

Regulations Relevant to Injection-Induced Seismicity

A. Federal Regulations

1. Safe Drinking Water Act

There is no federal law whose primary purpose is to reduce the risk that fluid withdrawals or injections will trigger seismic activity. But Part C of the Safe Drinking Water Act (“SDWA”) regulates subsurface injections for purposes of protecting underground sources of drinking water (“USDWs”). To a limited extent, the SDWA’s underground injection control (“UIC”) regulations have addressed seismicity concerns relating to groundwater protection.

Federal UIC regulations recognize six classes of UIC wells, with each class being subject to different regulations.

| Class I | Wells used to inject wastes “beneath the lowermost formation containing, within one-quarter mile of the well bore, an underground source of drinking water”\(^1\) |
| Class II | Wells in which fluids are injected for disposal of produced water and certain wastewater associated with oil and gas production; “enhanced recovery of oil or natural gas”; storage of liquid hydrocarbons; and (as the EPA interprets its regulations) any well that is hydraulically fractured using a frac fluid that contains diesel\(^2\) |
| Class III | Wells associated with certain mining activity\(^3\) |
| Class IV | Wells used for injection of wastes into a formation that contains an underground source of drinking water within one-quarter mile of the well\(^4\) |
| Class V | Injection wells that do not fit into any other category of injection well\(^5\) |
| Class VI | Wells for the injection of carbon dioxide for carbon sequestration\(^6\) |

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\(^1\) 40 C.F.R. § 144.6(a).

\(^2\) Id. § 144.6(b). For years, the EPA took the position that the SDWA did not apply to hydraulic fracturing, and the Agency’s SDWA regulations did not expressly include hydraulic fracturing in any of the classes of injection wells. See Keith B. Hall, “Regulation of Hydraulic Fracturing Under the Safe Drinking Water Act,” 19 Buff. Envtl. L.J. 1 (2011-2012) (providing a history of the EPA’s position on whether the Safe Drinking Water Act applies to hydraulic fracturing). In 2005, the SDWA was amended to state that, for purposes of the SDWA, the definition of underground injection excludes “the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities.” 42 U.S.C. § 300h(d)(1). But after the 2005 amendment, the EPA (which had interpreted its existing regulations as not applying to hydraulic fracturing) did not go back and amend its regulations to explicitly place hydraulic fracturing into a particular class of injection wells. Instead, the EPA took no action for several years, and then in 2010 announced that it interpreted wells that are hydraulically fractured using diesel as falling under Class II. Hall, supra, at 25–26, 28.

\(^3\) 40 C.F.R. § 144.6(c).

\(^4\) Id. § 144.6(d).

\(^5\) Id. § 144.6(e). The regulations originally only contained five classes of wells, with Class V being the catch-all category. When a sixth class was added the catch-all category remained as Class V and a new class, for wells used for carbon sequestration and storage, was added as Class VI.

\(^6\) Id. § 144.6(f).
Federal regulations require that an application for a Class I or Class VI injection well include an analysis of past seismicity in the area for which the injection well is proposed. The requirement appears to be motivated by the possibility that existing seismicity will interfere with containment of the injected fluids, rather than with the possibility that the injection will induce seismicity. The regulations do not require that such an analysis be included in applications for permits for other classes of UIC wells.

2. **Bureau of Land Management**

The Bureau of Land Management recently published new regulations to cover hydraulic fracturing on federal and Indian lands. In its responses to public comments, BLM noted that several public comments had urged the agency to restrict hydraulic fracturing in “areas with seismic zones.” BLM declined to do so, explaining that “research on the phenomena of induced seismicity from hydraulic fracturing operations is still ongoing and inconclusive.” BLM went on to state that the risk of seismicity could be addressed through the National Environmental Policy Act analysis and that the agency’s new fracturing rule requires applicants for permits to submit geological information that could assist such an analysis.

### B. **State Regulations**

1. **Arkansas**

   In Arkansas, oil and gas activity and Class II injection are regulated by the Arkansas Oil & Gas Commission. In response to a large number of earthquakes, the Commission issued an order in early 2011, placing a moratorium of approximately six months on the issuance of new Class II injection well permits for a particular area, based on “circumstantial evidence that recent earthquakes within the proposed area may be either enhanced or potentially induced by the operation of Class II . . . wells . . . .” The order also required that operators of existing Class II wells within the area begin submitting bi-weekly reports to the Commission to report the daily injection volumes and the maximum daily injection pressure.

