

Deep Well Injection Induced Seismicity

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Abstract: Injection of fluid into subsurface geologic strata for geothermal energy, oil production, and waste disposal has been linked to induced seismic activity in the United States as well as in several other countries. According to the report of the National Research Council of United States of America thousands of induced earthquakes were reported at the numerous sites, where oil and gas recovery and waste disposal activities took place. Most of these induced earthquakes were small magnitude events (Moment Magnitude [M_w] < 4), although earthquakes of magnitude (M_w) 6.5 to 7 were also reported near the oil and gas production sites. This paper presents the results of a review of case histories on increased seismic events due to deep well injection (DWI) and oil extraction. Key factors that may lead or contribute to increased seismicity will also be discussed.

Keywords: Induced seismicity; man-made seismicity; deep well injection; oil & gas exploration; waste disposal.

Case Histories of Deep Well Injection Induced Seismicity

Increased seismic events caused by human activities have been reported and documented. Most of these seismic events were low magnitude events. The documented cases are typically related to energy- and oil-production activities and injection of waste for disposal, although other human activities, such as mining and reservoir filling, have also been shown to cause increased seismic events [1]. Table 1 summarizes the cases of induced seismicity reported for the various energy technologies, as of 2012 [2,3]. The table also lists the number of felt events and the maximum earthquake magnitudes recorded at these sites, including an earthquake of magnitude 6.5 observed in a hydrocarbon withdrawal project.

This paper focuses on case histories of increased or induced seismic events due to DWI of large-volume waste fluid. Cases involving induced earthquakes due to oil production were also reviewed and presented. Six of these case histories are discussed below.

Case 1: Paradox Valley Brine Deep Well Extraction and Injection, Colorado, USA

The Paradox Valley Unit (PVU) is located in Montrose County in Southwest Colorado, USA and is operated by the U.S. Bureau of Reclamation.

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The facility includes, among others, 9 shallow extraction wells, a United States Environmental Protection Agency (EPA) Class V deep injection well (total depth of ± 4.9 km below ground surface), and the Paradox Valley Seismic Network (PVSN). The seismic network consists of 20 stations of velocity sensors and strong-motion accelerometers installed around the injection well location. The shallow wells extract brine from the aquifer along the Dolores River in southwestern Colorado, and after some treatment, the brine is injected back with high pressure to depths between 4.3 and 4.8 km [4].

The primary target of injection is the highly fractured Leadville Limestone, where the steeply dipping Wray Mesa Fault system trends sub-parallel to the strike of the Paradox Valley. The injection well was sited to optimize fluid disposal along these fault fractures. From 1991 to 2003, more than 4 million cubic meters (about 1 billion gallons) of brine was injected into the rock strata, with an average injection rate of 855 to 1,290 liters per minute (l/min) or 0.325 to 0.49 million gallons per day (mgd) during the operational period. The area had experienced very low seismicity prior to the injection. After the injection activities began, more than 4,600 induced earthquakes were recorded [5]. These induced seismic events were observed in two distinct zones: a principal zone surrounding the injection well and a secondary zone centered at ± 8 km northwest of the well location.

The injection and observations of induced seismic events at the PVU site can be divided into two main periods: injection tests and operational (continuous) injection. The following subsections summarize the well operation and induced seismicity observed during each of these periods [4].

Table 1. Summary Information of Reported Induced Seismicity in United State of America

