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## An introduction to this special section: Passive seismic and microseismic—Part 2

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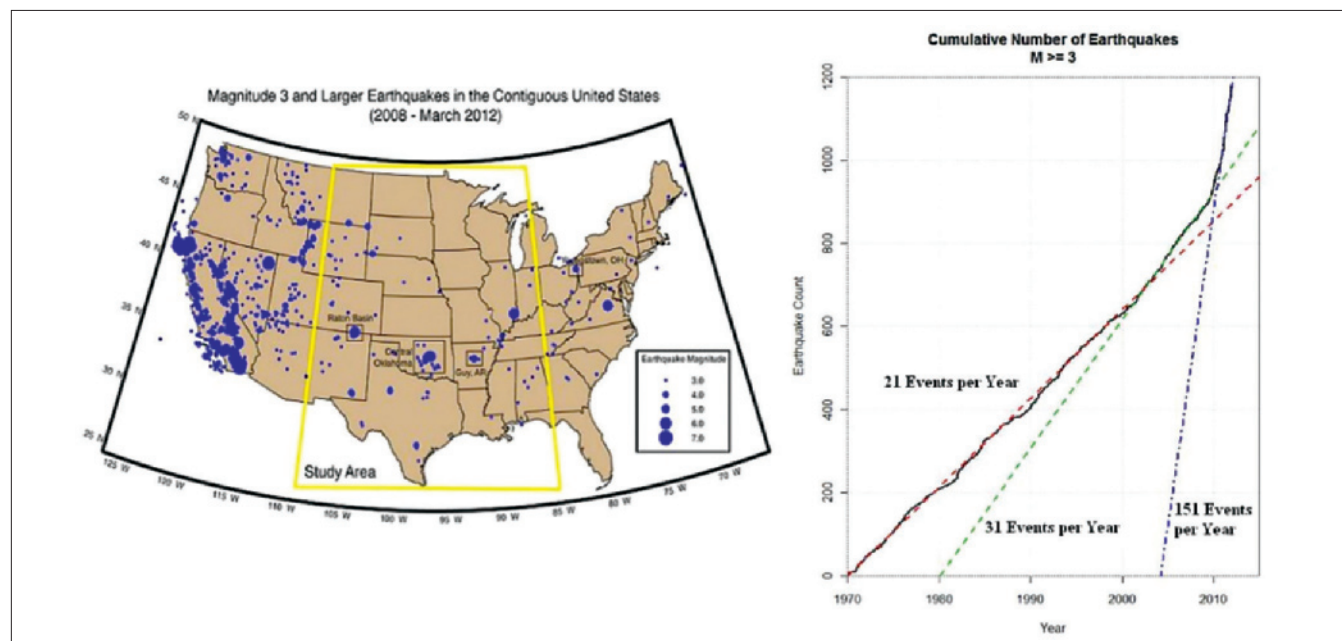
Welcome to the second half of *TLE*'s two-part special section on passive seismic and microseismic. This month, we focus again on monitoring hydraulic fracturing with microseismic with five articles, but also expand beyond "micro"seismicity, to include unintended "induced" seismicity that may occur during injection. Five articles in this special section focus on induced-seismicity topics. In this introduction, we will highlight various issues related to undesired induced seismicity which may be caused by hydraulic fracturing and deep, underground salt water disposal.

### Why should you care about induced seismicity?

The large increase in unconventional plays and hydraulic fracturing, discussed in the November special section introductory article (Goodway, 2012), has been accompanied with an increase in the generation of wastewater, which is a byproduct resulting from flowback after the stimulation procedure. Induced seismicity from the wastewater injection is extremely rare, occurring in less than 1% of the wells (NAS report, 2012, Shemeta et al., this issue). Induced seismicity ( $M > 1$ ) associated with hydraulic fracturing is even more rare. However rare, and regardless of the cause, induced seismicity

can create local and possibly damaging earthquakes. Even if nondamaging, induced earthquakes can be deemed a nuisance when felt by a local population. The occurrences of induced seismicity in the United States have affected oil and gas regulations and operations across the country and will be discussed further below.