   The Commission’s order also noted that the Arkansas Geological Survey had conducted studies, and that the Arkansas Geological Survey as well as the U.S. Geological Survey and the Center for Earthquake Research and Information would be conducting additional studies, and that later in the year the Commission would consider information gathered in those studies.

   The Commission considered such information during a meeting in July 2011 and issued an order placing a “permanent moratorium” on the issuance of new Class II permits in the area covered by the temporary moratorium issued earlier in the year. At the same time, the Commission entered a separate order that required the closure of the only existing Class II well that was still operating in the area (the permanent moratorium order noted that three other Class II wells in the area had been voluntarily closed by the operators).

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7 Id. §§ 146.62(b)(1), .82(a)(3)(v).
9 Id. at 16,182.
10 Id.
11 Id.
14 Id.
2. California

A California regulation that went into effect July 1, 2015, requires operators to monitor the California Integrated Seismic Network from the time they begin hydraulic fracturing of a well until 10 days after they have finished fracturing.\(^{16}\) If an earthquake of magnitude 2.7 or greater is detected within a distance of five times the “ADSA” or “axial dimensional stimulation area,” which is defined to mean “the estimated axial dimensions, expressed as maximum length, width, height, and azimuth, of the area(s) stimulated by a well stimulation treatment,”\(^{17}\) the operator must immediately notify the Division of Oil, Gas and Geothermal Resources (“DOGGR”).\(^{18}\) The regulations provide that DOGGR, in consultation with the operator and the California Geological Survey, will evaluate whether the hydraulic fracturing operation caused the seismic activity, whether there is a pattern of seismic activity that corresponds to hydraulic fracturing in the area, and whether the mechanical integrity of any active well within a radius of five times the ADSA has been compromised.\(^{19}\) No further hydraulic fracturing may be performed in a radius of five times the ADSA until DOGGR has determined that hydraulic fracturing in the area does not create a heightened risk of seismic activity.\(^{20}\)

3. Colorado

In Colorado, oil and gas activity and Class II injection wells are regulated by the Colorado Oil and Gas Conservation Commission. Starting in September 2011, the Commission began including a seismicity review in its evaluation of applications for new Class II injection well permits.\(^{21}\) As part of that review, the Commission works with the Colorado Geological Survey, which uses its own geologic maps, the U.S. Geological Survey earthquake database, and other information to evaluate the potential for seismicity. If there has been past seismicity in the vicinity of the proposed injection well location, the Commission requires the permit applicant to use geological data to define the seismicity potential and the proximity of the site to faults before approving the application.

4. Illinois

In 2013, Illinois enacted legislation directing the Illinois Department of Natural Resources (“Illinois DNR”) to adopt rules establishing a “traffic light” protocol to address the risk of induced seismicity at Class II injection wells.\(^{22}\) The legislation states that the rules described such protocol as one “allowing for low

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\(^{16}\) 14 Cal. Code Regs. § 1785.1(a).

\(^{17}\) Id. § 1781(f).


\(^{19}\) 14 Cal. Code Regs. § 1785.1(b)(2). If the concern is that the seismic event could have compromised well integrity, then it would seem that the area within which the integrity of all active wells must be checked should be an area surrounding the epicenter of the seismic event, but the regulation seems to contemplate a radius around the well that was hydraulically fractured.

\(^{20}\) Id. § 1785.1(b)(3). In some ways, it would seem that the area covered by the moratorium on fracturing, pending DOGGR’s determination that fracturing does not create heightened risk of seismic activity, should be based on the area around the hypocenter or epicenter of the seismic event, but the regulation appears to contemplate an area within a particular radius of the hydraulically fractured well.


\(^{22}\) 225 Ill. Comp. Stat. 732/1-96.
levels of seismicity while including additional monitoring and mitigation requirements when seismic events are of sufficient intensity to result in a concern for public health and safety.” 23 The legislation specifies that the additional mitigation must “provide for either the scaling back of injection operations with monitoring for establishment of a potentially safe operation level or the immediate cessation of injection operations.” 24

In late 2014, the Illinois DNR adopted regulations to create the required traffic light system. 25 The regulations provide that if the operation of a Class II UIC disposal well is suspected of having induced seismic activity, the operator must consult with the Illinois DNR regarding the possibility of installing a seismic monitoring system and reducing injection rates or pressures. 26

