Submission No 33

INQUIRY INTO WATER AUGMENTATION

Name: Name suppressed

Date received: 9 August 2016

Water Augmentation Inquiry

Submission:

Dear Committee,

I write to make a submission with respect to TOR 1b – potential for aquifer recharge.

I wish to raise concerns with any proposal in relation to potential re-injection of produced and/or treated waters from the onshore conventional or unconventional gas production industry, whether from coal seams, tight formations or shale.

The reinjection of treated or untreated water from gas production or extraction has the high potential to negatively impact the beneficial use characteristics of surface and groundwater systems, rivers and wetlands in inter-connected groundwater systems, such as in the Namoi, Moree and Liverpool Plains areas. Such water is radioactive and toxic to stock and native wildlife. Even treated water remains considerably 'salted'.

Previous re-injection attempts by Eastern Star gas (see attached document 'PEL 238 Trial program) involved 'treated' produced water into a surface waterway, Bohena Creek, which proved to be a disaster for Eastern Star Gas and Santos, when it was proved by the public that the actual water being discharged into the surface waterway was at times well outside of the permissable limits and was at times the raw untreated produced water. Whatever the agreed regulatory or theoretical composition of 'treated' water, this industry has a history of cowboy behaviour, resulting in 100s of water incidents in the Pilliga area.

I attach for your consideration a position statement of the National Water Commission saying that the unconventional gas industry, including reinjection of treated waste water **'presents a substantial risk to sustainable water management given the combination of material uncertainty about water impacts, the significance of potential impacts, and the long time period over which they may emerge and continue to have effect**".

In relation to current proposals by Santos in the Pilliga, I note that treated water from Leewood reverse osmosis plant will result in accumulation of 2.2 tons/ha/annum due to the application of the treated produced water on an irrigation area by both surface and underground drip irrigation, which is a form of re-injection using pressurised water. By comparison, the natural accumulation of salts/ha/annum due to rainfall is only 40kg/ha/annum.

This water quality has the potential to contaminate the aquifers in the area which are part of the southern discharge zone of the Great Artesian Basin, on which many landholders rely. It is also unknown over the longer term where such water will migrate, with potential to impact surface waters and wildlife.

With regard to overseas experiences with aquifer re-injection, a recent study published by Stanford University has shown that re-injection of produced water can result in contamination of shallow aquifers and drinking water resources.

In March 2016, the Federation of American Scientists investigated the impacts of aquifer re-injection and reported the technique could be behind the rapid increase in seismic activity in the USA. Whilst these earthquakes may not cause much surface damage, the high pressures involved may further fracture geological structures and result in new channels for water to migrate or be cross—contaminated. The damage may never be known and never be predicted and will only emerge over time. These risks cannot be managed. Scientists have limited capability to predict fractures from seismic activity because of uncertainty in the stress state of the geology, poor information of how injected water flows after injection and poor knowledge of faults that could slip under pressure.

In conclusion, I do NOT support the government's potential plans for permitting the extractive industry to reinject water, let alone be given financial credit for reinjecting that water back into aquifers.

Yours sincerely

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Human-Induced Earthquakes from Deep-Well Injection: A Brief Overview

Peter Folger
Specialist in Energy and Natural Resources Policy

Mary Tiemann
Specialist in Environmental Policy

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CRS REPORT
Prepared for Members and
Committees of Congress

Summary

The development of unconventional oil and natural gas resources using horizontal drilling and high-volume hydraulic fracturing has created new demand for wastewater disposal wells that inject waste fluids into deep geologic strata. Deep-well injection has long been the environmentally preferred method for managing produced brine and other wastewater associated with oil and gas production. However, an increasing concern in the United States is that injection of these fluids may be responsible for increasing rates of seismic activity. The number of earthquakes of magnitude 3.0 or greater in the central and eastern United States has increased dramatically since about 2009 from an average of approximately 20 per year between 1970 and 2000 to over 100 per year in the period 2010-2013. Some of these earthquakes may be felt at the surface. For example, 20 earthquakes of magnitudes 4.0 to 4.8 have occurred in central Oklahoma since 2009. The largest earthquake in Oklahoma history (magnitude 5.6) occurred on November 5, 2011, near Prague, causing damage to several structures nearby. Central and northern Oklahoma were seismically active regions before the recent increase in the volume of waste fluid injection through deep wells. However, the recent earthquake swarm does not seem to be due to typical, random changes in the rate of seismicity, according to the U.S. Geological Survey.

The relationship between earthquake activity and the timing of injection, the amount and rate of waste fluid injected, and other factors are still uncertain and are current research topics. Despite increasing evidence linking some deep-well disposal activities with human-induced earthquakes, only a small fraction of the more than 30,000 U.S. wastewater disposal wells appears to be associated with damaging earthquakes.

The potential for damaging earthquakes caused by hydraulic fracturing, as opposed to deep-well injection of wastewater from oil and gas activities, appears to be much smaller. Hydraulic fracturing intentionally creates fractures in rocks and induces microseismicity, mostly of less than magnitude 1.0—too small to feel or cause damage. In a few cases, however, hydraulic fracturing has led directly to earthquakes larger than magnitude 2.0, including at sites in Oklahoma, Ohio, England, and Canada.

The Environmental Protection Agency's (EPA) Underground Injection Control (UIC) program under the Safe Drinking Water Act (SDWA) regulates the subsurface injection of fluids to protect underground drinking water sources. EPA has issued regulations for six classes of injection wells, including Class II wells used for oil and gas wastewater disposal and enhanced recovery. Most oil and gas states administer the Class II program. Although the SDWA does not address seismicity, EPA rules for certain well classes require evaluation of seismic risk. Such requirements do not apply to Class II wells; however, EPA has developed a framework for evaluating seismic risk when reviewing Class II permit applications in states where EPA administers this program.

In 2011, in response to seismic events thought to be associated with wastewater disposal wells, EPA authorized a national technical work group to develop technical recommendations to address the risk of Class II disposal-induced seismicity. In February 2015, EPA issued a document outlining best practices for minimizing and managing such risks. How Congress shapes EPA or other agency efforts to address human-caused earthquakes may be an issue in the 114th Congress.

At the state level, several states have increased regulation and oversight of Class II disposal wells in response to induced seismicity concerns. In 2014, state oil and gas and groundwater protection agencies established a multi-state work group on injection wells and induced seismicity.

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Introduction

Human-induced earthquakes, also known as induced seismicity, are an increasing concern in regions of the United States where the produced fluids and wastewaters from oil and natural gas production activities are being injected into the subsurface through deep disposal wells. The immediate concern is that injection of these fluids into underground formations may be responsible for damaging earthquakes in regions that typically do not experience much seismic activity. Induced seismicity has garnered increased attention partly as a result of the rapid development of unconventional oil and gas resources using hydraulic fracturing (often referred to as fracking). Specifically, the use of high-volume hydraulic fracturing has contributed significantly to the volume of wastewater requiring disposal and has also created demand for disposal wells in new locations. It is important to distinguish between seismic activity possibly related to hydraulic fracturing itself and the possibility of human-induced earthquakes related to injecting fluids down disposal wells, which may not be located near where wells were fracked.

Human activities have long been known to have induced earthquakes in some instances: impoundment of reservoirs, surface and underground mining, withdrawal of fluids such as oil and gas, and injection of fluids into subsurface formations. With the increase in the use of horizontal drilling and hydraulic fracturing to extract oil and gas from shale, and the concomitant increase in the amount of fluids that are injected for high-volume hydraulic fracturing and for disposal, there are several indications of a link between the injected fluids and unusual seismic activity. **Figure 1** illustrates conceptually the processes of deep-well injection and the linkage to triggering earthquakes.

The principal seismic hazard that has emerged from the increased amount of oil and gas activity in the United States appears to be related to disposal of wastewater using deep-well injection in some regions of the country. For example, in a May 2, 2014, joint statement between the Oklahoma Geological Survey and the U.S. Geological Survey (USGS), researchers reported a 50% increase in the rate of earthquakes in Oklahoma since 2013.[1] A USGS analysis of the rising trend suggested that a likely contributing factor was deep-well injection of oil-and-gas-related wastewater.[2] But the relationship between earthquake activity and the timing of injection, the amount and rate of fluid injected, and other factors are still uncertain and are current research topics. A 2013 article that reviewed the current understanding of human-caused earthquakes noted that, of the more than 30,000 wastewater disposal wells classified by the Environmental Protection Agency (EPA) as Class II,[3] only a small fraction appears to be associated with damaging earthquakes.[4]

The potential for damaging earthquakes caused by hydraulic fracturing, as opposed to deep-well injection of wastewater from fracking and other oil and natural gas production, appears to be

[1] U.S. Geological Survey/Oklahoma Geological Survey joint statement, "Record Number of Oklahoma Tremors Raises Possibility of Damaging Earthquakes," May 2, 2014, http://earthquake.usgs.gov/regional/ceus/products/newsrelease_05022014.php.

[2] Ibid.

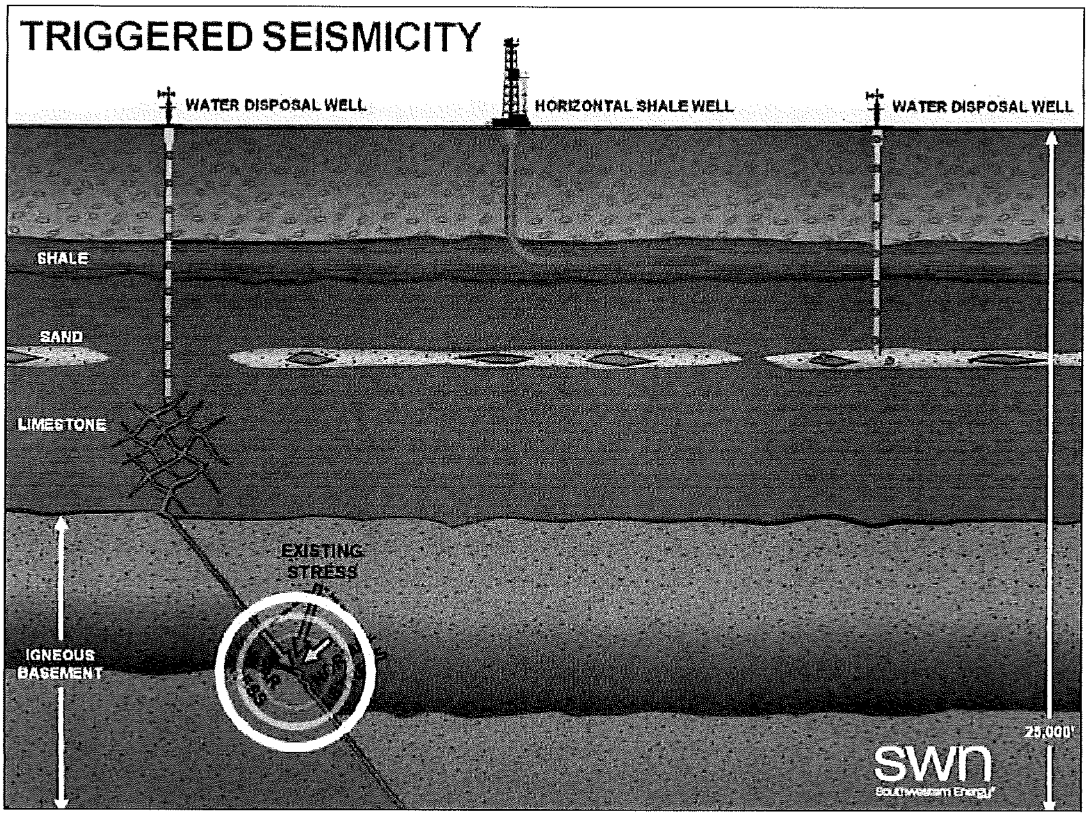
[3] EPA has established regulations for six classes of injection wells, including Class II wells used for the injection of fluids for enhanced oil and gas recovery and wastewater disposal. See section on "EPA Regulation of Underground Injection Activities" for more information.

[4] William L. Ellsworth, "Injection-Induced Earthquakes," *Science*, vol. 341, July 12, 2013, http://www.sciencemag.org/content/341/6142/1225942.full.

much smaller. The 2013 review article indicated that the vast majority of wells used for hydraulic fracturing itself cause microearthquakes—the results of fracturing the rock to extract natural gas—which are typically too small to be felt or cause damage at the surface. The 2013 review documented a few cases where fracking caused detectable earthquakes felt at the surface, but these were too small to cause damage.

This report reviews the current scientific understanding of induced seismicity, primarily in the context of Class II oil and gas wastewater disposal wells. The report also outlines the regulatory framework for these injection wells and identifies several federal and state initiatives responding to recent events of induced seismicity associated with Class II disposal.

Figure 1. Illustration of the Possible Relationship Between Deep-Well Injection and Induced Seismicity



Source: North Carolina General Assembly, presentation by the Arkansas Oil and Gas Commission, *Fayetteville Shale Overview, for the North Carolina Delegation*, slide 33, prepared by Southwestern Energy, November 21, 2013, http://www.ncleg.net/documentsites/committees/BCCI-6576/2013-2014/5%20-%20Feb.%204.%202014/Presentations%20and%20Handouts/Arkansas%20Site%20Visit%20Attachments/Att.%205%20-%20AOGC%20Presentation%2011-21-13%20%283%29.pdf.

Notes: The figure is for illustrative purposes only and does not depict any specific location or geological formation.

Congressional Interest

How deep-well injection is linked to induced seismicity, and state and federal efforts to address that linkage, are of interest to Congress because of the potential implications to continued development of unconventional oil and gas resources in the United States. If the current boom in onshore oil and gas production continues, then deep-well injection of waste fluids is likely to also continue and may increase in volume. Also, what Congress, the federal government, and the states do to address and mitigate possible human-caused earthquakes from deep-well injection of oil-and-gas-related fluids may provide some guidance for the injection and sequestration of carbon dioxide. Carbon dioxide sequestration would involve ongoing, long-term, high-volume, high-pressure injection via deep wells. Several large-scale injection experiments are currently underway; however, the relationship between long-term and high-volume carbon dioxide injection and induced earthquakes is not known.

The federal Safe Drinking Water Act (SDWA) authorizes EPA to regulate underground injection activities to prevent endangerment of underground sources of drinking water. The SDWA does not address seismicity; however, EPA underground injection control (UIC) program regulations include seismicity-related siting and testing requirements for hazardous waste and carbon sequestration injection wells. Such requirements are not included in regulations governing oil and gas wastewater disposal (Class II) wells, although regulators have the discretionary authority to add conditions to individual permits. In February 2015, EPA released a document outlining technical recommendations and best practices for minimizing and managing the impacts of induced seismicity from oil and gas wastewater disposal wells.[5]

In the 114th Congress, no legislation has been introduced to address induced seismicity associated with oil and gas wastewater disposal or other injection activities. On March 18, 2015, the Fracturing Responsibility and Awareness of Chemicals Act (S. 785) was introduced in the Senate. Among other things, the bill would amend the SDWA to include the injection of fluids and proppants for hydraulic fracturing in the definition of underground injection for purposes of the SDWA. A similar bill, H.R. 1482, was introduced in the House on March 19. It is unclear how the legislation would affect EPA regulatory authority regarding the potential for induced seismicity from hydraulic fracturing, unless it could be shown that induced seismicity caused by the hydraulic fracturing process posed a threat to underground sources of drinking water. As discussed, the potential for damaging earthquakes caused by hydraulic fracturing, as opposed to deep-well injection of wastewater from oil and gas activities, appears to be much smaller.

Current Scientific Understanding of Induced Seismicity in the United States

Since about the 1920s, it has been known that pumping fluids in and out of Earth's subsurface has the potential to cause earthquakes.[6] In addition, a wide range of other human activities have been known to cause earthquakes, including the filling of large reservoirs, mining, geothermal energy extraction, and others.[7] The mechanics of how human industrial activities may cause earthquakes are fairly well known: The human perturbation changes the amount of stress in Earth's crust, and the forces that prevent faults from slipping become unequal. Once those forces are out of

[5] U.S. Environmental Protection Agency, *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches*, Underground Injection Control National Technical Workgroup, November 12, 2014 (released February 6, 2015), http://www.epa.gov/r5water/uic/ntwg/pdfs/induced-seismicity-201502.pdf.

[6] National Research Council (NRC), "Induced Seismicity Potential in Energy Technologies," 2013, p. vii.

[7] Ellsworth, "Injection-Induced Earthquakes."

equilibrium, the fault ceases to be locked, and the fault slips, sending shock waves out from the fault that potentially reach the surface and are strong enough to be felt or cause damage.

Even knowing that human activities can cause earthquakes, and the mechanics of the process, it is currently nearly impossible to discriminate between man-made earthquakes and those caused by natural tectonic forces through the use of modern seismological methods.[8] Other lines of evidence are required to positively link human activities to earthquakes. That linkage is becoming increasingly well understood in parts of the United States where activities related to oil and gas extraction—deep-well injection of oil and gas wastewater and hydraulic fracturing—have increased significantly in the last few years, particularly in Oklahoma, Texas, Arkansas, Ohio, Colorado, and several other states.[9] Nevertheless, the majority of these activities are not known to cause earthquakes; most are termed aseismic (i.e., not causing any appreciable seismic activity, at least for earthquakes greater than magnitude 3).[10] (See text box below for a brief description of earthquake magnitude and intensity.)

Scientists currently have limited capability to predict human-caused earthquakes for a number of reasons, including uncertainty in knowing the state of stress in the earth, rudimentary knowledge of how injected fluids flow underground after injection, poor knowledge of faults that could potentially slip and cause earthquakes, limited networks of seismometers (instruments used to measure seismicity) in regions of the country where most oil-and-gas-related activities are occurring, and difficulty in predicting how large an earthquake will grow once it is triggered.[11]

Earthquake Magnitude and Intensity[12]

Earthquake magnitude is a number that characterizes the relative size of an earthquake. It was historically reported using the *Richter* scale. Richter magnitude is calculated from the strongest seismic wave recorded from the earthquake and is based on a logarithmic (base 10) scale: for each whole number increase in the Richter scale, the ground motion increases by 10 times. The amount of energy released per whole number increase, however, goes up by a factor of 32. The *moment magnitude* (M) scale is another expression of earthquake size, or energy released during an earthquake, that roughly corresponds to the Richter magnitude and is used by most seismologists because it more accurately describes the size of very large earthquakes. Sometimes earthquakes will be reported using qualitative terms, such as Great or Moderate. Generally, these terms refer to magnitudes as follows: Great (M>8); Major (M>7); Strong (M>6); Moderate (M>5); Light (M>4); Minor (M>3); and Micro (M<3). This report uses the moment magnitude scale, which is generally consistent with the Richter scale.[13]

[8] Ibid.