In June 2012, the National Research Council released a report examining the scale, scope, and consequences of seismicity induced during fluid injection and withdrawal related to geothermal energy development, oil and gas development including shale gas recovery, and carbon capture and storage (CCS) (NAS, 2012). The lead editor of this *TLE* special section (Shemeta) was a member of the NAS committee, and over a 14-month period the 12-member committee compiled information about induced seismicity, including site visits and meetings with operators, regulators, and the public, culminating in writing a summary report for the NAS. A brief synopsis of the NAS report related to the oil and gas activities and induced seismicity follows this article (Shemeta et al.). The full NAS report is available for free via the National Academy of Science Web site at [http://www.nap.edu/catalog.php?record\\_id=13355](http://www.nap.edu/catalog.php?record_id=13355)). The release of the induced-seismicity report generated interest by the U.S. federal government,



**Figure 1.** Left map shows the USGS midcontinent study area outlined in yellow. Earthquake locations occurring from 2008 to March 2012 are indicated by blue dots, scaled by magnitude. The black solid line in the right graph shows the cumulative number of earthquakes  $M3$  or greater in the midcontinent of the United States. The number of  $M3$  or greater earthquakes increases steadily at about 21 events per year until around 2000 (rate indicated by red dotted line), when it increases about 50% to 31 events per year (green dotted line). By 2008, the number increased sharply to about 151 events per year (black dotted line). Text and figures modified from USGS Web blog site. ([http://www.usgs.gov/blogs/features/usgs\\_top\\_story/is-the-recent-increase-in-felt-earthquakes-in-the-central-us-natural-or-man-made/?from=image](http://www.usgs.gov/blogs/features/usgs_top_story/is-the-recent-increase-in-felt-earthquakes-in-the-central-us-natural-or-man-made/?from=image)).

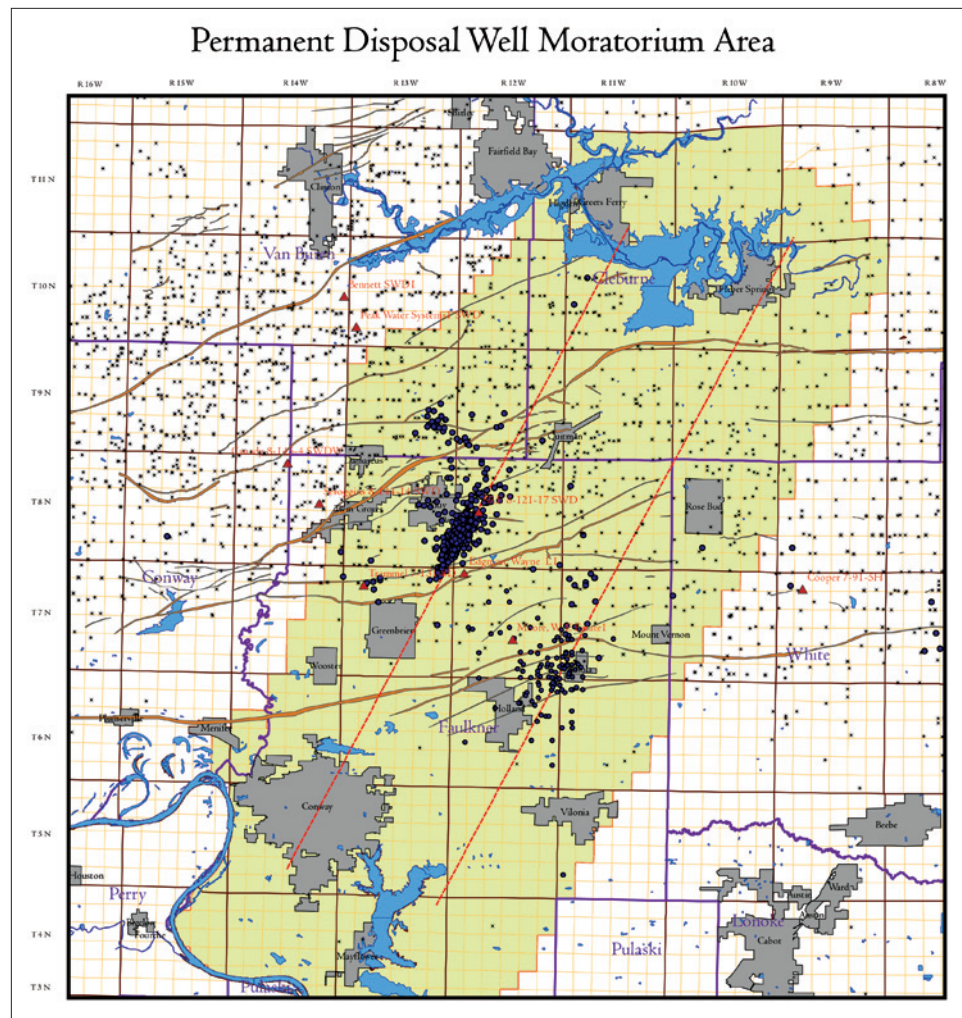
and was immediately followed by briefings for a variety U.S. Senate and House committees and a full committee hearing by the Senate Energy and Natural Resources on 19 June 2012.

### Are induced-seismicity rates increasing?

Since the release of the NAS induced-seismicity study in June, a documented case of injection-induced seismicity was reported in Youngstown, Ohio (M4.0) in late 2011 and early 2012; this induced seismicity was a result of injection in a salt water disposal (SWD) well (Ohio DNR 2012). During the same time period, another potential case of induced seismicity was reported in Texas (Frohlich, 2012, see article in this issue). These induced-seismicity occurrences were not included in the NAS report as results had not been released through peer-reviewed or official government reports prior to publication deadlines.

