STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

EXHIBITS IN THE MATTER OF THE HEARINGS CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 20313

APPLICATION OF MESQUITE SWD INC. FOR APPROVAL OF A PRODUCED WATER DISPOSAL WELL IN EDDY COUNTY, NEW MEXICO.

CASE NO. 20314

APPLICATION OF MESQUITE SWD INC. FOR APPROVAL OF A PRODUCED WATER DISPOSAL WELL IN EDDY COUNTY, NEW MEXICO.

CASE NO. 20472

APPLICATION OF MESQUITE SWD INC. FOR APPROVAL OF A PRODUCED WATER DISPOSAL WELL IN EDDY COUNTY, NEW MEXICO.

CASE NO. 20463

APPLICATION OF BLACKBUCK RESOURCES, LLC FOR APPROVAL OF A SALT WATER DISPOSAL WELL IN LEA COUNTY, NEW MEXICO.

CASE NO. 20465

APPLICATION OF SOLARIS WATER MIDSTREAM, LLC FOR APPROVAL OF A SALT WATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO.

Oil Conservation Division
Energy, Minerals and Natural Resources Department
State of New Mexico

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 1

The Division opposed issuance of an order for authority to inject for the five proposed wells at the surface locations detailed in the following list of cases where the Division has filed for appearance.

Case No.	Case Matter	Proposed Well	Proposed Surface Location
20313	Application of Mesquite SWD Inc. for Approval of a Produced Water Disposal Well in Eddy County, New Mexico.	Laguna Salada 13 SWD Well No. 1	685 feet from the South line and 50 feet from the East line (Unit P) of Section 13, T.23 S., R. 28 E., NMPM
20314	Application of Mesquite SWD Inc. for Approval of a Produced Water Disposal Well in Eddy County, New Mexico.	Laguna Salada 19 SWD Well No. 1	1752 feet from the South line and 1727 feet from the East line (Unit J) of Section 19, T.23 S., R. 29 E., NMPM
20472	Application of Mesquite SWD Inc. for Approval of a Produced Water Disposal Well in Eddy County, New Mexico.	Baker SWD Well No. 1	330 feet from the South line and 309 feet from the West line (Unit M) of Section 1, T.26 S., R. 31 E., NMPM
20463	Application of Blackbuck Resources, LLC for Approval of a Salt Water Disposal Well in Lea County, New Mexico.	Olive Branch Federal SWD No. 1	979 feet from the South line and 2620 feet from the East line (Unit N) of Section 17, T.24 S., R. 32 E., NMPM
20465	Application of Solaris Water Midstream, LLC for Approval of a Salt Water Disposal Well, Lea County, New Mexico.	Predator Federal SWD No. 1	1465 feet from the North line and 1893 feet from the East line (Unit G) of Section 17, T.24 S., R. 32 E., NMPM

The Division has sought to maintain a distance of 1.5 miles between injection sources (based on a ¾-mile radius from the well surface location or 7,920 feet between the Devonian disposal wells) that are Devonian wells designed for large-volume disposal in an effort:

1. to lessen the potential for induced-seismic events associated with disposal as recommended by the United States Environment Protection Agency's National Underground Injection Control (UIC) Technical Workgroup,

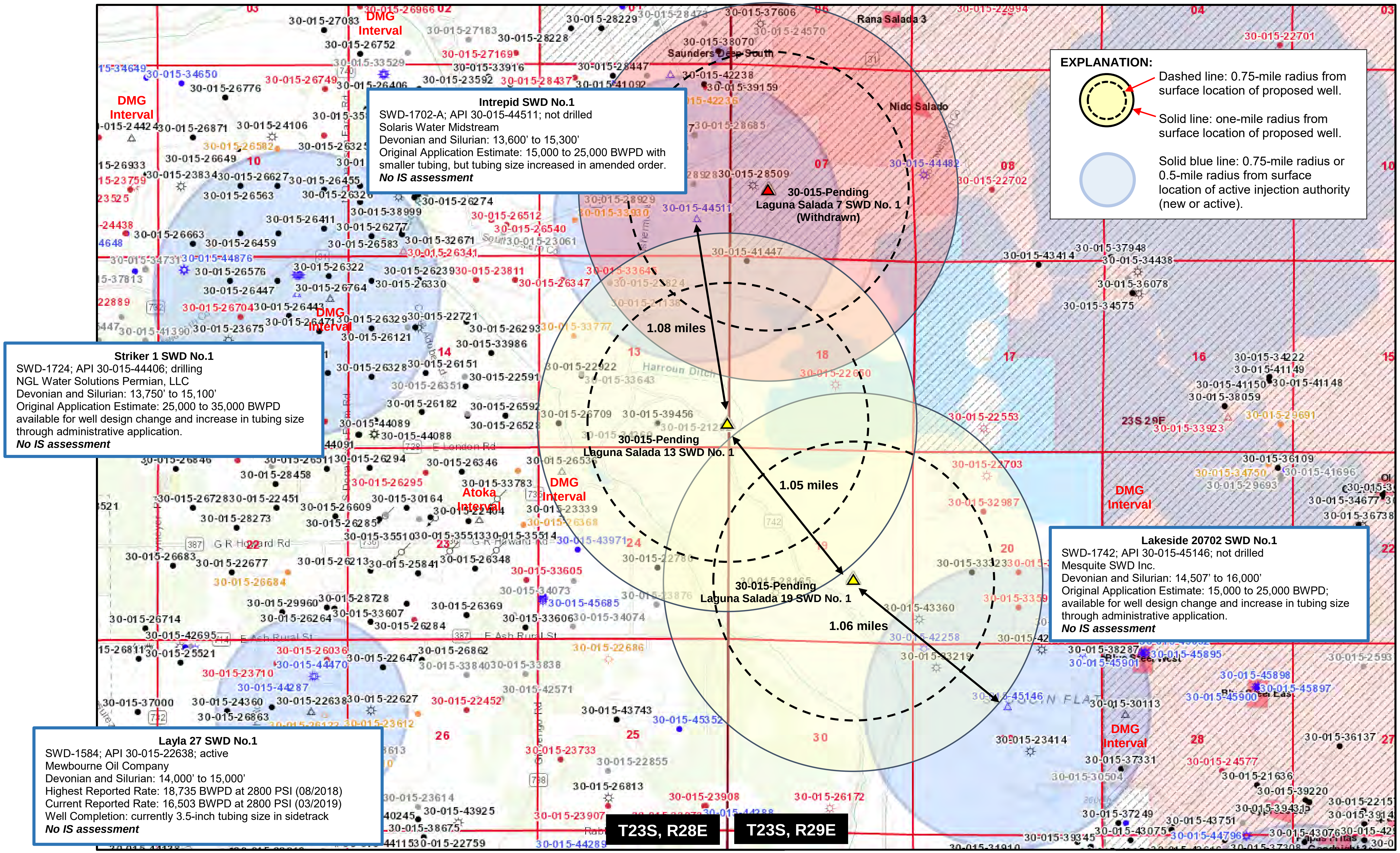
2. to minimize interference between wells in support of the effort to reduce the potential for induced-seismic events and to optimize the operational life of these wells (as a best management practice),
3. to protect correlative rights as directed under the New Mexico Oil and Gas Act, and
4. to maintain and improve the state's UIC program to support production while preventing waste as directed by the New Mexico Oil Conservation Commission in Commission Order No. R-14392-A.

The Division opposed the issuance of the proposed wells based on the proximity to the specific wells listed in the following table.

Case No.	Proposed Well	Figure Referenced	Competing Devonian Disposal Well With Distance From Proposed Well
20313	Laguna Salada 13 SWD Well No. 1	Division Exhibit 1 - Figure 1	1. Intrepid SWD No. 1 (API 30-015-44511) 1.08 miles 2. Laguna Salada 19 SWD Well No. 1 [Proposed] 1.05 miles
20314	Laguna Salada 19 SWD Well No. 1		1. Lakeside 20702 SWD No. 1 (API 30-015-45146) 1.06 miles 2. Laguna Salada 13 SWD Well No. 1 [Proposed] 1.05 miles
20472	Baker SWD Well No. 1	Division Exhibit 1 – Figure 2	1. Paduca 6 SWD No. 1 (API 30-025-43379) 1.24 miles 2. Red Bellied Cooter SWD No. 1 [Proposed] 1.17 miles
20463	Olive Branch Federal SWD No. 1	Division Exhibit 1 - Figure 3	1. Predator Federal SWD No. 1 [Proposed] 0.55 mile 2. Cotton Draw SWD No. 1 [Proposed] 1.29 miles
20465	Predator Federal SWD No. 1		1. Olive Branch Federal SWD No. 1 [Proposed] 0.55 mile 2. Station SWD No. 1 (API 30-025-43473) 1.43 miles

CASES NO. 20313 and 20314
Division Exhibit No. 1 - Figure 1

Pending Application for High-Volume Devonian Disposal Well
C-108 Applications for Laguna Salada Wells (T23S, R28-29E) – Mesquite SWD Inc.

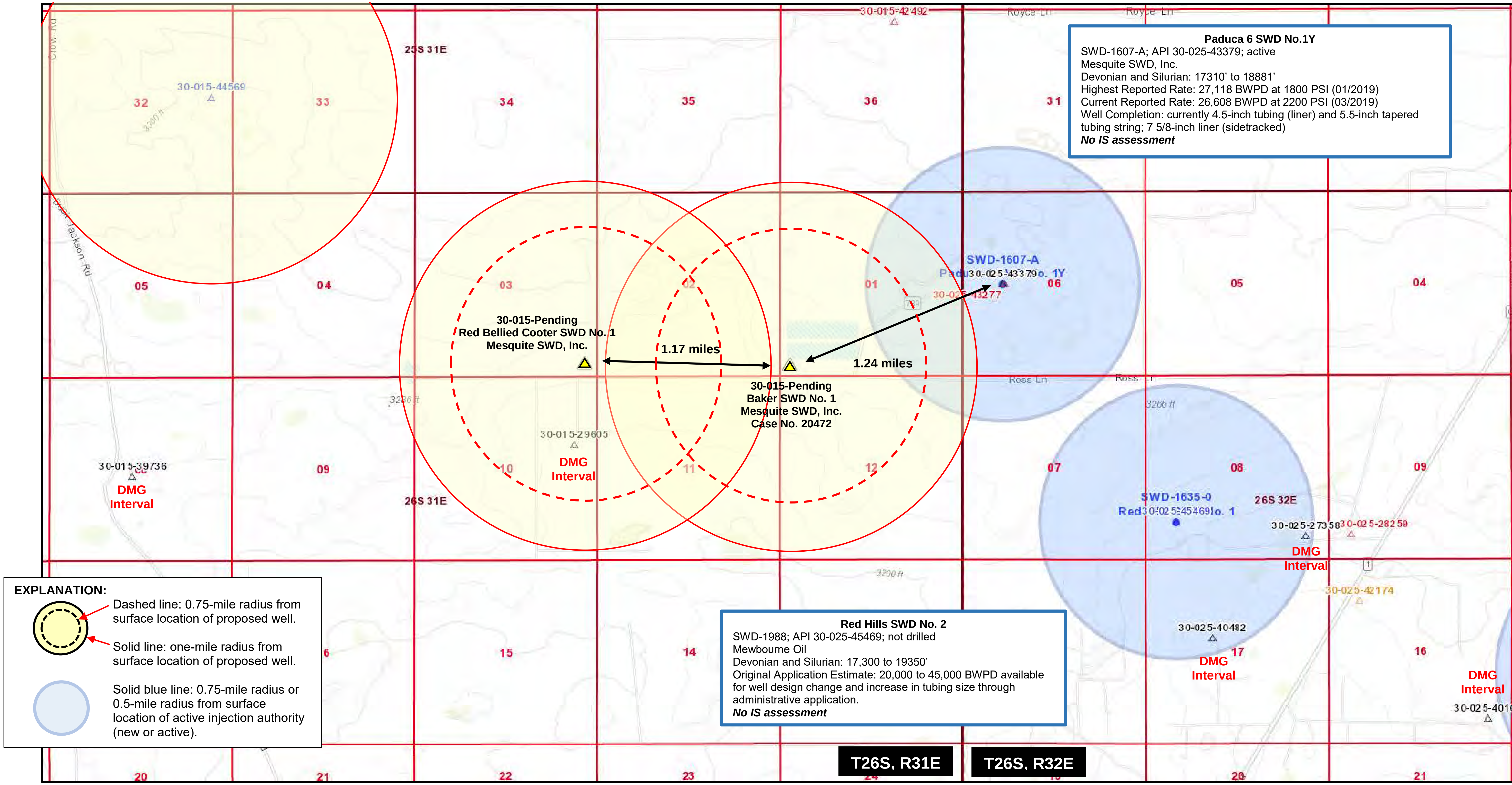


Laguna Salada 7 SWD No. 1; Mesquite SWD Inc.
API 30-015-Pending; Application No. pMAM1821132239; application withdrawn.

Pending applications manually plotted; approved SWD Orders from OCD GIS database
Prepared by P. Goetze; 05/22/2019

CASE NO. 20472
Division Exhibit No. 1- Figure 2

Pending Application for High-Volume Devonian Disposal Well
C-108 Application for the Baker SWD Well No. 1 – Mesquite SWD Inc.



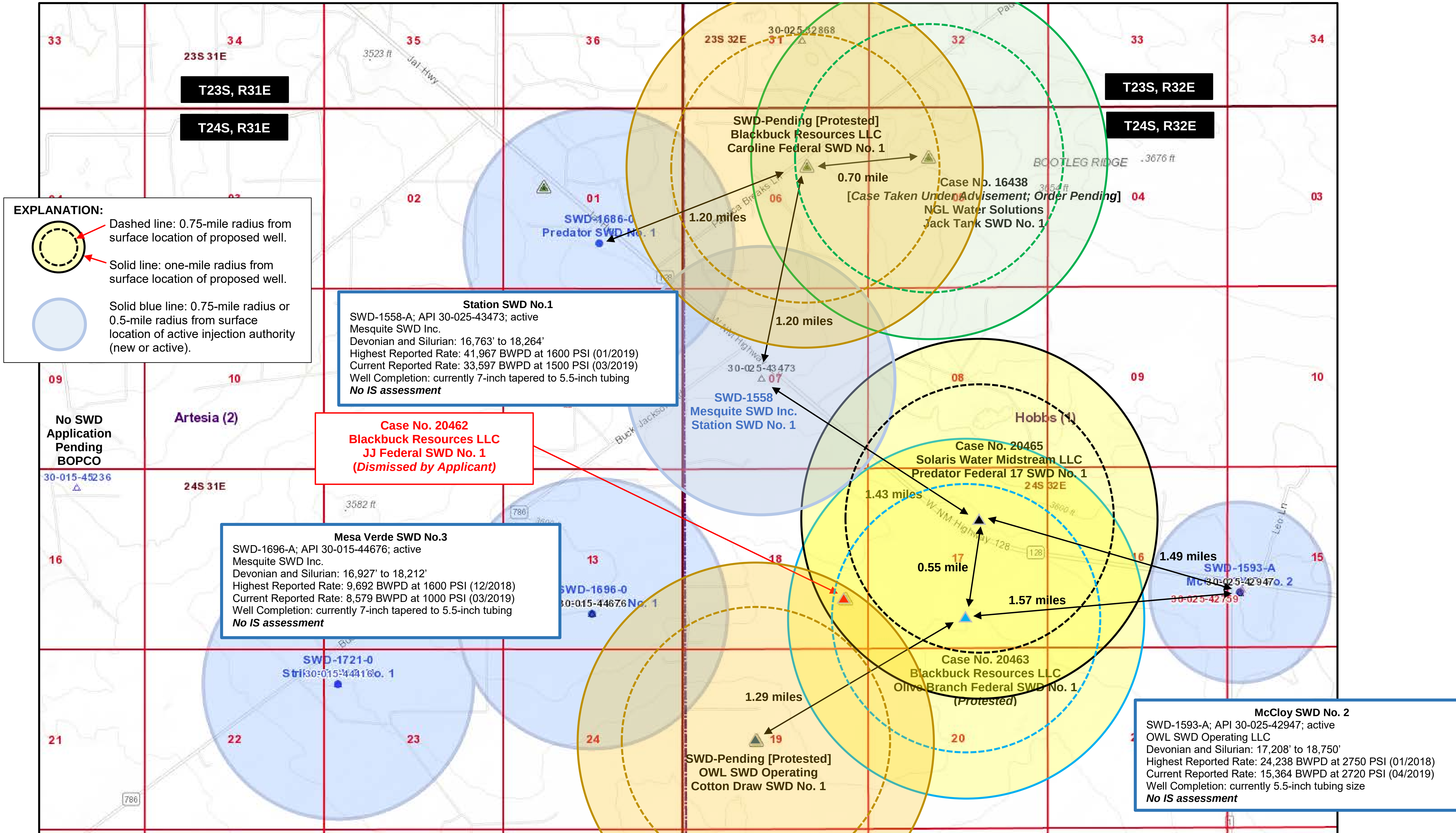
Baker SWD No. 1; Mesquite SWD, Inc.
API 30-015-Pending; Application No. pMAM1827553727; not protested; Case No. 20472; 330' FSL – 309' FWL; Sec. 1, T26S, R31E, NMPM

Red Bellied Cooter SWD No. 1; Mesquite SWD, Inc.
API 30-015-Pending; Application No. pLEL1832554216; not protested; 375' FSL – 210' FEL; Sec. 3, T26S, R31E, NMPM

Pending applications manually plotted; approved SWD Orders from OCD GIS database
Prepared by P. Goetze; 05/22/2019

CASES NO. 20463 and 20465
Division Exhibit No. 1 – Figure 3

Pending Applications for High-Volume Devonian Disposal Wells
C-108 Application for the Olive Branch Federal SWD No. 1 – Blackbuck Resources LLC
C-108 Application for the Predator Federal 17 SWD No. 1 – Solaris Water Midstream, LLC



Pending applications manually plotted; approved SWD Orders from OCD GIS database
Prepared by P. Goetze; 05/22/2019

CASES NO. 20313, 20314, 20472, 20460, 20463 and 20465
Division Exhibit No. 2

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

FEB - 6 2015

OFFICE OF WATER

MEMORANDUM

SUBJECT: Distribution of Final Work Product from the National Underground Injection Control (UIC) Technical Workgroup - *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches*

FROM: Ronald Bergman, Acting Director
Drinking Water Protection Division (4606M)
Office of Ground Water and Drinking Water

TO: UIC Program Managers
EPA Regions I-X

The Office of Ground Water and Drinking Water is pleased to provide the final product of the UIC National Technical Workgroup (NTW) entitled, *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches.* The report will be a valuable tool for UIC program managers addressing induced seismicity.

Within the past few years, many small to moderate magnitude earthquakes have been recorded in areas with Class II waste disposal injection wells (II-D) related to unconventional oil and gas production. To address the growing public concern that induced seismicity could endanger drinking water sources, EPA's Drinking Water Protection Division requested that the NTW develop a report with practical management tools to help federal and state UIC regulators address potential injection-induced seismicity.

The NTW was formed in 1995 to discuss technical issues related to the UIC Program and is comprised of staff from each EPA Regional Office, OGWDW, and select states authorized to implement the UIC program. The NTW provides a forum whereby technical issues relating specifically to the UIC Program can be discussed, reviewed and resolved by UIC program experts. The NTW provides an avenue for open dialogue, communication, and coordination between EPA and State representatives concerning technical matters related to underground injection as defined in the Safe Drinking Water Act (42 USC 6A, Part C). States with extensive programmatic experience in addressing induced seismicity participated in the development of this report, including Ohio, Colorado, Oklahoma, Texas, West Virginia, and Arkansas. A number of these states have developed state regulations or guidelines addressing induced seismicity and each of the states contributed valuable experience and expertise to this effort.

The NTW was tasked with summarizing the available information on induced seismicity and providing specific suggestions for managing induced seismicity within the context of the Class II UIC program.

The NTW developed the attached report using the existing Class II regulatory framework to recommend strategies for managing and minimizing the potential for significant injection-induced seismic events. The approaches in the report are non-regulatory in nature, and are within the Class II Director's discretion to apply. The report recommends practical steps to reduce the potential for induced seismicity in the areas of site assessment, well operation, monitoring, and management. It can help UIC managers evaluate the potential for induced seismicity in a planned injection operation, and describes permit conditions that can be added to manage this potential, so that oil and gas wastewater disposal operations can continue with adequate environmental safeguards.

The NTW report was informed by an extensive review of the technical literature on induced seismicity and evaluation of case study examples in Arkansas, Ohio, Texas, and West Virginia. The NTW considered data availability and variations in geology and reservoir characteristics. The draft report benefited from expert peer consultation and was submitted for independent scientific peer review prior to being finalized.

We are providing a copy of this report to you so you may distribute it to EPA and state UIC program personnel in your region and encourage UIC regulators to utilize the available tools and lessons learned to reduce the potential for injection-induced seismic events. The report is available on EPA's UIC website: http://www.epa.gov/r5water/uic/techdocs.htm. If you have any questions, please contact Bill Bates at (202) 564-6165.

Attachment

cc: (w/attachment)
Michel Paque, Executive Director - GWPC
Michael Smith, Executive Director - IOGCC

MINIMIZING AND MANAGING POTENTIAL IMPACTS OF INJECTION-INDUCED SEISMICITY FROM CLASS II DISPOSAL WELLS: PRACTICAL APPROACHES

Underground Injection Control National Technical Workgroup
U.S. Environmental Protection Agency
Washington, DC

Draft: December 24, 2013
Revised: November 12, 2014

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Executive Summary

The U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) program regulates injection of fluids related to oil and gas production as Class II injection wells for the protection of underground sources of drinking water (USDWs). Because seismic events from injection have the potential to cause endangerment of underground sources of drinking water, the UIC program director should be aware of that potential and be prepared with response options should seismic events become a concern. Unconventional resources and new technologies, such as horizontal drilling and advanced completion techniques, have expanded the geographic area for oil and gas production activities, resulting in a need for Class II disposal wells in some areas previously considered unproductive.

Recently, a number of small to moderate magnitude (M<5.0) earthquakes[1] have been recorded in areas with Class II disposal wells related to shale hydrocarbon production. To address the concern that induced seismicity could interfere with containment of injected fluids and endanger drinking water sources, EPA's Drinking Water Protection Division requested that the UIC National Technical Workgroup (NTW) develop a report with practical tools to help UIC regulators address injection-induced seismicity. The Induced Seismicity Working Group (WG) of the NTW developed this report in response, using the existing Class II regulatory framework to provide possible strategies for managing and minimizing the potential for significant injection-induced seismic events.[2] The report focuses on Class II disposal operations and not enhanced recovery wells or hydraulically fractured wells. In formulating the strategies in this report, the NTW conducted a technical literature search and review. Additionally, the NTW evaluated four case examples (in Arkansas, Ohio, Texas, and West Virginia) and considered data availability and variations in geology and reservoir characteristics.

Unconventional production activities and associated larger wastewater volumes have resulted in an increased need for disposal capacity. Some disposal wells handling the increased volumes are located in geographic areas where disposal has not previously occurred. A growing number of disposal wells, some of which are in these new geographic areas, have been suspected of inducing seismicity. Of the approximately 30,000 Class II disposal wells in the United States, very

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[1] Information on earthquake terms is included under Glossary Terms In the full report or at http://earthquake.usgs.gov/learn/glossary/ for general earthquake terms

[2] For the purposes of this report, the Induced Seismicity Working Group considers "significant" seismic events to be those of a magnitude that could potentially cause damage to or endanger underground sources of drinking water.

few disposal well sites have produced seismic events with magnitudes greater than M4.0.[3] In addition, EPA is unaware of any USDW contamination resulting from seismic events related to injection-induced seismicity.

Disposal wells are one of a number of historic causes of human activity-induced earthquakes. Others include construction and management of dams and water reservoirs, mining activities, oil and gas production, and geothermal energy production. Evaluation of induced seismicity is not new to the UIC program. The first comprehensive study was completed for the EPA Office of Water over 25 years ago, (Wesson and Nicholson, 1987[4]; finalized as Nicholson and Wesson, 1990). This report is intended to describe for UIC program management the current understanding of induced seismicity within the existing Class II regulatory framework for Class II disposal. The Class II UIC program does not have regulations specific to seismicity but includes discretionary authority that allows additional conditions to be added to the injection permit on a case-by-case basis, along with additional requirements for construction, corrective action, operation, monitoring, or reporting (including closure of the injection well) as necessary to protect USDWs.[5] Legal and policy considerations of Class II regulations, including regulatory revisions, are outside the scope of this technical report. This report is not a guidance document and does not provide specific procedures, but it does provide the UIC Director with considerations for addressing induced seismicity on a site-specific basis, using Director discretionary authority.

The NTW confirmed the following components are necessary for significant injection-induced seismicity: (1) sufficient pressure buildup from disposal activities, (2) Faults of Concern,[6] and (3) a pathway allowing the increased pressure to communicate with the fault. The NTW noted that no single recommendation addresses all of the complexities related to injection-induced seismicity, which is dependent on a combination of site geology, geophysical and reservoir characteristics. An absence of historical seismic events in the vicinity of a disposal well does not provide complete assurance that induced seismicity will not occur; however, this historic absence

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[3] National Research Council. Chapter 3, Table 3.4, page 104, and Chapter 7, injection wells for the disposal of water associated with energy extraction finding no. 1, *in* Induced seismicity potential in energy technologies. (Washington, DC: The National Academies Press, 2013), 104 and 171–172.

[4] R.L. Wesson and C. Nicholson, Earthquake hazard associated with deep well injection: A report to the U.S. Environmental Protection Agency, U.S. Geological Survey Open-file Report 87-331, 1987, 108 pp.

[5] 40 CFR §144.12(b); 40 CFR §144.52(a)(9) or (b)(1); or appropriate section of 40 CFR Part 147

[6] A Fault of Concern is a fault optimally oriented for movement and located in a critically stressed region. The fault is also of sufficient size and possesses sufficient accumulated stress / strain, such that fault slip and movement has the potential to cause a significant earthquake. Fault may refer to a single fault or a zone of multiple faults and fractures. See also Geologic Stress Considerations later in this document; APPENDIX B: Site Assessment Considerations for Evaluating Seismicity; and APPENDIX M: State of Stress for more complete discussion.

may be one indicator of induced seismicity if seismic events occur following activation of an injection well. Such a conclusion is based on the assumption that a reliable history of seismic monitoring in the region of the injection well exists. However, the accuracy of such monitoring depends on the robustness of the seismic monitoring network for any given area, along with consideration for how long such a network has been in place. Conclusive proof of induced seismicity is difficult to demonstrate but is not a prerequisite for taking early prudent action to address the possibility of induced seismicity.

The NTW developed a decision model (Figure 1) to inform UIC regulators about site assessment strategies and practical approaches for assessing the three fundamental components. The model begins with considerations for a site assessment dependent on location-specific conditions, because understanding the geologic characteristics of a site is an essential step in evaluating the potential for injection-induced seismicity. Monitoring, operational and management approaches with useful practical tools for managing and minimizing suspected injection-induced seismicity are recommended.

During its review, the NTW also found that the application of basic petroleum engineering practices coupled with geology and geophysical information can provide a better understanding of reservoir and fault characteristics. The multidisciplinary approach offers many ways of analyzing injection-induced seismicity concerns, possibly identifying anomalies that warrant additional site assessment or monitoring. Such an approach would be enhanced by collaborative work between a wide variety of individuals in industry, government, and scientific and engineering research organizations. Consequently, the NTW recommends that future research consider a practical multidisciplinary approach coupled with a holistic assessment addressing disposal well and reservoir behavior, geology, seismology and other appropriate specialty fields of study.

INTRODUCTION

The U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) program, authorized by the Safe Drinking Water Act, regulates injection of fluids related to oil and gas production into Class II wells, for the protection of underground sources of drinking water (USDW). There are approximately 30,000 Class II active disposal wells in the United States used to dispose of oil and gas related wastes, many of which have operated for decades. EPA is unaware of any USDW contamination resulting from seismic events related to injection-induced seismicity.[7] Very few of these disposal well sites have produced seismic events with magnitudes[8] greater than M4.0[9]. For example, at the time of this report, there were approximately 2,700 active disposals wells in Louisiana, with no recent significant[10] seismic events occurring as a result of the disposal activities. However, unconventional resources and new technologies, such as horizontal drilling and advanced completion techniques, have increased oil and gas production activities, resulting in a need for new Class II disposal wells in expanded geographic areas.

Disposal wells are just one of a number of historic causes of human activity-induced earthquakes.[11] Other causes may include construction and management of dams and water reservoirs, erection of skyscrapers, mining activities, oil and gas production, geothermal energy production and geologic carbon sequestration.

ENHANCED RECOVERY INJECTION WELLS

Class II injection wells include injection wells used for enhanced recovery as well as those used for oil and gas production wastewater disposal. Injection for enhanced recovery projects generally poses less potential to induce seismicity than wastewater disposal because pressure increases resulting from injection for enhanced recovery are partially offset by nearby production wells. Disposal wells have no offsetting withdrawal and therefore, have a greater potential for pressure buildup. Given the recent seismic activity associated with Class II disposal wells, this report focuses on recommendations to manage or minimize induced seismicity associated with these wells.

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[7] Seismic events resulting from human activities are referred to as induced, for this report.

[8] Magnitude will refer to the values reported by the USGS Advanced National Seismic System catalog.

[9] Chapter 3, Table 3.4, page 104, and Chapter 7, Injection Wells for the Disposal of Water Associated with Energy Extraction Finding No. 1, pages 171-172; "Induced Seismicity Potential in Energy Technologies," 2013 NAS Publication.

[10] For the purposes of this report, "significant" seismic events are of a magnitude that has the potential to cause damage or endanger underground sources of drinking water or cause infrastructure damage.

[11] Earthquake terms are included under *Glossary Terms* later in this report or http://earthquake.usgs.gov/learn/glossary/ for general earthquake terms.

Hydraulic Fracturing

Although not the emphasis of this effort, seismicity associated with hydraulic fracturing (HF) was addressed by a review of selected literature sources. HF has a low likelihood of inducing significant seismicity, for reasons explained below.

Unlike wastewater disposal wells where injection occurs for an extended period of time, HF is a short-term event designed to create cracks or permeable avenues in lower permeability hydrocarbon-bearing formations. HF activity is followed by the extraction of reservoir fluids and a decrease in pressure within the formation. Therefore, the "pressure footprint" of a well that has been hydraulically fractured is typically limited to the fracture growth or fracture propagation area (Gidley et al., 1990). In comparison, the "pressure footprint" of an injection well is related to the injection rate, duration of the injection period and transmissibility of the reservoir (Lee et al., 2003). Class II disposal wells typically inject for months or years and generate large "pressure footprints" with no offset production of fluids.

HF is designed to crack the formation to enhance production. Several studies have documented microseismicity (M<1) caused by HF (Das and Zoback, 2011; Phillips et al., 2002; Warpinski, 2009; and Warpinski et al., 2012). Studies have also documented numerous examples of small faults encountered during the HF process with microseismicity where magnitudes are below M0 (Maxwell et al., 2011; Warpinski et al., 2008). Recording these very low magnitude seismic events requires the use of downhole seismometers in nearby wells (Warpinski, 2009). Though rare, felt HF-induced seismicity is possible if the HF encounters a Fault of Concern.[12] Documented cases list seismic events up to M3.8 caused by HF communication with Faults of Concern (British Columbia Oil and Gas Commission, 2012; de Pater and Baisch, 2011; Holland, 2011 and 2013; Kanamori and Hauksson, 1992).

Geothermal Injection Wells

A number of informative references exist on induced seismicity and enhanced geothermal systems. These references cover a broad range of seismicity issues and outline many avenues of additional research needed (Hunt and Morelli, 2006; Majer et al., 2007 and 2011). These authors documented the combination of monitoring techniques with adjustment of operational parameters to control seismicity. For example, thermal stress, in addition to pressure buildup, plays a key role in geothermal seismicity and may be applicable to wastewater disposal wells,

[12]A Fault of Concern is a fault optimally oriented for movement and located in a critically stressed region. The fault is also of sufficient size, and possesses sufficient accumulated stress/strain, such that fault slip and movement has the potential to cause a significant earthquake. Fault may refer to a single fault or a zone of multiple faults and fractures.

depending on the temperature of the injected fluids and receiving formation (Perkins and Gonzalez, 1984).

CO_2 Geologic Sequestration

Geologic sequestration of CO_2 requires a Class VI UIC permit. The Class VI permitting process includes assessment of potential induced seismicity. Class VI regulations require a detailed review on a site-specific basis; consequently, Class VI wells were not considered in this report. Some research pertaining to potential seismicity from CO_2 geologic sequestration may be applicable to wastewater disposal.

Directive and Working Group

Revisions to Class II regulations are outside the scope of this technical report. This report is not a policy or guidance document and does not provide an exhaustive list of specific permitting procedures. It provides the UIC Director with considerations for minimizing and managing induced seismicity on a site-specific basis, using Director discretionary authority.

To address the concern that injection-induced seismicity could cause a breach in the containment of injected fluids and endanger drinking water sources, EPA's Office of Ground Water and Drinking Water (OGWDW) Drinking Water Protection Division requested that the UIC National Technical Workgroup (NTW) develop recommendations for consideration by UIC regulators (APPENDIX A). The UIC NTW consists of UIC staff from each EPA regional office, EPA headquarters, and six state UIC program representatives. The Injection-Induced Seismicity Working Group (WG) of the NTW was formed in June 2011 to spearhead development of a report recommending possible strategies for managing or minimizing significant seismic events associated with induced seismicity in the context of Class II disposal well operations. The WG was comprised of a subset of NTW members and members outside the NTW included for their expertise on the subject matter. A list of the WG members is provided later in this report. Drafts of the report were written by the WG, and finalized based on review by the NTW. Ultimately, the report is a product of the NTW.

Regulatory Authorities

This report describes, for UIC regulators, the current understanding of induced seismicity within the existing Class II regulatory framework for Class II disposal. Evaluation of induced seismicity is not new to the UIC program. Some UIC well classes address seismicity with specific regulatory requirements.[13] The Class II UIC program does not have regulations specific to seismicity but

[13] 40 CFR §146.62(b)(1) and §146.68(f) for Class I hazardous; §146.82(a)(3)(v) for Class VI geologic sequestration

rather includes discretionary authority that allows additional conditions to be added to the UIC permit on a case-by-case basis. Examples of this discretionary authority include additional requirements for construction, corrective action, operation, monitoring or reporting; (including well closure) as necessary to protect USDWs.[14] In the included case studies, the UIC Directors used discretionary authority to manage and minimize seismic events.

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. However, EPA is unaware of any USDW contamination resulting from seismic events related to injection-induced seismicity.

Report Purpose

The NTW's task was not to determine if there was a linkage between disposal and seismicity, but if a linkage was suspected, to identify practical approaches the UIC Director may use to minimize and manage injection-induced seismicity. A decision model was developed, which compiles and describes available options and illustrates a process for applying them to manage or minimize possible injection-induced seismicity. The site assessment considerations included in the model were those identified as pertinent by the WG, though other factors may also be appropriate depending on site-specific situations. The decision model also provides operational and monitoring options for managing injection-induced seismicity. It is supported by an extensive literature review and four case histories, which considered earthquake history, proximity of disposal wells to these events, and disposal well behavior.

Many of the recommendations and approaches discussed in this report may be applicable to other well classes. For example, disposal activities also occur in Class I hazardous and non-hazardous wells, various Class V wells, and Class VI wells. The U.S. Department of Energy and the International Energy Agency (IEA) have authored several publications dealing with specific Class V geothermal seismicity issues. The WG reviewed a number of publications as part of the literature survey for this report (APPENDIX K). Conclusions from some of these reports apply to this Class II injection-induced seismicity project and are referenced within the body of the report.

Injection-Induced Seismicity Project Objectives

The WG analyzed existing technical reports, data and other relevant information on case studies, site characterization and reservoir behavior to answer the following questions:

[14] 40 CFR §144.12(b); 40 CFR §144.52(a)(9) or (b)(1); or appropriate section of 40 CFR Part 147

1. What parameters are most relevant to screening for injection-induced seismicity?
2. Which siting, operating or other technical parameters are collected under current regulations?
3. What measurement tools or databases are available that may be used to screen existing or proposed Class II disposal well sites for possible injection-induced seismic activity?
4. What other information would be useful for enhancing a decision-making model?
5. What screening or monitoring approaches are considered the most practical and feasible for evaluating significant injection-induced seismicity?
6. What lessons have been learned from evaluating case histories?

WORKING GROUP TASKS

The UIC NTW was tasked by UIC management with developing a report including technical recommendations to manage or minimize significant levels of injection-induced seismicity.

The UIC NTW utilized the following to address the objectives:

1. Compare parameters identified as most applicable to induced seismicity with the technical parameters collected under current regulations
2. Prepare a decision model
3. Assess applicability of pressure transient testing and/or pressure monitoring techniques
4. Summarize lessons learned from case studies
5. Recommend measurements or monitoring techniques for higher risk areas
6. Analyze applicability of conclusions to other well classes
7. Recommend specific areas for further research needed

WORKING GROUP APPROACH

The WG adopted the following strategy:

1. Summarize geoscience factors and applications
2. Apply petroleum engineering methods
3. Compile and review historical and current scientific literature, including ongoing projects and material associated with upcoming reports on injection-induced seismicity
4. Select and study case examples of Class II brine disposal wells suspected of inducing seismicity and provide a summary of lessons learned for the following areas:
    a. North Texas
    b. Central Arkansas
    c. Braxton County, West Virginia
    d. Youngstown, Ohio

A study of disposal wells in areas with no seismic activity was not performed.

5. Develop a decision model
6. Consult with the U.S. Geological Survey (USGS) seismologists on the potential for using deep stress field measurements and the USGS earthquake information as screening tools (APPENDIX M:)
7. Compare data collected under existing UIC requirements to relevant information needed for assessment of injection-induced seismicity
8. Solicit review by EPA's UIC NTW and subject matter contributors from state agencies, academia, researchers and industry.

REVIEW PROCESS

As noted above, prior to submission to the NTW, the draft report was sent for review to specific subject matter experts and corrections made accordingly. After the NTW passed the report to OGWDW, it was decided to conduct an additional independent peer review.

PEER REVIEW

The OGWDW engaged one of its contractors to facilitate and coordinate an external review of the NTW report. In the process of developing the contract, OGWDW also developed charge questions to guide the reviewers in the areas of desired feedback. With guidance from EPA, the contractor developed a ranked list of about 20 experts. Six reviewers were selected from that list (Table 1), based on their qualifications, including experience with injection-induced seismicity.

TABLE 1: SELECTED PEER REVIEWERS

Peer Reviewer	**Jeff Bull**	**Robin McGuire**	**Craig Nicholson**	**Kris Nygaard**	**Heather Savage**	**Ed Steele**
Affiliation	Oil/Gas Industry	Consultant	Academia	Oil/Gas Industry	Academic Laboratory	Oil/Gas Industry and Consultant
Organization	Chesapeake Energy Corporation	Lettis Consultants International, Inc.	University of California, Santa Barbara	ExxonMobil	Lamont-Doherty Earth Observatory, Columbia University	Swift Worldwide Services
Professional Years	30+	30+	30+	20+	10+	40+

Peer Review Charge

The reviewers were asked to focus on four charge questions during their review and to provide expert advice and recommendations on these questions, in addition to providing general comments. The four charge questions, developed by EPA, were as follows:

Basic Mechanism of Injection-Induced Seismicity

The NTW identified three key components contributing to injection-induced seismicity: (1) the presence of a stressed fault, (2) pressure buildup from disposal operations, and (3) a pathway for the increased pressure to communicate from the disposal well to the fault. Do these three key elements capture the causal relationship of disposal-induced seismicity? Please comment on other elements relating induced seismicity to Class II disposal injection that might be useful to consider when developing strategies to minimize or manage injection-induced seismicity.

Variety and Validity of Approaches

The NTW identified site assessment considerations along with monitoring and operational approaches for assessing the three key components contributing to injection-induced seismicity. Please comment on the appropriateness of the site assessment considerations identified for assessing the potential for induced seismicity. What other site assessment considerations might be considered? Are the monitoring and operational approaches identified appropriate for minimizing or managing injection-induced seismicity? Are there additional considerations that might be considered to address the key elements contributing to injection-induced seismicity?

Reservoir Engineering Analysis Application

The NTW sought to expand the review of the pressure buildup and pathway components of induced seismicity beyond geosciences. The NTW integrated reservoir engineering analysis into the evaluation of the potential relationship between Class II injection activity and seismicity by using data that is already collected by owners and operators as well as standard evaluation techniques employed in the oil and gas industry. Is the reservoir engineering analysis suggested by the NTW reasonable for identifying anomalies in an effort to minimize or manage injection-induced seismicity? Please identify other analyses (including the type of data needed and benefits and disadvantages of their use) that might be useful for evaluating reservoir behavior during Class II disposal injection.

Recommended Future Efforts for the EPA

Please identify any additional key literature or other data sources that might be useful to ensure a comprehensive understanding of the potential for induced seismicity in the context of Class II disposal wells.

Final Peer Review Follow-up

Once all of the comments were received, the OGWDW requested help in assessing the comments.

The comment review team (team) consisted of EPA Region 6 staff, the past NTW chair and two representatives of OGWDW. The team assessed the comments and divided them into three categories described below; it also developed a strategy to re-engage the NTW for a final review of the report, once updated based on the peer review comments.

The team assessed and tabulated the peer reviewers' comments (APPENDIX N:) according to the relevant section of the report and the commenter. The team then classified each of the comments according to the following categories:

1. Comments requiring no response: These are typically statements or opinions by the commenter.
2. Comments relevant to the topic, but outside the scope of the project: These comments are addressed in more detail in APPENDIX A. This category of comments was grouped according to the nature of the comment, as described below.
    a. Authority: Comments related to the applicability of EPA authority.
    b. Scope: Comments outside the purpose of the report (providing a practical UIC management tool) including recommendations for policy changes, new

regulations, extensive research or additional studies, such as complex proprietary modeling.

c. Clarify: Comments relevant to the topic that were addressed by directing the commenter to the appropriate place in the report or by providing additional UIC program background information.

3. Comments relevant to the topic and within the scope of the project. These comments required revisions to the document.

Additional decisions included the following:

- The original cut-off date for inclusion of case studies (September 2013) was maintained.
- A separate list of the peer reviewers' recommended references was added to APPENDIX K: Subject Bibliography, excluding non-peer-reviewed articles.
- A new appendix was created to provide responses to all comments grouped in Category 2 (above).
- The following areas were outside the scope of the project and were not incorporated:
    - Adoption of a formal comprehensive risk assessment
    - Specific policy or regulatory requirements
    - Ongoing research, modeling or simulations
    - Basic UIC program discussions

Geoscience Factors Related to Injection-Induced Seismicity

The following paragraphs provide a general overview of the various geoscience aspects relevant to injection-induced seismicity. 0 describes these aspects in greater detail. The three key characteristics related to potential injection-induced seismicity that may lead to fault slippage and associated earthquakes are: (1) an increase in the formation pore pressure from disposal activities; (2) a fault (or zone of multiple faults and fractures) optimally oriented for movement, located in a critically stressed region, of sufficient size, and possessing sufficient accumulated stress/strain, such that fault slip and movement would have the potential to cause a significant earthquake (Fault of Concern); and (3) a permeable avenue (matrix or fracture permeability) allowing the pore pressure increase to reach the fault.

Background

In general, continental oil and gas deposits occur in sedimentary rocks deposited by ancient seas over granitic basement rocks. Basement rocks have been and continue to be subjected to ongoing global tectonic forces. These forces result in fracturing and faulting (fracturing with lateral displacement) and are the origin of the constantly stressed condition of continental basement rocks. Nearly all early cases of suspected injection-induced seismicity felt by humans have involved communication between disposal zones and basement faults. For these reasons, geologic site assessments related to potential injection-induced seismicity should include an analysis of both faults and stress conditions in basement rocks of the disposal well area. Since subsurface geologic stresses are transferred over great distances, fault and stress analyses should encompass a regional area around the disposal well.

Geologic Stress Considerations

Historic seismic activity is an indicator of critical stress in basement rocks. Subsurface stresses are typically not uniform in every direction. The orientation of faults with respect to the principal stresses is a fundamental indicator of which faults are subject to activation from pore pressure increases. Not all faults are Faults of Concern, only those optimally oriented in the subsurface stress field such that an increase in pore pressure can induce movement. Optimal orientation of faults is described in greater detail by Holland (2013). Unfortunately, the principal stress direction may not be readily known to injection well permitting authorities. Some options to help determine the principal stress direction include data on borehole geometry, the World Stress Map (APPENDIX M: Task 2; Tingay et al., 2006), or consultation with experts, such as state geological surveys or universities. These experts may provide an estimate of the principal stress direction for a particular area as well as information on the location and orientation of known faults in the area.

An additional resource is the Quaternary Fold and Fault Map created by a USGS consortium (APPENDIX M: Task 1). This map shows all active faults with surface expression that are known to have created earthquakes over M6.0. These faults were defined from the geologic record for the Quaternary age (the last 1.6 million years).

Geophysical Data

Across the United States, the USGS funds or maintains seismic arrays and associated databases that are excellent web-based resources for seismic history assessments. A summary of available databases is provided in APPENDIX L: . Seismometers in the permanent monitor grid in most of the central and eastern continental United States are spaced up to 200 miles (300 km) apart. With this spacing, the system is capable of measuring events down to approximately M3.0 or M3.5, although in some areas measurement capabilities may extend down to a M2.5. Hypocenter location error for the permanent array averages up to 6 miles (10 km) horizontally and 10,000 to 16,500 feet (3–5 km) vertically. In tectonically active areas such as the continental western margin and New Madrid Seismic Zone, the seismometer spacing is closer, resulting in more accurate earthquake locations (hypocenter by latitude, longitude and depth). Additionally, closer grid spacing generally allows measurement of seismic events of smaller magnitude. Despite the accuracy limitations, USGS or other seismicity databases described in APPENDIX L:

and APPENDIX M: are useful tools for initial site assessments. Event information included in databases is periodically updated over time as data are reprocessed. Relocated events are found in later publications and may not be in the seismicity databases.

Communication with Basement Rock

In almost all historic cases, felt injection-induced seismicity was the result of direct injection into basement rocks or injection into overlying formations with permeable avenues of communication with basement rocks. Therefore, the vertical distance between an injection formation and basement rock, as well as the nature of confining strata below the injection zone, are key components of any assessment of injection-induced seismicity. In areas of complex structural history, strata beneath the injection zone may have compromised vertical confining capability due to natural fracturing. Also, faulting in basement rock can extend into overlying sedimentary strata, thus providing direct communication between the disposal zone and the basement rock.

Importance of Porosity and Permeability of Injection Strata

Stratigraphic formations used as disposal zones can have a complex range of porosity types and permeability values. For this report, two fundamental types of porosity are considered; matrix porosity and fracture porosity. Matrix porosity refers to the rock pore spaces, whether formed during deposition or alteration following deposition. Natural fractures in rocks create a second type of porosity referred to as fracture porosity. Fractures can provide preferential flow paths for fluid flow (permeability). Matrix porosity generally is characterized by smaller interconnections and less permeability than fractures, but high matrix porosity offers more storage space, potentially limiting the horizontal extent of pressure distribution. Pressure buildup is more difficult to predict in naturally fractured flow-dominated disposal zones and can extend much farther from the injection well. Most of the case study wells suspected of injection-induced seismicity in this report involved naturally fractured disposal zones.

Petroleum Engineering Applications for Evaluating Induced Seismicity

Petroleum engineering applications have been used for decades in the oil and gas industry to evaluate wells and enhance hydrocarbon production. Petroleum engineering methodologies used in this document adhere to practices and equations commonly presented in petroleum engineering literature. The review of recent injection-induced seismicity literature revealed a lack of a multidisciplinary approach inclusive of petroleum engineering techniques. Additionally, typical Class II disposal permit reviews do not use many of the petroleum engineering analyses available, but such techniques could be useful in evaluating the potential for injection-induced seismicity.

Petroleum engineering methodologies provide practical tools for evaluating the three key components that must all be present for induced seismicity 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. Different well and reservoir aspects can be evaluated depending on the methods used. Specifically, petroleum engineering methods typically focus on the potential for reservoir pressure buildup and the reservoir flow pathways present around a well and at a distance, and characterize reservoir behavior during the well's operation. Petroleum engineering approaches enhance geological and seismological interpretations related to the characterization of faults and flow behavior. Some of the case study wells reviewed exhibited specific Hall integral and derivative responses (described further below and in APPENDIX D:) that corresponded to area seismic events. The Hall integral and derivative responses at these wells suggest hydraulic communication with a boundary (i.e., an offset well or fault) at some unknown distance from the well.

The petroleum engineering approach incorporates information typically collected from the permit application (well construction and completion data) and data on injection volumes and pressures reported for compliance purposes during operation of the well. This information is presented in a graphical format to illustrate behavior of the well over time. These graphs are compared to graphs of expected well behavior from various reservoir behavior models to identify anomalous patterns.

Review of operational data can provide a qualitative look at the well behavior. Operational analysis consists of plotting readily available data reported as part of the Class II disposal well permit compliance. These plots include:

- Injection volumes and wellhead pressures
- Bottomhole injection pressure gradient
- Hall integral and derivative

Plotting injection volumes and pressures in an appropriate format along with operating pressure gradients may highlight significant changes in disposal well behavior. The operating gradient plot can indicate whether a disposal well is operating above fracture gradient. The Hall integral and derivative plot utilizes operating data to characterize a well's long term hydraulic behavior by providing a long-term, long distance look into the disposal zone. For example, a decline in wellhead pressures coupled with an increase in volumes injected reflects enhanced injectivity (increased ease of injection), shown by the derivative dropping below the Hall integral, while the derivative trend rising above the integral represents increased injectivity. Changes in Hall integral and derivative trends can represent reservoir heterogeneities (i.e., faults, stratigraphic changes, etc.), changes in completion conditions, reservoir boundaries, and effects of offset wells. Details concerning the application of both the operating gradient and Hall integral and derivative plots are discussed in APPENDIX D: . Both plot types are utilized in the four case studies detailed in Appendices E through H.

Supplemental evaluations may be performed but require data or logs that may or may not be routine for Class II disposal permit activities. These evaluations quantitatively assess potential pathways and potential reservoir pressure buildup and may include the following:

- Step rate tests
- Pressure falloff tests
- Production logs
- Static reservoir pressure measurements

Step rate tests are used to determine the formation parting pressure (fracture extension pressure). The quality of the data analysis is dependent on the amount of pressure data recorded during the test. Pressure falloff tests can provide the completion condition of the well (wellbore skin) and reservoir flow characteristics. Production logs typically include temperature logs, noise logs, radioactive tracer surveys, oxygen activation logs or spinner surveys. These types of logs are used to evaluate the fluid emplacement at the well. Periodic static pressure measurements provide an assessment of reservoir pressure buildup. More details on supplemental testing and engineering evaluations are included in APPENDIX D: .

REVIEW OF SCIENTIFIC LITERATURE

LITERATURE SOURCES

Injection-induced seismicity has been documented in many reports dating from 1968 through 2013. The WG compiled and reviewed an extensive reference list included in APPENDIX K: . The primary resource was USGS Bulletin 1951 (Nicholson and Wesson, 1990).[15] Induced seismicity is a rapidly expanding area of research. This list is not a complete resource list. Inclusion of an article or website in APPENDIX K: does not reflect NTW's agreement with the conclusion of the article.

EARTHQUAKE REPORTING

The USGS Advanced National Seismic System (ANSS) comprehensive catalog (ComCat), the largest U.S. database of earthquake events, includes earthquakes from the USGS National Earthquake Information Center (NEIC) and contributing networks. The real-time report and some

[15] An earlier draft version (available only in EPA files) was assumed to have been replaced by the final publication.

of the catalogs include the location accuracy of the event. Catalog details may vary, but are an important consideration for induced seismicity analyses. Earthquake catalogs are discussed more fully in APPENDIX L: and APPENDIX M: . USGS, state geologic agencies and universities may also collect and/or host earthquake information on their websites. There may be differences between databases in detection thresholds, as well as inconsistencies in calculated epicenters, depths or magnitudes for each earthquake. Databases may not cover the same geographic regions. It should be noted that the expansion or development of regional seismometer networks may allow measurements of seismic activity at a lower magnitude threshold than previously recorded, creating the appearance of increased seismicity. Event interpretation is discussed more fully in APPENDIX D: .

POSSIBLE CAUSES OF INDUCED SEISMICITY

Seismicity induced by human activities has been extensively documented. Seismic events have been associated with mining, construction and management of dams and water reservoirs, geologic carbon sequestration, erection of skyscrapers, geothermal energy related injection, oil and gas production activities and disposal wells. Davis and Frohlich (1993), Nicholson and Wesson (1990, 1992), and Suckale (2009, 2010) studied case histories of potential oil- and gas-related induced seismicity across the United States and Canada. Several waste disposal case studies were investigated, including Rocky Mountain Arsenal and Paradox Valley in Colorado, and two locations in far northeastern Ohio (Ashtabula and Cleveland, occurring from 1986 to 2001). Opposing conclusions were drawn on whether the Ohio seismicity was related to injection (Seeber and Armbruster, 1993 and 2004; Gerrish and Nieto, 2003; Nicholson and Wesson, 1990). More recent publications concluded disposal activity induced seismicity in central Arkansas and Youngstown, Ohio (Horton, 2012; Horton and Ausbrooks, 2011; Holtkamp et al., 2013; Kim et al., 2012; Kim, 2013; ODNR, 2012). Disposal activities at the Rocky Mountain Arsenal, Paradox Valley and enhanced recovery at the Rangely Field, also in Colorado, have been associated with inducing seismicity. Operations at both Colorado facilities began prior to promulgation of federal UIC regulations. Production from the Rangely Field is ongoing.

Several studies concluded that the Rocky Mountain Arsenal seismicity was caused by injection (Davis and Frohlich, 1993; Nicholson and Wesson, 1990 and 1992; Suckale, 2009 and 2010). At the Rocky Mountain Arsenal, the largest three earthquakes, with magnitudes between M5.0 and M5.5, occurred over one year after injection stopped. In March 1962, injection of waste fluids from chemical manufacturing operations at the Rocky Mountain Arsenal was initiated into fractured crystalline basement rock beneath the facility. Initial injection exceeded the formation fracture pressure from March 1962 through September 1963, when the surface pump was removed, leaving injection to continue under hydrostatic pressure. Pumps were once again used for injection from April 1965 through February 1966, when injection ceased. Seismicity started

5 miles (8 km) from the well on April 24, 1962, ranging from M1.5 to M4.4 from 1962 through 1966, with three earthquakes ranging from M5.0 to M5.5 in 1967. Subsequent investigations identified a major fault near the well and showed a direct correlation between increases in bottomhole pressure during injection and the number of earthquakes, using rank difference correlation (Healy et al., 1968; Hsieh and Bredehoeft, 1981; Raleigh, 1972).

From 1969 through 1974, the relationship between seismicity and enhanced recovery injection operations at the Rangely Field in Colorado was studied (Raleigh, 1972; Raleigh et al., 1976). Reservoir pressures were controlled by varying injection rates into enhanced recovery wells and withdrawal rates from production wells within the Rangely Field to determine the relationship between pressure and induced seismicity. Fourteen seismometers deployed throughout the area recorded events ranging from M-0.5 to M3.1, which occurred in clusters in both time and space. Most of these events were below the threshold that is typically felt by humans.[16] Seismometer data and injection pressure and volume data, coupled with modeling, confirmed that earthquakes were induced through an increase in pore pressure. Frictional strength along the fault varied directly with the difference between total normal stress and fluid pressure (Raleigh et al., 1976). Unusual features in this case included measurable response to fluid pressure along one part of the fault, recordable compartmentalization within the reservoir around the fault, and verification that maintaining the reservoir pressure below a calculated threshold stopped the seismicity (Raleigh, 1972; Raleigh et al., 1976). The Rangely Field example illustrates how operational changes can be used to mitigate induced seismicity.

Numerous earthquakes were induced by Class V disposal operations in Paradox Valley, Colorado (Ake et al., 2002 and 2005; Block, 2011; and Mahrer et al., 2005). Seismicity is being managed using intermittent injection periods, injection rate control and extensive seismic monitoring. Additionally, a proposed second Class V disposal well located several miles from the existing well is being evaluated by the U.S. Bureau of Reclamation in response to an expanding area of seismicity. The existing well is required for salinity control for the Delores River and operates above fracture pressure. More information is included in APPENDIX J: .

Disposal wells have been suspected of inducing seismicity in a number of recent cases (USGS, 2013). Verifying the presence of alternative causes of seismicity, such as unusual changes in lake level (Holland et al., 2013; Klose, 2013; El Hariri et al., 2010), is a useful scientific approach.

[16] Microseismic and small seismic events may occur but go undetected or unfelt and pose no significant risk to human health or USDWs.

DETERMINATIONS OF INJECTION-INDUCED SEISMICITY

Nicholson and Wesson (1990) stated that induced seismicity determinations rely on three primary characteristics of earthquake activity:

1. Geographic association between the injection zone and the location of the earthquake
2. Exceedance of theoretical friction threshold for fault slippage
3. Disparity between previous natural seismicity and subsequent earthquakes following disposal with elevated pressures

Davis and Frohlich (1993) developed a practical approach for evaluating whether seismic events were induced by injection based on characteristics similar to those stated by Nicholson and Wesson (1990), e.g., history of previous seismic events, proximity in time and space and comparison of critical fluid pressures. The Davis and Frohlich approach utilizes a series of fundamental questions to evaluate the likelihood of induced seismicity. These questions are outlined below:

1. Are these events the first known earthquakes of this character in the region?
2. Is there a clear correlation between injection and seismicity?
3. Are epicenters near wells (within 3 miles or 5 km)?
4. Do some earthquakes occur at or near injection depths?
5. If not, are there known geologic structures that may channel flow to sites of earthquakes?
6. Are changes in fluid pressure at well bottoms sufficient to encourage seismicity?
7. Are changes in fluid pressure at hypocenter locations sufficient to encourage seismicity?

Although these approaches are qualitative and do not result in positive proof of injection-induced seismicity, they may be useful to UIC regulators as preliminary screening tools. Evaluating causality requires analysis of all important natural and anthropogenic triggers that can disrupt the subsurface stress regimes in proximity to faults in the local area. As such, proof of induced seismicity is difficult to achieve and may be time-consuming but is not a prerequisite for taking early prudent action to address the possibility of induced seismicity.

Note that petroleum engineering techniques used in analysis of oil and gas development were not typically used to evaluate reservoir characteristics potentially associated with induced seismicity in the scientific literature reviewed for this report.

CASE STUDY RESULTS

The WG task was to provide practical tools that the UIC Director could use to assess site conditions prior to developing a plan to minimize and manage seismicity. Case study efforts were directed toward assessments of typical UIC program compliance data and its usability for characterization of injection well behavior and possible correlation with area seismicity. The case studies were not intended to focus on site problems or program administration issues, but rather to determine if practical assessment tools could be developed. The WG also found no indication that the injection wells associated with the case study areas injected outside of the operational boundaries or designated injection zones established by the permit parameters or endangered a USDW.

A total of four geographic areas of suspected injection-induced seismicity were selected by the WG for more detailed evaluation. These case studies were selected from areas where disposal wells were suspected to have caused recent seismic events. Initially, the north Texas, central Arkansas, and Braxton County, West Virginia, areas were selected. The Youngstown, Ohio, area was included later in the project because a disposal well was the suspected cause of a series of seismic events in late 2011. No cases were evaluated where injection-induced seismicity was not suspected.

Initially, the WG identified disposal wells located in the vicinity of recent seismic events in the selected geographic areas. In order to compare well activities to seismic events, a focus area based on a defined radius around the well was used to gather seismic data. Historic seismic events for the cases were derived from six different database catalogs. These external databases are discussed in more detail in APPENDIX L: . A radius of between 5 and 12 miles (8 to 19 km) around each case study well was selected based on the spacing density of the existing seismometers and location of the seismicity in the immediate area of the well. Additionally, there is uncertainty regarding the depth to the hypocenter.

The specific strategies used by the WG for evaluating the cases included engaging researchers who had studied two of the cases, reviewing available geologic structure maps, acquiring specific injection well data from the four state regulatory agencies and communicating with a well operator. A petroleum engineering analysis, based on the collected well data, was also performed on each case study well. Additional geoscience background and the results of EPA's petroleum engineering analysis on these cases are discussed in greater detail in the appendix specific to each case study (APPENDIX E, APPENDIX F: , APPENDIX G: , and APPENDIX H:).

Each case is discussed below through a background summary of the seismic activity and a description of how the case was evaluated by the WG. A summary of the common characteristics and lessons learned from the case studies is included following the case study summaries.

North Texas Area

Several small earthquakes occurred in the central part of the Dallas-Fort Worth metroplex near the Dallas-Fort Worth (DFW) International Airport on October 31, 2008, and near the town of

Cleburne on June 2, 2009. Both areas are located in north central Texas, in the eastern portion of the Barnett shale play. Prior to 2008, no earthquakes had been reported within 40 miles (64 km) of the DFW and Cleburne case study areas. Although Barnett shale hydrocarbons were discovered in Wise County in 1981, extensive drilling into the Barnett shale began only in the late 1990s with the advancement of horizontal drilling and well completion technologies. Disposal wells are the primary management approach for handling the wastewater associated with increased drilling activities. As of January 23, 2012, there were 195 UIC permits for commercial disposal wells in the 24-county area, only 2 of which were permitted in 2012, and not all of which were active.[17]

The Railroad Commission of Texas (RRC) standard UIC permit application package incorporates some site data and well construction and completion information along with other supporting documentation to demonstrate the protection of USDWs (Johnson, 2011). Site documentation reviewed by the WG included surface maps, location plats, disposal depths and inventory of offset wells within the area of review. Well construction details provided to the state include well specifics (e.g., casing, cement information, perforations, and completion information) and disposal conditions (e.g., disposal zone, maximum allowable injection rate and surface pressure). In addition, an annual report filed by the operator provides monthly injection volumes and pressure data. WG review of the annual injection reports indicated that the study area wells operated within the permitted pressure limits. One of the Cleburne area disposal wells was dually permitted as a Class II and Class I disposal well by different regulatory agencies. UIC Class I well requirements include conducting annual falloff tests. These tests provided reservoir characteristics and pressures for compliance with the Class I well permit and were not required in response to area seismicity. The WG reviewed the available falloff tests that confirmed the Ellenburger disposal interval was naturally fractured.

Following the 2008 and 2009 events, the RRC identified active disposal wells in the area for further evaluation due to the wells' proximity to the epicenters of seismic events and the absence of seismicity prior to initiation of disposal. RRC opened a dialogue with the operators of the suspect disposal wells, resulting in the voluntary cessation of injection for two wells, one in the DFW area and one in the Cleburne area, in August 2009 and July 2009, respectively. Since the two wells were shut-in, the frequency of seismic events in the immediate focus area, as reported by the USGS website, has substantially decreased.

[17] RRC of TX website: http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/barnett-shale-information/

The RRC subsequently reviewed its permit actions for these wells and other wells in the area in an effort to determine if the activity could have been predicted. No indications of possible induced seismicity were found in these reviews. RRC also inspected the area to verify there were no resulting public safety issues from these events. In follow-up, the RRC consulted with industry representatives, along with researchers at the Texas Bureau of Economic Geology, Southern Methodist University and Texas A&M University. The RRC continues to monitor developments and research related to injection-induced seismicity.

However, later seismic activity in the DFW area was reported in Janská and Eisner (2012) and new episodic seismic events have occurred in other areas around Cleburne since the initial case study. Reviewing the multidisciplinary findings, available WG flow analysis supports cyclic radial flow followed by linear, fracture flow in the Ellenburger, a karstic carbonate disposal zone. There is a possibility that a few of the wells may have unintentionally created additional fracturing at the operating disposal pressures. Additionally, there appears to be a pattern of repeating cycles of decreased ability to inject followed by enhanced ease of injection, with the decreased injectivity corresponding to seismic events.

More details on this case study are available in APPENDIX E: .

Central Arkansas Area

From 2009 through 2011, a series of minor earthquakes occurred in the Fayetteville shale play near the towns of Guy and Greenbrier in Faulkner County, Arkansas. Regionally, the Enola area, located approximately 9 miles (14.5 km) southeast of Greenbrier, experienced a swarm of earthquakes starting in 1982 (Ausbrooks and Doerr, 2007).

The Arkansas Oil and Gas Commission (Commission) has members appointed by the governor of Arkansas. The Commissioners oversee the state oil and gas agency, also called the Arkansas Oil and Gas Commission (AOGC).

The AOGC standard UIC permit application package incorporates site assessment, well construction and completion information, along with other supporting documentation to demonstrate the protection of USDWs. Site assessment documentation includes surface maps, location plats, disposal depths, and inventory of offset wells within the area of review. Some permit applications contain detailed geologic information, such as a narrative, structure map, type log and additional interpretive data. Well construction details provided to the state include well specifics (e.g., casing, cement information, perforations, and completion information), and disposal conditions (e.g., disposal zone and maximum allowable injection rate and surface pressure). In addition, an annual report filed by the operator provides monthly injection volumes and pressure data. For one disposal well closest to the Enola area earthquakes, the AOGC also requires pressure falloff testing, additional seismic monitoring and intermittent injection during the permitting process. WG review of the annual injection reports indicated that the Enola area well operated within the permitted pressure limits.

In October 2009, 3.5 months after injection commenced, earthquake activity began in the immediate Greenbrier area. To investigate the earthquakes, the AOGC worked with the Arkansas Geological Survey (AGS) and the University of Memphis Center for Earthquake Research and Information (CERI), and additional seismographs were deployed. In December 2010, following increased frequency and higher magnitude earthquakes, the Commission established a moratorium on the drilling of any new Class II disposal wells in an area surrounding the immediate vicinity of the increased seismic activity. The Commission also required the operators of the seven existing Class II disposal wells operating in the moratorium area to provide hourly injection rates and pressures on a bi-weekly basis for a period of 6 months, through July 2011. During the moratorium period, the AGS and CERI analyzed the injection data and seismic activity to determine if there was a relationship.

In late February 2011, following a series of larger magnitude earthquakes, the operators of three disposal wells nearest to the seismic activity voluntarily terminated well operations prior to the issuance of the Commission cessation order issued on March 4, 2011. In July 2011, following the conclusion of the moratorium study, the Commission established a revised permanent moratorium area in which no additional Class II disposal wells would be drilled and required four of the original seven disposal wells to be plugged. The revised moratorium area was based on the trend of the Guy-Greenbrier fault, which the Commission determined as the probable cause of the seismic activity. The operators of three of the wells voluntarily agreed to plug the subject disposal wells and were consequently not parties to the July 2011 hearing heard by the Commissioners. Following the July 2011 Commission hearing, the AOGC issued an order to the operator of the fourth disposal well to plug that well. The order of the Commission issued in July 2011 became a final administrative regulation on February 17, 2012.

Since July of 2011, the AOGC, AGS and CERI continue to monitor disposal well operations and seismic activity. Additional seismic monitoring equipment has been purchased to facilitate the creation of an "early warning" system for emerging seismic activity, thereby allowing more time to develop appropriate responses.

Reviewing the multidisciplinary findings, operational data analysis indicated cycles of upward and downward shifts in both the Hall integral and derivative trends on the various plots for the four disposal wells with adequate monitoring history. As in other case studies, the upward shifts had at least some correspondence to area seismic events. The cyclic tandem plot patterns, when considered in conjunction with the area geology, embedded pressure transient tests, and the operating gradient plots, likely reflect a combination of reservoir rock heterogeneities, fracturing occurrence in the wells in the form of enhanced injectivity, and interaction with reservoir boundaries such as a fault.

More details on this case study are available in APPENDIX F: .

Braxton County, West Virginia

In April 2010, a series of earthquakes ranging in magnitude from M2.2 to M3.4 began in Braxton County, West Virginia. This area had previously experienced a M2.5 earthquake in 2000. Braxton County is located on the eastern edge of the Marcellus shale play, and drilling in this area began in 2006. In March 2009, a nearby Class II disposal well began injecting Marcellus oil and gas production wastewater into the Marcellus formation.

The West Virginia Department of Environmental Protection (WVDEP) Office of Oil and Gas standard UIC permit application package incorporates site assessment, well construction and completion information, along with other supporting documentation to demonstrate the protection of USDWs. The permit application for the well of concern contained detailed geologic information, such as an isopach and structure map. Site assessment documentation included surface maps, location plats, disposal depths, and inventory of offset wells within the area of review. Well construction details provided to the state included well specifics (casing, cement information, perforations and completion information) and disposal conditions (interval, rate and maximum pressure requested). The results of a step rate test were also included with the permit information. In addition, an annual report filed by the operator provides monthly injection volumes and pressure data. WG review of the annual injection reports indicated that the well operated within the permitted pressure limits. The data reported by the operator indicated that the well did not operate continuously.

In response to the seismic activity, the WVDEP reduced the maximum injection volume in September 2010. No additional earthquakes were recorded in the area after this restriction was enacted, until January 2012, when a M2.8 earthquake occurred. In response, the WVDEP further reduced the allowable monthly disposal volume by half the permitted value and researched the geologic structure of the area. The WVDEP and the WG found no conclusive evidence linking the cause of the seismicity to the disposal well.

In February 2012, WVDEP began requiring UIC permit applications to include detailed geologic information specifically to identify subsurface faults, fractures or potential seismically active features. This additional information requirement includes public or privately available geologic information, such as seismic survey lines, well records, published academic reports, government reports or publications, earthquake history, geologic maps or other like information to determine the potential for injection to lead to activation of fault features and increase the likelihood of earthquakes.