[9] According to the NRC report, seismic events likely related to energy development have been documented in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, Ohio, Oklahoma, and Texas. NRC, "Induced Seismicity Potential in Energy Technologies," p. 6.

[10] Ibid.

[11] William Leith, Senior Science Advisor for Earthquakes and Geologic Hazards, U.S. Geological Survey, "USGS Research into the Causes & Consequences of Injection-Induced Seismicity," presentation at the U.S. Energy Association, October 30, 2014, http://www.usea.org/sites/default/files/event-/Leith%20induced%20for%20DOE-USEA%20Oct14.pdf.

[12] For a more general discussion of earthquakes, see CRS Report RL33861, *Earthquakes: Risk, Detection, Warning, and Research*, by Peter Folger.

[13] U.S. Geological Survey FAQs, http://earthquake.usgs.gov/learn/faq/; and Magnitude/Intensity Comparison, at http://earthquake.usgs.gov/learn/topics/mag_vs_int.php.

A Historical Example: The Rocky Mountain Arsenal

Prior to the moment magnitude (M) 5.6 earthquake that occurred on November 6, 2011, in central Oklahoma (discussed below), an M 4.8 earthquake that struck northeast Denver on August 9, 1967, was generally accepted as the largest recorded human-induced earthquake. The M 4.8 earthquake was part of a series of earthquakes that began within several months of the 1961 start of deep-well injection of hazardous chemicals produced at the Rocky Mountain Arsenal defense plant. The earthquakes continued after injection ceased in February 1966.[14] The disposal well was drilled through the flat-lying sedimentary rocks into the underlying older crystalline rocks more than 12,000 feet deep, and injection rates varied from 2 million gallons per month to as much as 5.5 million gallons per month.[15] Earthquake activity declined after 1967 but continued for the next two decades. Scientists concluded that the injection triggered the earthquakes and that, even after injection ceased, the migration of the underground pressure front continued for years and initiated earthquakes along an ancient fault system many miles away from the injection well.[16] As discussed below, the Rocky Mountain Arsenal earthquakes had many similarities to the recent increased earthquake activity in some deep-well injection activities of the United States, including, for example, injection near or in underlying crystalline bedrock, activation of fault systems miles away from the well, and migration of the pressure front away from the point of injection months or years after injection stopped.

Deep-Well Injection of Oil and Natural Gas Wastewaters

The number of earthquakes of M greater than 3.0 in the central and eastern United States has increased dramatically since about 2009, from an average of approximately 29 per year between 1970 and 2000 to over 100 per year in the period 2010-2013.[17] **Figure 2** shows this increase in earthquake frequency as a steep increase in slope of the line of *cumulative* number of earthquakes starting in about 2004 but increasing sharply from about 2009, and departing from the relatively unchanging slope of the average number of earthquakes from 1970 to 2000, depicted as a dashed line.

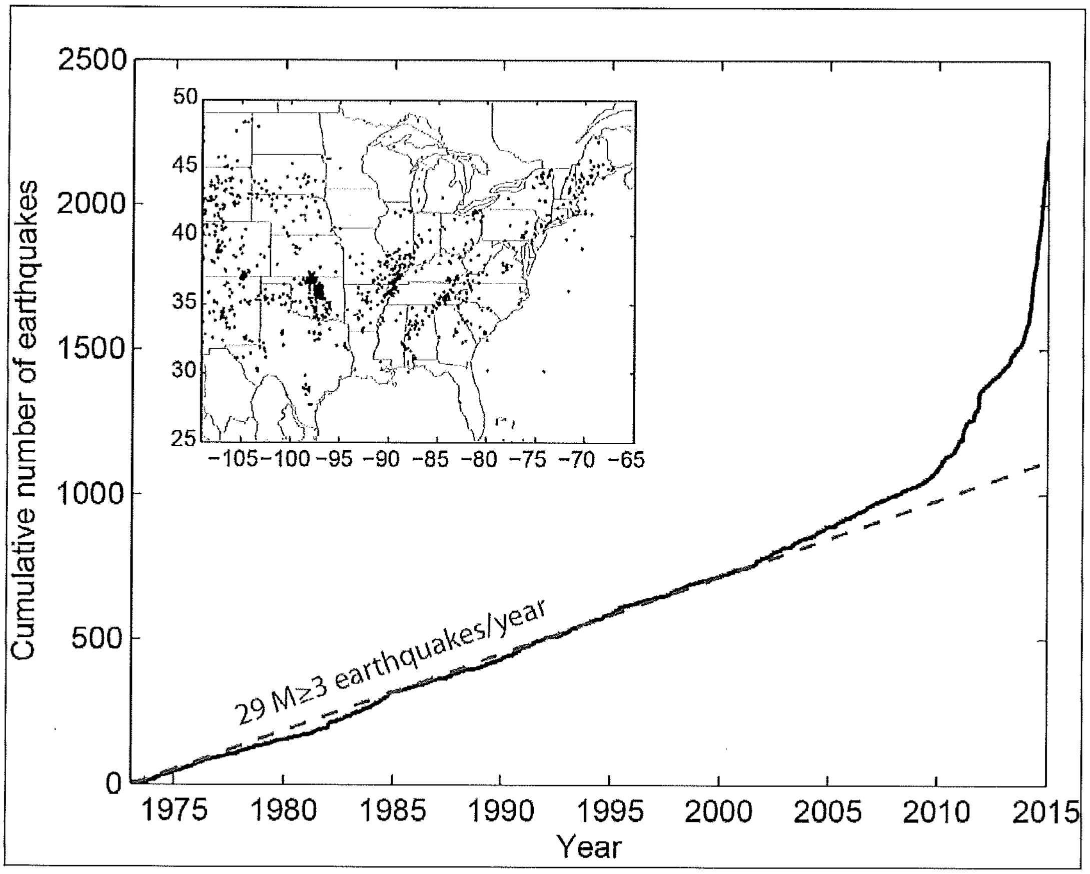
[14] J. H. Healy et al., "The Denver Earthquakes," *Science*, vol. 161, no. 3848 (September 27, 1968), pp. 1301-1310.

[15] Ibid.

[16] Ellsworth, "Injection-Induced Earthquakes."

[17] U.S. Geological Survey, "Man-Made Earthquakes Update," January 17, 2014, http://www.usgs.gov/blogs/features/usgs_top_story/man-made-earthquakes/.

Figure 2. Cumulative Number of Magnitude 3.0 or Greater Earthquakes in the Central and Eastern United States, 1970-2014



Source: U.S. Geological Survey, Earthquake Hazards Program, http://earthquake.usgs.gov/research/induced/.

Notes: The dashed line corresponds to the long-term rate of about 29 earthquakes of M 3.0 or greater per year. The straight line on this type of cumulative plot indicates that the average number of earthquakes per year is about the same, which is the case here prior to about 2004. The departure from the straight line after 2003, and particularly after 2009, indicates an increase in the number of earthquakes greater than magnitude 3.0 per year.

States experiencing higher levels of seismic activity compared to the pre-2005 average include Arkansas, Colorado, Texas, New Mexico, Ohio, Oklahoma, and Virginia.[18] More recently, seismic activity has increased in south-central Kansas compared to levels in 2013 and before, and there may be a link to deep-well injection of produced waters from unconventional oil and gas development. For some of these states, there is an increasing realization of a potential linkage between deep-well injection of oil and gas wastewaters and earthquakes, as the number of wells and volume of disposed wastewater have increased concomitant with increased domestic oil and gas production, particularly since about 2008 and 2009.[19] Several instances of suspected human-induced earthquakes that garnered media and national attention include the following:

[18] Ellsworth, "Injection-Induced Earthquakes."

[19] Ibid.

- October 2008/May 2009: M 2.5-3.3 earthquakes near Dallas-Fort Worth, Texas;[20]
- August 2010/February 2011: earthquake swarm in central Arkansas, with M 4.7 earthquake on February 27, 2011, near Greenbrier, Arkansas;[21]
- August 2011: M 5.3 earthquake in the Raton Basin, northern New Mexico/southern Colorado;[22]
- December 2011: M 3.9 earthquake near Youngstown, OH;[23] and
- November 2011: M 5.6 earthquake near Prague, OK.[24]

These examples are summarized below.

Colorado and New Mexico

An investigation of the seismicity in the Raton Basin of northern New Mexico and southern Colorado concluded that increased seismic activity since August 2001 was associated with deep-well injection of wastewater related to the production of natural gas from coal-bed methane fields.[25] The study linked the increased seismicity to two high-volume disposal wells that injected more than seven times as much fluid as the Rocky Mountain Arsenal well in the period leading up to an August 2011 M 5.3 earthquake in the Raton Basin.

Arkansas

A study of a 2010-2011 earthquake swarm in central Arkansas noted that the study area experienced an increase in the number of M 2.5 or greater earthquakes since 2009, when the first of eight deep-well injection disposal wells became operational.[26] The rate of M greater than 2.5 earthquakes increased from 1 in 2007 to 2 in 2008, 10 in 2009, 54 in 2010, and 157 in 2011, including a M 4.7 earthquake on February 27, 2011.[27] Although the area has a history of seismic activity, including earthquake swarms in the early 1980s, the study noted that 98% of the earthquakes during the 2010-2011 swarm occurred within six kilometers of one of the waste disposal wells. In response, the Arkansas Oil and Gas Commission (AOGC) imposed a

[20] Cliff Frohlich et al., "Dallas-Fort Worth Earthquakes Coincident with Activity Associated with Natural Gas Production," *The Leading Edge*, vol. 29, no. 3 (2010), pp. 270-275.

[21] U.S. Geological Survey, Earthquake Hazards Program, "Poster of the 2010-2011 Arkansas Earthquake Swarm," http://earthquake.usgs.gov/earthquakes/eqarchives/poster/2011/20110228.php.

[22] J. L. Rubinstein, W. L. Ellsworth, and A. McGarr, "The 2001-Present Triggered Seismicity Sequence in the Raton Basin of Southern Colorado/Northern New Mexico," talk delivered at the Seismological Society of America Annual Meeting, Salt Lake City, UT, April 19, 2013, pp. Abstract #13-206.

[23] Won-Young Kim, "Induced Seismicity Associated with Fluid Injection into a Deep Well in Youngstown, Ohio," *Journal of Geophysical Research—Solid Earth*, vol. 118, no. 7 (July 19, 2013), pp. 3506-3518.

[24] Danielle F. Sumy et al., "Observations of Static Coulomb Stress Triggering of the November 2011 M 5.7 Oklahoma Earthquake Sequence," *Journal of Geophysical Research—Solid Earth*, vol. 119, no. 3 (March 2014), http://onlinelibrary.wiley.com/doi/10.1002/2013JB010612/abstract.

[25] Rubinstein, Ellsworth, and McGarr, "The 2001-Present Triggered Seismicity Sequence."

[26] S. Horton, "Disposal of Hydrofracking Waste Fluid by Injection into Subsurface Aquifers Triggers Earthquake Swarm in Central Arkansas with Potential for Damaging Earthquake," *Seismological Research Letters*, vol. 83, no. 2 (2012), pp. 250-260.

[27] U.S. Geological Survey, Earthquake Hazards Program, "Poster of the 2010-2011 Arkansas Earthquake Swarm."

moratorium on oil and gas wastewater disposal wells in a 1,150-square-mile area of central Arkansas. Four disposal wells were shut down following injection of wastewater from the Fayetteville Shale.

Texas

A study of increased seismicity near Dallas-Fort Worth and Cleburne, Texas, identified a possible linkage between high injection rates of oilfield-related wastewater and earthquakes of M 1.5 or greater and found that all 24 of the most reliably located earthquake epicenters occurred within about 1.5 miles of one or more injection wells.[28] The study examined earthquakes occurring between 2009 and 2011 and noted that it was possible that some of the earthquakes had a natural origin but that it was implausible that all were naturally occurring. The investigation showed a probable linkage between earthquakes and some high-volume injection wells but also pointed out that in other regions of the study area there exist similar high-volume injection wells but no increased seismic activity. The study hypothesized that injection might trigger earthquakes only if the injected fluids reach suitably oriented nearby faults under regional tectonic stress.

Ohio

A study reported that the Youngstown, Ohio, area, where there were no known past earthquakes, experienced over 100 small earthquakes between January 2011 and February 2012.[29] The largest among the six felt earthquakes was an M 3.9 event that occurred on December 31, 2011. The study concluded that the earthquakes, which occurred within the Precambrian crystalline rocks lying beneath sedimentary rocks, were induced by fluid injection from a deep injection well. The study noted that the level of seismicity dropped after periods when the injection volumes and pressures were at their lowest levels, indicating that the earthquakes may have been caused by pressure buildup and then stopped when the pressure dropped.

Oklahoma

According to the USGS and the Oklahoma Geological Survey, the rate of earthquakes in central Oklahoma increased by 50% between October 2013 and May 2014.[30] The number of M 3.0 or greater earthquakes was 145 in the first four months of 2014, which exceeded the previous record of 109 M 3.0 or greater earthquakes annually set in 2013 and continued the trend of increasing seismic activity since about 2009 (**Figure 3**).[31]

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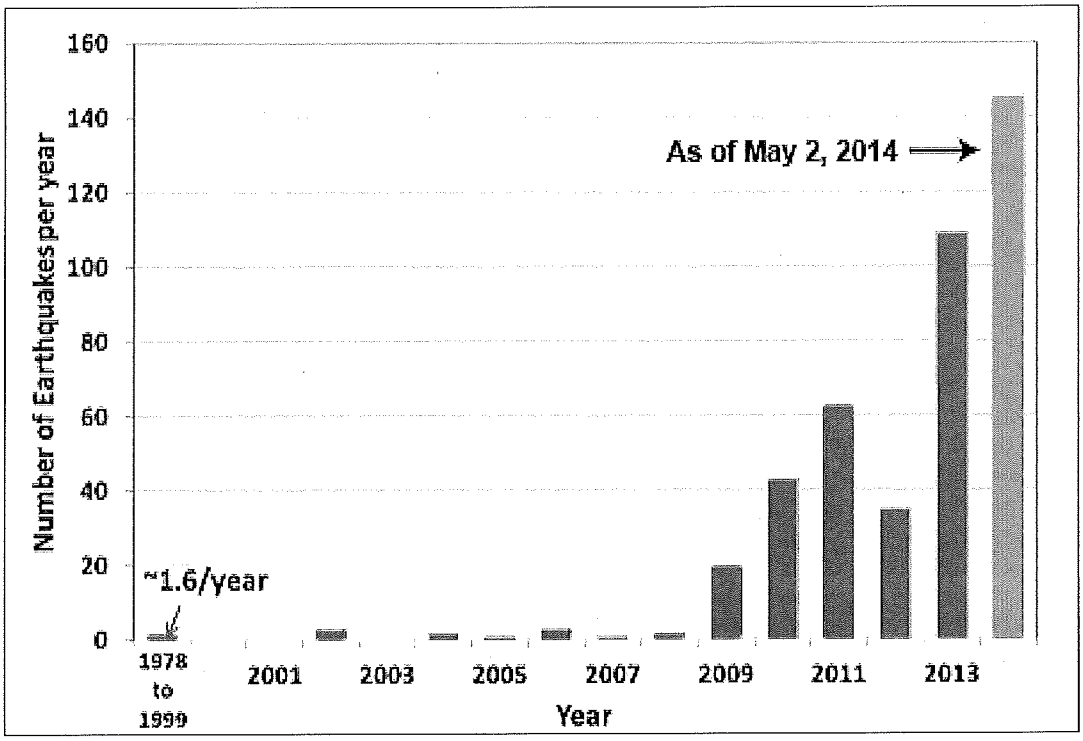
[28] Cliff Frohlich, "Two-Year Survey Comparing Earthquake Activity and Injection-Well Locations in the Barnett Shale, Texas," *Proceedings of the National Academy of Sciences*, vol. 109, no. 35 (August 28, 2012), pp. 13934-13938.

[29] Won-Young Kim, "Induced Seismicity Associated with Fluid Injection into a Deep Well in Youngstown, Ohio," *Journal of Geophysical Research—Solid Earth*, vol. 118, no. 7 (July 19, 2013), pp. 3506-3518.

[30] U.S. Geological Survey, "Record Number of Oklahoma Tremors Raises Possibility of Damaging Earthquakes," Joint USGS-Oklahoma Geological Survey joint statement, May 2, 2014, http://earthquake.usgs.gov/regional/ceus/products/newsrelease_05022014.php.

[31] Ibid.

Figure 3. Oklahoma Earthquakes of M 3.0 or Greater



Source: U.S. Geological Survey, "Record Number of Oklahoma Tremors Raises Possibility of Damaging Earthquakes," Updated USGS-Oklahoma Geological Survey Joint Statement on Oklahoma Earthquakes, May 2, 2014, http://earthquake.usgs.gov/contactus/golden/newsrelease_05022014.php. Modified by CRS.

Notes: Figure shows that 145 earthquakes of M 3.0 or greater occurred between January 1, 2014, and May 2, 2014. From 1978 through 2008, the state averaged about two M 3.0 or greater earthquakes per year (approximately 1.6 M 3.0 or greater earthquakes between 1978 and 1999, as shown on the figure).

Since 2009, 20 earthquakes of M 4.0 to M 4.8 have struck central Oklahoma. The largest earthquake in Oklahoma history—M 5.6—occurred on November 5, 2011, near Prague, causing damage to several structures nearby. Central and northern Oklahoma are seismically active regions; however, the recent earthquake swarm does not seem to be due to typical, random changes in the rate of seismicity, according to a USGS statistical analysis.[32] The statistical analysis suggested that the increased rate of seismicity could be due to deep-well wastewater injection and that an M 5.0 foreshock that preceded the M 5.6 earthquake on November 5, 2011, may have been induced by deep-well injection.[33] The M 5.0 event could then have triggered the subsequent M 5.6 event less than a day later.

Kansas

According to the Kansas Geological Survey, several earthquakes were recorded in south-central Kansas in 2013 and 2014 in the vicinity of wastewater injection wells.[34] One earthquake in

[32] Ibid.

[33] Sumy et al., "Observations."

[34] Rex C. Buchanan et al., Kansas Geological Survey, "Induced Seismicity: The Potential for Triggered Earthquakes in (continued...)