The United States Geological Survey (USGS) recently released a graph showing a dramatic increase in the number of  $M > 3$  earthquakes in the midcontinent area of the United States (Figure 1). In the study, the USGS reports the number of  $M > 3$  earthquakes since 1970 shows significant rate changes starting around 2000, changing from 21 events/year to 31 events/year, with a second apparent rate change in 2008 to 151 events/year (Figure 1). At the April 2012 Seismological Society of America meeting, USGS seismologist Bill Ellsworth suggested that these seismic rate changes, including areas in Colorado, Arkansas, and Oklahoma (excluding the recent Oklahoma M5.6 event) may be man-made (Ellsworth et al., 2012). The authors suggest the increased seismicity rates cannot be attributed to natural earthquake processes, such as volcanism or a tectonic mainshock-aftershock sequence, and thus may be caused by human activity. Finally, SWD wells may not be the only culprits for induced seismicity. A newly published report of hydraulic fracturing induced seismicity (M3.8) in the Horn River Basin, British Columbia, Canada, was released in August 2012, in a study by the British Columbia Oil and Gas Commission (BC Oil and Gas, 2012).

Although induced seismicity is relatively rare, state governments and regulators are more frequently taking actions aimed at either understanding the issue or more rigorously



**Figure 2.** Map of the Permanent Disposal Well Moratorium Area (light yellow) in Arkansas declared by the Arkansas Oil and Gas Commission following the earthquakes (dark blue dots) in the Guy-Greenbrier and Enola areas. Disposal wells are indicated by red triangles, stars indicate gas wells. Faults are shown by yellow lines. For a discussion of the Guy-Greenbrier activity, see Horton, 2012. Map source: Arkansas Oil and Gas Commission, 2012.

regulating oil and gas company operations. For example, in July 2011, the Arkansas Oil and Gas Commission declared a permanent disposal well moratorium after a link was suspected between SWD injection wells and the seismic activity (M4.7) in the Guy-Greenbrier area (Figure 2, Horton, 2012). In March of this year, Ohio modified the injection well permitting procedure following the M4 Youngstown earthquake sequence, calling the new rules for brine disposal among the nation's toughest, in response to the seismicity near the brine injection well in Youngstown (ONDR, 2012). In reaction to possible induced seismicity in Colorado in the Raton Basin area, the Colorado Oil and Gas Conservation Commission (COGCC) expanded the procedures in January 2011 for permitting SWD wells to include a review by the Colorado Geological Survey (CGS) of the potential for induced seismic events (COGCC, 2011).

### Types of wells with induced seismicity

In this article, we will discuss two different types of wells used by the oil and gas industry with the potential for



induced seismicity: hydraulically fractured wells and SWD wells. Production wells in low-permeability reservoirs are hydraulically fractured to create small fractures in the tight reservoir rock to enhance the flow of hydrocarbons into the wellbore. This is done for both vertical and horizontal wells. The hydraulic fracturing process injects fluid at rates and pressures above the fracture gradient of the formation. The process is often performed in a multistage process along the productive reservoir zone and the number of fracturing “stages” can vary from as few as 5 to more than 30 per well. The length of each stage is short in duration (on the order of a few hours). The entire fracturing process typically takes a few days to complete. Injection rates, fluid volumes, and well-head pressures are variable, and depend on the geomechanical properties of the formation being tested. Injection volumes are typically in the order of 70,000–130,000 thousand barrels of water per well. See King (2012) for a summary of hydraulic fracturing stimulation parameters typically used in the North America.

In contrast, SWD wells, classified by the EPA as “Class II” wells used for the disposal of brine from oil and gas production, are specially drilled to dispose of large volumes of wastewater over many years. The EPA estimates there are approximately 144,000 Class II injection wells in the United States, injecting more than 2 billion gallons of brine daily (source EPA Web site, <http://water.epa.gov/type/groundwater/uic/class2/>). SWD wells are specially targeted to place the disposal water into highly permeable formations in the subsurface. As injection rates and bottom hole pressures are often required to be below the fracture gradient, so the well head pressures, injection rates, and total fluid volumes are carefully monitored. The SWD wells are regulated by the state, EPA or both, and typically require extensive permitting and reporting procedures (see NAS, 2012 for review of Class II injection well regulatory requirements). The rates and volumes for a typical SWD well vary. In Texas, for example, an SWD well in the Barnett Shale area might inject 8000–11,000 barrels of brine per day (Frohlich, 2010).