Energy technology	Number of Projects	Number of Felt Induced Events	Maximum Magnitude of Felt Events	Number of Events $M \geq 4.0^d$	Net Reservoir Pressure Change	Mechanism for Induced Seismicity	Location of $M \geq 2.0$ Events
Vapor-dominated geothermal	1	300-400 per year since 2005	4.6	1 to 3 per year	Attempt to maintain balance	Temperature change between injectate and reservoir	CA (The Geysers)
Liquid-dominated geothermal	23	10-40 per year	4.1 ^b	Possibly one	Attempt to maintain balance	Pore pressure increase	CA
Enhanced geothermal systems	~8 pilot projects	2-10 per year	2.6	0	Attempt to maintain balance	Pore pressure increase and cooling	CA, NV
Secondary oil and gas recovery (waterflooding)	~108,000 (wells)	One or more events at 18 sites across the country	4.9	3	Attempt to maintain balance	Pore pressure increase	AL, CA, CO, MS, OK, TX
Tertiary oil and gas recovery (EOR)	~13,000	None known	None known	0	Attempt to maintain balance	Pore pressure increase (likely mechanism)	None known
Hydraulic fracturing for shale gas production	35,000 wells total	1	2.8	0	Initial positive; then withdraw	Pore pressure increase	OK
Hydrocarbon withdrawal	~6,000 fields	20 sites	6.5	5	Withdrawal	Pore pressure decrease	CA, IL, NB, OK, TX
Waste water disposal wells	~30,000	8	4.8 ^c	7	Addition	Pore pressure increase	AR, CO, OH
Carbon capture and storage, small scale	1	None known	None known	0	Addition	Pore pressure increase	IL
Carbon capture and storage, large scale	0	None	None	0	Addition	Pore pressure increase	None yet in operation

^a Note that that in several cases the causal relationship between the technology and the event was suspected but not confirmed. Determining whether a particular earthquake was caused by human activity is often very difficult. The references for the events in this table and the way in which causality may be determined are discussed in the report. Also important is the fact that the well numbers are those wells in operation today, while the numbers of events listed extend over a total period of decades.

^b One event of M 4.1 was recorded at Coso, but the committee did not obtain enough information to determine whether or not the event was induced.

^c M 4.8 is a moment magnitude. Earlier studies reported magnitudes up to M 5.3 on an unspecified scale; those magnitudes were derived from local instruments.

^d Although seismic events $M > 2.0$ can be felt by some people in the vicinity of the event, events $M \geq 4.0$ can be felt by most people and may be accompanied by more significant ground shaking, potentially causing greater public concern.

Source: National Research Council (2012)[2] and The National Academy of Sciences (2012)[3]

Injection Testing Period (July 1991 to April 1995)

A total of seven well tests were performed during the permitting period to obtain the EPA Class V permit for brine disposal. The injection duration was varied, ranging from 12 days to as long as 8 months, with different injection rates and well pressure. A total of 666 induced seismic events were detected during this period, and they were observed to be correlated to injection rate and pressure.

Injection Operational Period (May 1996 to 2003)

During this operational period, the injection rate was slowly increased to a fixed rate of 1,290 l/min or 0.49 mgd, and the maximum pressure at the head of the well was capped at ± 33 MPa. Induced seismic events were first detected after 111 days of continuous pumping, and more than 3,350 seismic events were recorded within ± 10 km of the well location through the end of 2003. The majority of these events were

Table 2. Injection Parameters During the Operation Period
Phases of Continuous Pumping

Phases	Approx. Duration Days	Avg. Wellhead Pressure (MPa)	Avg. Pressure at 4.3 km ^a depth (MPa)	Avg. Inj. Rate ^d (L/min)	Injectate: %PVB: % H ₂ O	Biannual 20-Day Shutdown (Yes/No)	Approx. No. Seismic Events
I	1100	33.8	80.7	1290	70:30	No	2446
II	332	33.8	80.7	1290	70:30	Yes	496
III	566	30.3	77.2	855	70:30	Yes	140
IV	724 + ^b	30.3 + ^c	79.3 + ^c	855	100:0	Yes	277

^aDepth = Top of the casing perforation interval, i.e., the top of the injection target horizon, the Leadville Limestone.

^bNumber includes days through 31 December 2003.

^cAverage pressure has been increasing following each 20-day shut-in.

^dAverage when pumping, does not include scheduled and unscheduled shut-downs.