Harper County in 2013 had a magnitude of 4.3, and three earthquakes in Sumner County in 2014 had magnitudes over 3.0.[35] Although a definitive connection to wastewater injection had not been established, increasing seismicity in Kansas near areas of wastewater injection led the Kansas governor to convene a task force on induced seismicity (see discussion below).

National Issues

The examples above indicate an increasing likelihood that in some instances, deep-well injection is linked to earthquakes, some greater than M 5.0. A human-induced M 6.0 or greater earthquake due to deep-well injection has not been observed, although scientists cannot rule out the possibility that one could occur in the future. However, the great majority of deep injection wells in the United States (UIC Class II) appear to be aseismic for earthquakes of M 3.0 or more.[36] Some observers conclude that most wells permitted for deep-well injection are in geologic formations that likely have a low risk of failure leading to damaging earthquakes if the injected fluids remain in the intended geologic structure.[37] The largest earthquakes apparently triggered by deep-well injection involved faulting that was deeper than the injection interval, suggesting to some that transmitting pressure from the injection point to deeper zones in basement rocks—below the sedimentary layers—increases the potential for triggering earthquakes.[38]

Changes to the U.S. Earthquake Hazard Maps

The current model for assessing the overall seismic hazard in the United States, which is used to set design provisions in building codes, intentionally excluded the seismic hazard posed by human-induced earthquakes in its most recent update in 2014.[39] This was done, in part, because natural seismicity is assumed to be time-independent[40] in assessing the earthquake hazard, and researchers were not sure how to treat induced earthquakes in their seismic hazard analysis. The natural tectonic processes driving the earthquake hazard are assumed to be nearly constant, which is why portions of California and Alaska, parts of the mid-continent, and other areas of the country are shown on the national seismic hazard maps with only small variations from year to year.[41] In contrast, human-induced seismicity varies in time—in this case—because of changes in injection rate, location, volume, depth of the injection, and other factors. Those characteristics likely rule out combining natural seismic hazards with human-induced seismic hazards on one

(...continued)

Kansas," Public Information Circular 36, April 10, 2014, http://www.kgs.ku.edu/Publications/PIC/pic36.html.

[35] Rex Buchanan, "Recent Seismic Activity in Kansas: Events and Responses," Independent Petroleum Association of America, Colorado Springs, CO, June 18, 2014, http://www.ipaa.org/meetings/ppt/2014Midyear/RexBuchanan.pdf.

[36] Ellsworth, "Injection-Induced Earthquakes."

[37] Ibid.

[38] Ibid.

[39] A. McGarr et al., "Coping with Earthquakes Induced by Fluid Injection," *Science*, vol. 347, no. 6224 (February 20, 2015), pp. 830-831.

[40] Time-independent in this context means that the tectonic forces that create the earthquake hazard are assumed to be relatively non-changing over a specified time period; in this case, the U.S. Geological Survey designates a 50-year time period. The earthquake hazard caused by deep-well injection can vary on a much shorter time scale, depending on how the wells are operated.

[41] See, for example, the National Seismic Hazard Maps published by the U.S. Geological Survey, http://earthquake.usgs.gov/hazards/products/conterminous/. For more information about earthquakes generally, see CRS Report RL33861, *Earthquakes: Risk, Detection, Warning, and Research*, by Peter Folger.

map.[42] Instead, work has been ongoing to produce a separate one-year hazard model for human-induced earthquakes.[43]

On April 23, 2015, the USGS released a preliminary attempt at modeling the seismic hazard posed by induced earthquakes. In the report, the USGS noted

> Forecasting the seismic hazard from induced earthquakes is fundamentally different from forecasting the seismic hazard for natural, tectonic earthquakes. This is because the spatio-temporal patterns of induced earthquakes are reliant on economic forces and public policy decisions regarding extraction and injection of fluids. As such, the rates of induced earthquakes are inherently variable and nonstationary. Therefore, we only make maps based on an annual rate of exceedance rather than the 50-year rates calculated for previous USGS hazard maps.[44]

The report also stated that a final model for induced earthquakes will be released after "further consideration of the reliability and scientific acceptability of each alternative input model." Despite its preliminary nature, the report concluded that induced seismicity greatly increases the seismic hazard in Oklahoma and other induced seismicity zones compared to the seismic hazard assessed in the 2014 maps that excluded induced seismicity.[45]

Hydraulic Fracturing

Hydraulic fracturing (often referred to as fracking) is the process of injecting a slurry of water, chemicals, and sand at high pressure to fracture oil- and gas-bearing rocks in order to provide permeable pathways to extract hydrocarbons.[46] Fracking has been employed with increasing frequency over the past decade or so to produce oil and natural gas from "unconventional" formations (e.g., shale)—those geologic strata that contained hydrocarbons but because of natural impermeability were not exploitable by conventional oil and gas producing methods. Fracking intentionally propagates fractures in the rocks to improve permeability. Fracking induces microseismicity, mostly less than M 1.0—too small to feel or cause damage. In some cases, fracking has led to earthquakes larger than M 2.0, including at sites in Oklahoma, Ohio, England, and Canada. Hydraulic fracturing is generally thought to present less of a risk than disposal wells for inducing large earthquakes, because the injections are short-term and add smaller amounts of fluid into the subsurface compared to most disposal wells.

Canada

Between April 2009 and July 2011 and over a five-day period in December 2011, nearly 40 seismic events were recorded in the Horn River Basin, northeast British Columbia, ranging from

[42] A. McGarr et al., "Coping with Earthquakes Induced by Fluid Injection."

[43] Ibid., p. 830.

[44] M. D. Petersen et al., *Incorporating Induced Seismicity in the 2014 United States National Seismic Hazard Model*, U.S. Geological Survey, April 23, 2015, p. 1, http://pubs.usgs.gov/of/2015/1070/pdf/ofr2015-1070.pdf.

[45] For a more detailed discussion of U.S. earthquake hazards and risk and the U.S. national earthquake hazard maps, see CRS Report RL33861, *Earthquakes: Risk, Detection, Warning, and Research*, by Peter Folger.

[46] This process has also been used for enhanced geothermal energy development, in which rocks are fractured to create permeable pathways to circulate fluids at depth. The fluids are heated by Earth's natural heat and then recirculated to the surface to drive a turbine and generate electricity.

M 2.2 to M 3.8.[47] A subsequent investigation indicated that the seismic events were linked to fluid injection during hydraulic fracturing activities near pre-existing faults. In contrast to the vast majority of hydraulic fracturing injection activities, which cause earthquakes not felt at the surface (e.g., over 8,000 fracking completions in the Horn River Basin without any associated anomalous seismicity), these anomalous seismic events were felt at the ground surface.

England

In Blackpool, England, hydraulic fracturing injection activities led to a series of small earthquakes ranging up to M 2.3, between March 28, 2011, and May 28, 2011.[48] These seismic events were not large enough to be felt at the surface but were strong enough to deform some of the well casing on the horizontal portion of the production well used for fracking the shale gas-bearing formation.

Oklahoma

In south-central Oklahoma, hydraulic fracturing injections between January 16, 2011, and January 22, 2011, induced a series of 116 earthquakes of M 0.6 to M 2.9, according to one study.[49] The study concluded that the lack of similar seismic activity prior to the fracking and after fracking ceased, among other factors, linked the fracking activities to the earthquakes. More recently presented work on the link between hydraulic fracturing and earthquakes in Oklahoma seems to further strengthen the association between fracking and earthquakes that may rarely exceed M 3.0 or even M 4.0 in some cases.[50] The more recent work in Oklahoma also indicated that the vast majority of fracking operations did not create anomalous seismicity.

Ohio

Recently published research on a series of small earthquakes in Harrison County, Ohio, indicated that hydraulic fracturing operations affected a previously unmapped fault in the Precambrian crystalline rocks lying below the sedimentary rocks that were being hydraulically fractured.[51] None of the Harrison County earthquakes exceeded magnitude 2.2, but various lines of evidence suggested that the fault responsible for the small earthquake was triggered by hydraulic fracturing operations. Some seismic activity possibly related to fracking in the Marcellus Shale and the

[47] BC Oil and Gas Commission, *Investigation of Observed Seismicity in the Horn River Basin,* August 2012, http://www.bcogc.ca/node/8046/download.

[48] Christopher A. Green, Peter Styles, and Brian J. Baptie, *Preese Hall Shale Gas Fracturing Review & Recommendations for Induced Seismic Mitigation,* April 2012, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/15745/5075-preese-hall-shale-gas-fracturing-review.pdf.

[49] Austin Holland, "Earthquakes Triggered by Hydraulic Fracturing in South-Central Oklahoma," *Bulletin of the Seismological Society of America,* vol. 103, no. 3 (June 2013), pp. 1784-1792.

[50] Austin Holland, "Induced Seismicity 'Unknown Knowns': The Role of Stress and Other Difficult to Measure Parameters of the Subsurface," presentation at the U.S. Energy Association Symposium: Subsurface Technology and Engineering Challenges and R&D Opportunities, Washington, DC, October 30, 2014, http://www.usea.org/event/subsurface-technology-engineering-challenges-and-rd-opportunities-stress-state-and-induced.

[51] Paul A. Friberg, Glenda M. Besana-Ostman, and Ilya Dricker, "Characterization of an Earthquake Sequence Triggered by Hydraulic Fracturing in Harrison County, Ohio," *Seismological Research Letters,* vol. 85, no. 6 (November/December 2014), pp. 1-13.

underlying Utica Shale led to changes in how Ohio permits wells.[52] The permitting changes include requirements to install seismic monitoring equipment if drilling will take place within three miles of a known fault or in an area with seismic activity greater than M 2.0. Further, if the monitors detect a seismic event greater than M 1.0, activities at the site must cease while the cause is investigated.

Other Hydraulic Fracturing Issues

One of the major shale gas plays in the United States, the Marcellus Shale—which underlies western Pennsylvania and portions of New York, West Virginia, and Ohio—occurs in a region of relatively low levels of natural seismic activity. Despite thousands of hydraulic fracturing operations in the past decade or so, only a handful of M 2.0 or greater earthquakes were detected within the footprint of the Marcellus Shale, as measured by a regional seismographic network.[53] The earthquake activity recorded in the Youngstown, OH, region was related to deep-well injection of waste fluids from the development of Marcellus Shale gas but was not associated with hydraulic fracturing of Marcellus Shale in Pennsylvania.[54]

The linkage between hydraulic fracturing itself and the potential for generating earthquakes large enough to be felt at the ground surface is an area of active research. It appears to be the case that hydraulic fracturing operations mostly create microseismic activity—too small to be felt—associated with fracturing the target formation to release trapped natural gas or oil. However, if the hydraulic fracturing fluid injection affects a nearby fault, there exists the potential for larger earthquakes possibly strong enough to be felt at the surface, as was the case in the Horn River Basin of western Canada.

Overview of the Current Regulatory Structure Regarding Induced Seismicity

The National Research Council (NRC) estimates that conventional oil and gas production and hydraulic fracturing combined generate more than 800 billion gallons of fluid each year. More than one-third of this volume is injected for permanent disposal in Class II injection wells.[55] Deep-well injection has long been the environmentally preferred option for managing produced brine and other wastewater associated with oil and gas production. However, the development of unconventional formations using high-volume hydraulic fracturing has contributed significantly to a growing volume of wastewater requiring disposal and has created demand for disposal wells in new locations. Recent incidents of seismicity in the vicinity of disposal wells have drawn renewed attention to laws, regulations, and policies governing wastewater management and have generated various responses at the federal and state levels. This section of the report reviews the

[52] Ohio Department of Natural Resources, *Ohio Announces Tougher Permit Conditions for Drilling Activities Near Faults and Areas of Seismic Activity*, April 11, 2014, http://ohiodnr.gov/news/post/ohio-announces-tougher-permit-conditions-for-drilling-activities-near-faults-and-areas-of-seismic-activity.

[53] Ellsworth, "Injection-Induced Earthquakes."

[54] Ibid.

[55] National Research Council, Committee on Induced Seismicity Potential in Energy Technologies, *Induced Seismicity Potential in Energy Technologies*, National Academy Press, Washington, DC, 2012, p. 110.

current regulatory framework for managing underground injection and identifies several federal and state initiatives in response to concerns surrounding Class II disposal and induced seismicity.

EPA Regulation of Underground Injection Activities

The principal law authorizing federal regulation of underground injection activities is the Safe Drinking Water Act (SDWA) of 1974, as amended.[56] The law specifically directs EPA to promulgate regulations for state underground injection control (UIC) programs to prevent underground injection that endangers drinking water sources.[57] Historically, EPA has not regulated oil and gas production wells, and as amended in 2005, the SDWA explicitly excludes the regulation of underground injection of fluids or propping agents (other than diesel fuels) associated with hydraulic fracturing operations related to oil, gas, and geothermal production activities.[58]

The SDWA authorizes states to assume primary enforcement authority (primacy) for the UIC program for any or all classes of injection wells. EPA must delegate this authority, provided that the state program meets certain statutory and EPA requirements. If a state's UIC program plan is not approved, or if a state chooses not to assume program responsibility, then EPA implements the UIC program in that state.

For oil-and-gas-related injection operations (such as produced water disposal through Class II wells), the law allows states to administer the UIC program using state rules rather than meeting EPA regulations, provided a state demonstrates that it has an effective program that prevents underground injection that endangers drinking water sources.[59] Most oil and gas states have assumed primacy for Class II wells under this provision.

Under the UIC program, EPA, states, and tribes regulate more than 800,000 injection wells. To implement the UIC program as mandated by the SDWA, EPA has established six classes of underground injection wells based on categories of materials injected by each class. In addition to the similarity of fluids injected, each class shares similar construction, injection depth, design, and operating techniques. The wells within a class are required to meet a set of appropriate performance criteria for protecting underground sources of drinking water (USDWs).[60] **Figure 4** provides an illustration of the six well classes established by EPA to implement the UIC program.

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[56] The Safe Drinking Water Act of 1974 (P.L. 93-523) authorized the UIC program at EPA. UIC provisions are contained in SDWA Part C, §§1421-1426; 42 U.S.C. §§300h-300h-5.

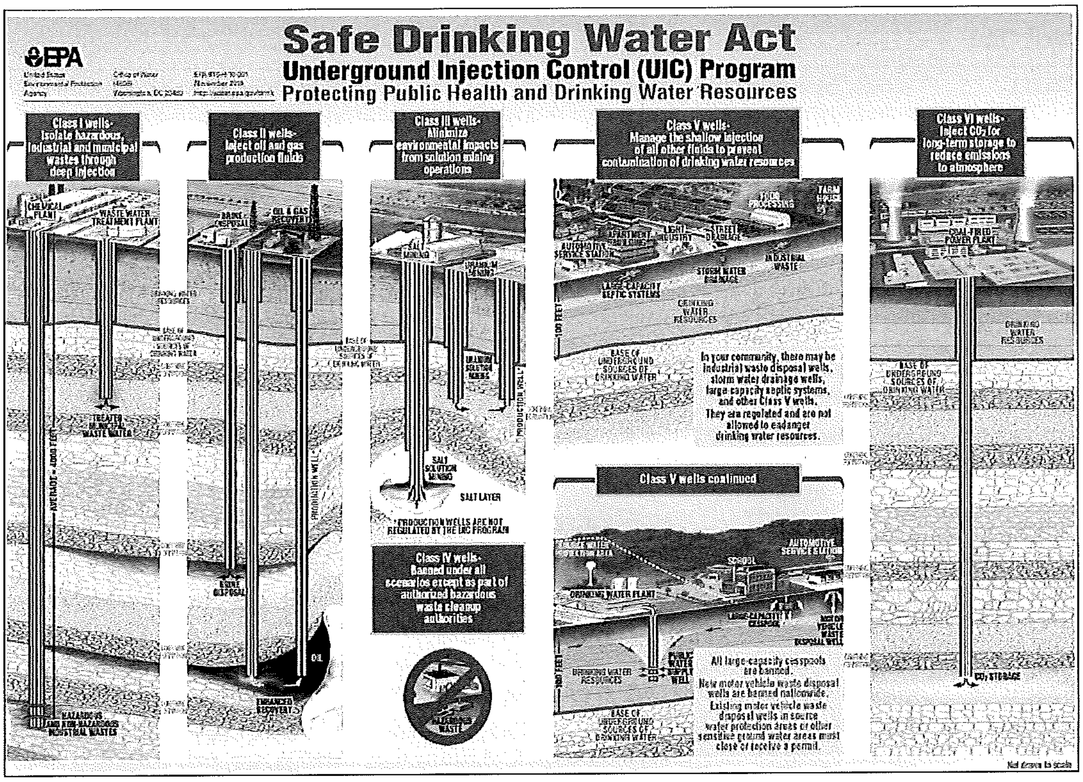
[57] 42 U.S.C. §300h(d). SDWA §1421.

[58] The Energy Policy Act of 2005 (EPAct 2005; P.L. 109-58, §322) amended the definition of "underground injection," SDWA§1421(d), to expressly exempt hydraulically fractured oil, gas, or geothermal production wells from the UIC program unless diesel fuels are used in the fracturing fluid.

[59] SDWA Section 1425 requires a state to demonstrate that its UIC program meets the requirements of Section 1421(b)(1)(A) through (D) and represents an effective program (including adequate record keeping and reporting) to prevent underground injection that endangers underground sources of drinking water. To receive approval under Section 1425's optional demonstration provisions, a state program must include permitting, inspection, monitoring, and record-keeping and reporting requirements.

[60] EPA regulations define a USDW to mean an aquifer or part of an aquifer that (a) supplies a public water system, or contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption, or contains fewer than 10,000 milligrams per liter (mg/L or parts per million) total dissolved solids; and (b) is not an "exempted aquifer." 40 C.F.R. 144.3.

Figure 4. Federally Regulated Underground Injection Wells



Source: U.S. Environmental Protection Agency, Underground Injection Control, Typical Injection Wells. For additional details, see http://water.epa.gov/type/groundwater/uic/wells_drawings.cfm.

Class II includes wells used to inject fluids associated with oil and gas production. Class II wells may be used for three broad purposes: (1) to dispose of brines (salt water) and other fluids associated with oil and gas production; (2) to store petroleum natural gas; or (3) to inject fluids to enhance recovery of oil and gas from conventional fields. There are roughly 180,500 Class II wells across the United States. Based on historical averages, roughly 80% of the Class II wells are enhanced recovery wells, and 20% are disposal wells (Class IId wells).[61]

Table 1 provides descriptions of the injection well classes and subcategories and estimated numbers of wells.