Reviewing the multidisciplinary findings, operational analysis of the single disposal well injecting into the Marcellus shale indicates a hydraulic response. Based on the tandem plot analysis, a reservoir boundary (or boundaries) such as a fault, a pinch out, or possibly the limits of fracture stimulation (effectively the limits of permeable rock) was encountered.

More details on this case study are available in APPENDIX G: .

YOUNGSTOWN, OHIO

Starting on March 17, 2011, a series of 12 small magnitude seismic events occurred in Mahoning County in and around Youngstown, Ohio, culminating in a M4.0 event on December 31, 2011. Evidence suggested that the newly permitted, Northstar 1 Class II saltwater disposal well was the cause of the seismic activity, and the injection well was voluntarily shut down a day before the M4.0 event. The Northstar 1 injection well had been permitted as a deep stratigraphic test well and was drilled to a depth of 9,184 feet into the Precambrian basement rocks in April of 2010. On July 12, 2010, the Northstar 1 was issued a Class II saltwater disposal permit, and injection operations commenced on December 22, 2010.

The first Class II saltwater disposal well was permitted in Mahoning County in 1985, and eight more wells were converted to Class II injection between 1985 and 2004. These Class II injection wells utilized depleted oil and gas zones or were plugged back to shallower, non-oil or gas geologic formations for disposal. Injection was predominantly for disposal of production brine associated with conventional oil and gas operations. With the development of the unconventional shale plays in Pennsylvania and the lack of disposal in Pennsylvania, there was a need for additional disposal operations. To accommodate some of this need, five commercial disposal wells (Northstar 1 through 4, and 6) were permitted and drilled in Mahoning County, Ohio.

Historically, seismic monitoring in Ohio has been sporadic, and seismic events have not been accurately determined. In 1999, the Ohio Seismic Network (OSN) was established with 6 stations, and there were 24 seismic stations in operation in 2011. The seismometer at Youngstown State University was added to the OSN in 2003. Due to the continued seismic events occurring around the Youngstown area and near the Northstar 1 injection well, four portable seismic units were deployed on December 1, 2011, by Lamont-Doherty Earth Observatory. This portable array allowed more accurate identification of seismic events. After the M4.0 event on December 31, 2011, the governor of Ohio placed a moratorium on other deep injection wells within a 7 mile radius of the Northstar 1 and put a hold on the issuance of any new Class II saltwater injection well permits until new regulations could be developed.

There is a seismically active zone in western Ohio and several episodically active faults 20 and 40 miles away from Youngstown (Baranoski, 2002 and 2013). Prior to the earthquakes recorded in 2011, the only known deep-seated fault was mapped approximately 20 miles (32 km) away from the seismic activity, based on a Pennsylvania Geological Survey report (Alexander et al., 2005). The vast majority of all historic and current seismic activity in Ohio occurs within the Precambrian basement rocks.

Due to the lack of deep geological information available for the Mahoning County area, a deep Precambrian basement fault in close proximity to the Northstar 1 went undetected. This fault was confirmed through evaluation of geophysical logs from the offset deep disposal wells and an interpreted seismic line.

According to the *Preliminary Report on the Northstar 1 Class II Injection Well and the Seismic Events in the Youngstown, Ohio, Area* (Ohio Department of Natural Resources, 2012), data suggest seismicity in the Mahoning County area is related to Class II disposal. The Northstar 1 was drilled 200 feet into the Precambrian basement rock. The Ohio Department of Natural Resources (ODNR) report also suggests that pressure from disposal activities may have communicated with the Fault of Concern located in the Precambrian basement rock. The ODNR now prohibits the drilling of Class II injection wells into the Precambrian basement rock and has enhanced the standard UIC permit requirements[18] to facilitate better site assessment and collection of more comprehensive well information. The additional permit requirements include the following options 'as deemed necessary' and are reviewed on a well-by-well basis: pressure falloff testing, geologic investigation to identify faulting in the immediate vicinity of the well, a seismic monitoring plan or seismic survey, comprehensive suite of well logs, an initial bottomhole pressure measurement and a radioactive tracer or spinner survey. Additional operational controls[19] consist of: daily injection volume and pressure monitoring; an automatic shut-off system; and monthly monitoring of annular pressure.

In late 2012, ODNR also implemented a proactive approach to seismic monitoring around deep Class II disposal wells in Ohio and purchased nine portable seismic units to bolster earthquake monitoring capabilities. All nine portable seismic units are in operation, and ODNR has been monitoring these seismic stations in real-time since late 2012. Additionally, two disposal well

[18] http://codes.ohio.gov/oac/1501%3A9-3-06
[19] http://codes.ohio.gov/oac/1501%3A9-3-07

operators have installed their own portable seismic arrays around two new wells that ODNR is also monitoring in real-time.

Reviewing the multidisciplinary findings led to the following summary: the Northstar 1 injection well was completed into an approximately 900 foot openhole interval that crossed multiple formations, including faulted basement rock. A production log indicated flow likely occurred into an openhole interval above the basement rock; however, the entire completion interval was exposed to the well's operating pressure. The tandem plot indicated, as in the other case studies, several cycles of decreasing and increasing ease of injectivity, with some correspondence between seismic events, and a portion of the cycles displaying decreasing injectivity (Hall derivative upswings).

More details on this case study are available in APPENDIX H: .

Common Characteristics, Observations, and Lessons Learned From Case Studies

The case studies highlighted in this report provided important lessons and observations as well as common characteristics for wells suspected of inducing seismicity. The lessons learned provided a basis for the decision model as well as the approaches for minimizing and managing induced seismicity. The case study common characteristics and observations contributed to the site conditions component of the decision model. Common characteristics, coupled with key case study observations and the lessons learned, are summarized below.

Common Characteristics and Observations

The common characteristics and observations represent those aspects noted by the WG across multiple case studies.

- Petroleum engineering analysis indicated some correspondence between disposal well behavior and seismicity (all case study areas).
- The magnitude of the earthquakes may increase over time as observed in some case studies (central Arkansas, Ohio and West Virginia).
- Injection into fractured disposal zones directly overlying or connected to basement rock may be more vulnerable to injection-induced seismicity (Arkansas and Ohio case study areas).
- Deep disposal wells were in direct communication or suspected to be in hydraulic communication with basement rocks and Faults of Concern, as in the central Arkansas and Ohio examples. Disposal commonly occurred into disposal zones with naturally fractured reservoir characteristics, as in the central Arkansas and north Texas case study examples.

- Operational analysis of disposal rates and pressures on case study wells showed multiple incidences of repeating cycles of decreased ability to inject followed by enhanced ease of injection, with the decreased injectivity corresponding to seismic events (all case study areas).
- Operating wells below fracture pressure avoids or minimizes fracture propagation. Determination of appropriate operating conditions may require actual testing, such as a step rate test, to measure the formation parting pressure, or conducting an operational analysis for indication of enhanced injectivity.

Lessons Learned

The following key lessons were learned from the case study reviews:

- Initiating dialogue with operators can enhance cooperation, resulting in early voluntary action from operators, including well shut-in, or acquisition of additional site data.
  - Initiating dialogue between the operator and UIC regulator resulted in the voluntary shut-in of some suspect disposal wells (north Texas, central Arkansas and Ohio).
  - In two instances, an operator showed a proprietary 3-D seismic interpretation to the permitting authority, revealing a deep-seated fault (north Texas and central Arkansas).
- Analysis of existing operational data may provide insight into the reservoir behavior of the disposal zone (all case study areas).
  - Hall integral and derivative plots may indicate a no-flow boundary, such as a fault plane or stratigraphic pinch out, at a great distance.
  - Hall integral and derivative plots may illustrate enhanced ease or increased difficulty of injection.
- Enhanced injectivity could represent injection-induced fracturing, opening or extension of natural fractures, higher pressures allowing fluid flow into lower permeability portions of the formation, or encountering an increased permeability zone at distance (all case study areas).
- Acquisition of additional data may provide an improved analysis.
  - Additional site characterization may be beneficial:
    - Demonstrating a confining layer between the disposal zone and basement rock, and structural interpretation does not indicate faults extending into basement rock.
  - Increased recording of operational parameters can improve the quality of the operational data analysis.

        - Increased frequency of monitoring for permit parameters improved the operational analysis (central Arkansas and Ohio).
- Conducting a falloff test can further refine the reservoir characterization.
    - Fractured flow behavior was confirmed from the falloff test analyses for the Ellenburger disposal zone in a Cleburne area well (north Texas).
- Engaging external geophysical expertise may allow determination of a more accurate location (x,y,z) of the active fault and stress regime, through reinterpretation or increased seismic monitoring.
    - Especially useful when earthquake event magnitudes increased over time (central Arkansas, Ohio and West Virginia).
- Lack of historic seismic events may be a function of lack of seismic activity, seismic activity below recordable levels, or epicenters away from population centers.
- Existing seismic monitoring stations are generally insufficient to pinpoint active fault locations; more sensitive and better located monitoring systems are needed to accurately identify active faults and detect smaller events.
    - Installation of additional stations resulted in reliable identification of active fault locations (central Arkansas and DFW airport area of north Texas).
    - Epicenters of recorded events are scattered, due to an insufficient number of network stations in proximity to the activity (West Virginia).
- Seismic event data is periodically updated.
    - During preparation of this report the seismicity data were downloaded on different dates, with many of the initial events later revised or deleted.
        - Deletions typically occur between the first event report and entry into the catalog (NEIC or ComCat).
        - Revisions cover 3-D location as well as magnitude.
            - Several of the catalogs have added a revision date to their entries to help identify such changes.
- Seismic event data may be reprocessed, resulting in relocation of the event.
    - Fine-tuned relocation is possible when a sufficiently detailed velocity model is developed.
    - Relocated events are found in later publications and may not be in the catalogs.
- A multidisciplinary approach helped to minimize and manage induced seismicity at a given location (all case study areas).
    - State geological survey or university researchers provided expert consultation, facilitated installation of additional seismometers and provided a clearer understanding of the deep-seated active faulting (north Texas and central Arkansas).
- Director discretionary authority was used to solve individual site-specific concerns:

- Directors used authority to acquire additional site information, request action from operators and prohibit disposal operations. For example, directors used the following approaches:
  - Increased monitoring and reporting requirements for disposal well operators to provide additional operational data for reservoir analysis (central Arkansas).
  - Required one operator to install a seismic monitoring array prior to disposal as an initial permit condition (central Arkansas).
  - Plugged or temporarily shut-in suspect disposal wells linked to injection-induced seismicity while investigating or interpreting additional data (all case study areas).
  - Defined a moratorium area prohibiting Class II disposal wells in a defined high-risk area of seismic activity (central Arkansas).
  - Decreased allowable injection rates and total monthly volumes in response to seismic activity (West Virginia).

Decision Model

The primary objective of the WG was to develop a practical tool, the decision model, for the UIC Director to consider in minimizing and managing injection-induced seismicity potentially associated with new or existing Class II disposal wells. The decision model is specifically designed for Class II disposal wells. However, the UIC Director should also consider other causative factors, such as lake level changes or different types of area operations (mining, production activities, etc.). As mentioned previously, the three key components behind injection-induced seismicity are (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. All three components must be present to induce seismicity. The decision model was designed to identify the presence of any of the three key components. Based on the historical successful implementation of the UIC program, the decision model would not be applicable to the vast majority of existing Class II disposal wells since most are not associated with seismic activity. Use of the decision model is predicated on UIC Director discretionary authority. Federal UIC regulations do not specifically address risk consequences associated with seismicity, but allow the UIC Director discretion to ensure protection of USDWs.

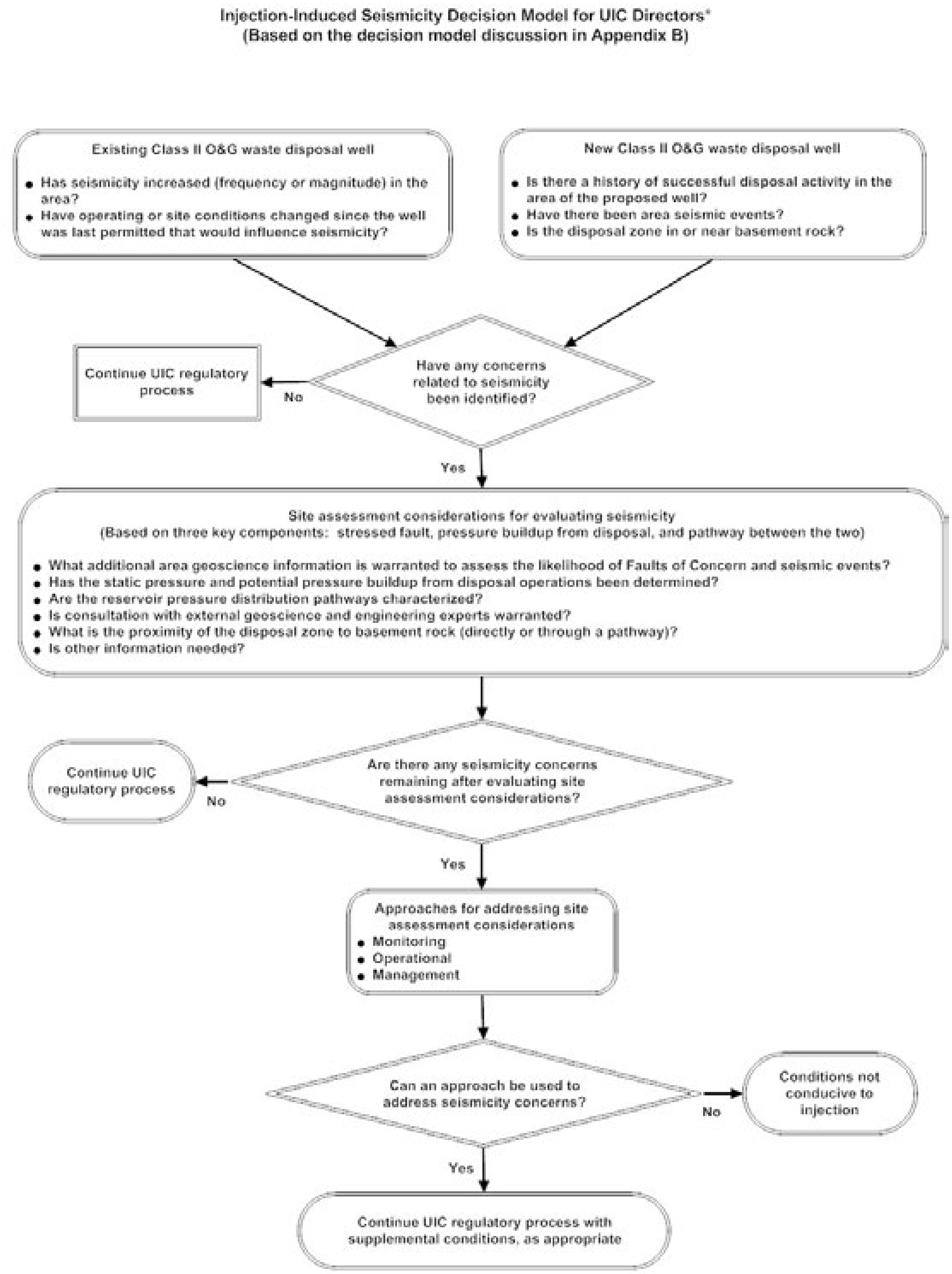
The decision model incorporates a site assessment consideration process addressing reservoir and geologic characteristics related to the three key components. The decision model provides the UIC Director with specific site assessment considerations and approaches to identify and address seismicity criteria for both existing and new disposal wells. No single question addresses all the considerations needed to evaluate a new or existing disposal well. If issues are identified, the decision model provides specific operational, monitoring and management approaches as options for addressing the issues.

The diagram of the decision model, Figure 1, is followed by a discussion of considerations for site assessment. The “area” referenced in the decision model is a geographic area with the extent determined by the Director using expertise about the site circumstances. Issues identified through the site assessment consideration thought process are then addressed, as needed, by a combination of operational, monitoring and management approaches. These options were identified by the WG from petroleum engineering methods, literature reviews, analyses of the case studies, and consultations with researchers, operators and state regulators. A more detailed discussion of the decision model is included in APPENDIX B: .

The decision model (Figure 1) contains three symbols that represent the following:

- Bubble – thought process
- Diamond – decision point
- Rectangle – outcome

FIGURE 1: INJECTION-INDUCED SEISMICITY DECISION MODEL



* Decision model is founded on Director discretionary authority

Existing or New Class II Disposal Well

The decision model was designed to address seismicity concerns related to new or existing disposal wells. Below are the different scenarios. Different site assessment considerations may be applicable to each scenario.

1. An existing disposal well operating in a zone with historical injection
2. An existing disposal well in an area not experiencing seismicity, where the operator requests a substantial increase to injection volumes or pressure
3. A new disposal well in a disposal zone or area where little or no disposal activity has previously occurred, with or without seismic activity

Scenario (1) may not warrant further site assessment based on successful historical operations, while scenarios (2) or (3) may warrant additional site characterization consideration, especially if the well is located in a region with possible Faults of Concern.

Have Any Concerns Related to Seismicity Been Identified?

An UIC Director who does not identify any injection-induced seismicity concerns may exit the decision model and continue through the normal UIC regulatory process; otherwise, a continuation through the model for further site assessment considerations may be warranted.

Site Assessment Considerations

Site assessment considerations identify and help the UIC Director evaluate any specific site characteristics that raise potential issues regarding injection-induced seismicity. Uncertainties about any one of the three key components may warrant collection or review of additional data within the site assessment consideration process.

Site assessment considerations may pertain to information from permit applications or post-approval permit monitoring data. Site assessment considerations may include aspects of both geosciences and petroleum engineering, so a multidisciplinary approach is advantageous. Details about the decision model diagram and its associated site assessment considerations are provided in APPENDIX B: .

Site assessment considerations determined to be relevant for the decision model were the following:

- What additional area geoscience information is warranted to assess the likelihood of Faults of Concern and seismic events?
- Has the static pressure and potential pressure buildup from disposal operations been determined?

- Are the reservoir pressure distribution pathways characterized?
- Is consultation with external geoscience and engineering experts warranted?
- What is the proximity of the disposal zone to basement rock (directly or through a pathway)?
- Is other information needed?

Are There Any Seismicity Concerns Remaining After Site Assessment?

An UIC Director who does not identify any injection-induced seismicity concerns following a more detailed site assessment may exit the decision model and continue through the normal UIC regulatory process. When an injection-induced seismicity concern is identified, the Director may determine an approach to address the concern. The site assessment considerations are intended to guide the Director in selecting operational, monitoring and management approaches that are appropriate for addressing induced seismicity issues.

Approaches for Addressing Site Assessment Issues

There are a number of approaches available to manage and minimize significant seismic events. These can be broadly categorized as operational, monitoring and management approaches. An operational approach may include, for example, restricting the maximum allowable injection rate or pressure. A monitoring approach may necessitate collection of additional monitoring data, for example, operational pressures, additional seismic monitoring or pressure transient well testing. A management approach supports a proactive approach for prompt action following seismic events and promotes agency, operator and public interaction. The UIC Director determines which, if any, approaches are important, depending on site-specific considerations. Details about the approaches for addressing issues associated with the site assessment considerations are provided in APPENDIX B: .

Can an Approach be Used to Successfully Address Seismicity Concerns?

Where the UIC Director does not identify a suitable approach for addressing seismicity concerns, conditions may not be suitable for disposal operations at that location. If monitoring, operational or management approaches provide the required level of protection, the Director may condition the permit accordingly or use discretionary authority to require the desired approaches without revoking the permit.

Research Needs

The WG did not exhaust all avenues with respect to research on the value of petroleum engineering approaches. An abundance of research describing seismology and geomechanical behavior in the form of physical rock properties exists, although studies that combined petroleum engineering and geoscience approaches could not be found by the WG. The WG recommends future practical research using a multidisciplinary approach and a holistic assessment addressing disposal well and reservoir behavior, geology and area seismicity. Such an approach would benefit from combined expertise in geology, petroleum engineering, geophysics and seismology, which may not be available through one entity. For example, areas of expertise should include, but may not be limited to structural and stratigraphic geology; rock mechanics (aka geomechanics); seismology; reservoir characterization; reservoir fluid flow mechanisms; and disposal well construction, completion and performance.

The WG employed Hall plots for the petroleum engineering analysis because regulators may perform these analyses using widely available spreadsheet software and routinely obtained program data. However, other petroleum engineering evaluations are also available that may be applicable, if converted to incorporate injection conditions. The WG identified correspondence between injection well operational characteristics and seismic events in some of the case study wells using Hall plots. Future research is needed to explore other simple engineering techniques that could be used to analyze potential correlations between disposal well operational long-term hydraulic behavior and earthquake events. One of the key outcomes of such a research project would be a practical set of methodologies to assess operating data using injection well permit reporting data normally acquired for existing UIC permits.

To clarify the meaning of the injectivity patterns observed in the case study wells, a comparison of typical injectivity responses for disposal wells in different fractured and unfractured formations would be invaluable. There are a host of variations on this theme, where additional information is needed in order to identify whether a response is associated with a single cause or stems from multiple sources. This information includes such things as formation character, offset disposal well interaction, proximity to a fault, and fracture initiation. A correlative study analyzing whether or not microseismicity accompanies the disposal would help to clarify the risk aspect. Where seismic responses appear, understanding the timing of disposal operations and the apparent response would be an important addition to the UIC knowledge base.

There is also a need for research related to geologic siting criteria for disposal zones in areas with limited or no existing data. The geologic and geophysical study could focus on new stratigraphic horizons that could serve as disposal zones in these areas, the nature of subsurface stresses in basement rocks of these areas, and a more detailed regional geological assessment of basement faults. If sufficient earthquake catalog data are available, additional research to devise a statistical analysis to relate Class II disposal wells operating parameters to induced seismicity would be useful.

Recommendations for Minimizing or Managing Injection-Induced Seismicity

The WG found that no single recommendation addresses all the complexities related to managing or minimizing injection-induced seismicity. Recommendations included in this report were derived from a combination of WG expertise, case studies, consultations with outside experts and data from literature reviews. Recommendations from the outcome of the decision model can be divided into three technical categories (site assessment considerations, operational and monitoring) and a management component. An early step in the induced seismicity evaluation process is to conduct a preliminary assessment. Based on the preliminary assessment and additional site assessment considerations, further operational, monitoring and management approaches may be warranted. The complete discussion of the decision model is located in APPENDIX B: .

Preliminary Assessment of Existing or New Oil and Gas Waste Disposal Wells

- Assess disposal history for correlation with area seismicity.
- Review area seismicity for increases in frequency or magnitude.
- Identify changes in disposal well operating conditions that may influence seismicity.
- Determine the depth to basement rock and potential connectivity to the disposal zone.

Site Assessment Considerations

Site assessment considerations were developed to identify and evaluate specific site characteristics that may represent potential issues for injection-induced seismicity. Many geologic and petroleum engineering considerations for site characterization are not part of the typical permit application process. Additional data collection or review of additional data may be warranted. Possible site assessment activities are shown below:

- Evaluate regional and local area geoscience information to assess the likelihood of activating faults and causing seismic events.
- Assess the initial static pressure and potential pressure buildup in the reservoir.
- Review the available data to characterize reservoir pathways that could allow pressure communication from disposal activities to a Fault of Concern.
- Consult with external geoscience or engineering experts as needed to acquire or evaluate additional site information.
- Determine the proximity of the disposal zone to basement rock.
- Consider collecting additional site assessment information in areas with no previous disposal activity and limited geoscience data or reservoir characterization, prior to authorizing disposal.

Approaches

Possible operational, monitoring and management approaches follow to address seismicity concerns that may arise from the site assessment evaluation. Several proactive practices were identified for managing or minimizing injection-induced seismicity. The applicability and use of any of these approaches should be determined by the Director.

Operational Approach

- Conduct a petroleum engineering analysis of operational data on wells in areas where seismicity has occurred, to identify potential correlation.
- Conduct pressure transient testing in disposal wells suspected of causing seismic events to obtain information about injection zone characteristics near the well.
- Perform periodic static bottomhole pressure monitoring to assess current reservoir pressures.
- Modify injection well permit operational parameters as needed to minimize or manage seismicity issues. This may require trial and error. Examples of modifications may include the following:
  - Reduce injection rates, starting at lower rates and increasing gradually.
  - Inject intermittently to allow time for pressure dissipation, with the amount of shut-in time needed being site-specific.
  - Separate multiple injection wells by a larger distance for pressure distribution since pressure buildup effects in the subsurface are additive.
  - Implement contingency measures in the event seismicity occurs over a specified level.
- Operate wells below fracture pressure to maintain the integrity of the disposal zone and confining layers.
- Perform annular pressure tests and production logging if mechanical integrity is a concern.

Monitoring Approach

- Increase frequency of monitoring for injection parameters, such as formation pressure and rates, to increase the accuracy of analysis.
- Monitor static reservoir pressure to evaluate pressure buildup in the formation over time.
- Install seismic monitoring instruments in areas of concern to allow more accurate location determination and increased sensitivity for seismic event magnitude.
- Increase monitoring of fluid specific gravities in commercial disposal wells with disposal fluids of variable density since the density impacts the bottomhole pressure in the well.

- For wells suspected of induced seismicity, take early actions, such as acquiring more frequent reports of injection volumes and pressures, reducing injection rates, and/or increasing seismic monitoring, rather than waiting on definitive proof of the causal relationship. Engage the operators early in the process, especially in areas that are determined to be vulnerable to injection-induced seismicity.
- Engage external multidisciplinary experts from other agencies or institutions. For example, Directors may utilize geophysicists to interpret or refine data from seismic events for accuracy and stress direction.
- Provide training for UIC Directors on new reservoir operational analysis techniques to help them understand the spreadsheet parameters.
- Employ a multidisciplinary team for future research to address possible links between disposal well and reservoir behavior, geology and area seismicity.
- Include a seismic threshold as a condition of the permit describing action to be taken in the event of initiation of or increase in seismic events. Thresholds could be based on the magnitude or frequency of events.
- Develop public outreach programs to explain the complexities of injection-induced seismicity.

REPORT/END PRODUCT TASK RESULTS

EPA requested that the NTW output include a specific list of elements in the final report (APPENDIX A:). This list is repeated below, with the corresponding section of this report summarizing the results listed immediately below the item. (Report locations are italicized.)

1. **Comparison of parameters identified as most applicable to induced seismicity with the technical parameters collected under current regulations**
   A point-by-point comparison is not possible as program requirements are widely variable across the various EPA regions and state agencies. The most commonly requested disposal permit parameters found to be useful in addressing potentially induced seismicity include accurate reporting[20] for the following:
    a. All available disposal formation data with respect to flow characteristics and continuity; i.e., static pressure, permeability, normal flow pattern (homogenous or linear) and potential disruptions to flow path (stratigraphic or structural)

[20] Many of these parameters may be requested, but not required.

   b. Annual reports of injection volumes and pressures (average and maximum); monthly is more useful than quarterly; daily is needed for more refined analysis

2. **Decision-making model—conceptual flow chart**

   Figure 1 under *Decision Model: Site Assessment Considerations* and at the end of *APPENDIX B*

   a. Provide strategies for preventing or addressing significant induced seismicity. (Note that prevention of earthquakes may not be possible where faults are critically stressed.)
      i. *Recommendations for Minimizing or Managing Injection-Induced Seismicity*; and first subheading
      ii. *APPENDIX B: Introduction*

   b. Identify readily available applicable databases or other information.
      i. *APPENDIX L: and APPENDIX M:*

   c. Develop site characterization check list
      i. *Recommendations for Minimizing or Managing Injection-Induced Seismicity: Site Assessment Considerations*
      ii. *APPENDIX B: Site Assessment Considerations for Evaluating Seismicity*

   d. Explore applicability of pressure transient testing and/or pressure monitoring techniques
      i. *Case Study Results*
      ii. *APPENDIX D - APPENDIX H*

3. **Summary of lessons learned from case studies**
      i. *Case Study Results: Common Characteristics, Observations, and Lessons Learned From Case Studies*

4. **Recommended measurement or monitoring techniques for higher risk areas**
   a. Approaches to address site assessment consideration
      i. *APPENDIX B: and APPENDIX D:*

5. **Applicability of conclusions to other well classes**

   Induced seismicity with respect to other well classes was discussed in the Introduction. The conclusions for the Class II disposal program may be applicable to other well classes; however, additional considerations may also be needed particularly for geothermal wells.
      i. *APPENDIX K: Subject Bibliography: Geothermal*

6. **Define if specific areas of research are needed**
      i. *Research Needs*

Report Findings

The following major report findings are derived from the literature reviews, case study reviews, and the development of the decision model:

- The three key components behind injection-induced seismicity are (1) sufficient pressure buildup from disposal activities, (2) a Fault of Concern, and (3) a pathway for the increased pressure to communicate from the disposal well to the fault. Successful disposal occurs in areas with one or two characteristics present, but not all three.
- The UIC Director should take early prudent action to minimize the potential for injection-induced seismicity rather than requiring substantial proof of the causal relationship.
- The WG applied petroleum engineering techniques not identified in the injection-induced seismicity literature. These techniques have useful application for assessing flow path and fault presence. Basic petroleum engineering practices coupled with geology and geophysical information may provide a better assessment of well operational behavior in addition to improved understanding of reservoir and fault characteristics.
- A multidisciplinary approach is important for the evaluation of the key three components. Understanding the geologic characteristics and reservoir flow behavior of a site involves methodologies from petroleum engineering, geology and geophysics disciplines.
- The case studies were useful for identifying common characteristics of suspect wells and actions UIC Directors took through discretionary authority to manage and minimize seismic events in these areas.
- Additional research is needed to explore correlations between disposal well operational behavior and nearby earthquake events, taking into consideration all possible causal effects.
- Future research should consider a practical multidisciplinary approach and a holistic assessment addressing disposal well and reservoir behavior, geology and area seismicity.
- The decision model developed through this effort is based on a thought process derived from a combination of case studies, literature reviews and understanding the conditions essential to cause seismicity. The WG selected a thought process versus a definitive framework to provide the Director with flexibility. The key questions of the decision model are:
    - Have any seismicity concerns been identified in new or existing wells?
    - Are there site considerations remaining following further review of data?
    - Can a monitoring, operational or management approach be used to successfully address seismicity concerns?

Greater detail regarding these findings can be found in the respective report sections and associated appendices.

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Glossary of Acronyms and Terms

Acronyms

AAPG	American Association of Petroleum Geologists
AGS	Arkansas Geological Survey
ANSS	USGS Advanced National Seismic System
AOGC	Arkansas Oil and Gas Commission
BHP	Bottomhole Pressure
CERI	Center for Earthquake Research and Information
ComCat	Comprehensive catalog
DFW	Dallas-Fort Worth
EPA	U.S. Environmental Protection Agency
HF	Hydraulic Fracturing
IEA	International Energy Agency
M4.0	Magnitude earthquake event; for instance, M4.0 means magnitude 4.0
NCEER	Central and Eastern United States, CERI Earthquake database
NEIC	National Earthquake Information Center, U.S. Geological Survey
NTW	National Technical Workgroup
ODNR	Ohio Department of Natural Resources
OSN	Ohio Seismic Network
PDE	Preliminary Determination Earthquake, NEIC Earthquake database
RRC	Railroad Commission of Texas
SMU	Southern Methodist University
SPE	Society of Petroleum Engineers
SRA	Eastern, Central & Mountain States NEIC Earthquake database
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
USHIS	Significant U.S. quakes, NEIC Earthquake database
WG	Injection-induced Seismicity Working Group
WVDEP	West Virginia Department of Environmental Protection Office of Oil and Gas

TERMS

Catalog aka earthquake catalog from USGS online Earthquake Search of the NEIC PDE catalog of earthquakes. http://earthquake.usgs.gov/earthquakes/eqarchives/epic/

Class II injection wells are wells that inject fluids (1) which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection, (2) for enhanced recovery of oil or natural gas; and (3) for storage of hydrocarbons which are liquid at standard temperature and pressure (40 CFR 146.5(b)).

Earthquake is a term used to describe both sudden slip on a fault, and the resulting ground shaking and radiated seismic energy caused by the slip, or by volcanic or magmatic activity, or other sudden stress changes in the earth (USGS). Earthquakes resulting from human activities will be called induced earthquakes in this report.

Epicenter is the point on the earth's surface vertically above the hypocenter (or focus) point in the crust where a seismic rupture begins. NEIC coordinates are given in the WGS84 reference frame. The position uncertainty of the hypocenter location varies from about 100 m horizontally and 300 m vertically for the best located events, those in the middle of densely spaced seismograph networks, to tens of kilometers for events in large parts of the United States.

Falloff test is a pressure transient test conducted by shutting an injection well in and observing the pressure decline at the well over a period of time.

Fault of Concern is a fault optimally oriented for movement and located in a critically stressed region. The fault is also of sufficient size, and possesses sufficient accumulated stress/strain, such that fault slip and movement has the potential to cause a significant earthquake. Fault may refer to a single fault or a zone of multiple faults and fractures. See also Geologic Stress Considerations; APPENDIX B: Site Assessment Considerations For Evaluating Seismicity; and APPENDIX M: State of Stress for more complete discussion.

Hypocenter, aka focus, is the 3-D location of the earthquake source, i.e., latitude, longitude, focal depth below ground.

Isopach is a contour map illustrating the variations of thickness of a defined stratum.

Magnitude is a number that characterizes the relative size of an earthquake at the hypocenter. Magnitude is based on the measurement of the maximum motion recorded by a seismograph or the energy released. Generally, damage is reported for magnitudes above 5.[21] Magnitude (M) will refer to the numbers reported by USGS or the NEIC, not separated between moment, body wave, or surface wave magnitudes.

Magnitude[22]	Earthquake Effects
2.5 or less	Usually not felt, but can be recorded by seismograph.
2.5 to 5.4	Often felt, but only causes minor damage.
5.5 to 6.0	Slight damage to buildings and other structures.
6.1 to 6.9	May cause a lot of damage in very populated areas.
7.0 to 7.9	Major earthquake. Serious damage.
8.0 or greater	Great earthquake. Can totally destroy communities near the epicenter.

Microseismicity has no formal definition, but generally is an earthquake with a magnitude less than 2. (*The Severity of an Earthquake*, USGS website: http://earthquake.usgs.gov/learn/topics/richter.php)

Step rate test is a pressure transient test that consists of a series of increasing injection rates as a series of rate steps and estimates the pressure necessary to fracture the formation.

Significant earthquakes/seismic events, for this report, are of a magnitude that can cause damage or potentially endanger underground sources of drinking water.

Static pressure, for this report, is the bottomhole pressure in the pore volume around the injection well measured in the wellbore at the end of a shut-in period that reaches stabilized conditions.

Tectonic is the rock structure and external forms resulting from the deformation of the earth's crust. (Dictionary of Geological Terms, 1976).

[21] Building damage was reported following 2011 earthquakes near Trinidad, Colorado (5.3); near Greenbrier, Arkansas (4.7); and the Soultz, France, project (2.9).

[22] Michigan Tech, <http://www.geo.mtu.edu/UPSeis/magnitude.html>, Accessed 11/10/14.

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APPENDIX A: UIC NATIONAL TECHNICAL WORKGROUP PROJECT TOPIC #2011-3

UIC NATIONAL TECHNICAL WORKGROUP PROJECT TOPIC: #2011- 3

Technical Recommendations to Address the Risk of Class II Disposal Induced Seismicity

Background

Recent reports of injection-induced seismicity have served as a reminder that the UIC Program can and should implement requirements to protect against significant seismic events that could ultimately result in USDW contamination. The UIC Program's Class I hazardous and Class VI siting provisions require rigorous evaluations for seismicity risks. The other well classes, in contrast, allow the UIC Director the flexibility to decide if and when such evaluations are needed. In light of the recent earthquake events in Arkansas and Texas, the UIC National Technical Workgroup (NTW) will develop technical recommendations to inform and enhance strategies for avoiding significant seismicity events related to Class II disposal wells.

Project Objectives

The UIC NTW will analyze existing technical reports, data and other relevant information on case studies, site characterization and reservoir behavior to answer the following questions:

1. What parameters are most relevant to screen for injection induced seismicity? Which siting, operating, or other technical parameters are collected under current regulations? (Geologic siting criteria, locations and depths of area pressure sources and sinks, injection rates and pressures, cumulative injection or withdrawals of an area, evaluation of fracture pressure, stresses or Poisson's ratio, etc.)
2. What measurement tools or databases are available that may screen existing or proposed Class II disposal well sites for possible injection induced seismic activity? What other information would be useful for enhancing a decision making model? (Flow chart incorporating seismicity/hazard database resources, reservoir testing methods, area faulting, measuring or recording devices, reservoir pressure transient models, seismic models, other screening tools, etc)
3. What screening or monitoring approaches are considered the most practical and feasible for evaluating significant injection induced seismicity?
4. What lessons have been learned from evaluating case histories?
    a. Did reviews of injection rate and pressure data sets reveal any concerns?
    b. Were any pressure transient tests conducted?
    c. How were the seismicity events attributed to Class II disposal activities?
    d. What levels of site characterization information were available?
    e. Which UIC regulations have regulators used to address the situation?
    f. Were there areas of concern identified that existing UIC regulations did not address?
    g. Any other lessons learned?

Output

The end-product of this analysis should be a report containing technical recommendations for avoiding significant levels of injection induced seismicity that EPA can share with UIC Directors. The UIC NTW will produce a report that includes the following elements:

1. Comparison of parameters identified as most applicable to induced seismicity with the technical parameters collected under current regulations
2. Prepare a decision making model – conceptual flow chart
    a. Provide strategies for preventing or addressing significant induced seismicity
    b. Identify readily available applicable databases or other information
    c. Develop site characterization check list
    d. Explore applicability of pressure transient testing and/or pressure monitoring techniques
3. Summary of lessons learned from case studies
4. Recommended measurement or monitoring techniques for higher risk areas
5. Applicability of conclusions to other well classes
6. Define if specific areas of research are needed

Milestones

- July 2011 – Authorization from UIC managers for UIC NTW to proceed with injection induced seismic project proposal. Assemble UIC NTW project team and assign tasks to project members. Collect and distribute, to UIC NTW project team, information from published studies, peer-reviewed articles, and State and Federal UIC programs.
- August 2011 – Create project sub-teams. Collect and evaluate information from case histories. Review compilation of information and develop technical recommendations for addressing risks of significant injection induced seismicity. Create project teams.
- September 2011 - Consolidate input from project sub-teams
- October 2011 – Prepare and present preliminary technical recommendations and report to UIC NTW membership. Finalize technical recommendations and report with input from UIC NTW membership.
- November 2011 – Submit report for presentation to UIC management
- December 2011 – Finalize report and post to public accessible UIC NTW website

Project Focus Group

Phil Dellinger (R6; Lead); Leslie Cronkhite (HQ; HQ-Lead); Jill Dean (HQ); Bob Smith (HQ); David Albright (R9); Sarah Roberts (R8); Tom Tomastik (Ohio Department of Natural Resources); Steve Platt (R3); Dave Rectenwald (R3), Susie McKenzie (R6), Brian Graves (R6), Ken Johnson (R6), Nancy Dorsey (R6), state representatives associated with case histories.

Target Delivery Date: December 2011

Headquarters Approval

Ann Codrington

7/20/11

Ann Codrington, Acting Director
Drinking Water Protection Division
Office of Ground Water and Drinking Water

Date

SPECIFIC GUIDANCE TO WORKGROUP: (space unlimited)

APPENDIX B: DECISION MODEL

INTRODUCTION

A key objective of this project was to develop a practical tool for Underground Injection Control (UIC) regulators to use in the evaluation of potential injection-induced seismicity or to manage and minimize suspected injection-induced seismicity. As a result, a decision model was developed for UIC regulators to consider based on site-specific data from the Class II disposal well area in question. The decision model was designed in consideration of the three key components necessary for inducing seismicity, (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 of Concern. Options for additional actions are included in this model.

The absence of recorded historical seismic events in the vicinity of a proposed Class II injection well does not mean there were not historic low-level seismic events. It is possible that low-level events occurred but were not detected by the historic seismic monitoring network. With the increased deployment of modern and more accurate portable seismic units or seismic arrays, many previously undetected low-level seismic events are now being documented in some areas of the United States. The increased deployment of these seismic instruments further enhances the ability to detect low-level seismic events, whether naturally occurring or induced. Nevertheless, the occurrence of measurable seismicity after the initiation of disposal in areas with little or no historic seismicity supports the possibility of induced seismicity.

Class II disposal activities have existed for decades without inducing significant seismicity. This decision model may not be applicable to areas with historically demonstrated successful disposal activities. Because of complex variations in geology and reservoir characteristics across the country, it is neither practical nor appropriate to provide a detailed step-by-step decision model. Instead, UIC Director discretionary authority will determine the applicability of this decision model to Class II disposal well activities and the need to address site-specific conditions. The model presented in this report summarizes the various considerations and approaches identified by the Injection-Induced Seismicity Working Group (WG) through petroleum engineering methods; geosciences considerations; literature review; analysis of the case studies; consultations with researchers, operators and state regulators; and feedback from subject matter experts. The decision model is included as Figure B-1 at the end of this appendix.

Areas for Review

Throughout the decision model discussion and Figure B-1, the "area" referenced is a geographic area with an extent determined by the Director based on usage, whether as a screening tool or a focused site-specific evaluation tool. The geographic area can also vary based on geologic setting and the available seismic monitoring network. Therefore, defining the term "area" with a specific areal extent was not practical for this report.

Options for a screening seismicity review include looking at the overall seismicity history of a broad area, statewide or by geologic province. A simple method is to use both a statewide historical seismicity map prepared by the U.S. Geological Survey (USGS) or another seismicity reporting service, and the Quaternary Fold and Fault Map created by a USGS consortium. APPENDIX M: Task 1 contains links and a more detailed discussion of these maps. This screening area could then be further subdivided by the level of seismic activity or quiescence.

In seismically active areas, the focused area of interest may center on the disposal well and related geologic structures of interest. For example, a more detailed, localized review may be recommended by the Director to further evaluate the potential for local geologic structures to affect the injection well operations. In determining the size of the focused search area, the Director should consider geology and the density of seismometers, which impacts the accuracy of the recorded seismic events in both the lateral and vertical directions. Generally, because of reduced seismometer spacing, accuracy of hypocenter locations outside of active seismic zones is on average 6 miles (10 km), as discussed in APPENDIX M: Task 1. Vertical accuracy varies significantly depending on seismic processing assumptions and seismometer density, but the error range is typically 10,000 to 16,500 feet (3–5 km). The accuracy of seismic events can be further refined by the deployment of portable units around the disposal well.

Quiescent areas are less likely to be of concern for injection-induced seismicity. For seismically active areas, the Director may decide to continue through the decision model process and address potential induced events through other means such as permit contingencies.

EXISTING VERSUS NEW CLASS II DISPOSAL WELL

EXISTING CLASS II OIL AND GAS WASTE DISPOSAL WELL

Two primary reasons the Director may find the decision model useful for existing wells are (1) increased seismicity or (2) change in operating condition of a well located in areas susceptible to seismic events. On a case-by-case basis, the Director may elect to continue further into the decision model by utilizing site assessment considerations to address potential injection-induced seismicity or to minimize and manage existing induced seismicity. If seismicity concerns arise during operation of the disposal well, the Director may revisit the decision model.

Increased seismicity can be determined by various means, such as media reporting, available seismic databases, or the USGS Earthquake Notification Service, which allows the user to customize notifications by area and magnitude. APPENDIX L: lists available databases. A change in relevant operating or site conditions since the well was last permitted may prompt further review by the Director. Relevant parameters should relate to the key components for inducing seismicity (sufficient pressure buildup, reservoir pathway, and Fault of Concern).

NEW CLASS II OIL AND GAS WASTE DISPOSAL WELL

For new disposal well applications, the Director may consider whether there is a history of successful disposal activity in the area of the proposed well. Successful disposal activity consists of years of historical disposal without seismic activity in the same geographic area and disposal zone. New wells located in such an area would not be of concern. However, a new disposal well located in an area with no previous disposal activity in the proposed zone may require additional analysis. Uncertainties in reservoir characterization may exist in new areas with few or no existing wells, possibly justifying the need for additional site characterization information and analysis. Additionally, the location of the disposal zone relative to basement rock may be a consideration on a site-by-site basis. Again, the Director's knowledge of the area and historic disposal activity may determine the need for further site consideration.

Have Any Concerns Related to Seismicity Been Identified?

If the Director does not identify any injection-induced seismicity concerns, he or she may exit the decision model and continue through the normal UIC regulatory process; otherwise, a continuation through the model for further site assessment considerations may be warranted. For a disposal well suspected of initiating seismic activity, the Director determines the appropriateness of advancing the well further through the decision model. The Director may also determine a level of seismicity relevant for further evaluation.

Site Assessment Considerations for Evaluating Seismicity

Once the Director has identified potential concerns related to injection-induced seismicity, additional site assessment considerations may be justified. With few exceptions, injection-induced seismicity occurs in response to increased pore pressure from injection, transmitted through a pathway, to a fault plane of concern (Nicholson and Wesson, 1992). Therefore, the WG identified site-specific assessment considerations for evaluating significant seismicity. These considerations may not all be applicable and are not listed in any order of importance. The Director determines which considerations may be applicable for an existing or proposed Class II disposal well based on site-specific information. Ultimately, through discretionary authority, the Director may require additional site assessment information or monitoring for the protection of underground sources of drinking water (USDW).

Site assessment considerations focus on identifying whether any of the three key components of injection-induced seismicity are present. The considerations included in the decision model are discussed individually below, along with the positive and negative aspects for each.

What Additional Area Geoscience Information Is Warranted To Assess the Likelihood of Faults and Seismic Events?

With few exceptions, injection-induced earthquakes occur in response to increased pore pressure from injection, transmitted through a pathway to a Fault of Concern. Understanding the area geology through available geoscience information may clarify two of the induced seismicity components: the nature of the pathway transmitting the pore pressure response and the identification of Faults of Concern subject to the pressure response. The lateral continuity and heterogeneity of the disposal zone influence both the pressure buildup from disposal operations and the distribution pathway. The effectiveness of overlying and underlying confining zones may influence the dispersion of pressure in all directions.

Accurate fault assessment, as part of the overall site characterization, is a critical aspect of managing injection-induced seismicity and includes determining the orientation of faults with respect to the geologic stress field. Subsurface faults exist throughout most of the country, and the presence of a fault itself may not be a concern. If a site is in an area with a history of seismic activity, Faults of Concern are likely present in the region. Consideration should be given to the possibility of deep-seated faulting (basement faulting), as reported with the Rocky Mountain Arsenal (Hsieh and Bredehoeft, 1981) and central Arkansas induced events (Ausbrooks, 2011a, 2011b, 2011c, 2011d; Horton and Ausbrooks, 2011).

There are a number of possible options for determining the presence or absence of faulting around a proposed or existing disposal well, including a review of published literature, state geological agency reports, commercial structure maps or interpretations of seismic survey results.[23] While the latter are the most definitive, they are also the most expensive and time-consuming to acquire, and they may require property access that cannot be readily obtained.

Well operators may have exploration seismic survey results that can enhance fault analysis for the site characterization. For example, active faults in central Arkansas and the Dallas-Fort Worth, Texas area were identified first from seismic activity and then verified on the operator's interpreted 3-D seismic surveys, (Chesapeake Energy, personal communication, meeting September 16, 2011). If seismic surveys are available, a re-analysis may help identify any deep-seated faults and associated fractures and their extent. Some faults, however, such as those that are near-vertical strike-slip, may be missed.

Correlations of geophysical logs or review of geologic cross-sections may indicate missing or faulted out rock sections. If a fault is present, information on the origin, displacement and vertical extent of the fault may be a consideration. Geophysical logs may also identify the rock characteristic of the disposal zone and the reservoir pathways the pressure from disposal operations may encounter. If site-specific geoscience information is limited or insufficient and regional studies indicate faults or subsurface stress in the broader area, additional information may be needed to evaluate the likelihood of inducing seismicity.

Geologic site characterization information on flow characteristics, fracture networks and stress fields may be available from: (1) regional and local geologic studies, or (2) information from

[23] Seismic survey lines are typically proprietary, but may be obtained commercially or viewed by special arrangement. If provided, the data may be submitted as confidential business information.

geophysical logs, core analysis and hydraulic fracturing results. Any published articles discussing the basin, reservoir rock or structural history of the area may indicate if faulting, fracturing or directional flow is present. Various publications provide information on determining optimal orientation of faults with respect to the stress field (Holland, 2013; Howe-Justinic et al., 2013).

Has the Static Pressure and Potential Pressure Buildup from Disposal Operations Been Determined?

Reservoir pressure buildup, one of the three key components of induced seismicity, is influenced by reservoir flow behavior, disposal rate and hydraulic characteristics of the disposal zone. To perform conventional reservoir pressure buildup calculations, knowledge of disposal zone hydraulic characteristics is required. Disposal zone hydraulic characteristics include static reservoir pressure, permeability, effective net thickness, porosity, fluid viscosity and system compressibility. Details about these characteristics are generally determined from some combination of fluid level measurements, pressure transient testing results, logging and completion data and fluid and rock property correlations. The static pressure provides a starting point for determining the pressure buildup during disposal activities. Once these values are obtained, the pressure buildup calculations can then be performed to assess the magnitude of pressure increases throughout the disposal reservoir.

Typically, an infinite-acting homogeneous reservoir with radial flow is assumed for the pressure buildup calculation. In many Class II disposal applications, limited reservoir property measurements are available, and actual pressure buildup calculations are done using assumed or accepted area formation characteristic values. Reservoir falloff tests can provide clarity as to whether the homogeneous reservoir behavior assumption is valid or whether pressure buildup projections should be calculated using a different set of fluid flow behavior assumptions. A static bottomhole pressure measurement, typically obtained at the end of a falloff test, may also provide an assessment of reservoir pressure increase around the injection well, offering insight into the magnitude of pressure buildup to which the area fault may have been subjected.

Naturally fractured disposal formations involving induced seismicity may require more complex pressure buildup prediction methods to account for non-radial reservoir behavior. Several cases of suspected injection-induced earthquakes in the literature appear to be characterized by injection zones located within fractured formations (Belayneh et al., 2007; Healy et al., 1968; Horton and Ausbrooks, 2011).

Is the Reservoir Pressure Distribution Pathway Characterized?

The potential pathway or the ability of the reservoir to transmit pressure to a Fault of Concern is best characterized by a combination of geosciences and petroleum engineering information.

Geologic information can help characterize the nature and continuity of the disposal zone. For example, a geologic isopach map or cross-section may define the lateral continuity of the disposal zone and the area potentially impacted by the pressure response from disposal operations. Evaluation of the confining capability of formations overlying and underlying the disposal zone may indicate the potential for pressure dispersal outside the disposal zone. A type log from the disposal well or area offset well may illustrate whether confining layers are present. Other useful aspects for consideration include the number of formations and thickness of permeable strata included within the disposal zone. Heterogeneities in the receiving formations will impact the pathway for pressure distribution away from the disposal well. This level of detailed information, while useful, is not typically required for Class II disposal well operations and therefore may not be available in all situations.

Review of daily drilling reports and open-hole geophysical logs may suggest characteristics of the disposal zone and overlying confining zones, helping to describe the reservoir pathway. For example, borehole washouts or elongated boreholes observed on a caliper log may suggest a high-stress or fractured zone. Heavier mud weights used while drilling may suggest the presence of higher pressure zones. Core data are not typically acquired during the drilling of Class II disposal wells, but if available, could show natural fractures (open or sealed), karstic rock or fault gouging if present. Open-hole geophysical logs, such as fracture finder logs, multi-arm dipmeters, borehole televiewers or variable-density logs may also assist in identifying fractured zones.

Production logging data in an existing well may supplement geologic data by providing additional insight about out-of-interval fluid movement and vertical pressure dispersal. Production logs such as radioactive tracer surveys, temperature logs, noise logs, flowmeters (e.g., spinner surveys) and oxygen activation logs can show where fluid exits the wellbore and allow estimates of fluid volumes being emplaced into the intervals identified. Wellbore fill at the base of a well may reduce the interval thickness, alter the injection profile, and increase the pressure buildup during disposal operations. For example, wellbore fill may cover a large portion of the disposal zone in a well with a short perforated interval; resulting in a greater pressure buildup within the thinner interval receiving fluid. Production logs can also indicate whether fluid is channeling upward or downward behind the casing to other intervals for potential hydraulic impact and show intervals impacted by cumulative long-term injection.

Petroleum engineering approaches, such as a reservoir falloff test, can also provide clues about the pressure transmission pathway by indicating whether the injection zone is exhibiting linear flow (i.e., it may be fractured) or homogeneous radial flow (i.e., the formation is non-fractured) manner. Falloff testing is not a requirement for Class II wells but has been used as a lower cost alternative in some Class II operations to characterize the disposal reservoir flow parameters, reservoir pressure buildup and well completion condition. Falloff testing is associated with the petroleum engineering approach discussed in further detail in APPENDIX D: .

Is Consultation with External Geoscience and Engineering Experts Warranted?

Site assessment considerations may require multidisciplinary evaluations, necessitating consultations with geophysicists, geologists and petroleum engineers. Consulting with seismologists and geophysicists at either state or federal geological surveys can provide additional information and may be necessary under certain site-specific conditions. For example, in the Arkansas case study, UIC regulators coordinated with researchers from the University of Memphis and Arkansas Geological Survey to successfully acquire critical information on ongoing low level seismic activity. Data from this effort formed the basis for a disposal well moratorium in the area of disposal-induced seismicity.

Seismic history for any area in the United States is readily available on the USGS website (see APPENDIX L:) and/or state geological agencies websites at no cost. Where seismometers have recorded sufficient quality and quantity of data, seismologists may be able to refine the actual event location and depth data to identify the fault location and principal stress direction.

Geologists can provide insight on reservoir geologic data and identify the presence of faults or potential for faulting. Reservoir analysis by petroleum engineers may evaluate the completion condition of the disposal well, provide estimates of pressure buildup and characterize pressure distribution away from the disposal well. Other expertise may be available through academia, consultants or other agencies.

What is the Proximity of the Disposal Zone to Basement Rock?

Most of the literature and case examples regarding alleged disposal-induced seismicity suggest that the seismicity is related to faults in basement rocks. Therefore, depth from the disposal zone to the basement rock or the existence of a flow pathway from the disposal zone to the basement rock may be a consideration. A comprehensive study of disposal in basement rock was not part of this study. Cases of successful disposal in basement rock may exist. A lower confining layer between the disposal zone and basement rock may restrict pressure communication with underlying faults, thereby minimizing the conditions for induced seismicity.

Is Other Information Needed?

Based on review of the available site characterization information, the Director may require additional information to respond to unique site-specific circumstances.

ARE THERE ANY SEISMICITY CONCERNS REMAINING AFTER SITE ASSESSMENT?

If the UIC Director does not identify any injection-induced seismicity concerns following a more detailed site assessment, the well evaluation exits the decision model and continues through the normal UIC regulatory process. When an injection-induced seismicity concern is identified, the Director may determine an appropriate approach to address the concern.

APPROACHES TO ADDRESS SITE ASSESSMENT CONSIDERATIONS

The WG identified operational, monitoring and management approaches to address any significant seismicity concerns identified after evaluating site assessment considerations. Some of the approaches could overlap in classification.

Selection of the appropriate approaches depends on a number of factors. Key factors for addressing site assessment concerns, such as knowledge of the area and timing of seismic events relative to disposal activities. Characterizing the flow behavior in the injection zone, quantifying reservoir conditions and delineating fault characteristics are best accomplished using a multidisciplinary team. The Director may elect to set up contingency measures in the event seismicity occurs or increases.

OPERATIONAL APPROACHES

Operational approaches short of shutting in the well may be applicable, though some may involve modification to permit conditions or additional reservoir testing. Some of these approaches are discussed in the following paragraphs.

Reducing injection rates or implementing intermittent injection may decrease reservoir pressure buildup and allow time for pressure dissipation. Determining the reduction in pressure buildup needed to manage or minimize seismicity may require trial and error. The resulting maximum allowable disposal rate or amount of shut-in time needed to remain below a determined reservoir pressure is site-specific. There would be no direct cost to implement, though the reduced disposal volume could impact facility operations and wastewater management.

Confirming site-specific fracture pressure through testing defines a limiting operating pressure value. Operating below the fracture pressure maintains the integrity of the disposal zone and confining layers. Operating a well above fracture pressure could create new pathways by initiating or extending a fracture. Determining the site-specific fracture pressure may require actual testing, such as a step rate test, to measure the actual formation parting pressure in lieu of a calculated fracture gradient. Additional cost would be associated with conducting a step rate test.

Conducting pressure transient tests in disposal wells suspected of causing seismic events may reveal the injection zone characteristics near the well, flow regimes that control the distribution of reservoir pressure, and completion condition of the well. A series of pressure transient tests may provide an indication that the reservoir characteristics and pathway remain consistent throughout the life of the well. Pressure transient testing would require some additional cost to the operator as well as specialized expertise to design and review the data.

Running production logs, such as a flowmeter (spinner survey), radioactive tracer survey or temperature log, to determine where fluids are exiting the wellbore is another useful testing technique for evaluating fluid emplacement. The thickness of the interval receiving fluid can impact the pressure buildup in the reservoir. The location of fluid emplacement could provide insight on the reservoir pathway. Additional costs would be incurred by the operator to run the logs.

Verifying mechanical integrity following a seismic event may include performing tests to evaluate the well and bottomhole cement. Annulus pressure tests can evaluate the integrity of the tubing, packer and production casing. A temperature log, noise log or radioactive tracer survey can confirm the location of fluid emplacement and verify no out-of-zone channeling of fluids.

Petroleum engineering analysis of available operational data (injection rate and pressure) in areas where seismicity has occurred may help characterize the flow behavior, such as enhanced injectivity, in the injection zone. Operational analysis can also quantify reservoir conditions and delineate fault characteristics. Operational analysis uses UIC compliance data so there is no additional cost to acquire data.

Pressure buildup effects in a formation are additive, so separating multiple injection wells by a larger distance may reduce the amount of pressure buildup. Again, the results are site-specific and depend on the quality and size of the disposal zone and number of disposal wells completed in the same formation. Higher costs would likely be associated with drilling multiple wells and transferring wastewater to the additional wells.

MONITORING APPROACHES

Monitoring approaches focus on reservoir pressure and well condition during disposal operations, along with levels of area seismic activity. In many cases, monitoring approaches can be conducted in conjunction with other approaches.

Requiring more frequent operational data collection to assess site-specific situations relevant to induced seismicity may be useful. The increased monitoring frequency adds improved data quality and quantity for use with operational analysis methods. More accurate data may require electronic measuring equipment to record and store data, which may add cost. The frequency of data collection can influence the accuracy of the analysis. For example, in the central Arkansas case study, hourly monitoring of injection pressure and volume yielded more data for analysis than the monthly data typically reported.

Monitoring static reservoir pressure provides an indication of the pressure buildup in the formation over time. Depending on the site-specific conditions, static pressure can likely be obtained using a surface or downhole pressure gauge or fluid level measurement. A static reservoir pressure is easy and inexpensive to obtain; however, it requires the well be shut-in for a period of time prior to the measurement.

Monitoring the specific gravity of the wastewater, especially in commercial disposal wells with variable disposal fluid density, allows conversion of surface pressures to bottomhole at no additional cost. The specific gravity impacts the hydrostatic pressure component of the bottomhole pressure calculation.

Monitoring using a pre-existing seismic network may provide an early warning of seismic activity, if the network is suitably configured and continuously evaluated. The monitoring program could use the existing USGS seismic monitoring network or include seismometers proactively installed prior to the injection operation. Tracking earthquake trends (magnitude and event frequency) for events in an area of possible induced seismicity can reveal possible increases in seismicity even before the events become significant. For example, in the Arkansas, Ohio, and West Virginia case studies, an upward trend in the magnitude of associated events is apparent.

Additional seismometers should result in more accurate determinations of seismic event locations, as well as greater sensitivity, allowing detection of smaller events. The USGS recommends configuring a monitoring network capable of detecting events with magnitudes as low as M2.0. In central Arkansas, additional monitoring stations were deployed. The additional monitoring stations provided increased accuracy and resolution, leading to identification of a previously unknown basement fault. Additional seismic monitoring stations and data analysis require additional costs, as well as geophysical expertise to process and review the data.

Management Approaches

A management approach addresses the human aspect of induced seismicity, including agency, operator and public interaction. As discussed below, these approaches provide proactive practices for managing or minimizing injection-induced seismicity.

Undertaking earlier action rather than requiring substantial proof prior to action by the Director to minimize and manage injection-induced seismicity is a prudent approach for a number of reasons. Early proactive action, such as implementing more stringent operating conditions to decrease pressure buildup, may avoid escalation of event magnitudes and prevent complete shutdown of the well. Early discussions with surrounding operators may allow regulators access to additional data, for example 3-D seismic data, or result in voluntary action. For example, in the north Texas area, communication between the UIC Director and operator resulted in the voluntary shut-in of a suspect disposal well. Early action may also increase public confidence in the regulatory agency.

Contacting external multidisciplinary experts from other agencies or institutions to address site assessment concerns may result in improved quality of response to seismicity concerns. For example, geophysicists may be able to interpret the active fault from the seismic events, along with stress directions, while geologists provide an overall picture of the setting, and engineers evaluate the well responses in conjunction with comments from the others. An initial cooperative effort may have minimal cost.

Providing technical training for UIC regulators specific to petroleum engineering evaluations or geoscience techniques could benefit preparedness of the program and expand options for minimizing and managing seismicity. At a minimum, it would raise awareness of the advantages and disadvantages of the various techniques and disciplines. Some costs may be associated with the training.

Utilizing a multidisciplinary team for practical research of links between disposal well and reservoir behavior, geology and area seismicity allows all complex aspects of seismicity to be reviewed. It may be possible to utilize in-house personnel from other disciplines to aid in the effort.

Establishing a contingency plan, e.g., based on a seismic magnitude and/or frequency threshold, can assure that specific expedited response actions by the injection well operator occur in response to surrounding area seismic events. For example, contingency conditions could be as simple as immediately notifying and working with the permitting agency to evaluate the situation. The use of existing seismic monitoring and reporting databases is inexpensive, but limited data accuracy may require additional expense to supplement the existing network. A contingency plan provides an alternative to approval or denial of a permit.

Developing public outreach programs to explain some of the complexities of injection-induced seismicity may have some value.

CAN AN APPROACH BE USED TO SUCCESSFULLY ADDRESS SEISMICITY CONCERNS?

The site assessment considerations are intended to guide the UIC Director in selecting the appropriate operational, monitoring and management approaches to address induced seismicity issues. If the Director does not identify an acceptable approach to address seismicity concerns, conditions may not be suitable to disposal operations at that location. If monitoring, operational or management approaches provide the required level of protection, the Director may condition the permit accordingly or use discretionary authority to require the desired approaches needed without revoking the permit.

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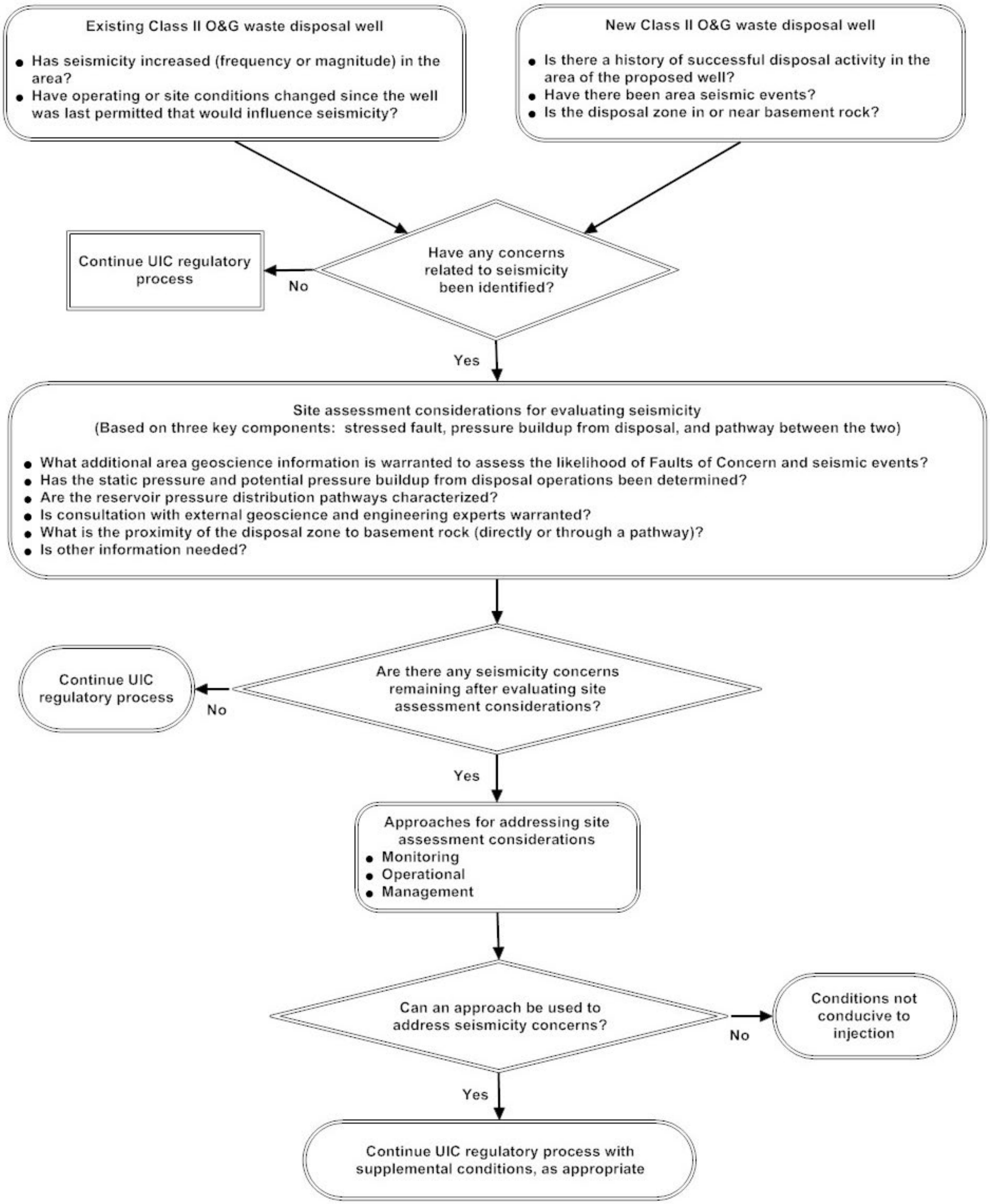
FIGURE B-1: INJECTION-INDUCED SEISMICITY DECISION MODEL FOR UIC DIRECTORS



* Decision model is founded on Director discretionary authority

CASES NO. 20313, 20314, 20472, 20463 and 20465
Index of Division Exhibit No. 3

Exhibit No.	Exhibit Name
3-A	Nicholson, C. and Wesson, R., 1990, Earthquake hazard associated with deep well injection – A report to the U. S. Environmental Protection Agency; United States Geological Survey Bulletin 1951; 74 p.
3-B	Ellsworth, W., *et. al*., 2015, *Increasing seismicity in the U. S. midcontinent: implications for earthquake hazard*; The Leading Edge (Society of Exploration Geophysicists), Special Section: Injection-induced seismicity; p. 618-626.
3-C	Folger, P. and Tiemann, M., 2016, Human-induced earthquakes from deep-well injection: a brief overview; Congressional Research Service Report 7-5700; 29 p.
3-D	Walters, r., Zoback, M., Baker, J., and Beroza, G., 2015, Characterizing and responding to seismic risk associated with earthquakes potentially triggered by saltwater disposal and hydraulic fracturing; submitted to Seismological Research Letters; Stanford University; 19 p.

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 3-A

Earthquake Hazard Associated With Deep Well Injection– A Report to the U.S. Environmental Protection Agency

U.S. GEOLOGICAL SURVEY BULLETIN 1951

Prepared in cooperation with the
Environmental Protection Agency

Earthquake Hazard Associated With Deep Well Injection—A Report to the U.S. Environmental Protection Agency

By CRAIG NICHOLSON and ROBERT L. WESSON

Prepared in cooperation with the
Environmental Protection Agency

Under certain circumstances, the increased pore pressure resulting from fluid injection, whether for waste disposal, secondary recovery, geothermal energy, or solution mining, can trigger earthquakes. This report discusses known cases of injection-induced seismicity and how and why earthquakes may be triggered, as well as conditions under which the triggering is most likely to occur. Criteria are established to assist in regulating well operations so as to minimize the seismic hazard associated with deep well fluid injection

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CIP

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PLATE
[In pocket]

FIGURES

TABLES

EARTHQUAKE MAGNITUDE SCALE APPROXIMATIONS

Local (M_L)	Body-wave (m_b)	Surface-wave (M_S)	Moment (**M**)
4.6	4.55	—	4.6
4.8	4.8	—	4.8
5.0	5.0	4.4	5.0
5.2	5.2	4.7	5.2
5.4	5.4	5.0	5.4
5.6	5.55	5.3	5.6
5.8	5.7	5.6	5.8
6.0	5.85	5.9	6.05
6.2	6.0	6.2	6.30
6.4	6.15	6.4	6.55
6.6	6.3	6.75	6.85
6.8	6.5	7.05	7.15
7.0	6.7	7.35	7.45
7.2	6.9	7.65	7.80
7.4	7.1	7.95	8.15

Earthquake Hazard Associated With Deep Well Injection—A Report to the U.S. Environmental Protection Agency

By Craig Nicholson[1] *and* Robert L. Wesson[2]

SUMMARY

Within the United States, injection of fluid into deep wells has triggered documented earthquakes in Colorado, Texas, New York, New Mexico, Nebraska, and Ohio and possibly in Oklahoma, Louisiana, and Mississippi. Investigations of these cases have led to some understanding of the probable physical mechanism of the triggering and of the criteria for predicting whether future earthquakes will be triggered, based on the local state of stress in the Earth's crust, the injection pressure, and the physical and the hydrological properties of the rocks into which the fluid is being injected.