The total volume of wastewater directly associated with hydraulic fracturing versus other oil field activities such as produced water, is difficult to estimate. The amount of flow-back water (“load water”) from a hydraulic fracturing procedure can be highly variable, with typical recoveries ranging from 5 to 50% of the total fluid volume injected (King, 2012). Wastewater can come from other oil field activities besides hydraulic fracturing such as produced water during coal-bed methane production and conventional oil and gas production, enhanced oil recovery, etc.

### Induced seismicity in Texas

In 2008 and 2009, Texas experienced unusual seismic activity in the Dallas-Fort Worth (DFW) area (largest event M3.3) and Cleburne, located 30 miles south of Fort Worth (Frohlich et al., 2010). The activity near DFW was attributed to a Barnett Shale SWD well (Frohlich et al., 2010). This *TLE* special section includes three articles on induced seismicity in Texas. Frohlich discusses his recent 2012

*Proceedings of the National Academy of Science (PNAS)* paper which examines two years of USArray seismic data. The USArray stations used in the study were part of a multiyear seismic station deployment of 400 high-quality broadband seismic stations over specific areas of the United States (see [www.usarray.org](http://www.usarray.org) for details of the USArray project). Frohlich examines data recorded from November 2009 to September 2011 over the active shale gas development area of the Barnett Shale, and finds 64 magnitude  $M > 2$  earthquakes near SWD injection wells, each of which was injecting at a rate greater than 150,000 barrels of water per month. This study shows seismic activity continuing in the DFW area, Cleburne, and six new areas in the Barnett Shale development area. It is interesting to note that more than 100 SWD wells in his study area also have this same injection rate with no detected seismicity.

The DFW seismic activity initially recorded in 2008–2009 is revisited by Reiter et al. in this special section with precise relocations and source characterization of the seismic swarm near the SWD well. The authors use a new robust method to measure source parameters using coda waves. Additionally in this special section, Janská and Eisner also focus attention to the DFW area, looking at seismicity starting in 2008 to the continued seismic activity near the suspected SWD well. The authors suggest the DFW seismic activity may be naturally occurring as the earthquake sequence has continued for more than two years after the shutdown of the suspected SWD injection well. They suggest that the regional network data may have missed seismicity occurring prior to the onset of injection in the suspected SWD well.

### Induced seismicity and hydraulic fracturing

It is well-documented that hydraulic fracturing commonly induces microearthquakes in the  $M -4.0$  to  $-1.0$  size range (see Warpinski et al., 2012, for a comprehensive review of hydraulic fracture induced microseismicity). Indeed, analysis of microseismic activity has proven to be a useful tool for assessing hydraulic fracturing procedures. Although more than 35,000 wells have been hydraulically fractured worldwide (EPA, 2011), few cases of “undesired” induced seismicity have been reported. In general, the short duration and relative small volumes of hydraulic fracturing process may limit the potential for inducing large, potentially damaging events (NAS, 2012).

Prior to 2012, the largest documented hydraulic-fracture-induced seismic event in oil and gas operations was the M2.3 earthquake that occurred 2011, in Blackpool, England (de Pater and Baisch, 2011). Suspected, but not fully documented, hydraulic fracturing related seismicity (M1.0 to 2.8) was observed in Oklahoma in 2011 near Eola Field where earthquakes occurred in close time and spatial area to a nearby hydraulic fracturing procedure (Holland, 2011).

Earthquakes up to M3.8 were recently reported occurring in the Horn River Basin by the British Columbia Oil and Gas Commission during hydraulic fracturing procedures (B.C. Oil and Gas, 2012). The report describes seismicity recorded from 2009 to 2011, ranging in size from M2.2 to 3.8