[61] U.S. Environmental Protection Agency, *Class II Wells—Oil and Gas Related Injection Wells (Class II)*, http://water.epa.gov/type/groundwater/uic/class2/index.cfm, May 9, 2012.

Table 1. UIC Program: Classes of Injection Wells and Nationwide Numbers

Well Class	Purpose and Uses
Class I	Wells inject hazardous wastes, industrial non-hazardous liquids, or municipal wastewater beneath the lowermost underground source of drinking water (USDW). (680 wells, including 117 hazardous waste wells)
Class II	Wells inject brines and other fluids associated with oil and gas production and hydrocarbons for storage. The wells inject fluids beneath the lowermost USDW. (>172,000 wells) Types of Class II wells[a]: • **Enhanced recovery wells:** Separate from, but often surrounded by, production wells, these wells are used to inject produced water (brine), fresh water, steam, polymers, or carbon dioxide (CO_2) into oil-bearing formations to recover additional oil (and sometimes gas) from production wells. These wells may also be used to maintain reservoir pressure. Approximately 80% of Class II wells are ER wells. • **Disposal wells:** Produced water and other fluids associated with oil and gas production (including flowback from hydraulic fracturing operations) are injected into these wells for permanent disposal. Approximately 20% of Class II wells are disposal (Class IId) wells. • **Hydrocarbon storage wells:** More than 100 Class II wells are used to inject hydrocarbons (petroleum and natural gas) into underground formations for storage.
Class III	**Class III** wells inject fluids associated with solution mining of minerals (e.g., salt and uranium) beneath the lowermost USDW. (22,131 wells)
Class IV	**Class IV** wells inject hazardous or radioactive wastes into or above USDWs. These wells are banned unless authorized under a federal or state groundwater remediation project. (33 wells)
Class V	**Class V** includes all injection wells not included in Classes I-IV, including experimental wells. Class V wells often inject non-hazardous fluids into or above USDWs, and many are shallow, on-site disposal systems (e.g., cesspools and stormwater drainage wells). Some Class V wells (e.g., geothermal energy and aquifer storage wells) inject below USDWs. (400,000-650,000 wells)
Class VI	**Class VI**, established in 2010, includes wells used for the geologic sequestration of CO_2. (2 permits approved in 2014)

Source: U.S. Environmental Protection Agency, *Underground Injection Control Program, Classes of Wells, and Class II Wells—Oil and Gas Related Injection Wells (Class II)*, http://water.epa.gov/type/groundwater/uic/wells.cfm, and UIC well surveys.

Notes: Regulations for Class I (hazardous waste) and Class VI (CO_2 sequestration) wells include evaluation of seismic risk among requirements to prevent movement of fluids out of the injection zone to protect USDWs.

a. A Class II permit would be required for an oil, gas, or geothermal production well if diesel fuels were to be used in the hydraulic fracturing fluid.

Consideration of Seismicity in EPA UIC Regulations

The SDWA does not mention seismicity; rather, the law's UIC provisions authorize EPA to regulate underground injection to prevent endangerment of underground sources of drinking water. However, seismicity has the potential to affect drinking water quality through various means (e.g., by damaging the integrity of a well, or creating new fractures and pathways for fluids to reach groundwater). EPA UIC regulations include various requirements aimed at protecting USDWs by ensuring that injected fluids remain in a permitted injection zone. Some of these measures could also reduce the likelihood of triggering seismic events. For example, injection pressures for Class II (and other) wells may not exceed a pressure that would initiate or propagate fractures in the confining zone adjacent to a USDW.[62] As a secondary benefit, limiting injection pressure can prevent fractures that could act as conduits through which injected fluids could reach an existing fault.

EPA regulations for two categories of injection wells—Class I hazardous waste disposal wells and Class VI wells for geologic sequestration of CO_2—specifically address evaluation of seismicity risks with siting and testing requirements. For Class I wells, EPA regulations include minimum criteria for siting hazardous waste injection wells, requiring that wells must be limited to areas that are geologically suitable. The UIC Director (i.e., the delegated state or EPA) is required to determine geologic suitability based upon an "analysis of the structural and stratigraphic geology, the hydrogeology, and the seismicity of the region."[63] Testing and monitoring requirements for Class I wells state that "the Director may require seismicity monitoring when he has reason to believe that the injection activity may have the capacity to cause seismic disturbances."[64]

For Class VI CO_2 sequestration wells, EPA regulations similarly require evaluation of seismicity risks through siting and testing requirements. In determining whether to grant a permit, the UIC Director must consider various factors, including potential for seismic activity.

> Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit ... and the Director shall consider ... information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment.[65]

EPA regulations for oil and gas wastewater disposal wells (or other Class II wells) do not include these provisions or otherwise address seismicity; however, the regulations give discretion to UIC Directors to include in individual permits additional conditions as needed to protect USDWs (including requirements for construction, corrective action, operation, monitoring, or reporting).[66] Again, for the purpose of protecting drinking water sources, permits for all Class I, II, and III wells must contain specified operating conditions, including "a maximum operating pressure calculated to avoid initiating and/or propagating fractures that would allow fluid movement into a USDW."[67] Regulations for Class I wells further specify that "injection pressure must be limited such that no fracturing of the injection zone occurs during operation."[68]

Outside of regulations, EPA has recently taken steps to address induced seismicity concerns associated with Class II disposal wells. For example, EPA Region III now evaluates induced seismicity risk factors when considering permit applications for Class II wells. (Region III

[62] 40 C.F.R. §146.23(a)(1).

[63] 40 C.F.R. §146.62(b)(1).

[64] 40 C.F.R. §146.68(f).

[65] 40 C.F.R. §146.82(a)(3)(v).

[66] Relevant provisions for Class II wells are published at 40 C.F.R. §144.12(b) and 40 C.F.R. §144.52(a)(9) or (b)(1). See also 40 C.F.R. Part 147.

[67] U.S. Environmental Protection Agency, *Technical Program Overview: Underground Injection Control Regulations*, EPA 816-R-02-005, revised July 2001, p. 65, http://water.epa.gov/type/groundwater/uic/upload/2004_5_3_uicv_techguide_uic_tech_overview_uic_regs.pdf.

[68] Ibid., p. 66.

directly implements the UIC program in Pennsylvania and Virginia.[69]) In responding to public comments on a Class II well permit application, the regional office noted the following:

> Although EPA must consider appropriate geological data on the injection and confining zone when permitting Class II wells, the SDWA regulations for Class II wells do not require specific consideration of seismicity, unlike the SDWA regulations for Class I wells used for the injection of hazardous waste.... Nevertheless, EPA evaluated factors relevant to seismic activity such as the existence of any known faults and/or fractures and any history of, or potential for, seismic events in the areas of the Injection Well as discussed below and addressed more fully in "Region 3 framework for evaluating seismic potential associated with UIC Class II permits, updated September, 2013."[70]

Federal Initiatives to Address Induced Seismicity

As discussed above, the SDWA does not directly address seismicity; rather, the law authorizes EPA to regulate subsurface injections to prevent endangerment of drinking water sources. In 2011, in response to earthquake events in Arkansas and Texas, EPA asked the Underground Injection Control National Technical Workgroup to "develop technical recommendations to inform and enhance strategies for avoiding significant seismicity events related to Class II disposal wells." The workgroup was specifically asked to address concerns that induced seismicity associated with Class II disposal wells could cause injected fluids to move outside the containment zone and endanger drinking water sources. EPA requested that the report contain the following specific elements:

- Comparison of parameters identified as most applicable to induced seismicity with the technical parameters collected under current regulations.
- Decisionmaking model/conceptual flow chart to:
  - provide strategies for preventing or addressing significant induced seismicity,
  - identify readily available applicable databases or other information,
  - develop site characterization checklist, and
  - explore applicability of pressure transient testing and/or pressure monitoring techniques.
- Summary of lessons learned from case studies.
- Recommended measurement or monitoring techniques for higher risk areas.
- Applicability of conclusions to other well classes.
- Define specific areas of research as needed.[71]

[69] EPA also directly implements the UIC program for other oil and gas producing states, including Kentucky, Michigan, and New York.

[70] U.S. Environmental Protection Agency Region III, *Response to Comments for the Issuance of an Underground Injection Control (UIC) Permit for Windfall Oil and Gas, Inc.*, 2013, pp. 3-9, http://www.epa.gov/reg3wapd/pdf/public_notices/WindfallResponsivenessSummary.pdf.

[71] U.S. Environmental Protection Agency, *Minimizing and Managing Potential Impacts of Induced-Seismicity from Class II Disposal Wells: Practical Approaches*, draft report of the Underground Injection Control National Technical Workgroup, November 27, 2012, p. A-1-2.

In February 2015, EPA released the National Technical Workgroup's final report, *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches*, which addressed the above tasks.[72] The report does not constitute formal agency guidance, nor has EPA initiated any rulemaking regarding this matter. Rather, the document includes practical management tools and best practices to "provide the UIC Director with considerations for addressing induced seismicity on a site-specific basis, using Director discretionary authority."[73] (The UIC Director is the state program director where the state has program primacy or EPA in states where EPA implements the program directly.)

Among other findings, the report identifies three key components that must be present for injection-induced seismic activity to occur:

> (1) sufficient pressure buildup from disposal activities; (2) a fault of concern; and (3) a pathway allowing the increased pressure to communicate from the disposal well to the fault.[74]

As discussed, current Class II regulations give discretion to UIC Directors to include in individual permits additional conditions and requirements as needed to protect USDWs.[75] The *Practical Approaches* document notes that, while EPA is unaware of any USDW contamination resulting from seismic events related to induced seismicity, potential USDW risks from seismic events could include

- loss of disposal well mechanical integrity,
- impact to various types of existing wells,
- changes in USDW water level or turbidity,
- USDW contamination from a direct communication with the fault inducing seismicity or contamination from earthquake-damaged surface sources.[76]

The report includes a decision model to inform regulators on site assessment strategies and recommends monitoring, operational, and management approaches for managing and minimizing suspected injection-induced seismicity. Among the management recommendations, the report suggests that, for wells suspected of causing induced seismicity, managers should take early actions (such as requiring more frequent pressure monitoring or reducing injection rates) rather than requiring definitive proof of causality.[77]

The authors also identified research needs to better understand potential for injection-related induced seismicity, including research regarding geologic siting criteria for disposal zones in

[72] U.S. Environmental Protection Agency, *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches*, Underground Injection Control National Technical Workgroup, November 12, 2014 (released February 2015), http://www.epa.gov/r5water/uic/techdocs.htm#ntwg. The report includes case studies of induced seismicity events and responses in four states: Arkansas, Ohio, Texas, and West Virginia.

[73] Ibid., ES-2.

[74] Ibid., p. 27.

[75] Relevant provisions for Class II wells are published at 40 C.F.R. §144.12(b) and 40 C.F.R. §144.52(a)(9) or (b)(1). See also 40 C.F.R. Part 147.

[76] U.S. Environmental Protection Agency, *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches*, p. 4.

[77] Ibid., p. 35.

areas with limited or no data. As a general principal, the workgroup recommend that future research be conducted using a holistic and multidisciplinary approach, combining expertise in petroleum engineering, geology, geophysics, and seismicity.[78]

The Department of Energy (DOE) conducts a research program to promote development of the nation's geothermal resources, including development of enhanced geothermal systems (EGS). The development of EGS can enable uneconomical hydrothermal systems to produce geothermal energy on a large scale. However, the process of injecting fluids to enhance permeability of hydrothermal systems may trigger seismic events. In 2012, DOE released an Induced Seismicity Protocol to mitigate risks associated with the development of these systems.[79] Some of the approaches and mitigation measures included in the DOE protocol may be applicable to issues posed by Class II disposal wells.

State Initiatives

Several states and state organizations have been assessing the possible relationship between injection wells and seismic activity.[80] In March 2014, the Interstate Oil and Gas Compact Commission (IOGCC)[81] and the Ground Water Protection Council (GWPC)[82] formed an Induced Seismicity Work Group with state regulatory agencies and geological surveys to "proactively discuss the possible association between recent seismic events occurring in multiple states and injection wells."[83]

Additionally, several states have strengthened oversight and added new operational conditions and requirements for Class II disposal wells in response to recent seismic events that appear to be injection related. Policy and regulatory developments adopted or under consideration by several states are outlined briefly below. Typically, these states have expanded their standard permit application packages to include, for example, requirements for additional existing geologic information and studies and stricter operating requirements. Also, some states have banned the drilling of injection wells in geologic zones of known seismic risk.

[78] Ibid., pp. 31-32.

[79] Ernie Majer, James Nelson, and Ann Roberson-Tait et al., *Protocol for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems*, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, DOE/EE-0662, January 2012, 45 pp., https://www1.eere.energy.gov/geothermal/pdfs/geothermal_seismicity_protocol_012012.pdf.

[80] See, for example, Ground Water Protection Council, *White Paper Summarizing a Special Session on Induced Seismicity*, February 2013, http://www.gwpc.org/sites/default/files/events/white%20paper%20-%20final_0.pdf. See also Association of American State Geologists, "Induced Seismicity," http://www.stategeologist.org.

[81] The Interstate Oil and Gas Compact Commission is a multi-state agency that "serves as the collective voice of member governors on oil and gas issues and advocates states' rights to govern petroleum resources within their borders." The commission works with other stakeholders and is chartered to "efficiently maximize oil and natural gas resources through sound regulatory practices while protecting health, safety and the environment." http://iogcc.publishpath.com/.

[82] The Ground Water Protection Council represents state groundwater protection and underground injection control agencies, http://www.gwpc.org/.

[83] States First Initiative, *States Team Up to Assess Risk of Induced Seismicity*, April 29, 2014, http://www.statesfirstinitiative.org, or http://www.statesfirstinitiative.org/#!States-Team-Up-to-Assess-Risk-of-Induced-Seismicity/c8t8/72D0196F-1DAB-4617-B446-B009A1D902FB.

Arkansas

In response to the Guy-Greenbrier earthquake swarm associated with injections of wastewater from shale gas production, the Arkansas Oil and Gas Commission (AOGC) in 2010 imposed a moratorium on new disposal wells in the vicinity of the increased seismic activity and required operators of seven existing wells in the area to report hourly injection rates and pressures bi-weekly through July 2011.[84]

In 2011, the AOGC revised rules governing Class II wells and established a permanent moratorium zone in the area of a major fault system. The state banned new disposal wells and required plugging of four existing wells within the zone.[85] (Operators voluntarily plugged the other three wells of concern.) The rules also require commission approval and a public hearing before any Class II wells within specified distances from the Moratorium Zone Deep Fault or a regional fault can be drilled, deepened, reentered, or recompleted. Class II wells proposed for disposal above or below the Fayetteville Shale formation are subject to new siting and spacing requirements, and permit applicants are required to provide information on the structural geology of an area proposed for a new disposal well. For existing disposal wells, the state required permit holders to install flow meters and submit injection volume and pressure information at least daily.[86] State officials continue to monitor disposal well operations and seismic activity. The state purchased seismic additional monitoring equipment, which supports an "early warning" system for detecting and responding to any emerging seismic activity.[87]

Colorado

The Colorado Oil and Gas Conservation Commission (COGCC) has identified in existing rules and policies various requirements that reduce the likelihood of induced seismicity.[88] These safeguards, which are imposed through the permitting process, include setting limits on injection volume and rate and requiring that the maximum allowable injection pressure is set below the fracturing pressure for the injection zone.[89] In 2011, the COGCC expanded the UIC permit review process specifically to minimize risk of induced seismicity from oil and gas wastewater disposal. The changes followed a significant earthquake near wells injecting wastewater produced from a coalbed methane field. The COGCC now has the Colorado Geological Survey (CGS) review permit applications to evaluate the area for the proposed well site for seismic activity. The CGS reviews state geologic maps, the USGS earthquake database, and area-specific information. After reviewing the geologic history and maps of the area for faults, the CGS may recommend a more

[84] U.S. Environmental Protection Agency, *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches*, p. 20.

[85] Specifically, the rules state: "Unless otherwise approved by the Commission after notice and a hearing, no permit to drill, deepen, re-enter, recomplete or operate a Class II Disposal or Class II Commercial Disposal Well may be granted for any Class II or Class II Commercial Disposal wells in any formation within [a prescribed] area ('Moratorium Zone')." AOGC Rule H-1, Section (s)(2).

[86] Arkansas Oil and Gas Commission, General Rule H—Class II Wells, Rule H-1: Class II Disposal and Class II Commercial Disposal Well Permit Application Procedures, Section (s).

[87] U.S. Environmental Protection Agency, *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches*, p. 20.

[88] The COGCC administers the UIC program in accordance with EPA regulations. 40 C.F.R. §§144-147.

[89] Colorado Oil and Gas Conservation Commission, *COGCC Underground Injection Control and Seismicity in Colorado*, January 19, 2011.

detailed review of subsurface geology or seismic monitoring prior to new drilling. Additionally, the Division of Water Resources conducts a review of the proposed injection zone.[90]

In July 2014, the COGGC reported that it is working with the Colorado Geological Survey, USGS researchers, and state universities to establish an induced seismicity advisory group. Issues for consideration by the advisory group include development of a more comprehensive statewide seismicity monitoring network and improved guidance for managing high-volume injection.

Kansas

Kansas Governor Sam Brownback convened a State Task Force on Induced Seismicity in response to a significant increase in seismic activity—predominately in three counties—compared to seismic activity in 2013 and years prior. According to the task force report, Kansas has approximately 5,000 disposal wells used to inject waste fluids from oil and gas operations.[91] The action plan called for increased seismic monitoring to improve the state's ability to detect earthquakes greater than magnitude 1.5. The plan also provides a response plan, which would be triggered by earthquakes of magnitude 2.0 or greater. The plan further outlines a set of criteria under which disposal wells located within six miles of the earthquake would be evaluated and a determination made as to whether any regulatory remedies under current statutory authorities are warranted.

Ohio

Following the Youngstown earthquakes in 2011 associated with Class II disposal wells, the Ohio Department of Natural Resources (ODNR) prohibited all drilling into the Precambrian basement rock and added new permit requirements for Class II disposal wells to improve site assessment and collection of more comprehensive information. The rules became effective in October 2012 and are implemented on a well-by-well basis through the permitting process. The supplemental permit application requirements could include pressure fall-off testing, geological evaluation of potential faulting, seismic monitoring program (baseline and active injection), minimum geophysical logging suite, radioactive tracer or spinner survey, and any other tests deemed necessary by the Division of Oil and Gas Resources Management.[92] Before approving a new Class II disposal well, state officials now review existing geologic data for known faulted areas. ODNR will also require companies to run a complete suite of geophysical logs on newly drilled Class II disposal wells. Companies are required to give ODNR a copy of the log suite and may be required to provide analytical interpretation of the logging. For all new Class II permit applications, ODNR requires installation of monitoring technologies, including a continuous pressure monitoring system and an automatic shutoff system.[93] Additionally, the state has

[90] Ibid.