Source: Ake et al., 2005 [4]

small magnitude earthquakes ($M_w \leq 2.5$); only 15 events were felt on the ground surface. The largest induced seismic events were two M_w 3.5 to 3.6 earthquakes that occurred in 1999 and an M_w 4.3 earthquake on May 27, 2000. The May 27, 2000 earthquake produced a peak horizontal acceleration of about 0.3 g.

The operational (or continuous) period is further grouped into four phases, as summarized in Table 2 along with the injection parameters implemented during each of these phases.

Figure 1 shows plots of injection rate and frequency of induced seismic events for the four phases of operation described in Table 2. The data indicate the following:

- The induced seismic events were the highest in Phase I (through middle of 1999).
- After the M_w 3+ earthquakes in 1999, PVU implemented a 20-day shutdown for every 6 months of continuous operation (Phase II). The purpose of these shutdowns was to allow the pressure at depths to diffuse, reducing the potential of inducing large magnitude earthquakes. As shown in Figure 1, these regular shutdowns significantly reduced the seismic activity (from as high as ± 150 events per month to less than ± 50 events per month).
- Despite the lower seismic activity due to shutdowns, an M_w 4.3 event occurred on May 27, 2000. This event required the PVU to reduce the injection rate from 1,290 l/min to 855 l/min, a 33 percent reduction (Phase III). The reduced injection rate resulted in further reduction in induced seismic events (see Figure 1).
- During Phase IV, the injectate composition was changed from 70 percent brine (PVB) plus

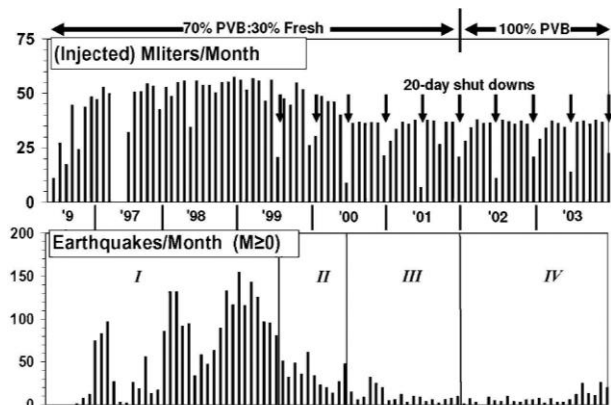


Figure 1. Plots of Injection Rate and Frequency of Induced Seismic Events Versus Time (Through 2003)

Source: Ake et al., 2005[4]

30 percent fresh water to 100 percent PVB, while the injection rate was kept at 855 l/min. This was done to increase the disposal rate of brine. As of the end of 2003, no noticeable increase (as compared to Phase III) in induced seismicity was observed.

Figure 2 depicts the more recent data (through January 2011) collected by the Bureau of Reclamation [6,7]. These recent data confirm the observations and findings of previous studies and identify four key parameters for induced seismicity: injection volume, injection rate, downhole pressure, and percent of day injecting. Of these four parameters, downhole pressure exhibits the best correlation with the occurrences of near-well seismicity over time [6].

Case 2: Rocky Mountain Arsenal, Colorado, USA

The Rocky Mountain Arsenal site was used by the U.S. Army to manufacture weapons. In 1961, a well was drilled to a depth of ± 3.7 km into the crystalline