In addition, the regulations provide for the issuance of “Yellow Light Alerts” to all operators of UIC Class II disposal wells located within 6 miles of the epicenter of a seismic event with a magnitude between 2.0 and 4.0. 27 If any operator receives three Yellow Light Alerts within a one-year period, the operator must immediately reduce injection rates and consult with the Illinois DNR and the Illinois State Geological Survey. 28 An operator receiving its third Yellow Light Alert within a year must immediately cease operations if it also has received a Notice of Violation relating to injection rates, pressure, or mechanical integrity of the same well. 29 The operator also must immediately cease operations if it receives a fifth Yellow Light Alert within a year. 30

The Illinois DNR issues a “Red Light Alert” to all operators of Class II UIC disposal wells located within 10 miles of the epicenter of an earthquake of magnitude 4.0 or greater. 31 An operator receiving such an alert must immediately cease operations if its well is within 6 miles of the earthquake. 32 Further, the Illinois DNR must order any operator of a Class II injection well to cease operations immediately if conditions “create imminent danger to the health and safety of the public, or significant damage to property . . . .” 33

5. Kansas

In response to an increase in seismic events in Kansas, Governor Sam Brownback established a task force to develop a “State Action Plan” to address the issue. 34 The task force issued a draft plan in April...

23 Id. 732/1-96(c).
24 Id. 732/1-96(d).
27 Id. § 240.796(b), (d)(1).
28 Id. § 240.796(d)(3).
29 Id. § 240.796(c)(1).
30 Id. § 240.796(e)(3).
31 Id. § 240.796(b), (d)(4).
32 Id. § 240.796(e)(4).
33 Id. § 240.796(e).
and, after accepting public comments on the draft for approximately one month, submitted a revised draft in September 2014. The draft was amended again in January 2015 to produce a final draft.

The final draft made certain recommendations. For example, after noting that Kansas currently relies on two seismic monitors operated by the U.S. Geological Survey, and that those two monitors are not sufficient to precisely locate the hypocenters of earthquakes, the Action Plan recommended that the state fund a permanent network of seismometers. The recommended network would allow Kansas to detect and locate earthquakes with a magnitude of 1.5 or greater. The Action Plan also recommended that Kansas fund a portable seismic array that could be deployed to areas experiencing seismic activity in order to obtain more detailed information regarding seismic events. Finally, the Action Plan proposed a formula for giving a numerical score to seismic events based on various criteria, and further proposed that numerical scores above a certain number would prompt regulators to increase monitoring and evaluate whether other regulatory steps are appropriate for a particular injection well or area.

In March 2015, the Kansas Corporation Commission issued an order that appears to be based in part on the Action Plan’s suggestion that regulators require increased monitoring and consider other regulatory action after the occurrence of any seismic events earn or exceed a specified numerical value under the Plan’s formula. The March 2015 order requires operators of injection disposal wells located in certain areas to measure daily injection volumes and pressures, and to report each month on the daily figures for the prior month.

Further, for disposal wells in those areas, the order reduces the maximum allowable rate of injection into the Arbuckle formation. For example, throughout Sumner and Harper Counties, two counties that have seen the largest increase in seismic activity, a limit of 25,000 barrels per day will apply for injections into the Arbuckle formation. And in certain areas in those counties, the maximum allowable injection rate will be reduced in a series of steps that culminates in a maximum allowable rate of 8,000 barrels of saltwater injection a day, with that ultimate limit going into effect 100 days after issuance of the order. In addition, in the area where the most restrictive injection rates apply, operators generally will be limited to an injection pressure of 250 psi. These operating restrictions apply both to future disposal wells and existing wells, with the order thus having the effect of amending existing permits.

39 Id. ¶ 13.
40 See id. ¶¶ 12, 15.
41 Id. ¶ 15.
42 Id. ¶ 12.
43 Id. ¶ 12(e).
44 See id. ¶¶ 12, 15.
Finally, the order requires operators to measure and report to the Commission the true vertical depth of their disposal wells. Operators must plug back any wells that have penetrated beneath the Arbuckle formation in order to confine fluids to that formation.

6. Ohio

In Ohio, oil and gas activity and Class II injection wells are regulated by the Ohio Department of Natural Resources Division of Oil & Gas Resources. After a series of earthquakes occurred near Youngstown, Ohio in late 2011, the Department conducted an investigation and ultimately concluded in a March 2012 report that the earthquakes had likely been caused by operations at a particular injection disposal facility.