[91] Kansas Department of Health and Environment, Kansas Corporation Commission, Kansas Geological Survey, *Kansas Seismic Action Plan*, September 26, 2014, p. 1, http://kcc.ks.gov/induced_seismicity/state_of_kansas_seismic_action_plan_9_26_14_v2_1_21_15.pdf.

[92] Ohio Department of Natural Resources, Division of Oil and Gas Resources, Underground Injection Control (UIC), http://oilandgas.ohiodnr.gov/industry/underground-injection-control.

[93] Ohio Department of Natural Resources, Class II Disposal Well Reforms/Youngstown Seismic Activity Questions and Answers, https://oilandgas.ohiodnr.gov/portals/oilgas/pdf/YoungstownFAQ.pdf.

purchased portable seismic units and implemented a proactive approach to seismic monitoring around deep Class II wells.[94]

In 2014, ODNR drafted new rules for construction of horizontal production wells that are to be hydraulically fractured (i.e., shale oil and gas wells) in response to seismic activity the state determined had a "probable connection to hydraulic fracturing near a previously unknown microfault."[95] The draft rules include standards for design, approval, and construction of horizontal well sites and would strengthen drilling permit conditions for wells located near faults or areas linked to previous seismic activity.[96]

Oklahoma

Oklahoma has more than 11,600 Class II wells, including 4,626 Class II disposal wells and 7,037 enhanced oil recovery wells. As discussed above, seismicity events have increased markedly in recent years as Class II disposal wells have been used to manage large volumes of produced water from oil and gas production activities. The state reports that most of the wastewater disposed of in the state is the naturally occurring saltwater brine that is produced to the surface along with the oil and gas, and a relatively small portion is flowback from hydraulically fractured wells.[97]

In 2013, in response to injection-related induced seismicity concerns, the Oklahoma Corporation Commission (OCC) initiated a "traffic light" permitting system for Class II disposal wells. The system is based on National Academy of Sciences recommendations[98] and continues to evolve to reflect new information. Under the system, all disposal well permit applications must be reviewed for proximity to faults and seismicity in the area of the proposed well. Specifically, regulators must determine whether a location of a proposed well is within three miles of a stress fault, within six miles of a seismic cluster, or within another "area of interest." If so, the well operator is asked to demonstrate level of risk of induced seismicity and to provide more technical data, and a public hearing must be held on the permit application.[99] In 2015, the OCC greatly expanded "areas of interest" where injection wells are subject to additional requirements to include seismic clusters.

The "yellow light" permitting requirements apply to proposed wells in areas where some seismicity concerns exist but do not meet prescribed "red light" criteria. Among other conditions that may be imposed, "yellow light" permits are granted for only six months, and permit language may be made more stringent at any time. Additionally, operators may be required to monitor for

[94] U.S. Environmental Protection Agency, *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches*, pp. 24-25.

[95] Ohio Department of Natural Resources, "Ohio Announces Tougher Permit Conditions for Drilling Activities near Faults and Areas of Seismic Activity," press release, April 11, 2014, http://ohiodnr.gov/news/post/ohio-announces-tougher-permit-conditions-for-drilling-activities-near-faults-and-areas-of-seismic-activity.

[96] Ohio Department of Natural Resources, Division of Oil and Gas Resources Management, Draft Rules and Review (Ch. 1501:9-2-02 OAC), http://oilandgas.ohiodnr.gov/.

[97] Oklahoma Geological Survey, "Statement on Oklahoma Seismicity," summary statement, April 21, 2015, http://earthquakes.ok.gov/wp-content/uploads/2015/04/OGS_Summary_Statement_2015_04_20.pdf.

[98] NRC, "Induced Seismicity Potential in Energy Technologies," ch. 6, "Steps Toward a 'Best Practices' Protocol," pp. 151-164. See also Mark D. Zoback, "Managing the Seismic Risk Posed by Wastewater Disposal," *Earth Magazine*, April 2012, pp. 38-43.

[99] Tim Baker, Director, Oil and Gas Conservation Division, Oklahoma Corporation Commission Town Hall Presentation on Seismicity/Updates to the Traffic Light System, http://earthquakes.ok.gov/wp-content/uploads/2015/04/OGCD_Presentation.pdf.

background seismicity and shut down wells every 60 days for bottom hole pressure readings. A shutdown is mandatory in the event of defined seismic activity.[100]

In March 2015, the OCC announced new directives for disposal well operators currently operating in "areas of interest" that inject into the Arbuckle formation. Under the directives, operators were required to provide to the Oil and Gas Conservation Division, by April 18, 2015, information showing that Class II disposal wells in the area of interest were not in contact or communication with the crystalline basement rock. Wells that meet the criteria are allowed to resume normal operations. For any wells found to be in contact/communication with basement rock, operators must plug back the wells to a shallower depth and meet specified criteria. Operators who have not provided the requested information or do not have an approved plugging schedule must reduce injection volumes by 50%.[101]

Texas

In November 2014, the Texas Railroad Commission (RRC) published amendments to the state's oil and gas rules to incorporate requirements related to seismic events in connection with wastewater disposal permits, monitoring, and reporting.[102] Several of the new requirements are listed below.[103]

- Applicants for disposal well permits are required to provide information from the USGS regarding the locations of any historical seismic events within 100 square miles of the proposed well site.
- A permit for a Class II disposal well "may be modified, suspended, or terminated if injection is likely to be or determined to be contributing to seismic activity."[104]
- The RRC may require permit applicants to provide additional information (e.g., logs, geologic cross-sections, and pressure front boundary calculations) if the well is to be located in an area where conditions may increase the risk that fluids will not be confined in the injection interval. (Such conditions may include complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events using available USGS information.)
- Operators may be required to conduct more frequent monitoring and reporting of disposal well injection pressures and rates if certain conditions are present that could increase the risk that fluids will not be confined to the injection interval.

Although states have taken various actions in response to recent seismic events and wastewater injection, additional regulatory actions could result as experience is accrued from current approaches. Additional developments might also result from the IOGCC and GWPC Induced

[100] Office of the Oklahoma Secretary of Energy and Environment, "Oklahoma Corporation Commission," http://earthquakes.ok.gov/what-we-are-doing/oklahoma-corporation-commission/.

[101] Oklahoma Corporation Commission, "Media Advisory—Ongoing OCC Earthquake Response," press release, March 25, 2015, http://www.occeweb.com/. The directives apply to 347 of 900 Arbuckle disposal wells.

[102] *Texas Register*, 39 *TexRegN*8988, November 14, 2014, amending 16 T.A.C. §3.9, §3.46, http://www.sos.state.tx.us/texreg/pdf/backview/1114/1114adop.pdf.

[103] 39 *TexReg* 8996-9005, 16 T.A.C. §3.9.

[104] 16 T.A.C. §3.9(6)(A)(vi).

Seismicity Work Group as state regulatory agencies and geological surveys continue to evaluate this issue.

Conclusion

The scientific understanding of linkages between deep-well injection of waste fluids from oil and gas production, and from hydraulic fracturing operations, is rapidly evolving. This poses a challenge to state and federal policy makers who are tasked with making policy, regulatory, and permitting decisions in a relatively short time frame, concomitant with the evolving scientific study and understanding, and given public concern over the possibility of damaging earthquakes from some of the deep disposal wells. Some states have already implemented changes to their regulatory and permitting requirements, as discussed above. The vast majority of Class II disposal wells and hydraulic fracturing wells do not appear to be associated with significant seismic events. Additional geologic studies and reviews adopted by some states should address some potential risks; however, it is likely that states and possibly the federal government will continue to explore ways to understand and mitigate against the possibility of damaging earthquakes caused by a small number of wells.

In February 2015, EPA published a report outlining best practices to minimize and manage seismic events associated with oil and gas wastewater injection. The agency has not issued related guidance or initiated any regulatory actions.

Congress may be interested in oversight of EPA's UIC program or, more broadly, in federally sponsored research on the relationship between energy development activities and induced seismicity. Although only a small fraction of the more than 30,000 U.S. wastewater disposal wells appears to be problematic for causing damaging earthquakes, such incidents may raise questions as to whether other energy-related activity—specifically, underground injection for carbon dioxide sequestration—may present similar risks.

Author Contact Information

Peter Folger
Specialist in Energy and Natural Resources Policy
pfolger@crs.loc.gov, 7-1517

Mary Tiemann
Specialist in Environmental Policy
mtiemann@crs.loc.gov, 7-5937

Forcenergy Australia Pty Ltd

Water Disposal by Re-injection

PEL 238 Trial Program

Contents

Figures

Tables

1. Summary

Forcenergy Australia Pty Ltd (FEN) plan to commence a trial program to evaluate the feasibility of re-injection as a means of disposing of surplus water produced from coalbed methane (CBM) gas well operations.

The trial program will utilize two disposal wells to re-inject water from six CBM production wells.

The trial program will be conducted in the Bohean Gas Field, situated approximately 25 kilometres south south-west of Narrabri.

Both injection wells are barefoot completions with seven-inch steel casing cemented back to surface from immediately above the re-injection zone. Bohena No.2D is completed in the Digby Formation and Bohena No.6H is completed in the Hoskissons coal seam.

Disposal water is produced from wells completed in coals of the Maules Creek Formation.

The disposal zones are located well below aquifers of the Great Artesian Basin (GAB), and are separated from the GAB by 226 metres or more of Late Permian and Triassic sedimentary strata containing numerous impermeable bed seals.

Water quality in the GAB will be monitored throughout the trial program to ensure cross-contamination of aquifers is not occurring.

2. Well Locations

The trial program will be conducted in the Bohean Gas Field, situated approximately 25 kilometres south south-west of Narrabri.

Figure 1 shows the location of Petroleum Exploration License 238 (PEL 238) operated by FEN in the Gunnedah Basin, in relation to N.S.W. and to major towns and roads of the *North-west Slopes & Plains* region.

Figure 2 shows the location of FEN's current operations area within PEL 238 and the Bohena, Wilga Park and Coonarah gas fields in relation to the town of Narrabri.

Figure 3 shows the location of wells in the Bohena gas field.

> The two water disposal wells, Bohena No.2D and Bohena No.6H are highlighted. These two wells were drilled to evaluate the gas production potential of the Digby Sandstone and the Hoskissons coal interval. Results of testing were disappointing and it is now proposed to utilize these wells for water disposal.

Bohena No.1 was drilled as an oil exploration well in 1963. It was completed as a water well in the Pilliga Sandstone unit of the GAB and is licensed to the State Forests of N.S.W. (SFNSW). This well will be used to monitor water quality in the GAB to ensure cross-contamination of aquifers is not occurring.

Water produced from the Bohena No.2, No.3, No.4 and No.5 wells, on the western side of the Newell Highway, will be piped to and injected down Bohena No.2D.

Water produced from the Bohena No.6 and No.7 wells, on the eastern side of the Newell Highway, will be piped to and injected down Bohena No.6H.

Bohena No.9, No.10 and No.11, also shown in Figure 3, are well locations that have not yet been drilled. Bohena No.3C was a slim diameter, stratigraphic core hole, which is now scheduled for plug and abandonment.

3. Injection Well Configuration

Both injection wells are barefoot completions with seven-inch steel casing cemented back to surface from immediately above the re-injection zone.

Figures 4 and 5 show the wellbore, casing and wellhead configuration of Bohena No.2D.

Bohena No.2D is completed into the Digby Formation. Long string casing (7" OD, 26 pounds/foot, K55 grade steel, 8 round long thread coupling) is set at 577.4 metres and full-hole cemented. The total depth of the well is 619.0 metres with 41.6 metres of open hole over the Digby Formation. The casing is rated at an internal yield pressure of 4,980 psi. The wellhead assembly is rated to 3000 psi.

Figures 6 and 7 show the wellbore, casing and wellhead configuration of Bohena No.6H.

Bohena No.6H is completed into the Hoskissons coal seam. Long string casing (7" OD, 26 pounds/foot, K55 grade steel, 8 round long thread coupling) is set at 677.5 metres and full-hole cemented. The total depth of the well is 691.0 metres with 13.5 metres of open hole over the Hoskissons coal seam. The casing and wellhead assembly carry the same ratings as for Bohena No.2D.

4. Injection Well Stratigraphy

Tables 1 and 2 summarize the age, depth, thickness and lithology of stratigraphic units drilled in Bohena No.2D and 6H.

Both wells spudded in a thin veneer of undifferentiated Quaternary sediments overlaying the GAB.

Jurassic age GAB sedimentary rocks (Pilliga Sandstone & Purlawaugh Formation) were drilled to a depth of approximately 300 metres in both wells.

Rock units of the Permo-Triassic Gunnedah Basin where then drilled from the base of the GAB to total depth.

Both injection wells are barefoot completions with seven-inch steel casing cemented back to surface from immediately above the proposed re-injection zone. Bohena No.6H is completed into the Hoskissons coal seam within the Black Jack Group and Bohena No.2D is completed into the overlaying Digby Formation

The total depth of Bohena No.6H is 691.0 metres with 13.5 metres of open hole over the Hoskissons coal seam. The total depth of Bohena No.2D is 619.0 metres with 41.6 metres of open hole over the Digby Formation.

The disposal zones are located well below aquifers of the Great Artesian Basin (GAB). The separation interval between the GAB and the top of the injection zone is 226 metres in Bohena No.2D and 332 metres in Bohena No.6H. The intervening Late Permian and Triassic sedimentary strata contain numerous impermeable bed seals.

5. Water Disposal Program

Water produced from the Bohena No.3, No.4 and No.5 wells, on the western side of the Newell Highway, will be transferred via 2" *poly-pipe* to a holding pond at the Bohena No.2/2D location. The collected water will then be re-injected down Bohena No.2D, along with water produced from Bohena No.2, using a small triplex pump.

Water produced from the Bohena No.7 well, on the eastern side of the Newell Highway, will be transferred to the Bohena No.6/6H location. The collected water will be re-injected down Bohena No.6H, along with water produced from Bohena No.6.

Casing pressure and re-injection rates will be monitored using chart recorders and flow-meters at both sites for the duration of the trial program.

Operations are scheduled to commence early to mid-July and to be evaluated over a three-month trial period. If results are satisfactory, the program will become ongoing.

6. Water Quality Issues

Table 3 summarizes the results of standard water analyses from FEN's monthly monitoring program. The analyses were performed by Amdel Limited (Adelaide).

Bohena No.2D

In-situ water quality of the Digby Formation is an average derived from four samples acquired during a three-day gas production test on Bohena No.2D.

Injection water quality is an average derived from the most recent analysis result from each of the Bohena No.2, No.3, No.4 and No.5 wells, and volume weighted based on the current water production rate from each well.

Bohena No.6H

In-situ water quality of the Hoskissons coal is an average derived from eight samples acquired during two months of gas production testing on Bohena No.6H.

Injection water quality is an average derived from the most recent analysis result from each of the Bohena No.6 and No.7 wells, and volume weighted based on the current water production rate from each well.

The table shows that the quality of the re-injected water is superior to the in-situ water quality at both re-injection sites.

At the Bohena No.2D injection site the Digby Formation in-situ water has a total measured dissolved salt (MDS) content of 14,844 mg/l. The MDS of the re-injected water will be 12,535 mg/l.

At the Bohena No.6H injection site the Hoskissons coal in-situ water has a MDS of 18,317 mg/l. The MDS of the re-injected water will be 7,884 mg/l.

When the trial program is fully operational, approximately 217 barrels of water per day (BWPD) or 34.5 kilolitres per day will be re-injected into the Digby formation in Bohena No.2D. Approximately 140 BWPD (22.3 kl per day) will be re-injected into the Hoskissons coal in Bohena No.6H.

Water quality from the Pilliga Sandstone in the SFNSW Bohena No.1 water bore will be monitored through out the trial program to ensure cross-contamination of reservoirs is not occurring.

Bohena No.1 is located approximately 80 metres away from Bohena No.2D

Water samples will be taken on a weekly basis from two weeks preceding the commencement of re-injection to four weeks after. Subsequent samples will be on a monthly basis for the duration of the trial program and then three-monthly if the re-injection program becomes an ongoing operation.