Of the well-documented cases of earthquakes related to fluid injection, most are associated with water-flooding operations for the purpose of secondary recovery of hydrocarbons. This is because secondary recovery operations often entail large arrays of wells injecting fluids at high pressures into small confined reservoirs that have low permeabilities. In contrast, waste-disposal wells typically inject at lower pressures into large porous aquifers that have high permeabilities. This explains, in large part, why, of the many hazardous and nonhazardous waste-disposal wells in the United States, only two have ever been conclusively shown to be associated with triggering significant adjacent seismicity. These are wells located near Ashtabula, Ohio, and near Denver, Colo. In the case near Ashtabula, a series of small, shallow earthquakes was triggered close to the bottom of a 1.8-kilometer (km)-deep well; the largest of these was of magnitude (M) 3.6 and occurred in 1987. In the Denver case, the injection well responsible was located at the Rocky Mountain Arsenal, where fluid was being injected into relatively impermeable crystalline basement rock. This caused the largest known injection-induced earthquakes to date (three M 5–5.5 earthquakes), the largest of which caused an estimated $0.5 million in damages in 1967. Although these induced earthquakes were by no means devastating, they did occasion extensive attention and concern and led, at least in the Denver case, to the cessation of all related injection well operations.

In each of the well-documented examples, convincing arguments that the earthquakes were induced relied upon three principal characteristics of the earthquake activity. First, there was a very close geographic association between the zone of fluid injection and the locations of the earthquakes in the resulting sequence. Second, calculations based on the measured or the inferred state of stress in the Earth's crust and the measured injection pressure indicated that the theoretical threshold for frictional sliding along favorably oriented preexisting fractures likely was exceeded. And, third, a clear disparity was established between any previous natural seismicity and the subsequent earthquakes, with the induced seismicity often being characterized by large numbers of small earthquakes that persisted for as long as elevated pore pressures in the hypocentral region continued to exist.

Earthquakes are generated by slip on faults or fractures. A fault or fracture in close proximity to a high-pressure injection well thus becomes a potential location for induced earthquakes. The conditions for sliding on a fault are characterized by the Mohr-Coulomb failure criterion, which relates the shear stress required for fault slip to the inherent cohesion or shear strength and the coefficient of friction on the fault, the normal stress resolved across the fault, and the pore fluid pressure. This relation, which depends on the orientation of the faults or the fractures relative to that of the existing state of stress, as well as on the effect of any changes in pore pressure resulting from fluid injection, is normally characterized by using the Mohr circle description. In this simple model, as fluid pressure increases, the apparent strength of the fault decreases, thus shifting the Mohr effective stress circle closer towards the failure condition; as a result, the potential for induced earthquakes also increases.

Because the conditions for failure strongly depend on the state of stress in the Earth's crust, measuring the *in situ* stress conditions is important to assess accurately the potential for inducing earthquakes. Several approaches are possible, but the most reliable method is the hydraulic fracture technique in which the pressure required to create

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small fractures in the wellbore is measured precisely. This method is a variation of the standard hydrofracture technique that is used to increase the transmissivity of a reservoir. Although pressures are monitored during commercial hydrofracture operations, few, if any, of these pressure records would constitute an adequate or precise stress measurement. However, because sufficient measurements of stress are now available across much of the United States, a number of regional stress patterns have begun to emerge, and, thus, it is now possible to predict the general orientation and, to some extent, the magnitude of the principal stresses at a given site. Supplemental measurements would be required, however, to provide accurate information relevant to the determination of maximum allowable levels of injection pressure at each specific site of well operations.

The hydrologic properties of the reservoir also have a strong effect on the potential for inducing earthquakes by deep well injection. Transmissivity and storativity control the rate at which pore pressure will increase in the reservoir formation as a result of fluid injection. For a given volume of fluid flow, higher values of transmissivity and storativity allow lower injection pressures required to attain a desired injection rate and, consequently, a lower potential for triggering earthquake activity. Transmissivity and storativity can be estimated from tests made during well completion and can be verified later by actual pressure-time records acquired during well operation. Estimates of the changes in pore pressure as a result of fluid injection into a particular reservoir formation can be predicted by analysis of the pressure history at the wellbore and by using variations of the standard techniques from reservoir engineering or ground-water hydrology.

Unresolved issues relating to the hazard associated with earthquakes induced by deep well injection include a relatively poor understanding of the causes of natural earthquakes in the Central and the Eastern United States and difficulties in quantifying either the spatial or the temporal variations in tectonic stress or in assessing the potential for fault reactivation in general. There is also considerable uncertainty in estimating the maximum size of expected induced earthquakes or in quantifying the significance of small induced earthquakes (should they begin to occur near the bottom of an injection well) relative to the specific level of risk. An additional environmental concern, about which little is understood, is the potential for induced earthquakes to breach the confining layer of a waste-disposal reservoir, which would then permit the possible upward migration of contaminated fluids. This possibility emphasizes the need to monitor an area once adjacent seismicity is detected, to determine accurately the relative position of the earthquakes to the zone of fluid injection, and to assess the type and the extent of the faulting involved.

On the basis of the present understanding of the phenomena of injection-induced earthquakes, several factors are recommended for consideration in the development of regulations and procedures for controlling deep well injection operations. These recommendations are made from a seismological point of view alone and are not intended to supersede or replace alternative considerations made for other purposes. The recommended considerations include the following:

Site Selection

- Reservoirs that are characterized by high transmissivity and storativity and, therefore, are capable of receiving fluid at low injection pressures are less likely to be the site of induced earthquakes.
- An estimate of the tectonic stress based on regional or surface measurements made before drilling could serve as an early warning of potential earthquake problems and unanticipated low formation fracture or breakdown pressures.
- Because faults within the range of influence of an injection well are the potential loci for induced earthquakes, the absence of significant faults reduces the possibility of triggered seismicity. Geologic and geophysical surveys conducted to detect faults that may intersect the reservoir also would help in evaluating the integrity of the confining layer.
- The existence of regional seismicity in the vicinity of a proposed site should be taken as evidence of sufficient levels of tectonic stress and of the presence of potential slip surfaces (faults) necessary for natural and induced earthquakes.

Well Drilling and Completion

- Estimates of the storativity and the transmissivity of the reservoir based on standard measurements of permeability, porosity, and reservoir thickness made at the time of well completion would provide an important means of predicting the buildup of injection pressure required to maintain a given injection rate.
- If it can be accomplished without threatening the confining zone, then a stress measurement that uses the hydraulic fracture technique in or below the reservoir rock is the key environmental parameter for predicting the potential for induced earthquakes and the possibility of low-formation fracture pressures.
- Careful measurement of the initial formation pore pressure at the time of well completion and before injection provides important information on the proximity to failure conditions in the unaltered natural state.
- If anticipated injection pressures approach the levels expected to trigger earthquakes according to the Mohr-Coulomb failure criterion, assuming regional or generic values for the coefficient of friction and the cohesion of faults, then more precise local measurements of these values would reduce, if possible, the

uncertainty in the specific level of injection pressure at which earthquakes would be expected.

Well Operation and Monitoring

- If reliable measurements of the local stress field are available, then it is possible to estimate the maximum injection pressure that can be used without fear of fracturing the formation or inducing earthquakes by allowing slip on a preexisting fault. These estimates can be made by using the Mohr-Coulomb failure criterion.
- Actual pressure-time curves measured at the wellhead can be compared with predicted curves to assure that the reservoir is behaving as assumed. Any increase in apparent transmissivity should be scrutinized as possible evidence for the opening of fractures or the occurrence of faulting.
- If the maximum injection pressure at a site approaches the critical level anticipated to trigger the occurrence of earthquakes, then it would be prudent to monitor the injection operation by using at least one high-sensitivity seismograph. Monitoring should continue as long as significant levels of elevated fluid pressure are maintained in the reservoir.
- The occurrence of any earthquakes near the bottom of an injection well should be reviewed carefully to assess the possibility that potentially damaging earthquakes might be induced and the potential for fracturing or faulting through the containment zone. Installation of additional seismic monitoring stations would then be recommended to locate and analyze any subsequent earthquake activity.

INTRODUCTION

The injection of waste into deep isolated aquifers is being increasingly utilized for the disposal of certain types of hazardous fluid materials (Environmental Protection Agency, 1974, 1985). Other deep well injection operations are carried out routinely for the disposal of nonhazardous waste (for example, excess oil field brine), solution mining, purposes of geothermal energy extraction, the secondary recovery of hydrocarbons, and the underground storage of natural gas intended for later redistribution during peak winter months. Of these different types of well operations, secondary recovery is by far the most common use of deep well fluid injection (Mankin and Moffet, 1987). Although most deep well injection operations have no impact on earthquake activity, it has been shown conclusively that, under some conditions, the increase of fluid pressure in the reservoir associated with deep well injection can trigger or induce earthquakes. The first and best known instance, as well as the largest, of these induced earthquakes occurred during the mid-1960's in association with the waste injection well at the Rocky Mountain Arsenal near Denver, Colo. Since this discovery, additional examples of earthquakes induced by deep well injection have been documented (pl. 1; table 1). It is conceivable, if not likely, that other examples of such induced earthquakes may have gone unnoticed because they were small and no seismograph stations were nearby to record them.

Investigations of several of the earthquakes associated with deep well injection have led to some understanding of the probable physical mechanism for the triggering and of the criteria for predicting whether earthquakes will be triggered that depend on the local state of stress in the Earth's crust, the injection pressure, and the physical and the hydrologic properties of the rocks into which the fluid is being injected. The purpose of this report is to summarize the current state of understanding of this phenomenon, to describe the criteria for predicting whether earthquakes will be triggered by fluid injection, and to indicate from a seismological point of view factors to be considered in developing regulations and operating procedures to minimize the seismic hazard associated with deep well injection.

Although several research issues remain unresolved, considerable information is currently available that may be of use in the development of operating procedures for deep injection wells that will minimize the possibility of problems associated with induced earthquakes. Fortunately, favorable conditions for the siting of a deep injection well, namely the desirability of high permeability and porosity in the injection zone and a site situated away from known fault structures also tend to be conditions for which the occurrence of induced earthquakes is less likely. Thus, implementation of these recommendations probably would have minimal adverse impact on site selection or operational procedures for injection wells located at otherwise favorable sites.

This report also includes four appendixes. Appendix A contains case histories of earthquakes associated with well operations. Appendix B is a brief summary of reservoir-induced seismicity. Appendix C describes the components of the Modified Mercalli Intensity Scale. Appendix D is a glossary.

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Table 1. Acknowledged cases of seismicity associated with well operations

Well site or oil field location	Type	Depth (m)	Injection pressure (bars)	Maximum earthquake magnitude	Year injection began-ended	Year of earthquakes
Ashtabula, Ohio	Waste disposal	1,845	100	3.6	1986–	1987
Cogdell Canyon Reef, Tex.	Secondary recovery	2,071	199	4.6	1956–	1974–79
Dale, N.Y.	Solution mining	426	55	1.0	1971	1971
Rocky Mountain Arsenal, Denver, Colo.	Waste disposal	3,671	76	5.5	1962–66	1962–67
Fenton Hill, N. Mex.	Geothermal/stimulation	2,700	200	<1.0	1979	1979
Flashing Field, Tex.	Gas withdrawal	3,400	?	3.4	1958–	1973?–83
The Geysers, Calif.	Geothermal	3,000	?	4.0	1966–	1975–
Gobles Field, Ontario, Canada	Secondary recovery	884	?	2.8	1969–	1979–84
Imogene Field, Tex.	Gas withdrawal	2,400	?	3.9	1944–	1973?–83
Love County, Okla.	Secondary recovery/stimulation	3,622	277	2.8?	1965–, 1979–	1977–79
Matsushiro, Japan	Research	1,800	50	2.8	1970	1970
Northern Panhandle, Tex.	Secondary recovery	2,022	21	3.4	1979–	1983–84
Calhio, Perry, Ohio	Waste disposal	1,810	114	2.7?	1975–	1983–87
Rangely, Colo.	Secondary recovery/research	1,900	83	3.1	1958–	1962–75
Rocky Mountain House, Alberta, Canada.	Gas withdrawal	4,000	?	4.0	1970–	1974–
Sleepy Hollow, Neb.	Secondary recovery	1,150	56	2.9	1966–	1977–84
Snipe Lake, Alberta, Canada	.....do.	?	?	5.1	1963–	1970
Cold Lake, Alberta, Canada	Secondary recovery/waste disposal	?	?	~2.0	?	1984–
Permian basin fields:				4.4		1964–
Dollarhide, Tex.-N. Mex.	Secondary recovery	2,590	138	~3.5	1959–	1964–
Dora Roberts, Tex.	....do.	3,661	431	~3.0	1961–	1964–
Kermit Field, Tex.	....do.	1,829	221	~4.0	1964–	1964–
Keystone I Field, Tex.	....do.	975	103	~3.5	1957–	1964–
Keystone II Field, Tex.	....do.	2,987	176	~3.5	1962–	1964–
Monahans, Tex.	....do.	2,530	207	~3.0	1965–	1964–
Ward-Estes Field, Tex.	....do.	914	117	~3.5	1961–	1964–
Ward-South Field, Tex.	....do.	741	138	~3.0	1960–	1964–
War-Wink South, Tex.	Gas withdrawal	1,853	?	~3.0	1969–	1964–

formed the calculations and provided the originals for figures 12–15. We thank Pradeep Talwani (University of South Carolina), Mary Lou Zoback (USGS), and John Armbruster (Lamont-Doherty Geological Observatory) for copies of their papers, figures, and data in advance of publication and Carl Stover (USGS) for a timely copy of his latest map on U.S. seismicity. James Zollweg (USGS) and James Lawson, Jr. (Oklahoma Geophysical Observatory), provided personal insights into some of the more obscure potentially induced earthquake activity along the Gulf Coast and in Oklahoma, respectively, and Jock Campbell (Oklahoma Geological Survey) and Timothy Baker and Robert McCoy (Oklahoma Corporation Commission) provided additional information on oil and gas activities in their State. For information regarding recent activity in Ohio, we would especially like to thank individuals at the Lamont-Doherty Geological Observatory, the Ohio EPA, the Ohio Geological Survey, Weston Geophysical, and Woodward-Clyde Consultants. We appreciate reviews and comments on the manuscript from John Bredehoeft, Robert Hamilton, William Leith, Evelyn Roeloffs, and Keith Evans.

OVERVIEW OF EARTHQUAKES INDUCED BY DEEP WELL INJECTION

Well-documented examples of seismic activity induced by fluid injection include earthquakes triggered by waste injection near Denver (Healy and others, 1968; Hsieh and Bredehoeft, 1981); secondary recovery of oil in Colorado (Raleigh and others, 1972), southern Nebraska (Rothe and Lui, 1983), West Texas (Davis, 1985), and western Alberta (Milne, 1970) and southwestern Ontario, Canada (Mereu and others, 1986); solution mining for salt in western New York (Fletcher and Sykes, 1977); and fluid stimulation to enhance geothermal energy extraction in New Mexico (Pearson, 1981). In two specific cases—near Rangely, Colo. (Raleigh and others, 1976), and in Matsushiro, Japan (Ohtake, 1974)—experiments to control directly the behavior of large numbers of small earthquakes by manipulation of fluid injection pressure were conducted successfully. Table 1 gives a brief listing of each of the cases in which seismicity was clearly associated with fluid injection or other types of adjacent well activities. A more complete summary is provided in Appendix A.

Other cases of induced seismicity, which were the result of either fluid injection or reservoir impoundment, were reviewed and discussed by Simpson (1986a). Unlike fluid injection, however, induced seismicity associated with dams and reservoirs also is affected by the actual physical weight of the water impounded. By contributing to the local stress regime, this effect of the water load can change the local hydrologic properties of the reservoir rock and thus magnify the resulting changes in pore fluid pressure associated with elevating the local water table (Roeloffs, 1988). A brief discussion of the phenomenon of reservoir-induced seismicity is presented in Appendix B.

Although it is true that earthquakes can be triggered without fluid injection (for example, see the sections on the Wilmington and the Flashing oil fields in Appendix A), most of the earthquakes induced by well activities are associated with water-flooding operations to enhance the secondary recovery of hydrocarbons (table 1). This is not surprising because the conditions for failure are much more favorable in injection operations of this type. Fluid injection for the purpose of secondary recovery typically involves injection at high fluid pressures into confined reservoirs of limited extent and low permeability. Often, the producing field is a structural trap, perhaps defined by fault-controlled boundaries. However, in waste-disposal operations, it is preferable to inject into large porous aquifers having high permeabilities that are away from known fault structures. Furthermore, waste-disposal operations typically involve only one to a few wells at any one location, whereas secondary recovery techniques often involve large arrays that comprise tens of wells over the entire extent of the producing field. These differences between the two types of injection operations make well activities for the purpose of secondary recovery much more conducive to triggering adjacent seismicity.

In each of the well-documented examples of earthquakes triggered by deep well injection, convincing arguments that the earthquakes were induced relied upon three principal characteristics of the earthquake activity. First, there was a very close geographic association between the zone of fluid injection and the locations of the earthquakes in the resulting sequence. Second, calculations based on the measured or the inferred state of stress in the Earth's crust and the measured injection pressure indicated that the theoretical threshold for frictional sliding along favorably oriented preexisting fractures, as indicated by the Mohr-Coulomb failure criterion, was likely exceeded. And, third, a clear disparity was established between any previous natural seismicity and the subsequent earthquakes, the induced seismicity often being characterized by large numbers of small earthquakes occurring within a relatively short time interval.

Many of the sites where earthquakes have occurred operate at injection pressures well above 100 bars ambient (table 1). The exceptions tend to be sites characterized by a close proximity to recognized surface or subsurface faults. In the Rangely and the Sleepy Hollow, Nebr., oil field cases, faults are located within the pressurized reservoir and were identified on the basis of subsurface structure contours. The Attica-Dale, N.Y., and the Matsushiro cases occurred close to prominent fault zones exposed at the surface (the Clarendon-Linden and the Matsushiro fault systems, respectively). In the most prominent case of induced seismicity as the result of waste-disposal operations, the Rocky Mountain Arsenal well near Denver, fluid was inadvertently injected directly into a major subsurface fault structure, which was identified later on the basis of the subsequent induced seismicity (Healy and others, 1968) and the properties of the reservoir into which fluid was being injected, as reflected in the pressure-time record (Hsieh and Bredehoeft, 1981).

The Rocky Mountain Arsenal case is considered to be the classic example of earthquakes induced by deep well injection. Before this episode, the seismic hazard associated with deep well injection had not been appreciated fully. At the Rocky Mountain Arsenal, injection into the 3,700-meter (m)-deep disposal well began in 1962 and was quickly followed by a series of small earthquakes, many of which were felt in the greater Denver area (fig. 1*A*). It was not until 1966, however, that a correlation was noticed between the frequency of earthquakes and the volume of fluid injected (fig. 2). Pumping ceased in late 1966 specifically because of the possible hazard associated with the induced earthquakes; afterward, earthquakes near the bottom of the well stopped. Over the next 2 years (yr), however, earthquakes continued to occur up to 6 km away from the well as the anomalous pressure front, which had been established around the well during injection, continued to migrate outward from the injection point. The largest earthquakes in the sequence (M 5.0–5.5) occurred in 1967 (fig. 1*B*), long after injection had stopped and well away from the point of fluid injection itself.

These results imply that the fluid pressure effects from injection operations can extend well beyond the expected range of actual fluid migration. Indications have shown, however, that the risk posed by triggered earthquakes can be mitigated by careful control of the activity responsible for the induced seismicity. As shown by a number of the cases detailed in Appendix A, seismicity eventually can be stopped either by ceasing the injection or by lowering pumping pressures. The occurrence of the largest earthquakes involved in the Rocky Mountain Arsenal case a year after pumping had ceased, however, indicates that the process, once started, may not be controlled completely or easily.

CONDITIONS FOR EARTHQUAKE GENERATION

The case histories of injection-induced seismicity documented in Appendix A demonstrate that, in sufficiently

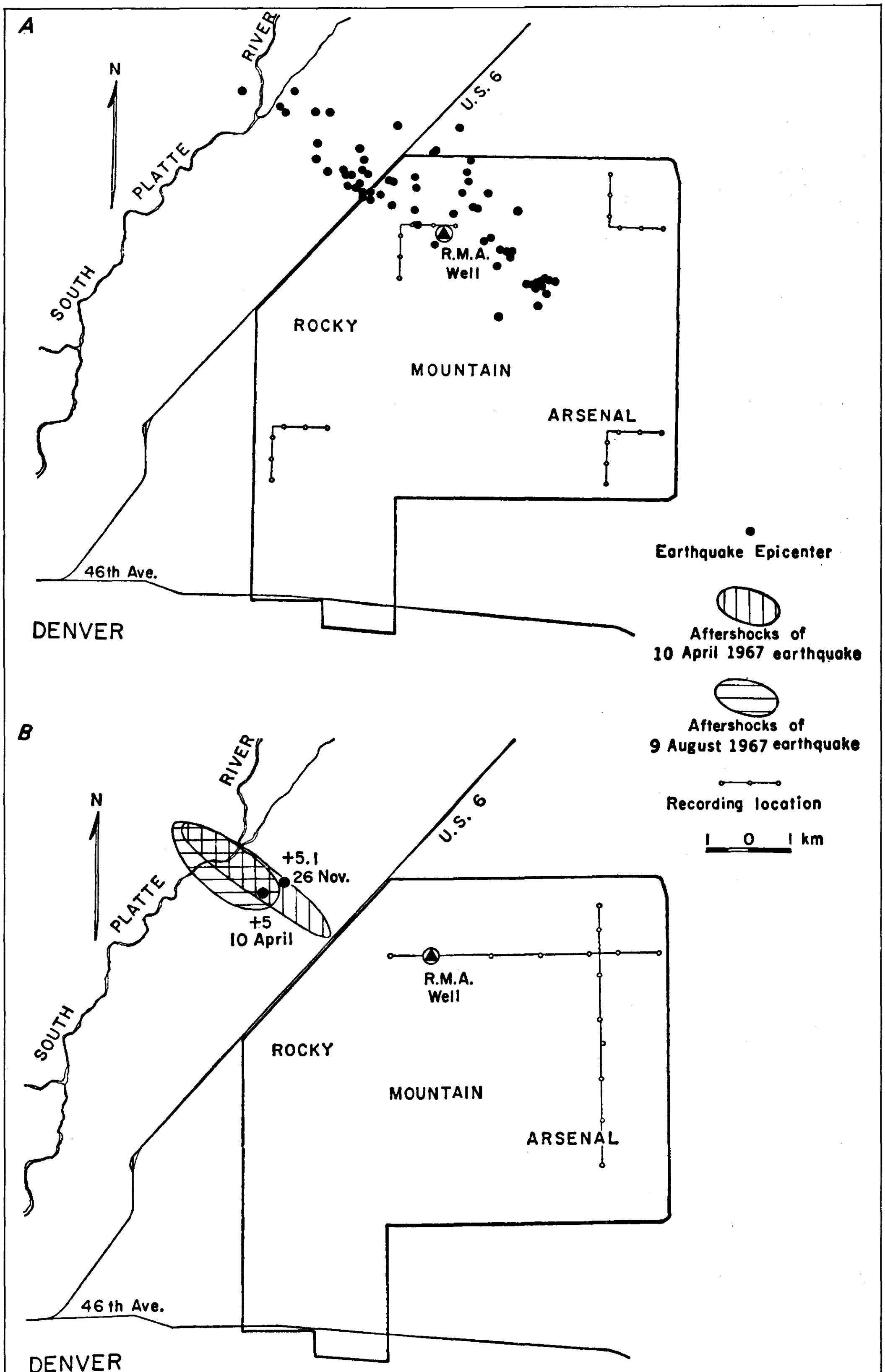


Figure 1. Earthquake activity near the Rocky Mountain Arsenal waste-disposal well, Colorado. *A*, Epicentral distribution of earthquakes during January and February 1966. *B*, Aftershock distributions of the large 1967 earthquakes. Reprinted from Healy and others (1968) and published with permission.

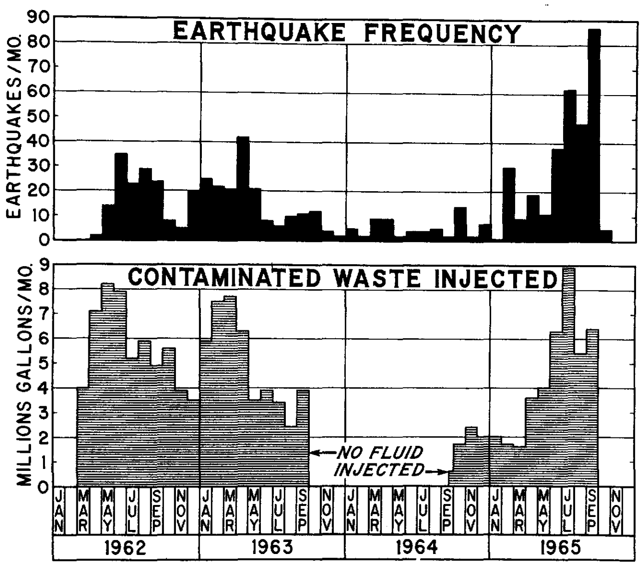


Figure 2. Correlation between earthquake frequency (top) and volume of contaminated waste injected (bottom) at the Rocky Mountain Arsenal well, Colorado. Reprinted from Healy and others (1968) and published with permission.

prestressed regions, elevating formation fluid pressure by several tens of bars can cause a previously quiescent area to become seismically active. However, not all high-pressure injection wells trigger earthquakes. The reasons why depend on the characteristics of the earthquake faulting process, the local hydrologic and geologic properties of the zone of injection, the *in situ* stress field, and the specific conditions for earthquake triggering, many of which have not been understood or appreciated until recently. A fundamental distinction must be recognized, however, between factors that *cause* earthquakes versus mechanisms that may *trigger* earthquakes. Earthquakes result from the sudden release of stored elastic strain energy by frictional sliding along preexisting faults. The underlying causes of earthquakes are, therefore, the forces that are responsible for the accumulation of elastic strain energy in the rock and that raise the existing state of stress to near critical levels. Consequently, the hazard associated with fluid injection is not that it can generate sufficient strain energy for release in earthquakes, but that it may act locally to reduce the effective frictional strength of faults and, thereby, to trigger earthquakes in areas where the state of stress and the accumulated elastic strain energy are already near critical levels as a result of natural geologic and tectonic processes.

Mohr-Coulomb Failure Criterion

Because the shear strength of intact rock is considerably greater than the frictional strength between rock surfaces, slip during an earthquake typically occurs along preexisting faults and will occur when the shear stress (τ) resolved across the fault exceeds the inherent shear strength (τ_0) and the frictional stress on the plane of slip. Quantitatively, this condition is termed the Mohr-Coulomb failure criterion and is expressed by the following linear relation:

$$\tau_{crit} = \tau_0 + \mu\sigma_n,$$

where τ_{crit} is the critical shear stress required to cause slip on a fault, μ is the coefficient of friction, and σ_n is the normal stress acting across the fault (Jaeger and Cook, 1979). For weak fault zones that have little cohesion, τ_0 is nearly zero, and slip will occur when τ is greater than or equal to an amount that is simply the product of μ and the stress normal to the plane of slip; that is, the frictional strength of the fault:

$$\tau_{crit} = \mu\sigma_n.$$

Figure 3 shows values of maximum shear stress (τ) as a function of effective normal stress (σ_n) for a variety of rock types (Byerlee, 1978). For most rock types, the data indicate that μ ranges between 0.6 and 1.0.

When fluid is present in the rocks, the effective σ_n is reduced by an amount equal to the pore pressure, and the shear stress (τ) required to cause sliding is reduced to the following:

$$\tau_{crit} = \mu\,(\sigma_n - p).$$

This reduction in the effective strength of crustal faults is the essential mechanism of induced seismicity; that is, for a constant state of tectonic stress, the effective strength of crustal faults can be reduced below the critical threshold by increasing the fluid pressure contained within the rocks, which leads to a sudden slip and the occurrence of an earthquake.

Description of the State of Stress By Using the Mohr Circle

A simple graphical method for describing the state of stress and how it is altered by the introduction of fluids under pressure is given by the Mohr circle diagram (fig. 4, right; Jaeger and Cook, 1979; Simpson, 1986a). The stresses acting on a given fault plane can be specified with respect to an orthogonal coordinate system and are referred to as the principal stress axes along which stresses are purely compressional. The stress components relative to these principal axes are called the principal stresses and are usually designated σ_1 (maximum), σ_2 (intermediate), and σ_3 (minimum). Shear (τ) and normal (σ_n) stresses along and across fractures of various orientations are linear combinations of the maximum and the minimum compressive stresses (σ_1 and σ_3, respectively) and are defined by the

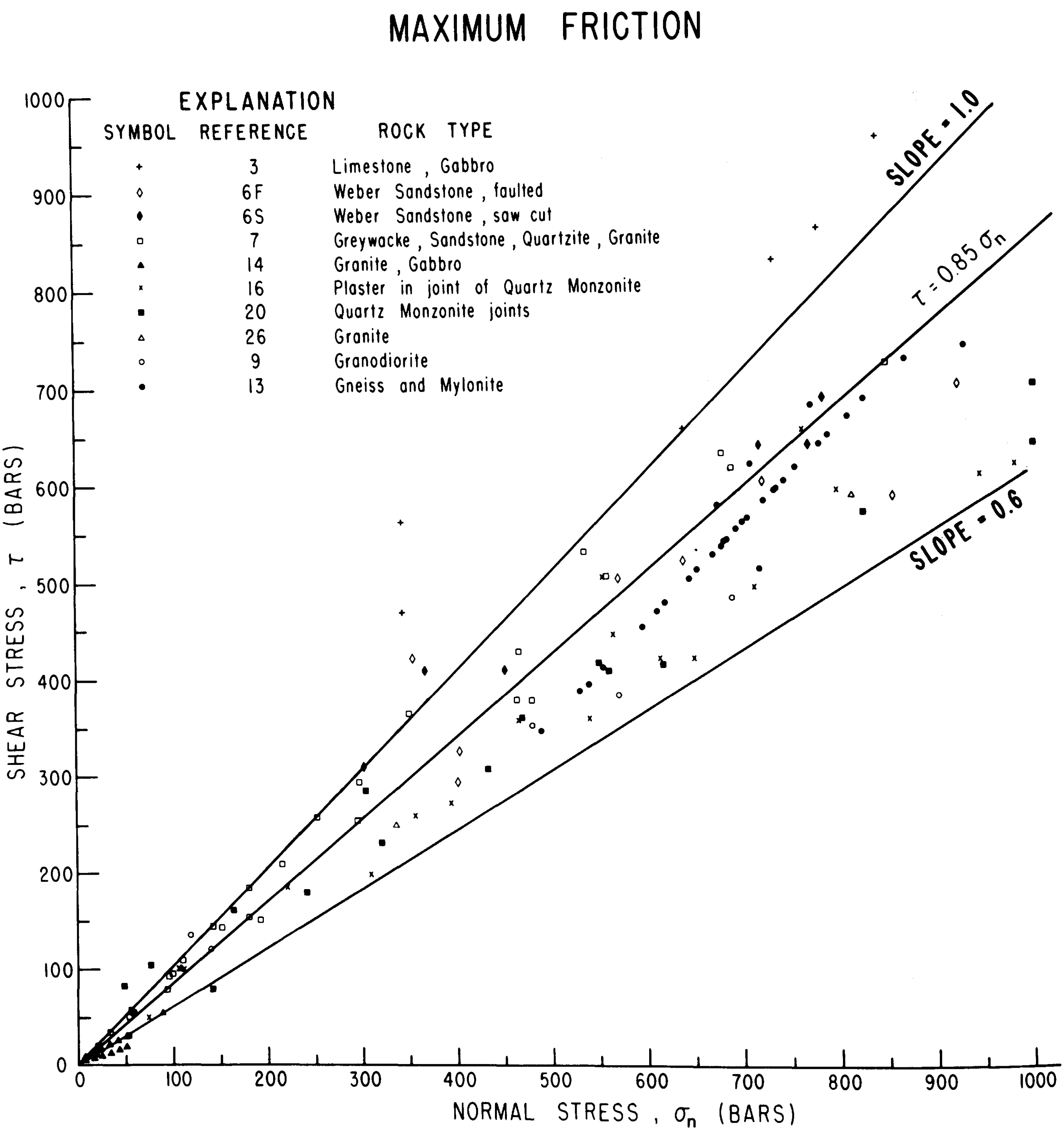


Figure 3. Maximum shear stress as a function of effective normal stress for a variety of rock types. The data suggest that the coefficient of friction ranges between 0.6 and 1.0. τ, shear stress; σ_n, normal stress; and μ, coefficient of friction. Reprinted from Zoback and Healy (1984) and published with permission.

locus of points around the Mohr circle, whose center is the average between σ_1 and σ_3 (fig. 4*B*, right). Thus, for a specific fault plane oriented at angle α with respect to the σ_3 direction (fig. 4*B*, left), τ and σ_n acting along and across that plane will be determined by a specific point on the Mohr circle (identified by angle 2α drawn from the middle, fig. 4*B*, right). Larger stress differences between the maximum and the minimum principal stresses (that is, the deviatoric stress) result in larger Mohr circles and, thus, larger available shear stresses for causing slip along favorably oriented fractures.

The Coulomb failure criterion is represented by a line that has a slope equal to μ and an intercept equal to τ_0 (fig. 4*A*). Relative effective values of σ_1 and σ_3 necessary for

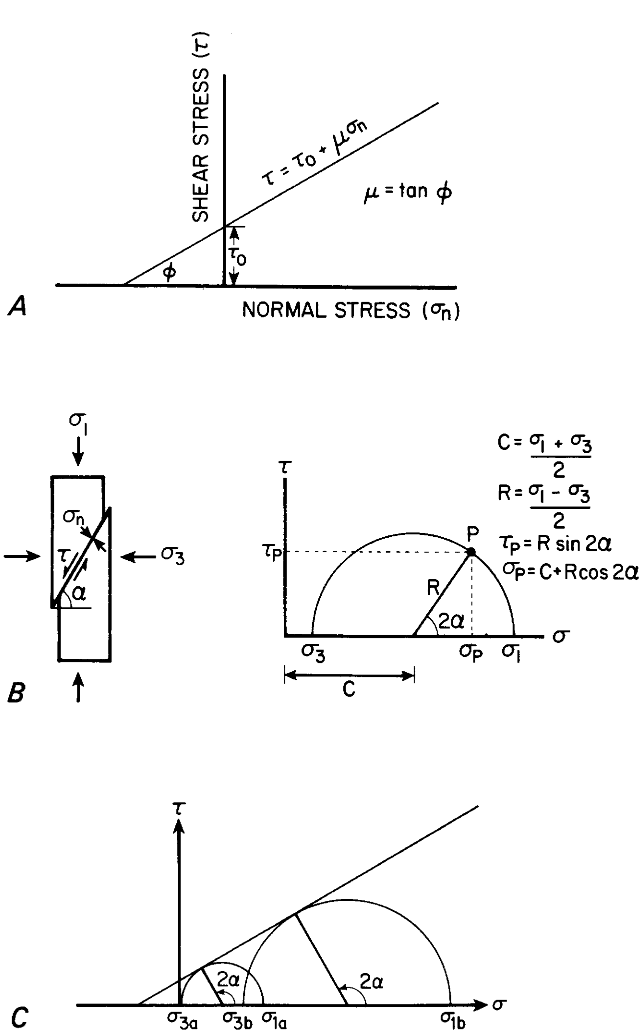


Figure 4. Relations between effective stresses and conditions for failure (slip) on a preexisting fault. *A*, Coulomb's law for failure in dry rock showing the relation between the shear stress (τ) required for failure and the normal stress (σ_n) acting across the plane of slip. Here τ_0 is the cohesion, μ is the coefficient of friction, and ϕ is the angle of internal friction. *B*, The Mohr circle diagram (right), which provides a graphical method by which the maximum (σ_1) and the minimum (σ_3) principal (compressive) stresses can be resolved into shear (τ) and normal (σ_n) components on a plane at angle α to the σ_3 direction (left). The resolved shear (τ_p) and the normal stress (σ_p) define a point (P) given by the radius (R) and center (C) of the Mohr circle. *C*, The Mohr-Coulomb failure criterion. Given any particular state of stress, failure will occur on a plane containing the intermediate stress (σ_2) and oriented at an angle α to σ_3 if the Mohr circle containing points σ_1 and σ_3 intersects the Columb failure curve defined in *A*. Reprinted from Simpson (1986a) and published with permission.

failure thus define circles tangent to this failure envelope (fig. 4*C*). In other words, fault planes whose orientations with respect to a given stress field (σ_1 and σ_3) define values along the Mohr circle that intersect the failure envelope for a given τ_0 and μ will be most likely (most favorably oriented) to slip (fig. 4*C*).

Figure 5 shows how an initial stress state (right Mohr circle) determined at the bottom of a well near Perry, Ohio, is modified by changes in pore pressure (Appendix A). As discussed in the previous section, in the presence of a fluid, compressive stresses are opposed by the hydrostatic fluid pressure. This reduces the effective stress levels by an amount equal to the formation pore pressure and moves the Mohr circle to the left (fig. 5, middle circle). In this example, the state of stress under hydrostatic conditions is close to but does not exceed the failure criterion for a fracture that has no cohesion. Increasing the pore pressure by an amount equal to a nominal injection pressure of 110 bars moves the Mohr circle even farther towards the failure envelope (fig. 5, left circle) and, in fact, for the example shown, indicates that a critical stress level is reached for fractures having τ_0 of as much as 40 bars and μ of 0.6. Fractures that have less cohesion or lower coefficients of friction also would be susceptible to failure.

Conditions for Induced Seismicity

By using the Mohr-Coulomb failure criterion, it is now possible to specify the conditions under which seismicity is most likely to be triggered by fluid injection. First, the existing regional stress field needs to be characterized by high deviatoric stress; that is, the difference between σ_1 and σ_3 is large, which results in large Mohr circles (compare circles in fig. 4*C*). This does not require that the state of stress itself be large, only that large stress differences exist for different fault orientations. In fact, many area identified as close to incipient failure are characterized by relatively low states of stress (σ_{1a} and σ_{3a} in fig. 4*C*). This

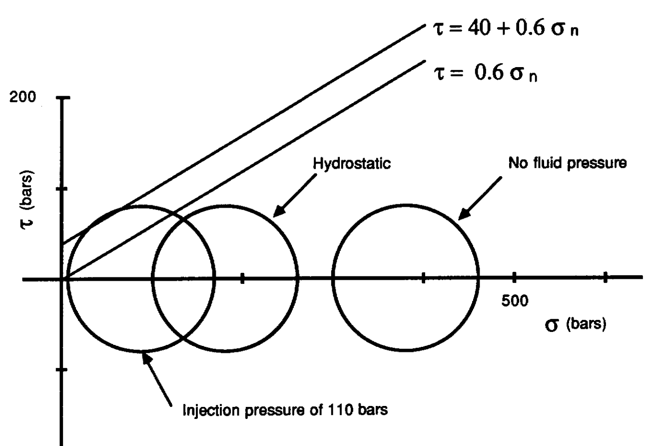


Figure 5. Estimates of shear stress and principal stresses in relation to possible Coulomb failure curves at a nominal depth of 1.8 km near the bottom of an injection well near Perry, Ohio (table 1). τ, shear stress; σ, principal stress; and σ_n, normal stress.

is because low stress states may correspond with low normal stresses acting across potential slip surfaces. Low normal stress implies low frictional strength; thus, faults are weak and easily induced to slip. In the Rocky Mountain Arsenal case, the induced earthquakes occurred in a region of normal faulting that is characterized by a relatively low state of stress and, as a consequence, by a relatively low effective normal stress (but a high shear stress) acting across the fault that slipped (Zoback and Healy, 1984).

Second, preexisting favorably oriented faults or fractures must be available for slip. In general, the shallow part of the Earth's crust is characterized by numerous fractures of different sizes and orientations. However, many of these fractures are small and are capable of generating only small earthquakes of little consequence, and many may not have the proper orientation relative to the existing regional tectonic stress field such that the conditions for failure are met. Thus, for fluid injection to trigger substantial numbers of significant earthquakes, a fault or faults of substantial size must be present that are properly oriented relative to the existing state of stress, characterized by relatively low effective shear strength, and sufficiently close in proximity to well operations to experience a net pore pressure increase. As discussed in in the section "Hydraulic Factors in Earthquake Triggering," the effects of fluid injection dissipate rather quickly as distance from the well increases. This implies that, for typical values of hydrologic properties commonly associated with aquifers of large spatial extent targeted as reservoirs for waste disposal by fluid injection, the pore pressure effect beyond about 10 km is minimal.

Third, injection pressures at which well operations are conducted are relatively high; for example, the Cogdell Canyon Reef oil field in West Texas (table 1), where the largest earthquake known to be associated with secondary recovery operations in the United States was triggered (Davis, 1985), operates at fluid injection pressures of nearly 200 bars above ambient. Other extensive well operations that are in the same tectonic province and, in fact, operate within the same pay zone (the Canyon Reef Formation) are not inducing adjacent seismicity, but these wells typically operate at injection pressures of 100 bars or less. Similarly, the Calhio waste-disposal wells in northeastern Ohio (table 1) may have triggered several small earthquakes in close proximity (<5 km) to the injection site (Nicholson and others, 1988), yet a number of other injection wells that utilize the same basal sandstone layer (the Mount Simon Formation) for the disposal of hazardous and nonhazardous wastes have not done the same. These other wells, however, typically operate at about half the pressure utilized by Calhio. Interestingly, a waste-disposal well located near Ashtabula, Ohio, that became operational in July 1986 and that utilized the same reservoir formation and similar injection pressures to those used by the Calhio wells (Appendix A) triggered a M 3.6 earthquake and a large number of aftershocks in July 1987 (Armbruster and others, 1987).

The hydrologic properties of a reservoir are responsible for how rapidly fluid is accepted and, thus, control the injection pressure required to maintain a constant fluid injection rate (volume of fluid flow into the well). These properties also control how rapidly the pore pressure increase in the reservoir dissipates with distance from the point of fluid injection. Aquifers of large spatial extent, which require low injection pressures for high injection rates, also dissipate the pressure effect most rapidly. This insures that, unless fluid is injected directly into a fault zone (as in the Rocky Mountain Arsenal case), the net pore pressure change from fluid injection will not extend for any appreciable distance from the well. Thus, the distance between a favorably oriented fault or fracture capable of slip and an operating injection well also will become a critical factor in determining the potential for induced seismicity.

Assessing the proximity of favorably oriented preexisting fractures to a potential waste-disposal site in the Central and the Eastern United States is difficult because many of the fault structures responsible for earthquakes in the past and, presumably, the most likely ones responsible for earthquakes in the future are not easily identified. Unlike large historical earthquakes in the Western United States, those that have occurred in the East have yet to produce any primary surface manifestation. This makes identification of active faults or potentially active faults difficult. Reducing the risk of siting an injection well near a major fault may require extensive subsurface geologic mapping to assess the proximity of potential fault structures. Substantial progress has been made, however, in the ability to assess the local state of stress and, thus, to ascertain the degree to which any potential faults or fractures in the vicinity of the well may be close to failure (Evans, 1988).

STATE OF STRESS IN THE EARTH'S CRUST IN THE UNITED STATES

Estimating the state of stress throughout the continental United States has become a very active area of research over the past several years. Its determination is extremely important to a further understanding of regional patterns of crustal deformation and to any accurate assessment of the local seismic hazard. The amount of energy available to be released in an earthquake is determined by the amount of elastic strain energy stored in the rocks of the Earth's crust. The amount of strain energy available for release depends, in turn, on the state of stress. It is the state of stress that determines how close to failure a preexisting fault may be and, as shown in the section "Hydraulic Factors in Earthquake Triggering," how much fluid pressure is required to trigger fault slip or to hydrofracture intact rock. Because of its importance, the variation in time and space of the magnitude and the direction of the stress field has become the subject of recent intense study. In many cases, the techniques developed to determine the state of stress actually measure secondary effects, such as strain. The greatest difficulty, however, is measuring the necessary parameters at depths where earthquakes actually occur; otherwise, questionable extrapolations must be used from measurements made at shallow depths. In the case of earthquakes induced by fluid injection, the seismicity is likely to be shallow and in close proximity to the well itself. Thus, the advantage in assessing the potential for an existing well to trigger earthquakes is that its presence provides reasonable access to the hypocentral regions where any potential induced events are most likely to occur.

Determining Magnitudes and Orientations of the Local State of Stress

Measurements of the state of stress can be accomplished through a variety of techniques. In general, it is somewhat easier to determine the orientation of the principal stresses than it is to determine their magnitude. Nevertheless, orientations alone are important because the current stress regime may be substantially different from that which existed when major faults in the area were originally produced. This is especially true in the Eastern United States, where most faults are old, seismicity is relatively low, and the identification of active fault structures is more difficult. The orientation of the principal stresses determined from actual *in situ* measurements (fig. 6) can thus aid in identifying those faults that have orientations conducive to slip in the existing tectonic stress field. Orientations and, to some extent, relative magnitudes of the principal stresses can be determined from earthquake focal mechanisms (Michael, 1987), borehole elongations (Gough and Bell, 1981; Plumb and Hickman, 1985), core-induced drilling fractures (Evans, 1979; Plumb and Cox, 1987), and, in some cases, the orientation of young geologic features, such as dikes, volcanic vent alignments, or recent fault offsets (Zoback and Zoback, 1989). Reliable determination of the absolute magnitude of the principal stresses typically requires measurements made by using the hydraulic fracture technique.

Stress Orientation Indicators

Earthquake Focal Mechanism Solutions

Earthquake focal mechanisms are some of the most commonly utilized indicators of principal stress directions (Michael, 1987). Focal mechanism solutions define two alternative planes of slip, as well as two stress axes—one of compression and one of tension (see fig. A1). A discussion of the possible orientations that these particular stress axes may have relative to the principal stress directions is given by McKenzie (1969).

The principal contribution of focal mechanism solutions is that they readily identify the specific type of faulting and the orientation of actual planes of slip (faults) in the local area. By inference, the relative magnitude of the state of stress can then be derived, if one of the three principal stresses (σ_1, σ_2, or σ_3) is assumed to correspond with the vertical stress (S_v) induced by the weight of the overburden. Thus, in areas dominated by normal faulting, S_v corresponds with σ_1, implying that the magnitude of the other two orthogonal stresses (S_H and S_v, which correspond to the maximum and the minimum horizontal compressive streses, respectively) are less than the overburden pressure. In regions of strike-slip faulting, S_v is intermediate, and, in regions of thrust faulting, S_v is less than either S_H or S_h (Anderson, 1951). If the orientation of the principal stresses is known from other data in the same stress province, then focal mechanisms can be used to predict the orientation of available planes of slip and the degree to which such planes are close to the plane of maximum shear.

Wellbore Breakouts

Wellbore breakouts, also known as borehole elongations, are a phenomenon of wellbore deformation induced by inhomogeneous stresses in the crust (fig. 6*C*). When a well is drilled into a medium, the presence of the cavity creates stress concentrations around the borehole wall (Hubbert and Willis, 1957). These stress concentrations are greatest in the section of the wall parallel to the direction of the minimum horizontal compressive stress, S_h. Bell and Gough (1979) interpreted the elongation of the borehole to be the result of spalling of weak material off the wellbore wall caused by localized compressive shear failure in the region where the compressive stress concentration is largest. Subsequent data (Plumb and Hickman, 1985; Plumb and Cox, 1987) has confirmed that wellbore breakouts are indeed the result of stress-induced shear failure under compression and that the orientations of the borehole elongations consistently reflect the orientation of S_h (Zoback and others, 1985). Measurement of the shape of the borehole wall with depth by using standard logging techniques (dipmeter or televiewer) can assess the consistency of the orientations of S_H and S_h as a function of depth, as well as their spatial variation between wells (fig. 6*A*).

Core-Induced Fractures

A recently identified stress orientation indicator, similar in some respects to wellbore breakouts, is the presence of core-induced drilling fractures observed in retrieved bottom-hole cores. These phenomena, also called petal centerline fractures, typically consist of near-vertical or steeply dipping planar fractures observed in the oriented rock cores (fig. 6*C*) and are believed to represent extensional fractures formed in advance of a downcutting drill bit

(Kulander and others, 1977; GangaRao and others, 1979). However, unlike wellbore breakouts, which are compressional features (and, therefore, form parallel to S_h), the orientation of these fractures is thought to parallel the maximum horizontal compressive stress, S_H. Evans (1979) examined oriented cores from 13 natural gas wells in Pennsylvania, Ohio, West Virginia, Kentucky, and Virginia and determined core-induced fracture orientations for hundreds of meters of core in most of the wells. Plumb and Cox (1987) also compiled regional data sets of core-induced fracture orientations (fig. 6*B*). The inferred S_H directions derived from these measurements are generally consistent within wells, between nearby wells, and with adjacent hydraulic fracturing results, borehole elongations, and focal mechanism solutions (fig. 6).

Fault Offsets and Other Young Geologic Features

In the presence of an inhomogeneous stress field, young geologic features, such as dikes or volcanic vent alignments, are most likely to propagate in a direction parallel to S_H. This assumes, however, the absence of any preexisting fabric or other structural features, such as faults, that may preferentially control dike or vent-alignment formation. Fault offset data can be used like focal mechanism solutions to help constrain the orientation and the relative magnitudes of the existing stress field (Angelier, 1979; Michael, 1984), the added advantage being that the actual fault plane is known. The stress orientations derived, however, are valid only for the time period during which fault slip occurred and so are not necessarily valid for the

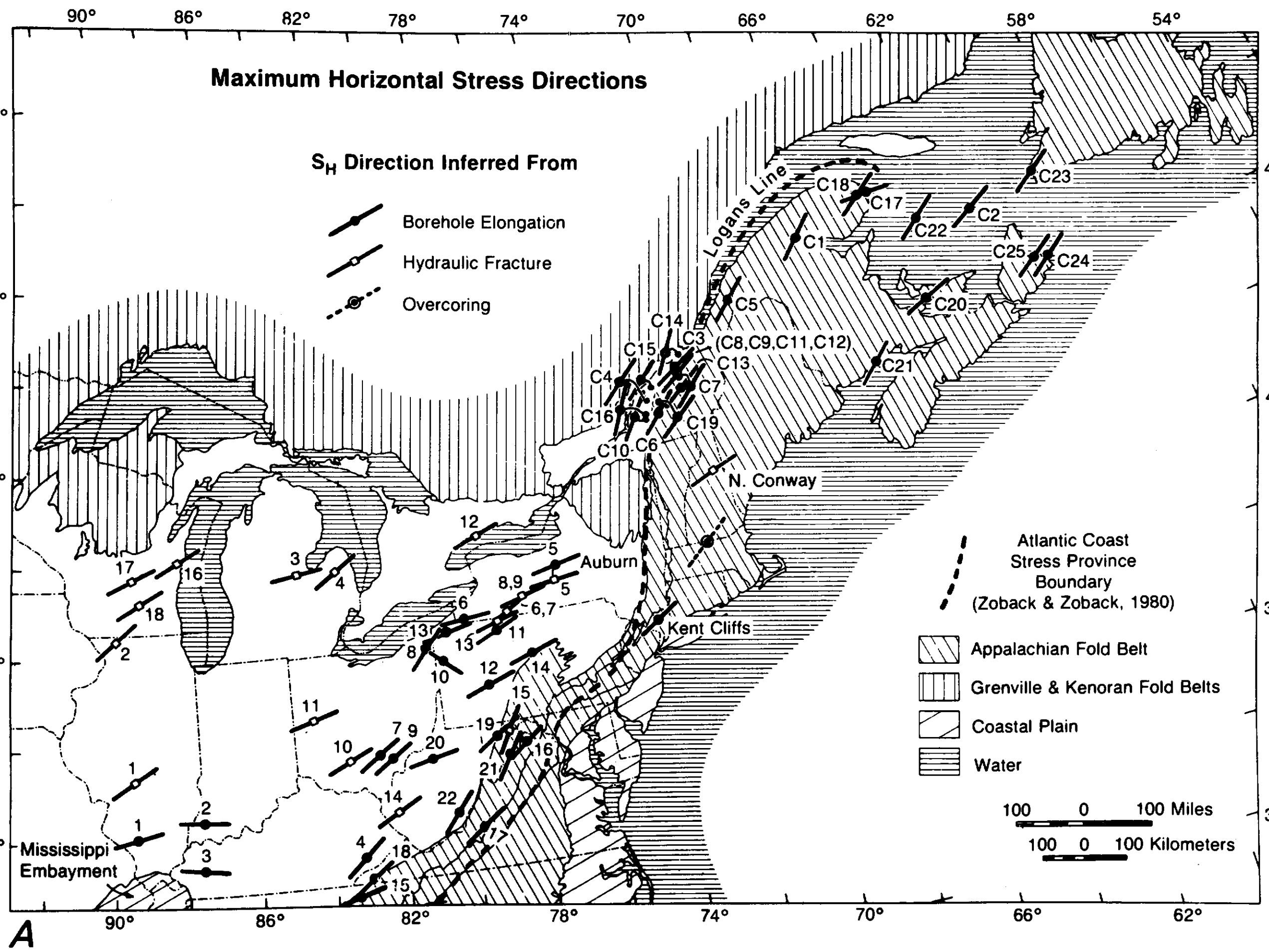
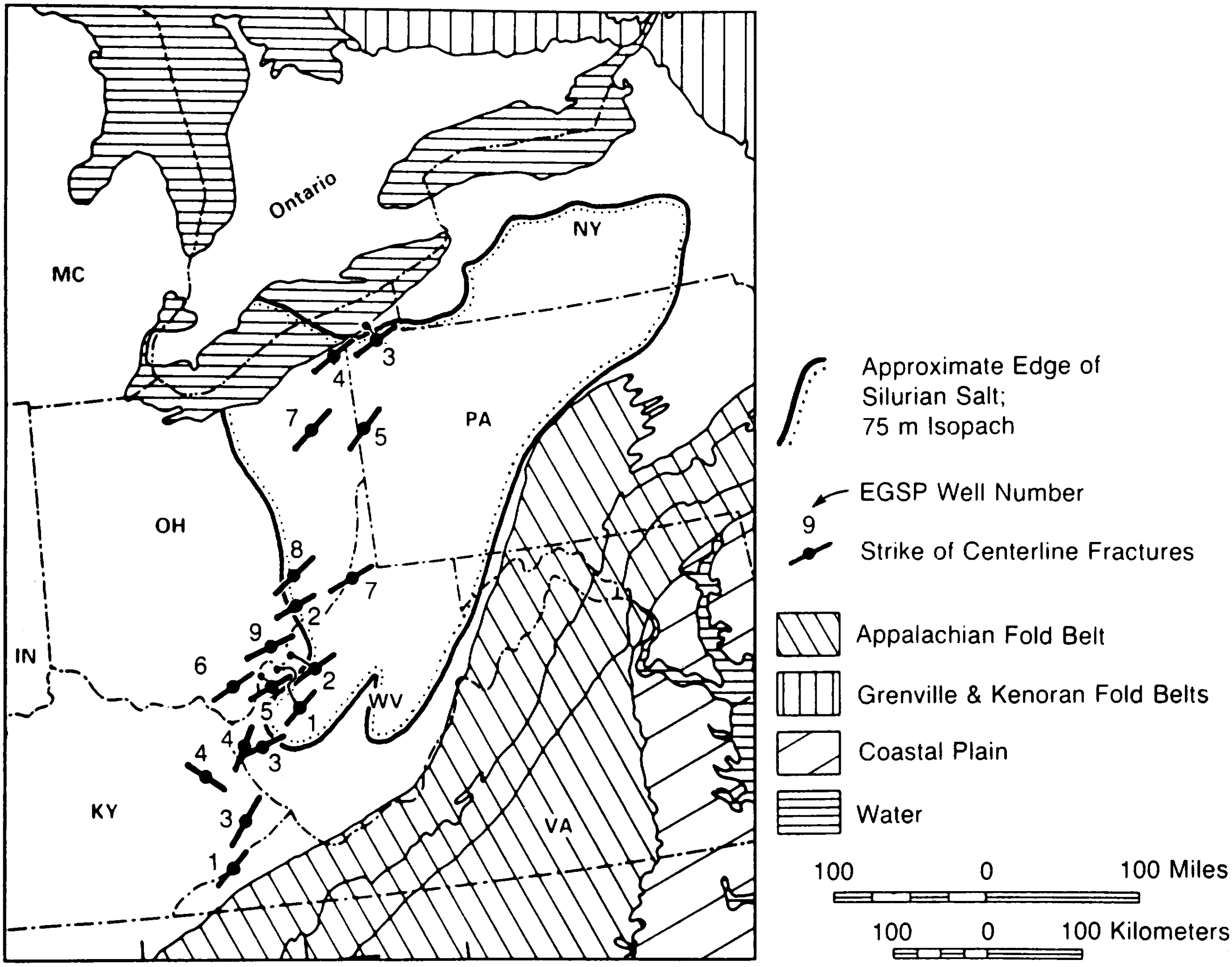
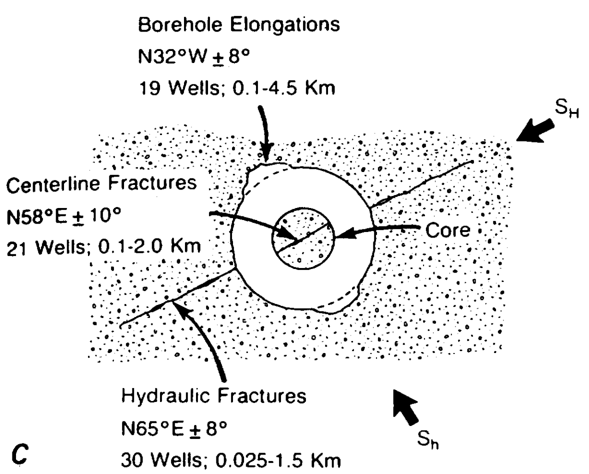


Figure 6. Maximum horizontal stress directions, strikes of core-induced fractures, and the orientation of various stress indicators. *A*, Maximum horizontal stress directions based on borehole measurements—borehole elongation data (dots); hydraulic fracture data (squares); and overcoring measurements (circled dots). *B*, The strikes of centerline fractures observed in Eastern Gas Shales Project (EGSP) cores. East-northeast-trending centerline fractures found throughout the Appalachian Basin correlate with contemporary stress directions shown in *A*. *C*, The relation between orientations of various stress indicators and principal stress directions observed in wells from the Appalachian Basin. Reprinted from Plumb and Cox (1987) and published with permission.



B

Figure 6. Continued.



C

Figure 6. Continued.

current tectonic stress field, particularly if the age of faulting is old.

Hydraulic Fracture Stress Measurements in Wells and Types of Pressure-Time Records

The most reliable measurements of the magnitude and the orientation of *in situ* stresses are made by the hydraulic fracture technique (Noorishad and Witherspoon, 1984). The principle involved with this technique is similar to that for core-induced fractures in that failure results from tension rather than from compression. In the hydraulic fracture technique, one principal stress is assumed to be parallel to the borehole and equal in magnitude to the overburden pressure; that is, S_v. If at any point the fluid pressure in the borehole exceeds the strength of the intact rock and the stress concentration around the wellbore, then a hydraulic fracture is produced (fig. 6*C*). Because the points at which the borehole wall is weakest correspond to a vertical plane perpendicular to S_h, the hydraulic fracture will most likely propagate in that plane. The magnitude of S_h, therefore, can be determined from the pressure acting on the hydraulic fracture immediately after pumping into the well is stopped and the well is shut in. This is called the instantaneous shut-in pressure (ISIP). The magnitude of S_H can then be determined, providing that the assumption of elastic stress concentration around a circular borehole is valid. In some cases, however, the material around the wellbore clearly cannot support the concentration of stresses and fails in compression, resulting in borehole elongation (Bell and Gough, 1983), as discussed above. When this happens, the assumption of elastic behavior near the wellbore is clearly not valid, and S_H cannot be determined in the intervals exhibiting wellbore breakouts.

Basically, the method of hydraulic fracture stress measurement is to pack off an unfractured section of the wellbore and then to increase the fluid pressure in that section until a fracture occurs in the borehole wall. Because the section is isolated (that is, packed off), the pressure is monitored carefully, and, because only a small volume of fluid is used, a small controlled fracture is produced rather than a massive hydraulic fracture, as in the case of well stimulation to enhance circulation (Pearson, 1981). The fluid pressure required to cause the fracture is called the fracture pressure or the breakdown pressure (P_b). After a fracture is produced, fluid pressure in the packed-off section is then cycled repeatedly to determine the pressure required to reopen the fracture (P_{fo}) by pumping small volumes at a constant flow rate and by permitting "flow-backs" to occur following each injection cycle to allow for the drainage of excess fluid pressure. In general, the pressure and flow records produced under these controlled conditions will reflect both of the procedures used during hydraulic fracturing and the *in situ* stress field. Thus, careful analysis of the pressure-time histories recorded during hydrofracturing can be used to estimate the magnitude of the principal stress components. Stress orientation is then determined by using a borehole televiewer or impression packer to ascertain the orientation of the hydraulic fracture created. Figure 7 shows an example of a typical hydraulic fracture pressure-time record from a well drilled to a depth of 185 m in crystalline rock near the San Andreas Fault in central California. In the case of a waste-disposal well, this measurement ideally would be made in the anticipated zone of injection or, if possible, in the basement rock below the waste-disposal aquifer, so as not to interfere with the integrity of the confining layer.

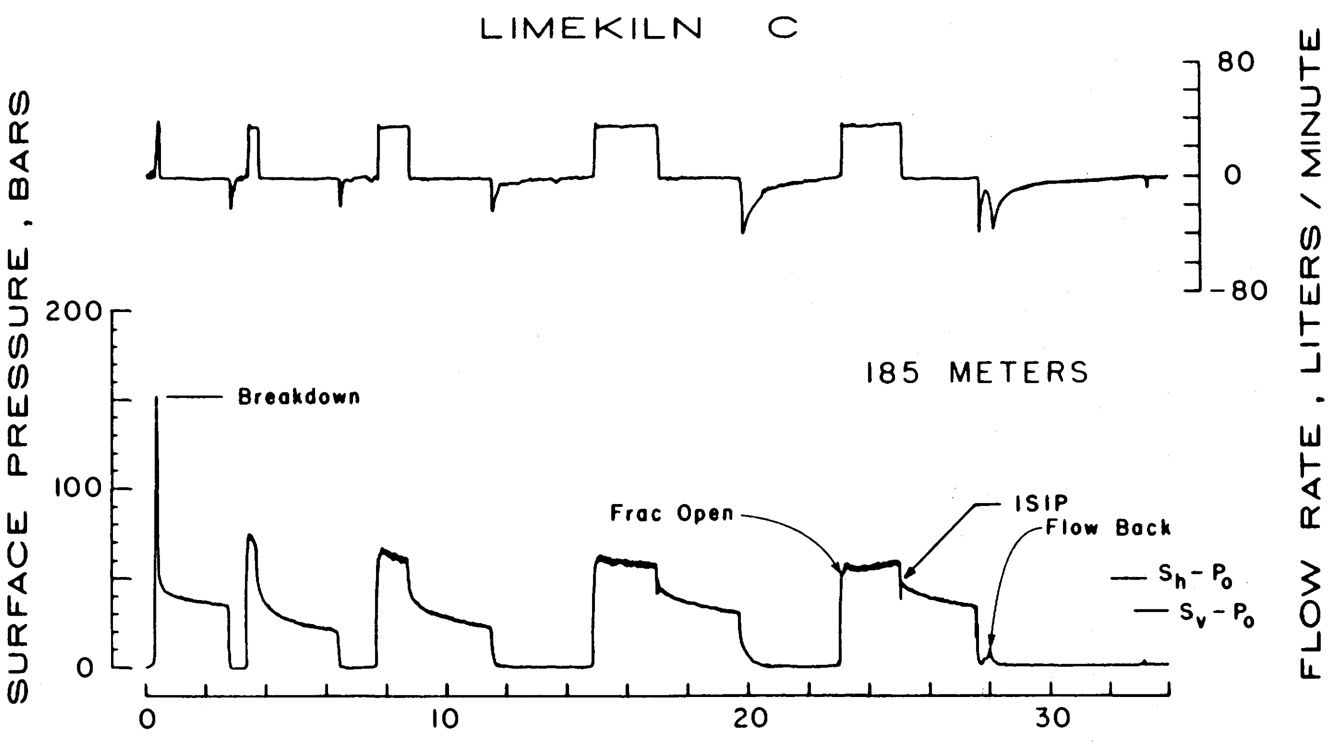


Figure 7. Surface pressure and flow versus time records during a hydraulic fracture stress measurement made at a depth of 185 m in the Limekiln C well, which was drilled 4 km from the San Andreas Fault in central California. The breakdown, fracture opening, and instantaneous shut-in surface pressures (ISIP) are indicated. S_h, minimum horizontal stress; S_v, vertical stress; and P_o, initial pore pressure. Reprinted from Hickman and Zoback (1983) and published with permission.

It should be noted that when the term "fracture pressure" is used in commercial stimulation operations, it rarely corresponds with the value of the "breakdown pressure" referred to in hydraulic fracturing stress measurements. This is because, in commercial stimulation operations, the section of the borehole wall to be fractured often contains preexisting fractures of random orientation that possess various cohesive strengths of unknown quantity. Because commercial stimulation, therefore, typically involves reopening preexisting cracks rather than generating a new fracture of known orientation, "fracture pressure" from commercial hydrofracture operations often represents an unspecified value between the breakdown pressure (P_b) and the fracture-opening pressure (P_{fo}) discussed in the context of hydraulic stress measurement techniques.

From the results of Hubbert and Willis (1957), Haimson and Fairhurst (1967) derived the following equation:

$$P_b = 3S_h - S_H - p + T_0,$$

which relates P_b to S_h and S_H, the initial formation pore pressure (p), and the formation tensile strength (T_0). As mentioned before, S_h can be determined from the ISIP. Determination of the magnitude of S_H requires knowledge of T_0. A good *in situ* measure of T_0 can be inferred from the difference between P_b and P_{fo} (fig. 8*A*). In practice, several successive cycles of fluid injection may be required to measure this quantity accurately (fig. 8*B*). It was then recognized that, if the initial formation p and the ISIP were known, then S_H could be determined directly from P_{fo}:

$$P_{fo} = 3S_h - S_H - p$$

(Bredehoeft and others, 1976). Figure 7 shows how each of the three values (P_b, P_{fo}, and the ISIP) are reflected in the pressure-time history of an actual hydraulic fracture record.

On the basis of the equations above for P_b and P_{fo}, at least three types of pressure-time histories can be identified, depending on the relative values of P_b, P_{fo}, and S_h. Figure 9 shows examples of these three types of pressure records and how each can be distinguished.

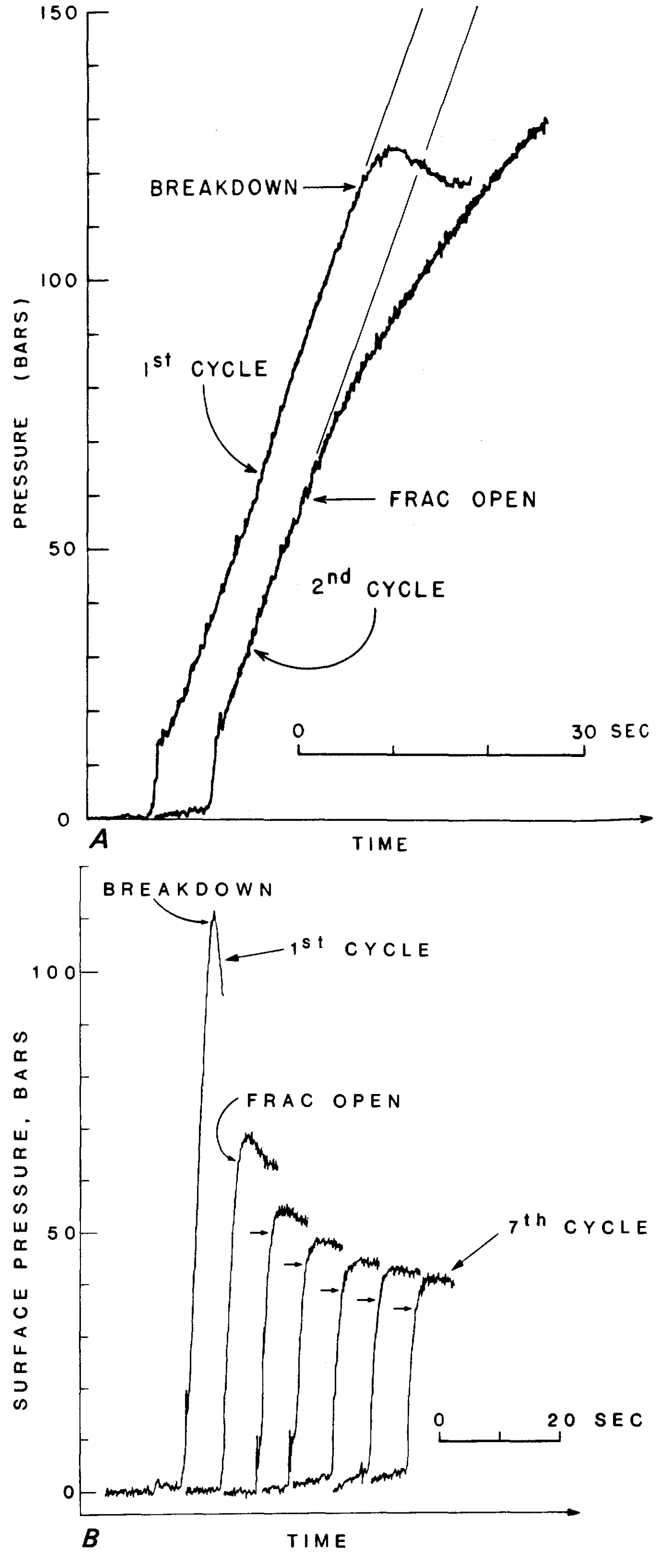


Figure 8. Injection pressure versus time during initial hydraulic fracturing and subsequent cycles of pumping. *A*, Differences between the initial cycle in which a fracture occurs (breakdown) and the subsequent cycles that reopen (fracture-opening pressure) and possibly extend the previously formed crack. *B*, Multiple pumping cycles showing the decrease in fracture-opening pressure with each cycle. Reprinted from Hickman and Zoback (1983) and published with permission.

