt a common-sense approach guided by the best available science. They are intended to be living documents that evolve as new knowledge and experience are gained. The protocols consist of recommended steps to manage induced seismicity. How a protocol is implemented and which of the recommended steps are required depends on factors such as past seismicity in the area, community acceptance, and proximity to sensitive facilities. The protocols and best practices are not intended as a “one-size-fits-all” approach. Instead, stakeholders are able to tailor their procedures to project-specific circumstances using protocols as a set of recommended steps to address induced seismicity hazard and risk.

The U.S. DOE protocol recommends the following steps to address project-related induced seismicity issues:

1. Perform a preliminary screening evaluation: Does the project satisfy basic hazard criteria? These include consideration of proximity to known active faults, past induced seismicity, proximity to population centers, amount of injection and time of injection, and public acceptance issues.
2. Implement an outreach and communication program: Continue to inform and educate the community about potential seismic hazards and risks related to project operations. An important step is gaining acceptance by non-industry stakeholders and promoting safety.
3. Review and select criteria for ground vibration and noise: Which receptor communities and structures will be affected by induced seismicity? This will inform criteria for setting maximum event sizes.

4. Establish a seismic monitoring system. What is the history of seismicity in the area? How is the natural background level of seismicity distributed in space and time?
5. Quantify the hazard from natural and induced seismic events: How big an event is expected and what are the seismicity rates and magnitude distributions? This may be difficult for induced seismicity at sites where there is limited knowledge of geological and site conditions.
6. Characterize the risk of induced seismic events: Given information from steps 3, 4, and 5, perform a risk analysis. This is generally challenging for induced seismicity. The minimum objective is to place bounds on risk.
7. Develop a risk-based mitigation plan: e.g., a “stop light” procedure such as that described below and appropriate insurance coverage, etc.

Figure 4.D-1 shows an example of a proposed implementation strategy for the oil and gas induced seismicity protocol that a consortium of member companies of the American Exploration and Production Council (AXPC) is considering. This is a proposed draft that was shown at the Kansas Induced Seismicity State Task Force (<http://kcc.ks.gov/induced-seismicity/>) meeting in Wichita, Kansas on April 16, 2013, and represents the collective opinions of an expert panel of geologists, geophysicists, hydrologists, and regulatory specialists drawn from AXPC member and other companies. (This proposed draft does not represent the views of any specific trade association or company.)

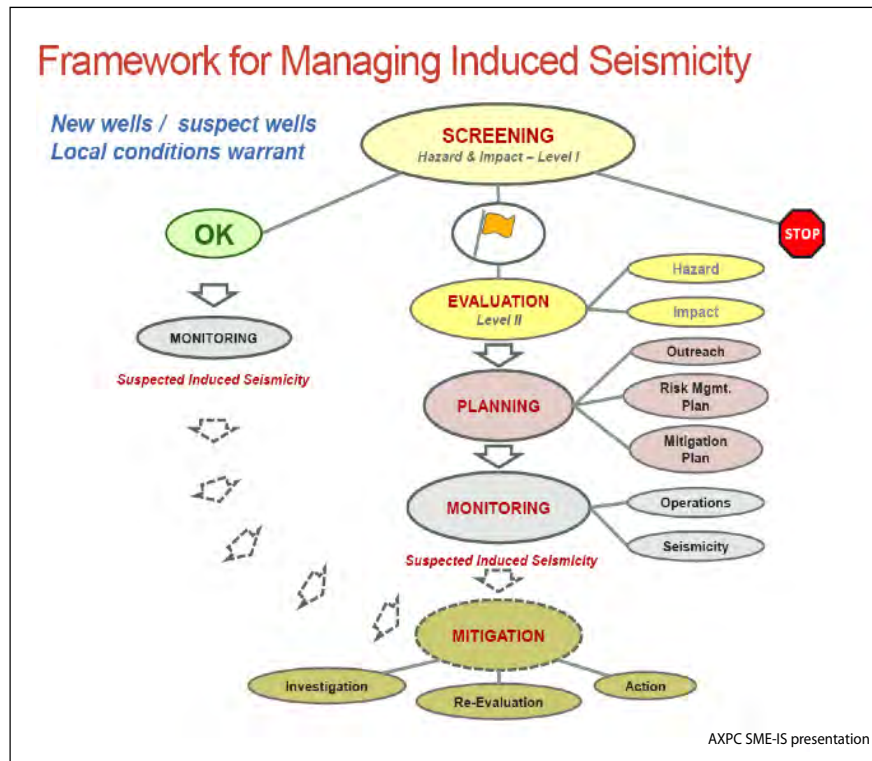


Figure 4.D-1. AXPC proposed draft implementation strategy for a protocol for managing and mitigating induced seismicity related to well stimulation.

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