A few months later, the Department revised its rules regarding injection disposal to address the threat of induced seismicity. Ohio’s regulation regarding permits for injection disposal was amended to provide that the Division of Oil & Gas Resources may require that the operator of an existing well conduct certain testing not otherwise required under the regulations. For example, the Division may require pressure fall-off testing, investigation of potential faulting within the immediate vicinity of the proposed site of the injection well, tracer or spinner surveys, and various logs. The Division also may require the operator to submit a plan for seismic monitoring. In addition, the Division may require that the operator cease operations while the Division is evaluating any of the information that must be submitted, and may order the plugging of the injection well if the Division deems such action necessary. Finally, the revised regulation gives the Division the authority to “implement graduated maximum allowable injection pressure requirements based upon data provided . . . .”

The Department also amended its regulation regarding operation of injection disposal wells. As amended, the regulation states that all injection wells permitted after the effective date of the amendment must be “continuously monitored using a method acceptable to the chief” of the Division. The regulation also requires that operators install a device that will automatically shut off the injection well if injection pressures exceed the maximum pressure allowed by the permit for that well.

7. Oklahoma

In Oklahoma, oil and gas activity and Class II injection wells are regulated by the Oklahoma Corporation Commission, through the Commission’s Oil & Gas Division. The Commission’s regulations generally require that operators of injection disposal wells record injection volumes and pressures on a monthly basis. But the Commission amended its regulations in September 2014 to provide that, for injection into the Arbuckle Formation, the state’s deepest injection formation, operators must monitor and

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45 Id. ¶ 16.
46 Id. ¶ 17.
48 Ohio Admin. Code 1501:9-3-06(C).
49 Id.
50 Id. 1501:9-3-06(C)(3).
51 Id. 1501:9-3-06(D).
52 Id. 1501:9-3-06(E).
53 Id. 1501:9-3-07(F).
54 Id. 1501:9-3-07(G).
record injection volumes and pressures on a daily basis, keep the records for at least three years, and provide the records to the Commission upon request.\textsuperscript{56}

In addition, the induced seismicity “traffic light” system recommended by the National Academy of Sciences continues to evolve as new data becomes available.\textsuperscript{57} In reviewing applications for Class II injection well permits, Commission staff now considers such factors as seismicity in the area around the proposed well site and the proximity of the site to faults as part of the Commission’s decision whether the permit should be granted and, if so, whether any special restrictions should be imposed.

Further, in so-called “areas of interest” or “yellow light” areas, the Commission will require operators to record injection volumes and pressures daily. Such areas originally were defined to include all locations within 10 kilometers of the epicenter of an earthquake with a magnitude of 4.0 or greater.\textsuperscript{58} In January 2015, the Commission announced that it had expanded the definition of “area of interest” to include not only the locations originally included, but also all locations within 10 kilometers of a “swarm,” which is defined for purpose of the rule as two earthquakes, at least one of which has a magnitude of at least 3.0, that are located within 0.25 miles of each other; all locations within three miles of a seismically active fault; and all locations within three miles of a stressed fault, whether or not there has been seismic activity.\textsuperscript{59} Applications for UIC permits in such areas are subject to special review and if a permit is granted, it may be granted subject to special conditions.

In March 2015, the Commission announced that in areas of interest, each operator of an injection disposal well would be required to reduce injection rates by 50% unless the operator demonstrated that it was not injecting below the Arbuckle formation.\textsuperscript{60} The Commission explained that disposal below the Arbuckle formation poses increased risk of inducing seismicity because it puts injected fluid in communication with solid basement rock.\textsuperscript{61}

\section*{8. Texas}

In Texas, oil and gas activity and Class II injection wells are regulated by the Railroad Commission. On October 28, 2014, the three members of the Commission unanimously adopted revisions to Texas’s existing fluid injection regulations in order to address and minimize the risk of induced seismicity.\textsuperscript{62} The new rule became effective on November 17, 2014, amending Texas Administrative Code Title 16 sections 3.9 and 3.46 to:

\begin{itemize}
  \item provide that any person applying for a permit for a new injection well to dispose of saltwater or other oil and gas waste must include with his application information from the U.S. Geological Survey seismic database regarding historical earthquake activity in a 100-square-mile area around the proposed injection site (a circle with an area of 100 square miles would have a radius of approximately 5.64 miles or 9.08 kilometers),\textsuperscript{63}
\end{itemize}