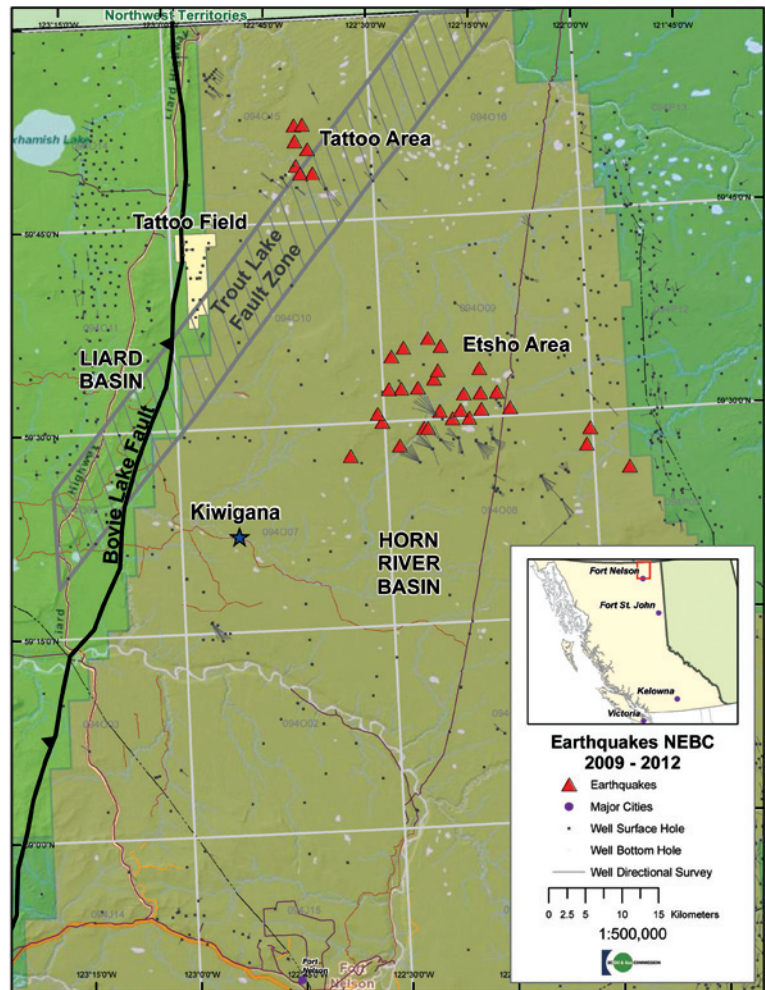
during hydraulic fracturing operations in three different areas of the Horn River Basin (Figure 3). The anomalously large seismic events during hydraulic fracturing are still under study by field operators and other stake holders in the area. Included in this special section is an article by Baig et al., which discusses differences in fluid-triggered events in borehole microseismic data and larger-magnitude, stress-triggered events. The instrumentation issues with recording small negative magnitude events and larger M1–3 earthquakes is discussed in this article. The consistency in magnitude calculations pose difficulties in assessing the size of events, magnitudes estimates can differ more than 0.5 in size depending on the network and magnitude calculation method used (Shemeta and Anderson, 2010), this are discussed in Monk’s commentary on “Measuring earthquakes” in this special section.

**What causes undesired induced seismicity?**

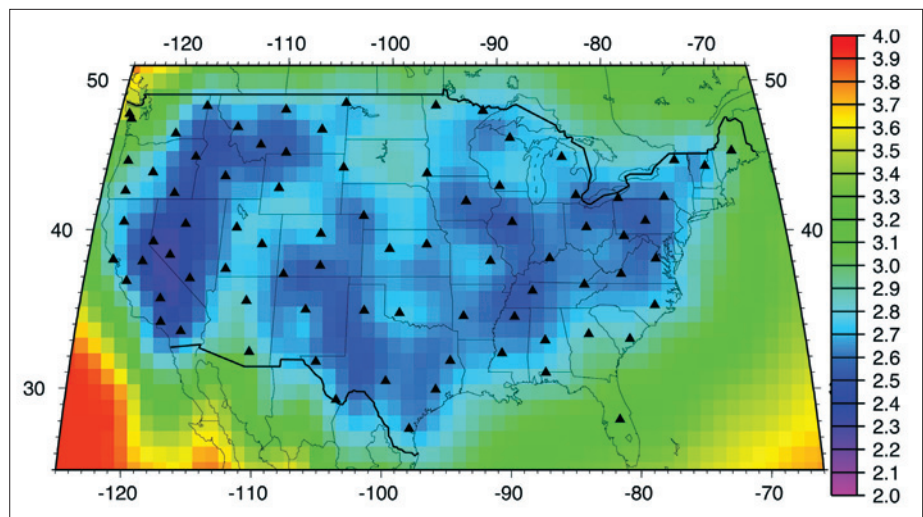
It is widely accepted that pore pressure increases because injection reduces the effective normal stress along a pre-existing fault, allowing the fault to slip and cause an earthquake (Hubbert and Rubey, 1959). Therefore, changes in stress or pore pressure because of human activity that cause an increase in shear stress and/or the increase in pore pressure could potentially cause a fault to slip and cause an earthquake (NAS, 2012). The magnitude of the induced earthquake will depend on the amount of slip along the fault: the larger the fault slip, the larger the earthquake (see Shemeta and Anderson, 2010 for review on earthquake size). The orientation of the fault with respect to the local stress field will determine which faults are most likely to fail. However, the ability to predict when and where induced seismicity will occur remains difficult, because of the complex interrelationship between many factors including stress, strain, fracture and fault orientation, fluid volumes and injection rates and pressures, pore pressure changes, etc.