Comparison of Fracture Pressure and the Mohr-Coulomb Failure Criterion

The increase in formation pore pressure by fluid injection in a well can induce either a new hydraulic fracture or slip on a preexisting fault. In both cases, the critical pressure necessary for failure is dependent on the *in situ* stress field. Pressure limitations of maximum allowable injection pressures established for various waste-disposal operations typically are set below the estimated value of P_b to prevent an uncontrolled fracture of the confining layer

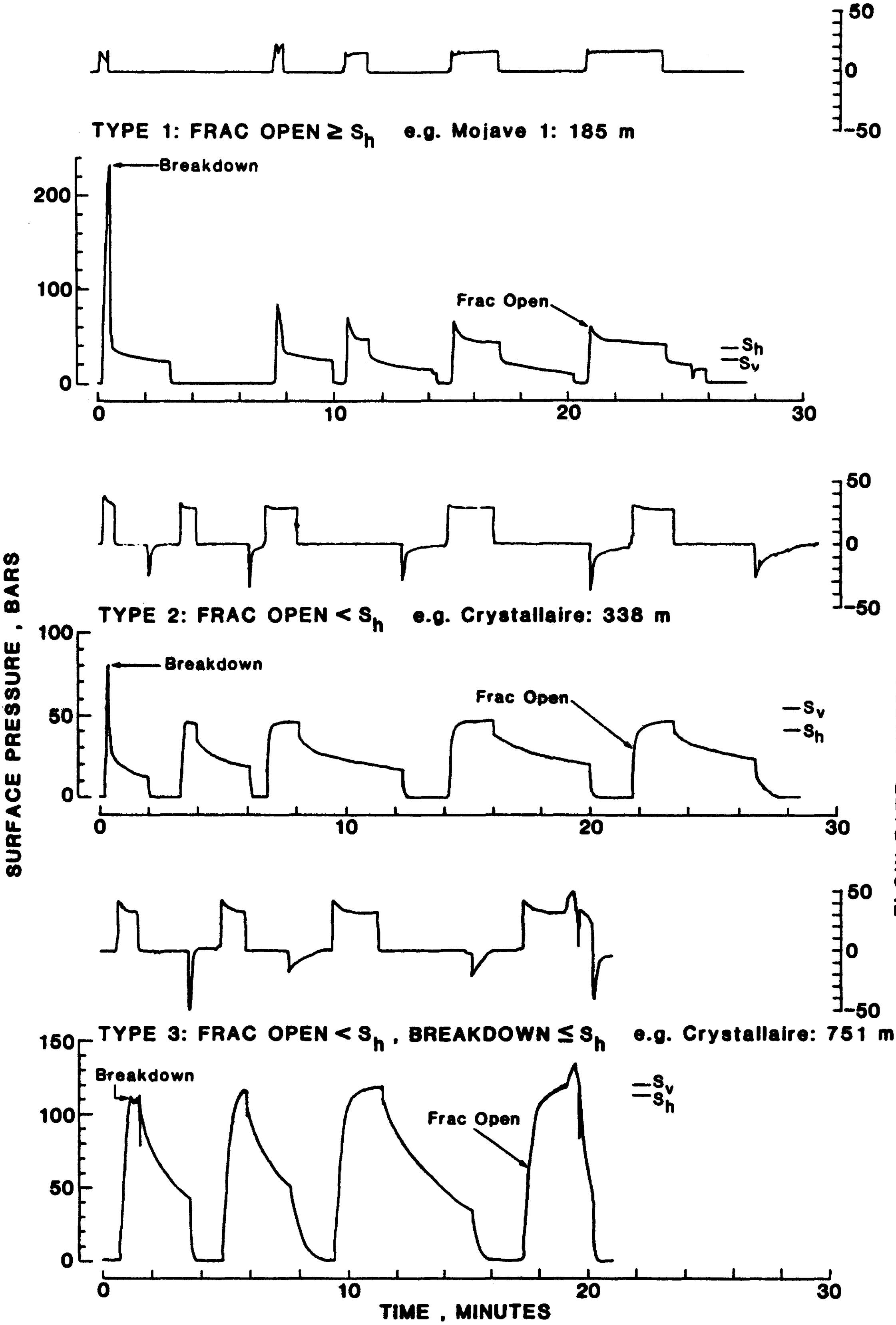


Figure 9. Three different types of hydraulic fracture pressure-time histories taken from two wells drilled near the San Andreas Fault in southern California. The examples are defined by the differences in the magnitudes of the breakdown and fracture opening pressures relative to the minimum horizontal principal stress. The calculated magnitude of the vertical stress is shown for comparison. S_h, minimum horizontal stress; and S_v, vertical stress. Reprinted from Hickman and Zoback (1983) and published with permission.

above the aquifer used for waste disposal and the potential contamination of potable water supplies. Although the concept of P_b is well recognized in the drilling and well-operations industry, its dependence on the regional tectonic stress field, as well as on the tensile strength of the rock, often is not appreciated fully. Thus, before reasonable levels of injection pressure are set, accurate knowledge of the existing state of stress is extremely important.

In terms of the relative magnitudes of fluid pressure needed to induce slip on a preexisting fault versus the fluid pressure necessary to cause a hydraulic fracture, the pressure needed to cause slip is typically much lower; for example, suppose the state of stress can be characterized by a regime in which the vertical stress (S_v) is close to S_H and the stress ratio α of S_h to S_H is 0.65. The breakdown pressure (P_b) required to hydrofracture intact rock is then given by the following equation:

$$P_b = S_v\,(3\alpha - 1) - p + T_0.$$

At a nominal depth of 2 km and for a rock density of 2.6 grams per cubic centimeter, S_v is about 510 bars. If T_0 is taken to be 40 bars and p is near hydrostatic (p = 200 bars), then P_b = 325 bars, or 125 bars above ambient. Fracture-opening pressure (P_{fo}) would be 285 bars, or 85 bars above ambient. However, the critical fluid pressure (P_{crit}) necessary to induce sliding on a favorably oriented preexisting fracture that has no cohesion is equal to the following:

$$P_{crit} = (K\,\sigma_3 - \sigma_1)/(K - 1),$$

where $K = [(\mu^2 + 1)^{1/2} + \mu]^2$ (Jaeger and Cook, 1979). For μ = 0.6 and the stress regime given above, this relation reduces to the following:

$$P_{crit} = S_v\,(3\alpha - 1)/2\ ,$$

which, for the values of α and S_v given above, yields P_{crit} = 242 bars, or only 42 bars above ambient. If the fault exhibits cohesion, then the critical fluid pressure required to induce slip is proportionately greater. Nevertheless, under the conditions assumed above, an increase in fluid pressure of 42 bars above ambient would be sufficient to induce slip on planes having no cohesion that contain σ_2 and are oriented about 30° relative to σ_1; 85 bars above ambient would be sufficient to open preexisting fractures (increase transmissivity) oriented parallel to σ_1; and 125 bars would be sufficient to fracture the intact rock of the borehole wall hydraulically.

Thus, setting maximum injection levels at pressures below that required to fracture the intact borehole wall will *not* guarantee the prevention of induced seismicity if favorably oriented preexisting faults are present near the well. Conducting a controlled hydraulic fracture stress measurement, however, will determine the safe level of fluid injection pressure to prevent an uncontrolled hydrofracture and the proximity to failure of any adjacent potential slip surface.

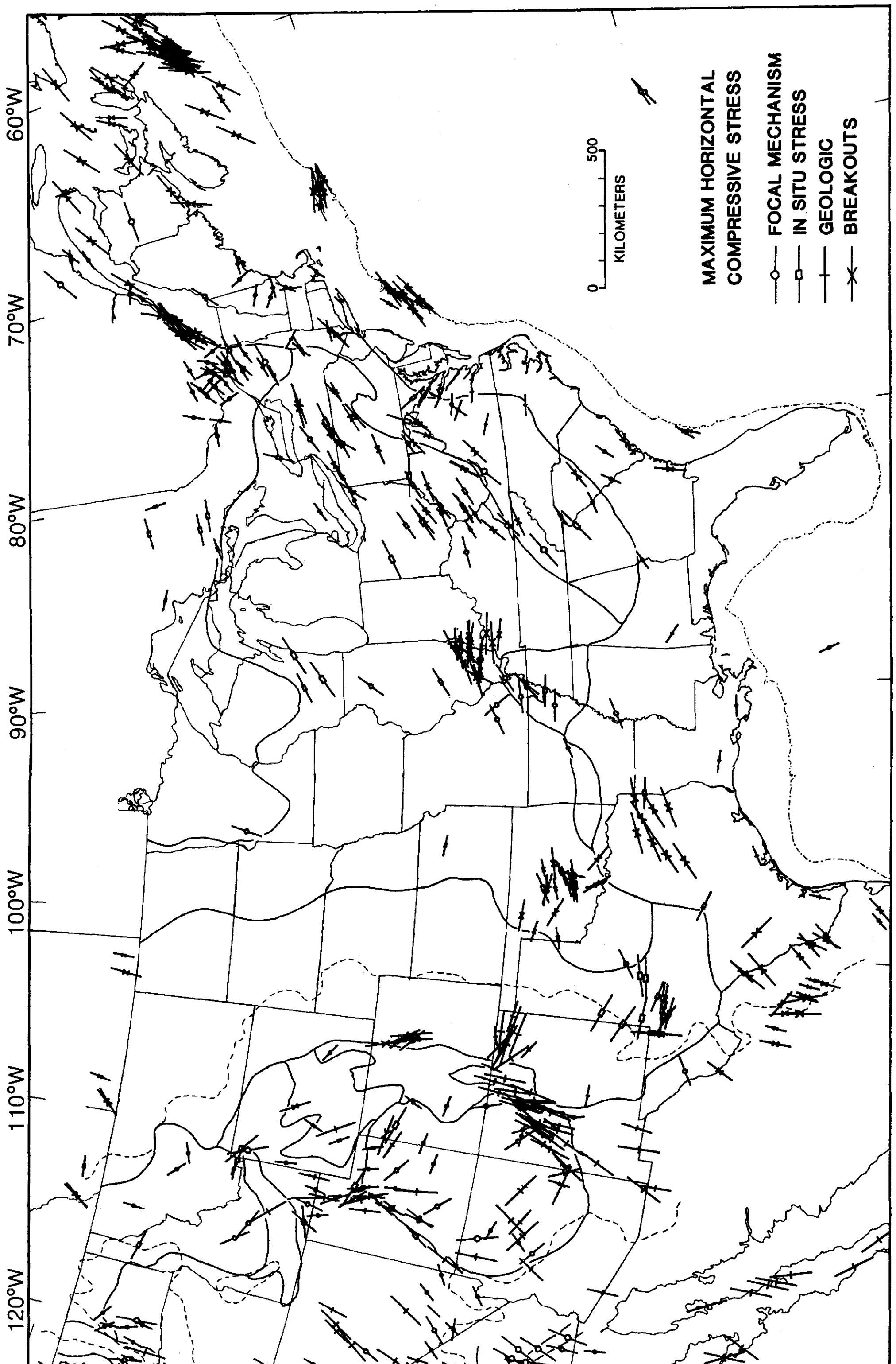
Summary of Stress Measurements to Date

Compilations of various stress measurements have been made by several investigators (Sbar and Sykes, 1973; Lidener and Halpern, 1978; Zoback and Zoback, 1980, 1989). These summaries suggest that the continental United States can be divided into distinct stress provinces, within which the stress field is fairly uniform in magnitude and in direction. Figures 6 and 10 show some of the most recent compilations of stress orientations within the conterminous United States (Plumb and Cox, 1987; Zoback and Zoback, 1989). Both sets of compilations identify the type of stress indicator used at each site. A more generalized stress map showing average principal stress orientations, the stress regime, and delineating the stress provinces is shown in figure 11. In some cases, the boundary between various provinces is sharp, whereas, in others, it is broad and transitional.

Much of the Central and the Eastern United States, where a large number of waste-disposal wells are concentrated, is characterized by a compressive stress regime (fig. 11). Reverse and strike-slip faulting would be most likely to occur in this part of the country, as the vertical stress (S_v) is less than one or both of the horizontal stresses. Because the maximum principal compressive stress (σ_1) is horizontal and typically oriented northeast to east, planes striking 30° to 45° relative to S_H would be oriented most favorably for slip. For large parts of the Central United States, the magnitudes of the principal stresses indicate that only relatively small increases in pore pressure along such favorably oriented fractures are required to induce slip (Evans, 1988).

HYDROLOGIC FACTORS IN EARTHQUAKE TRIGGERING

In all the well-documented cases of injection-induced seismicity, the increase of pore pressure resulting from the fluid injection is the key perturbation to the natural environment responsible for triggering the earthquakes. A well-developed body of theory and computational techniques exists for the estimation of the temporal and the spatial distribution of the pressure field generated by an injection operation. Relatively straightforward analytic techniques are available for most simple geometries, such as radial flow in a confined horizontal aquifer. Numerical modeling techniques are also available for more complicated geometries. The most complete analyses of the hydrologic factors involved in earthquake triggering were conducted in association with the Rocky Mountain Arsenal and the Rangely earthquake sequences (Raleigh and others,


MAXIMUM HORIZONTAL COMPRESSIVE STRESS
FOCAL MECHANISM
IN SITU STRESS
GEOLOGIC
BREAKOUTS
0
500
KILOMETERS
60°W
70°W
80°W
90°W
100°W
110°W
120°W
130°W
40°N
30°N

1976; Hsieh and Bredehoeft, 1982). In the Rocky Mountain Arsenal case, the pressure field was dominated by a fault or fracture zone of finite width that had high permeability relative to the country rock. Although the reservoir geometry was less complex at Rangely, the pressure field also seemed to be affected by the presence of a zone of high permeability that coincided with a mapped subsurface fault (see fig. A2*A*). For most cases of Class I injection wells (that is, those wells used for the disposal of hazardous waste), sites are chosen to avoid faults where possible, and, in such cases, estimating the development of the pressure field established around the well by fluid injection can rely on using relatively simple methods. However, if, after the completion of the well, evidence comes to light suggesting that a more complex model of reservoir geometry is appropriate, then it would be necessary to reassess the net effect of fluid injection by utilizing more precise and sophisticated techniques for analysis.

Most of the common methods available for calculation of the pressure field from an injection well are adaptations of standard techniques used in ground-water modeling (Davis and DeWiest, 1966; Freeze and Cherry, 1979; Fetter, 1980). However, as mentioned above, changes in the standard techniques are required in the presence of faults, fractures, or other possible pathways for anisotropic fluid flow. In addition, if fluid is being injected into a rock of extremely low permeability, typical of the crystalline basement where most earthquakes occur, then other factors of importance may also come into play. Methods for calculating ground-water flow in such low-permeability environments are discussed by Neuzil (1986).

The critical reservoir characteristics for predicting the pressure field around an injection well are the transmissivity and the storativity of the rocks. The lower the transmissivity is, the more confined the "pressure bulb" around the bottom of the well is and the more likely that high pore fluid pressures will be established, thus increasing the concern for earthquake triggering. Inasmuch as earthquakes occur on faults and these same faults can act as zones of high permeability (high transmissivity), determining the presence of faults or fractures is important for predicting the occurrence of induced seismicity.

In many cases where potentially active faults occur at some distance from the injection well, accurate fluid pressure changes are difficult to anticipate because detailed information about the hydrologic properties of the reservoir away from the injection well are lacking; for instance, supposing waste is injected into a basal sedimentary unit overlying crystalline basement, although much may be known about the zone of injection, little may be known about the hydrologic characteristics of the deeper basement rock, where the potential for earthquakes—owing to the presence of faults and fractures—may be significant. As shown below, some estimate of the average characteristics of the reservoir in the vicinity of a well can be inferred from measurements made during well completion and detailed monitoring of the pressure-time history.

◀ **Figure 10.** Maximum horizontal compressive stress orientations throughout the conterminous United States. Solid lines, physiographic provinces typically exhibiting nearly uniform stress fields. Reprinted from Zoback and Zoback (1989) and published with permission.

Reservoir Properties

For a given reservoir geometry, the fluid pressure field generated by injection is governed by transmissivity and storativity, which are functions of porosity (n), the permeability, and the elastic constants of the aquifer. These parameters can be determined from laboratory tests on well cores, piezometer tests, or pumping tests. Pumping tests have the desirable characteristic that they average over a large *in situ* volume of the aquifer and, therefore, represent the most realistic estimates. The storativity (S), which gives the amount of fluid released per unit column of aquifer for a unit decline in head, can be calculated from the following expression:

$$S = \rho g h\ (\alpha_v + n\beta),$$

where ρ is fluid density, g is the acceleration of gravity, h is the aquifer thickness, α_v is the vertical compressibility of the aquifer, and β is the fluid compressibility. Transmissivity (T) is defined as follows:

$$T = \boldsymbol{K}b,$$

where $\boldsymbol{K}$ is the saturated hydraulic conductivity, and b is the thickness of the aquifer (Freeze and Cherry, 1979). Hydraulic conductivity ($\boldsymbol{K}$) is simply as follows:

$$\boldsymbol{K} = k\rho g/\eta,$$

where k is the specific or intrinsic permeability, and η is the dynamic viscosity of the fluid. The storativity and the transmissivity of the reservoir can be estimated from pumping tests by using curve-matching techniques that apply either the Theis log-log plot or the Jacob semi-log plot methods (Freeze and Cherry, 1979).

Fluid Pressure Changes Resulting From Injection

For purposes of illustration, two types of reservoir models are presented—an infinite isotropic reservoir and an infinite strip reservoir that has infinite length but finite width and thickness; that is, rectangular cross section. These models are simply for the purpose of studying how fluid pressure may propagate horizontally away from an

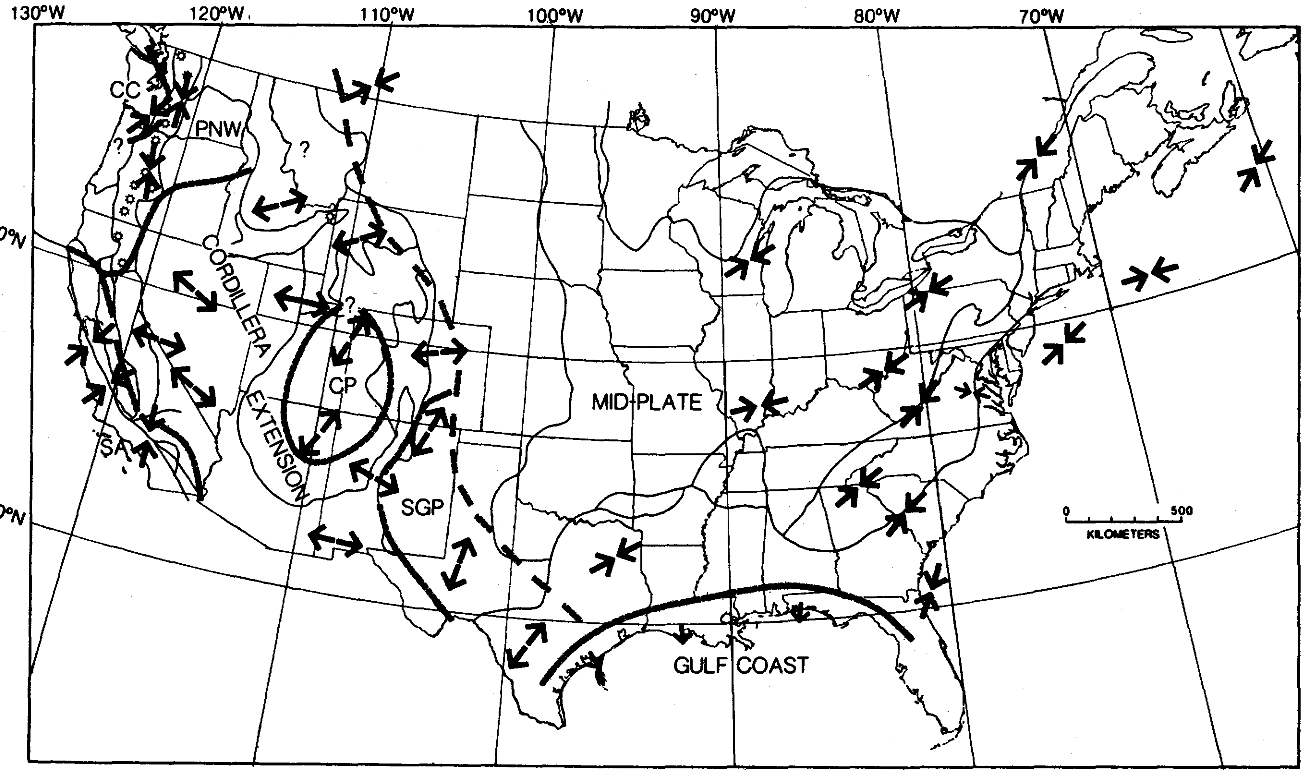


Figure 11. Generalized stress provinces of the conterminous United States. Outward-pointing arrows, areas characterized by extensional deformation (that is, normal faulting); inward-pointing arrows, regions dominated by compressional tectonism (that is, reverse and strike-slip faulting); dashed lines, horizontal stress provinces—CC, Cascade convergent; PNW, Pacific Northwest; SA, San Andreas; CP, Colorado Plateau; and SGP, Southern Great Plains. Reprinted from Zoback and Zoback (1989) and published with permission.

injection well. They do not address the question of how fluid pressure effects might migrate downward from the injection horizon towards potential earthquake-producing structures in the basement.

Infinite Reservoir Model (Radial Flow)

The simplest model for estimating the development of a pressure field around an injection well is radial flow in a single infinite isotropic aquifer of constant thickness. The fluid pressure $p(r,t)$ at distance (r) and time (t) as a result of a constant flow rate (Q) into a reservoir that extends uniformly in all directions is given by the following equation:

$$p(r,t)=\frac{\rho g Q}{4\pi T}\int_{u}^{\infty}\frac{e^{-\xi}}{\xi}\,d\xi\ ,$$

in which $u = r^2S/4Tt$ (Freeze and Cherry, 1979). Figures 12 and 13 show example calculations for the pressure field around an injection well in Ohio. The values of storativity [5.4×10^{-5} square meters per second (m^2/s)] and transmissivity (4.5×10^{-6} m^2/s) in the radial flow model are rather low compared to those for optimal waste-disposal operations; thus, the pressure at the wellbore required to achieve the desired rate of fluid injection is rather high. Figure 12 shows the pressure change versus time curve at the wellbore for a well that has a radius of 12 cm and assuming a constant injection rate of 6.7×10^6 liters per month (L/mo). Figure 12 also shows how a change in shape of the reservoir can effect the pressure-time history at the wellbore. Thus, whether pressure is rising because of fluid injection or falling because injection has stopped (in this case, after a nominal injection period of 15 yr), the pressure history is characteristic of the reservoir geometry.

In the radial flow model, the pore pressure (p) rises relatively rapidly during the first few years and then continues to rise at an ever-decreasing rate. Once injection has stopped, the decline in pressure at the wellhead is most rapid in the radial flow model. The attenuation of the pressure field with distance away from the well is shown in figure 13. With increasing time, the pressure bulb around the well continues to grow. After 10 yr of injection, the pressure increase at a distance of 5 km from the well is about 15 percent of the value at the wellbore.

Infinite Strip Reservoir Model

If fluid flow is confined to a narrow reservoir of finite width, then the fluid pressure at a given distance from the

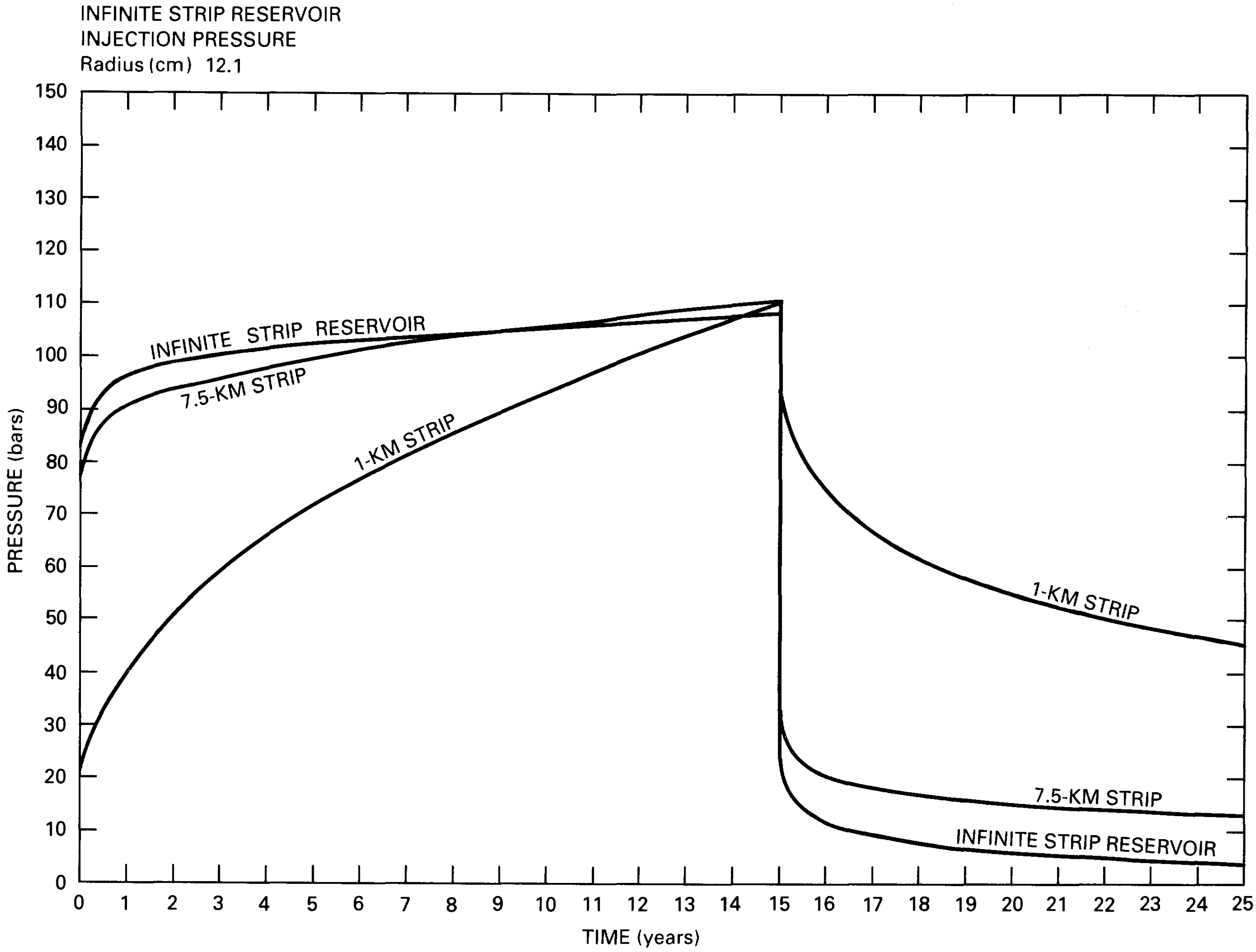


Figure 12. Injection pressure versus time as calculated from the equations in the text for radial flow (infinite width) and finite width (1.0 and 7.5 km) reservoir models. An injection rate of 6.7 million L/mo is used and is assumed to cease after 15 yr. Transmissivities are varied between models to produce approximately 110 bars of wellhead pressure after 15 yr (from Wesson and Nicholson, 1986).

well will be higher than that of the radial flow case. This type of model was used by Hsieh and Bredehoeft (1981) to calculate the pressure distribution around the Rocky Mountain Arsenal well implicated in the 1967 Denver earthquake sequence. Even if no specific evidence suggests that such a similar linear zone of high permeability is characteristic of a particular reservoir geometry, such calculations still may be useful to illustrate how large a pressure buildup is possible at any given distance and to show how the pressure history at the wellbore is diagnostic of the shape of the reservoir into which fluid is being injected.

For injection into the center of a strip of finite width (w) and infinite extent in the x direction, a constant injection rate (Q) produces a pressure given by the following:

$$p(x,y,t)=\frac{\rho g Q}{4\pi T}\sum_{m=-\infty}^{\infty}\int_{u_m}^{\infty}\frac{e^{-\xi}}{\xi}\,d\xi\ ,$$

where y is the distance from the center of the strip, and $u_m = [x^2 + (y + mw)^2]S/4Tt$. Figure 12 shows how the pressure at the wellbore will increase with time for reservoirs of infinite length and various widths. Figures 14 and 15 show the attenuation of the pressure field with distance away from the well for the same two models. Two strip models are considered—a width of 1 km and a transmissivity of 2.0×10^{-5} m^2/s and a width of 7.5 km and a transmissivity of 4.5×10^{-6} m^2/s. The transmissivities are selected to make the pressure-time curves comparable to those exhibited by the radial flow case discussed in the previous section. Two points are clear. First, for a constant fluid injection rate, the pressure required at the wellbore initially rises more gradually for either of the two infinite strip reservoir models than for the case of radial flow but continues to rise at a more rapid rate at later time intervals. Second, the narrower the postulated reservoir is, the higher the formation fluid pressure that will be achieved with time

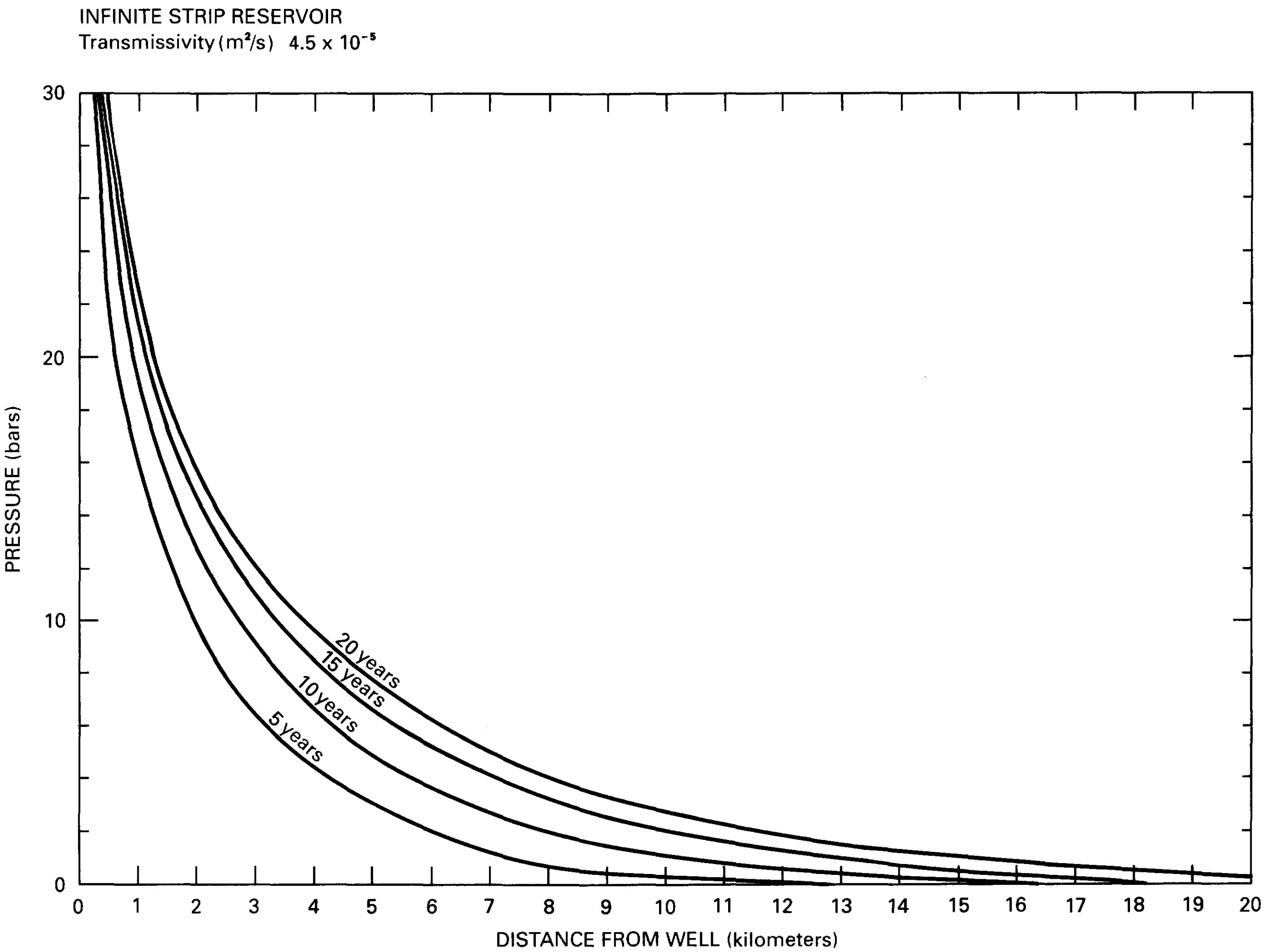


Figure 13. Calculated increased pore pressure versus distance as a result of injection into a confined reservoir of infinite extent (radial flow) and transmissivity of 4.5×10^{-5} m^2/s (from Wesson and Nicholson, 1986). Time intervals are 5, 10, 15, and 20 yr.

at large distances from the wellbore. Moreover, once injection has ceased, the decline in pressure at the wellhead is more gradual for either of the two infinite strip models than for radial flow. Because reservoir geometry has such a significant effect on the pressure-time curves, it is evident that analysis of the history of injection pressure at the wellhead can be used to help discriminate the shape of the reservoir into which fluid is being injected.

UNRESOLVED ISSUES

Although much is known about how earthquakes are induced by deep well injection, full understanding of the earthquake process is far from complete. Many issues remain unresolved and, as such, produce large uncertainties in the confidence with which adequate and appropriate regulations can be formulated. The following problems are considered to be some of the principal unresolved questions that bear directly on the issue of accurate seismic risk assessment.

The Problem of Seismicity in the Central and the Eastern United States

From a seismic hazard point of view, the contiguous United States can be divided along a boundary roughly corresponding to the eastern front of the Rocky Mountains. Most of the earthquakes in the area to the west (pl. 1) are associated with active, well-defined geologic processes. In contrast, the cause of many of the earthquakes in the Central and the Eastern United States is still poorly understood. In the West, the association of earthquakes, particularly large ones ($M \geq 6.5$), with geologic faults is well established. In many cases, these faults are visible at the surface, and, by using geologic techniques, it is possible to demonstrate that displacement has occurred along these faults during the geologically recent past. However, with the exception of

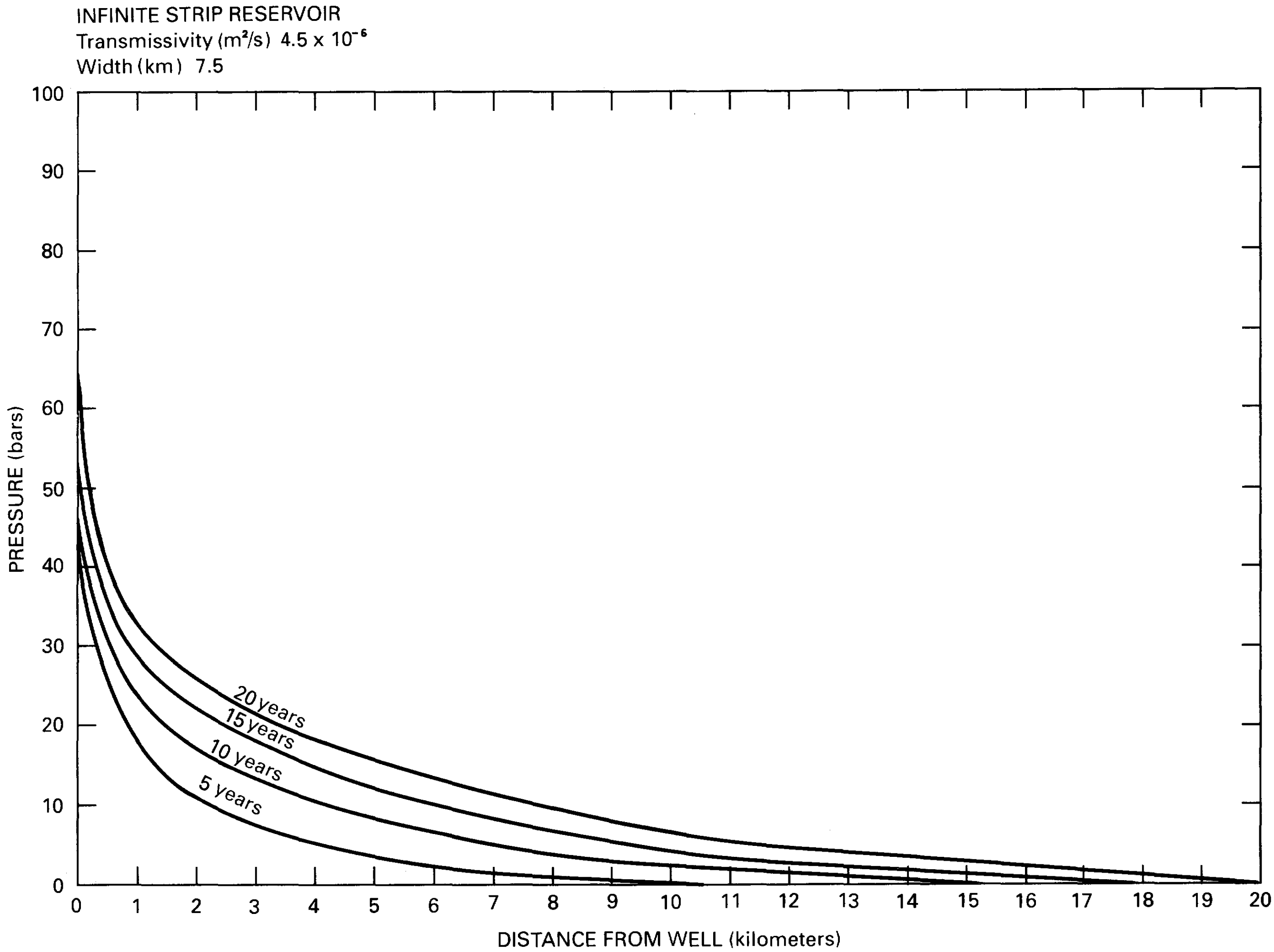


Figure 14. Increased pressure versus distance along the axis of an infinite strip reservoir 7.5 km wide and transmissivity as in figure 13 (from Wesson and Nicholson, 1986). Time intervals are 5, 10, 15, and 20 yr.

evidence for subsurface faulting in the vicinity of the 1811–12 New Madrid, Mo., earthquakes, the relation between faults and earthquakes in the Central and the Eastern United States has been much more elusive. This issue has been clouded even further by the discovery of the Meers Fault in the Wichita Mountains of Oklahoma, along which large, relatively recent movement has occurred (Gilbert, 1985), yet no current or historical seismicity has been associated with it (Lawson, 1985). The Charleston, S.C., earthquake of 1886 provides perhaps the best example of some of the difficulties involved. Despite the continuing occurrence of small earthquakes in the Charleston area, as well as extensive regional and local geologic and geophysical investigations, no commonly agreed upon fault or faults judged to be responsible for the large historic earthquake has yet to be discovered. Consequently, the primary basis for estimating future locations of earthquakes in the Central and the Eastern United States remains the catalog of historic earthquake epicenters.

Magnitudes of Induced Earthquakes

Although it seems extremely unlikely that deep well injection alone could induce a truly large earthquake in the Central or the Eastern United States, no satisfactory method is currently available for estimating the maximum size of earthquake that might be produced. Indeed, no method exists for estimating the increased probability for triggering earthquakes of any magnitude as the result of raising the pore fluid pressure through deep well injection.

Observations indicate that the magnitude of an earthquake increases roughly as the logarithm of the length of fault along which displacement occurs (fig. 16). Slip is also proportional to fault length. Thus, a magnitude 8 earthquake typically involves faulting along hundreds of kilometers of fault and several meters of slip, whereas a magnitude 3 earthquake might involve faulting over a surface that has a dimension of several tens of meters and slip of only a few centimeters. The magnitudes of the largest earthquakes

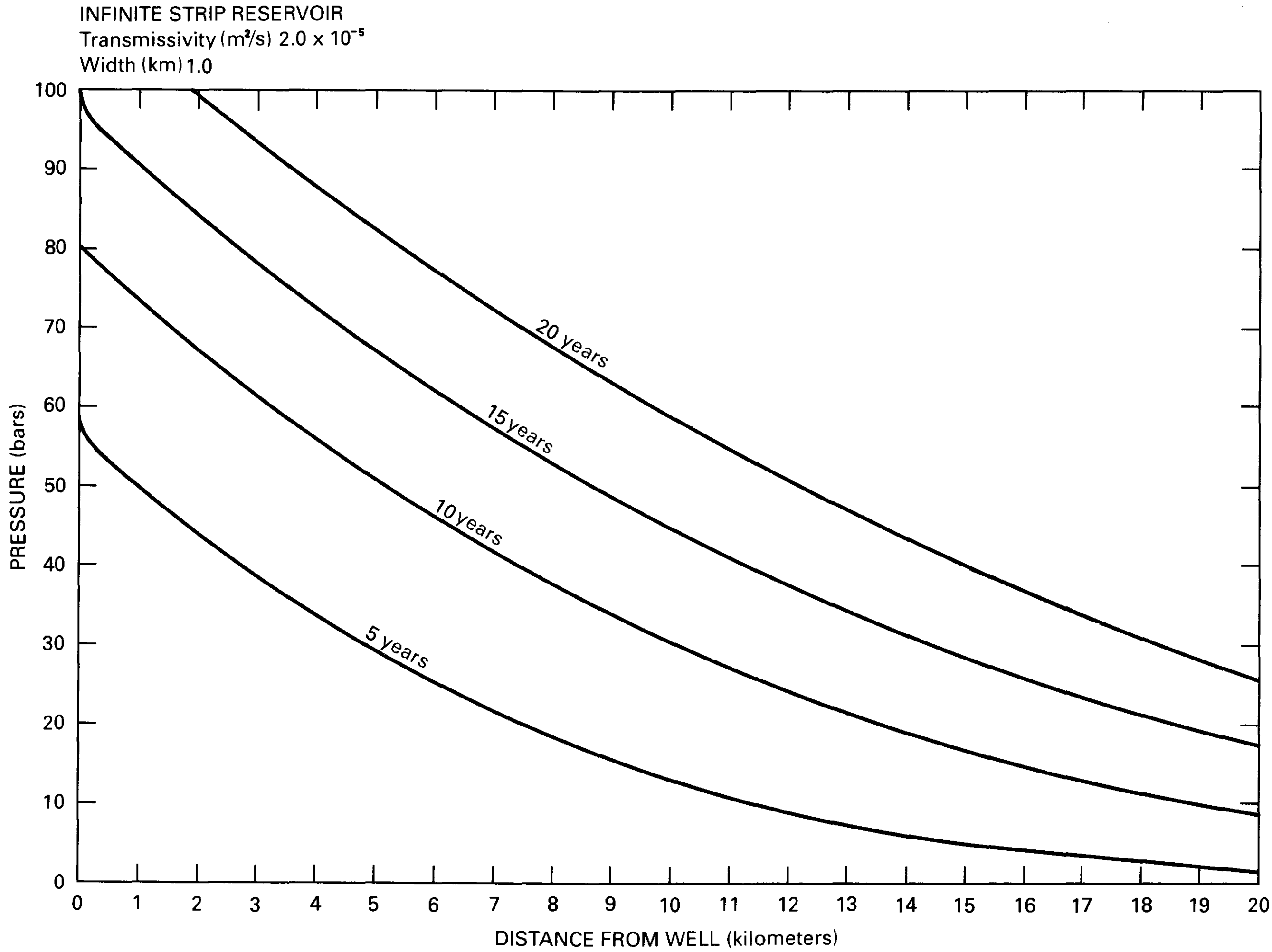


Figure 15. Increased pressure versus distance along the axis of an infinite strip reservoir 1 km wide and transmissivity of 2.0×10^{-5} m^2/s (from Wesson and Nicholson, 1986). Time intervals are 5, 10, 15, and 20 yr.

associated with deep well injection were between 5 and 5.5 (table 1, Rocky Mountain Arsenal in 1967 and Snipe Lake, western Alberta, in 1970). Although none of the induced earthquakes recorded so far would be considered devastating, the potential for damage from such earthquakes could be larger than for those in more tectonically active regions because many of the induced events are shallow and occur in areas of low expected seismic hazard and in regions of low attenuation of seismic waves; for example, the Attica earthquake of 1929 discussed in Appendix A. Earthquakes in the Central and the Eastern United States typically cause damage over much larger areas as compared to earthquakes of the same size in the Western United States. This is primarily the result of the lower attenuation of seismic waves in the East versus the West, but other factors also may be involved.

One of the factors that may affect earthquake damage potential and that seems to distinguish earthquakes in the Central and the Eastern United States from those in the West is a tendency for eastern earthquakes to be associated with relatively small rupture areas for a given magnitude earthquake. If true, then this would imply that eastern earthquakes exhibit more slip per unit fault area than do western earthquakes and would imply that eastern earthquakes reflect higher stress drops. This would be coincident with the thinking that the crust of the Earth beneath the Central and the Eastern United States is older, colder, and, therefore, stronger than that beneath the Western United States. This is also consistent with the idea that large earthquakes east of the Rocky Mountains typically have much longer repeat times than those to the west, allowing faults to heal and regain much of their frictional strength lost during dynamic slip in past earthquakes (fig. 16; Kanamori and Allen, 1986). This apparent difference is important because, if correct, smaller faults in the vicinity of a well located in the Eastern United States could produce larger earthquakes than might be anticipated on the basis of relations derived from more seismically active areas in the West (Thatcher and Hanks, 1973).

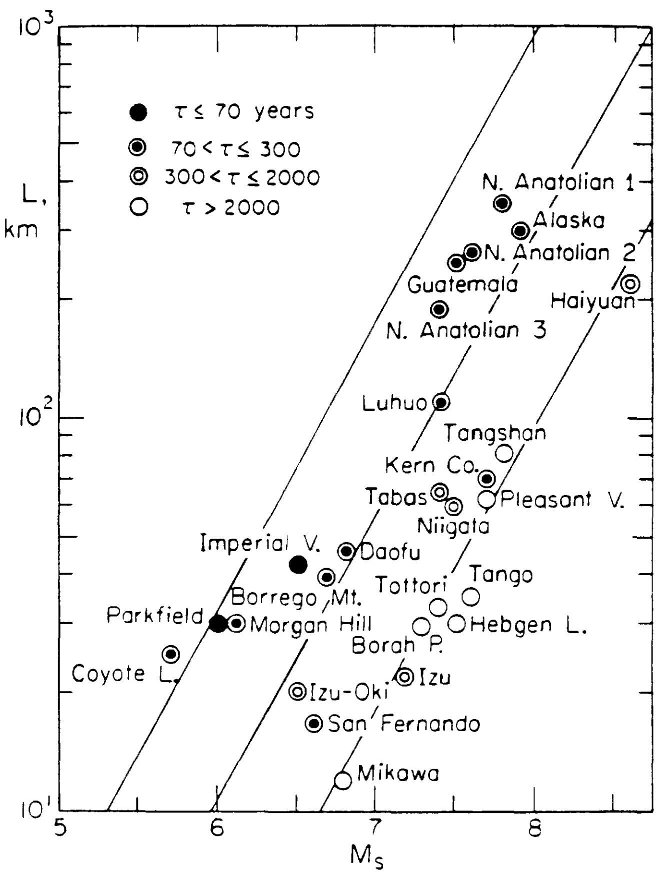


Figure 16. Relation between surface-wave magnitude and fault length. Shown for reference are theoretical lines of constant stress drop (1, 10, and 100 bars, left to right, respectively). Earthquakes that have longer repeat times generally exhibit shorter rupture lengths (L) for the same size earthquake; compare the 1983 M_S 7.3 Borah Peak, Idaho, earthquake with the 1976 M_S 7.5 Guatemala earthquake. M_S, surface-wave magnitude; L, fault length; and τ, repeat times. Reprinted from Kanamori and Allen (1986) and published with permission.

Potential for Reactivation of Old Faults

It is sometimes suggested that earthquakes in the Central and the Eastern United States occur on reactivated, geologically old faults. Currently, the phenomenon of reactivation is poorly understood (Sibson, 1985). Because of the large uncertainties in the inherent shear strength and the time-dependent nature of friction with slip on faults, no criteria exist for predicting whether an old fault might be reactivated, except to determine how close in orientation an existing fault may be relative to preferred planes of slip in the current regional tectonic stress field, as predicted by the Mohr-Coulomb failure criterion.

Importance of Small Induced Earthquakes

It is possible that a deep well injection operation may induce small earthquakes in the immediate vicinity of the bottom of the well, as has been the case in several of the secondary oil recovery and solution mining cases described in Appendix A. If these earthquakes are below the threshold for damage or, perhaps, even below the threshold for noninstrumental detection, then it is not unreasonable to ask whether these earthquakes constitute a risk. Two questions arise—Do these small earthquakes indicate the potential for larger, potentially damaging earthquakes? and do these small earthquakes indicate the possibility of breaching the confining horizon?

In answer to the first question, the occurrence of even small earthquakes indicates that, at least locally, the conditions for seismic slip are satisfied. In the Western United States, the association of small, natural earthquakes with a geologically recognizable fault is taken as sufficient evidence that the entire fault is active and, consequently, that a potentially larger earthquake, controlled by the dimension of the fault, is possible. Unfortunately, our lack of knowledge concerning the size and the distribution of buried faults in the Central and the Eastern United States prevents a similar line of reasoning. Thus, without detail subsurface information, it is not possible to estimate the maximum size of earthquake that could be induced once seismicity is detected near an active injection well.

The second question is more directly pertinent to the containment of hazardous wastes. The occurrence of small earthquakes near the bottom of a deep injection well may indicate faulting or fracturing processes that conceivably could lead to a breach in the overlying confining zone and, therefore, conceivably could permit hazardous materials to migrate upward toward potential drinking water supplies. An important consideration is, therefore, whether the induced seismicity is occurring within the sedimentary section or within the deeper basement rock, and, if so, how close to the confining layer is the zone of seismic activity. Such questions could only be addressed if additional seismic monitoring equipment is installed to locate accurately any subsequent earthquake hypocenters and to resolve the type and extent of faulting involved. However, until such answers are forthcoming, it would seem prudent to regard the occurrence of small earthquakes near the bottom of a deep injection well with concern.

Spatial and Temporal Variability of Tectonic Stress

Although the actual pressure of fluid injection is certainly a critical factor in determining the potential for inducing earthquakes through deep well injection, another key environmental parameter is the state of the preexisting tectonic stress field. If stress conditions on nearby faults have already reached critical levels near failure, then only a small change in pore pressure as a result of fluid injection may prove sufficient to trigger adjacent seismicity. Measurements available to date suggest that the orientations and, possibly, the magnitudes of the principal horizontal stresses are relatively constant, or at least slowly varying, over wide regions of the country. This suggests that once a particular injection operation has triggered earthquakes, other injection wells in the same tectonic stress province may be equally likely to induce similar seismic activity.

Insufficient measurements exist, however, to indicate how rapidly in time and space the stress field may actually vary. In the Central and the Eastern United States, there is at present little indication that the tectonic stress field changes rapidly with time. In the Western United States, geodetic measurements suggest that small, but significant, stress changes can occur over time scales of months to years (Raleigh and others, 1982). In particular, the occurrence of a major earthquake nearby could dramatically affect the local stress field on a time scale of seconds. Assessing the spatial variation in stress is almost as troublesome; for example, some areas in the Central and the Eastern United States tend to have small earthquakes more frequently than others. Whether this is related to the spatial variation in the tectonic stress field or, alternatively, to the spatial distribution and orientation of potential planes of slip is unknown.

CONSIDERATIONS FOR FORMULATING REGULATIONS AND OPERATIONAL PROCEDURES

In terms of the earthquake hazard associated with deep well injection, the three critical parameters that need to be evaluated are the magnitude of the preexisting tectonic stress, the injection pressure, and the proximity and the characteristics of any faults or fractures that may be affected by pore pressure increases caused by fluid injection operations. The preexisting tectonic stress can be measured at the time of well completion or can be extrapolated from measurements made in adjacent wells within the same geologic province. The injection pressure will be controlled by the desired injection rate and by the hydrologic properties of the receiving reservoir. Although the presence of large faults may be obvious at the surface, the presence of smaller faults within the proposed reservoir formation may be extremely difficult to detect. Thus, the two earthquake-related factors that are most amenable to regulation or control are the site selection (and by inference, the characteristics of the reservoir chosen for injection) and the maximum injection pressure.

The following recommendations are made from the point of view of addressing the potential seismic hazard associated with injection-induced earthquakes. These recommendations are not intended to replace or reduce existing procedures or restrictions established on the basis of environmental concerns or other considerations and, therefore, do not constitute by any means a complete list of all the factors needed to be considered in discussing potential hazards associated with the disposal of hazardous waste by deep well injection.

Site Selection

Reservoir That Has High Transmissivity and Storativity

The potential operator of a waste-injection well desires a reservoir that has high transmissivity and storativity because, for a given volume of fluid to be injected, the higher the transmissivity and the storativity are, the lower the required injection pressure will be. High transmissivity and storativity also are very desirable from the point of view of reducing earthquake hazard because the lower the injection pressure is, the less likely the prospect of inducing or triggering earthquakes becomes.

Stress Estimate

An estimate of the state of stress in the area of the projected reservoir is important at an early stage in the selection of a potential site of deep well injection because, to a large extent, the state of stress controls the formation fracture pressure and the pressure threshold for triggering slip on preexisting faults (the Mohr-Coulomb failure criterion). An estimate of high deviatoric stress in the reservoir region should serve as a warning that the formation fracture pressure (P_b) and the Mohr-Coulomb failure pressure will be low.

The most reliable estimates of the state of stress in the reservoir will be those based upon measurements made in the reservoir rock itself. However, it is likely that a reasonable estimate can be made before drilling from the interpolation of regional stress measurements, particularly from hydrofracturing measurements made in the same reservoir rock at nearby wells. Surface or shallow well measurements also may be of value, although the extrapolation of such measurements to significant depths may be unreliable.

Absence of Faults

The possibility for triggering induced earthquake activity appears to be significantly enhanced if any part of the reservoir affected by the planned injection is cut by a significant fault or fracture. Obviously, the presence of a fault that might present a flow path through the confining zone is also of concern in evaluating the integrity of the reservoir. Moreover, because the effect of the fluid injection pressure typically extends farther from the wellbore than the distance to which any of the injected fluid actually migrates, faults or fractures that are beyond the anticipated migration distance should be considered carefully.

Clearly, it is easier to prove the existence of a fault than to prove the absence of one. Before drilling, the existence of a fault may be inferred from surface geologic mapping, subsurface geologic studies in nearby wells, or geophysical studies, such as gravity, magnetic, or seismic reflection surveys. It should be remembered, however, that should drilling or operation of the well reveal a previously unknown fault or fracture, then an analysis and reevaluation of the fluid injection operations may be required.

Regional Seismicity

Inasmuch as the occurrence of earthquakes, even relatively small ones, indicates the existence of faults or fractures and the presence of stresses sufficiently high to cause seismic fault slip, a proposal to locate a deep injection well in an area of significant seismicity should be regarded with caution, particularly if there is any indication that some of the earthquakes occur near the depth of the reservoir. Potential well sites located along strike of regional basement structures that exhibit contemporary seismicity or of extrapolated linear trends in earthquake epicenters should also be avoided, if possible.

Well Drilling and Completion

Transmissivity and Storativity

Estimates of the transmissivity and the storativity of the reservoir are critical to the estimate of the maximum injection pressures required over time to accommodate the desired volume and rate of fluid injection. Insofar as possible, estimates of these quantities should be made by *in situ* measurements at the time of well completion and should be supplemented by laboratory measurements as required. Necessary measurements made at the time of well completion include the effective permeability, the average thickness of potential injection zones, and other related measurements, such as the porosity and the elastic constants of the reservoir formation.

Before beginning injection operations, it would be highly desirable for the potential operator to present a calculation of the predicted injection pressure that would be required to accommodate the desired rate of fluid flow and its expected increase over time. This calculation should be based on the inferred values of transmissivity and storativity measured in the borehole and would provide a standard against which any unusual or unanticipated changes in pressure history observed at the well could be evaluated.

Stress Measurement in Reservoir Rock

From the point of view of assessing the potential for inducing earthquakes through deep well injection, the most useful single measurement is a high-quality stress measurement made in the reservoir rock within the injection well itself. Currently, the most reliable and accurate method of making such a measurement is by using the hydraulic fracture technique. In general, the measurements made in association with standard commercial hydraulic fracture operations for well stimulation are not precise enough for this purpose. To make an adequate stress measurement, it is necessary to select an unfractured length of hole by using an impression packer or borehole televiewer; to use a carefully controlled low volume of fluid, which generally requires the use of a specially designed hydrofracture tool (called a double straddle-packer unit); and to monitor the operation by using sensitive fluid pressure equipment. It is also highly desirable to repeat the measurement at several places along the unfractured drill hole to obtain an estimate of the measurement uncertainty.

Given the importance of maintaining the integrity of the confining zone, there may be concern that even the small fractures created by the hydraulic fracture stress measurement technique or the subsequent propagation of those fractures could threaten the integrity of the confining zone. Certainly, if the well is to be stimulated by commercial hydraulic fracturing, then no incremental risk is associated with the fractures generated during the stress measurements. If the well is not to be stimulated, but a stress measurement is still desired, then it should be possible to keep the fractures generated very close to the borehole and nearly limited to the section of the borehole that has been packed off—if the stress measurements are done carefully and at low injection volume. Estimates of the size of the fracture generated by most controlled hydraulic stress measurements, based on borehole televiewer or impression packer results, typically are on the order of 10 m or less (K.F. Evans, Lamont-Doherty Geological Observatory, oral commun., 1987). Such fractures would not represent a significant threat to the integrity of a confining layer that is often chosen (and mandated in the case of hazardous-waste-disposal operations) to have a thickness 10 to 100 times larger. The primary benefit in making these measurements is that the operator and the regulator will have a direct measurement of the formation breakdown and the fracture reopening pressures, as well as a reliable estimate of the zero-cohesion Mohr-Coulomb failure pressure. With these measurements in hand, the operator and the regulator will be in a position to establish relatively safe maximum pressure levels for injection operations, which will minimize the possibility of creating uncontrolled new fractures or of extending or causing seismic failure on preexisting faults.

If it is judged to be undesirable to carry out hydraulic fracturing measurements in the reservoir itself out of concern for the integrity of the confining zone, then it may be possible to obtain meaningful and relevant measurements at depths in the borehole above or below the confining zone. Ideally, such measurements should be carried out at sufficient depth to avoid near-surface effects and possible zones of stress decoupling caused by low-strength sedimentary layers or structures, such as salt beds (fig. 6*B*), between the measurement depth and the reservoir. Strictly from the point of view of the relevance of the stress measurements, the deeper the better.

Pore Pressure Measurement

Because fluid pressures modify the local effective stress fields (and, by supposition, the frictional strength of faults), an important measurement required to understand the state of stress in the reservoir before the beginning of injection is the initial pore pressure (p) in the reservoir formation. This measurement also provides a baseline against which to evaluate, quantify, and monitor the expected increase in formation fluid pressure as a result of the subsequent injection operations.

Faulting Parameters

If there is any indication that the injection pressures will approach the zero-cohesion Mohr-Coulomb failure pressure, then it would be prudent to measure the coefficient of friction (μ) of the reservoir rock and the adjacent basement rock, as well as to estimate, if possible, the cohesion of any adjacent faults or fractures present (or potentially present) in the reservoir or surrounding country rock. These measurements would help provide better, more reliable estimates of the critical stress levels needed for fault slip, as determined by the Mohr-Coulomb failure criterion.

Well Operation and Monitoring

Determination of Maximum Allowable Injection Pressure

From the point of view of earthquake hazard, the key decision facing the operator and the regulator is the establishment of the maximum allowable injection pressure. Without considering the potential for slip on preexisting faults, an absolute upper limit of permissible injection pressure presumably would be the formation fracture (or breakdown) pressure (P_b). It should be emphasized, however, that the standard estimates of a "safe" maximum injection pressure, which are based on some fixed percentage of the so-called normal vertical gradient of formation fracture pressure of about 0.75 to 1.0 pound per square inch per foot may not be conservative at all. This is because the formation fracture pressure critically depends on the local state of stress and, in particular, on the deviatoric stress. The higher this stress is, the lower the formation fracture pressure will be, regardless of the expected values derived from the measured vertical overburden gradient. Strict "rules-of-thumb" that do not take into account the spatial variation in the state of stress will not specify adequately the "safe" upper limit of the formation fracture pressure.

In terms of potential earthquake triggering, however, the lowest possible critical injection pressure is the zero-cohesion Mohr-Coulomb failure pressure. This is the pressure at which frictional sliding would occur on favorably oriented preexisting faults or fractures with no cohesion. If the projected injection pressures are below this threshold, then no earthquake problems should be anticipated. In contrast, if the desired injection pressures are above this threshold, then it is necessary to consider whether any significant faults or fractures exist in close proximity to the point of fluid injection, what their orientation may be, and the magnitude of their possible cohesion. If, as a result of fluid injection, conditions on adjacent faults are allowed to reach the Mohr-Coulomb failure limit, taking into account the appropriate cohesion (τ_0), then earthquake activity should be anticipated.

Comparison of Actual and Predicted Pressure-Time Records

The pattern of fluid injection pressure measured at the wellhead over time and, indeed, the fall of pressure over time during any interruption in injection activities give important information about the average hydrologic characteristics of the reservoir. Comparison of the actual pressure versus time records with those predicted from the measured or the estimated reservoir characteristics (transmissivity, storativity, shape, physical extent) would provide an assessment of whether the initial assumptions, such as radial flow in a confined homogeneous aquifer, were correct or required modification. Obviously, any increase in the apparent transmissivity of the reservoir should be scrutinized as a possible indication that fluid has reached a fracture system. Unexpectedly rapid increases in injection pressure needed to maintain flow rates at constant volume over time may indicate a tighter reservoir formation than anticipated and, thus, a possible need to reduce the desired rate of fluid injection.

Seismic Monitoring

If any question exists about the possibility of inducing earthquakes, particularly if the projected injection pressure is above the zero-cohesion Mohr-Coulomb failure pressure, then it would be prudent to carry out a seismic monitoring program to detect the occurrence of any adjacent earthquake activity. This also would be advisable if the well is situated in an area that has a previously well-defined history of seismic activity or if the well site is in close proximity (less than 20 km) to a known major fault structure. Preferably, this monitoring program should begin as far in advance of the anticipated injection operations as possible to establish a background level of seismicity against which any potentially injection-induced earthquakes might be compared. To be meaningful, instrumentation should be sensitive enough to detect earthquakes in the magnitude 0 to 1 range located near the bottom of the well. Figure 17 is a seismogram of one such microearthquake detected within 3 km of the Calhio, Ohio, injection wells discussed in Appendix A. To obtain this degree of sensitivity in the presence of the high levels of seismic noise often associated with industrial activity in the vicinity of the well itself, it may be necessary to locate the monitoring equipment somewhat off-site or in

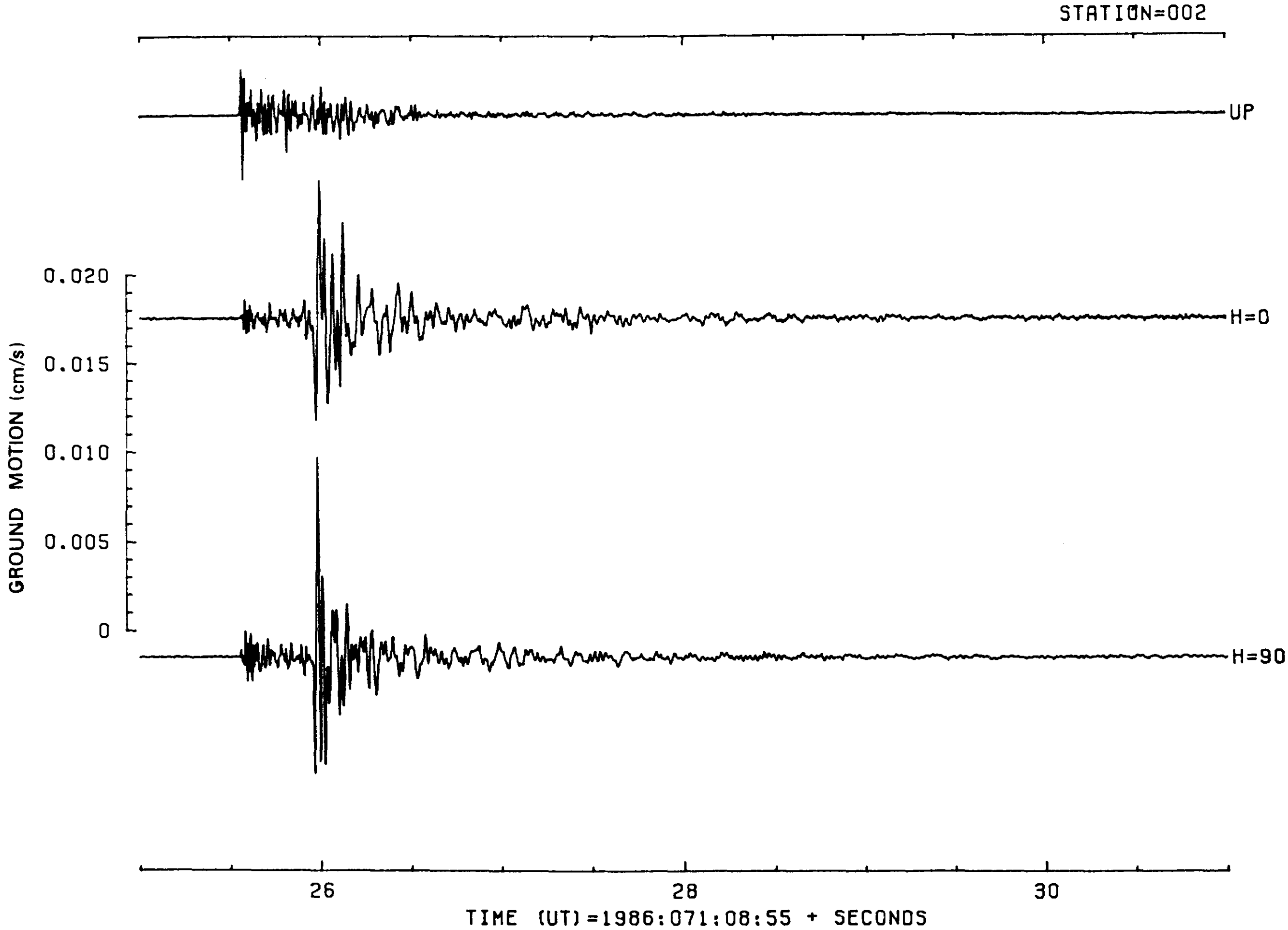


Figure 17. Seismogram of an earthquake that has a magnitude of about 0.5 and that is located at a depth of about 2 km and within less than 3 km of the bottom of an injection well in northeastern Ohio (from Wesson and Nicholson, 1986).

an adjacent borehole. Significant reductions in noise level can be obtained by placing the seismic instrumentation in boreholes at depths as small as a few tens of meters.

Monitoring should continue for as long as it takes to verify that elevated injection pressures are unlikely to trigger significant earthquake activity. This may require several years of observation because of the length of time involved to attain maximum (that is, critical) injection pressure at a constant injection rate and to allow for the diffusion of significant pore fluid effects away from the well. The time interval between initiation of injection and the largest earthquakes at the Rocky Mountain Arsenal site was 5 yr; for the Snipe Lake case (Appendix A), the time lag was 7 yr. Similar time intervals between injection and the largest earthquakes in the triggered sequence have been observed in other cases; however, the time between the initiation of injection and the onset of microearthquake activity is often short; for example, the Rocky Mountain Arsenal, the Attica-Dale, and the Ashtabula cases discussed in Appendix A.