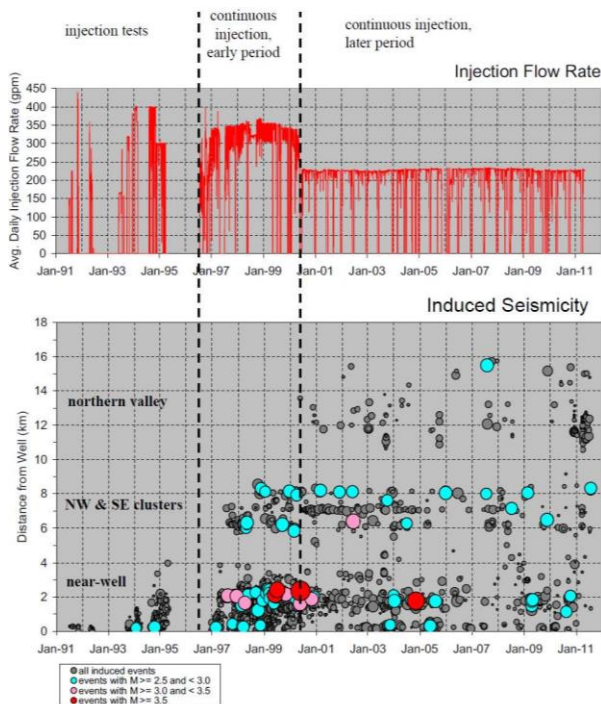


Figure 2. Plots of Injection Rate and Induced Seismic Events vs. Time (Through 2011)
 Source: National Research Council, 2012[2]

rocks for chemical fluid disposal. Small earthquakes were detected soon after the injection, with the majority of these events occurred within 5 miles of the injection point and aligned with the orientation of vertical fractures found in the rock. As reported by McClain (1970) [8], “in June of 1962, several earthquakes occurred which were large enough to be felt by residents and caused considerable concern. By November of 1965, over 700 shocks had been recorded and, although 75 of these had been felt, no damage was reported”.

There were four periods or phases of injection at this site:

- Phase I: 181,000 gals/day of fluid was injected under pressure from March 1962 through September 1963.
- Phase II: Injection was stopped due to observed seismicity from October 1963 through August 1964.
- Phase III: A reduced volume of 65,800 gals/day of fluid was injected under gravity fed from September 1964 through April 1965
- Phase IV: Injection was increased to 148,000 gals/day under pressure till the operation was stopped in late 1965.

Figure 3 plots the histograms of waste injection volume and observed earthquake frequency with time, showing high correlation between injection volume and induced earthquake frequency. It should be noted that although the injection was completely

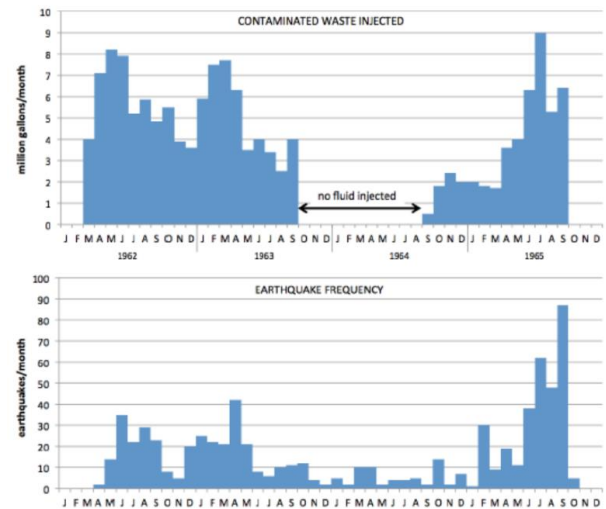


Figure 3. Histograms Showing Relation Between Volume of Waste Injection and Earthquake Frequency
 Source: National Research Council, 2012[2] - Adopted from Evans (1966) [10], Healy et al. (1968)[11], McClain (1970)[8] and Hsieh and Bredehoeft (1981)[12]

stopped in early 1966, earthquakes continued to occur for several more years till late 1980’s. The largest earthquakes were estimated to have Moment Magnitudes of 4.5 to 4.8 [9].

Case 3: Geysers Geothermal Steam Field, California, USA

The Geysers geothermal energy site is situated about 75 miles north of San Francisco in Northern California. It is one of the most productive geothermal fields in the world and has well-documented records of seismicity associated with geothermal energy development. The power plant was supplied with steam from a total of 420 production wells. After the steam was used to operate turbines for power generation, the waste was then injected back into the ground at similar depths using 20 injection wells. Because the volume of injected waste was less than the steam produced, water was later added to replace the mass loss.