\begin{itemize}
\item \textsuperscript{56} \textit{Id.} § 165:10-5-7(c)(3)(B).
\item \textsuperscript{57} See Oklahoma Corporation Commission statement on proactive approach to seismic activity, http://www.occeweb.com/SeismicStatementB.pdf.
\item \textsuperscript{58} \textit{Id.}
\item \textsuperscript{60} \textit{Id.}
\item \textsuperscript{61} \textit{Id.}
\item \textsuperscript{63} 16 Tex. Admin. Code §§ 3.9(3)(B), .46(b)(1)(C).
\end{itemize}
expressly state that the Commission staff has the authority to modify, suspend, or terminate a disposal well permit if scientific data indicates that a disposal well has been determined to be contributing to seismic activity or is likely to be determined to be contributing to seismic activity,\textsuperscript{64}

authorize Commission staff to require operators to report injection volumes and pressures on a more frequent basis than the annual basis otherwise required if conditions exist that increase the risk that fluids will not be contained in the “injection interval,”\textsuperscript{65} and

allow the Commission staff to require that an applicant for a new injection permit submit information not otherwise required for a permit application, “such as logs, geologic cross-sections, pressure front boundary calculations, and/or structure maps, to demonstrate that fluids will be confined” if the location proposed for the well is one where conditions exist that increase the risk of non-containment.\textsuperscript{66}

An earlier version of the proposed revisions would have required applicants to calculate the boundary of the pressure front at which pressure would be elevated by 5 pounds per square inch (psi) (1 psi equals 6894.76 Pascal’s) after 10 years of operation at the maximum injection proposed in the permit application. The Commission explained that 10 years is the typical expected life of an injection disposal well, that basing calculations on the maximum proposed daily injection rate was conservative, and that 5 psi was toward the lower end of a 1.4 to 14 psi range recommended by some commentators for an area for which it would be prudent to require submission of historical earthquake data. But during the period for public comment on the proposed rules, several persons submitted comments stating that pressure front calculations are subject to large uncertainties. In response to those comments, the Commission revised the portion of the proposed rule requiring submission of historical earthquake data to require that the data be provided for the area within a circle equal to 100 square miles, centered at the proposed injection well site, instead of the area within the 5 psi, 10-year pressure front.\textsuperscript{67}

\textsuperscript{64} Id. §§ 3.9(6)(A), .46(d).
\textsuperscript{65} Id. §§ 3.9(11), .46(f).
\textsuperscript{66} Id. §§ 3.9(3)(C), .46(b)(1)(D).
\textsuperscript{67} See Memorandum from Cristina Self, Attorney, Office of General Counsel, to Texas Railroad Commissioners (Oct. 21, 2014), http://www.rrc.state.tx.us/media/24613/adopt-amend-3-9and3-46-seismic-activity-102814-sig.pdf.
C. Canada

1. Alberta

On February 19, 2015, the Alberta Energy Regulator ("AER") issued Subsurface Order No. 2, which requires use of a “traffic light” system when hydraulic fracturing is to be performed in a particular area.  

Under the order, a company holding a license to drill a well must assess the potential for seismicity that might be induced by hydraulic fracturing operations before beginning any well completion that will include hydraulic fracturing.  

The licensee must conduct monitoring that is sufficient to detect any seismic event of 2.0 or larger that occurs within 5.0 km of the well. In addition, the licensee must develop a plan for mitigating any seismicity that is above a magnitude of 2.0, and be prepared to implement the plan.  

If the licensee detects or becomes aware that someone else has detected a seismic event of magnitude 2.0 or greater within 5 km, the licensee must immediately notify AER and implement the traffic light plan for mitigating seismicity. If the licensee detects or becomes aware that someone else has detected a seismic event of magnitude 4.0 or greater within 5 km of the well, the licensee must immediately notify AER and immediately halt its fracturing operations.  

The hydraulic fracturing operations cannot be resumed without AER’s written consent, and the AER is not allowed to grant its consent unless the licensee develops and implements a plan that is acceptable to AER to modify operations so as to eliminate or reduce future seismicity to a magnitude below 4.0.  

The AER issued its Subsurface Order No. 2 after two series of seismic events in the Fox Creek area of Alberta—one cluster of 18 events in December 2014 that ranged between 2.7 and 3.7 in magnitude and a set of several events in January 2015 that ranged between 2.4 and 4.4 in magnitude. The events were suspected of having been induced by hydraulic fracturing operations.

2. British Columbia

The British Columbia Oil & Gas Commission has written certain provisions relating to induced seismicity into permits and has announced that it plans to incorporate those requirements into its regulations. These include requirements for increased monitoring and reporting, and a requirement that operations cease if an earthquake of magnitude 4.0 or greater is detected in the vicinity.

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69 AER Subsurface Order No. 2, supra note 67, at 1.

70 Id.

71 Id.

72 Id. at 1–2.


75 Id. at 21–22.