Although one seismic station may be adequate for detecting earthquakes (and, in favorable cases, for estimating the distance of the earthquake to the station), a minimum of three stations would be necessary to determine the locations and focal depths of any earthquakes should they be detected in the vicinity of the well. Thus, once any induced seismicity is detected, it would then be appropriate to supplement an initial monitoring station with additional stations to provide reliable and accurate earthquake locations and focal depths.

Consideration of Small Earthquakes Near the Bottom of a Well

The occurrence of any earthquakes, even as small as magnitude 0, near the bottom of a well should be viewed with concern. Confirmation that earthquakes are indeed triggered by injection operations can often be obtained by comparing the frequency of earthquakes with the cycling of the injection pressure (fig. 2). It should be noted, however, that the pressure changes at the wellbore are damped out with distance from the well. Therefore, induced or triggered earthquakes at some distance from the borehole should not be expected to correlate as well with the cycling of injection pressure as earthquakes in the immediate vicinity of the bottom of the well. If earthquakes thought to be related to injection operations are detected, then the following questions are appropriate: Is it possible that induced earthquakes might cause damage or injury in the surrounding area? and is it possible that the earthquakes indicate fault displacement that might threaten the integrity of the confining zone? If the answer to either of these questions is "yes," then consideration should be given to reducing the injection pressure. It should be remembered, however, that once the pore pressure in the reservoir or in adjacent rocks is raised above the critical pressure capable of triggering seismic faulting, lowering the pressure at the wellbore may not lead immediately to the cessation of earthquake activity. Seismicity would not be expected to stop until the pressure in the affected region has decayed below the critical value.

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APPENDIXES A–D

APPENDIX A—CASE HISTORIES OF EARTHQUAKES ASSOCIATED WITH WELL OPERATIONS

Rocky Mountain Arsenal, Colorado

The first well-documented case of injection-induced seismicity occurred at the Rocky Mountain Arsenal near Denver in 1966–67. The injection of 17 to 21 million L/mo of hazardous waste into a 3,671-m-deep disposal well was quickly followed by many felt earthquakes (fig. A1*A*) in a region where the last felt earthquake occurred in 1882 (Healy and others, 1968). Comparisons between the onset of seismicity and well operations and between earthquake frequency and average injection rate showed a convincing correlation (fig. 2; Evans, 1966a). Although injection ceased in February 1966, earthquakes triggered by the increased fluid pressure established around the wells continued for several years (fig. A1*C*). In 1967, three large earthquakes—each with a magnitude of greater than 5—occurred, causing minor structural damage in and around the greater Denver area.

In terms of their relative spatial distribution, a study of event locations indicated that the induced earthquakes began initially near the bottom of the injection well, then migrated out along a northwesterly trend for a distance of about 6 to 7 km (fig. A1*A*). After the earthquake sequence had been in progress for 5 yr (1½ yr after injection had stopped), earthquakes primarily occurred, not near the base of the well, but within the previously defined linear zone at a distance of 4 to 6 km from the well and at depths of 4 to 7 km. The largest earthquakes in the sequence (M 5–5.5) occurred in April, August, and November 1967 (fig. A1*B*), after which activity began to decline.

A total of 620 million liters (L) of fluid were injected at average rates of 478 L/min before well operations ceased. Maximum top-hole pressure (THP) reached 72 bars, which corresponded to an estimated bottom-hole pressure (BHP) of 415 bars (Evans, 1966a). Hsieh and Bredehoeft (1981) demonstrated that the records of pressure falloff at the disposal well were consistent with injection into a long narrow reservoir, a conclusion supported by the elongate shape of the seismogenic zone. No hydraulic stress measurements were ever made near the Rocky Mountain Arsenal. From the pressure at which the volume rate of fluid injection increased rapidly, Healy and others (1968) inferred a least compressive stress of 362 bars at the bottom of the disposal well and estimated a maximum compressive stress to be at least the overburden pressure of 830 bars. This assumption proved valid when it was demonstrated that the three largest earthquakes exhibited predominantly normal faulting along nodal planes that were parallel to the trend of earthquake epicenters (fig. A1*B*; Herrmann and others, 1981). Formation pore pressure before injection was estimated to be 269 bars. From these calculations and by using the Mohr-Coulomb failure criterion, a fluid pressure increase of 32 bars was determined to be sufficient to trigger seismic activity along favorably oriented preexisting fractures (Hsieh and Bredehoeft, 1981; Zoback and Healy, 1984). The observation that the earthquake locations were confined to those parts of the reservoir where the pressure buildup from fluid injection exceeded the critical threshold, as predicted by the Mohr-Coulomb failure criterion, strongly supports the conclusion that the earthquake activity was related to injection well operations and was consistent with fluid pressures within the reservoir initiating failure along favorably oriented fractures that had cohesive strengths of as much as 82 to 100 bars. The continuation of seismicity over time and the outward migration of earthquakes from the well were explained by the outward propagation of the critical levels of fluid pressure, even after the injection had stopped.

Rangely, Colorado

Water flooding for the secondary recovery of oil near Rangely began in 1958. Wells drilled to the producing horizon extended to depths of about 2 km. As of June 1970, 9,700 million L of water had been injected at a THP of about 83 bars; this represented a net increase of 2,300 million L after accounting for petroleum withdrawal (Gibbs and others, 1973). Following the installation of seismic monitoring equipment in 1962, earthquakes were found to be occurring within the oil field. In 1969, a dense network of stations was installed to determine accurate earthquake hypocenters and fault plane orientations. Seismic activity was found to be concentrated in a narrow zone, about 4 km long and 1.5 km wide, which crossed the boundary of the field to the southeast (fig. A2*A*; Raleigh and others, 1972). Hypocenters tended to cluster in two groups—one located at depths of 2 to 2.5 km near the wells and within the injection zone, and the other at depths of 3 to 5 km about 1 to 2 km from the wells. The maximum magnitude of the earthquakes generated was 3.1.

Hydraulic fracture data obtained at the bottom of one of the wells (fig. A2, top) indicated values for the maximum compressive stress (σ_1) of 552 bars, the intermediate principal stress (σ_2) oriented vertically and equal to 427 bars, and the least compressive stress (σ_3) of 314 bars. By using the Mohr-Coulomb failure criterion, Raleigh and others (1972) combined these hydraulic stress measurements with the locations and the fault orientations of the earthquakes, as well as laboratory-determined properties of the rock at depth to calculate that a pore pressure of about 260 bars (or 90 bars above the original formation fluid pressure of 170 bars) would have been sufficient to induce slip. This value was consistent with the formation fluid pressure of 275 bars measured in the oil field at the time that

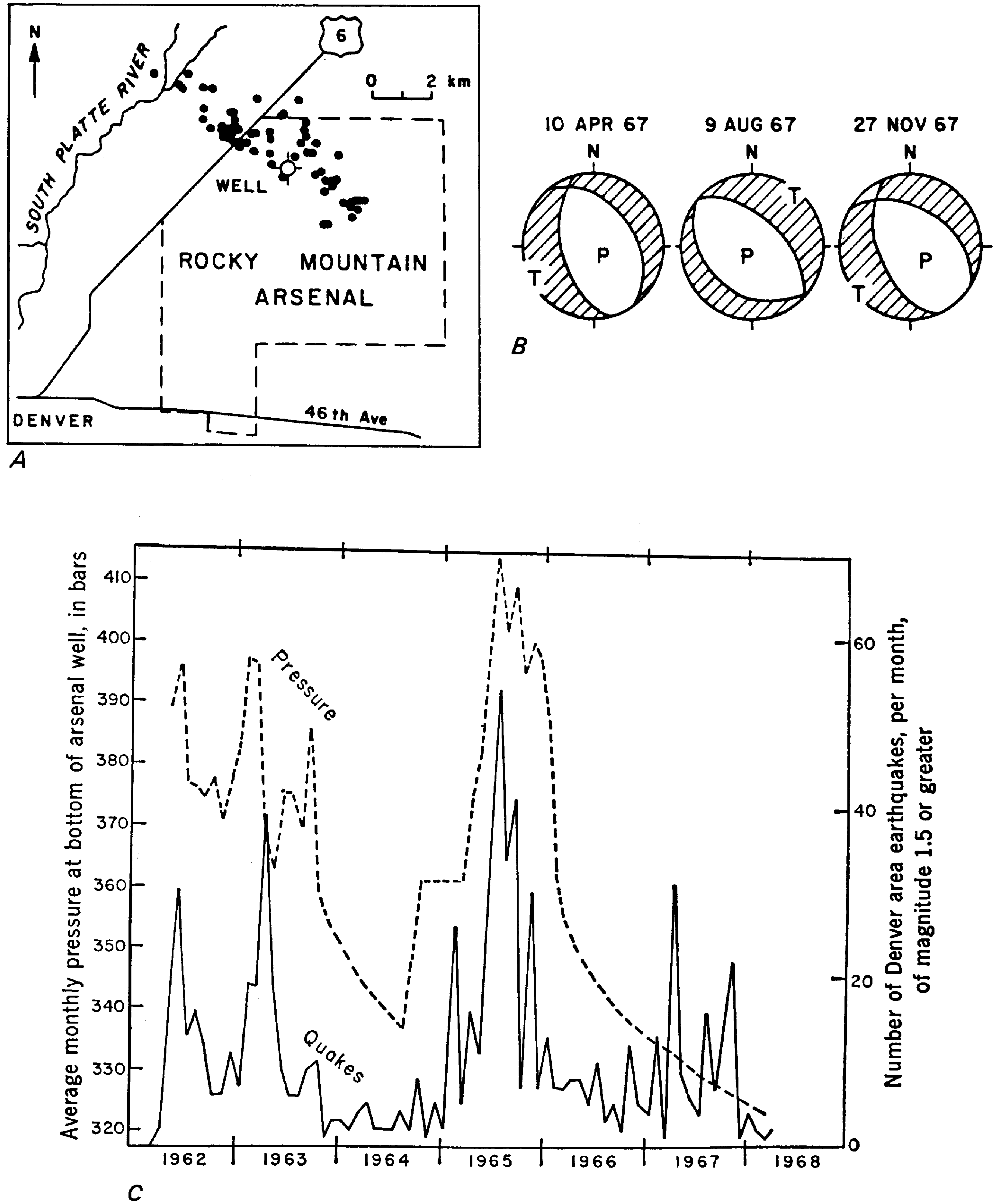


Figure A1. Earthquakes associated with the Rocky Mountain Arsenal well near Denver, Colo. *A*, Locations of earthquakes. Solid circle, location. *B*, Surface-wave focal mechanism solutions of the three largest Denver earthquakes. *C*, Numbers of earthquakes per month and average monthly injection pressure at the bottom of the well. *A*, reprinted from Healy and others (1968) and published with permission. *B* and *C*, reprinted from Zoback and Healy (1984) and published with permission.

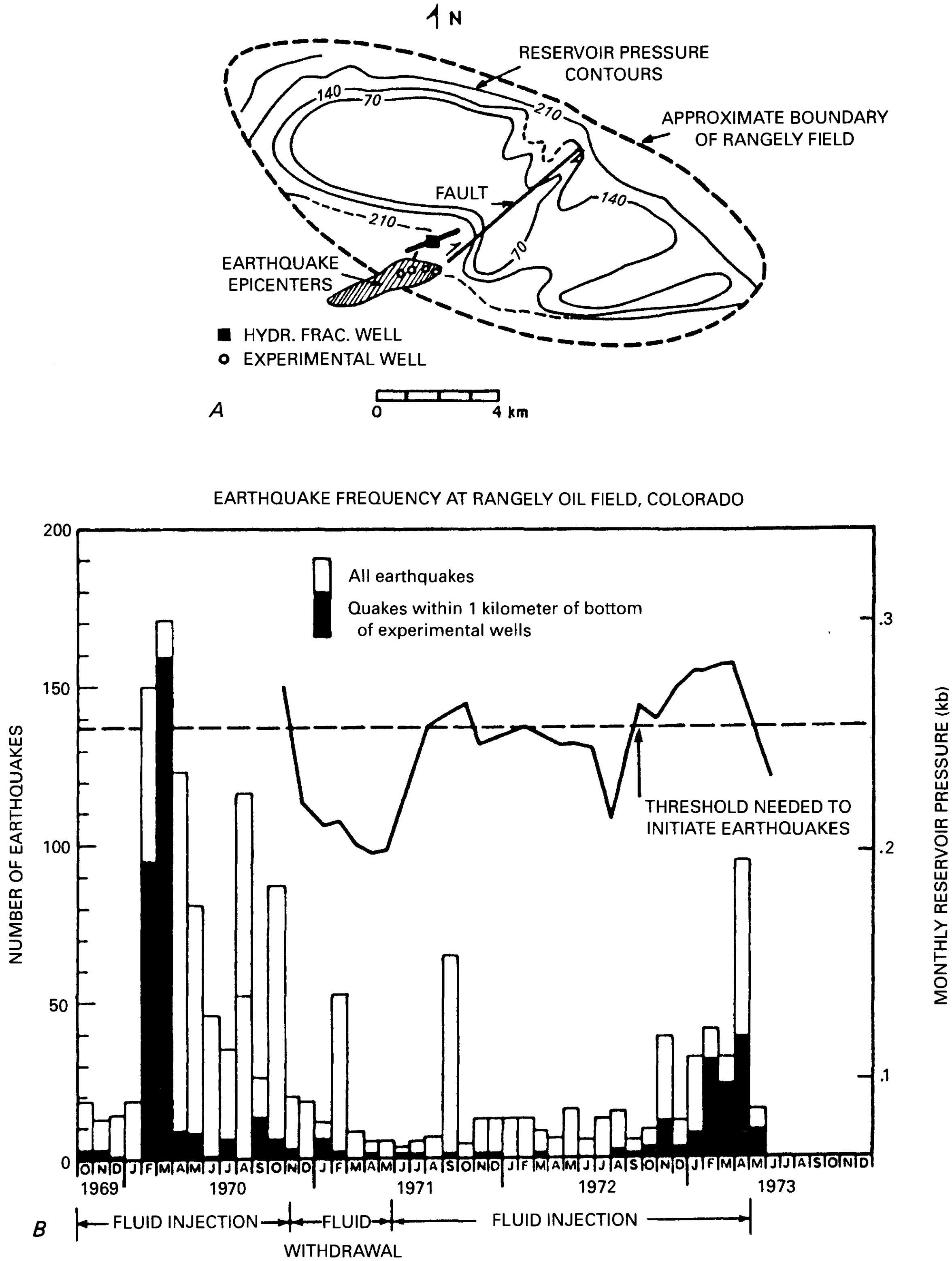


Figure A2. Seismicity and fluid injection, Rangely oil field, Colorado. *A*, Field geometry. Heavy dashed lines, approximate field boundary; light solid lines (dashed where inferred), reservoir pressure contours; hachured region, seismicity; solid square, location of the well used for hydrofracture stress measurements; and short line crossing the solid square, direction of the maximum horizontal compressive stress (S_H). *B*, Seismicity correlated with monthly reservoir pressure (heavy solid line). Reprinted from Raleigh and others (1976) and published with permission.

the induced seismicity began and corresponded to the critical pore pressure below and above which earthquake activity could be turned off and on when the injection pressure was varied intentionally in a later controlled experiment (fig. A2*B*; Raleigh and others, 1976). This experiment in earthquake control established the validity of the Mohr-Coulomb failure model in predicting the critical threshold of stress and pore pressure necessary for earthquake occurrence. Each time the fluid pressure in the part of the field where earthquakes had appeared previously exceeded the predicted threshold, more earthquakes began to occur (fig. A2*B*). Earthquake activity declined whenever the fluid pressure fell below the threshold.

Attica-Dale, New York

Solution mining for salt in the Attica-Dale area (fig. A3) triggered a marked increase in microearthquake activity in 1971. As many as 80 earthquakes per day were concentrated within 1 km of a 426-m-deep injection well (fig. A4; Fletcher and Sykes, 1977) in an area where the previous record of activity was less than 1 event per month. All these earthquakes were small and had estimated magnitudes of between -1.0 and 1.0. THP at the injection well typically operated between 52 and 55 bars, or only a few bars less than that calculated to induce sliding on preexisting fractures that have no cohesion, based on the Mohr-Coulomb failure criterion and analysis of hydrofracture stress measurements conducted about 100 km from the activity. Seismicity continued in the Dale brine field for as long as elevated pore pressure was maintained (fig. A5). The low level of background activity before high-pressure injection began, the dramatic increase in activity following injection, and the rapid cessation of activity following a decrease in injection pressure below about 50 bars (fig. A6) strongly suggest that this seismicity was induced by injection activities.

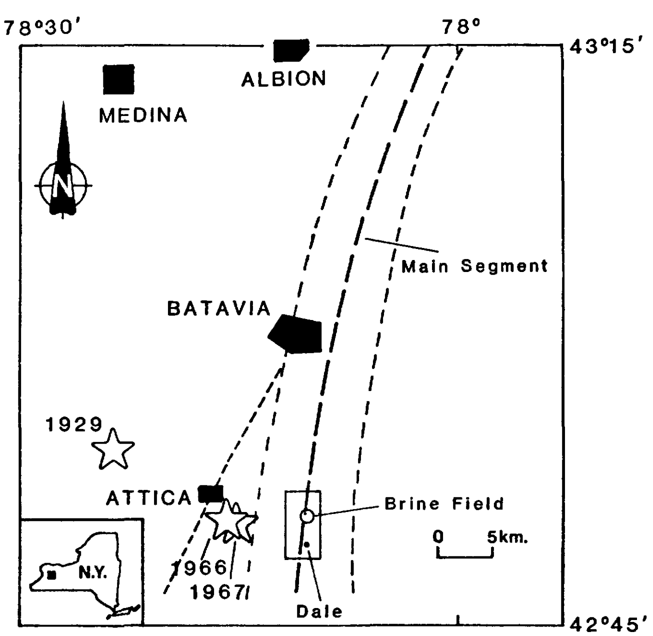


Figure A3. Location of the Dale brine field, western New York. Circle, field; heavy dashed line, Clarendon-Linden Fault; lighter dashed line, lesser secondary faults; stars, epicenters of large historical earthquakes near Attica in 1929, 1966, and 1967; and box, approximate area shown in figure A4 (from Nottis, 1986).

Texas Oil Fields

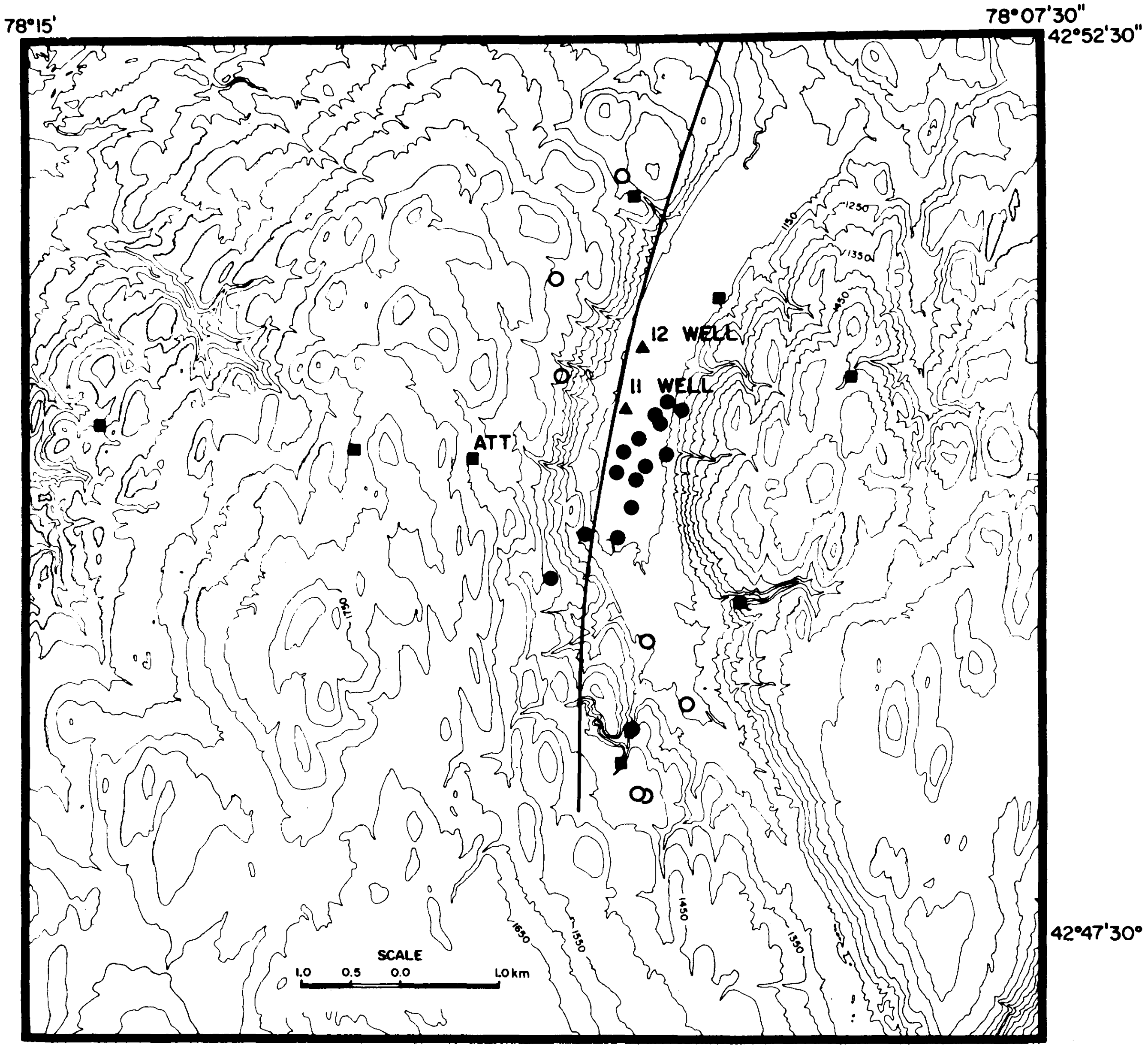
Permian Basin, West Texas and Southeastern New Mexico

Cases of induced seismicity associated with fluid injection operations for the secondary recovery of oil and gas have been suggested for several areas in Texas (pl. 1). One of the earliest reports alludes to an increase in seismicity associated with petroleum production and waterflooding operations in the Permian basin of West Texas near Kermit (Shurbet, 1969). A marked increase in earthquakes above magnitude 3 was observed to correlate with a dramatic increase in the number of injection wells operating at pressures greater than 70 bars. This increase in seismicity was of particular interest because of its proximity to a radioactive-waste-disposal site in southeastern New Mexico (fig. A7*A*; Rogers and Malkiel, 1979). About 20 earthquakes (the largest of which was about M 4.4) were recorded between November 1964 and December 1976. Twelve stations were subsequently installed to monitor this seismicity and to determine whether, in fact, the earthquakes were directly related to oil field activities. Between December 12, 1975, and June 26, 1977, 406 earthquakes were detected, most of which were at depths of less than 5.0 km and nearly all in areas that had active water-flooding operations (fig. A7*B*). Continued monitoring through September 1979 by the local network identified several pronounced clusters of seismic activity. The largest and most active area coincides with the War-Wink South oil and gas field located in the Delaware Basin region of Ward County, West Texas (Keller and others, 1981; Keller and others, 1987). Much of this seismicity is shallow and exhibits predominantly normal faulting (Keller and others, 1987), which is consistent with subsidence as a result of gas withdrawal. Other areas of activity include earthquakes in 1976 and 1977 associated with the Dollarhide oil field that extends into southeastern New Mexico, as well as more-recent seismicity located on the Central Basin Platform in the vicinity of the Keystone oil field (Orr, 1984; Orr and Keller, 1985). Nine of the local water-flooding projects that typically operated at injection pressures of greater than 100 bars are listed in table A1 (Texas Railroad Commission, 1971, 1985). These wells range in depth from 800 to 3,700 m. Measurements of *in situ* stress determined from hydrofracturing indicated a maximum regional compressive stress

Table A1. Characteristics of well operations and reservoir properties associated with possible induced seismicity

[Depth, bottom of well; thickness, of reservoir; k, permeability; THP, top hole pressure; BHP, bottom hole pressure; p_0, initial formation pore pressure; S_h, minimum horizontal compressive stress; S_H, maximum horizontal compressive stress; S_v, vertical stress; Max mag, maximum magnitude; ***, not applicable (injection not performed)]

Well site or oil field location	Depth (m)	Thickness (m)	k (mD)	Porosity (percent)	THP (bars)	BHP (bars)	p_0 (bars)	S_h (bars)	S_H (bars)	S_v (bars)	Max mag	Year of earthquakes
Ashtabula, Ohio	1,845	46	0.6	10	100	284	191	320	>460	460	3.6	1987
Catoosa, Okla.											4.7?	1956, 1960
Cogdell Canyon Reef, Tex.	2,071	43	18–30	7	199	406	215			476	4.6	1974–79
Dale, N.Y.	426	16			55	98		76	>109	109	1.0	1929?, 1966?, 1971
Rocky Mountain Arsenal, Denver, Colo.	3,671		0.03	2	76	415	269	362	<830	830	5.5	1962–67
East Texas, Tex.	1,113	3	200	23	103	214	70			256	4.3	1957, 1985
Fenton Hill, N. Mex.	2,700		.01		200	493	265	405	<635	635	<1.0	1979
Flashing Field, Tex.	3,400	50	13	15	***	71	352			768	3.4	1973–83
The Geysers, Calif.	3,000		<.05	3			<35	245	785	785	4.0	1975–
Gobles Field, Ontario, Canada	884	9			***		45			225	2.8	1979–84
Hunt Field, Miss.											3.6	1976–78
Imogene Field, Tex.	2,400	33	14	17	***	146	246			542	3.9	1973–84
Lake Charles, La.	1,411	49			93	234			<325	325	3.8	1983–
Love County, Okla.	3,622	427			277	632		538	~833	833	2.8?	1977?–, 1979
Matsushiro, Japan	1,800				50	230				460	2.8	1970
Northern Panhandle, Tex.	2,022	21	50	15	21	223	145			465	3.4	1983–84
Calhio, Perry, Ohio	1,810	88	6	8	114	294	200	320	>460	460	2.7?	1983–87
Rangely, Colo.	1,900	350	1	12	83	275	170	314	552	427	3.1	1962–75
Rocky Mountain House, Alberta, Canada.	4,000				***			>1,020	>1,020	1,020	4.0	1974–80
Sleepy Hollow, Nebr.	1,150	100	26		56	171	115		<265	265	2.9	1977–84
Snipe Lake, Alberta, Canada											5.1	1970
Permian basin fields:											4.4	1964–79
Dollarhide, Tex.-N. Mex.	2,590	59	17	14	138	397	179			596	~3.5	1964–79
Dora Roberts, Tex.	3,661	38	1	7	431	797	324			842	~3.0	1964–79
Kermit Field, Tex.	1,829	5	1	15	221	404	198			421	~4.0	1964–79
Keystone I Field, Tex.	975	11	21	20	103	200	90			224	~3.5	1964–79
Keystone II Field, Tex.	2,987	101	7	3	176	475	204			687	~3.5	1964–79
Monahans, Tex.	2,530	12	6	4	207	460	131			582	~3.0	1964–79
Ward-Estes Field, Tex.	914	11	35	16	117	208	103			210	~3.5	1964–79
Ward-South Field, Tex.	741	5	30	21	138	212	76			170	~3.0	1964–79
War-Wink South, Tex.	1,853	2.5	17	18	***					426	~3.0	1964–79



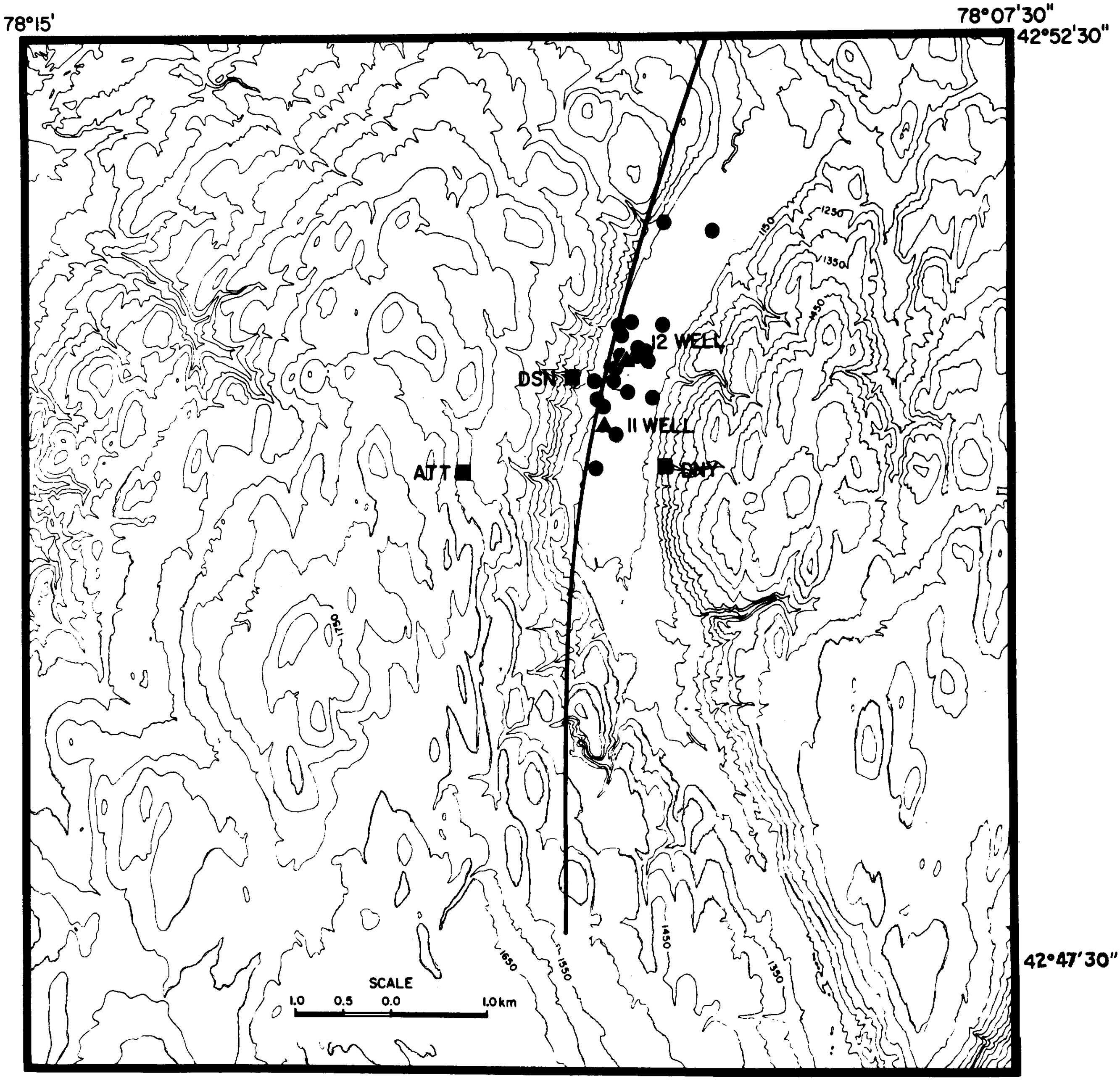
A

Figure A4. Epicenters of well located earthquakes near the Dale brine field, New York. Solid circles, well located earthquakes; squares, monitoring stations; triangles, injection wells; open circles, epicenters that have poor resolution; and solid line, Clarendon-Linden Fault. *A*, October 1971. *B*, November 1971. Reprinted from Fletcher and Sykes (1977) and published with permission.

of 150 bars and a minimum compressive stress of 85 bars at depths of about 485 m.

Cogdell Canyon Reef Oil Field, West Texas

The largest earthquake to occur in known association with an oil field injection operation within the United States was a magnitude 4.6 to 4.7 event near Snyder in June 1978. This earthquake, which was part of a sequence of events that apparently had been active since 1974 (Davis, 1985), was located in the Cogdell Canyon Reef oil field of West Texas (fig. A8). Initial formation pressure at the time of discovery (1949) amounted to 215 bars BHP. By 1956, pressure in the field had dropped to 79 bars BHP, which necessitated a water-flooding and pressure-maintenance program. A dramatic increase in the numbers of injection wells, volumes of fluid pumped, and effective pressures took place in the early 1970's, shortly after which the first felt earthquake was experienced (Harding, 1981a). Surface injection pressures ranged as low as 45 to 95 bars, but



B

Figure A4. Continued.

typically operated between 186 to 217 bars THP. By using the Mohr-Coulomb failure criterion, these higher values of injection pressure were determined to be sufficient to induce slip on favorably oriented fractures (Davis, 1985). Because injection pressure in the field remained fairly constant, there is little correlation between the injection pressure and the episodic nature of the earthquake activity. There is some correlation, however, between volumes of fluid injected and the rate of local earthquake occurrence (fig. A9). The data were interpreted to suggest that large (felt) earthquakes were preceded by a reduction in field permeability (which corresponded to a drop in volume of water accepted by the reservoir at constant pressure) followed by an increase in permeability after each of the major earthquake sequences (Harding, 1981a).

Because of the proximity of the earthquakes to oil field operations, a small local network of stations was operated from February 1979 through August 1981 (fig. A8; Harding, 1981a). As of 1985, a total of about 30 earthquakes had been spatially associated with the Cogdell

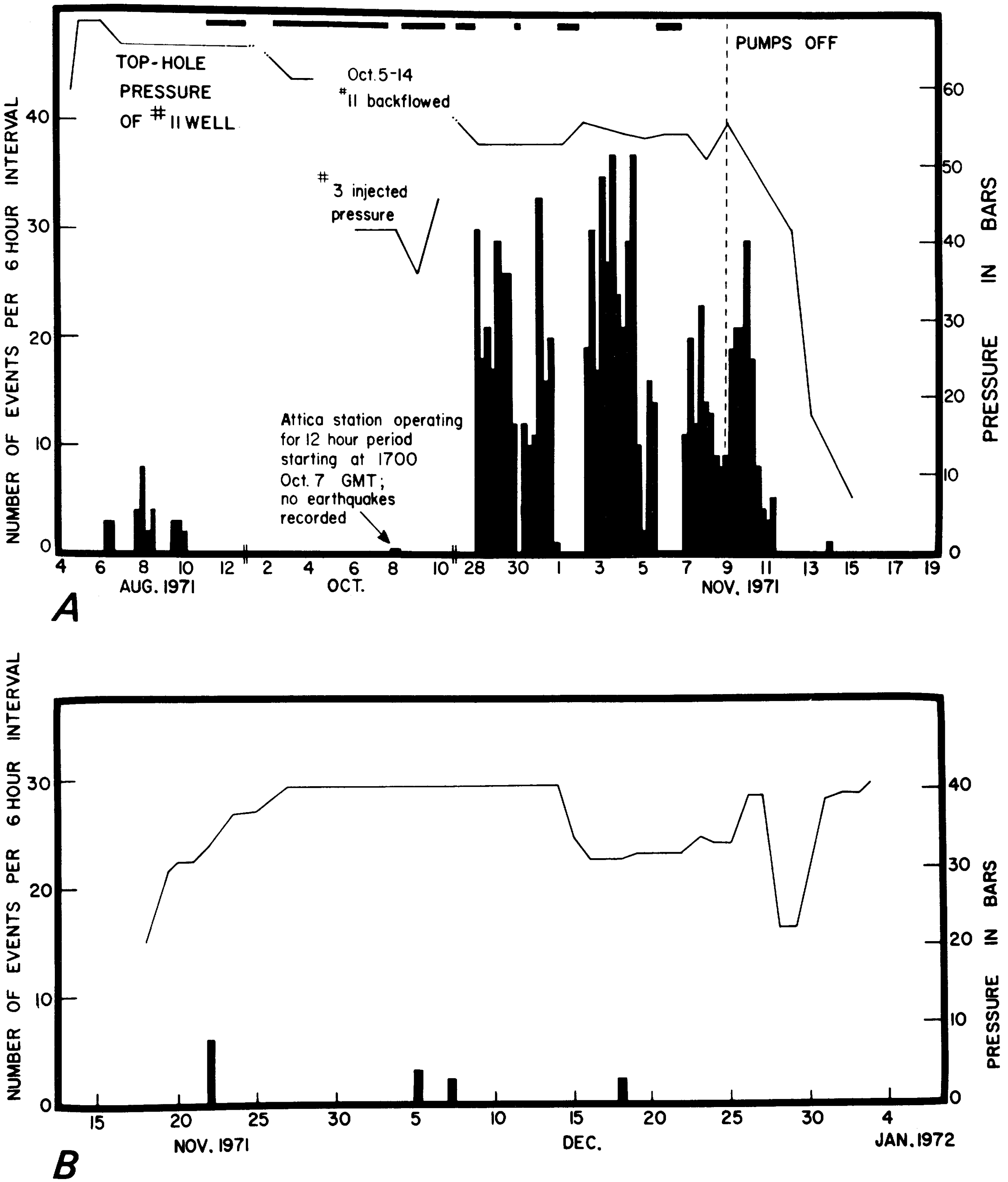


Figure A5. Number of earthquakes and pumping pressures (light solid lines) with time in the Dale brine field, New York. *A*, From August 4 to November 19, 1971, when top-hole injection pressures in well 11 typically exceeded 50 bars. Note the abrupt cessation of activity after pumping was shut down on November 9. *B*, Similar to *A* but from November 15, 1971, to January 4, 1972, when the maximum injection pressure did not exceed about 40 bars. Reprinted from Fletcher and Sykes (1977) and published with permission.

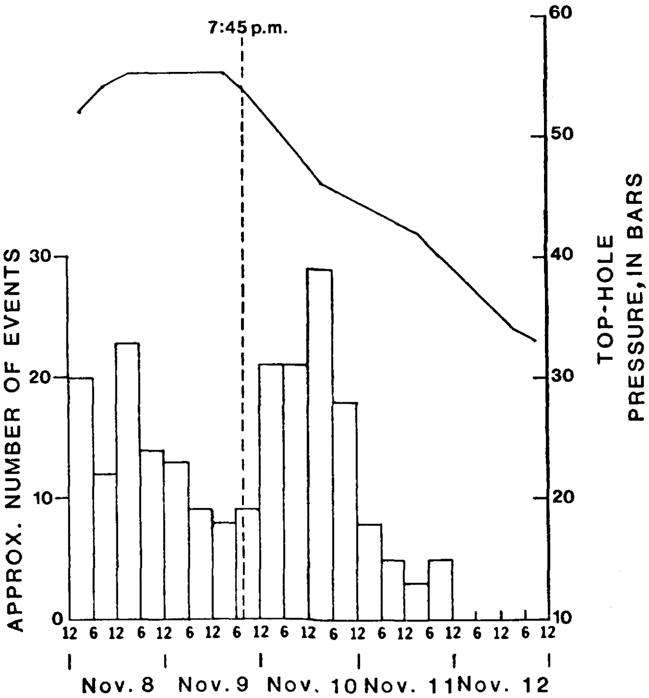


Figure A6. Enhanced section of figure A5 for well 11 of the Dale brine field, New York, showing the rapid decrease in seismicity after pumping ceased at 7:45 p.m. on November 9, 1971, and well pressure (solid line) subsequently declined below about 50 bars (from Nottis, 1986).

Canyon Reef oil field (fig. A8); most of the events occurred between April 1977 and August 1979. Many of the wells that penetrate to the Canyon Reef Formation operate at depths of between 2,070 and 2,265 m. These well depths coincide with the shallow focal depths (on the order of 3 km or less) of the earthquakes located within the oil field (Harding, 1981b) and are nearly the same as the focal depth (3 km) determined for the June 1978 event (Voss and Herrmann, 1980).

Atascosa County, South Texas

Seismic activity also has been identified with the *withdrawal* of oil and gas from two fields in south Texas (pl. 1; Pennington and others, 1986). Production from the Imogene oil and gas field began in 1944; the depth of the producing horizon is 2.4 km. Initial fluid pressure in the field was approximately 246 bars and was reduced to 146 bars by 1973. In the Flashing gas field, production began in 1958 at a depth of 3.4 km. Initial pore pressure in the producing formation was 352 bars but was reduced to only 71 bars (or 20 percent of the original value) by 1983. The rapid withdrawal of fluid and gas apparently resulted in subsidence and differential compaction of the producing horizon in both fields, which is similar to the situation in the War-Wink gas field. Seismic activity began in 1973; the largest earthquake (M 3.9) occurred in the Imogene field in March 1984. In both cases, the sizes and the number of earthquakes increased over time, which is consistent with a model for the evolution of the hydrologic characteristics of the field whereby the strength of the rock increases as fluid pressure decreases. The earthquakes are believed to be generated as formation pore pressure is reduced to the point that further fluid extraction and subsequent subsidence results in strain accumulation in the newly strengthened rock. If the strains are large enough, then the amount of energy accumulated in the rock is apparently sufficient to cause earthquakes as large as magnitude 3 to 4 (Pennington and others, 1986).

The Geysers, California

In a case similar to Atascosa County, Tex., a large number of small earthquakes ($M_L \leq 4$) have been triggered by the reduction in steam pressure caused by energy production in The Geysers geothermal area near Clear Lake in northwestern California (fig. A10; Oppenheimer, 1986). The Geysers is the site of a vapor-dominated steam field where, by the early 1980's, 150 wells had been drilled to depths of between 0.8 and 3.0 km. Earthquake activity has increased in The Geysers area by nearly a factor of two over seismicity levels before production; about 10 microearthquakes that have magnitudes of greater than 0.5 typically occur each day. Evidence that the increased seismicity was induced relied upon the spatial and the temporal distribution of the microearthquakes in the vicinity of the producing steam wells. During the period from 1975 to 1981, earthquakes were found to occur in previously aseismic areas within months following the initiation of steam extraction from newly developed regions of the reservoir. Seismic activity also correlated with energy production or rate of steam extraction (fig. A11). Earthquake hypocenters were found to extend from 0 to 6.5 km in depth, but earthquakes that had focal depths of less than 3.5 km were typically located within a few hundred meters laterally from the sites of active steam wells (Eberhart-Phillips and Oppenheimer, 1984). Although some of the extracted steam is condensed and reinjected, the reduction in effective normal stress caused by increased pore pressure is not considered to be the likely mechanism to explain the induced seismicity. Steam pressure in the field actually has declined by about 1 bar/yr since 1966 as a result of cooling, and the number of earthquakes did not correlate with volumes of steam condensate injected into the wells. The two possible mechanisms thought to be responsible for the increased seismicity are the increased shear stresses that are a result of volumetric thermal contraction caused by reservoir cooling (Denlinger and others, 1981) and by reservoir subsidence arising from large fluid mass withdrawal (Majer and McEvilly,

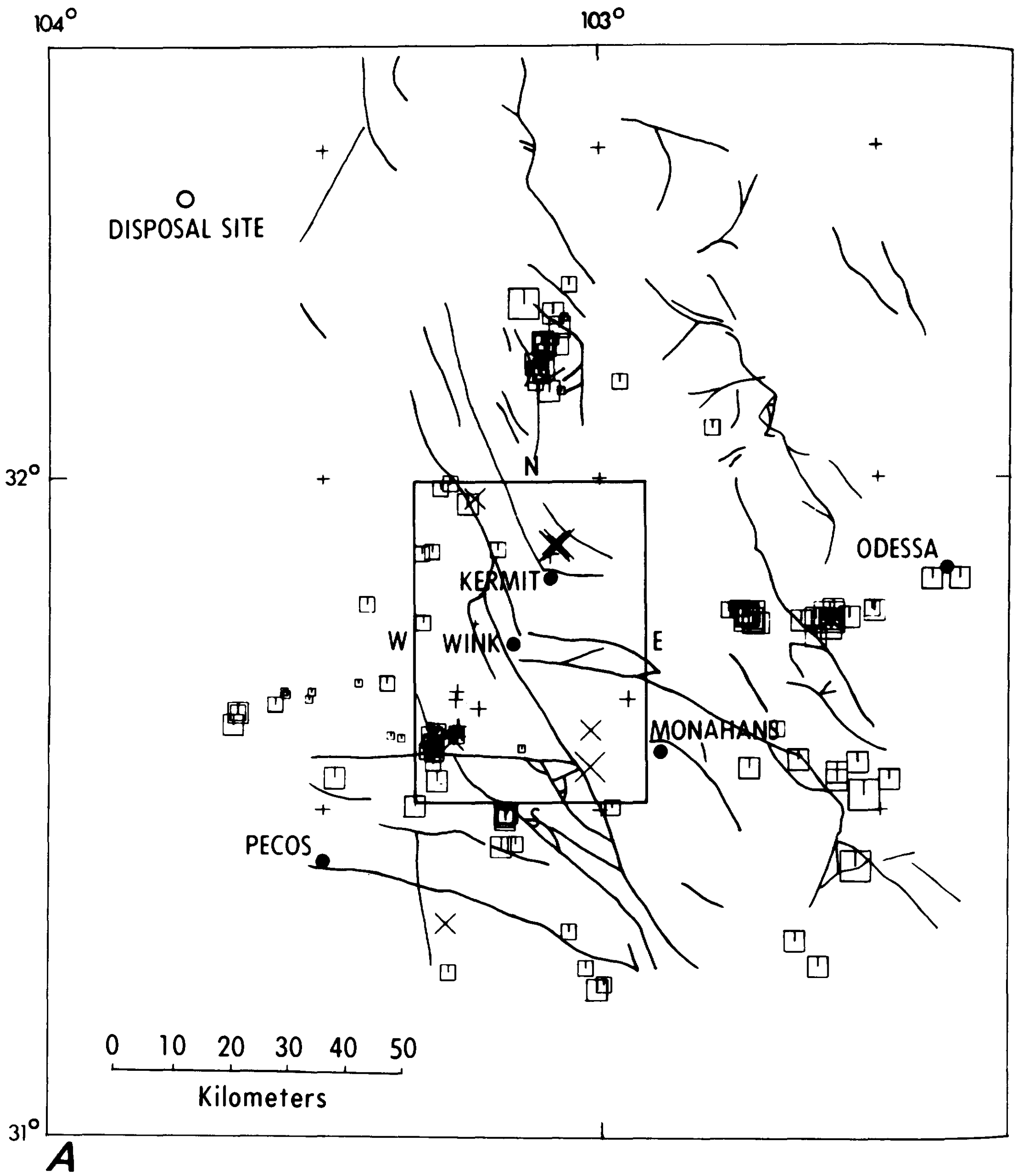
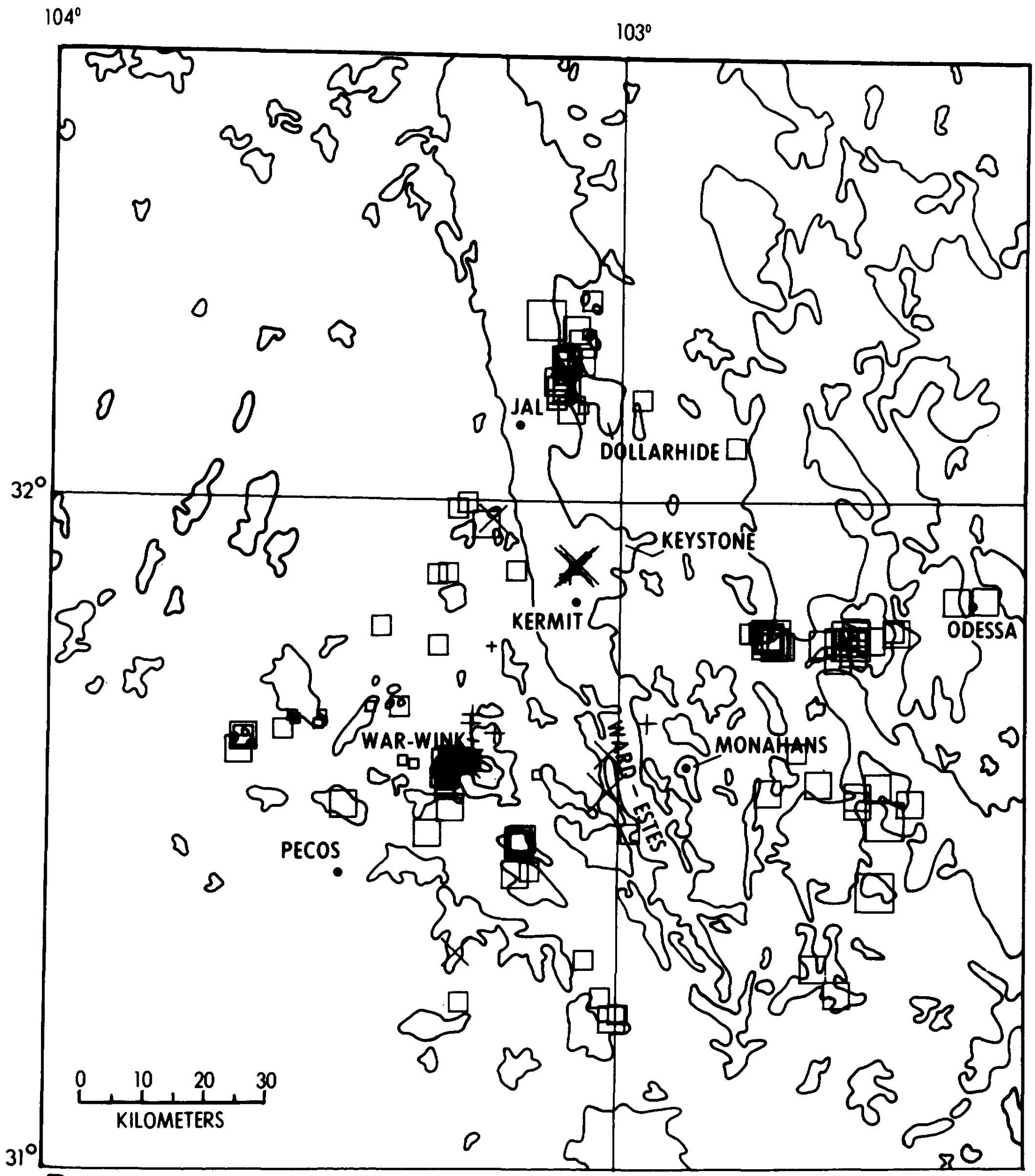


Figure A7. Earthquakes located in the Central Basin Platform of the Permian Basin, West Texas, from January 1976 to July 1977. *A*, Earthquake epicenters and known pre-Permian basement faults shown with solid lines; radioactive-waste-disposal site in New Mexico is shown by the open circle. *B*, Epicenters and outlines of oil fields; labeled fields are sites of active water-flooding operations during the same time period. *A* and *B*, Size of symbol indicates magnitude—X, 3.0 to 4.0; x, 2.0 to 3.0; +,1.0 to 2.0; +, ≤1.0; square sizes indicate less reliable earthquake epicenters in the same magnitude ranges. Reprinted from Rogers and Malkiel (1979) and published with permission.

1979) or, alternatively, the conversion of continuous aseismic slip into seismic slip (that is, earthquakes) by an increase in the coefficient of friction following the deposition of exsolved solids (probably silica) onto slipping fracture surfaces (Allis, 1982).

Fenton Hill, New Mexico

Several hundred microearthquakes were generated during a massive hydraulic fracturing experiment conducted at Fenton Hill (pl. 1) in March 1979 (Pearson, 1981). The



B

Figure A7. Continued.

purpose of the experiment was to stimulate a fracture in a deep (2,930-m) injection well that would propagate so as to intersect an adjacent production well to be used in a hot-dry rock geothermal energy project. Hydraulic stimulation involved nearly 460,000 L of water injected over a 5½-hr period. Maximum THP was held constant at 200 bars. During the experiment, activity averaged 3 to 4 microearthquakes per minute. Formation pore pressure before injection was measured at about 265 bars. Maximum and minimum effective horizontal stresses were found to be 370 and 140 bars, respectively. By using the Mohr-Coulomb failure criterion, Pearson (1981) determined that only 30 bars of increased pore pressure was sufficient to initiate slip on favorably oriented preexisting joints. Most of the small earthquakes appeared to be localized to within 30 m of the expanding hydraulic fracture. Unfortunately, the stimulated fracture failed to intersect the desired production well. In a subsequent attempt, 7.6 million L of water was injected at a depth of 3,400 m at a rate of 1,600 L/min, which triggered an additional 850 microearthquakes in the vicinity of the well (House and McFarland, 1985).

Sleepy Hollow Oil Field, Nebraska

After the installation of sensitive monitoring equipment in Nebraska in 1977, a concentration of seismic

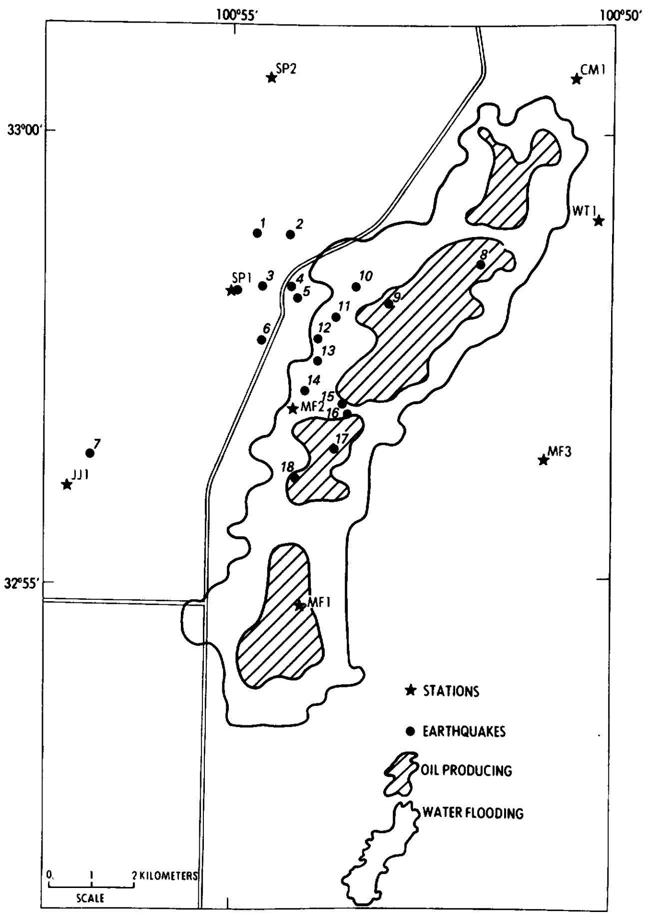


Figure A8. Epicenters of well located earthquakes in the Cogdell Canyon Reef oil field near Snyder, Tex. Also shown are the locations of network stations and the extent of water flooding and oil production (from Harding, 1981a).

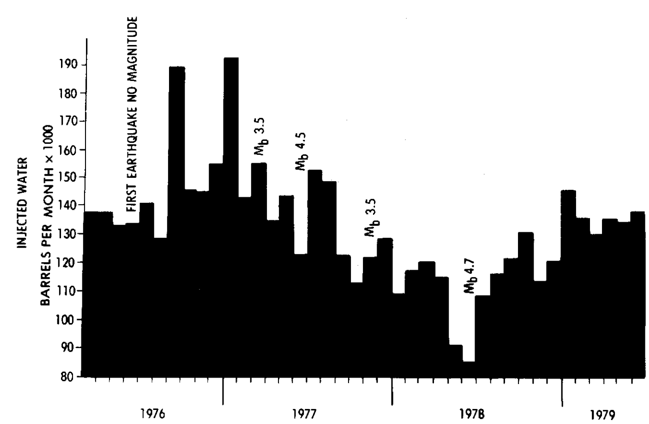


Figure A9. Cumulative monthly volume (barrels) of water injected in the Cogdell Canyon Reef oil field, Texas, and times of reported felt earthquakes (from Harding, 1981a). M_b, body-wave magnitude.

activity was identified near the Kansas-Nebraska border (pl. 1). From March 1979 to March 1980, subsequent investigations using portable instruments (fig. A12*A*) detected 31 earthquakes in close proximity to the most productive oil field in the State—the Sleepy Hollow (Evans and Steeples, 1987). Water flooding to enhance recovery had been in operation since 1966. As shown in figure A13*A*, water injection typically operated at 52 bars THP within the Lansing Group (depths of 1,050–1,130 m) and 22 bars within the Sleepy Hollow sandstone (Reagan) formation (1,150–1,170 m depth), which corresponded to 172 and 142 bars BHP, respectively. Most of the well located earthquakes occurred within the confines of the producing field and at depths of less than 2 km (Rothe and Lui, 1983) in an area where well-defined subsurface faults (fig. A13*B*) were present, based on structure contour maps. Maximum magnitude of the induced seismicity was 2.9. In a later monitoring program, an additional 250 microearthquakes were detected within the active field between April 1982 and June 1984 (fig. A12*B*; Evans and Steeples, 1987), when the average THP in the field reached as high as 56 bars.

Southwestern Ontario, Canada

Oil and gas production from the Gobles oil field, which is located in southwestern Ontario about 55 km east-northeast of London (fig. A14*A*) began in 1960 (Mereu and others, 1986); the producing horizon is 884 m deep. Because formation fluid pressure was lower than expected, water-flooding operations to enhance recovery began in 1969. Historically, this area of southwestern Ontario has had a very low level of seismic activity. In December 1979, a M 2.8 earthquake was detected in the vicinity of the oil field. From July 1980 through August 1984, a portable network of stations recorded 478 earthquakes within and around the producing area (fig. A14*B*). All the locatable events were shallow and exhibited travel-times consistent with hypocenters at a focal depth coincident with the producing horizon. No spatial correlation with specific wells was identifiable, however, and, although earthquake activity varied considerably in time, fluctuations in activity rate did not correlate with injection pressure, which, for the most part, remained nearly constant. This area is located just west of the Dale brine field in western New York and just north of injection-induced seismicity in northeastern Ohio (see section "Recent Seismicity and Injection Operations—Northeastern Ohio").

Matsushiro, Japan

Besides the Rangely oil field experiment, one of the few attempts to specifically manipulate earthquake behavior by fluid injection occurred near Matsushiro, Japan. In 1970, 2.9 million L of water was injected at a depth of 1,800 m,

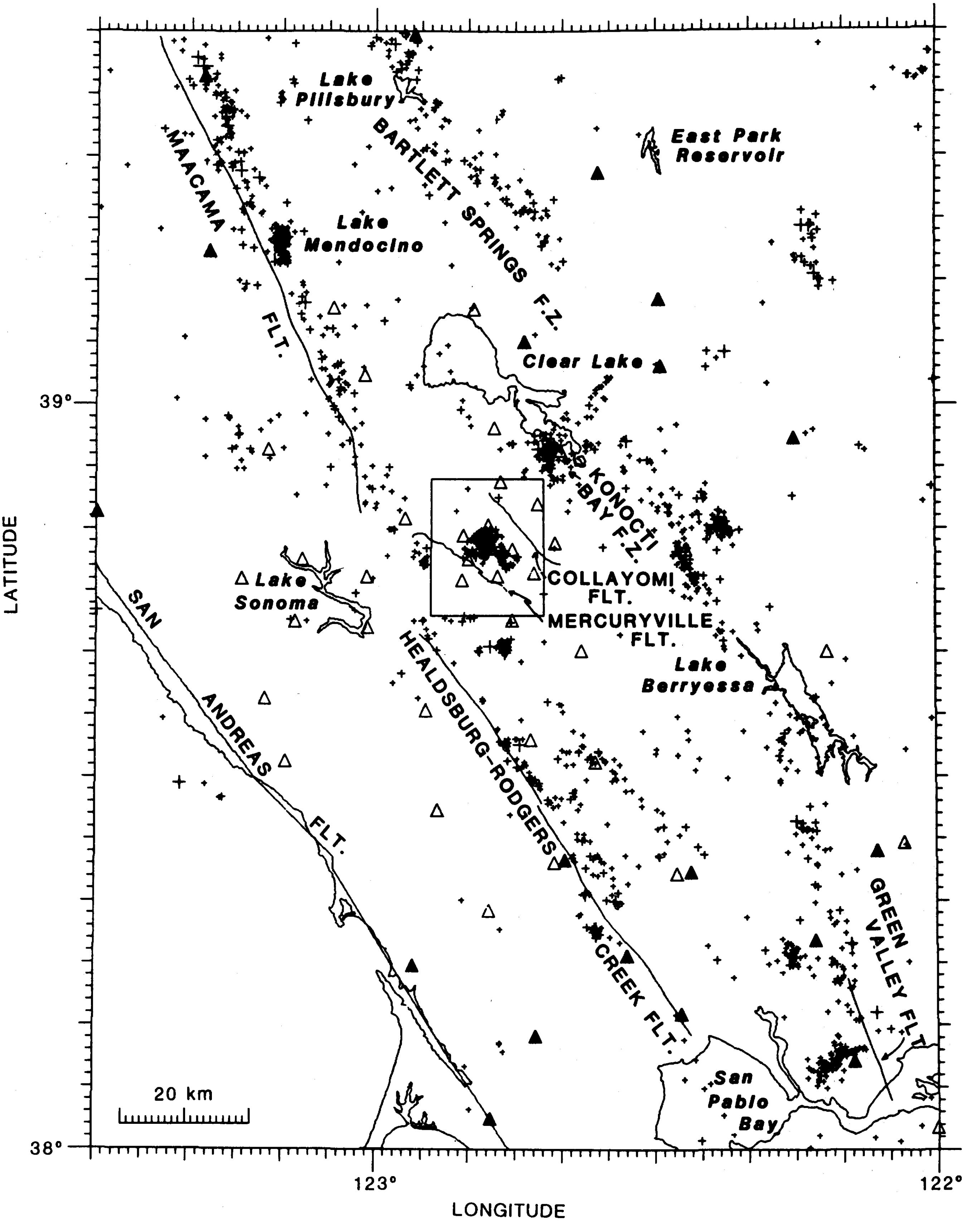


Figure A10. The Geysers geothermal area, California, and surrounding region. Epicenters outside the box represent well located earthquakes from January 1976 through December 1984. Seismicity inside the box is from the period January 1984 through October 1985. Open box, geothermal area; +, $M_L \geq 1.5$ epicenters; open triangles, locations of CALNET stations; and solid triangles, locations of stations used for locations of regional seismicity. Reprinted from Oppenheimer (1986) and published with permission.

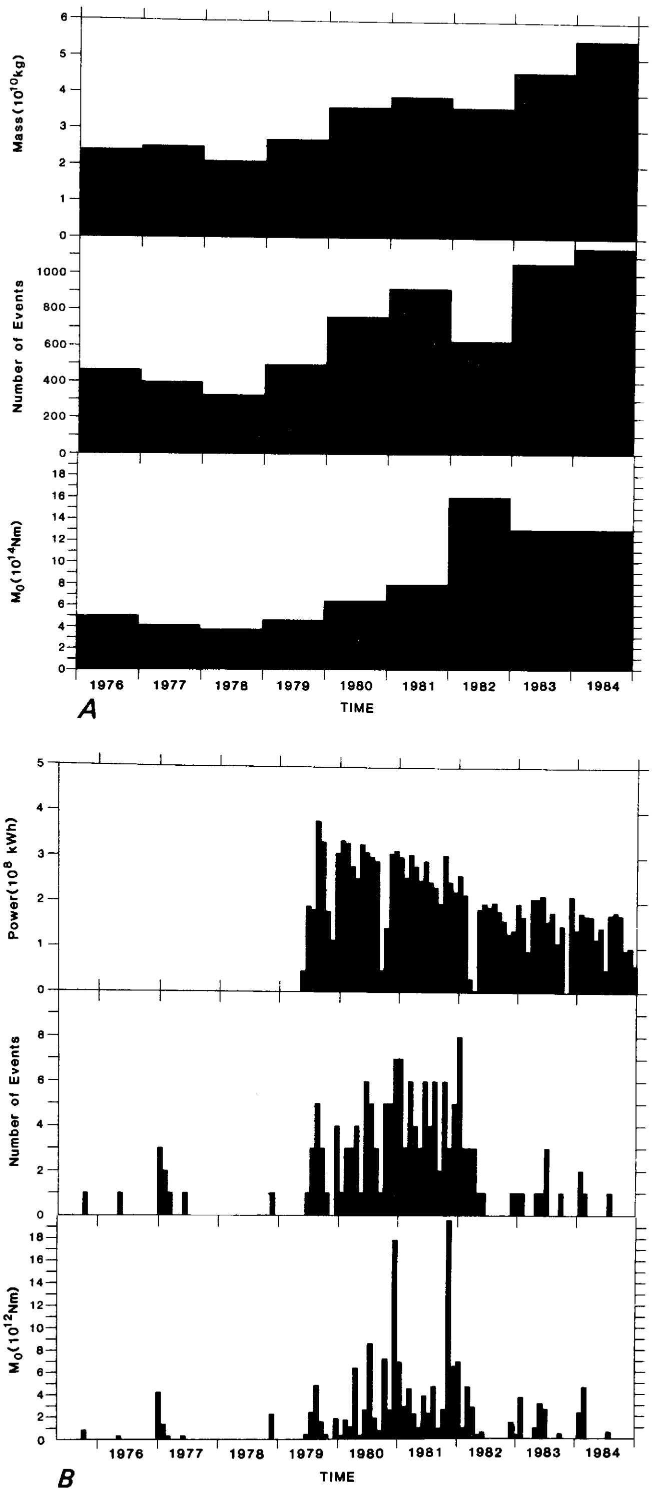


Figure A11. Water withdrawn and power generated as compared with the rates of seismicity at The Geysers geothermal field, California. *A*, Yearly net mass of water withdrawn. *B*, Monthly power generated. Both are compared with numbers and moments of earthquakes. Reprinted from Oppenheimer (1986) and published with permission.

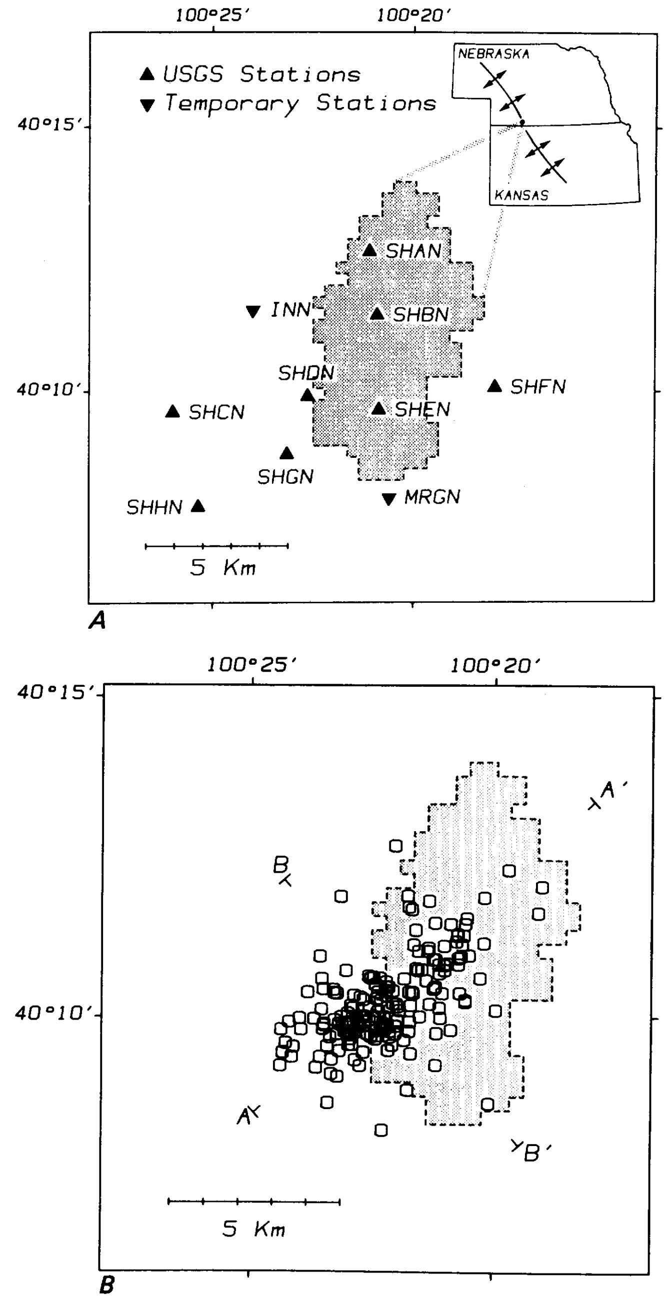


Figure A12. Seismic monitoring stations and earthquake epicenters, Sleepy Hollow oil field, Nebraska. *A*, Seismic monitoring stations. Shaded region, producing area of the field; and triangles, stations. *B*, Earthquake epicenters in the vicinity of the field between April 1982 and June 1984. Reprinted from Evans and Steeples (1987) and published with permission.

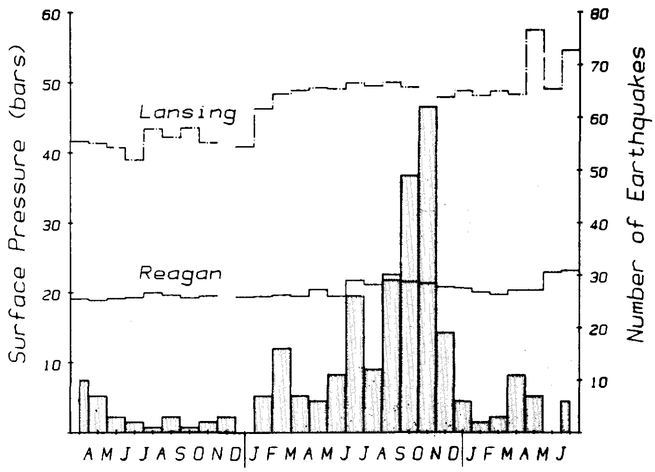
THP's of 14 to 50 bars, and injection rates of 120 to 300 L/min (Ohtake, 1974). During the 2 months (mo) of the experiment, several hundred small earthquakes were triggered within 4 km of the well and at depths of 1.5 to 7.5 km. A delay of 5 to 9 days (d) was observed between the onset of the increased seismicity and the increased injection pressure. Activity was significantly greater during injection than either before or after the experiment. Much of the induced seismicity was localized along the northeast-dipping Matsushiro fault zone, whereas most of the background seismicity was scattered in the hanging wall (Ohtake, 1974). No attempts were made to determine the *in situ* state of stress or the critical threshold for failure as indicated by the Mohr-Coulomb failure criterion, but the observed time delay for the onset of seismicity and the subsequent migration in depth of the earthquakes were consistent with inferred values of permeability and the time required for pore pressure effects to migrate to the area where the earthquakes were observed.