The development area is in a relatively high seismic region near the San Andreas Fault system in Northern California, and no active faults are known to cross the site. Thousands of small earthquakes were detected soon after the steam production, and some of them caused damages to nearby buildings. Figure 4 depicts the progression of observed seismicity as the steam field was expanded from about 3 to 30 square miles in a period of about 25 years. The figure clearly shows a close correlation between spatial (location and depth) distribution of induced seismicity and steam production location (green squares on upper panel figure). The majority of earthquakes occurred near/around the wells (see bottom panel figure).

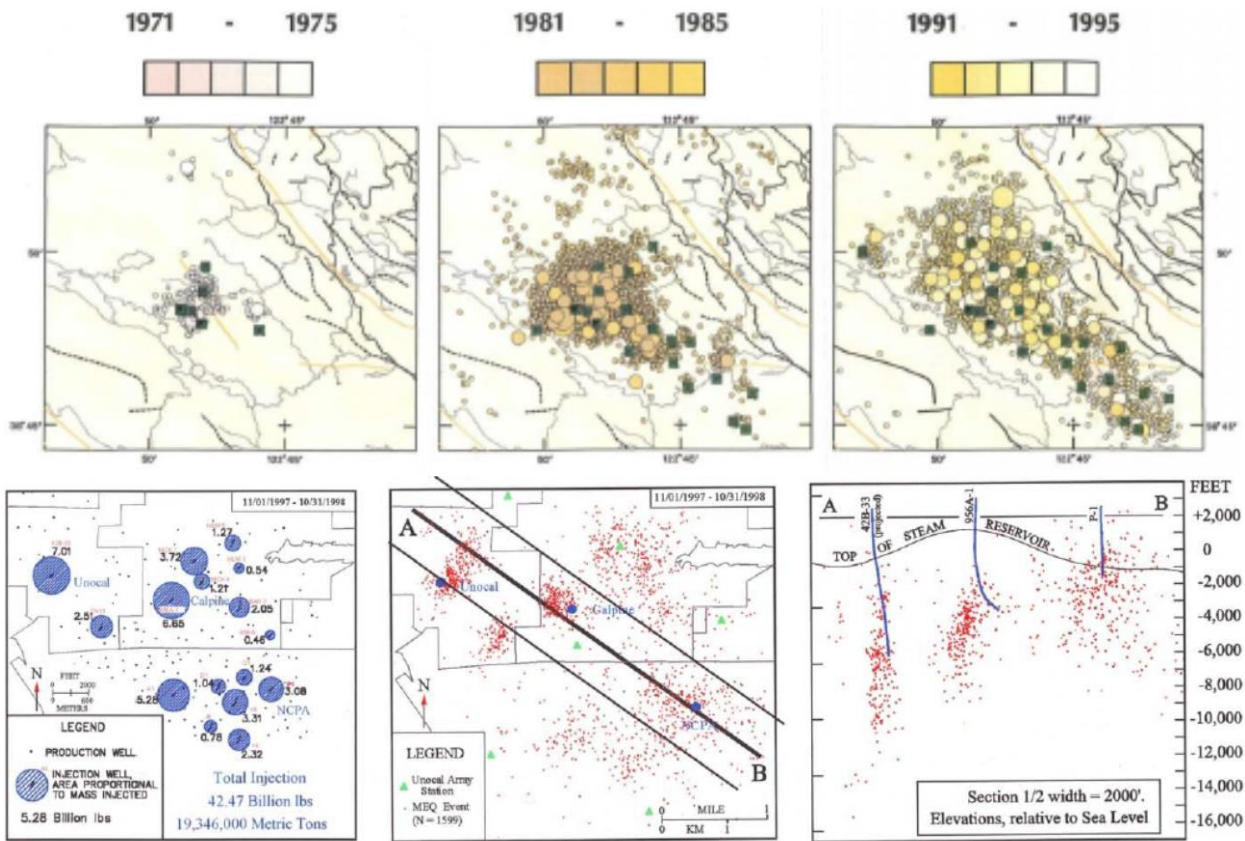


Figure 4. Upper panel: Observed Seismicity at the Geysers from 1971 to 1995 as Stream Field Expanded; Bottom panel: Locations of Injection Wells and Locations and Depth Distribution of Induced Seismicity at the Geysers from 1997-1998
 Source: National Research Council, 2012 [2] - Adopted from Preiss et al. (1996)[13] and Beall et al. (1999)[14]

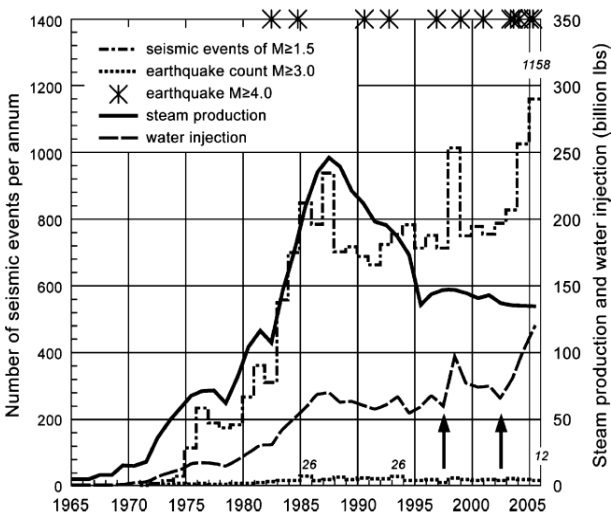


Figure 5. Recorded Historical Seismicity in Relation with Steam Production and Injection at Geysers
 Source: Majer et al. (2007)[15]

Figure 5 plots the annualized seismicity in relation with volumes of production steam and injected water. The figure indicates the following: 1) the volume of injected water and total seismicity events ($M \geq 1.5$) are highly correlated, 2) the majority of induced seismicity were small magnitude events ($M < 3.0$), and 3) only a few were magnitude ≥ 4.0 events.