Figure 1: PEL 238 Regional Loacation Map

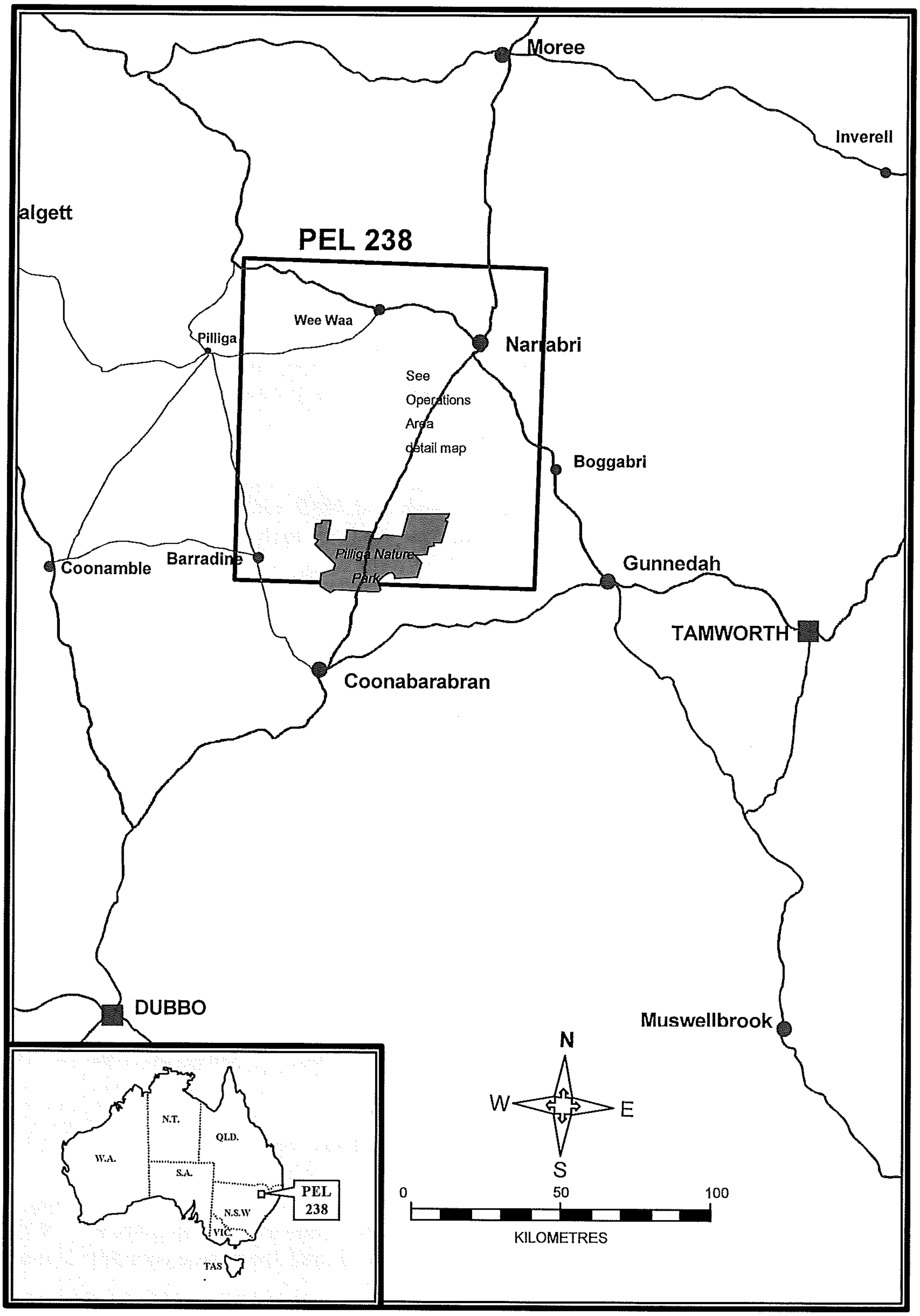


Figure 2: FEN Operations Area, PEL 238

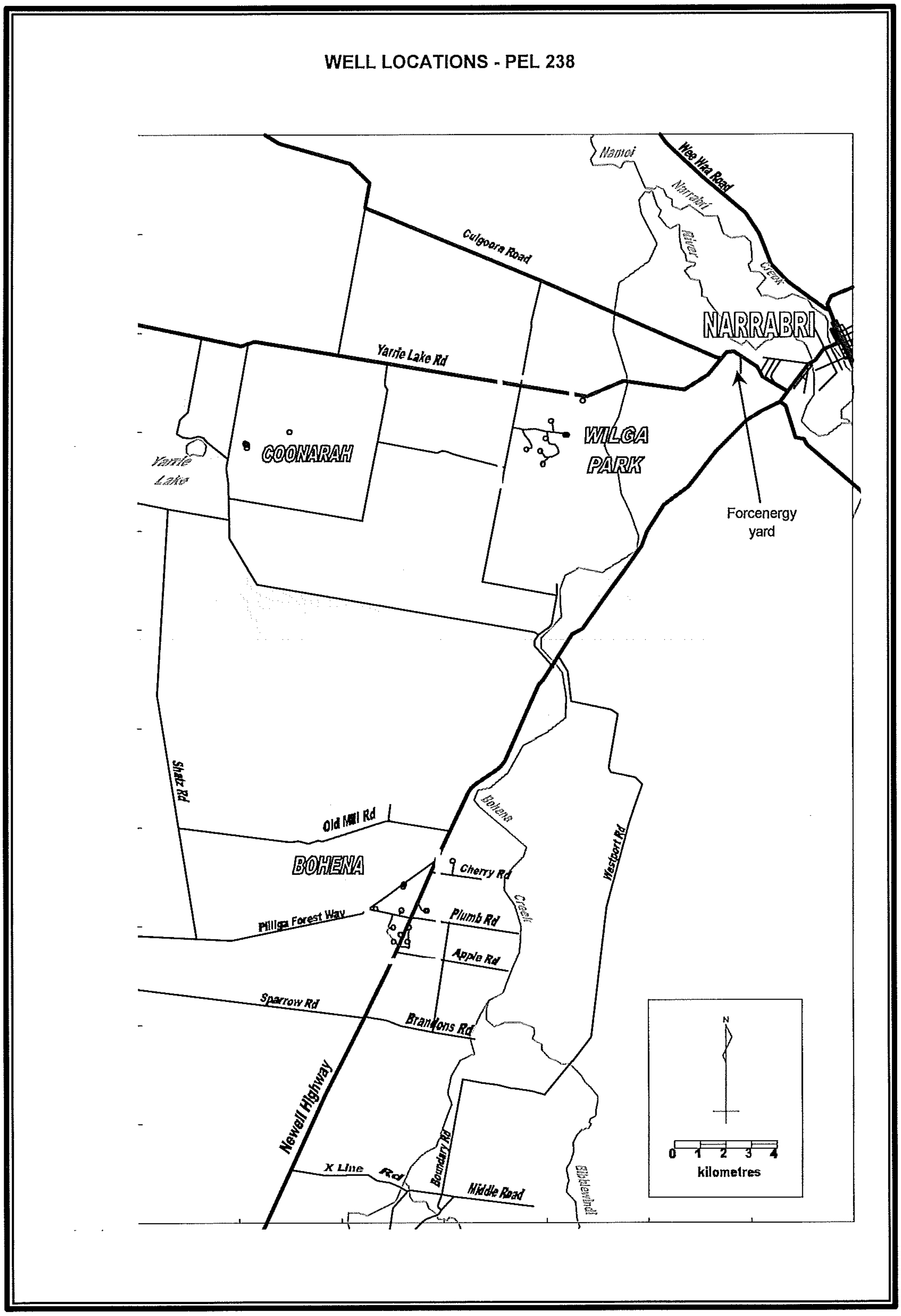


Figure 3: Re-injection Well Locations, Bohena Gas Field

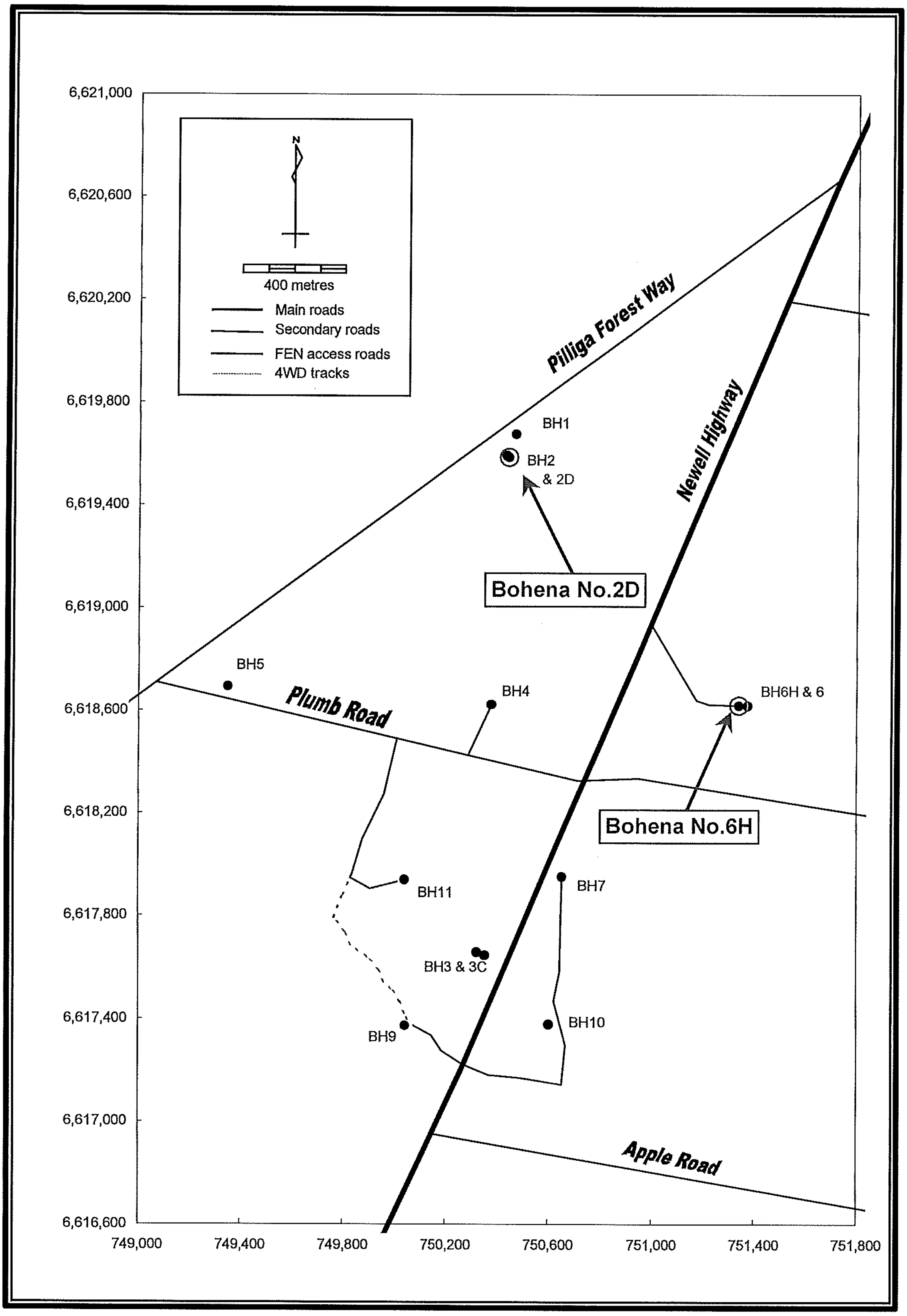


Figure 4: Well Configuration, Bohena No.2D

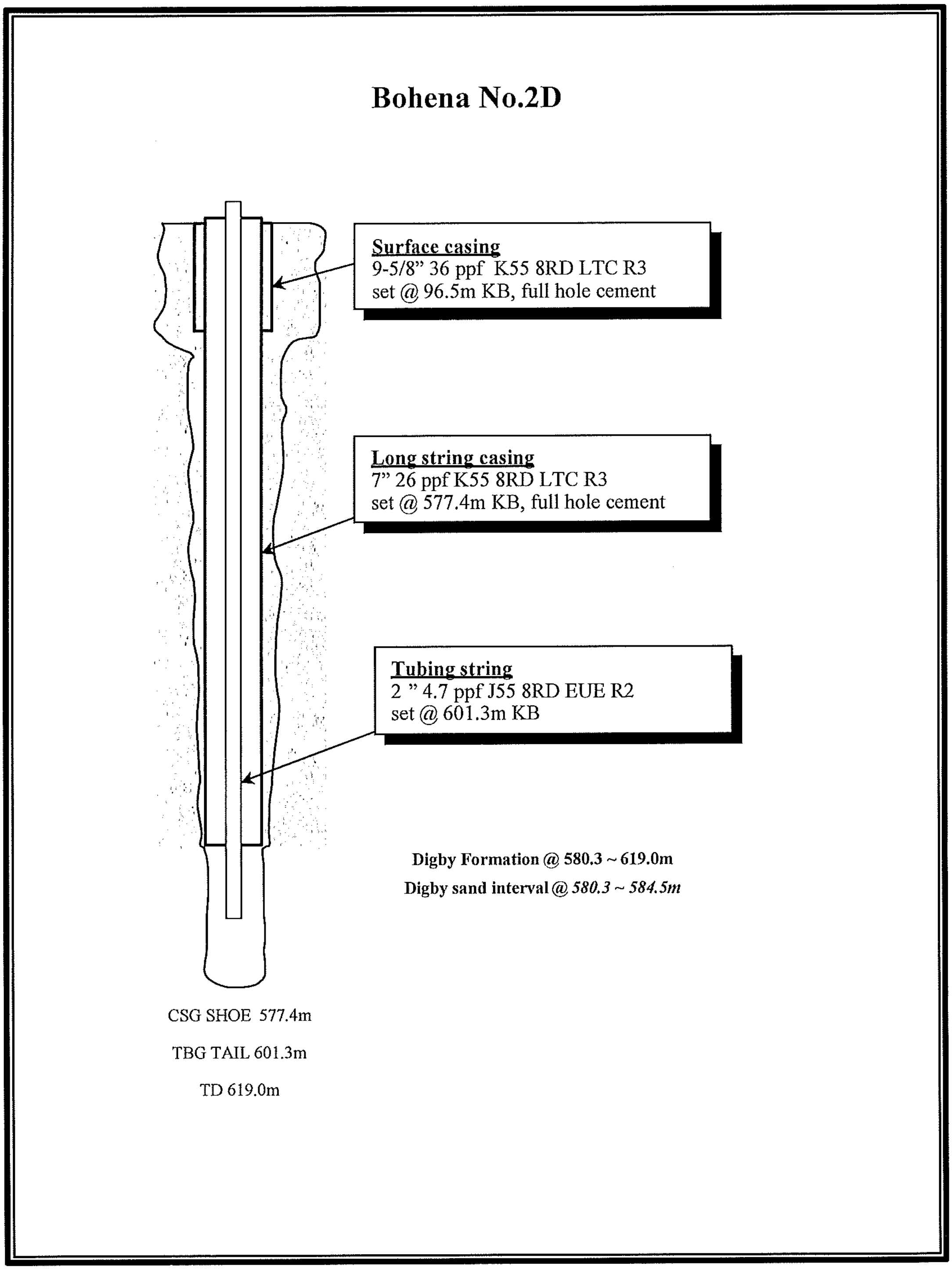
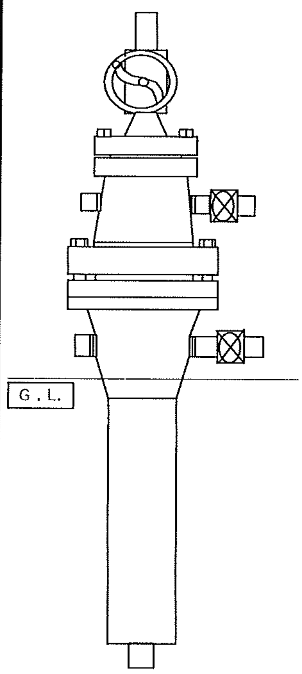


Figure 5: Wellhead Diagram, Bohena No.2D

Forcenergy Australia Pty. Ltd.

WELLHEAD DIAGRAM

WELL: **Bohena No.2D** DATE: 11/09/98



CELLAR INSTALLED

DESCRIPTION			
GATE VALVE	MAKE/TYPE SIZE/RATING FITTINGS		2" API GATE VALVE x 3000 psi 2" NPT threaded ends, HWO, N-I trim 2-7/8" eue to 2" npt swage
ADAPTOR FLANGE	MAKE/TYPE SIZE/RATING		National Kverner - F/SWTCM 7 1/16" R45 x 2 -7/8" EUE male thread 3000 psi
TUBING SPOOL	MAKE/TYPE SIZE/RATING		Cameron Type F 7-1/16" x 11" 3000 psi R45 x R53
	OUTLET 1	VALVE/ FITTINGS	2" NPT WITH 2" NPT BALL VALVE 2 x 2" NPT SCHD. 80 NIPPLE,
	OUTLET 2		2" npt 3000 psi bull plug
TUBING HANGER	MAKE/TYPE SIZE/RATING LIFT THD./BPV PREP.		Cameron / FBB 7" x 2-7/8" / 3000 psi mandrel 2-7/8 EUE , No BPV thread prep. (2-7/8" EUE x 2-3/8" EUE swage nipple at top of tubing string)
*CASING BOWL	MAKE/TYPE SIZE/RATING		Cameron 11" 3000 PSI X 9-5/8" 8RD
	OUTLET 1	VALVE/ FITTINGS	2" NPT WITH 2" NPT BALL VALVE 2 x 2" NPT SCHD. 80 NIPPLE,
	OUTLET 2	VALVE/ FITTINGS	2" NPT 3000 psi bull plug

COMPLETION DETAILS		
SURF. CSG.	SIZE,WT./GR./THREAD DEPTH	9-5/8" 36ppf K55 8RD LTC R3 96.5m
PROD. CSG.	SIZE,WT./GR./THREAD DEPTH	7" 26ppf K55 8RD LTC R3 577.4m
TUBING	SIZE,WT./GR./THREAD. DEPTH / No of joints STRING WT. INDICATED CALCULATED	2-3/8 4.7ppf J55 8RD EUE R2 601.27m (62 jts)
REMARKS		