Less Well Documented or Possible Cases

Western Alberta, Canada

On March 8, 1970, a M 5.1 earthquake occurred near Snipe Lake (fig. A15; Milne, 1970). No significant earthquakes had previously occurred in the area, and, on the basis of the limited felt area and preliminary determinations of focal depth (<9 km), the 1970 event appeared to have been relatively shallow (Milne and Berry, 1976). At the time of the earthquake, 646 oil and gas wells were in operation within 80 km of Snipe Lake. Production began in 1954, and water injection to maintain field pressure had been in effect in 56 wells since 1963. Although little else is known about this event, this earthquake is considered to be the first and largest known Canadian example of an earthquake induced by fluid injection in a producing oil field because it occurred within an oil-producing area where fluid injection was actively taking place (Milne and Berry, 1976).

Confirmation that well activities in western Alberta are triggering earthquakes was documented near Rocky Mountain House (fig. A15; Wetmiller, 1985, 1986), where a microearthquake survey was conducted in 1980. In 23 d of operation, a seven-station network detected 146 earthquakes, of which 67 events were locatable. The largest earthquake recorded was a magnitude 3.4. All the locatable earthquakes occurred in a very small source area (fig. A16*A*) that was about 4 km long by 4 km wide by 1 km thick at a depth of 4 km. This source region coincides with the base of the Paleozoic section and is the site of the Strachan D-3A gas field, which is a Devonian-aged limestone-reef sour gas reservoir and western Alberta's major producer of natural gas. Production began in the field in the early 1970's, and a marked increase in seismicity, including earthquakes as large as M 4.0, began in 1974 (fig.



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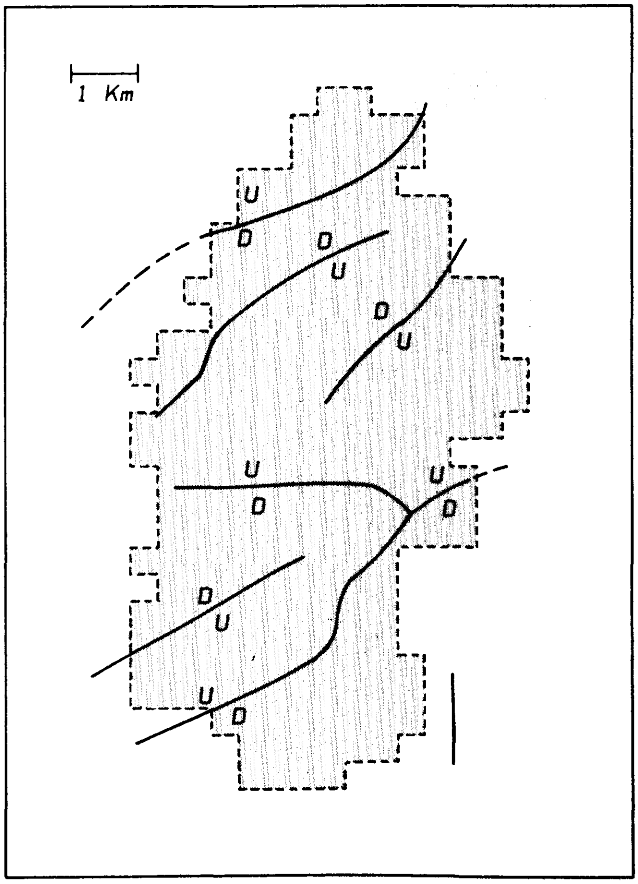
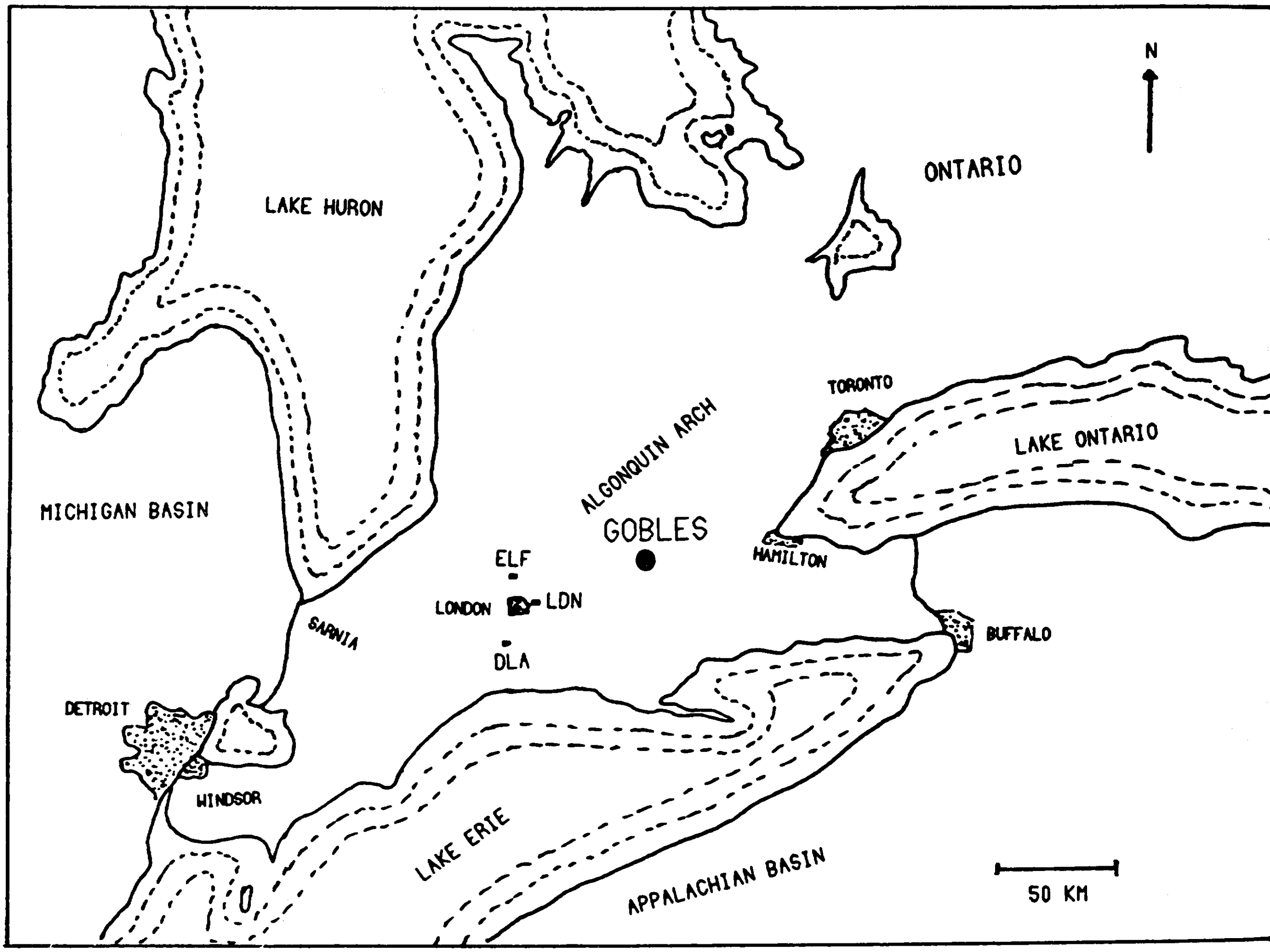


B

Figure A13. Formation fluid pressures and mapped faults, Sleepy Hollow oil field, Nebraska. *A*, Average monthly pressures within the two formation reservoirs used for injection and the number of earthquakes per month. Ten injection wells were added in May and June 1983. *B*, Mapped faults in the Precambrian basement in the vicinity of the field (shaded area). Reprinted from Rothe and Lui (1983) and published with permission.



A

Figure A14. Location and earthquake epicenters, Gobles oil field, southwestern Ontario, Canada. Seismic stations of the University of Western Ontario permanent seismic array are shown. *A*, Location of the field (solid circle). *B*, Earthquake epicenters in the vicinity of the field relative to location of local monitoring stations (solid squares). Reprinted from Mereu and others (1986) and published with permission.

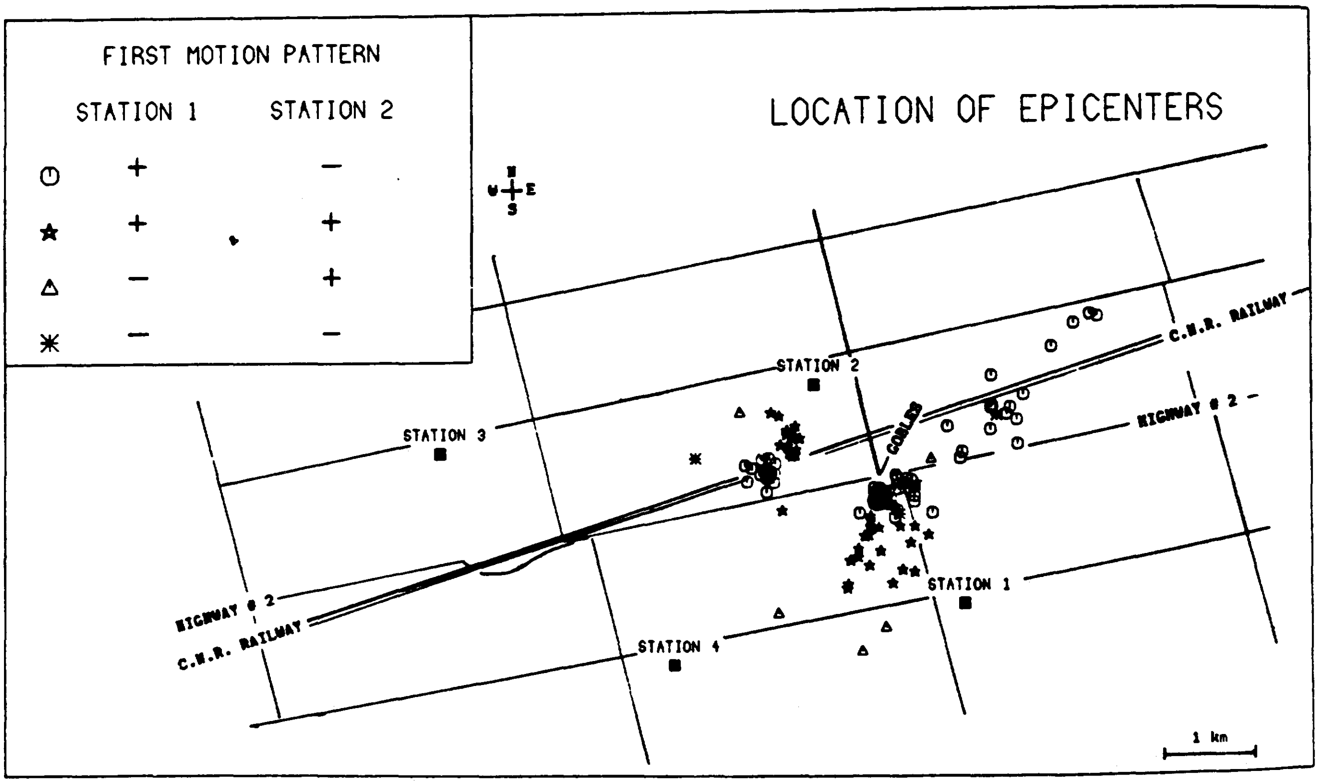
A16*B*; Wetmiller, 1986). The timing and the spatial correspondence of the microearthquake activity directly in or below the actual zone of production strongly suggests that the local seismicity is being triggered by gas production. The predominant thrust-faulting focal mechanisms exhibited by the earthquakes, however, indicate that the seismicity may be related to crustal unloading, which is similar to the situation of possible induced earthquakes near the Gazli gas field in Soviet Uzbekistan (Simpson and Leith, 1985), rather than to other cases of shallow normal-faulting events associated with subsidence of petroleum fields without secondary fluid injection (Yerkes and Castle, 1976; Pennington and others, 1986).

Since 1984, a six-station seismic network has been operating in the Cold Lake area of Alberta (Kapotas and Kanasewich, 1989), where heavy oil is being extracted by using an *in situ* process of steam injection. Local microearthquake activity ranges from 20 to more than 100 events per year. The induced tremors are mostly less than M 2 and, on the basis of geomorphological characteristics of the bedrock topography, appear to follow a major inferred subsurface fault structure through the area of heavy-oil production. Within the network, induced earthquakes occur at shallow focal depths consistent with formation levels of steam injection and oil extraction. Southeast of the array, earthquakes are also detected in association with fluid injection operations to dispose of excess oil field brine (Kapotas and Kanasewich, 1989).

Historical Seismicity and Solution Salt Mining

Western New York

The identification of recent induced seismic activity with the Dale brine field (Fletcher and Sykes, 1977) and



B

Figure A14. Continued.

with secondary recovery operations in southwestern Ontario (Mereu and others, 1986) suggests that a relation may exist between the older historical earthquakes in western New York and the adjacent solution mining operations in production at the time. Solution salt mining operations have been in operation in the northwestern region of the State since the late 19th century (Dunrud and Nevins, 1981). In 1929, a large (M 5.2) earthquake occurred near Attica (fig. A3), that caused significant damage in the epicentral region [VIII on the Modified Mercalli Intensity Scale (MM), Appendix C]. Subsequent earthquakes in 1966 (M 4.6) and 1967 (M 3.8) also generated relatively high intensities for their size (Herrmann, 1978). These high intensities were attributed to the shallow focal depths of the earthquakes (about 2 km, or roughly on the same order as the depth of the active solution salt mining wells). Past investigators have attributed these earthquakes near Attica to tectonic slip along the Clarendon-Linden fault system (fig. A3); however, the shallow focal depths and the proximity to protracted mining operations suggest that these earthquakes also may have been triggered by the adjacent mining operations. Unfortunately, the lack of detailed records of injection activities or direct measurements of the state of stress in the epicentral region make any definitive correlation between these older historical earthquakes and mining operations difficult.

Northeastern Ohio

The association of solution mining with the occurrence of small earthquakes in western New York State (Fletcher and Sykes, 1977) and the extensive salt mining operations in northeastern Ohio (Clifford, 1973) suggested the possibility that some of the earthquake activity in Ohio also may be related to solution salt mining (fig. A17). Solution mining for salt began in northeastern Ohio in 1889 (Clifford, 1973; Dunrud and Nevins, 1981) and continues to the present, although several previously active operations have been closed down. The target horizon for the mining operations is the Silurian Salina Formation at a depth of 600 to 900 m, depending on the distance from Lake Erie. On the basis of their spatial proximity and temporal association, it could be argued that several earthquakes in the northeastern region of the State are related to active solution salt mining operations. In particular, earthquakes in 1898, 1906, and 1907 (Stover and others, 1979), which were located within the Cleveland metropolitan area, as well as earthquakes in 1932 and 1940, which were about 50 km south of Cleveland, are possible examples. However, in view of the large number of earthquakes reported before the initiation of solution mining and the apparent occurrence of at least some earthquakes in northeastern Ohio beyond the range of the expected influence of mining operations, it seems reasonably clear that at least some of the earthquakes are

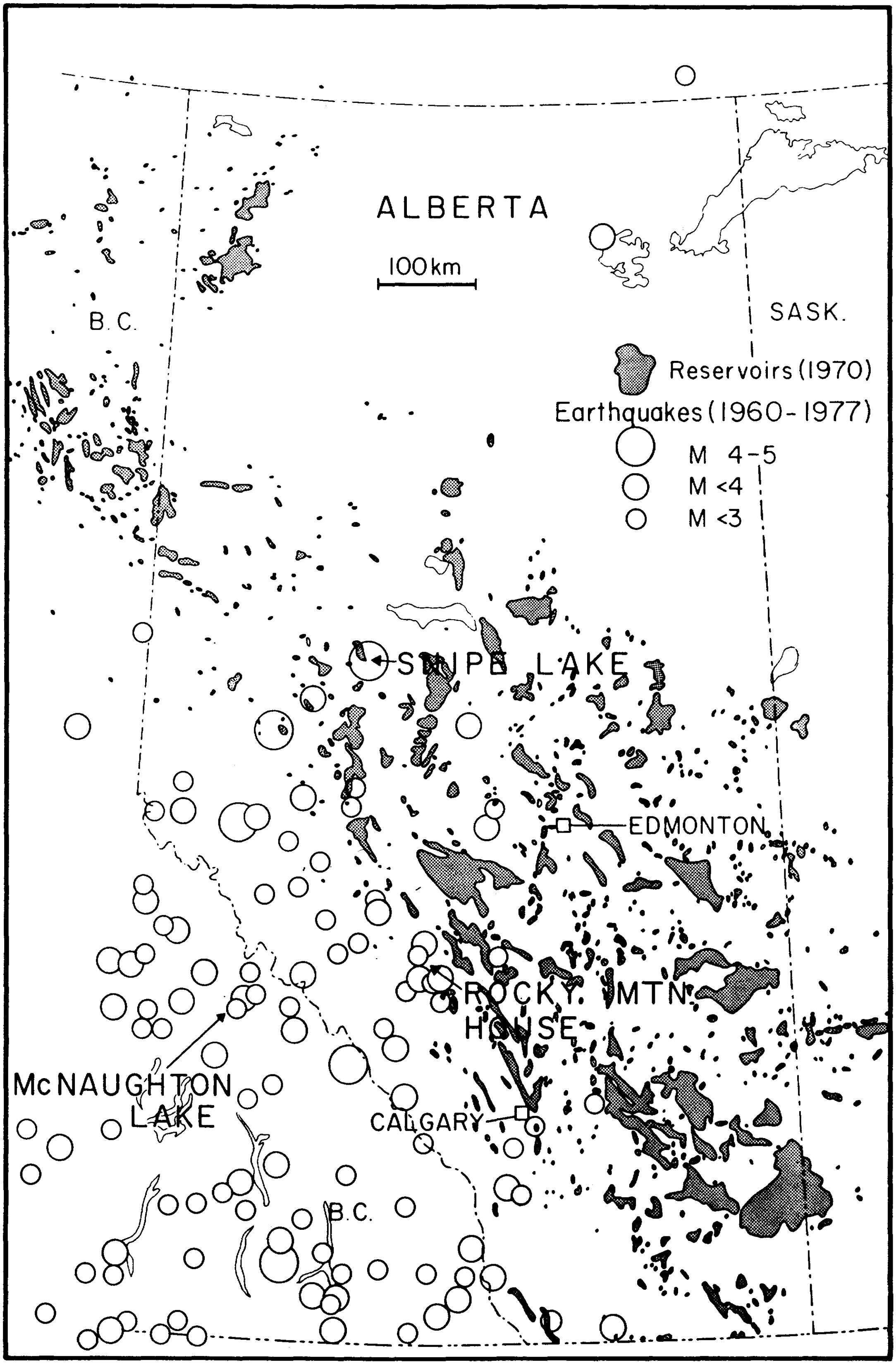


Figure A15. Earthquakes in Alberta, Canada (1960–77), and locations of active oil and gas reservoirs (shaded areas). Reprinted from Wetmiller (1986) and published with permission.

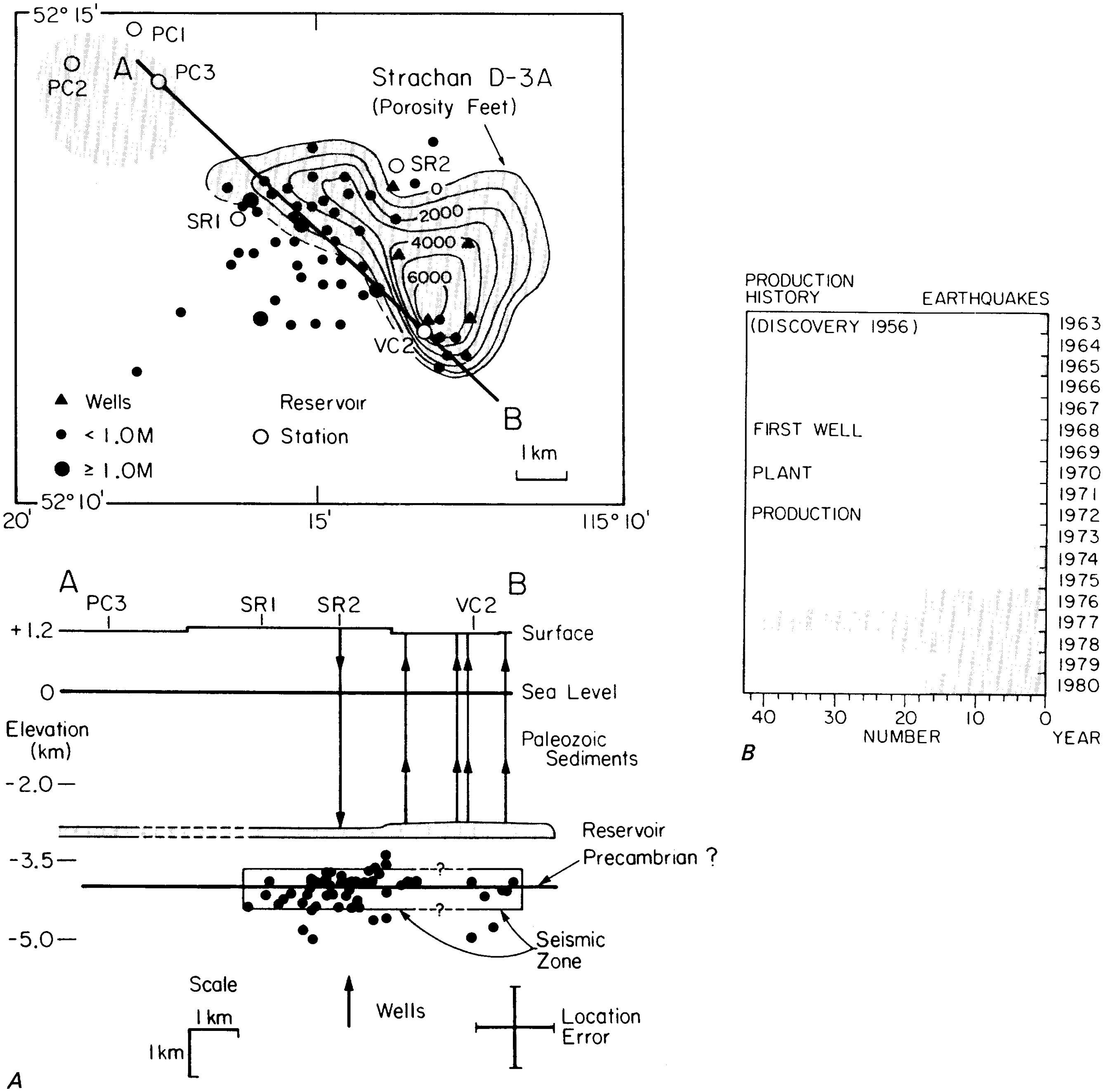


Figure A16. Locations of microearthquakes, production history, and earthquake activity, Strachan D-3A reservoir and gas field, western Alberta, Canada. *A*, Detail of the distribution in area and cross section of the microearthquakes (solid circles) located by the 1980 field survey within the reservoir and main production wells (solid triangles). *B*, Production history and annual earthquake activity at the field. Reprinted from Wetmiller (1986) and published with permission.

natural and that solution mining is not a necessary condition for the occurrence of earthquake activity.

Recent Seismicity and Injection Operations in Northeastern Ohio

On January 31, 1986, at 11:46 EST, an earthquake of magnitude 5.0 occurred about 40 km east of Cleveland, Ohio, and about 17 km south of the Perry Nuclear Powerplant (fig. A18). Within hours, a dense network of portable stations was installed to monitor possible aftershock activity (Wesson and Nicholson, 1986). As of April 15, only 13 aftershocks were detected, 6 of which occurred within the first 8 d. At the time of the mainshock, three deep injection wells for the disposal of hazardous and nonhazardous waste were operating within 15 km of the epicentral region and,

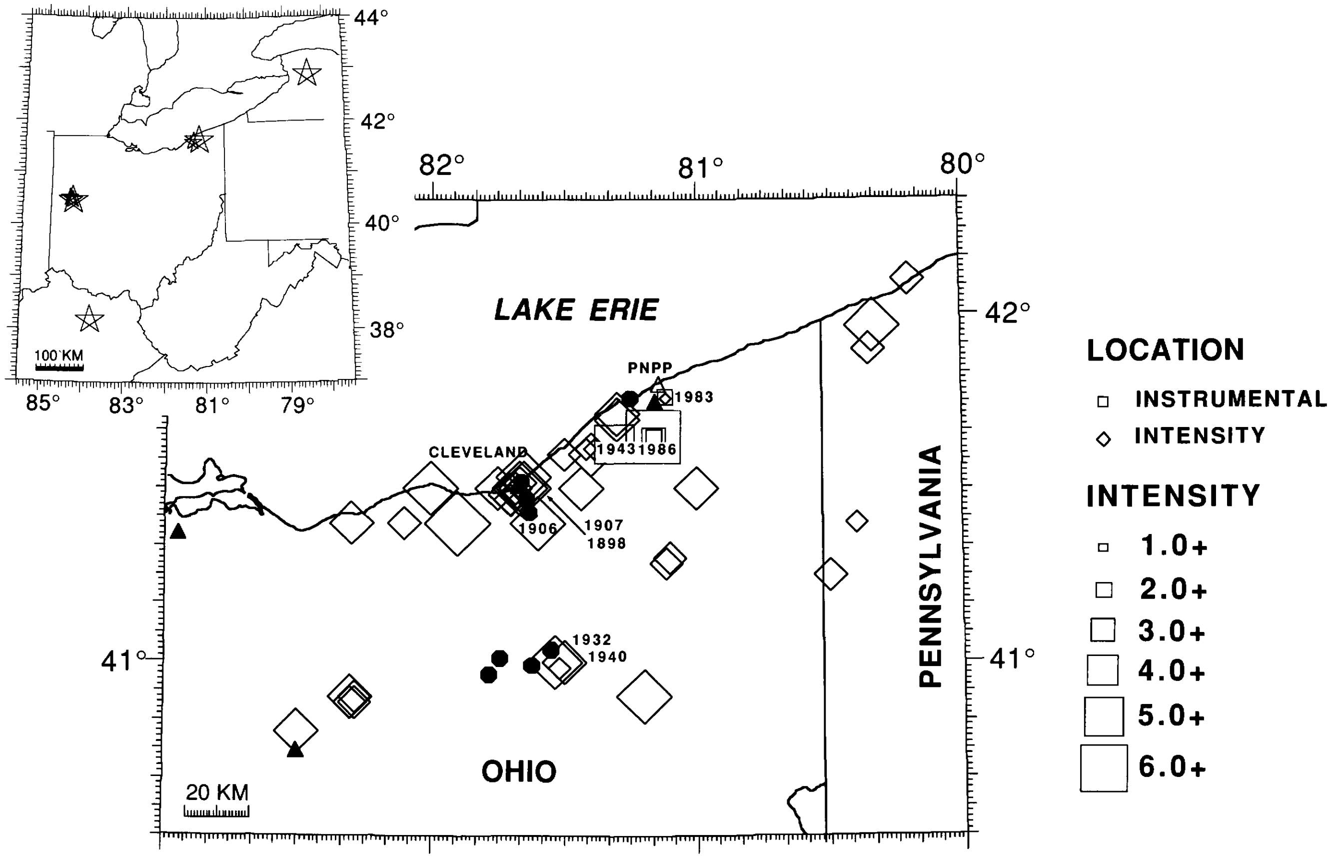


Figure A17. Locations of the Perry Nuclear Powerplant, the January 31, 1986, earthquake, and the significant historical seismicity and dates of occurrence, northeastern Ohio. Most of the seismicity precedes initiation of injection activities. PNPP, powerplant; large square, January 31 earthquake; solid octagons, sites of solution salt mining, typically in operation from 1900 to 1940; solid triangles, deep waste injection wells drilled from 1968 to 1971; diamonds, poorly located earthquakes, typically based on felt reports; squares, instrumentally located earthquakes; and stars, recent regional $M \geq 4.5$ earthquakes (from Nicholson and others, 1988).

since 1975, have been responsible for the injection of nearly 1.2 billion L of fluid at a nominal depth of 1.8 km. Injection pressures at typical injection rates of 320 L/min reached a maximum of 112 bars THP.

Although the distance between the major injection wells and the January 31 earthquake (12 km) is greater than the corresponding distances in either the Denver or the Dale earthquakes, the total volume of fluid injected and the injection pressures involved are proportionately greater. Estimates of stress inferred from commercial hydrofracturing measurements suggest that the state of stress in northeastern Ohio is close to the theoretical threshold for failure along favorably oriented preexisting fractures, as determined by the Mohr-Coulomb failure criterion (fig. 5). The maximum horizontal compressive stress is greater than the vertical stress of 460 bars, the minimum horizontal stress is about 300 bars, and, before injection, the initial formation pore pressure was measured at about 200 bars (Wesson and Nicholson, 1986). This implies that, at a nominal injection pressure of 110 bars, the zone immediately surrounding the well bottom would be in a critical stress state for favorably oriented fractures that have cohesive strengths of as much as 40 bars and a coefficient of friction (μ) of 0.6 (fig. 5). Calculations of the pressure effect in the epicentral region based on modeling the fluid flow away from the wells and comparison with the history of pressure increase at the wells with time and continued pumping suggest that a radial flow model (instead of the narrow confined aquifer implicated in the Denver case) is the most appropriate. This model implies that, as a result of fluid injection since 1975, the expected fluid pressure increase in the epicentral region of the 1986 earthquakes would have been only a few bars. Since 1983, however, several small earthquakes have occurred at shallow depths and within less than 5 km from the wells (fig. A18)—where the calculated pressure increase as a result of fluid injection is about 15 bars or greater (Nicholson and others, 1988).

The increased depth and distance from the wells to the 1986 mainshock epicenter and its aftershocks, the lack of large numbers of small earthquakes typical of many induced sequences, the history of small to moderate earthquakes in the region before the initiation of injection, and

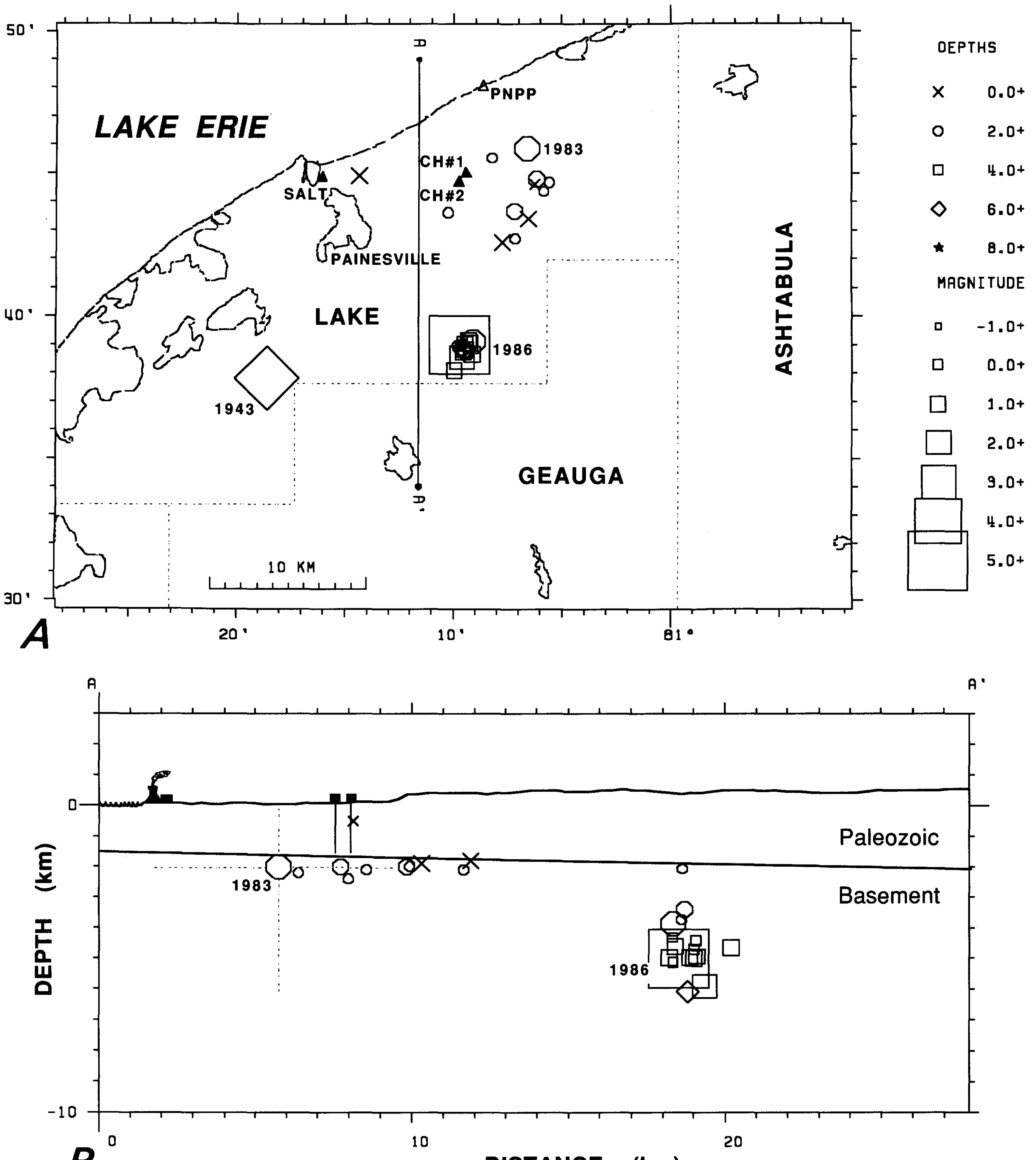


Figure A18. Deep injection wells and earthquake epicenters, Lake County, Ohio. *A*, Location of deep injection wells and earthquake epicenters through early 1987. Large uncertainties in location are associated with the 1943 and the 1983 earthquake epicenters. Solid triangles, injection wells; CH#1 and CH#2, deep waste-disposal wells; SALT, Painesville brine well; PNPP, Perry Nuclear Powerplant. *B*, Vertical cross section, no exaggeration, along the line *A–A'* shown in *A* (from Nicholson and others, 1988).

the attenuation of the pressure field with distance from the injection wells all argue for a "natural" origin for the January 31 earthquake. In contrast, the proximity to failure conditions at the bottom of the wells and the spatial association of at least a few small events suggest that triggering by well activities can not be precluded.

Ashtabula, Ohio

Confirmation that deep well fluid injection in northeastern Ohio has the potential for triggering earthquake activity was demonstrated dramatically on July 13, 1987. A M 3.6 earthquake occurred near Lake Erie, just east of Ashtabula and about 40 km northeast of the location of the January 31, 1986, earthquake (fig. A19). Except for one earthquake in 1857, no other earthquakes were known to have occurred within 30 km of Ashtabula. In the weeks following the mainshock, an unusually large number of aftershocks (more than 70 events) were generated (Armbruster and others, 1987). All the well located earthquakes were clustered in a narrow east-west-striking vertical plane about 1.5 km long that extended from about 1.6 to 3.2 km in depth (fig. A20; Armbruster and others, 1987; Seeber and others, 1988). The earthquakes occurred less than 1 km from the bottom of a hazardous-waste-disposal well that had been in operation only since July 1986. The injection well is about 1.8 km deep and operates at a nearly uniform flow rate of 114 L/min and at an injection pressure of about 100 bars THP (Ernie Rotering, Ohio EPA, written commun., 1987). Between July 1986 and June 1987, well operations were responsible for nearly 62 million L of hazardous fluid waste being injected into the basal sandstone layer (the Mount Simon Formation). The proximity to the active injection well and the temporal correlation of the seismicity with the initiation of well activities (about a year earlier) strongly suggests that the Ashtabula earthquakes of July 1987 were induced (Seeber and others, 1988).

Los Angeles Basin, California

The massive withdrawal of oil from one of the largest fields in the Los Angeles Basin, the Wilmington oil field (fig. A21), resulted in significant subsidence within the city limits of Long Beach. Up to 8.8 m of surface subsidence was observed over an elliptically shaped area between 1928 and 1970 (Mayuga, 1970). This rapid subsidence, which reached a maximum rate of 71 centimeters per year in 1951 9 mo after peak oil production (fig. A22), resulted in several damaging earthquakes, specifically in the years 1947, 1949, 1951, 1954, 1955, and 1961. In all cases, the earthquakes were unusually shallow (approximately 500 m deep) and generated high intensities for their size. The largest earthquake occurred on November 17, 1949, and caused nearly 200 wells to go off production, many of them permanently (Richter, 1958). Damage was estimated to be in excess of $9 million. The area affected equaled over 5.7 square kilometers (km^2) and involved measured displacements of 20 centimeters. This would correspond to an earthquake that had a moment magnitude of 4.7 and is consistent with a magnitude of 5.1 estimated from the

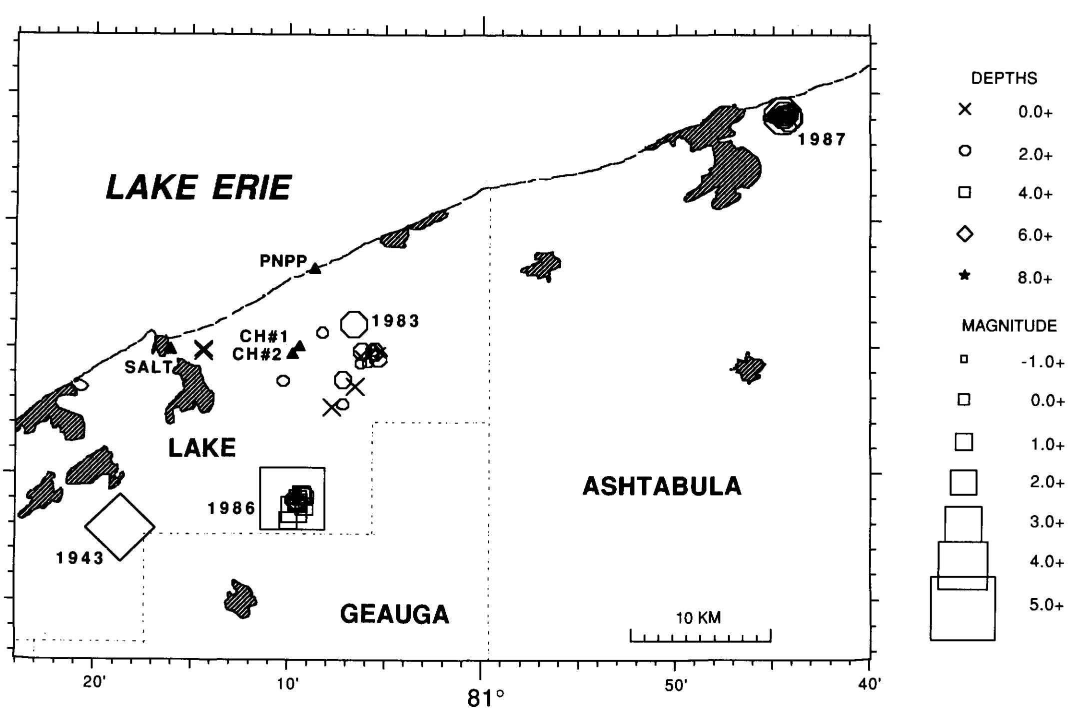


Figure A19. Location of the 1987 induced earthquake sequence in northeastern Ohio near Ashtabula relative to the 1986 earthquakes in Lake County.

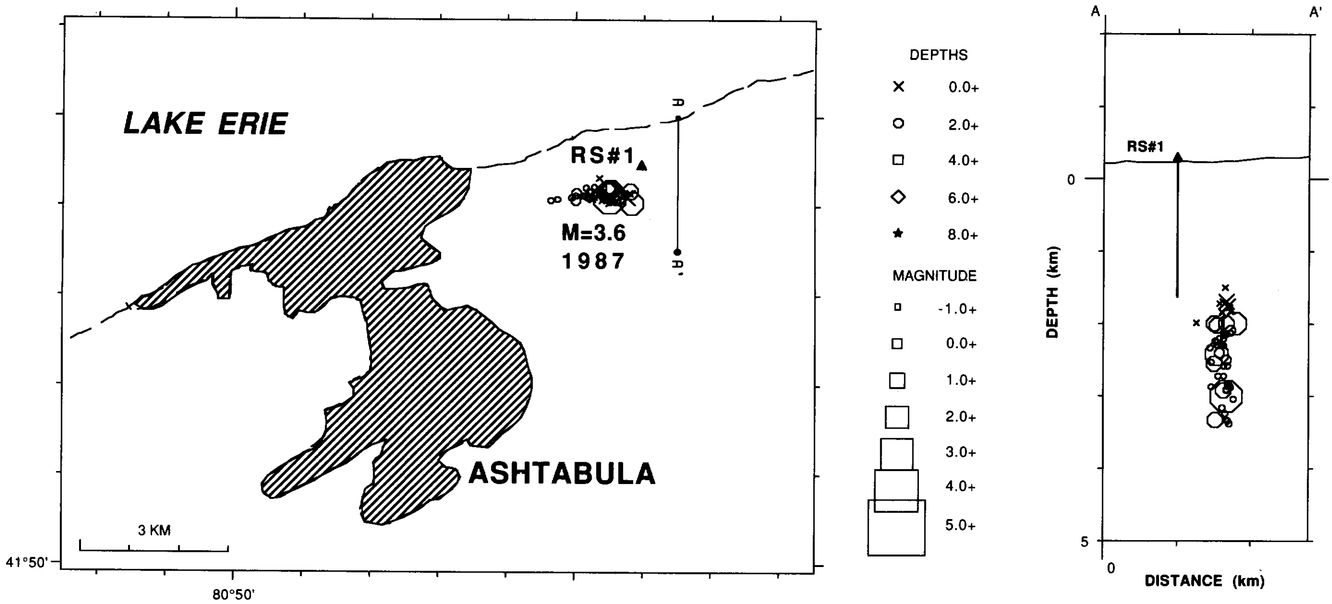


Figure A20. The 1987 Ashtabula, Ohio, earthquake hypocenters relative to the location of a nearby active, high-pressure, waste-disposal injection well (triangle, RS#1). Earthquake data provided courtesy of John Armbruster (Lamont-Doherty Geological Observatory, written commun., 1987).

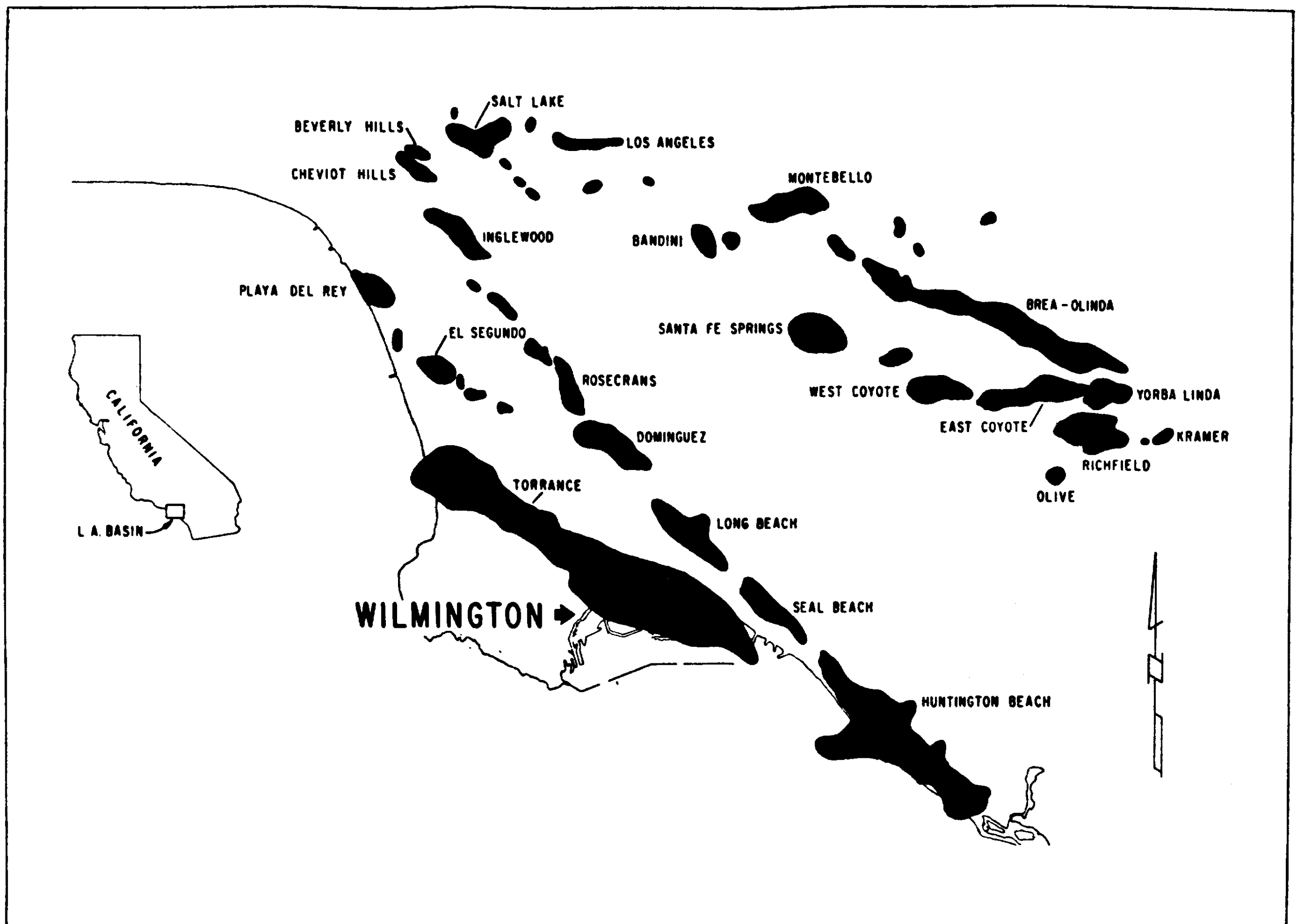


Figure A21. Distribution of the oil fields (shaded areas) in the Los Angeles Basin, Calif. (from Mayuga, 1970).

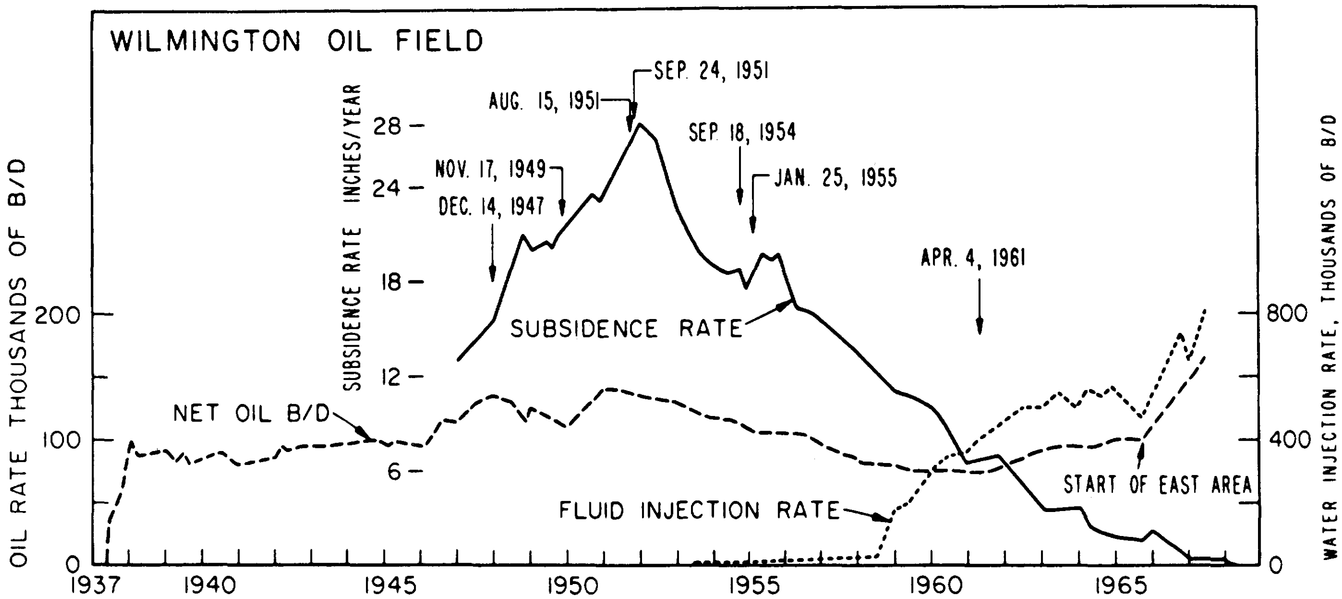


Figure A22. Subsidence rate in the center of the Wilmington oil field, California, compared with oil production and water injection rates. Arrows, major damaging earthquakes. Reprinted from Kovach (1974) and published with permission.

unusually well developed surface waves generated by the event (Kovach, 1974).

Water flooding of the field and adjacent areas was initiated in 1954 in an attempt to halt subsidence and to enhance the secondary recovery of oil. Teng and others (1973) reported on the seismic activity associated with 14 oil fields operating within the Los Angeles Basin where water-flooding operations were taking place. As of 1970, total fluid injection was 250,000 million L at depths that ranged from 910 to 1,520 m.

Although much of the seismicity in the area is natural and occurs predominantly at depths as deep as 16 km along the Newport-Inglewood Fault (Hauksson, 1987), seismic activity during 1971 appeared to correlate, at least in part, with injection volumes from nearby wells (fig. A23; Teng and others, 1973). However, many of the earthquakes detected were small (M<3.2) and occurred at depths of 5 km or more, which made it difficult to distinguish them from the natural background seismicity. Subsequent injection operations have stabilized to the point where fluid injection nearly equals fluid withdrawal and little, if any, seismic activity can be directly attributable to injection well operations (Egill Hauksson, University of Southern California, oral commun., 1986).

Northern Texas Panhandle and East Texas

In 1984, a small network of monitoring stations was operated under contract to the Office of Nuclear Waste Isolation, U.S. Department of Energy, in the Palo Duro Basin of the northern Texas Panhandle (Stone and Webster

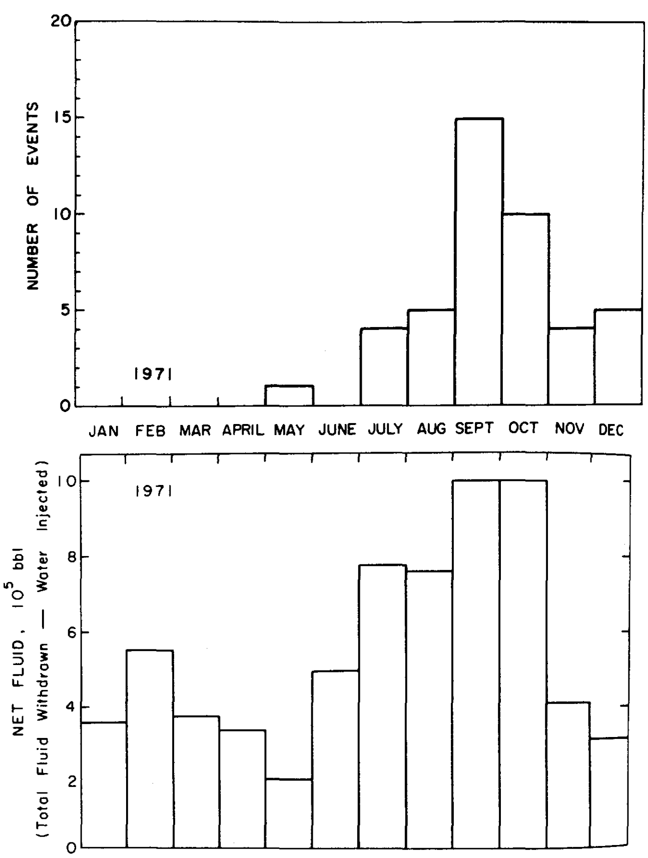


Figure A23. Seismicity and volumes of fluid injected along the Newport-Inglewood Fault, Los Angeles County, Calif., in 1971. Reprinted from Teng and others (1973) and published with permission.

Engineering, written commun., 1985). Between April 27 and October 5, 1984, 34 small earthquakes were detected near the Mansfield station in eastern Oldham County (Davis, 1985). The largest of these events occurred on May 21 and had a local magnitude of 3.1 (pl. 1). Before this episode of seismicity, only one other earthquake was known to have occurred in this part of Texas—a M 3.4 event on April 3, 1983 (Davis, 1985). Several small oil fields had been discovered recently in eastern Oldham County and were producing at the time both earthquakes occurred. In particular, the Lambert No. 1 field, located about 7 km from the Mansfield station, began injection of water for secondary recovery in September 1979 at an average rate of 39,750 liters per day. Definitive correlation of the seismicity with oil field operations, however, was not possible because of the poor earthquake location capability of the wide-aperture network.

In East Texas, a sequence of four earthquakes occurred near Gladewater on March 19, 1957. The largest of these events had an estimated magnitude of 4.3 and generated a felt area of 47,000 km^2 (Nuttli and Herrmann, 1978). Little else is known about this sequence; however, Docekal (1970) recognized that the earthquake epicenters corresponded to an area of active oil production located in East Texas on the western flank of the Sabine Uplift and speculated on whether the earthquakes may have been induced. Water flooding to enhance production had been in effect in at least one field since 1942 at injection pressures of greater than 100 bars (Texas Railroad Commission, 1971). More recently, commercial stimulation of the Cotton Valley tight gas sands, which also are located in East Texas, triggered microearthquake activity at a depth of 2.6 to 3.7 km (Lacy, 1985).

Oklahoma

On October 30, 1956, a M 4.2 to 4.7 earthquake occurred near Catoosa, about 20 km east of Tulsa in northeastern Oklahoma (fig. A24; Nuttli and Herrmann, 1978). This event generated a relatively high maximum intensity (MM VII) for its size and felt area, which suggested a shallow focal depth (Nuttli and Zollweg, 1974). The maximum intensity reported for this event was based on damage to the Coshow No. 2 oil and gas well, which was active at the time of the earthquake (Brazee and Cloud, 1958). The well was forced to shut down because apparent displacements in the producing formation, as a result of the earthquake, disrupted the wellbore. Producing wells within the Catoosa District gas field were operational by 1941, and water flooding to enhance secondary recovery was conducted at one time, but details of the operation are not available (Robert McCoy, Oklahoma Corporation Commission, oral commun., 1987). In March 1960, two smaller earthquakes were felt in the same general area (fig. A24; Luza and others, 1978) shortly after an industrial-waste-disposal well became operational in January (Johnson and others, 1980). Since then, however, no significant seismic activity has been detected in the region, even though gas-production and waste-disposal operations have continued and sensitive seismic monitoring equipment has been operating in nearby Tulsa since 1961 (Luza and Lawson, 1983).

In Carter and Love Counties, southern Oklahoma, 400 earthquakes were detected from May 1, 1977, to December 31, 1978 (Luza and Lawson, 1980). Most of these events were too small to locate (fig. A24); however, of the few that were, nearly all occurred in areas of active oil and gas production, and all occurred at relatively shallow focal depths. On June 23, 1978, commercial stimulation of a 3,050-m-deep well near Wilson triggered 70 earthquakes in 6.2 hours (hr) (Luza and Lawson, 1980).

A similar situation occurred in May 1979, when a well located about 1 km from the Wilson monitoring station (fig. A24) was stimulated over a 4-d period in a massive hydraulic fracturing program. Three different formations were eventually hydrofractured on three separate occasions at average depths of 3.7, 3.4, and 3.0 km (J.E. Lawson, Jr., Oklahoma Geophysical Observatory, written commun., 1987). Maximum injection pressures reached 277 bars THP, and the instantaneous shut-in pressure (ISIP) at the greatest depth was measured to be 186 bars THP. The well was fractured from the bottom up. The first fracturing episode was followed about 20 hr later by about 50 earthquakes over the next 4 hr; the second fracture (at a depth of 3.4 km) was followed immediately by about 40 earthquakes in the subsequent 2 hr; and no increase in activity was noticed following the third fracture (J.E. Lawson, Jr., Oklahoma Geophysical Observatory, written commun., 1987). The largest earthquake in any of the sequences had a magnitude of 1.9; two of the earthquakes were felt. The largest total volume of fluid injected during any one procedure amounted to 5.7×10^4 L at an average injection rate of 230 L/min.

Oil has been produced in this same area since 1953. Earthquakes in the southern portion of the State have been detected since 1974, and earthquakes in Love County have been detected ever since a local monitoring station was installed in 1977 (fig. A24; Luza and others, 1978). Secondary recovery operations in Love County began in May 1965 (Tim Baker, Oklahoma Corporation Commission, oral commun., 1987). It must be noted, however, that similar commercial hydrofracturing operations in other nearby wells did not trigger noticeable increases in seismic activity, as did the massive hydraulic fracturing program in 1978 and 1979.

Whether additional earthquakes that have occurred in Oklahoma (fig. A24) are associated with oil and gas production is difficult to assess. Over 3,100 oil and gas fields exist within the State (most of which are still active), and nearly every felt or located earthquake has been found

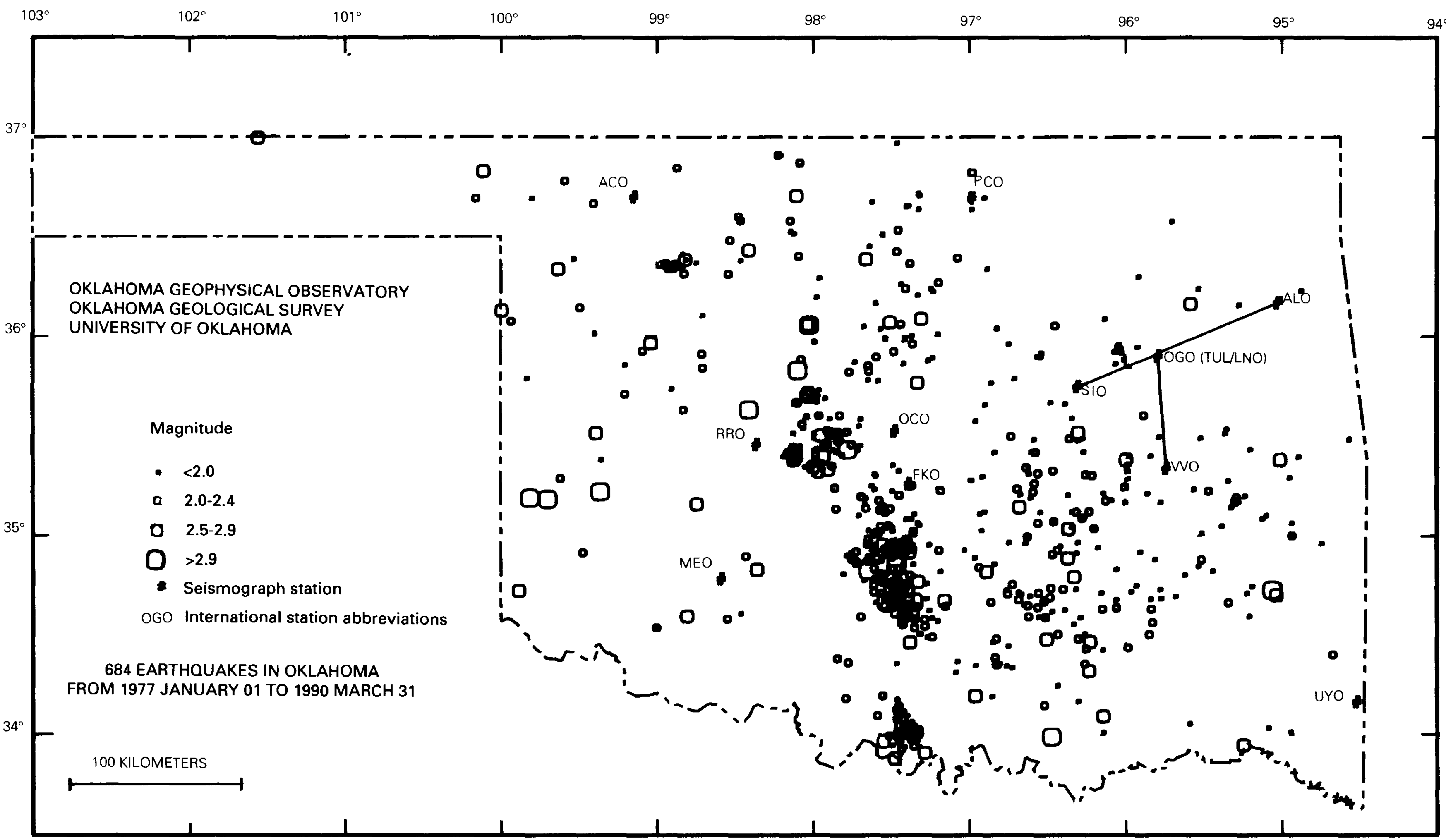


Figure A24. Earthquake epicenters in Oklahoma (684) from January 1, 1977, to March 31, 1990) (J.E. Lawson, Jr., Oklahoma Geophysical Observatory, written commun., 1990).

to occur in close proximity to at least one of them. The converse, however, is not true. Since the early 1900's, oil and gas production has been active in large areas of Oklahoma that have yet to show any detectable signs of seismic activity. Furthermore, many of the regions without earthquakes are actively water flooding to enhance secondary recovery, while many of the seismically active areas are not. Some of these later cases, where seismicity is occurring in areas without fluid injection, may be related to subsidence from massive oil and gas withdrawal, as in the cases of the Flashing gas field in southern Texas or the War-Wink oil and gas field in West Texas. A possible example is a series of nine earthquakes that occurred between October 12 and 18, 1968. All were concentrated in the vicinity of the East Durant gas field, Bryant County (fig. A24), which had been in production since 1958. The largest earthquake in the series was a magnitude 3.5 and generated a maximum intensity of MM VI at the epicenter (Luza and others, 1978).

Gulf Coast Region—Louisiana and Mississippi

In 1978, a magnitude 3.5 earthquake was felt strongly in Melvin, Ala. (pl. 1). Portable monitoring equipment was installed shortly after the earthquake, but only one small aftershock was detected. On the basis of the hypocenter determined for this one event, both earthquakes appeared to be at a focal depth of about 1 km and within 1 to 2 km of the Hunt oil field, which is located just across the State border in Mississippi (J.E. Zollweg, U.S. Geological Survey, oral commun., 1978, 1987). Four earthquakes of similar magnitudes (3.0–3.6) had been detected in the same area since 1976. Although no injection procedures were apparently in operation at the time of the 1978 earthquake, water flooding to enhance extraction had occurred previously.

A similar situation was noted in 1983, when a M 3.8 earthquake was detected in southwestern Louisiana near Lake Charles (pl. 1). Oil and gas operations had been active in the region for several decades, as well as injection activities from a nearby waste-disposal well, but lack of station coverage precluded accurate determination of the earthquake's location and focal depth and so made any direct correlation with particular well operations unresolvable. However, a small microearthquake network, which was installed in 1980 to monitor potential seismicity associated with a geothermal energy project located farther south, has continued to detect a low level of seismic activity in the Lake Charles region, presumably associated with the 1983 earthquake (Stevenson, 1985).

APPENDIX B—SUMMARY OF RESERVOIR-INDUCED SEISMICITY

The phenomenon of seismicity induced by the impoundment of reservoirs is more widespread and better documented than that of injection-induced seismicity; however, the mechanism of reservoir-induced seismicity is more complicated and not as well understood (Gupta and Rastogi, 1976; Simpson, 1986a). Reservoir-induced earthquakes were first described in association with the filling of Lake Mead, Nev. (Carder, 1945), but it was not until the late 1960's, when earthquakes larger than M 5.5 occurred at four major reservoirs (Hsinfengkiang, China, Kremasta, Greece, Lake Kariba, Rhodesia, and Koyna Reservoir, India), that sufficient concern was raised to warrant investigation of the mechanism controlling reservoir-induced seismicity. The largest of the earthquakes believed to have been induced by the impoundment of a reservoir occurred at Koyna Reservoir in 1967 and had a magnitude of 6.5. It caused over 200 deaths, 1,500 injuries, and considerable damage to the nearby town and the dam. Thus, the hazard associated with reservoir-induced seismicity is significant.

Unlike injection operations that only affect pore pressure, the presence of a large reservoir modifies the environment in several ways. First, the large mass of the reservoir represents a large increase in the imposed load, which increases the *in situ* elastic stresses. The load of water also affects the pore pressure directly (by the infiltration of the reservoir water and subsequent raising of the water table) and indirectly (through the closure of water-saturated pores and fractures in the rock beneath the reservoir load). This coupling between the elastic and the fluid effects in the rock, as well as the poorly understood response of inhomogeneities in material and hydrologic properties of the rock to changes in stress induced by the reservoir load, make modeling the impact of reservoirs much more difficult than for cases of fluid injection (Simpson, 1986a). Nevertheless, there are enough similarities between injection- and reservoir-induced earthquakes that they both provide a number of constraints on the mechanism of triggered seismicity.

Although the magnitude of the net pore pressure change produced by reservoir impoundment is often considerably less than at many fluid injection sites, the larger physical dimensions of the reservoirs allows their influence to extend over much broader areas. There are, however, a number of cases of reservoir-induced seismicity in which the load effect from the reservoir is believed to be minimal. These cases include some of the largest earthquakes associated with reservoir impoundment and are usually characterized by a large distance between the earthquake and the reservoir, as well as a long time interval between impoundment and the earthquake occurrence; for example, 1975 M_s 5.7 Oroville, Calif., and 1981 m_b 5.3 Aswan, Egypt.

If these cases do indeed represent seismicity induced by the reservoir, then the triggering mechanism is believed to be similar in many respects to that of injection-induced seismicity. In these cases, the mainshocks occurred along major mapped surface faults that intersected the reservoir. Thus, increased fluid pressure as a result of impoundment may have been able to migrate out along the fault zones, which reduced effective stress levels and thereby enhanced the probability for failure in an earthquake. Because the changes in pore pressure as a result of impoundment are believed to be relatively small at the increased distances involved in these cases, this suggests that the states of stress in those areas were already near critical levels for failure prior to impoundment (Simpson, 1986a).

A particularly good example of reservoir-induced seismicity occurred at the Nurek Reservoir, Tadjikistan, Soviet Central Asia (fig. B1; Simpson and Negmatullaev, 1981). In this case, the water height and the rate of change in water height proved to be critical parameters (fig. B2). At Nurek and at several other similar sites of reservoir-induced seismicity, changes in water height of only a few meters, which correspond to pressure changes of less than 1 bar, have triggered swarms of small earthquakes (fig. B2). This observation suggests that seismicity can be triggered on faults that otherwise remain stable, even at stress levels extremely close to failure (Leith and Simpson, 1986). In many cases of reservoir-induced seismicity, an accurate assessment of the magnitude of the critical stress change necessary for failure is difficult to determine because major heterogeneities in elastic and hydrologic properties of the rock may tend to concentrate or amplify changes in pore pressure caused by compaction and the redistribution of pore fluids in response to changes in water level (Simpson, 1986b). In the case of fluid injection, however, the total mass of the fluid involved is relatively small, and so the need to consider the coupled interaction among applied load, elastic stresses, and pore pressure is generally absent.

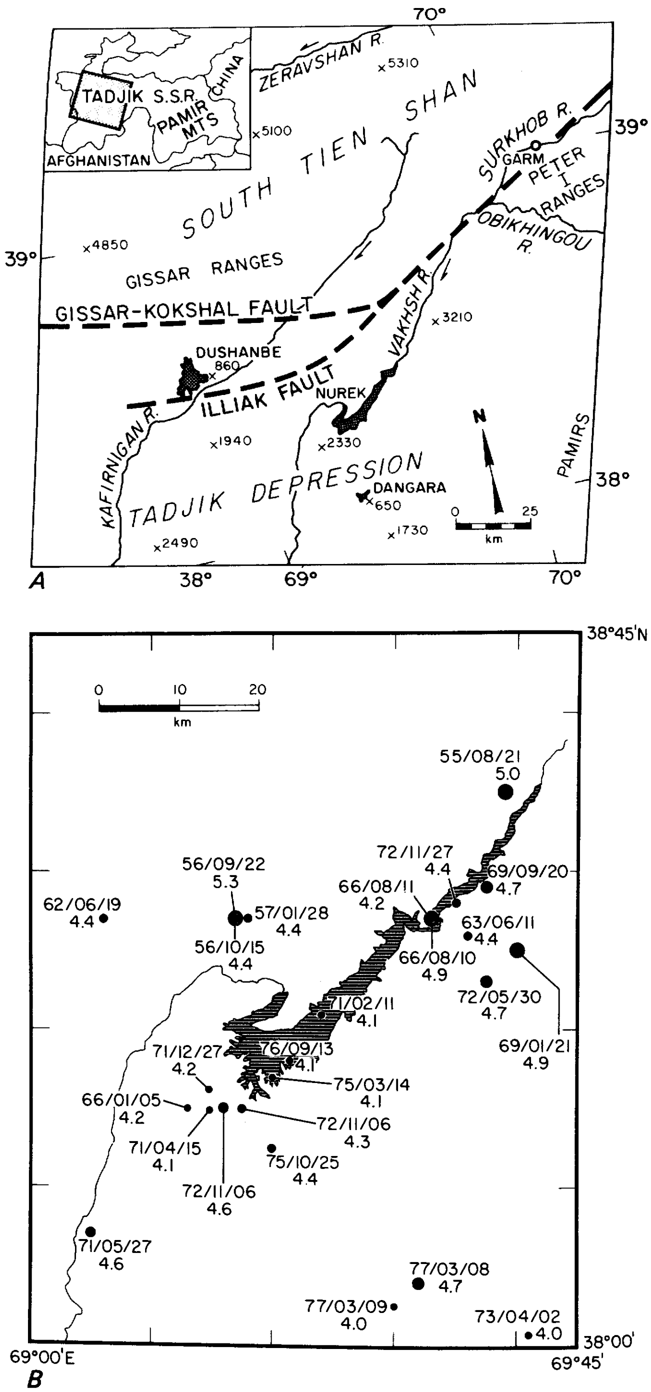


Figure B1. Location and historical seismicity, Nurek Reservoir, Tadjikistan, Soviet Central Asia. *A*, Location map of the reservoir. *B*, Historical seismicity in the vicinity of the dam. Reprinted from Simpson and Negmatullaev (1981) and published with permission.