Case 4: Montebello Oil Production, Southern California, USA

The 1987 M_w 6.0 Whittier Narrows earthquake occurred in the San Gabriel Valley of Southern California. This earthquake occurred on a blind thrust fault (i.e., the rupture did not extend to the ground surface) near the northern part of the Elsinore Fault Zone beneath an active oil production field at a depth of ± 9.5 km below ground surface [16,1].

Although a causal relationship between the earthquake and oil-production activities can be considered weak due mainly to the ± 8 km vertical separation between the earthquake hypocenter and oil-producing formation, a mechanical connection between the two has been postulated [16,1]. It is suggested that removal of oil and water from the upper crust may result in imbalanced forces in the deeper seismogenic layer that, in turn, induce earthquakes (see Figure 6 below).

This hypothesis is further supported by similar earthquake events in California (the 1983 M_w 6.5 Coalinga and 1985 M_w 6.1 Kettleman North Dome earthquakes) and in Gazli, Uzbekistan (the 1976 M_w 7.0 Gazli earthquake). These three earthquakes all occurred beneath oil-production fields.

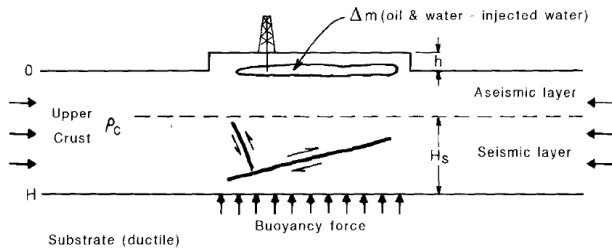


Figure 6. Removal of Crustal Mass May Result in Failure of Deeper Layer

Source: McGarr, 1991[16]

Although oil extraction is different than deep brine or wastewater injection, these case histories may contribute to the understanding of the potential for inducing moderate to large magnitude earthquakes by fluid injection in a high seismic tectonic plate boundary area, especially near an active fault system.