AUTHOR: J. White | DRAFTED: | DATE DRAWN: 7/04/99

Figure 6: Well Configuration, Bohena No.6H

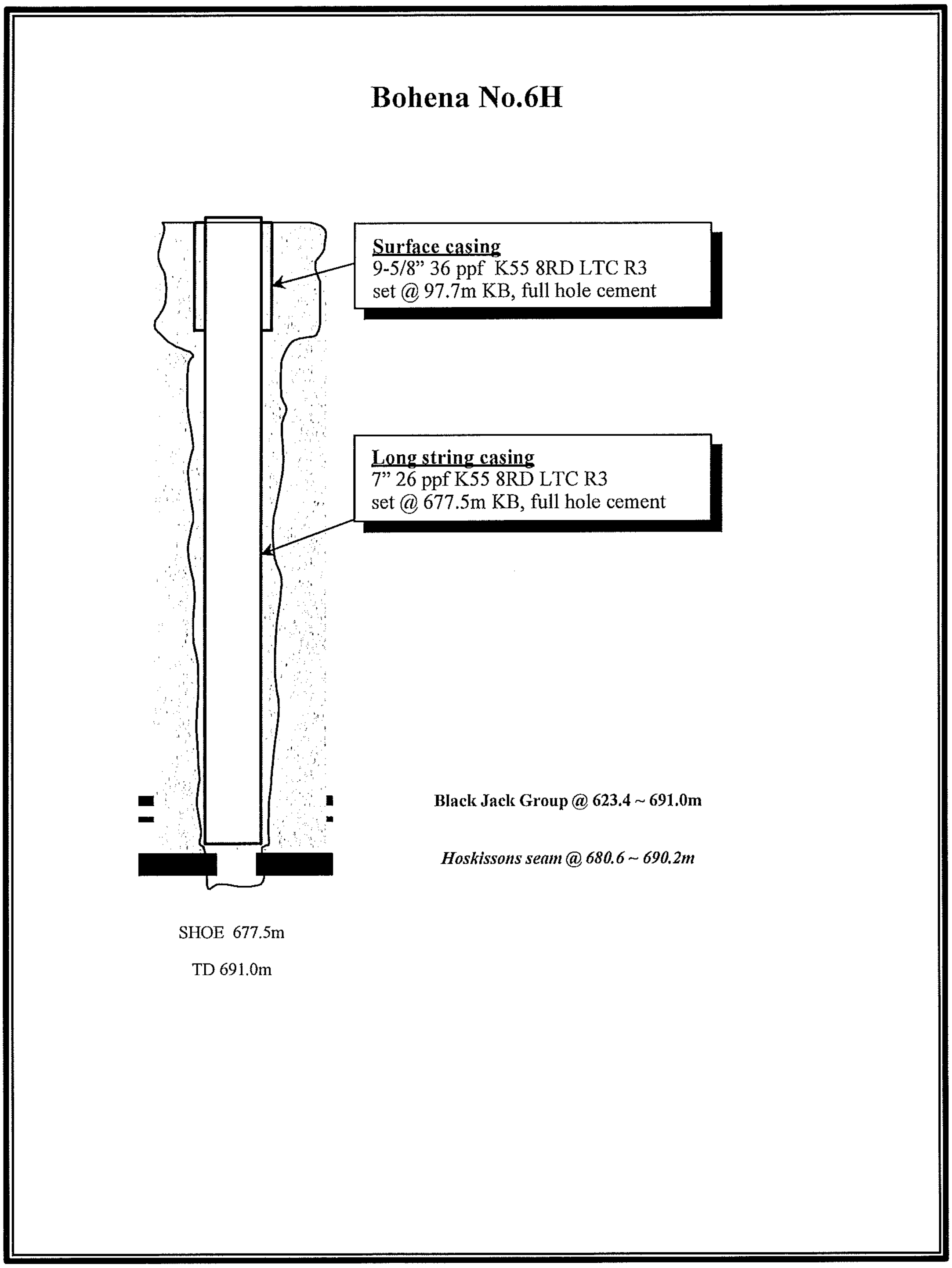
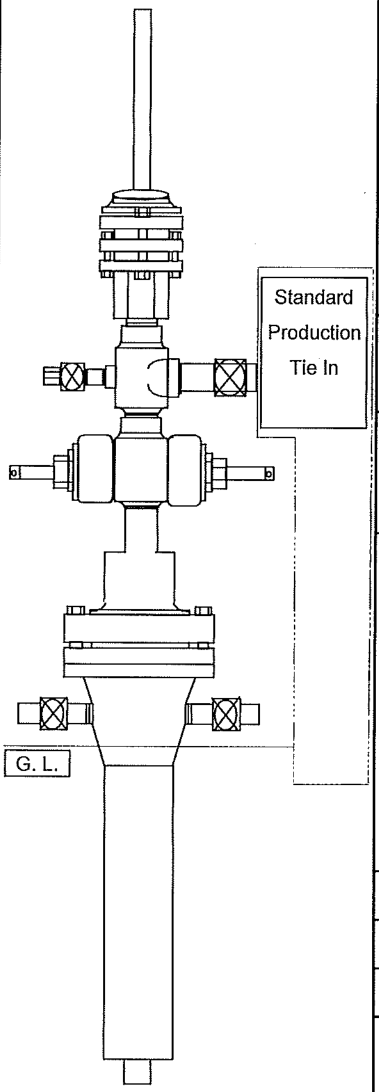


Figure 7: Wellhead Diagram, Bohena No.6H

Forcenergy Australia Pty. Ltd.

SINGLE PUMPING WELLHEAD

WELL: Bohena No.6H DATE: 30/08/98



DESCRIPTION

STUFFING BOX	MAKE/TYPE SIZE/RATING	HUBER / SELF ALIGNING 2-7/8 1500 PSI
PUMPING TEE	SIZE/RATING OUTLETS/FITTINGS	2-7/8 EUE X 2-7/8 EUE 2" NPT x 1" NPT
BOP	MAKE/TYPE SIZE/RATING/RAMS	RATIGAN 212 2-7/8 EUE , 1500 PSI , 5/8"-1 1/4"
ADAPTOR FLANGE	MAKE/TYPE SIZE/RATING	National Kverner - F/SWTCM 7 1/16" R45 x 2 -7/8" EUE male thread 3000 psi
TUBING HANGER	MAKE/TYPE SIZE/RATING LIFT THD./BPV PREP.	National Kverner / SWTC-1W 7" x 2-7/8" / 3000 psi / Wrap Around 2 7/8 EUE , No BPV thread prep.

*CASING BOWL (Tubing Head)	MAKE/TYPE SIZE/RATING		National Kverner - F/SWTCM 7" 8rd BTM x 7 1/16" R45 3000 psi
	OUTLET 1	VALVE/ FITTINGS	2" NPT WITH 2" NPT BALL VALVE 2 x 2" NPT SCHD. 80 NIPPLE, 2" NPT FIG. 2 UNION 2000 PSI STANDARD PRODUCTION TIE-IN
	OUTLET 2	VALVE/ FITTINGS	2" NPT WITH 2" NPT BALL VALVE 2 x 2" NPT SCHD. 80 NIPPLE, 2" NPT FIG. 2 UNION 2000 PSI 2" NPT BULL Plug,1/2" NPT VALVE WITH 1/2" NPT VATRIX NIPPLE

COMPLETION DETAILS

SURF. CSG.	SIZE,WT./GR./THREAD DEPTH	9-5/8" 36ppf K55 8RD LTC R3 97.74m
PROD. CSG.	SIZE,WT./GR./THREAD DEPTH	7" 26ppf K55 8RD LTC R3 677.46m
TUBING	SIZE,WT./GR./THREAD. DEPTH / No of joints STRING WT. INDICATED CALCULATED	2-7/8 6.5ppf J55 8RD EUE R2 677.71 (68 jts)
REMARKS		

CELLAR INSTALLED

AUTHOR: J. White	DRAFTED:	DATE DRAWN: 12/10/98

Table 1: Drilled Stratigraphy, Bohena No.2D

ERA		PERIOD		STRATIGRAPHY GROUP	STRATIGRAPHY FORMATION	DEPTH TO TOP m K.B.	DEPTH TO BASE m K.B.	THICK-NESS m	ELEV. TOP m AHD	LITHOLOGY
MESOZOIC / CAINOZOIC	Surat Basin Units	QUATERNARY / LATE JURASSIC			Undifferentiated Quaternary surficial sediments Pilliga Sandstone	4.0	300.0	296.0	255.5	Undifferentiated alluvial deposits, sand, silt & clay Quartz pebble and quartzose sandstone with minor lithic sandstone & siltstone
MESOZOIC	Surat Basin Units	JURASSIC			Purlawaugh Formation	300.0	351.0	51.0	-40.5	Thinly bedded lithic labile sandstone interbedded with siltstone & mudstone
MESOZOIC	Gunnedah Basin Units	TRIASSIC	MIDDLE		Deriah Formation	351.0	375.8	24.8	-91.5	Lower fine to medium, green volcano-lithic sandstone, upper of-white lithic sandstone & mudstone
MESOZOIC	Gunnedah Basin Units	TRIASSIC	MIDDLE		Napperby Formation *including 90.0m intrusives @ 490.3 – 580.3m (Early Jurassic)*	375.8	580.3	204.5	-116.3	Upward coarsening sequences, base dominantly mudstones, middle sandstones & mudstones, upper dominantly sandstones
MESOZOIC	Gunnedah Basin Units	TRIASSIC	EARLY		Digby Formation *Digby sand @ 580.3 – 584.5m*	580.3	619.0+	38.7+	-324.8	Poorly sorted volcanic-lithic pebble orthoconglomerate overlain by massive, parallel or crossbedded coarse to fine grained quartz-lithic and then quartzose sandstone
Total Depth						619.0			-363.5	

Table 2: Drilled Stratigraphy, Bohena No.6H

ERA		PERIOD		STRATIGRAPHY GROUP	STRATIGRAPHY FORMATION	DEPTH TO TOP m K.B.	DEPTH TO BASE m K.B.	THICK-NESS m	ELEV. TOP m AHD	LITHOLOGY
MESOZOIC / CAINOZOIC	Surat Basin Units	QUATERNARY / LATE JURASSIC			Undifferentiated Quaternary surficial sediments Pilliga Sandstone	4.0	298.1	294.1	257.3	Undifferentiated alluvial deposits, sand, silt & clay Quartz pebble and quartzose sandstone with minor lithic sandstone & siltstone
MESOZOIC	Surat Basin Units	JURASSIC			Purlawaugh Formation	298.1	345.7	47.6	-36.8	Thinly bedded lithic labile sandstone interbedded with siltstone & mudstone
MESOZOIC	Gunnedah Basin Units	TRIASSIC	MIDDLE		Deriah Formation	345.7	367.1	21.4	-84.4	Lower fine to medium, green volcano-lithic sandstone, upper of-white lithic sandstone & mudstone
MESOZOIC	Gunnedah Basin Units	TRIASSIC	MIDDLE		Napperby Formation *including 72.9m intrusives @ 515.3 – 588.2m (Early Jurassic)*	367.1	588.1	221.0	-148.1	Upward coarsening sequences, base dominantly mudstones, middle sandstones & mudstones, upper dominantly sandstones
MESOZOIC	Gunnedah Basin Units	TRIASSIC	EARLY		Digby Formation	588.1	623.4	35.3	-326.8	Poorly sorted volcanic-lithic pebble orthoconglomerate overlain by massive, parallel or crossbedded coarse to fine grained quartz-lithic and then quartzose sandstone
PALAEOZOIC	Gunnedah Basin Units	PERMIAN	LATE	Black Jack Group	*Hoskissons seam @ 680.6 – 690.2m*	623.4	691.0+	67.6+	-362.1	Conglomerate & sandstone (quartzose and lithic), siltstone, claystone, coal, stoney coal and carbonaceous siltstone, minor tuff & tuffaceous sediments
Total Depth						691.0			-433.7	

Table 3: In-situ & Injection Water Quality

Well		BH002D		BH006H	
Water Sample Type		Average In-situ Water Quality	Volume Weighted Injection Water Quality	Average In-situ Water Quality	Volume Weighted Injection Water Quality
Sample Source Unit		Digby	Maules Ck in BH002/3/4/5	Hoskissons	Maules Ck in BH006/7
Current Water Production	BWPD	~	217	~	140
Current Water Production	kl/day	~	34.5	~	22.3
PROPERTIES pH		8.7	7.4	8.1	7.3
Resistivity	Ohm.M @ 25°C	1.04	0.83	0.50	0.93
Conductivity	μS/cm @ 25°C	9,685	12,432	19,888	11,197
CATIONS Potassium	as K mg/L	40	54	93	84
Sodium	as Na mg/L	5,190	3,613	7,036	2,984
Calcium	as Ca mg/L	0	11	8	5
Iron	as Fe mg/L	0	0	2	0
Magnesium	as Mg mg/L	11	3	5	1
Manganese	as Mn mg/L	0	0	0	0
TOTAL	mg/L	5,221	3,681	7,141	3,073
ANIONS Chloride	as Cl mg/L	907	1,525	609	1,153
Hydroxide	as OH mg/L	0	0	2	0
Nitrate	as NO3 mg/L	4	10	13	7
Bicarbonate	as HCO3 mg/L	5,836	7,263	17,323	6,724
Carbonate	as CO3 mg/L	2,870	0	736	0
Sulphate	as SO4 mg/L	7	57	9	0
TOTAL	mg/L	9,623	8,854	18,317	7,884
DERIVED Ion Balance	(<5% OK) %	2.7	1.4	2.0	3.8
Total Alkalinity	as CaCO3 mg/L	4,783	5,953	14,879	5,511
Meas. Dis. Salts	(Cat+An) mg/L	14,844	12,535	25,458	10,957
Theor. Dis. Salts	(from cond) mg/L	6,198	7,956	12,728	7,167

Australian Government

National Water Commission

Position Statement
Coal Seam Gas and Water

The Coal Seam Gas and water challenge

The Coal Seam Gas (CSG) industry offers substantial economic and other benefits to Australia. At the same time, if not adequately managed and regulated, it risks having significant, long-term and adverse impacts on adjacent surface and groundwater systems.

In light of the scale of potential benefits and associated risks, the National Water Commission is highlighting the need for appropriate management of CSG developments, consistent with the objectives of the National Water Initiative (NWI). To meet NWI objectives, the Commission recommends that industry, water and land-use planners, and governments adopt a precautionary approach to CSG developments, ensuring that risks to the water resource are carefully and effectively managed.

Current projections indicate the Australian CSG industry could extract in the order of 7,500 gigalitres of co-produced water from groundwater systems over the next 25 years, equivalent to ~300 gigalitres per year. In comparison, the current total extraction from the Great Artesian Basin is approximately 540 gigalitres per year.

Potential impacts of CSG developments, particularly the cumulative effects of multiple projects, are not well understood.

Potential risks to sustainable water management

- Extracting large volumes of low-quality water will impact on connected surface and groundwater systems, some of which may already be fully or overallocated, including the Great Artesian Basin and Murray-Darling Basin.
- Impacts on other water users and the environment may occur due to the dramatic depressurisation of the coal seam, including:
  - changes in pressures of adjacent aquifers with consequential changes in water availability
  - reductions in surface water flows in connected systems
  - land subsidence over large areas, affecting surface water systems, ecosystems, irrigation and grazing lands.
- The production of large volumes of treated waste water, if released to surface water systems, could alter natural flow patterns and have significant impacts on water quality, and river and wetland health. There is an associated risk that, if the water is overly treated, 'clean water' pollution of naturally turbid systems may occur.
- The practice of hydraulic fracturing, or fraccing, to increase gas output, has the potential to induce connection and cross-contamination between aquifers, with impacts on groundwater quality.
- The reinjection of treated waste water into other aquifers has the potential to change the beneficial use characteristics of those aquifers.

In addition to these water management risks, CSG development could also cause significant social impacts by disrupting current land-use practices and the local environment through infrastructure construction and access.

The Commission is concerned that CSG development represents a substantial risk to sustainable water management given the combination of material uncertainty about water impacts, the significance of potential impacts, and the long time period over which they may emerge and continue to have effect. Therefore, an adaptive and precautionary management approach will be essential to allow for progressive improvement in the understanding of impacts, including cumulative effects, and to support timely implementation of 'make good' arrangements.

CSG and the National Water Initiative

Under clause 34 of the NWI, the signatory governments agreed that there may be special circumstances facing the petroleum and minerals sectors that need to be addressed by policies and measures beyond the scope of the NWI Agreement. In this context, all governments noted that specific project proposals would be assessed according to environmental, economic and social considerations, and that factors specific to resource development projects (such as isolation, relatively short project duration, water quality issues, and obligations to remediate and offset impacts) may require specific management arrangements outside the scope of the NWI.

Progress on CSG related reforms

In its 2009 Biennial Assessment of national water reform progress, the Commission found that the circumstances in which special clause 34 would apply are not defined and identified in a consistent and transparent manner. Little progress had been made in the five years since the signing of the NWI in fleshing out the special provisions for the minerals, petroleum and related industries. As a consequence, there has been little integration of those industries with broader water markets and water planning processes, despite the potential for considerable benefits in many cases.

The potential impacts of CSG extraction are currently managed through state and territory laws and policies, including environmental approval processes with subsequent conditions or special arrangements often implemented to mitigate risks to the environment and communities. These conditions are set by the approving authority which can be a state government minister or appointed official. In certain circumstances, the Commonwealth Minister for the Environment will have a role in approving and setting conditions for projects under the Commonwealth *Environment Protection and Biodiversity Conservation Act*.

While these processes have the capacity to address many of the issues relating to water and CSG development, they are often not well integrated with state and territory water planning and management arrangements.

The Commission's work on CSG

The Commission is completing a discussion paper on CSG water issues and potential impacts to provide useful background information for regulators, water managers and other water users. A$1.8 million *Potential local and cumulative effects of mining on groundwater resources* project funded by the Commission is also developing tools and guidelines to account for potential local and cumulative effects of mining on groundwater resources. These guidelines and tools are intended to assist in the management of CSG.

Principles for managing CSG and water

The Commission believes that wherever there is potential for significant water resource impacts, CSG activities should be incorporated into NWI consistent water planning and management regimes from their inception. Given the high level of uncertainty around water impacts, and the temporal nature of CSG developments, this will likely require a precautionary approach that demands innovation from water managers and planners, and significantly greater coordination with existing project approval processes.

Specifically, the Commission proposes the following principles be applied by state and territory jurisdictions to managing the cumulative impacts of CSG water:

- The interception of water by CSG extraction should be licensed to ensure it is integrated into water sharing processes from their inception.
- Project approvals should be transparent, including clear and public articulation of predicted environmental, social and economic risks along with conditions implemented to manage the risks.
- Adequate monitoring, including baseline assessment of surface and groundwater systems, should be undertaken to provide a benchmark for assessing cumulative impacts on other water users and water-dependent ecosystems.

- Jurisdictions should work to achieve consistent approaches to managing the cumulative impacts of CSG extraction. Such arrangements should consider and account for the water impacts of CSG activities in water budgets and manage those impacts under regulatory arrangements that are part of, or consistent with, statutory water plans and the National Water Initiative.
- Potential options to minimise the cumulative impacts of extraction on the water balance should be pursued as a first priority. These options include aquifer reinjection, where water quality impacts are acceptable, and groundwater trading or direct substitution for other water use.
- If discharges to surface waters are unavoidable, discharges should be conditioned so that environmental values and water quality objectives, including water quality to meet public health objectives, are protected. In such circumstances discharges to ephemeral streams should be pulsed to avoid flows in naturally dry periods.
- Jurisdictions should undertake water and land-use change planning and management processes in an integrated way to ensure that water planning implications of projects are addressed prior to final development approval.
- Clear accountabilities should be identified for any short- or long-term cumulative impacts from CSG processes, clarifying which organisations are responsible for managing and rectifying or compensating for any impacts.
- The full costs, including externalities, of any environmental, social and economic water impacts and their management should be borne by the CSG companies. This includes, if not already in place, mechanisms such as bonds and sureties that deal with uncertainty and the timeframes associated with potential impacts. Given that these timeframes may extend for 100 or more years, current systems need to be re-evaluated.
- A precautionary and adaptive approach to managing and planning for CSG activities is essential to enable improved management in response to evolving understanding of current uncertainties. This includes impacts such as long-term reductions in adjacent aquifer pressures and levels, and impacts on environmental assets that are not adequately protected by current 'make good' mechanisms.
- Water produced as a by-product of CSG extraction, that is made fit for purpose for use by other industries or the environment, should be included in NWI-compliant water planning and management processes. This will enable CSG producers to manage this resource in accordance with the principles of the National Water Initiative.