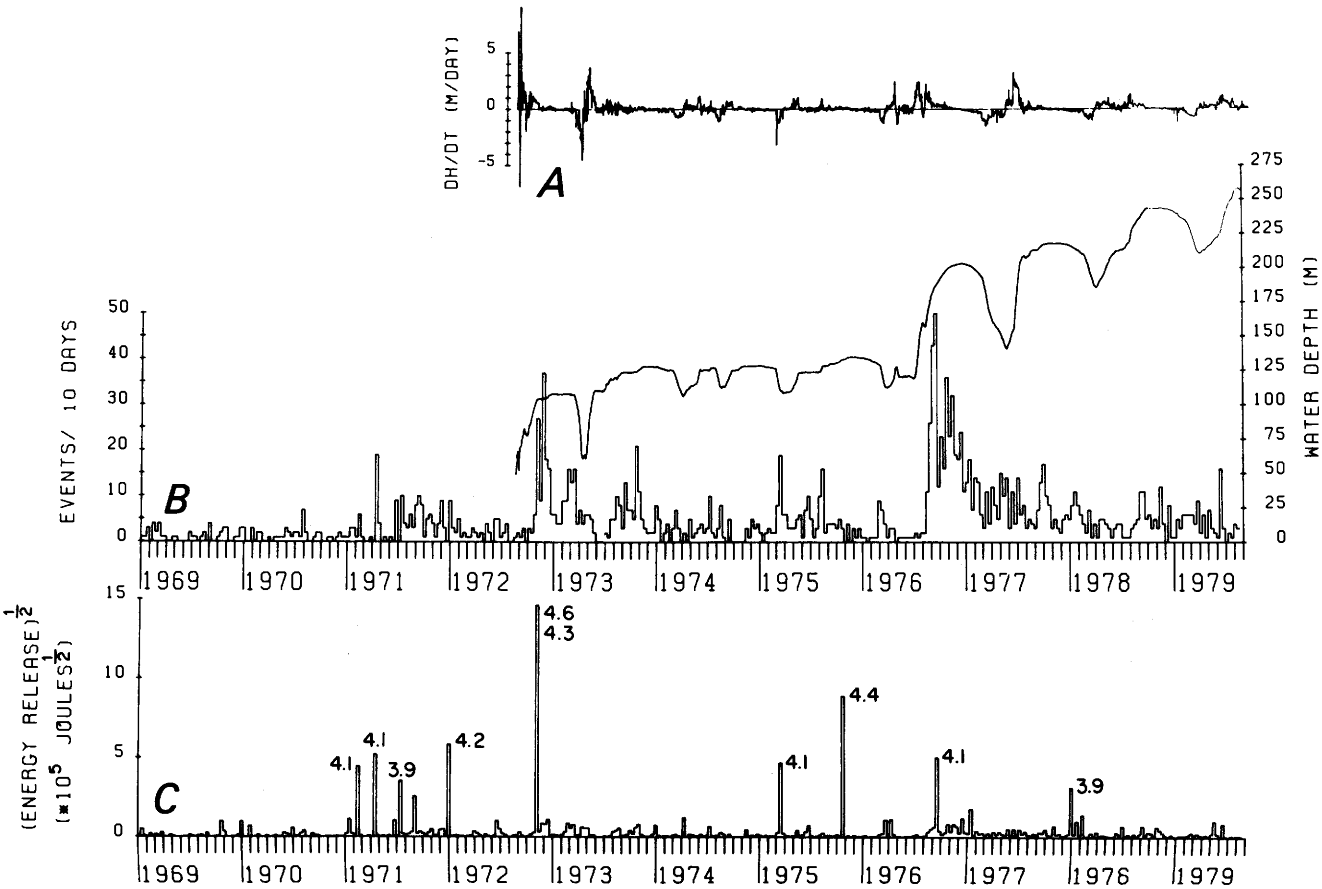


Figure B2. Temporal variations in seismicity, seismic energy release, water height, and daily changes in water level (DH/DT), Nurek Reservoir, Tadjikistan, Soviet Central Asia. Reprinted from Simpson and Negmatullaev (1981) and published with permission.

APPENDIX C—MODIFIED MERCALLI INTENSITY SCALE

This scale measures the intensity of ground shaking as determined from observations of the effects of an earthquake on people, structures, and the Earth's surface. This scale assigns to an earthquake event a Roman numeral from I to XII.

I Not felt by people, except rarely under especially favorable circumstances.

II Felt indoors only by persons at rest, especially on upper floors. Some hanging objects may swing.

III Felt indoors by several. Hanging objects may swing slightly. Vibration like passing of light trucks. Duration estimated. May not be recognized as an earthquake.

IV Felt indoors by many, outdoors by few. Hanging objects swing. Vibration like passing of heavy trucks or sensation of a jolt like a heavy ball striking the walls. Standing automobiles rock. Windows, dishes, doors rattle. Wooden walls and frames may creak.

V Felt indoors and outdoors by nearly everyone; direction estimated. Sleepers awakened. Liquids disturbed, some spilled. Small unstable objects displaced or upset; some dishes and glassware broken. Doors swing; shutters, pictures move. Pendulum clocks stop, start, change rate. Swaying of tall trees and poles sometimes noticed.

VI Felt by all. Damage slight. Many frightened and run outdoors. Persons walk unsteadily. Windows, dishes, glassware broken. Knickknacks and books fall off shelves; pictures off walls. Furniture moved or overturned. Weak plaster and masonry cracked.

VII Difficult to stand. Damage negligible in buildings of good design and construction; slight to moderate in well-built buildings; considerable in badly designed or poorly built buildings. Noticed by drivers of automobiles. Hanging objects quiver. Furniture broken. Weak chimneys broken. Damage to masonry; fall of plaster, loose bricks, stones, tiles, and unbraced parapets. Small slides and caving in along sand or gravel banks. Large bells ring.

VIII People frightened. Damage slight in specially designed structures; considerable in ordinary substantial buildings, partial collapse; great in poorly built structures. Steering of automobiles affected. Damage to or partial collapse of some masonry and stucco. Failure of some chimneys, factory stacks, monuments, towers, elevated tanks. Frame houses moved on foundations if not bolted down; loose panel walls thrown out. Decayed pilings broken off. Branches broken from trees. Changes in flow or temperature of springs and wells. Cracks in wet ground and on steep slopes.

IX General panic. Damage considerable in specially designed structures; great in substantial buildings, with some collapse. General damage to foundations; frame structures, if not bolted, shifted off foundations and thrown out of plumb. Serious damage to reservoirs. Underground pipes broken. Conspicuous crack in ground; liquefaction.

X Most masonry and frame structures destroyed with their foundations. Some well-built wooden structures and bridges destroyed. Serious damage to dams, dikes, embankments. Landslides on river banks and steep slopes considerable. Water splashed onto banks of canals, rivers, lakes. Sand and mud shifted horizontally on beaches and flat land. Rails bent slightly.

XI Few, if any, masonry structures remain standing. Bridges destroyed. Broad fissures in ground; earth slumps and landslides widespread. Underground pipelines completely out of service. Rails bent greatly.

XII Damage nearly total. Waves seen on ground surfaces. Large rock masses displaced. Lines of sight and level distorted. Objects thrown upward into the air.

APPENDIX D—GLOSSARY

[Terms set in bold type are defined elsewhere in the glossary. Sources: Ziony (1985), Bates and Jackson (1987), and Nance (1989)]

Acceleration. The time rate of change of velocity of a reference point during an **earthquake**. Commonly expressed in percentage of gravity (g) equal to 980 centimeters per square second.

Active fault. A **fault** that is considered likely to undergo renewed movement within a period of concern to humans. *Also called* capable fault.

Aftershock. An **earthquake** or tremor that follows a larger earthquake or mainshock and originates at or near the **focus** of the larger earthquake. Generally, **major earthquakes** are followed by many aftershocks, which decrease in frequency and magnitude with time. Such a series of tremors may last many days for small earthquakes or many months for large ones.

Amplification. An increase in **seismic** signal **amplitude** as waves propagate through different earth materials.

Amplitude. Zero-to-peak value of any wavelike disturbance; corresponds to half the height of the crest of a wave above the adjacent trough.

Aquifer. A geological subsurface formation containing and transmitting ground water, usually restricted to a body of rock that is sufficiently permeable to yield useful quantities of water to wells or springs.

Aseismic. (1) Not associated with an **earthquake** or earthquake activity. (2) An area that is not subject to earthquakes.

Attenuation. A decrease in **seismic** signal **amplitude** as waves propagate from the seismic source. Attenuation is caused by geometrical spreading of **seismic wave** energy and by the absorption and scattering of seismic energy in different earth materials.

Basement rock. Relatively hard, undifferentiated solid rock that underlies commonly softer sedimentary rock, unconsolidated sediment, alluvium, or soil. *Also called* bedrock.

Body wave. A **seismic wave** that travels through the interior or body of the Earth and is not related or confined to a specific boundary surface. **Primary** and **secondary waves** are examples of body waves.

Bottom-hole pressure. The fluid pressure measured in the bottom of a well. It consists of the wellhead pressure (**top-hole pressure**) plus a term to account for the weight of the column of fluid in the well. The abbreviation is BHP.

Breakdown pressure. The hydraulic pressure needed to **fracture** the intact rock of a borehole wall. The symbol is P_b. *Also called* fracture pressure.

Coefficient of friction. Constant of proportionality for that part of the shear strength of a rock or other intact solid that depends on the **normal stress** applied across the potential shear surface or **fracture**. The symbol is μ.

Cohesion. The **shear** strength of a rock not related to internal friction; that is, dependent on applied **normal stress**. The symbol is τ_0. *Also called* inherent shear strength.

Compressibility. The relative change of volume with pressure on the **aquifer** matrix. Reciprocal of the elastic bulk modulus of the medium. For solids, the symbol is α; for fluids, the symbol is β.

Core-induced fractures. Vertical fractures found in oriented bottom-hole cores caused by the downcutting drill bit. *Also called* petal-centerline fractures.

Creep. Slow, more or less continuous movement that may occur either along faults owing to ongoing **tectonic** deformation or along slopes owing to gravitational forces.

Crust. The outermost major layer of the Earth, ranging from about 9 to 60 km thick worldwide; characterized by **primary-wave** velocities of less than 8 kilometers per second (km/s).

Density. Mass per unit volume. The symbol is ρ.

Deviatoric stress. The difference in magnitude between the maximum (σ_1) and minimum (σ_3) **principal stresses**.

Dip. Inclination of a planar geologic surface (for example, a **fault** or formation) from the horizontal.

Displacement. The difference between the initial position of a reference point and any later position. (1) In seismology, displacement is typically calculated by integrating an accelerogram twice with respect to time and is expressed in centimeters. (2) In geology, displacement is the permanent offset of a geologic or manmade reference point along a fault or landslide.

Dynamic viscosity. A measure of the internal resistance of a fluid to flow. The symbol is η. *Also called* viscosity coefficient or absolute viscosity.

Earthquake. Groups of **elastic waves** propagating in the Earth, generated by a sudden disturbance of the Earth's elastic equilibrium, usually caused by a sudden movement in the Earth's **crust**.

Earthquake hazard. Any physical phenomenon associated with an **earthquake** that may produce adverse effects on human activities.

Effective stress. In the presence of a fluid, **stress** is partly compensated by the buoyancy of the fluid pressure. This reduces the effective magnitude of the stress by an amount equal to the **pore pressure**.

Elastic rebound theory. The theory that movement along a **fault** is the result of an abrupt release of a progressively increasing elastic **strain** between the rock masses on either side of the fault. Such movement (or faulting) returns the rocks to a condition of little or no strain and converts the stored elastic strain energy into kinetic energy (motion along the fault), heat caused by friction, new fractures, and the generation of **elastic waves**, which radiate outwards from the point of rupture, the **hypocenter**.

Elastic wave. A wave that is propagated by some kind of elastic deformation; that is, a deformation that disappears when the forces causing the deformation are removed. A **seismic wave** is a type of elastic wave.

Epicenter. The point of the Earth's surface vertically above the **hypocenter** or **focus** of an **earthquake** (where a **seismic** rupture initiates).

Fault. A **fracture** or fracture zone along which there has been **displacement** of the sides relative to one another parallel to the fracture plane or planes.

Fault trace. Intersection of a **fault** with the ground surface; also, the line commonly plotted on geologic maps to represent a fault.

Favorably oriented fracture. A **fracture** whose orientation in an existing **stress** field is close to the orientation for maximum **shear stress** resolved across the fracture plane; typically within the range 30° to 45° relative to the maximum **principal stress** direction (σ_1).

Focal depth. The depth of the **hypocenter** or **focus** of an **earthquake**.

Focal mechanism. An analysis to determine the attitude of the causative **fault** and the direction of slip along the fault during an **earthquake** from the radiation pattern of **seismic waves** generated. The analysis most commonly uses the direction of first motion of **primary waves** recorded at numerous **seismograph** stations and yields two possible orthogonal orientations for the fault rupture and the direction of seismogenic slip. From these data, inferences can be made concerning the principal axes of **stress** in the region of the earthquake. *Also called* fault-plane solution.

Focus. The source of a given set of **elastic waves**; the true center of an **earthquake**, within which the **strain** energy is first converted to elastic wave energy. *See also* **Hypocenter**.

Foreshock. A small tremor that precedes a larger **earthquake** or mainshock by seconds to weeks and that originates at or near the **focus** of the larger earthquake.

Fracture. (1) A breakage in the rock strata due to mechanical failure by applied **stress**. (2) Deformation due to momentary loss of **cohesion** or loss of mechanical resistance to differential stress and a release of stored elastic energy.

Fracture-opening pressure. The injection pressure needed to just open a newly created **hydraulic fracture**. The symbol is P_{fo}.

Frequency. (1) Rate of occurrence. (2) Number of cycles occurring in unit time. Hertz, which is the unit of frequency, is equal to the number of cycles per second.

Geophysical survey. The use of one or more techniques of physical measurement to explore Earth properties and processes. For subsurface exploration, this usually involves indirect methods, such as gravity measurements, to infer rock densities, and so forth.

Head. (1) The elevation to which water rises at a given point as a result of reservoir **pore pressure**. (2) Water-level elevation in a well or elevation to which water of a flowing artesian well will rise in a pipe extended high enough to stop the flow.

Hydraulic conductivity. The ease with which water is conducted through an **aquifer** and is defined as the rate of flow of water through a unit cross section under a unit **hydraulic gradient** at the prevailing temperature. The symbol is **K**. *Also called* coefficient of permeability.

Hydraulic fracture. An artificial **fracture** generated in the rock around a well by high pressure fluid injection. *Also called* hydrofracture.

Hydraulic gradient. In an **aquifer**, the rate of change to **total head** per unit distance of flow at a given point and in a given direction.

Hydrostatic pressure. The pressure exerted by the water at any given point in a body of water at rest. For ground water, the hydrostatic pressure is equal to the weight of the water above the reference point or reference horizon, or the product of the fluid **density** (ρ), the **acceleration** of gravity (g), and the fluid depth.

Hypocenter. The point in the Earth where an **earthquake** rupture initiates.

Induced seismicity. Earthquake activity triggered by environmental changes caused by man; usually associated with either the injection or extraction of large amounts of fluid in the ground or the impoundment of a **reservoir**.

Instantaneous shut-in pressure. The fluid pressure recorded in the wellbore after a new **hydraulic fracture** is opened, injection is stopped, and the well is "shut-in" or closed. Under ideal conditions, this is a measure of the minimum **principal stress** (σ_3) acting to close the fracture. The abbreviation is ISIP.

Intensity. A subjective measure of the damage of an **earthquake** at a particular place as determined by its effects on people, structures, and earth materials. Intensity depends not only on the earthquake **magnitude**, but also on the distance from the point of reference to the **epicenter**, the earthquake **focal depth**, the type of faulting, and the local geology. The principal scale used in the United States today is the Modified Mercalli Intensity Scale (Appendix C).

Intrinsic permeability. The characteristic resistance to fluid flow of a porous medium alone, independent of the properties of the fluid. The symbol is k.

Isoseismal. A line connecting points on the Earth's surface at which **earthquake intensity** is the same. It is usually a closed curve around the **epicenter**.

Lithostatic pressure. The vertical pressure at any point at depth in the rock due to the overburden or weight of the overlying rock mass. *See also* **Vertical stress**.

Magnitude. A number that characterizes the size of an **earthquake**, usually based on measurement of the maximum **amplitude** recorded by a **seismograph** for **seismic waves** of a particular **frequency**. Scales most commonly used are (1) **local magnitude** (M_L), (2) **surface-wave magnitude** (M_S), and (3) **body-wave magnitude** (m_b). None of these scales satisfactorily measures the largest possible earthquakes because each relates to only the amplitude of certain frequencies of seismic waves and because the spectrum of radiated seismic energy changes with earthquake size. To compensate, the **moment magnitude (M)** scale, based on the concept of seismic moment, was devised and is uniformly applicable to all sizes of earthquakes.

Body-wave magnitude. This scale measures the maximum **amplitude** of waves that pass through the interior—the body—of the Earth and that have a period between 1 and 10 seconds (s). The symbol is m_b.

Local magnitude. This scale is commonly referred to as Richter magnitude. Although only accurately applied to California earthquakes, it is still quite useful today for describing smaller and more moderate earthquakes but not for measuring truly large earthquakes. It provides a good estimate to engineers of the high-frequency **accelerations** generated by an earthquake. The symbol is M_L.

Moment magnitude. This is perhaps the most meaningful scale today for large and great earthquakes, in that it reflects the total energy released. The measurement takes into account the surface area of the **fault** that moved to cause the earthquake, the average **displacement** along the fault plane, and the rigidity of the fault material. Seismic moment (M_o) is the result, and the moment magnitude is simply a scaled logarithm of this value. This scale was developed only in the late 1970's, which is why great earthquakes, such as that in Alaska in 1964, which was originally evaluated as a magnitude M_S 8.5, have been upgraded—Alaska now has an moment magnitude rating of 9.2. The symbol is **M** or M_w.

Surface-wave magnitude. This scale was formulated to describe earthquakes at distant locations. The scale principally measures **surface waves** of 20-s period or a wavelength of approximately 60 km. The symbol is M_S.

Major earthquake. An **earthquake** having a **magnitude** of 6.5 or greater.

Maximum horizontal stress. The maximum component of **principal stress** in the horizontal plane. The symbol is S_H.

Mean stress. The average of the three **principal stresses**.

Microearthquake. A small **earthquake** usually observable only with sensitive instruments. Typically corresponds to an earthquake of **magnitude** 2 or less. *Also called* microseismic event.

Minimum horizontal stress. The minimum component of **principal stress** in the horizontal plane. The symbol is S_h.

Mohr circle. A graphical representation of the state of **stress** at a particular point and at a particular time. The coordinates of each point on the circle are the **shear stress** (τ) and the **normal stress** (σ_n) on a particular plane.

Mohr-Coulomb failure criterion. The condition whereby failure (slip) is expected on a preexisting **fault** whenever the combinations of **shear stress** (τ) and **normal stress** (σ_n) resolved across the fault plane (as defined by the loci of points on the **Mohr circle**) meet or exceed the Coulomb criteria for frictional failure; that is, the shear stress is equal to the inherent fault **cohesion** (τ_o) plus the product of the **coefficient of friction** (μ) and the effective **normal stress** ($\sigma_n - p$). This level of **shear stress** is called the critical stress (τ_{crit}).

Normal fault. A steeply to slightly inclined **fault** in which the block above the fault (the hanging wall) has moved downward relative to the block below (the footwall).

Normal stress. The component of **stress** oriented normal (perpendicular) to a given **fault**, fracture plane or slip surface. The symbol is σ_n.

Permeability. The capacity of a porous rock or soil for transmitting fluid or gas; it is a measure of the relative ease of fluid flow under unequal pressure.

Plate tectonics. A widely excepted theory that considers the Earth's **crust** and upper mantle to be composed of a number of large, rigid plates that move relative to one another. Interaction along plate boundaries is then the major cause of **earthquakes** and volcanic activity.

Pore pressure. Pressure of water in pores of a saturated medium. The symbol is p.

Pore space. Space occupied by voids within the rock matrix capable of holding either fluid or gas.

Porosity. Percentage ratio of void volume to the bulk (total) volume of rock or soil sample. It is a measure of the fluid bearing capacity of the medium. The symbol is n.

Primary wave. A type of elastic **body wave** that propagates by alternating compression and expansion of material in the direction of propagation. It is the fastest of the seismic waves (typically traveling at speeds of 5–6.8 km/s in the crust and 8–8.5 km/s in the upper mantle, just below the crust), and is analogous to a traveling sound wave. The abbreviation is P wave.

Principal stress. A **stress** that is perpendicular to one of three mutually orthogonal planes on which the **shear stress** is zero and in whose direction stresses are purely compressive; a stress that is normal to a principal plane of stress. The three principal stress are identified as σ_1, maximum or greatest principal stress; σ_2, intermediate principal stress; and σ_3, minimum or least principal stress.

Rake. The direction of **displacement** (slip) resolved across a **fault** plane, measured in degrees from the horizontal.

Reservoir. (1) A recipient for the collection of liquid. In geology, a subsurface rock formation that has sufficient **porosity** and **permeability** to except and retain a large amount of fluid or gas under adequate trap conditions. (2) A manmade body of water impounded behind a dam.

Reverse fault. A moderately inclined fault in which the block above the fault (the hanging wall) has moved upward relative to the block below the fault (the footwall).

Secondary recovery. Production of oil or gas as a result of artificially augmenting the **reservoir** energy, usually by injection of water or other fluid at high pressure. Secondary-recovery techniques are generally applied after substantial reservoir depletion. *See also* **Water flooding**.

Secondary wave. A type of **seismic body wave** that propagates by a shearing motion of material, so that wave motion or oscillation is perpendicular (transverse) to the direction of propagation. It does not travel through liquids or through the outer core of the Earth. Its speed is typically 2.8 to 4 km/s in the crust and 4.3 to 4.5 km/s in the upper mantle, just below the crust. This wave arrives later than the faster **primary wave**. The abbreviation is S wave.

Seismic. Pertaining to an **earthquake** or earth vibration, including those that are artificially produced.

Seismicity. Earthquake activity; the geographical and the historical distribution of earthquakes.

Seismic risk. The probability of social or economic consequences of an **earthquake**.

Seismic wave. An **elastic wave** generated by a sudden impulse, such as an **earthquake** or an explosion.

Seismogram. A record of ground motion or of vibration of a structure caused by an **earthquake** or an explosion; the record produced by a **seismograph**.

Seismograph. An instrument that detects, magnifies, and records ground vibrations, especially **earthquakes**. The resulting record is a **seismogram**.

Separation. In geology, the distance between any two parts of a reference plane (for example, a sedimentary unit or a geomorphic surface) offset by a **fault** measured in any plane. Separation is the amount of apparent fault **displacement** and is nearly always less than the actual slip.

Shear. A mode of failure whereby two adjacent parts of a solid slide past one another parallel to the plane of failure.

Shear stress. The component of **stress** that acts tangential to a plane through any given point in a body. The symbol is τ.

Shear wave. A secondary or transverse **elastic wave**.

Slip rate. The average **displacement** at a point along a **fault** as determined from geodetic measurements from offset manmade structures or from offset geologic features whose age can be estimated. It is measured parallel to the dominant slip direction or estimated from the vertical or the horizontal **separation** of geologic, geodetic, or other markers.

Storativity. The capacity of an **aquifer** to accept (store) or release fluid under a change in applied **pore pressure** (p) and is defined as the amount of fluid in storage released from a column of aquifer with unit cross section under a unit decline in pressure **head**. The symbol is S. *Also called* storage coefficient.

Strain. The amount of any change in dimensions or shape of a body when subjected to deformation under an applied **stress**.

Stress. The force per unit area acting on a surface within a body. Nine values are required to characterize completely the state of stress at a point: three normal components (which are purely compressive) and six shear components, relative to three mutually perpendicular reference axes.

Strike. The orientation of the line of intersection of any plane with the horizontal measured in degrees from true north; the direction or trend taken by a structural surface, such as a **fault** plane, as it intersects the horizontal.

Strike-slip fault. A **fault** in which movement is principally horizontal, parallel to the **strike** of the fault.

Subsidence. Downward settling of the Earth's surface with little or no horizontal motion. May be caused by natural geologic processes (such as sediment compaction or **tectonic** activity) or by human activity (such as mining or withdrawal of ground water or petroleum).

Surface faulting. Displacement that reaches the ground (or sea floor) surface during slip along a **fault**. Commonly accompanying moderate and large **earthquakes** having **focal depths** to 12 km. Surface faulting may also accompany **aseismic tectonic creep** or natural or man-induced **subsidence**.

Surface wave. Seismic wave that propagates along the Earth's surface.

Tectonic. Pertaining to either the forces or the resulting structural features from those forces acting within the Earth; refers to crustal rock-deformation processes that affect relatively large areas.

Tensile strength. The maximum applied **tensile stress** that a body can withstand before failure occurs. The symbol is T_0.

Tensile stress. A **normal stress** that tends to cause separation across the plane on which it acts.

Top-hole pressure. The fluid pressure measured at the wellhead. The abbreviation is THP.

Total head. The sum of the elevation **head**, pressure head, and velocity head of a liquid. For ground water, the velocity-head component is generally negligible.

Transmissivity. The rate at which water is transmitted through a unit width of **aquifer** under a unit **hydraulic gradient**; it is equal to the product of the **hydraulic conductivity** and the thickness of the aquifer. The symbol is T.

Vertical stress. The **stress** at any point at depth in the rock due to the overburden or weight of the overlying rock mass; equal to the product of the average **density** of the overlying column of rock, the **acceleration** of gravity, and the depth. The symbol is S_v. *See also* **Lithostatic pressure**.

Water flooding. A **secondary recovery** technique in which water is injected into a petroleum **reservoir** to force additional oil out of the reservoir rock and into producing wells.

Water table. The upper surface of a body of unconfined ground water at which the water pressure is equal to the atmospheric pressure.

Wellbore breakouts. Deformation of the wellbore wall caused by spalling of weak material induced by compressive **shear** failure. *Also called* borehole elongations.

Increasing seismicity in the U. S. midcontinent: Implications for earthquake hazard

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Abstract

Earthquake activity in parts of the central United States has increased dramatically in recent years. The space-time distribution of the increased seismicity, as well as numerous published case studies, indicates that the increase is of anthropogenic origin, principally driven by injection of wastewater coproduced with oil and gas from tight formations. Enhanced oil recovery and long-term production also contribute to seismicity at a few locations. Preliminary hazard models indicate that areas experiencing the highest rate of earthquakes in 2014 have a short-term (one-year) hazard comparable to or higher than the hazard in the source region of tectonic earthquakes in the New Madrid and Charleston seismic zones.

Introduction

In July 2014, the U. S. Geological Survey (USGS) released an update of the 2008 National Seismic Hazard Map (NSHM) (Petersen et al., 2014) for the coterminous United States (Figure 1). The NSHM provides guidance for the seismic provisions of building codes and portrays ground motions with a 2% chance of being exceeded in an exposure time of 50 years. In the tectonically active western United States, the hazard model is derived from a combination of geologic studies of active faults, geodetic measurement of crustal deformation, and seismological observations of earthquakes and the shaking they produce. Over most of the central and eastern United States (CEUS), the hazard model is derived by projecting the spatially smoothed historical earthquake rate, with aftershocks removed, forward in time under the assumption that seismicity is described by a time-independent Poisson process. Parts of the midcontinent, however, have experienced increased seismicity levels since 2009 — locally by two orders of magnitude — that are incompatible with the underlying assumption of a constant rate of earthquake occurrence (Ellsworth, 2013).

The 2014 NSHM acknowledged this problem but disregarded the increased activity. This was deemed appropriate for the specific purpose of underpinning seismic design standards for new construction. The 2014 NSHM excluded selected earthquakes in 14 areas, of which eight were identified as sources of induced seismicity in the 2008 edition of the NSHM (Petersen et al., 2014). Both the developers of the NSHM and its users acknowledge that the rise of seismicity in the midcontinent must be understood if we are to capture fully the earthquake hazard in both space and time.

The space-time distribution of the post-2009 increased seismicity, as well as numerous published case studies, strongly implies that much of the increase is of anthropogenic origin and primarily is associated with wastewater disposal in UIC Class II wells (Frohlich, 2012; Horton, 2012; Keranen et al., 2013; Keranen et al., 2014; Kim, 2013; Andrews and Holland, 2015). If so, the assumptions and procedures used to forecast natural earthquake rates from past rates might not be appropriate. Here we examine the changing earthquake activity rates and discuss key issues that must be resolved to quantify the hazard posed by increased seismicity in the midcontinent.

Recent changes in seismicity

Earthquakes have been known to be a natural part of the landscape in the CEUS since colonial times. The historical record of earthquakes generally begins after settlement by literate people who recorded their observations in journals, letters,

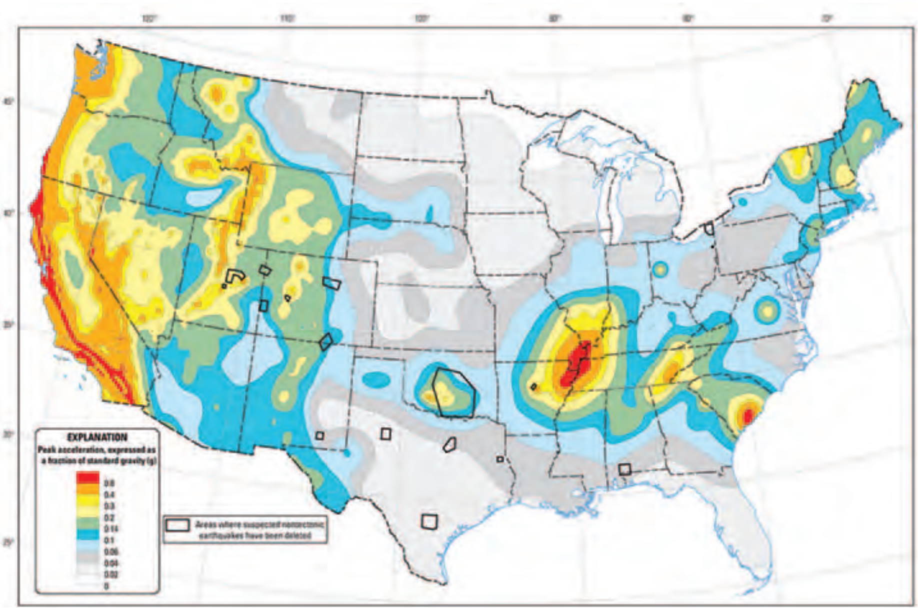

Figure 1. 2014 National Seismic Hazard Map (NSHM) for the coterminous United States showing peak acceleration with a 2% probability of being exceeded in 50 years. Polygons identify areas where recent seismicity was removed in preparation of the map, corresponding to areas where earthquakes are known to be induced or where seismic activity increased after 2006. After Petersen et al. (2015), Figure 1. Courtsey of U. S. Geological Survey.

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and newspapers. The first documented reports of earthquakes with epicenters in the midcontinent west of the Mississippi River, for example, date from the 1840s. Felt reports of earthquakes provided the primary data used to estimate location and magnitude until the 1930s, when instrumental recordings became the primary data source.

Using a newly compiled earthquake catalog for the CEUS (Petersen et al., 2014), we examine the earthquake rate in two equal-sized areas: an eastern zone that includes the M 7+ 1811–1812 New Madrid earthquakes, the M 6.9 1886 Charleston, South Carolina, earthquake, and the M 5.6 2011 Virginia earthquake; and a western zone that includes the principal areas where seismicity has increased in the past decade, including the 2011 M 5.3 Trinidad, Colorado, and 2011 M 5.6 Prague, Oklahoma, earthquakes (Figure 2). To study how seismicity rates have changed, it is necessary to establish the magnitude completeness of the catalog. This can be done by examining the cumulative magnitude-frequency distribution (MFD, or Gutenberg-Richter relation). The MFD for earthquakes invariably follows an exponential distribution that can be written as $\log_{10}(N(M)) = a - bM$, where N(M) is the number of earthquakes in a sample with magnitudes ≥ M. Over the magnitude range where a catalog is complete, the cumulative MFD follows a straight line with slope $-b$ on a linear-log plot.

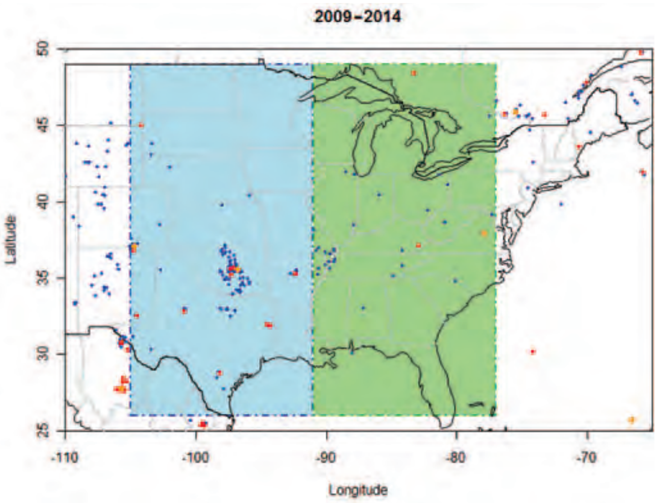

Figure 2. Seismicity 2009–2014: M 3–3.9 (blue), M 4–4.9 (red), M ≥ 5 (orange). Eastern area (green) includes the source regions of the M > 7 1811–1812 New Madrid earthquakes and M 6.9 1886 Charleston, South Carolina, earthquake. Western area (blue) encompasses areas where earthquake rate has increased since 2009.

Magnitude-frequency plots for the eastern and western areas are divided into time periods corresponding to the early instrumental era (1930–1966) and four subdivisions of the modern instrumental era (1967–2014) (Figure 3). The observed MFD distributions in the eastern area for all time periods (Figure 3b) have consistent *a*- and *b*-values, indicating that a time-independent Poisson process should have predictive power for future earthquake occurrence over a 50-year period appropriate for building codes. The catalog also appears to be complete for M ≥ 3.5 over the entire time period as well as complete for M ≥ 3.0 after 1967.

The situation is quite different in the western area (Figure 3a). Although the magnitude of completeness agrees with the eastern area for the same time periods, the earthquake rate (*a*-value) increases systematically with time after 2000. We can be confident that the increased seismicity is not a reporting artifact because the same procedures were used to analyze the earthquakes throughout the CEUS, and hence any procedural change would show up in both regions. The constant rate of earthquake activity (M ≥ 3.5) from 1930 through 2000 increased slightly between 2001 and 2008, and it underwent a major increase in 2009. The excess earthquakes in 2001–2008 appear to be located exclusively in the Raton Basin on the Colorado–New Mexico border (Rubinstein et al., 2014). From 2009 to the present, most of the excess activity has occurred in Oklahoma, with contributions from Arkansas, Colorado, Kansas, New Mexico, and Texas.

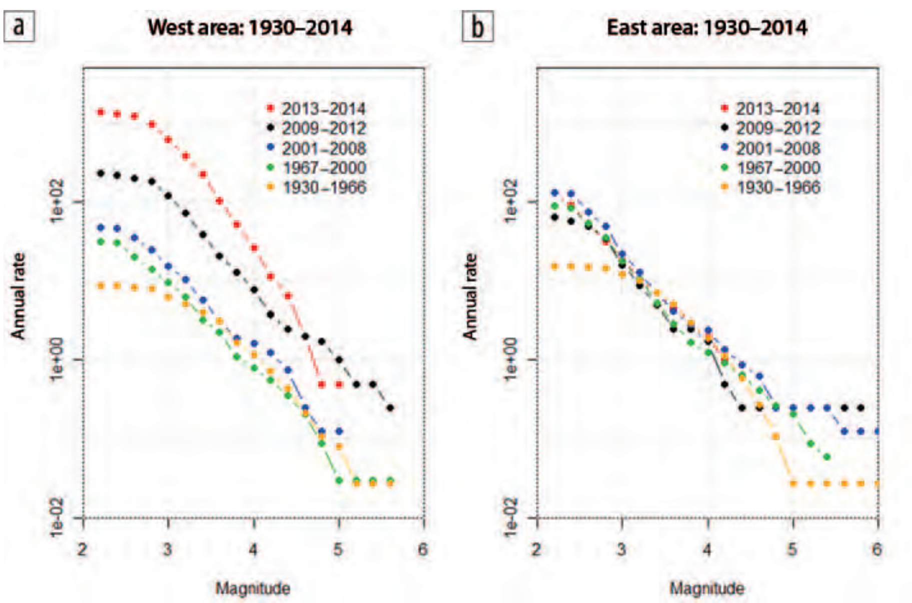

Figure 3. Annual frequency of occurrence of earthquakes with magnitude greater than or equal to magnitude value for (a) the western area and (b) eastern area. Earthquakes are from the catalog used to produce the 2014 NSHM, divided into time intervals indicated by color key.

The evolution of the earthquake rate changes can be visualized by plotting the running count of earthquakes (Figure 4). The cumulative curve in the eastern area behaves as would be expected for a constant random process that combines a time-independent Poisson process augmented by an aftershock process. The west region has intervals that might be satisfied by such a model, but there are two clear violations of the constant-rate requirement. The first occurs between 1962 and 1970, and it can be attributed entirely to the Denver earthquakes induced by fluid injection in a deep well on the Rocky Mountain Arsenal (Healy et al., 1968). After removing these events from the running count, it agrees with a constant-rate random process until 2009, when the rate increases manyfold. We also can model the seismicity rate in each region using an inhomogeneous (time-varying) random process. A simple model for the rate parameter derived by fitting a smooth function to the cumulative curves for the eastern and western areas (without the Denver earthquakes) shows that the eastern rate is nearly constant, although the western rate increases slightly in 2001 and then accelerates after 2009 (Figure 4).

We can identify quantitatively where the excess seismicity is occurring in both space and time by comparing the observed seismicity with the expected number of earthquakes from a prior model. By comparing the expected and observed number of earthquakes, the probability of observing at least as many events as in the actual catalog can be determined. Areas with improbable numbers of earthquakes correspond to low p values ($p \leq 0.05$) in Figure 5. Note that the anomalous seismicity extends beyond the zones defined in the 2014 NSHM in northern Oklahoma and southern Kansas (Figure 1), which used earthquake data only through 2012.

Natural or induced?

This is the most challenging and perhaps the most contentious question being asked about the recent change in seismicity. Although some people have argued that more research is needed or that the scientific case for a connection between industrial activities and earthquakes has yet to be made, an extensive and solid body of scientific investigations, theory, and even experiments documents how earthquakes can be induced (Nicholson and Wesson, 1990). As early as 1968, the potential for inducing earthquakes by wastewater injection was acknowledged as a risk factor for underground waste management (Galley, 1968). That also was the year the link between injection at the Rocky Mountain Arsenal and the Denver earthquakes was established firmly (Healy et al., 1968). The Denver earthquakes occurred as fasr as 10 km from the injection point and persisted for more than a decade after injection ceased. Until 2011, the Denver earthquakes were the largest (M_W 4.9) known to have been induced by injection.

It was hypothesized at the time that the increase in the pore-fluid pressure from injection was the mechanism that activated an ancient fault. The pressure required to overcome the frictional resistance to slip is given by the effective-stress relation $\tau_{crit} = \mu(\sigma_n - P) + \tau_o$. At failure, the critical shear stress τ_{crit} equals the product of the coefficient of friction μ and the effective normal stress given by the difference between the applied normal stress σ_n and the pore pressure P plus the cohesive strength of the fault τ_o. The fault will remain locked as long as the applied shear stress is less than the strength of the contact. Increasing the shear stress, reducing the normal stress, and/or elevating the pore pressure can bring the fault to failure, triggering the nucleation of the earthquake.

This theory was tested in the field by the USGS in the Rangely, Colorado, oil field between 1969 and 1973 (Raleigh et al., 1976). The shear stress and initial pore pressure were measured in situ, and the coefficient of friction of the rocks was measured in the laboratory, from which the critical pore pressure needed to destabilize the faults was predicted. The experiment not only established the validity of the effective- stress model but also demonstrated that the pore-pressure perturbation extended kilometers from the injection point and responded rapidly to pressure changes at the wellhead.

It is rare to have the extensive knowledge of the stress, pore pressure, and hydrologic conditions that was available for the Rangely experiment. Consequently, most studies must rely on spatial and temporal correlations when assessing the possible involvement of industrial activity in the seismicity. Many of the areas with significantly elevated seismicity identified in Figure 5 have been investigated using available seismicity, well, and

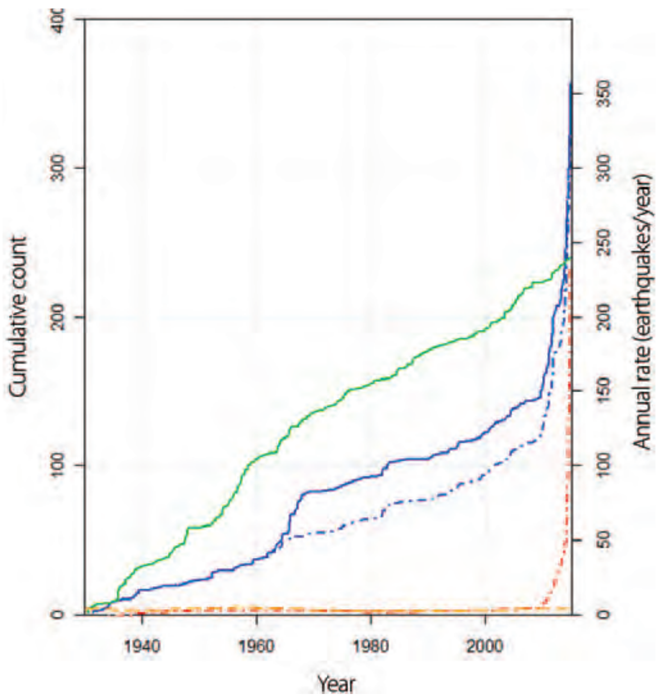

Figure 4. Cumulative count of M ≥ 3.5 earthquakes from 1930 through 2014 for the eastern (green) and western areas (blue) defined in Figure 2. The dashed-dotted blue line corresponds to cumulative count in the western area after removal of earthquakes induced by fluid injection at the Rocky Mountain Arsenal, Colorado, between 1962 and 1969. Annual rate of earthquake occurrence derived from a model fit to the cumulative curves shown by the orange and red lines for the eastern and western areas, respectively.

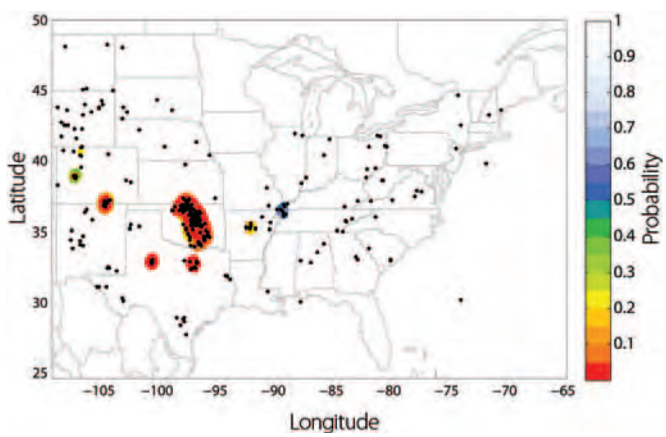

Figure 5. Map showing probability of observing at least as many earthquakes as occurred, M ≥ 3, between January 2009 and 31 December 2014 (black dots) given the earthquake rate model from the 2008 NSHM. Areas with significant excess of earthquakes include central Oklahoma, Raton Basin on the Colorado–New Mexico border, the greater Dallas–Fort Worth, Texas, area, and the Cogdell oil field in western Texas.

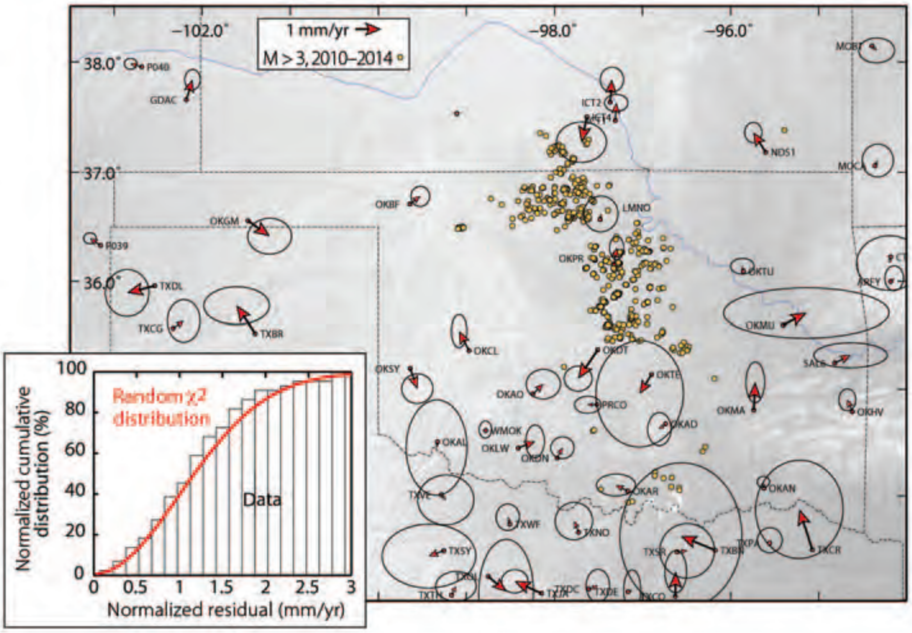

Figure 6. Crustal-movement rate in Oklahoma and surroundings determined from continuous Global Positioning System (GPS) measurements. Uncertainties have a 95% confidence level and include white plus time-correlated noise. A rigid rotation has been removed so that the residuals are deviation from rigid behavior, i.e., strain. Inset compares the cumulative distribution of observed velocities (black bins) with the theoretical χ^2 distribution expected if residuals were distributed normally in two dimensions with a unit variance (red line). The residuals are well described by a random, nontectonic process. Earthquakes of M ≥ 3 in 2013–2014 are shown by orange circles.

geologic data. In many cases, the evidence points to wastewater disposal by injection as the cause (Frohlich, 2012; Horton, 2012; Keranen et al., 2013; Kim, 2013; Keranen et al., 2014; Rubinstein et al., 2014; Andrews and Holland, 2015; Hornbach et al., 2015).

Although hydraulic-fracturing treatments are known to induce earthquakes occasionally (British Columbia Oil and Gas Commission, 2014), there was no detectable seismic response (M ≥ 2.5) in Pennsylvania during the development of the Marcellus shale (Ellsworth, 2013). It is unknown to what degree earthquakes induced during fracking operations have contributed to the rise in seismicity in the western area because the times and locations of fracking jobs are not presently available in most states. Earthquakes also accompany enhanced oil-recovery operations in some fields, such as at Rangely, Colorado, and in the Cogdell field in Texas, but not others, even in the same structural province (Gan and Frohlich, 2013). Production-induced earthquakes are common in geothermal fields and have been observed in gas fields in southern Texas (Nicholson and Wesson, 1990) as well as in the Groningen field in the Netherlands (Muntendam-Bos et al., 2015; van Thienen-Visser and Breunese, 2015), among others.

Several alternatives to the fluid-injection hypothesis, including drought, recharge of reservoirs as drought eases, and natural variations in earthquake activity, have been put forward as explanations for the increased seismicity in Oklahoma and Texas, although none that we are aware of appears in the published literature. Because drought had been particularly severe in north Texas, Hornbach et al. (2015), in a study of the Azle-Reno area earthquakes of 2013–2014, consider the effects of both a depressed water table and changes in lake level in a nearby reservoir on the source volume of the earthquakes. They show that the maximum stress changes from either mechanism were one to three orders of magnitude smaller than stress changes associated with stress triggering, whereas the pressure increase at the fault from nearby injection wells was sufficient to induce earthquakes.

The magnitude of the earthquake rate change in the western area after 2008 (Figure 4) precludes a random fluctuation about the historic mean as a viable explanation. Could we be witnessing a tectonic event? To test this possibility, we examined the crustal-deformation rate in Oklahoma by using continuous GPS data from 2002 to the end of 2014, following the procedures of Calais et al. (2006). Across Oklahoma, GPS data contain no evidence for contemporary crustal deformation (Figure 6). Only one site, OKDT, has a displacement rate that is nominally different from zero at the 95% confidence level; however, it is not confirmed by neighboring sites OKAO, PRCO, and OKAD. The apparent differential motion between OKDT and OKTU, located on opposite sides of the seismicity, corresponds to an extensional strain of 1×10^{-8}/year between the sites. This, however, is in the direction of maximum horizontal compression. If real, this strain would reduce the stress driving the earthquakes. We found no evidence for deformation anywhere in the state that would increase the stress driving the contemporary seismicity and concluded that there is no evidence for a natural tectonic origin of the increased seismicity.

If disposal of wastewater by injection is the principal cause of the excess seismicity, as now appears almost certain (Keranen et al., 2014; Andrews and Holland, 2015), it nonetheless needs to be stated clearly that disposal of wastewater by injection in UIC Class II wells more often than not results in no detectable seismic response. Consequently, the existence of a well has low predictive power for seismicity by itself. Frohlich et al. (2015) study the relation between earthquakes and disposal wells in the Bakken Shale of North Dakota and Montana using data from the USArray Transportable array from 2008 through 2011. Only three earthquakes were found that could be associated with disposal wells. Using the same methods and data, Frohlich (2012) finds dozens of earthquakes in the Barnett Shale of north Texas that clustered near several high-volume injection wells, but none associated with other injection wells. This suggests that for increased fluid pressure to induce earthquakes, three conditions must be met: (1) a preexisting fault must be present; (2) the fault must be oriented suitably in the tectonic stress field to slip; and (3) the pore-pressure perturbation must be sufficient to overcome the frictional strength of the fault.

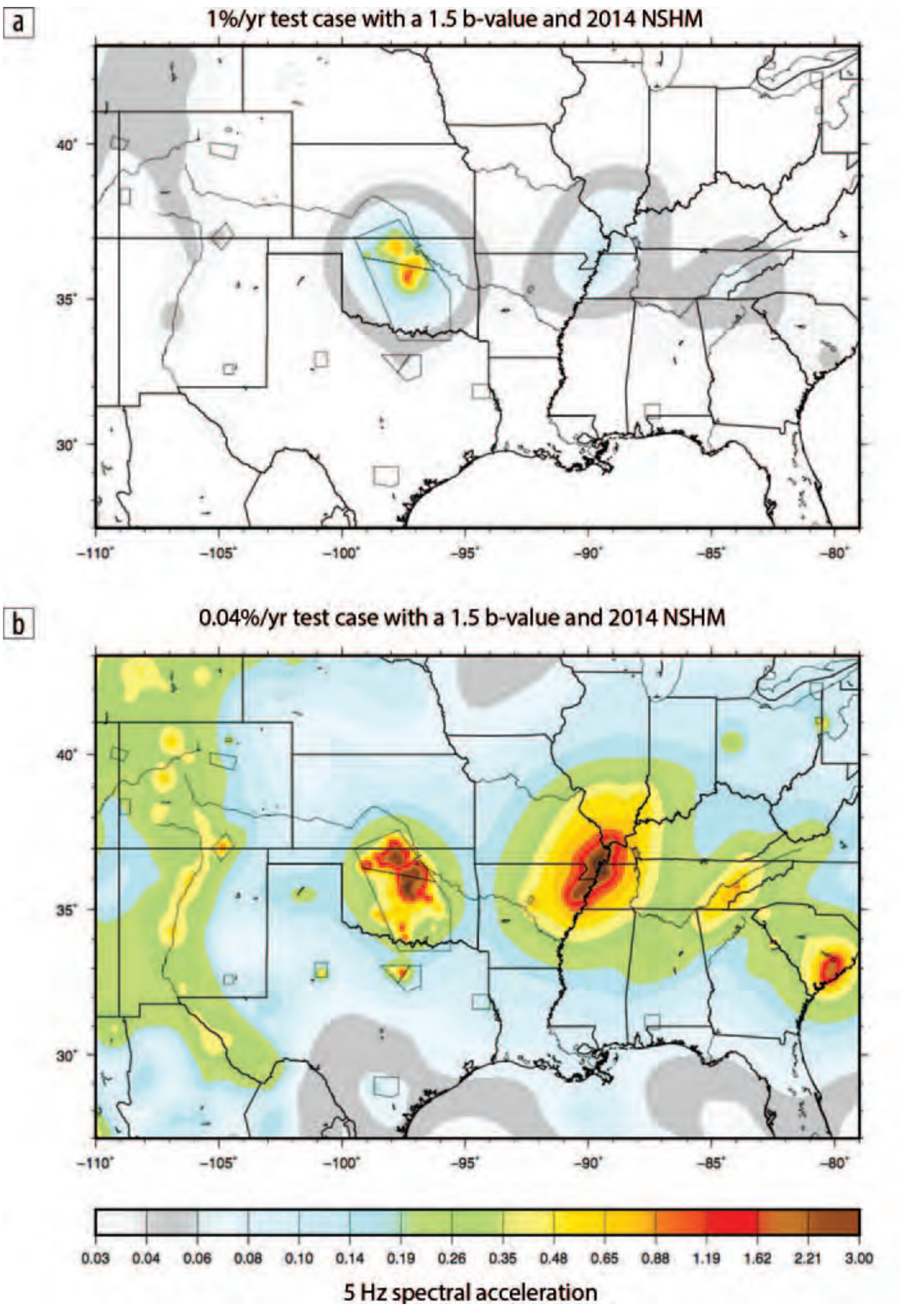

Figure 7. Uniform hazard maps for (a) 1% and (b) 0.04% probability of exceedance in one year. This example calculation uses a 2014 nondeclustered catalog with M ≥ 2.5, *b* = 1.5, 5-km smoothing, eight NSHM ground-motion models, and USGS craton M_{max} model (mean M 7). The 5-Hz (0.2-s) spectral accelerations are in units of g (acceleration of gravity) and correspond approximately to the resonance frequency of two-story structures. After Petersen et al. (2015), Figure 16. Courtesy of U. S. Geological Survey.

Seismic hazard

Quantitative estimates of the likelihood and severity of future earthquake shaking in the NSHM are based on the method of probabilistic seismic hazard analysis (PSHA) Cornell, 1968). In PSHA, the likelihood of shaking at a site (not the occurrence of an earthquake) derives from the distribution of potential future earthquakes around the site (some could be hundreds of kilometers distant), the rate of occurrence for each earthquake source (as a function of earthquake magnitude), and the expected shaking at the site for each possible earthquake.

The increased earthquake activity in the midcontinent presents some particular challenges for probabilistic seismic hazard analysis. Conventionally, the goal of PSHA is to provide quantitative guidance for seismic provisions of building codes corresponding to the serviceable life of buildings, bridges, and other structures. How can this be done when the earthquake process is nonstationary in both space and time? We might be able to make viable forecasts of tomorrow's earthquakes based on the past week, month, or year. However, it is difficult to compute hazard at the exceedance levels of the NSHM for the next 50 years. Are there alternatives for quantifying the hazard over shorter time periods, and for whom would they be of value?

These questions were explored at the National Seismic Hazard Workshop on Induced Seismicity, cohosted by the Oklahoma Geological Survey and USGS in Midwest City, Oklahoma, on 18 November 2014. The workshop was attended by more than 150 participants representing petroleum producers; geophysical service providers; university, private-industry, and government researchers; state geological surveys; state and federal regulators; the reinsurance industry; and users of hazard models, including local government, state departments of transportation, and state architects. There was broad agreement that a one-year forecast would have value, and this is the present focus of the USGS effort for the NSHM (Petersen et al., 2015). The workshop also highlighted some key challenges for making one-year hazard forecasts, including (1) rapidly evolving temporal and spatial patterns of seismicity, (2) uncertainty in the MFD for induced earthquakes, and (3) potential differences in ground-motion prediction equations between natural and induced earthquakes.

Epistemic uncertainty in the components of the hazard model can be incorporated through the use of a logic tree that considers alternative models. Petersen et al. (2015) explore in detail the sensitivity of the hazard to alternative choices for the parameters in the logic tree. A representative example of one path through the logic tree shows the hazard to be elevated broadly across Oklahoma and surrounding states (Figure 7). In north-central Oklahoma, hazard is comparable to or higher than the hazard in the source region of tectonic earthquakes in the New Madrid and Charleston seismic zones.

Discussion

As of this writing in early 2015, the seismicity rate in north-central Oklahoma and south-central Kansas continues at unprecedented levels. In just the month of January 2015, residents of Oklahoma reported feeling more than 130 earthquakes, including 59 with magnitudes between 3.0 and 4.3. In southern Kansas, 21 earthquakes strong enough to be felt occurred, including nine with magnitudes between 3.0 and 3.9. What risk do future earthquakes pose to those living in the affected areas?

The current seismicity level in the midcontinent also needs to be kept in perspective. Since the upsurge in earthquake activity in 2009, a total of 10 events with $M \geq 4.5$ has occurred; seven of these in 2011 and one each in the following three years. The largest (the M 5.6 2011 Prague, Oklahoma, earthquake) resulted in insured losses in excess of $10 million and sent some injured people to the hospital for treatment. Fortunately, no one was killed in that earthquake or any of the other events. Damage to unreinforced masonry buildings occurred in several of the other events, including the M 5.3 2011 Raton Basin, Colorado, earthquake and the M 4.8 Timpson, Texas, earthquake. Although reports of damage have been received for others, the main effect of most of the hundreds of felt earthquakes has been the nuisance of unexpected shaking, fraying nerves, and anxiety over the unknown potential for stronger shaking in the future.

Similar concerns have been raised in many other countries. For example, residents of the Netherlands have been experiencing shaking from earthquakes induced by long-term production of gas from the Groningen field (Van Eck et al., 2006). The Dutch Petroleum Company and the government are working together to manage the hazard by adjusting production to reduce the risk by strengthening structures and to compensate those who have suffered losses.

Going forward, the most probable risks in areas of increased seismicity include life-threatening injuries caused by falling objects and economic loss from damage to structures with low capacity to absorb moderate earthquake shaking. Rational decisions to improve life safety and to reduce losses require sound scientific input. Although hazard-model estimates such as the example shown in Figure 7 can be improved, there is no question that increased hazard accompanies higher levels of earthquake activity.

The potential for catastrophic loss in a larger-than-experienced earthquake must not be neglected, particularly in areas where buildings in service were constructed before modern seismic-design standards were established. Although the 2007 M 5.6 earthquake in San Jose, California, caused little more than cosmetic damage in a heavily urbanized area with strong earthquake codes and decades of preparation, the 2011 M 5.6 earthquake in largely rural central Oklahoma resulted in losses in the millions to unreinforced masonry structures, and the 1986 M 5.7 San Salvador, El Salvador, earthquake took more than 1000 lives, injured another 10,000 people, and made 100,000 homeless. The lesson to be drawn from these examples is that earthquake safety depends not only on the strength of shaking but also on the capacity of structures and society to survive it.

Learning how to prepare for, behave during, and respond after earthquakes is a proven means of improving life safety and reducing losses. Many resources are freely available, including Dart et al. (2011), which provides clear guidance on how to prepare for, survive, and recover from earthquakes. Participation in annual earthquake drills such as the Great Central U. S. ShakeOut also provides an excellent means for increasing earthquake safety awareness at school and in the workplace.

Conclusions

Earthquake activity has undergone a manifold increase in the U. S. midcontinent since 2009, principally in Oklahoma but also in Arkansas, Colorado, Kansas, New Mexico, and Texas. The nature of the space-time distribution of the increased seismicity, as well as numerous published case studies, strongly indicates that the increase is of anthropogenic origin, principally driven by injection of wastewater coproduced with oil and gas from tight formations. Enhanced oil recovery and long-term production also contribute to the rise in seismicity at a few locations. In contrast, the earthquake rate in the regions of highest long-term earthquake hazard in the central and eastern United States has remained steady for at least the last 85 years.

Incorporating rapidly changing rates of earthquakes into hazard models challenges the standard methodologies that are predicated on a time-independent rate of earthquake occurrence. Computing hazard for the next year appears feasible and has value for decisions aimed at managing the hazard or reducing vulnerability. Currently, such forecasts project the immediate past rate of earthquakes forward.

Forecasting more than "last year's earthquakes" will require a deeper understanding of the physical processes and conditions that link perturbations to the earth system to its response in seismic events. A key challenge is to develop a hazard-modeling capability that not only accounts for temporally varying activity rates but also anticipates where induced earthquakes could start or stop in response to changing industrial drivers. Despite these many challenges, there are reasons to be optimistic that the hazard can be managed. TLE

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

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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 hydraulic fracturing has created new demand for disposal wells that inject waste fluids into deep geologic formations. 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, where there are many injection wells, has increased dramatically since about 2009. For example, over 60 earthquakes of magnitudes 4.0 to 4.8 have occurred in central Oklahoma from 2009 to mid-year 2016. Some of these earthquakes may be felt at the surface. The largest earthquake in Oklahoma history (magnitude 5.8) occurred on September 3, 2016, near Pawnee, causing damage to several structures. Central and northern Oklahoma were seismically active regions before the recent increase in the volume of waste fluid injection. However, the sharp uptick in earthquake activity does not seem to be due to typical, random changes in the rate of seismicity, according to several studies.

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 to 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. However, the U.S. Geological Survey (USGS) deemed the increase in earthquake hazard in the central United States—likely from deep-well injection—sufficient to release a new one-year seismic hazard forecast for 2016 that includes contributions from both induced and natural 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 to increase the flow of oil and gas. The technique induces microseismicity, mostly of less than magnitude 1.0—too small to feel or cause damage at the surface. In a few cases, however, hydraulic fracturing has led directly to earthquakes larger than magnitude 2.0, including at sites in Oklahoma, Ohio, and England. In western Canada, earthquakes greater than magnitude 3.0 have been associated with hydraulic fracturing activities, although only from a very small percentage of hydraulic fracturing wells.

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 producing 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.

Although only a small fraction of U.S. wastewater disposal wells appears to be problematic for causing damaging earthquakes, the potential for injection-related earthquakes has raised an array of issues and has affected oil and gas wastewater disposal in some areas. In response to induced seismicity concerns, both EPA and state work groups have issued recommendations for best practices to minimize and manage such risks. Several states have increased regulation and oversight of Class II disposal wells. Congress may be interested in oversight of EPA's UIC

program or in federally sponsored research on the relationship between energy development activities 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 are being injected into the subsurface through deep disposal wells. The immediate concern is that injection of these fluids underground may cause 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. In examining these issues, it is important to distinguish between seismic activity possibly related to hydraulic fracturing itself and the possibility of seismic activity 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.

The principal seismic hazard that has emerged from increased oil and gas production in the United States appears to be related to disposal of wastewater using deep-well injection in some regions of the country. For example, one study showed the central United States has experienced a sharp increase in seismicity since 2009, increasing from an average of 24 earthquakes per year of magnitude 3.0 (M 3.0) or greater prior to 2009,[1] to an average of 193 earthquakes of M 3.0 or greater through 2014.[2] The number of M 3.0 or greater earthquakes in the central United States has continued to increase; **Figure 1** shows that the central United States experienced an average of 330 earthquakes of M 3.0 per year or greater from 2009 through January 2016.

Earthquake Magnitude and Intensity[3]

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 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.

Source: 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.

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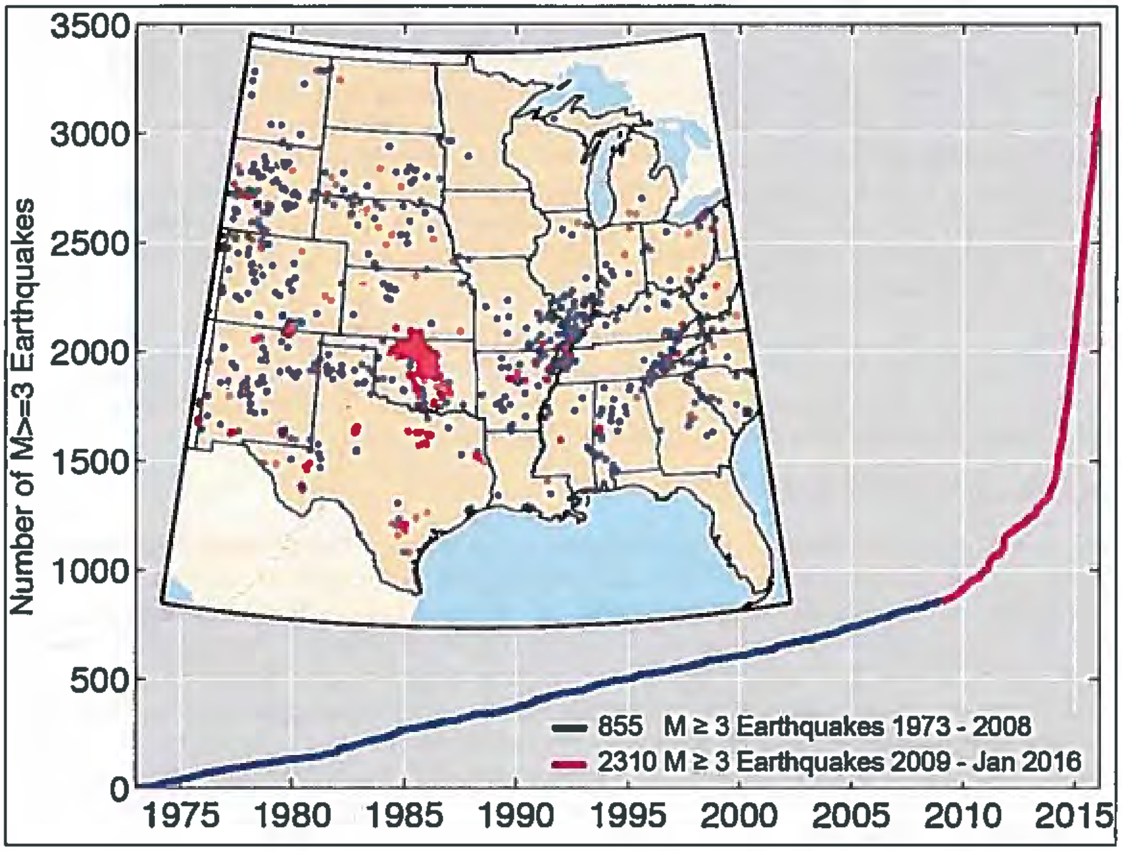
[1] Earthquakes of magnitude 3.0 or more can typically be felt at the ground surface. See Box: Earthquake Magnitude and Intensity, above.

[2] Justin L. Rubinstein and Alireza Babaie Mahani, "Myths and Facts on Wastewater Injection, Hydraulic Fracturing, Enhanced Oil Recovery, and Induced Seismicity," *Seismological Research Letters*, vol. 86, no. 4 (July/August 2015), p. 1060. Hereinafter Rubinstein and Mahani, 2015.

[3] For a more general discussion of earthquakes, see CRS Report RL33861, *Earthquakes: Risk, Detection, Warning, and* (continued...)

Figure 1. Cumulative Number of Magnitude 3.0 or Greater Earthquakes in the Central and Eastern United States, 1973-2016



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

Notes: The graph included earthquakes through January 2016. Starting around 2009, the long-term rate of approximately 29 M 3.0 or greater earthquakes per year increased significantly. Between 2009 and January 2016 the region experienced approximately 330 M 3.0 or greater earthquakes per year.

Many studies suggest that the most important contributing factor to this rising trend likely is deep-well injection of oil-and-gas-related wastewater.[4] However, the precise relationships between earthquake activity and the timing of injection, the amount and rate of fluid injected, and other factors are still not well understood, although a better understanding of these complex relationships appears to be emerging.[5] Several studies have pointed out that, of the more than 30,000 wastewater disposal wells classified by the Environmental Protection Agency (EPA) as Class II,[6] only a small fraction appears to be associated with damaging earthquakes.[7] However,

(...continued)

Research, by Peter Folger.

[4] See, for example, Rubinstein and Mahani, 2015; A. McGarr et al., "Coping with Earthquakes Induced by Fluid Injection," *Science*, vol. 347, no. 6224 (February 20, 2015), p. 830, hereinafter McGarr et al., 2015; William L. Ellsworth, "Injection-Induced Earthquakes," *Science*, vol. 341, July 12, 2013, http://www.sciencemag.org/content/341/6142/1225942.full, hereinafter Ellsworth, 2013.