**Detecting and locating potentially induced earthquakes on a regional scale**

Detecting and locating induced seismicity in the M1–3 range is challenging. Regional seismic arrays exist around the world are typically designed to detect and locate earthquakes that pose a risk to public safety. Hence seismically active areas, such as California are densely instrumented, whereas seismically quiet areas, such as Florida, have

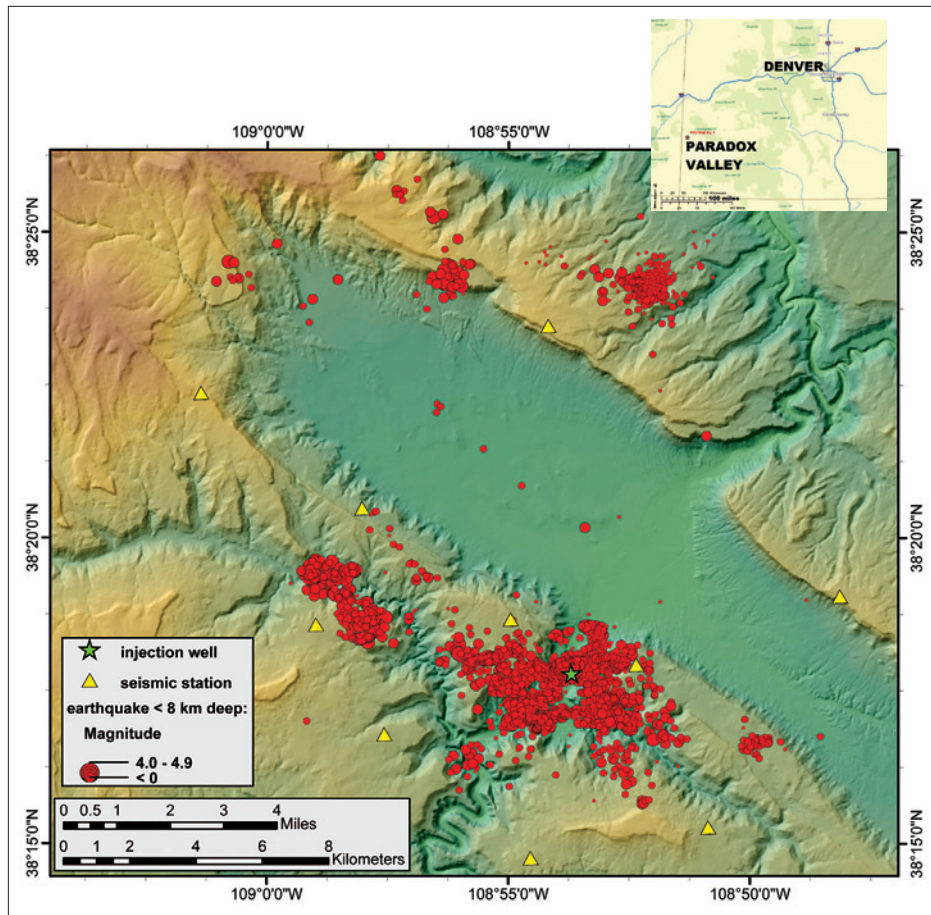


*Figure 3. Map showing two of the three areas with M2–3.8 earthquakes induced during hydraulic fracturing operations in NE British Columbia (courtesy of BC Oil and Gas Commission).*



*Figure 4. Map of the lower 48 states showing the minimum detectable earthquake magnitude using the ANSS array operated by the USGS/NEIC. Shading indicates the minimum-sized earthquake that can be detected, as indicated by the magnitude color bar on the right. The black triangles mark seismic station locations (courtesy NEIC).*





**Figure 5.** Map of seismicity (red dots scaled by magnitude) less than 8 km depth in the Paradox Valley (Colorado) near the SWD well (green star) from 1991 to present. Yellow triangles indicate seismic stations. Upper right inset shows location of Paradox Valley in western Colorado (courtesy of Lisa Block and Chris Wood, U.S. Bureau of Reclamation).

sparse seismic arrays. Groups responsible for operating seismic arrays typically determine an earthquake detectability map, showing the seismic array geometry and minimum detection magnitude within the array. The magnitude detection level for the USGS NEIC array (Figure 4), for example, is about M3.0 for most of the lower 48 states. The accuracy of the event locations from a regional array will vary depending on the size and location of the earthquake. Small (M1–3), shallow (< 2 km depth) earthquakes are difficult to detect and locate on a regional seismic array and can have reported errors on the order of several miles in both depth and surface position. Thus, using the existing regional seismic arrays to detect and locate small, potentially induced earthquakes remains a challenge. Attempting to correlate the earthquakes to a particular oil and gas operation is even more problematic because of the large uncertainty in the event locations.