The consequences of not managing the water risks and uncertainties associated with the economic benefits of CSG are substantial. Therefore, the Commission strongly argues for the careful, transparent and integrated consideration of water-related impacts in all approval processes.

The Commission's position is that NWI-consistent water access entitlements should be made available to coal seam gas activities wherever possible, as the use of Clause 34 of the NWI is only intended to operate in exceptional circumstances. Where Clause 34 is used, a clear and transparent explanation of why it was used, rather than complying with the normal water planning and management regime, should be provided.

National Water Commission
December 2010

Stanford News (http://news.stanford.edu/)

MARCH 29, 2016

Stanford researchers show fracking's impact to drinking water sources

A case study of a small Wyoming town reveals that practices common in the fracking industry may have widespread impacts on drinking water resources.

BY ROB JORDAN

Only one industry is allowed to inject toxic chemicals into underground sources of drinking water – hydraulic fracturing, or "fracking." Concerns about this practice have riled the U.S. political landscape and communities around the country, perhaps nowhere more so than in Pavillion, Wyoming, population 231.

U.S. Environmental Protection Agency staff members sample a monitoring well for contaminants from hydraulic fracturing. A Stanford study in Pavillion, Wyoming, finds that practices common in the fracking industry have affected the community's drinking water. *(Image credit: Dominic DiGiulio)*

A new study by Stanford scientists published in *Environmental Science & Technology (http://pubs.acs.org/journal/esthag)* finds for the first time that fracking operations near Pavillion have had clear impact to underground sources of drinking water. The research paints a picture of unsafe practices including the dumping of drilling and production fluids containing diesel fuel, high chemical concentrations in unlined pits and a lack of adequate cement barriers to protect groundwater.

The well field has gone through several corporate hands since the 1960s, but various fracking operators have used acid and hydraulic fracturing treatments at the same depths as water wells in the area.

"This is a wake-up call," said lead author Dominic DiGiulio, a visiting scholar at Stanford School of Earth, Energy & Environmental Sciences. "It's perfectly legal to inject stimulation fluids into underground drinking water resources. This may be causing widespread impacts on drinking water resources."

"Decades of activities at Pavillion put people at risk. These are not best practices for most drillers," said co-author **Rob Jackson (http://earth.stanford.edu/rob-jackson)**, the Michelle and Kevin Douglas Provostial Professor at the **School of Earth, Energy & Environmental Sciences (http://earth.stanford.edu/)**.

As part of the so-called frackwater they inject into the ground, drilling companies use proprietary blends that can include potentially dangerous chemicals such as benzene and xylene. When the wastewater comes back up after use, it often includes those and a range of potentially dangerous natural chemicals.

"There are no rules that would stop a company from doing this anywhere else," said Jackson, who is also a senior fellow at the **Stanford Woods Institute for the Environment (http://woods.stanford.edu)** and at the **Precourt Institute for Energy (http://energy.stanford.edu/)**.

The study, based on publically available records and documents obtained through the Freedom of Information Act, is part of Jackson's ongoing research on shallow fracking and its impact on groundwater. He and his colleagues have done various studies across the United States and in the Pavillion Field, an area of Wyoming's Wind River Basin pocked by more than 180 oil and gas wells, some of them plugged and abandoned.

Back in 2008, the residents of Pavillion complained of a foul taste and odor in their drinking water and questioned whether it was related to physical ailments. In 2011, the U.S. Environmental Protection Agency issued a preliminary report putting the tiny town at the center of a growing fracking debate.

The EPA report, which linked shallow fracking to toxic compounds in aquifers, was met with heavy criticism from the drilling industry as well as state oil and gas regulators. Three years later, having never finalized its findings, EPA turned its investigation over to Wyoming. The state released a series of reports without firm conclusions, and, as of last month, has said it has no firm plans to take further action. In the meantime, the federal Agency for Toxic Substances and Disease Registry has advised area residents to avoid bathing, cooking or drinking with water from their taps.

The new Stanford study goes a step beyond the 2011 EPA report to document not only the occurrence of fracking chemicals in underground sources of drinking water but also their impact on that water that is making it unsafe for use.

The ripple effect goes well beyond Pavillion.

"Geologic and groundwater conditions at Pavillion are not unique in the Rocky Mountain region," said DiGiulio. "This suggests there may be widespread impact to underground sources of drinking water as a result of unconventional oil and gas extraction."

To avoid what happened in Pavillion, Jackson and DiGiulio suggest further investigation and regulations to limit shallow fracking and require deeper protective casings. Wyoming does not require the cementing of surface casings, and only two U.S. states, Colorado and Texas, have special requirements for shallow hydraulic fracturing. Safeguards mean little, however, if they are not enforced – something the EPA has done a mixed job with, according to Jackson.

"The EPA has consistently walked away from investigations where people and the environment appear to have been harmed" by fracking's impact on groundwater, Jackson said.

Media Contacts

Dominic DiGiulio, Stanford School of Earth, Energy & Environmental Sciences: (580) 279-9283, ddigiuli@stanford.edu
Rob Jackson, School of Earth, Energy & Environmental Sciences: (650) 497-5841, rob.jackson@stanford.edu
Rob Jordan, Stanford Woods Institute for the Environment: (650) 721-1881, rjordan@stanford.edu

(mailto:?subject=An%20interesting%20article%20from%20Stanford%20News&body=I%20want%20to%20share%20this%20news%20story%20from%20Stanford%20University%20with%20you%3A%20http%3A%2F%2Fstanford.io%2F1pONt3j)

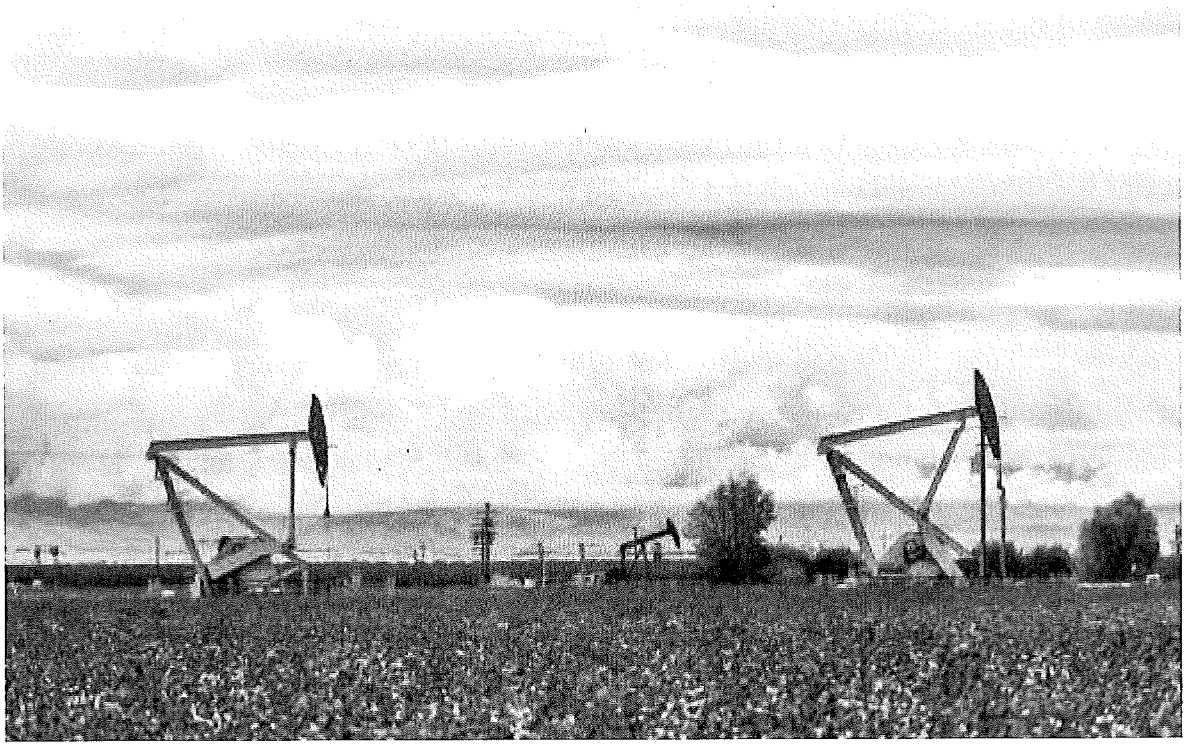
ClimateWire

ENVIRONMENT

Fracking Can Contaminate Drinking Water

It took nearly a decade, but former EPA scientist Dominic DiGiulio has proved that fracking has polluted groundwater in Wyoming

By Gayathri Vaidyanathan, ClimateWire on April 4, 2016



Credit: Education Images / Contributor via Getty Images

Former EPA scientist Dominic DiGiulio never gave up.

Eight years ago, people in Pavillion, Wyo., living in the middle of a natural gas basin, complained of a bad taste and smell in their drinking water. U.S. EPA launched an inquiry, helmed by DiGiulio, and preliminary testing suggested that the groundwater contained toxic chemicals.

Then, in 2013, the agency suddenly transferred the investigation to state regulators without publishing a final report.

Now, DiGiulio has done it for them.

He published a comprehensive, peer-reviewed study last week in *Environmental Science and Technology* that suggests that people's water wells in Pavillion were contaminated with fracking wastes that are typically stored in unlined pits dug into the ground.

The study also suggests that the entire groundwater resource in the Wind River Basin is contaminated with chemicals linked to hydraulic fracturing, or fracking.

This production technique, which involves cracking shale rock deep underground to extract oil and gas, is popular in the United States. It's also controversial. There are thousands of wells across the American West and in California that are vulnerable to the kind of threat documented in the study, DiGiulio said. He is now a research scholar at Stanford University.

"We showed that groundwater contamination occurred as a result of hydraulic fracturing," DiGiulio said in an interview. "It contaminated the Wind River formation."

The findings underscore the tension at the heart of the Obama administration's climate change policy, which is based on replacing many coal-fired power plants with facilities that burn cleaner natural gas.

That reliance on natural gas has sometimes blinded agencies to local pollution and health impacts associated with the resource, said Rob Jackson, an earth scientist at Stanford and co-author of the study. In 2015, EPA said in a controversial draft study that hydraulic fracturing has not had "widespread, systemic impacts on drinking water resources in the United States" (*Greenwire*, June 4, 2015).

"The national office of EPA has tended to downplay concerns of their own investigators, in part because the Obama administration has promoted natural gas," Jackson said. "Natural gas is here to stay. It behooves us to make it as safe and environmentally friendly as possible."

EPA spokeswoman Julia Valentine said the agency hasn't yet finalized its assessment that natural gas has no "widespread, systemic impacts." As part of that process, the agency will evaluate all recent research, including DiGiulio's study, she said.

Encana Corp., the company that operated in the Pavillion basin, said repeated testing has shown people's water wells are safe for consumption.

"After numerous rounds of testing by both the state of Wyoming and EPA, there is no evidence that the water quality in domestic wells in the Pavillion Field has changed as a result of oil and gas operations; no oil and gas constituents were found to exceed drinking water standards in any samples taken," said Doug Hock, an Encana spokesman.

LABS CAN'T SEE FRACKING CHEMICALS

Water testing began in 2009 when the local EPA office responded to complaints from residents. EPA headquarters, and DiGiulio, got involved in January 2010.

"Conducting a groundwater investigation related to fracking is extremely complicated," DiGiulio said. "It is difficult because a lot of the compounds used for hydraulic fracturing are not commonly analyzed for in commercial labs."

These labs were originally set up for the Superfund program, under which EPA cleans up the most contaminated sites in the nation. They are great at detecting chemicals found at Superfund sites but not as good at detecting chemicals used in fracking, DiGiulio said.

"You have some of these very water-soluble exotic compounds in hydraulic fracturing, which were not amenable to routine lab-type analysis," he said.

One such chemical was methanol. The simplest alcohol, it can trigger permanent nerve damage and blindness in humans when consumed in sufficient quantities. It was used in fracking in Pavillion as workers pumped thousands of gallons of water and chemicals at high pressure into the wells they were drilling. About 10 percent of the mixture contained methanol, DiGiulio said.

So the presence of methanol in the Pavillion aquifer would indicate that fracking fluid may have contaminated it. But methanol degrades rapidly and is reduced within days to trace amounts. Commercial labs did not have the protocol to detect such small traces, so DiGiulio and his colleagues devised new procedures, using high-performance liquid chromatography, to detect it. They devised techniques for detecting other chemicals, as well.

By then, Pavillion was roiling in controversy as EPA and residents collided with industry. EPA had drilled two monitoring wells, MW01 and MW02, in 2011, and its testing had found benzene, diesel and other toxic chemicals. But these results were contested by oil and gas industry representatives, who criticized EPA's sampling techniques (*EnergyWire*, Oct. 12, 2012). They pointed to a technical disagreement between EPA and the U.S. Geological Survey on the best methods to cast doubt on EPA's overall findings.

EPA realized it needed a consensus on its water testing methodology. In February 2012, it assembled a technical team from the USGS, Wyoming state regulators and tribal representatives from the Wind River Indian Reservation. They retested the monitoring wells in April 2012.

This time, they also tested for methanol. But EPA never released those results to the public. In 2013, the agency backed out of its investigation in Pavillion, handing it over to state regulators, who moved forward using a $1.5 million grant from Encana (*EnergyWire*, June 21, 2013). DiGiulio said the decision had come from EPA's senior management.

METHANOL, DIESEL AND SALT

Industry representatives repeatedly pointed out that EPA had not published a peer-reviewed study on its findings.

"If the EPA had any confidence in its draft report, which has been intensely criticized by state regulators and other federal agencies, it would proceed with the peer review process," Steve Everley, a spokesman for Energy in Depth, an industry group, said at the time. "But it's not, which says pretty clearly that the agency is finally acknowledging the severity of those flaws and leaning once again on the expertise of state regulators."

In December 2015, state regulators published a draft of their findings. It stated that fracking had not contributed to pollution in Pavillion, according to the *Casper Star Tribune*. The report said the groundwater is generally suitable for people to use.

When DiGiulio retired from EPA in 2014, he trained his sights on Pavillion. He felt he had to finish his work.

"EPA had basically handed the case over and a peer-reviewed document was never finalized," he said. "If it is not in the peer-reviewed literature, then it presents a problem with credibility in terms of findings. It is important that the work be seen by other scientists and enter the peer review realm so that other scientists will have access to virtually everything."

Since 2012, a trove of new data had accumulated from USGS, EPA and state regulators. He obtained EPA's methanol testing results through a Freedom of Information Act request and downloaded the rest of the information from the Wyoming oil and gas regulator's website. All of it was publicly available, waiting for the right person to spend a year crunching the information.

The end result: a peer-reviewed study that reaffirms EPA's findings that there was something suspicious going on in Pavillion. More research is needed.

The sampling wells contained methanol. They also contained high levels of diesel compounds, suggesting they may have been contaminated by open pits where operators had stored chemicals, DiGiulio said.

The deep groundwater in the region contained high levels of salt and anomalous ions that are found in fracking fluid, DiGiulio said. The chemical composition suggests that fracking fluids may have migrated directly into the aquifer through fractures, he said.

Encana had drilled shallow wells at Pavillion, at depths of less than 2,000 feet and within reach of the aquifer zone, said Jackson of Stanford University.

"The shallow hydraulic fracturing is a potential problem because you don't need a problem with well integrity to have chemicals migrate into drinking water," he said.

The study also shows that there is a strong upward flow of groundwater in the basin, which means contamination that is deep underground could migrate closer to the surface over time.

"Right now, we are saying the data suggests impacts, which is a different statement than a definitive impact," DiGiulio said. "We are saying the dots need to be connected here, monitoring wells need to be installed."

SHALLOW WELLS ARE PREVALENT

EPA came to the same conclusion in a blistering response last week to Wyoming's draft findings.

"Many of our recommendations suggest that important information gaps be filled to better support conclusions drawn in the report, and that uncertainties and data gaps be discussed in the report," said Valentine, the EPA spokeswoman.

The state had tested people's water wells and detected 19 concerning chemicals. But regulators had concluded that only two chemicals exceeded safe limits and the water could be used for domestic purposes. EPA disagreed. Nearly half the 19 chemicals are unstudied, and scientists do not know the safe level of exposure, EPA stated.

Keith Guille, spokesman for Wyoming's Department of Environmental Quality, declined to comment on DiGiulio's study and on EPA's response to the state's draft report. The state is finalizing its findings and has its eyes set on the future, he said.

"We are not done yet," Guille said.

Energy in Depth, the industry group that had earlier criticized EPA for not publishing a peer-reviewed study, said that DiGiulio's study is "a rehash of EPA's old, discredited data by the very researcher who wrote EPA's original report."

Jackson stressed that the contamination seen at Pavillion could occur in other states where, according to a study published last year in *Environmental Science & Technology* on which he was the lead author, fracking sometimes occurs at shallow depths. That includes the Rocky Mountain region, New Mexico, Colorado, Utah, Montana and California. At present, no state has restrictions on how shallowly a company can frack, he said.

"Shallow hydraulic fracturing is surprisingly common, especially in the western U.S.," Jackson said. "Here in California, half of the wells are fracked shallower than about 2,000 feet."

Given the threat, fracking deserves much greater scrutiny than it has so far received from the Obama administration, said Hugh MacMillan, a scientist with the environmental group Food and Water Watch.

"Communities have never argued that every well goes bad; they've argued that when you drill and [are] fracking thousands, too many go bad," he said. "For those living on groundwater, it becomes a matter of luck, and that's not right, because over years, more and more people's luck runs out."

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ABOUT THE AUTHOR(S)

Gayathri Vaidyanathan

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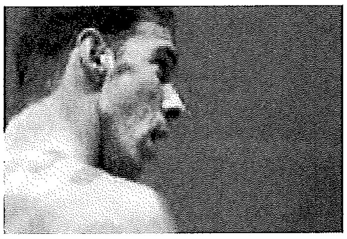

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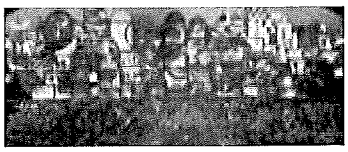

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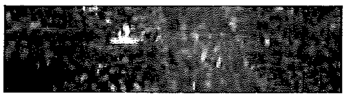

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