Case 5: Inglewood Oil Production, Southern California, USA

The failure of Baldwin Dam in 1963 has been in part blamed on the nearby Inglewood oil production activities. At the time of the dam failure, the Inglewood oil field operated more than 600 wells, and some of these wells were located as close as 200 meters from the dam. The results of investigation performed after the failure indicate that the failure was due to the breakdown of the underlying drainage system, which in turn, caused release of reservoir water that undermined the dam integrity. Several fault traces that are part of the Inglewood Fault System have also been mapped across the reservoir floor.

It has been speculated that the withdrawal and injection (flooding) activities on the nearby Inglewood oil field caused the area to subside and fault traces to move. These subsidence and fault movements (creeps) are believed to cause the failure of the drainage system and ultimately the dam itself.

Case 6: Guy and Greenbrier Wastewater Injection, Arkansas, USA

This case involves eight Class II wastewater injection wells in central Arkansas near the towns of Guy and Greenbrier. Injection operation started in April 2009, and a swarm of earthquakes ($M_w \leq 4.7$) was observed starting in September 2010 in the vicinity (within ± 6 kilometers) of the well sites. Figure 7 shows the locations of the seismic stations (black squares), injection wells (red dots), induced seismic events between October 1, 2010 and February 15, 2011 (dark grey dots), and seismic events recorded between February 16, 2011 and March 8, 2011 (white dots). As shown in the figure, one of injection wells (Well #5) appears to intersect the Enders Fault.

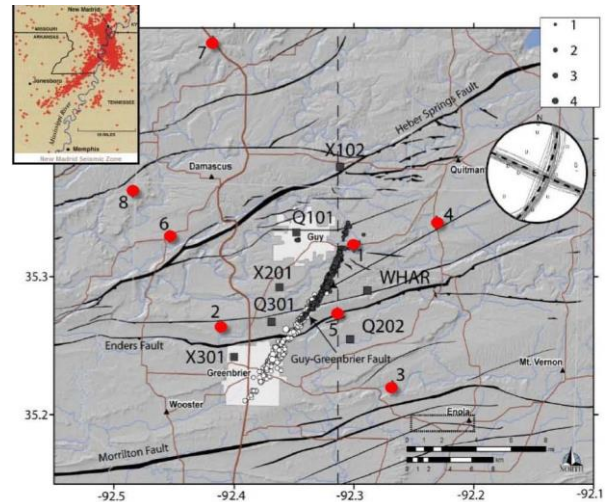


Figure 7. Recorded Seismicity and Locations of Seismic Stations and Injection Wells

Source: National Research Council, 2012[2]

Historically, the Guy and Greenbrier areas had experienced seismic activities (seismic swarms), which are believed to be associated with the nearby New Madrid Seismic Zone (located on the northeastern corner of Arkansas). The New Madrid Seismic Zone is the largest known seismic source east of the Rocky Mountains, and the source of the 1811–1812 great earthquake series (M_w 7.0 to 8.1) in the area.

The exact causes of the observed seismicity are not completely known. Judging from the seismicity pattern, however, it is conceivable that the recorded seismic events have direct correlation with the ongoing injection activities. It has been postulated that injection at Well #5, which intersects the Enders Fault, may allow the wastewater to migrate through the fault's planes into deeper crustal structures [17]. The pore pressure generated during injection may also reduce the contact stresses on the planes, causing the fault to slip in an earthquake.