The respective regional seismic array detection issues are clearly shown by the recent Horn River Basin (BC Oil and Gas, 2012) and Texas seismicity studies (Frohlich, 2012 and this issue). The Canadian National Seismic Network (CNSN) reported and located events as small as M2 prior to 2009, but failed to detect events reported by oil and gas operators running dense proprietary seismic arrays. For example, CNSN reported only 4 events in mid June to mid

August 2011 in the Horn River area, while a proprietary seismic array reported 19 events (BC Oil and Gas Commission, 2012). Two different earthquake catalogs missed possible induced seismicity in the Barnett Shale: USGS NEIC array in Texas reported only 8 of the 67 events found by Frohlich's 2012 study, while an augmented seismic array using the USArray stations caught 22 of the 67 reported events (Frohlich 2012, this issue).

Enhancement of the CNSN array in the Horn River Basin area was recommended by the BC Oil and Gas Commission based on the seismic event detection difficulties in the Horn River Basin. Included in the findings of the NAS induced-seismicity study was a recommendation to install local seismic arrays for accurate earthquake locations in areas of suspected induced seismicity. The NAS report suggested all local seismic monitoring data and results should be fully disclosed to the public (NAS, 2012). Responsibility and requirements for seismic monitoring in induced seismicity in potentially troublesome areas has not been established by regulators, but may be

required in the future in after a problem is suspected. The joint cooperation between operators, regulators, the scientific community and the public is needed to fully address induced-seismicity concerns.

#### Local site characterization and induced-seismicity susceptibility

The occurrence of injection-induced seismicity over extensive areas of brine injection appears to be associated with the proximity of the well to favorably oriented basement faults. The most active seismic regions in the world are near highly stressed areas in the crust, for example near plate boundaries or volcanic areas; however it has been suggested that the crust is in a near a critical state of stress almost everywhere and small stress changes may cause a favorably oriented fault to slip (Zoback and Zoback, 1980, 1989). Hence, it is difficult to assign high and low risk areas for induced seismicity based only on historical seismicity patterns. For example, the DFW area in Texas had a 150+ year history with no felt seismicity prior to the activity recorded in 2008 and 2009 (Frohlich, 2010). Often brine disposal wells are owned and operated by small Mom-and-Pop operators with few resources for expensive site-characterization studies.

It is well established that injection near optimally oriented

pre-existing faults can be problematic; therefore, geologic characterization of pre-existing faults in proposed injection areas is probably necessary. Regional geologic maps often contain information about local faulting patterns and the world wide stress map can be useful for characterizing the regional stress state (Heidbach et al., 2008). It is important to note that faults reactivated by injection may be in a different orientation than that predicted from knowledge of the present day stress field. In the Guy-Greenbrier area of Arkansas, for example, the regional fault trends trend approximately NE-SW but the induced earthquakes appeared to be on a reactivated fault oriented NNE, which was interpreted to be an older fault trend than the mapped regional fault trend (Figure 2, Horton, 2012).

Over time, the effects of subsurface injection can travel for miles past the injection point, as illustrated by the seismic activity in Paradox Valley, Colorado, where the U.S. Bureau of Reclamation injects naturally occurring saline water in a SWD well to prevent it from entering the Colorado River (Block and Wood, 2010). An evolving seismic array has continuously monitored the area since 1985, and only one natural event was recorded prior to injection tests, which began in 1991. Induced events were recorded shortly thereafter, with the rate of induced events increasing greatly once continuous injection started in 1996. After 16 years of continuous injection, more than 5800 likely induced shallow earthquakes ranging from  $M -0.5$  to 4.3 have been recorded. Initially, those events were concentrated within 4 km of the well, but within about a year after the start of continuous injection, events were also occurring in a cluster located 5–8 km away. In recent years, potentially induced events have occurred at distances as far as 16 km from the injection well (Figure 5).

### Is an induced-seismicity protocol needed?

There is little formal structure within the oil and gas operations to deal with induced-seismicity issues and the complex interplay between government, industry operators and the public. The U.S. geothermal industry, however, has dealt with issues regarding induced seismicity for decades. Last year the U.S. Department of Energy (DOE) released a protocol addressing induced seismicity for enhanced geothermal systems (EGS) ([http://www1.eere.energy.gov/geothermal/pdfs/geothermal\\_seismicity\\_protocol\\_012012.pdf](http://www1.eere.energy.gov/geothermal/pdfs/geothermal_seismicity_protocol_012012.pdf)) for regulators, geothermal operators and the public. EGS technology involves injecting large volumes of water into hot reservoir rock in order to create a heat exchange system. The EGS induced-seismicity protocol outlines steps for addressing induced seismicity including community outreach, criteria for ground vibration regulation, seismic monitoring, and seismic hazard and risk assessment. A traffic light system is used in the EGS seismicity protocol to assign operational actions to preset magnitude thresholds, ranging from green, “normal operations,” to red “stop all operations.” In addition to the EGS induced-seismicity protocols, the Geysers geothermal field operators in northern California regularly meet with the local population (many locals feel hundreds of earthquakes every year related to geothermal operations) and regulators

to openly discuss and deal with issues of induced seismicity and the field operations.