Key Factors for DWI Induced Seismicity

There are about 151,000 Class II injection wells currently operating in the United States. Very few felt seismic events (i.e., events with $M_w \geq \pm 3.0$ to 4.0) have been reported or documented as directly caused by wastewater disposal operations; the majority of these events were small magnitude earthquakes (i.e., events with $M_w < 3.0$ to 4.0) [2].

Accurate information on fluid injection and/or extraction is critical for assessing the potential of induced seismicity. The factors believed to be responsible for inducing seismic events are complex and interrelated. DWI induced seismicity is likely due to changes in in-situ stresses in the Earth's crust caused by injected fluid pressure. The injected fluid pressure will reduce

normal or contact stresses acting on a fracture's planes, which in turn, will reduce shear resistance to sliding. If reduction in shear resistance is large enough to cause slippage of the blocks, then an earthquake will occur. High fluid pressure can also change in-situ stress conditions within the solid rock formation and induce earthquakes.

The following key factors should be considered in assessing the potential of DWI induced seismicity [2]:

- Earthquake history of the DWI area. Historical seismicity of the region provides the background or natural seismic environment prior to injection activities. It can be used as a basis to assess if any increased seismicity occurs naturally or is caused by injection activities.

High seismic activity, especially in tectonic plate boundary areas, may also indicate that the in-situ stresses on the Earth's crust are already in a delicate equilibrium state, and any disturbances from injection may induce earthquakes.

- Presence of nearby fault(s). Injecting and/or extracting fluid near a known fault may alter the stress conditions on and along the fault's planes. Increased fluid pressure due to injection can reduce the contact stresses between plates, which in turn, will reduce their sliding resistance and lead to earthquakes.

The vulnerability to produce fault slippage depends on fault activity, dimension, and orientation as well as on existing stress state. These include fault slip rate, strike, dip, and rake angles; top and bottom fault depths; and seismogenic depth and length. Distance of fault planes to injection well is also a critical factor in assessing the potential of inducing earthquakes.

- Injection and/or extraction parameters. The parameters include rate of injection and/or extraction, duration of injection and/or extraction, volume and temperature of injected and/or extracted fluids, spatial distribution of wells, and generated pore pressure at depth.

Observations made on some of the case histories have indicated that net fluid balance (i.e., total balance of fluid injected and extracted) appears to have the most impacts on pore pressure changes in the subsurface rock/soil over time; operation with balanced fluid volume seems to produce fewer induced seismic events. Reducing injection volume, rates, and pressure has also been successful in decreasing rates of induced seismicity.

- Existing stress conditions. As discussed previously, injection pressure alters the in-situ stress equilibrium both in terms of stress amplitudes and principal directions in the Earth's crust. If the changes are significant enough, movements of existing fractures (or faults) could be initiated, leading to seismic events. The orientation of

fracture planes with respect to principal stress directions determines the likelihood of generating seismic events. Faults with low-dipping angles (i.e., almost horizontal faults) should be less susceptible to stress-induced sliding.

- Characteristics of target geologic strata. The characteristics of geologic strata that fluid is being injected into are important factors in the generation of induced seismic events. In fractured rocks, the injected fluid will travel along the network of fractural planes, and the impacts would largely be the reduction in contact stresses on the planes; whereas in permeable rocks, the fluid will migrate through the rock's pores and change the principal stress amplitudes and directions.

Conclusions

Several case histories related to increased or induced seismic events due to DWI were reviewed. Although cause-and-effect relationship of these induced seismic events is not exactly known, the case histories presented in this paper clearly indicate probable correlations between DWI activities and induced seismicity. The great majority of injection operations have not resulted in felt seismicity due to their low magnitudes, although earthquakes with M_w as large as 6.5 to 7 were detected beneath or near some of the oil and gas fields.

Additional studies are needed to better understand the mechanism of pressurized flow in geologic strata, especially near faults, and how the pressure changes the stress conditions within strata. A coupled flow-and-tectonic model and a ground motion predictive model for induced seismicity are required to assess and quantify the seismic hazards associated with DWI.

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