States recently affected by induced seismicity such as Colorado, Ohio, and Arkansas have developed rigorous new standards for new Class II injection wells, as discussed above. No induced-seismicity protocol document exists for the oil and gas industry, although the American Petroleum Institute (API), American National Gas Alliance (ANGA), and the American Exploration and Production Council (AXPC) have collaborated to distribute information about seismicity associated with hydraulic fracturing and injection wells ([http://www.api.org/-/media/Files/Policy/Hydraulic\\_Fracturing/Facts-HF-and-Seismic-Activity.pdf](http://www.api.org/-/media/Files/Policy/Hydraulic_Fracturing/Facts-HF-and-Seismic-Activity.pdf), [http://www.api.org/-/media/Files/Policy/Hydraulic\\_Fracturing/UIC-and-Seismicity.pdf](http://www.api.org/-/media/Files/Policy/Hydraulic_Fracturing/UIC-and-Seismicity.pdf)). AXPC is currently developing a white paper on induced seismicity which will include a suggested protocol for managing the risk of induced seismicity. The collaboration between all the stake holders including oil and gas operators, regulators, the scientific community and local communities regarding induced seismicity will be needed to address this rare, but significant, phenomenon.

Now returning our attention to microseismic and passive seismic monitoring related to hydraulic fracture diagnostics, the second part of the December special section includes five articles analyzing both surface and borehole microseismic data.

Grechka and Zhao apply interferometric processing to seismic noise recorded during borehole microseismic monitoring in the Eagle Ford, Niobrara, and Bakken formations, which results in estimates of the local P- and S-wave velocity fields. Which particular component one is able to resolve depends on the spatial orientation of the sensor array and the sensor components employed. The method can be used to suppress tube waves as well as constructing velocities profiles between wells with receivers.

In “Analysis of passive surface waves from ambient-noise recordings,” Panea et al. describe a way to invert surface waves for a near surface shear wave velocity profile. Here the twist is to apply interferometry to passive recordings of ambient noise on vertical component geophones. An interesting comparison is made with an analysis of active surface wave data suggesting that the passive data may be helpful in deriving shallow shear wave velocity profiles for use with event locations in surface and shallow borehole microseismic monitoring.

The article “Checking up on the neighbors: Quantifying uncertainty in relative event location” by Poliannikov et al., describes a new hybrid method to reduce the uncertainty of microseismic event locations. Conventionally, each microseismic event recorded in a borehole is located “in isolation” as if there were no other events. In the double-difference method, relative time differences between similar, neighboring events are used to collapse the uncertainty of each event with respect to the others. In this article the authors describe a hybrid method, combining double differences and interferometry, to reduce the effects of noise and velocity uncertainty on the relative event location accuracy.



Forghani-Arani et al., show in “Noise suppression in surface microseismic data” that preprocessing methods can enhance both P- and S-wave microseismic emissions. They demonstrate that the presence of correlated cultural and ambient noise (mainly surface-waves) decreases the effectiveness of surface passive seismic data and hence noise suppression is a critical step in surface microseismic monitoring. A noise suppression technique based on the  $\tau$ - $p$  transform is developed and applied to a semi-synthetic surface passive seismic dataset recorded over a Barnett Shale reservoir undergoing hydraulic fracturing. The article clearly demonstrates that the technique not only improves the signal to noise ratios of the microseismic events, but also preserves the event waveforms. This is a critical issue in surface microseismic monitoring as low signal to noise is a limiting factor in processing this type of data.

Estimates of the stimulated reservoir volume from microseismic event locations are important for assessing the effectiveness of hydraulic fracturing and potential performance of the well. In the final article of the special section, Goodway et al., explore the link between hydraulic fracture effectiveness and geophysical responses in NE British Columbia’s Horn River Basin. They do this through a combination of rock physics models, isotropic prestack inversion for  $\lambda\rho$  and  $\mu\rho$ , and stress analysis from anisotropic 3D seismic data. The derived attributes are integrated with borehole microseismic and 4D time-lapse seismic for SRV estimates. The authors suggest that this combination of the measurements enables an improved SRV estimate, and may provide a more rigorous prediction of completion success and well performance. **TLE**

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*Acknowledgments: The lead editor of this special section (Julie Shemeta) thanks Tad Smith for suggesting her involvement in the special section, as well as his support and help throughout the process of putting together both the November and December issues. We would especially like to thank all the authors who contributed articles for the special sections, including those we could not include because of space limitations. We are grateful to Hal Macartney, Jim Rutledge, and Jeff Meredith for their helpful reviews and suggestions on the introductory article, as well as the B.C. Oil and Gas Commission, U.S. Bureau of Reclamation, and the USGS NEIC for use of figures for this article.*

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