[5] See, for example, F. Rall Walsh III and Mark D. Zoback, "Oklahoma's Recent Earthquakes and Saltwater Disposal," *Science Advances*, vol. 1 (June 18, 2015), hereinafter Walsh and Zoback, 2015.

even though it is only a small fraction, the overall number of disposal wells is so large that the total seismic hazard, at least for the central United States, appears to have increased measurably (see "National Issues—Changes to the U.S. Earthquake Hazard Maps").[8]

The potential for damaging earthquakes caused by injection of fluids for hydraulic fracturing operations, as opposed to deep-well injection of wastewater from fracking and other oil and natural gas production, appears to be much smaller. Multiple studies indicate that the vast majority of fluid injections into production wells for hydraulic fracturing cause microearthquakes—the results of fracturing the rock to extract oil or natural gas—which are typically too small to be felt or cause damage at the surface.[9] There are some cases where fracking caused detectable earthquakes felt at the surface, but most were too small to cause damage (see "Hydraulic Fracturing" below).

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.

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 for 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—intended to reduce greenhouse gas emissions—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 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.[10]

(...continued)

[6] 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" for more information.

[7] See, for example, Ellsworth, 2013; McGarr et al., 2015; Rubinstein and Mahani, 2013.

[8] McGarr et al., 2015, p. 830.

[9] See, for example, Rubinstein and Mahani, 2015; Ellsworth, 2013; and Walsh and Zoback, 2015.

[10] 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, (continued...)

In the 114th Congress, no legislation has been introduced to address induced seismicity associated with oil and gas wastewater disposal or other injection activities. The Fracturing Responsibility and Awareness of Chemicals (FRAC) Act of 2015 was introduced in the House (H.R. 1482) and the Senate (S. 785). Among other things, the bills would amend the SDWA term "underground injection" to include the injection of fluids and proppants used in hydraulic fracturing operations, thus authorizing EPA to regulate this process under the SDWA. It is unclear whether 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 appears to be much smaller than deep-well injection of wastewater from oil and gas production activities.

Current 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.[11] 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.[12] 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 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.[13] 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.[14] Nevertheless, the majority of deep-well injection and hydraulic fracturing 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 M 3.0).[15]

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

(...continued)

November 12, 2014 (released February 6, 2015), http://www.epa.gov/r5water/uic/ntwg/pdfs/induced-seismicity-201502.pdf.

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

[12] Ellsworth, 2013.

[13] Ibid.

[14] 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.

[15] Ibid.

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.[16]

Despite these uncertainties, a simple conceptual model for understanding how deep-well injection may be triggering earthquakes is starting to evolve, particularly for Oklahoma, which has experienced the greatest change in seismicity since about 2009. In the conceptual model, injecting oil and gas wastewater into the sedimentary formation increases its pore pressure.[17] Over time the increase in pore pressure propagates into pre-existing faults in the crystalline basement rocks underlying the sedimentary formation[18] (see **Figure 2**). Some of the faults in the crystalline basement rocks are "critically stressed," meaning that any change to the pre-existing pressure regime has the potential to initiate "slip" along the fault. Slip along a fault creates an earthquake; the size of the earthquake is generally related to the amount of slip and the length of the fault. Furthermore, studies indicate that even small pressure perturbations have the potential to cause relatively large earthquakes along these critically stressed pre-existing faults in crystalline basement rocks.[19] This may have been the case for the large, M 5.6 and M 5.8 earthquakes in Oklahoma in 2011 and 2016, respectively.[20]

[16] 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.

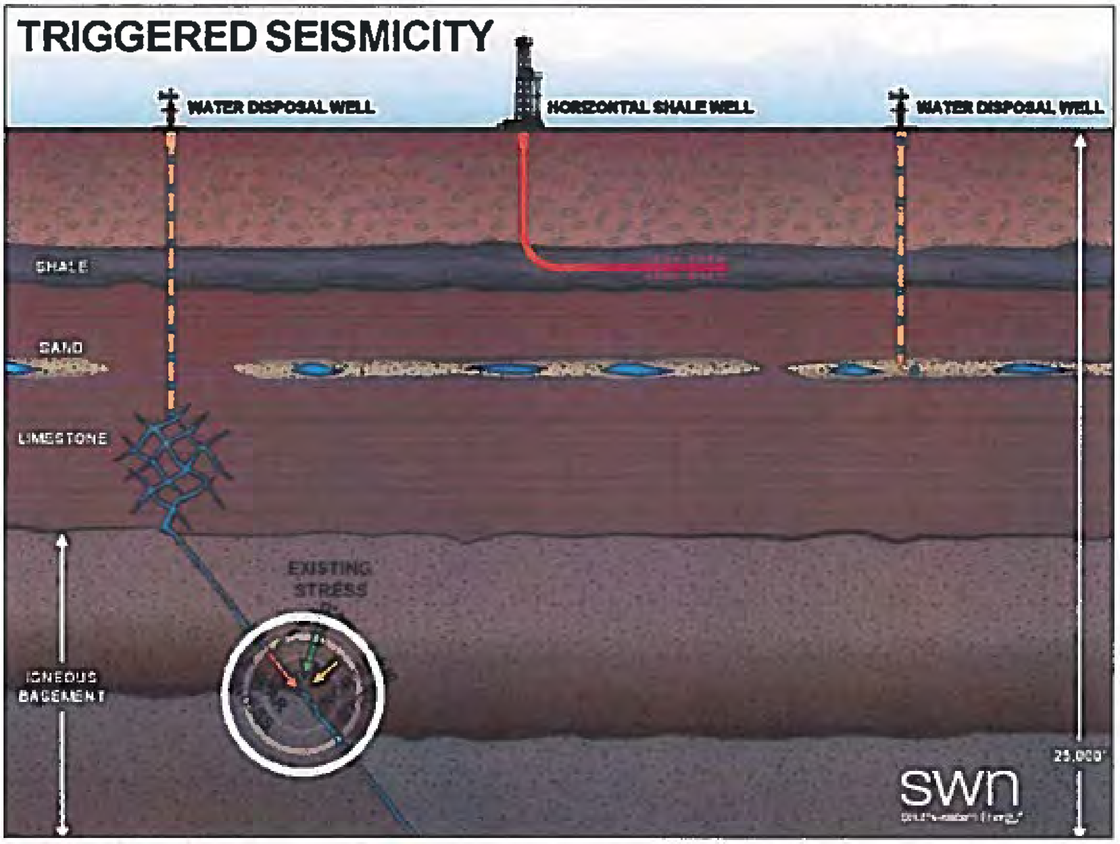
[17] Pore pressure refers to the measure of hydrostatic pressure of the fluid trapped in the pores of a rock. In the case of deep-well injection, the increase in pore pressure caused by the injection of fluids can be transmitted into the basement crystalline rocks if the fluids in pre-existing faults in the basement rocks are hydraulically connected to the sedimentary rocks where the well is located. The injected fluid itself does not necessarily have to travel into the crystalline basement faults to trigger an earthquake; the pressure wave induced by the deep-well injection is potentially sufficient to perturb the stresses on the fault and induce an earthquake.

[18] Simply, crystalline basement rocks refer to older igneous or metamorphic rocks that lie beneath younger sedimentary rocks. Oil and gas wastewaters are typically injected into the overlying sedimentary rocks.

[19] See, for example, Walsh and Zoback, 2015.

[20] Ibid.

Figure 2. 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. The term "triggered" in the figure is synonymous with the term induced as used in this report.

A Historical Example: The Rocky Mountain Arsenal

Prior to the M 5.6 earthquake that occurred on November 6, 2011, in central Oklahoma, an M 4.8 earthquake that struck northeast Denver, on August 9, 1967 was generally accepted as the largest recorded human-induced earthquake in the United States. 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.[21] 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.[22] Earthquake activity declined after 1967 but continued for the next two

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

[22] Ibid.

decades. Scientists concluded that the injection triggered the earthquakes. 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.[23] 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

As stated above, the number of earthquakes of M greater than 3.0 in the central and eastern United States has increased dramatically since about 2009 (**Figure 1**). The steep increase in the frequency of M 3.0 or greater earthquakes indicates 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 considered to be linked to deep-well injection has not yet been observed, although the September 3, 2016, M 5.8 earthquake northwest of Pawnee, OK, was the largest ever recorded in the state and may be associated with deep-well injection (see Box on p. 11).

Many observers conclude that most wells permitted for deep-well injection are in geologic formations that likely have a low risk of failure that could lead to damaging earthquakes if the injected fluids remain in the intended geologic structure.[24] 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.[25]

States experiencing higher levels of seismic activity compared to the pre-2005 average include Arkansas, Colorado, Texas, New Mexico, Ohio, Oklahoma, and Virginia.[26] Seismic activity has also increased in south-central Kansas compared to levels in 2013 and before, where there may be a link to deep-well injection of produced waters from unconventional oil and gas development.[27] 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.[28] Several instances of suspected human-induced earthquakes that garnered media and national attention include the following:

- October 2008/May 2009: M 2.5-3.3 earthquakes near Dallas-Fort Worth, TX;[29]
- August 2010/February 2011: earthquake swarm in central Arkansas, with an M 4.7 earthquake on February 27, 2011, near Greenbrier, AR;[30]

[23] Ellsworth, 2013.

[24] Rubinstein and Mahani, 2015.

[25] Walsh and Zoback, 2015.

[26] Ellsworth, 2013.

[27] Rex C. Buchanan et al., Kansas Geological Survey, "Induced Seismicity: The Potential for Triggered Earthquakes in Kansas," Public Information Circular 36, April 10, 2014, http://www.kgs.ku.edu/Publications/PIC/pic36.html.

[28] Rubinstein and Mahani, 2015.

[29] 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.

- August 2011: M 5.3 earthquake in the Raton Basin, northern New Mexico/southern Colorado;[31]
- November 2011: M 5.7 earthquake near Prague, OK;[32]
- December 2011: M 3.9 earthquake near Youngstown, OH;[33] and
- September 2016: M 5.8 earthquake near Pawnee, OK.[34]

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.[35] 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.[36] 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.[37] 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 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.

(...continued)

[30] 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.

[31] 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.

[32] 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.

[33] 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.

[34] Oklahoma Geological Survey, *Pawnee Earthquake Fact Sheet*, http://www.ou.edu/content/dam/ogs/documents/statements/OGS-Fact_Sheet_Pawnee_Earthquake_2016-09-03.pdf.

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

[36] 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.

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

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. The study found that all 24 of the most reliably located earthquake epicenters occurred within about 1.5 miles of one or more injection wells.[38] 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.[39] 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

Figure 1 shows that the earthquake rate in the central and eastern United States has increased significantly since 2009; more than 50% of those earthquakes since 2009 have occurred in central Oklahoma.[40] **Figure 3** shows the rate of increase in M 3.0 or greater earthquakes in Oklahoma, in particular the steep increases during 2014 and 2015. As of 2014, the earthquake rate for M 3.0 or greater earthquakes in Oklahoma exceeded the rate for earthquakes of a similar magnitude in California.[41] The rate for M 3.0 earthquakes since 2009 is nearly 300 times higher than for previous decades.[42]

In the past, Oklahoma has experienced earthquakes large enough to be felt at the surface, including two earthquakes in the range of M 5.0 or greater in 1918 and 1952.[43] However, studies indicate that it is highly improbable that the increase in earthquake activity since 2009 is part of a natural fluctuation in earthquake rates.[44] Studies of the geology of central Oklahoma indicate that the region includes a complex belt of ancient, buried faults that cut through the Arbuckle

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[38] 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.

[39] 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.

[40] D.E. McNamara et al., "Efforts to Monitor and Characterize the Recent Increasing Seismicity in Central Oklahoma, " *The Leading Edge*, June 2015, pp. 628-639.

[41] Ibid, p. 629.

[42] D.E. McNamara et al., "Earthquake Hypocenters and Focal Mechanisms in Central Oklahoma Reveal a Complex System of Reactivated Subsurface Strike-Slip Faulting, " *Geophysical Research Letters*, vol. 42, no. 8 (April 28, 2015).

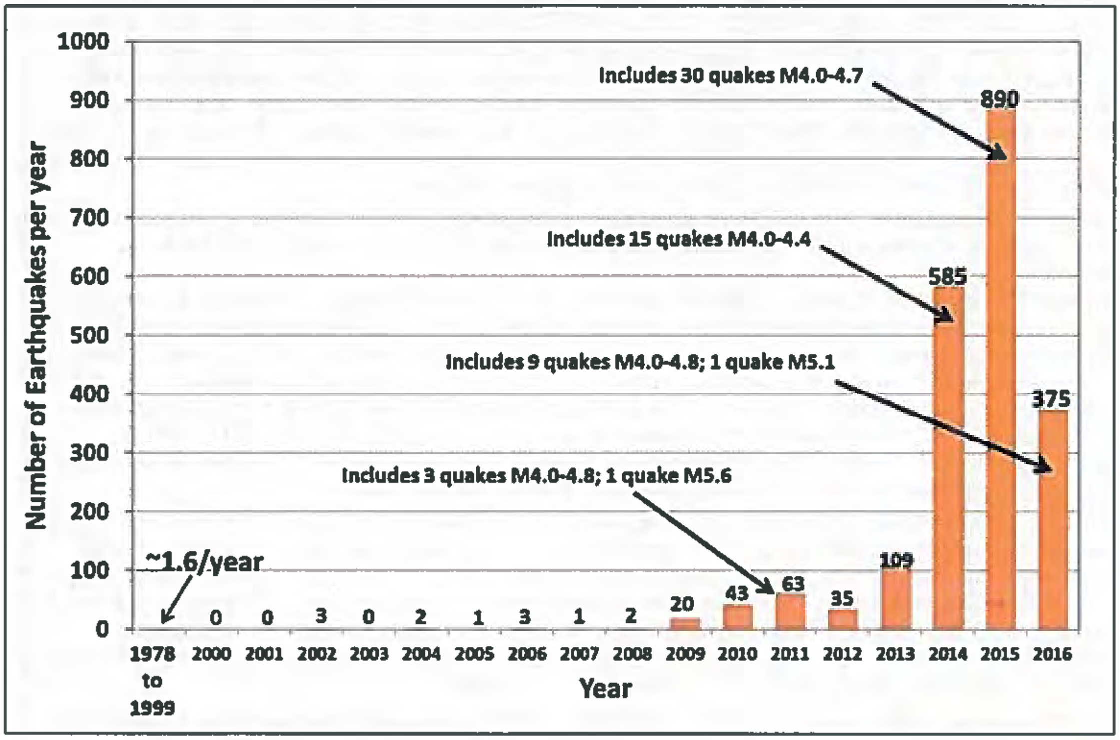
[43] Ibid.

[44] Ibid.

Formation—the formation into which many of the oil and gas wastewater fluids are injected—and extend deeper into the older crystalline basement rocks.[45] The disposal of wastewaters into the Arbuckle Formation may be reactivating these faults and causing earthquakes.[46]

In addition to the spike of M 3.0 and greater earthquakes in Oklahoma, the state has also experienced its largest earthquakes ever recorded: a M 5.7 event near Prague on November 5, 2011, and a M 5.8 event near Pawnee on September 3, 2016. The combination of increased frequency of felt earthquakes and relatively large magnitude events has focused attention on Oklahoma and the state and federal response to the new hazard (see text box on p. 11).

Figure 3. Oklahoma Earthquakes of M 3.0 or Greater



Source: U.S. Geological Survey, email communication September 7, 2016. Modified by CRS.

Notes: The bar representing 2016 includes earthquakes through June 22, 2016. The M 5.6 event noted for 2011 has been modified to an M 5.7 earthquake by the USGS. The M 5.8 earthquake of September 3, 2016, is not included.

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.[47] One earthquake in Harper County in 2013 had a magnitude of 4.3, and three earthquakes in Sumner County in 2014

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[45] Ibid.

[46] Ibid.

[47] Rex C. Buchanan et al., Kansas Geological Survey, "Induced Seismicity: The Potential for Triggered Earthquakes in Kansas," Public Information Circular 36, April 10, 2014, http://www.kgs.ku.edu/Publications/PIC/pic36.html, (revised August 2015).

had magnitudes over 3.0.[48] 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 in January 2014.The task force resulted in an action plan for dealing with earthquakes possibly induced by deep well injection. For example, in March 2015 the Kansas Corporation Commission required operators to reduce the rate of injection in five areas where wells were disposing fluids into the deep Arbuckle Formation (the same formation that occurs in Oklahoma, discussed above).[49]

Magnitude 5.8 Earthquake Near Pawnee, OK, September 3, 2016

On September 3, 2016, a magnitude 5.8 earthquake occurred about 9 miles northwest of Pawnee, OK, and was felt throughout Oklahoma and many other states. Prior to the September 3 event, the largest earthquake to strike Oklahoma was an M 5.7 temblor on November 5, 2011, about 30 miles east of Oklahoma City near the town of Prague. In response to the September 3 earthquake, the Oklahoma Corporation Commission (OCC)—the state entity responsible for regulating oil and gas activity in Oklahoma—ordered a total of 48 injection wells within the OCC jurisdiction to shut down or reduce injection volumes. In addition, 19 wells in the vicinity of the earthquake were located in the Osage Nation Mineral Reserve, where the U.S. Environmental Protection Agency administers the UIC program: operators of these wells agreed to shut down wells consistent with actions in state jurisdiction. The authority for the OCC actions is discussed more fully below in "State Initiatives".

According to a September 12, 2016 OCC press release announcing the closures, the identification of specific injection wells to shut down or curtail injection volumes resulted from new data resulting from work by the Oklahoma Geological Survey and the U.S. Geological Survey that identified the likely fault systems responsible for the earthquake. The September 12 order amended an order issued by the OCC on the day of the earthquake to shut down and curtail operations of a different set of wells based on a preliminary evaluation of the faults responsible for the September 3 earthquake. (Similarly, EPA contacted operators of 3 additional wells in the Osage Nation Mineral Reserve and requested them to reduce injection volumes; 11 wells were allowed to resume operations at reduced injection levels, and 5 wells remained shut down.)The first order from the OCC was to shut down 37 disposal wells near the epicenter. The orders to immediately shut down or curtail injection wells reflect the OCC's current understanding of the links between injection activities and earthquakes, as manifest in their emergency authorities for issuing mandatory instructions to wells disposing wastewater into the Arbuckle Formation.

As discussed above in "Deep-Well Injection of Oil and Natural Gas Wastewaters", the Arbuckle Formation is of great interest to scientists and regulators because of its proximity to crystalline bedrock and the potential for deep-well injection to possibly reactivate existing faults. The difficulties in assigning a specific well's activities to a specific fault and subsequent earthquake did not preclude the OCC from taking immediate action to shut down or curtail the set of wells that may have a connection to the September 3 earthquake. These recent actions reflect an evolution of understanding of the relationship between deep well injection and earthquakes and the regulatory regime and actions by Oklahoma, and other states, to respond to human-induced earthquakes.

The magnitudes of the September 3, 2016, and the November 5, 2011, earthquakes focuses attention on a scientific and policy challenge: what is the relationship between the sharp increase in frequency of M 3.0 and greater earthquakes in Oklahoma since 2009 and the probability for larger and potentially damaging earthquakes. Despite the rapid uptick in earthquake frequency in Oklahoma (see **Figure 3**), most of the earthquakes have not caused damage. However, both the 2011 and 2016 larger magnitude events damaged buildings and caused injuries. The possibility of perturbing the preexisting faults in the crystalline bedrock below the Arbuckle Formation may be emerging as a mechanism for creating larger earthquakes. Whether the current scientific understanding of the link between deep-well injection and earthquakes in the crystalline basement rocks is sufficient to craft policies that eliminate the chances of large, damaging human-induced earthquakes is not clear.

National Issues—Changes to the U.S. Earthquake Hazard Maps

Until recently, the 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

[48] Ibid.

[49] Ibid.

by human-induced earthquakes.[50] This was done, in part, because natural seismicity is assumed to be time-independent in assessing the earthquake hazard,[51] and researchers were not sure how to treat potentially 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.[52] 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 mean combining natural seismic hazards with human-induced seismic hazards on one map is difficult.[53]

Despite the difficulty, and because of the sharp uptick in seismic activity in the central and eastern United States since 2009, on March 28, 2016, the USGS released a one-year seismic hazard forecast for 2016 that includes contributions from both induced and natural earthquakes (revised June 16, 2016).[54] (See **Figure 4.**)

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

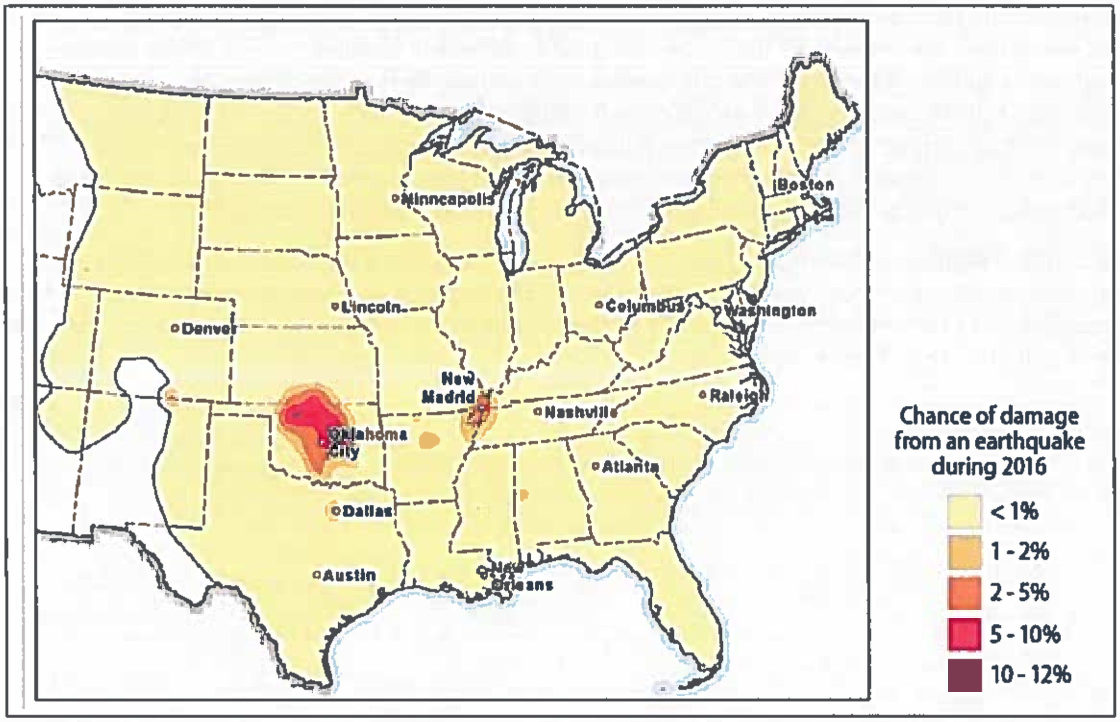
[51] Time-independent in this context means that the tectonic forces that create the earthquake hazard are assumed to be relatively non-changing over a specified time period; in this case, the U.S. Geological Survey designates a 50-year time period. The earthquake hazard caused by deep-well injection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

[52] 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.

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

[54] Mark D. Petersen et al., *2016 One-Year Seismic Hazard Forecast for the Central and Eastern United States From Induced and Natural Earthquakes*, U.S. Geological Survey, Open-File Report 2016-1035, June 17, 2016, https://pubs.er.usgs.gov/publication/ofr20161035.

Figure 4. Chance of Damage from an Earthquake in the Central and Eastern United States in 2016



Source: Mark D. Petersen et al., *2016 One-Year Seismic Hazard Forecast for the Central and Eastern United States From Induced and Natural Earthquakes*, U.S. Geological Survey, Open-File Report 2016-1035, June 17, 2016, https://pubs.er.usgs.gov/publication/ofr20161035, p. 39. Modified by CRS.

Notes: Chance of damage refers to all types of structures, including buildings, bridges, and pipelines.

The map in **Figure 4** shows two main areas of earthquake hazard: the zone near New Madrid, Missouri, and the zone extending around Oklahoma City into south-central Kansas. The New Madrid area represents primarily a zone of natural seismic hazard, whereas the zone in Oklahoma is primarily an area of induced seismicity hazard. The induced seismicity hazard from deep-well injection represents what might be considered a short-term hazard, compared with the perennial seismic hazard from natural tectonic forces, because to some degree the chance of an earthquake caused by deep-well injection depends on the injection activity.[55]

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.[56] 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

[55] For more information about earthquake risk in the United States generally, see CRS Report RL33861, *Earthquakes: Risk, Detection, Warning, and Research*, by Peter Folger.

[56] 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.

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, and England. In western Canada earthquakes larger than M 3.0 have been correlated to fracking.[57] 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 M 2.2 to M 3.8.[58] 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. A statistical study associated fracking activities at 39 wells in the Western Canadian Sedimentary Basin (WCSB) with seismic events greater than M 3.0, including an earthquake of M 4.6.[59] The study indicated that most of the seismic activity in the WCSB since 1985 seems to be associated with oil and gas activity, although only a small portion of fracking operations appear to be linked to seismic activity (0.3% of wells used for hydraulic fracturing).[60] The study warned that hydraulic fracturing may have induced earthquakes in isolated cases even days after injection activities ceased, suggesting that policies that curtail injection (such as "traffic-light" protocols, discussed below in "State Initiatives") may not have an immediate effect in preventing the occurrence of injection-induced events.[61]

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.[62] 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.

[57] Gail M. Atkinson et al., "Hydraulic Fracturing and Seismicity in the Western Canada Sedimentary Basin," *Seismological Research Letters*, vol. 87, no. 3 (May/June 2016). Hereinafter Atkinson et al., 2016.

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

[59] Atkinson et al., 2016. The Western Canadian Sedimentary Basin underlies about 540,000 square miles of western Canada, including portions of Manitoba, Saskatchewan, Alberta, British Columbia, and the Northwest Territories.

[60] Ibid.

[61] Ibid.

[62] 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.

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.[63] 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.[64] The more recent work in Oklahoma also indicated that the vast majority of fracking operations did not create anomalous seismicity.

Ohio

Research on a series of small earthquakes in Harrison County, Ohio that occurred in 2013, 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.[65] 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 underlying Utica Shale led to changes in how Ohio permits wells.[66] 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. Furthermore, 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 have been detected within the footprint of the Marcellus Shale, as measured by a regional seismographic network.[67] 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.[68]

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[63] 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.

[64] 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.

[65] 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.

[66] 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.

[67] Ellsworth, 2013.

[68] Ibid.

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 and other parts of the Western Canadian Sedimentary Basin.

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.[69] 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 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

As stated earlier, the principal law authorizing federal regulation of underground injection activities is the Safe Drinking Water Act (SDWA) of 1974, as amended.[70] The law specifically directs EPA to promulgate regulations for state underground injection control (UIC) programs to prevent underground injection that endangers drinking water sources.[71] 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.[72]

The SDWA authorizes states and Indian tribes to assume primary enforcement authority (primacy) for the UIC program for any or all classes of injection wells.[73] EPA must delegate this

[69] 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.

[70] 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.

[71] 42 U.S.C. §300h(d). SDWA §1421.

[72] 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.

[73] For most SDWA programs, including the UIC provisions, 'state' is defined to include the District of Columbia and territories (SDWA §1401; 42 U.S.C. §§300f(14). Tribes are authorized to receive primacy under SDWA §1451; 42 U.S.C. §300j-11. Navajo Nation and the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation have (continued...)

authority, provided that the state or tribal program meets certain statutory and EPA requirements.[74] 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. Tribes may also be delegated primacy for the UIC program,

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.[75] Most oil and gas states and some tribes 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).[76] **Figure 5** provides an illustration of the six well classes established by EPA to implement the UIC program.

(...continued)

attained primacy for Class II wells.

[74] To receive primacy, a state, territory, or Indian tribe must demonstrate to EPA that its UIC program is at least as stringent as the federal standards. The state, territory, or tribal UIC requirements may be more stringent than the federal requirements. For Class II wells, states or tribes must demonstrate that their programs are effective in preventing endangerment of Underground Sources of Drinking Water.

[75] 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.

[76] 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 5. 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 liquid hydrocarbons; or (3) to inject fluids to enhance recovery of oil and gas from conventional fields. There are more than 172,000 Class II wells across the United States. Based on historical averages, roughly 80% of the Class II wells are enhanced recovery wells,[77] and 20% are disposal wells (often referred to as Class IId wells).[78]

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

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 liquid 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 liquid hydrocarbons (e.g., petroleum) 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. (Two permits were 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.

[77] Enhanced recovery wells are 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.

[78] 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.

a. Additionally, 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.[79] 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."[80] 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."[81]

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.[82]

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).[83] 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

[79] 40 C.F.R. §146.23(a)(1).

[80] 40 C.F.R. §146.62(b)(1).

[81] 40 C.F.R. §146.68(f).

[82] 40 C.F.R. §146.82(a)(3)(v).

[83] 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.

USDW."[84] Regulations for Class I wells further specify that "injection pressure must be limited such that no fracturing of the injection zone occurs during operation."[85]

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 directly implements the UIC program in Pennsylvania and Virginia.[86]) In responding to public comments on a Class II well permit application in 2013, 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."[87]

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.

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[84] 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.

[85] Ibid., p. 66.

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

[87] 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.

- Applicability of conclusions to other well classes.
- Defined specific areas of research as needed.[88]

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.[89] 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."[90] (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.[91]

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.[92] 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, or
- USDW contamination from a direct communication with the fault inducing seismicity or contamination from earthquake-damaged surface sources.[93]

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.[94]

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[88] 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.

[89] 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.

[90] Ibid., ES-2.

[91] Ibid., p. 27.

[92] 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.

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

[94] Ibid., p. 35.

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 areas with limited or no data. As a general principal, the workgroup recommended that future research be conducted using a holistic and multidisciplinary approach, combining expertise in petroleum engineering, geology, geophysics, and seismicity.[95]

State Initiatives

Several states and state organizations have been assessing the possible relationship between injection wells and seismic activity.[96] In March 2014, the Interstate Oil and Gas Compact Commission (IOGCC)[97] and the Ground Water Protection Council (GWPC)[98] formed an Induced Seismicity Work Group (ISWG) with state regulatory agencies and geological surveys to "proactively discuss the possible association between recent seismic events occurring in multiple states and injection wells."[99] In September 2015, the workgroup issued a primer on potential injection-induced seismicity to provide "guidance in mitigating seismic risks associated with waste water disposal wells, not hydraulic fracturing."[100]

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.

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[95] Ibid., pp. 31-32. In another federal initiative, the Department of Energy (DOE) is conducting 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 previously 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. Some of the approaches and mitigation measures included in the DOE protocol may be applicable to issues posed by Class II disposal wells. See 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.

[96] 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.

[97] 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/.

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

[99] 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.

[100] Ground Water Protection Council and Interstate Oil and Gas Compact Commission, Potential Injection-Induced Seismicity Associated with Oil & Gas Development: A Primer on Technical and Regulatory Considerations Informing Risk Management and Mitigation, September 2015, http://www.statesfirstinitiative.org/induced-seismicity-work-group.

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.[101]

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.[102] (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.[103] State officials continue to monitor disposal well operations and seismic activity. The state purchased additional seismic monitoring equipment, which supports an "early warning" system for detecting and responding to any emerging seismic activity.[104]

Colorado

The Colorado Oil and Gas Conservation Commission (COGCC) has identified in existing rules and policies various requirements that aim to reduce the likelihood of induced seismicity.[105] 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.[106] 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 detailed review of subsurface geology or seismic monitoring prior to new drilling. Additionally, the Colorado Division of Water Resources conducts a review of the proposed

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

[102] 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).

[103] 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).

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

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

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

injection zone. If seismicity is identified in the vicinity of the proposed injection well site, the COGCC requires the operator to define the seismic potential and the proximity to faults using the geological and geophysical data prior to approval.[107]

In 2014, the COGGC worked with the Colorado Geological Survey, USGS researchers, and state universities to establish an induced seismicity advisory group. Issues for consideration by the advisory group included development of a more comprehensive statewide seismicity monitoring network and improved guidance for managing high-volume injection. COGGC has deployed regional seismic monitoring networks and implemented a traffic light system following seismic events in the vicinity of a disposal well.[108]

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.[109] 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 provided a response plan, which would be triggered by earthquakes of magnitude 2.0 or greater. The plan further outlined a set of criteria under which disposal wells located within six miles of an earthquake would be evaluated and a determination made as to whether regulatory remedies under current statutory authorities would be warranted. As recommended, the state has purchased a portable seismic array and established monitor stations.

In 2015, the Kansas Corporation Commission issued an order limiting injection rates for more than 70 wells to monitor the effects of seismic activity. The order limited injection rates for all wells injecting into the Arbuckle Formation in two counties and imposed daily monitoring and monthly reporting requirements for high-volume Arbuckle wells. The order identified five areas of seismic concern based on earthquake clusters that triggered responses under the seismic action plan. Operators of affected wells were required to limit injection volumes at certain times and plug back wells that penetrated the base of the Arbuckle Formation.[110]

Ohio

Following the Youngstown earthquakes in 2011 associated with Class II disposal wells,[111] 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

[107] Ibid.

[108] Ground Water Protection Council and Interstate Oil and Gas Compact Commission, *Potential Injection-Induced Seismicity Associated with Oil & Gas Development: A Primer on Technical and Regulatory Considerations Informing Risk Management and Mitigation*, September 2015.

[109] 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.

[110] Kansas Corporation Commission, Commission Order, Docket No. 15-CONS-770-CMSC (order), http://www.kcc.state.ks.us/induced_seismicity/index.htm.

[111] Ohio Department of Natural Resources, *Preliminary Report on the Northstar Class II Injection Well and the Seismic Events in the Youngstown, Ohio, Area* , March 2012, http://oilandgas.ohiodnr.gov/portals/oilgas/downloads/northstar/reports/northstar-executive_summary.pdf.

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.[112] 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.[113] Additionally, the state has purchased portable seismic units and implemented a proactive approach to seismic monitoring around deep Class II wells.[114]

Hydraulic Fracturing

In 2014, ODNR drafted new rules and imposed new drilling requirements for construction of horizontal production wells that would be hydraulically fractured (i.e., shale gas and oil wells) in response to seismic activity the state determined had a "probable connection to hydraulic fracturing near a previously unknown microfault."[115] The rules include standards for design, approval, and construction of horizontal well sites and strengthen drilling permit conditions for wells located near faults or areas linked to previous seismic activity.[116]

New permits for horizontal drilling within 3 miles of a known fault or area of seismic activity greater than a 2.0 magnitude, now include requirements for companies to install seismic monitors. If the monitors detect a seismic event in excess of 1.0 magnitude, the well operator would be required to halt activities while the cause is investigated. If a probable connection to hydraulic fracturing is identified, then the operator would be required to suspend hydraulic fracturing operations.[117]

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. In 2015, the state reported that most of the wastewater disposed of in the state is the naturally occurring saltwater brine that is brought to the surface

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

[113] 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.

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

[115] 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.

[116] Ch. 1501:9-2-02 OAC, http://codes.ohio.gov/oac/1501%3A9-2.

[117] Ohio Department of Natural Resources, Division of Oil and Gas Resources Management, "Shale Well Drilling and Permitting: Seismic Restrictions," http://oilandgas.ohiodnr.gov/shale#SEIS.

along with the oil and gas, and a relatively small portion is flowback from hydraulically fractured wells.[118]

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[119] and has continued 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. For applications for new wells, 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.[120] 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 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.[121]

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 (OGCD), 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 met the criteria were allowed to resume normal operations. For any wells found to be in contact/communication with basement rock, operators were required to plug back the wells to a shallower depth and meet specified criteria. Operators who did not provide the requested information or did not have an approved plugging schedule were required to reduce injection volumes by 50%.[122] Since April 2015, the OCC has used the traffic light system multiple times to impose restrictions on well operations in prescribed areas following seismic events.

Following the seismic event on September 3, 2016, the OCC used its emergency authorities to issue mandatory instructions for wells injecting into the Arbuckle Formation. The OGCD required operators to shut in (temporarily shut down) all Arbuckle disposal wells within a 725 square-mile area. Wells within five miles of the location of the earthquake were required to shut in no later than September 10, 2016, and wells located between 5 and 10 miles of the earthquake

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[118] 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.

[119] 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.

[120] 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.

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

[122] 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.

were required to shut in by September 13, 2016. The 725 square-mile area included 211 square miles of Osage County, a portion of which is part of the Osage Nation Mineral Reserve. EPA implements the UIC program in Osage County, and the agency requested operators to shut in 17 disposal wells. EPA reports that these operators agreed to do so consistent with the state's directives.

On September 12, 2016, OCC expanded the seismicity impact area of concern to 1,116 square miles based on new data. The total number of wells of interest increased to 67, including 48 wells under OCC jurisdiction and 19 under EPA jurisdiction. Of these, 27 in OCC jurisdiction were required to cease operations with the remainder operating at reduced disposal volumes. EPA requested operators at 14 wells to reduce injection volumes by 25% of recent levels. Five wells in the Osage Nation Mineral Reserve remained shut in.

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.[123] Several of the new requirements are listed below.[124]

- 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."[125]
- 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 Seismicity Work Group initiative, as state regulatory agencies and geological surveys continue to evaluate this issue.

[123] *Texas Register*, 39 *TexReg*\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.

[124] 39 *TexReg* 8996-9005, 16 T.A.C. §3.9.

[125] 16 T.A.C. §3.9(6)(A)(vi).

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; however, due to the growing volumes injected by these wells and increased seismicity in some disposal areas, an increasing concern in the United States is that injection of these fluids may be responsible for increasing rates of seismic activity. 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.

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Characterizing and Responding to Seismic Risk Associated with Earthquakes Potentially Triggered by Saltwater Disposal and Hydraulic Fracturing

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Abstract

Since 2009, there has been a dramatic increase in the number of small-to-moderate size earthquakes in the central and eastern United States. In a number of cases, the increase in seismicity appears to be associated with injection of saltwater related to oil and gas development. To address this issue of triggered seismicity, regulatory agencies, private companies, and public interest groups have proposed an assortment of guidelines and regulations for reducing the risks associated with potentially triggered earthquakes. We present here a framework for risk assessment for triggered seismicity associated with saltwater disposal and hydraulic fracturing and include several factors that are not currently considered in standard earthquake hazard and risk assessment procedures. The framework includes a site characterization component to determine the hazard in the area, followed by the utilization of risk tolerance matrices for regulators, operators, stakeholders, and the public to consider depending on exposure. The hazard and risk assessment workflow includes the use of a traffic light system that incorporates geologic and geophysical observations as well as earthquake magnitudes or ground motions, as criteria for whether a particular set of events warrant a response.

Introduction and Context

For nearly a century, earthquakes apparently triggered by fluid injection have been observed in many parts of the world (NRC, 2012). Although injection-related seismicity is a well-known phenomenon, recent years have seen a dramatic increase in earthquake occurrence apparently associated with oil and gas development. This increase has been most notable in the central and eastern United States (Ellsworth, 2013). Recent occurrences of felt events in areas of significant populations have brought attention to this issue from the public, oil and gas operators, regulators, and academics.

The primary physical processes responsible for injection-related seismicity are generally well known (see reviews by NRC, 2012; Suckale 2009). Simply put, increased fluid pressure decreases the effective normal stress on a fault. The effective stress resists fault slip by acting perpendicular to the fault, essentially clamping it shut. As pore pressure increases, it reduces this effective normal stress and may cause the fault to unclamp, potentially triggering the release of accumulated strain energy on a pre-existing fault that is already close to failure (NRC, 2012). These faults are often referred to as critically stressed. Earthquakes on critically stressed faults influenced by fluid injection are referred to as triggered because relatively small perturbations potentially trigger the release of already-stored energy through an earthquake (McGarr et al., 2012). The pressure change resulting from fluid injection simply triggers its release.

As the increase in triggered earthquakes becomes more problematic, it is clear that it would be advantageous to develop an initial seismic risk assessment to be carried out for proposed and pre-existing fluid injection sites (The Royal Society, 2012). Earthquake hazard and risk assessments are well established but have historically focused on natural earthquakes and rarely anthropogenic earthquake triggering. Our work builds largely from previously published work, but differs in that we present a comprehensive framework that considers the scientific factors necessary for a hazard and risk assessment workflow in a format that is site-adaptable and can be updated as hazard and risk evolve with time. This changing hazard and risk may be due to a new geological understanding, updates made to the operational factors, changes in the exposure, or changes to the tolerance for risk at the site.

We offer suggestions for how to incorporate anthropogenic factors, which we term "operational factors," that may influence the occurrence of triggered seismicity in a site-specific manner, as well as the exposed populations, properties, structures, and infrastructure. Additionally, we discuss the use of risk tolerance matrices that take into consideration the level of tolerance the affected groups have for earthquakes triggered by fluid injection, including the operators, regulators, stakeholders, and public. These concepts are discussed more thoroughly in an expanded document available online at: https://pangea.stanford.edu/researchgroups/scits/publications.

Hazard and Risk Assessment Workflow

Our proposed hazard and risk assessment workflow for earthquakes triggered by hydraulic fracturing and saltwater disposal is meant to be site-specific and adaptable (Figure 1). It includes an

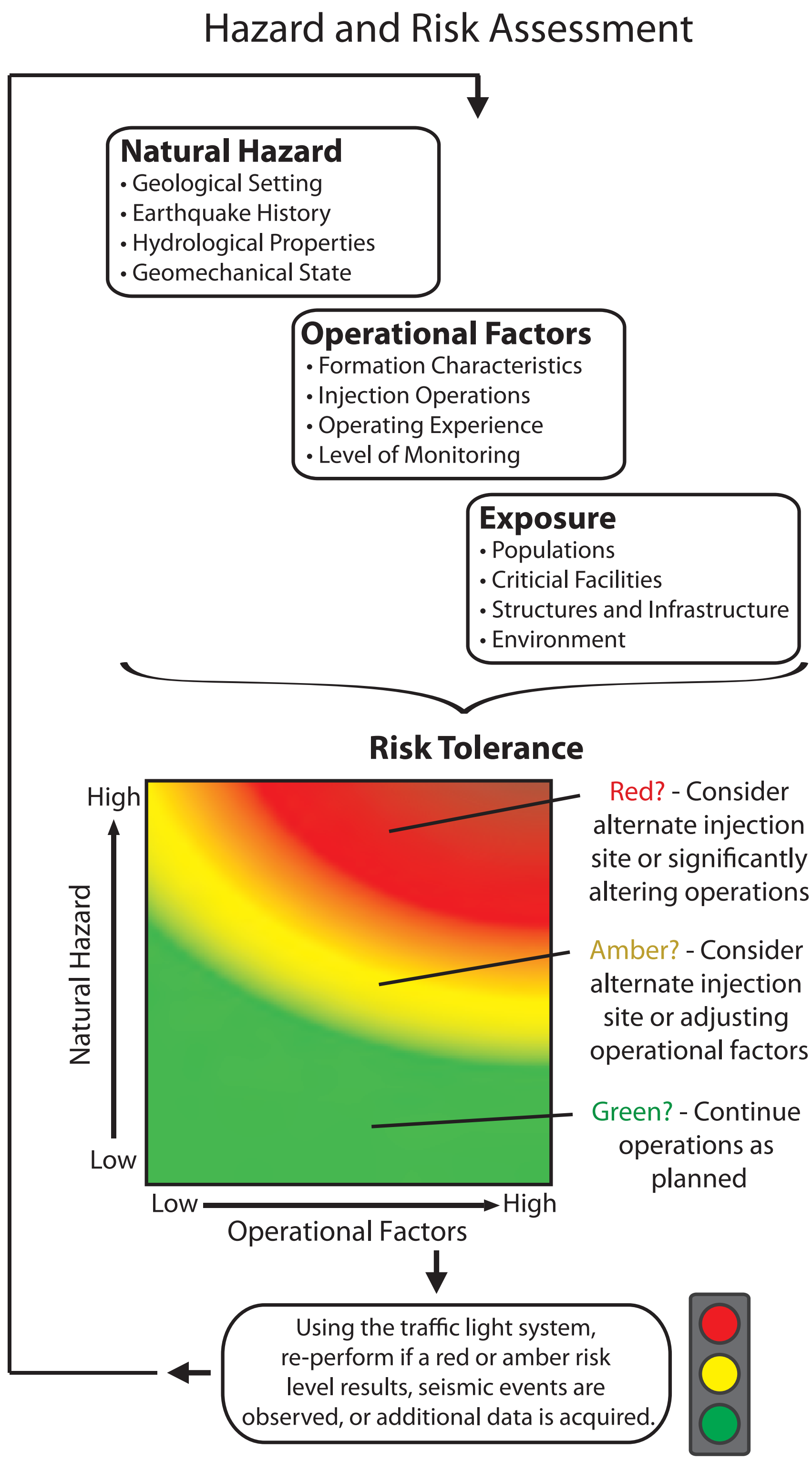

Figure 1. Hazard and risk assessment workflow. In concept, the hazard, operational factors, exposure, and tolerance for risk are evaluated prior to injection operations. After injection begins, the occurrence of earthquakes in the region and additional site-characterization data could require iterations of the workflow. As shown below, there are different risk tolerance matrices for different levels of exposure.

analysis of the earthquake hazard at a site using what is known of the geology, hydrology, earthquake history, and geomechanics of the area and when used with a Probabilistic Seismic Hazard Analysis (PSHA) (e.g. McGuire, 2004) is the basis for determining the probable level of natural seismic hazard. This is used in conjunction with operational factors that influence the potential for the occurrence of triggered earthquakes, including specific injection practices, the operating experience in the area and of the company responsible, and the formation characteristics. Once probabilities of experiencing various levels of natural ground motion have been computed, they can be combined with the associated likely consequences to evaluate risk. Consequences depend upon the level of exposure of the site and surrounding area, and the contributing operational factors. As such, risk assessment and planning needs to occur jointly with planning of operations that might affect risk. Both the operational factors and exposure are described further below.

The proposed workflow is intended to be implemented prior to injection operations and then used iteratively as new information related to the hazard and risk becomes available. While this process may be difficult in practice, it is important to reflect upon examples of injection operations where a risk tolerance assessment could have prevented triggered events, such as the earthquakes triggered by injection in Basel, Switzerland (Deichmann and Giardini, 2009). In cases where the risk is non-negligible, mitigation can include additional monitoring and data collection (Nygaard et al., 2013).

Operational Factors

Along with the earthquake history and geologic, hydrologic, and geomechanical characteristics of a site, a number of operational factors also contribute to the potential for triggered seismicity (Figure 2). It is the responsibility of the operators and regulators to determine the level of impact the operational factors have on the risk level of a project. Operational factors are specific to triggered seismicity and not included in standard seismic hazard and risk calculations. Since these operational factors are not included in current PSHA procedures, here we account for them separately in the formation of a project's risk tolerance matrix. Conceptually, we would like to quantify factors that influence the likelihood of earthquake occurrence in terms of the seismic source model of the hazard analysis calculation. But, because it is currently difficult to link these operational factors in a quantitative or causative manner to earthquake occurrence, we take an indirect approach and consider operational factors as a separate metric to be used when assessing risk.

First, there are particular formation characteristics that may affect the risk at a site in addition to choosing injection well locations sufficiently far from potentially active faults. Specifically, examining whether the injection interval is in communication with the basement or an underpressured (sub-hydrostatic) environment. If the injection formation is located directly above the basement without the presence of a sealing formation or if it appears as though a permeable path may be connecting the injection formation with the basement, the earthquake risk for the project may increase significantly.

Operational Factors	Formation Characteristics	Injection Operations		Operating Experience
		Wastewater Injection	Hydraulic Fracturing	
Significant	Injection horizon likely in communication with basement, underpressured injection interval	High cumulative injection volumes and rates	High fluid injection volumes and pressures near active faults, no flowback performed	Limited injection experience in region, past earthquakes clearly or ambiguously correlated with operations
Moderate	Injection horizon potentially in communication with basement, slightly underpressured injection interval	Moderate cumulative injection volumes and rates	Moderate fluid injection volumes and pressures near active faults, flowback possibly performed	Moderate injection experience in region with no surface felt ground shaking
Minor	Injection horizon not in communication with basement	Low cumulative injection volumes and rates	Low fluid injection volumes and pressures remote from active faults, flowback possibly performed	Extensive injection experience in region with no surface felt ground shaking

Figure 2. Factors related to operations that contribute to the level of risk at an injection site.

Second, the specific injection operations also have the potential to affect the level of risk associated with a project and site. The injection rates and volumes at single wells may be correlated with earthquake activity at a site. An increasingly significant operational consideration for saltwater disposal wells is the rate of injection of a well, or group of wells in close proximity. Moreover, high rates of injection in neighboring wells can cause a cumulative effect in the form of an unusually large pressure 'halo' that could trigger slip on potentially active faults in an area.

Modeling by Keranen et al. (2014) showed that the pressure generated by four very high rate injection wells is expected to be significant in the vicinity of the wells. The diffuse seismicity now occurring in Oklahoma appears to be the result of increased pressure in the Arbuckle saline aquifer and underlying basement rocks as a result of the cumulative injection from many injection wells over a number of years (Walsh and Zoback, 2015).

Exposure

In the context of triggered seismicity, the exposure associated with a particular site depends on the number, proximity, and condition of critical facilities, local structures and infrastructure, the size and density of the surrounding population, and protected sites that have the potential to experience ground shaking as a result of fluid injection. Specific items to identify include populations, hospitals, schools, power plants, dams, reservoirs, historical sites, hazardous materials storage and natural resources (e.g. protected species) influenced by ground shaking (AXPC, 2013). If an injection project is proposed near one or more of these items, the risk for the project increases commensurately. It is important to consider whether nearby structures and infrastructure are capable of withstanding ground motion that could be caused by a triggered seismic event, keeping in mind that standards of construction vary widely depending on the year of construction, applicable building codes and other factors. Structures and infrastructure may include buildings, roads, pipelines, and electrical distribution systems (AXPC, 2013). Figure 3 offers a summary of details relating to exposure to consider when determining the level of impact these parameters have on the overall risk.

The area of concern for factors related to exposure will be site-dependent. The AXPC (2013) suggests considering populations that are within a 10-mile radius of the injection site. However, earthquakes can potentially be triggered at some distance away from an injection site and ground shaking from a moderate earthquake can be felt over a wide region. Determining this area of concern could be done in a way that incorporates the site-specific conditions of the geology, hydrology, geomechanical characterization, earthquake history and exposure to risk as well as whether injection from neighboring operators may have a cumulative contribution to the risk in the area.

Exposure	Critical Facilities	Structures and Infrastructure	Environment	Populations
High	Facilities in the immediate vicinity with the potential to suffer damage	Few designed to withstand earthquakes based on current engineering practices	Many historical sites, protected species, and/or protected wildlands	High population density and/or total population
Moderate	Facilities in the nearby area	Many designed to withstand earthquakes based on current engineering practices	Few historical sites, protected species, and/or protected wildlands	Moderate population density and/or total population
Low	No facilities in the area	Most designed to withstand earthquakes based on current engineering practices	No historical sites, protected species, and/or protected wildlands	Low population density and/or total population

Figure 3. Technical factors that contribute to the level of exposure at an injection site.

Risk Matrices

Once the seismic hazard, exposure, and operational factors are determined for a given project, operators and regulators can aggregate the results using a risk matrix method. Figure 4 shows how the results from the hazard assessment via PSHA (vertical axis), the operational factors (horizontal axis) and the exposure (top, middle or bottom figure) can be aggregated to perform such an evaluation, as expanded upon from concepts proposed by Nygaard et al. (2013). Figure 4A shows generalized risk tolerance matrices for areas of low exposure, medium exposure, or high exposure. In our proposed risk tolerance matrices, the green regions would be considered favorable given appropriate operational practices, amber regions would be considered acceptable but may require enhanced monitoring, restricted operational practices and real-time data analysis, and red regions would require significant mitigating actions.

An understanding of the risk that exists for a particular project will allow the affected parties to determine the level of tolerance they have for the estimated risk. The tolerance for potential ground shaking will be shaped by the political, economic, and emotional state of the populations involved, making it inherently site-specific. In high-risk cases or for those who have a low tolerance for the determined risk, certain locations may not allow injection to proceed. Alternatively, in other areas, the tolerance for risk may be sufficiently high to not interfere with the proposed injection project. Of course, how one determines the exact levels of exposure, operational factors, hazard, and subsequent risk, to inform the specific risk tolerance matrix used for a particular project is somewhat subjective and requires collaboration among the stakeholders.

We consider several examples of actual injection operations to illustrate the use of the risk tolerance matrix in Figure 4B. In each case, we have only performed a rough analysis to provide context based on the current scientific literature. When this workflow is implemented a more thorough analysis should be performed, including the use of PSHA to determine the probable hazard for a given project. For PSHA results to be utilized in this matrix, the ground shaking intensity with a given exceedance rate will need to be determined. Unlike building code applications, where the focus is on strong but very rare ground motion intensities, for triggered seismicity the interest is likely to be in more frequent (i.e., higher-exceedance-rate) but smaller intensity ground motions. We estimate the probable hazard in light of what we know after each of these earthquakes occurred (Figure 4B). It is important to note that each project will have its own risk tolerance that will be determined by the public and stakeholders directly impacted. In order to reflect these differences in risk tolerance, the colored portions of the risk tolerance matrices should shift either up or down (to become more lenient or strict, respectively).

In a low exposure area, we consider the Horn River Basin hydraulic fracturing project in British Columbia, shown in Figure 4B, to describe the qualitative strategy used to determine the project's location on the risk tolerance matrix. The Horn River Basin area is a remote location with very low exposed population, little to no built infrastructure. It had experienced no significant earthquakes between 1985 and 2007 when development began (Nygaard et al., 2013). In April 2009 and December 2011, 38 earthquakes were recorded between M 2.2 to M 3.8 on the National Resources Canada (NRCAN) seismic network. Following Nygaard et al. (2013) we consider the probable ground shaking to be between MMI II and MMI V. In Figure 4B, we plot the Horn River Basin example in a region shaded green in the low exposure risk tolerance matrix suggesting that additional mitigation efforts may not be needed.

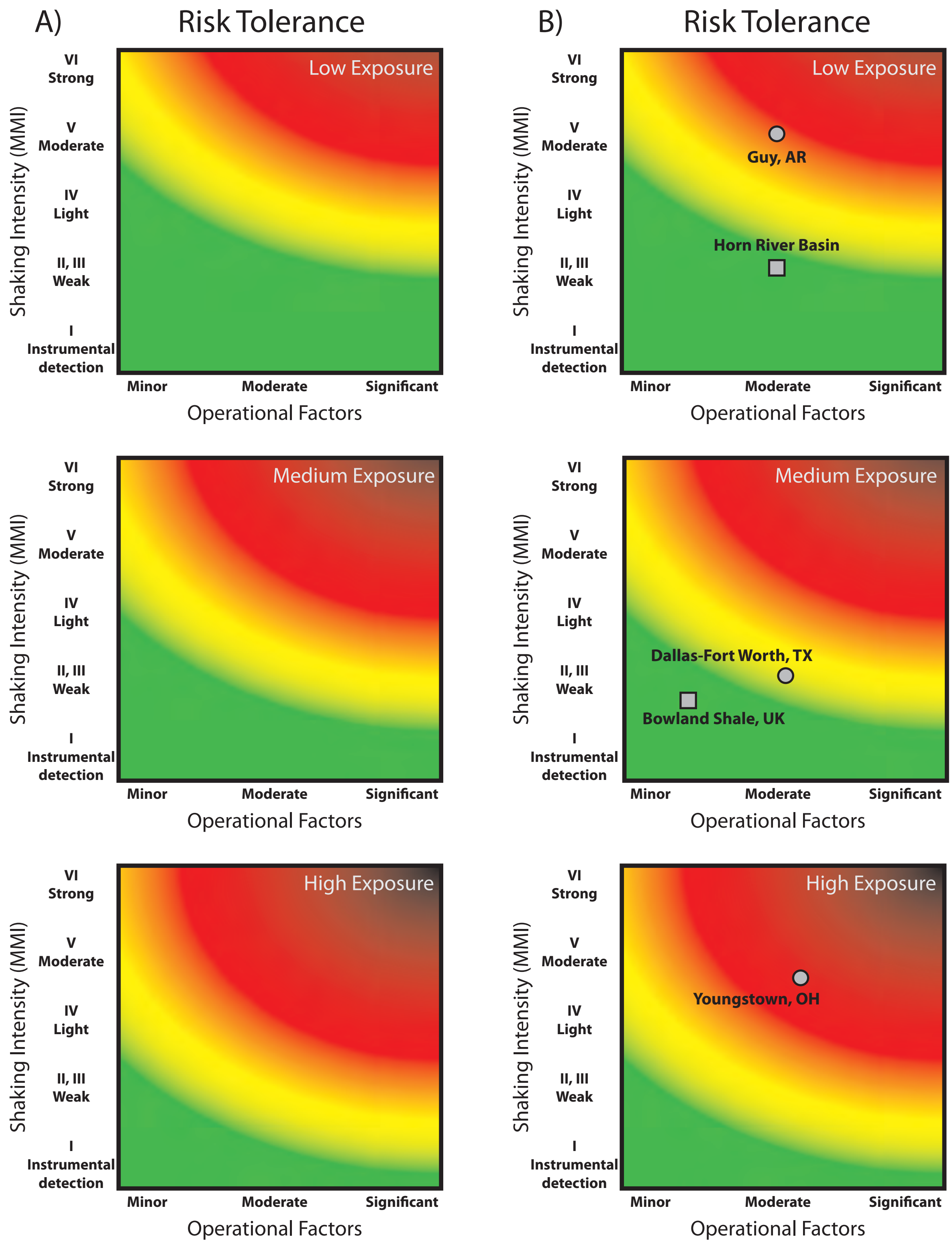

Figure 4. Risk tolerance matrices. (A) Generalized risk tolerance matrices associating the level of shaking intensity (from PSHA), the operational factors (Figure 2), exposure (Figure 3), and the tolerance for risk of a particular injection project. (B) Examples of projects being plotted on the risk tolerance matrices in light of what we know after events have occurred. Squares represent hydraulic fracturing projects and circles represent saltwater disposal projects.

If we now imagine the Horn River Basin case occurring in a medium exposure area, the project would be located in the amber portion of the medium exposure risk tolerance matrix suggesting that heightened monitoring and data analysis, in addition to potentially adjusting injection operations, may be appropriate. If we extend this and now imagine the Horn River case in a high exposure level, the project would be in the red portion of the high exposure risk tolerance matrix. This suggests that limiting injection or potentially abandoning the well, extending earthquake monitoring and analysis, and communicating with area regulators and neighboring operators may be appropriate.

In addition to the Horn River Basin, we consider the possible placement of other projects onto the risk tolerance matrices, including the Guy, Arkansas saltwater disposal site (Horton, 2012), the Dallas-Fort Worth saltwater disposal (Frohlich et al., 2011), the Youngstown, Ohio saltwater disposal site (Kim, 2013), and the Bowland Shale (Preese Hall) hydraulic fracturing site (Green et al., 2012; Clarke et al., 2014). The Guy, Arkansas wastewater disposal project was placed in the red portion of the low exposure risk tolerance matrix because of it being located in an area with a low population density and few structures and infrastructure, but the occurrence of a M 4.7 earthquake with an extended lineation of earthquake epicenters in 2011 (Horton, 2012). The Dallas-Fort Worth saltwater disposal site experienced several earthquakes of M 3.3 and below October 2008 and May 2009 (Frohlich et al., 2011). We considered the site to be of medium exposure because of the close proximity of the Dallas-Fort Worth airport resulting in the project being located in the amber portion of the medium exposure risk tolerance matrix. The Youngstown, Ohio saltwater disposal site was placed in the red portion of the high exposure risk tolerance matrix due to its proximity to the Youngstown, Ohio urban area and the occurrence of a M3.9 earthquake in December 2011 (Kim, 2013).

The Bowland Shale hydraulic fracturing project was placed in the green portion of the medium exposure risk tolerance matrix because the project used a fairly unaggressive injection strategy located in a moderately populated area that experienced a M 2.3 earthquake in 2011 (Green et al., 2012; Clarke et al., 2014). However, it is clear the stakeholders involved in hydraulic fracturing operations in the United Kingdom have a very low tolerance for risk and might consider the medium exposure risk tolerance matrix to not be strict enough as shown here. Therefore, they may produce risk tolerance matrices for their sites that show the transitions between the green, amber, and red portions occurring at lower possible shaking intensities.

Traffic Light Systems and Rapidly Changing Risk

Traffic light systems are a risk management tool that can be used to address the possibility of seismic risk changing with time due to the occurrence of unexpected seismicity in an area of saltwater disposal or hydraulic fracturing. Traffic light systems have historically been used in enhanced geothermal settings and have been based on ground shaking or magnitude thresholds to signify whether the injection project should continue as planned (green), modify operations due to heightened risk (amber), or suspend operations due to severe risk (red) (Majer et al., 2012; NRC, 2012; DECC, 2013). These systems have the potential to provide an excellent means of communication between the operating companies, regulators, the media and the public. They allow private companies and responsible State and Federal Agencies to communicate 1) the possible significance of the unusual seismic activity, 2) the steps that should be taken to understand better the risk associated with the seismicity and 3) the conditions under which remedial action might be taken.

The standards used by individual projects for traffic light systems would be most effective if they were tailored to a site-specific and dependent on the risk assessment, rather than fixed for all circumstances. The systems could be developed with guidance from regulators and the local geologic surveys taking into account all aspects of hazard and risk (CAPP, 2012 and Nygaard et al., 2013). Early in the development of the traffic light system it is important to use the outcome of the risk tolerance assessment to decide whether earthquake monitoring is necessary and, if so, how the seismic data will be observed and analyzed. It may be beneficial to consider not only earthquake magnitude thresholds and ground shaking but also particular geological observations in an attempt to be more proactive in mitigating triggered earthquake risks. In cases of high risk, this may include the continual performance of in-depth, real-time analysis of microseismic data that would aim to identify particular event characteristics that could foreshadow felt or damaging earthquakes, as discussed below.

Traffic light systems are dependent on the level of monitoring used at the site, which is determined by the outcome of the risk assessment. Earthquake monitoring is beneficial and appropriate at injection sites with sufficiently high risk. This monitoring could be done using data from regional or local arrays, or operational arrays specific to the injection site. How frequently data is requested and collected from the local arrays or acquired from operational arrays and then analyzed will be based on the seismic hazard and risk assessment. In cases of significantly high risk, it may be necessary to have a real time telemetry system in place that allows for the constant delivery of data to an automated event analysis system. An automated system that detects, locates, and estimates the magnitude of the earthquakes in the region would allow for an efficient means of determining if any events have characteristics such as events highlighting faults and determining if the events have a larger spatial coverage and faster migration rate than expected. In the case of low risk, it may not be necessary to have a real-time automated system, but instead a system that allows the data to be requested or collected on an as needed or periodically.

The traffic light systems we present here for saltwater disposal (Figure 5) and hydraulic fracturing (Figure 6) encourage a site-specific, risk-informed, real-time risk management system that could be increasingly effective when updated as new data becomes available. The level of risk at a site informs the level of the seismic monitoring network used and any necessary operational adjustments. Our proposed system incorporates often subtle but potentially diagnostic geological and geophysical characteristics that may indicate a potentially larger event to come. This is done by focusing on specific observations that suggest the presence of a fault large enough to host a significant triggered earthquake.

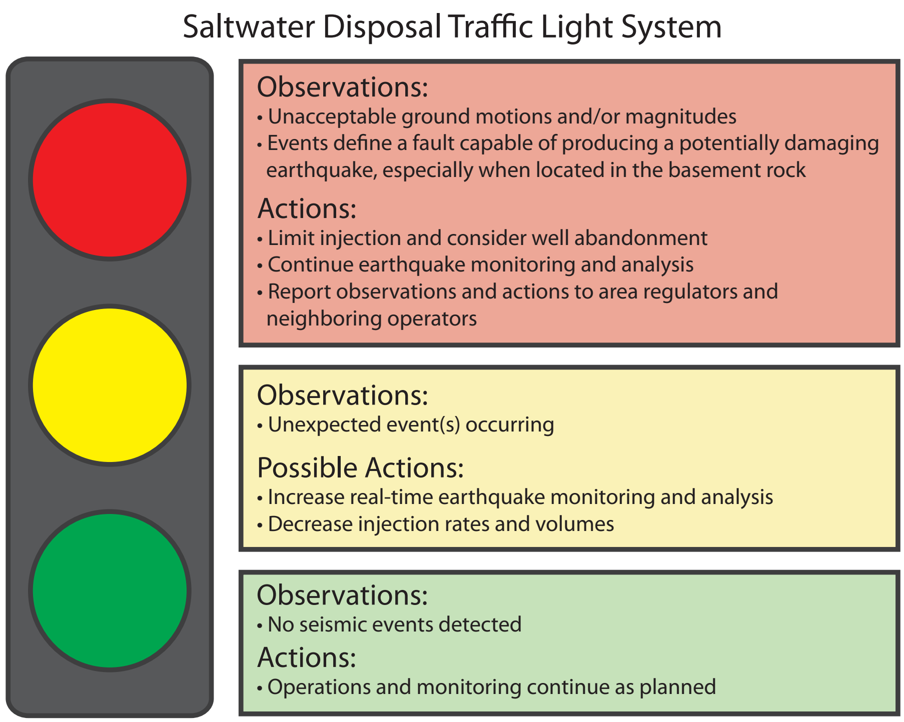

Figure 5. Traffic light system applicable to saltwater disposal. The green, amber, and red panels represent the levels of heightened awareness frequently represented in traffic light systems. Within each panel we suggest what observations might be considered and possible actions to take.

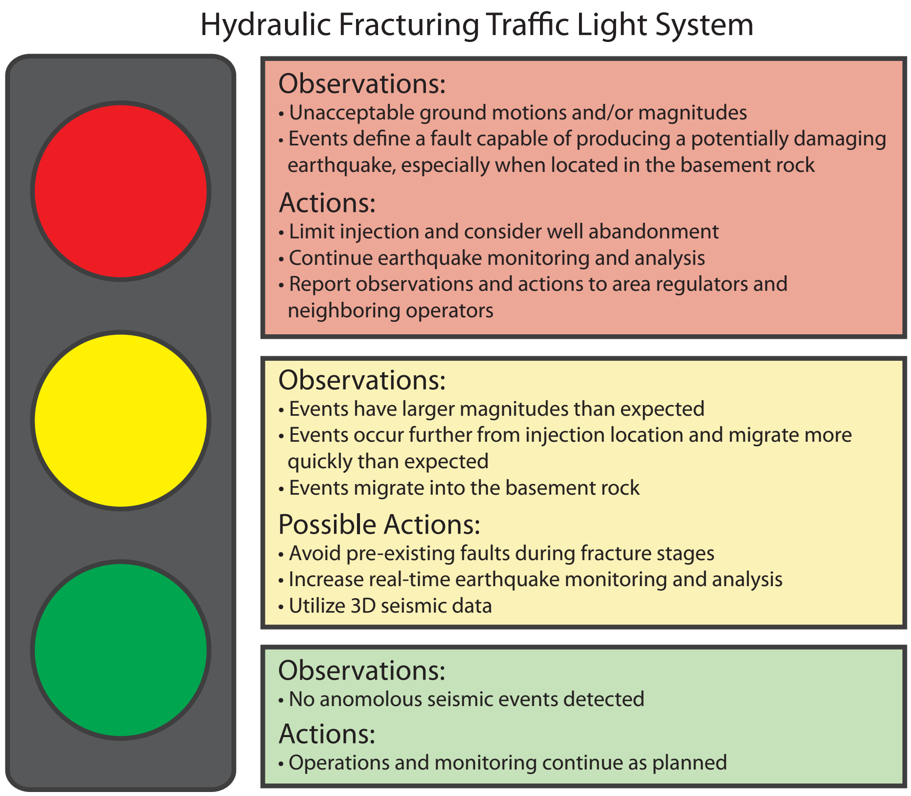

Figure 6. Traffic light system applicable to hydraulic fracturing. The green, amber, and red panels represent the levels of heightened awareness frequently represented in traffic light systems. Within each panel we suggest what observations might be considered and possible actions to take.

Of particular concern, and a key observation in mitigating risk, is whether there is the potential for triggered earthquakes to occur on relatively large, critically stressed, pre-existing basement faults. Over the life of an injection project, it is thought that pore pressure perturbations have the potential to migrate toward critically stressed, permeable faults in the crystalline basement. A relatively simple conceptual model involving the migration of pressure perturbations from injection horizons in Oklahoma to active basement faults has begun to evolve that shows how long-duration fluid injection has the potential to trigger slip on relatively large faults (Keranen et al., 2013; Zhang et al., 2013).

Figure 7 illustrates well-documented earthquake scaling relationships of relatively large triggered earthquakes based on their reported magnitudes (as summarized in Stein and Wysession, 2009). From these scaling relationships, we can see that a M4.7 earthquake, the largest magnitude event that occurred at Guy, Arkansas (Horton, 2012), suggests slip on a fault that is a kilometer in length. Fault patch sizes this significant are often larger than the thicknesses of the formations in which fluids are being injected, suggesting that fluids are migrating toward other formations (i.e. crystalline basement) capable of hosting such faults.

Faults large enough for potentially damaging triggered earthquakes may be identifiable using observations outlined in the proposed traffic light system. These observations include considering whether event locations highlight faults (either previously identified or not), whether those faults are preferentially oriented for shear failure in the current state of stress, whether the events have a larger spatial coverage and migrate faster than expected, or whether the events have higher magnitudes than expected.

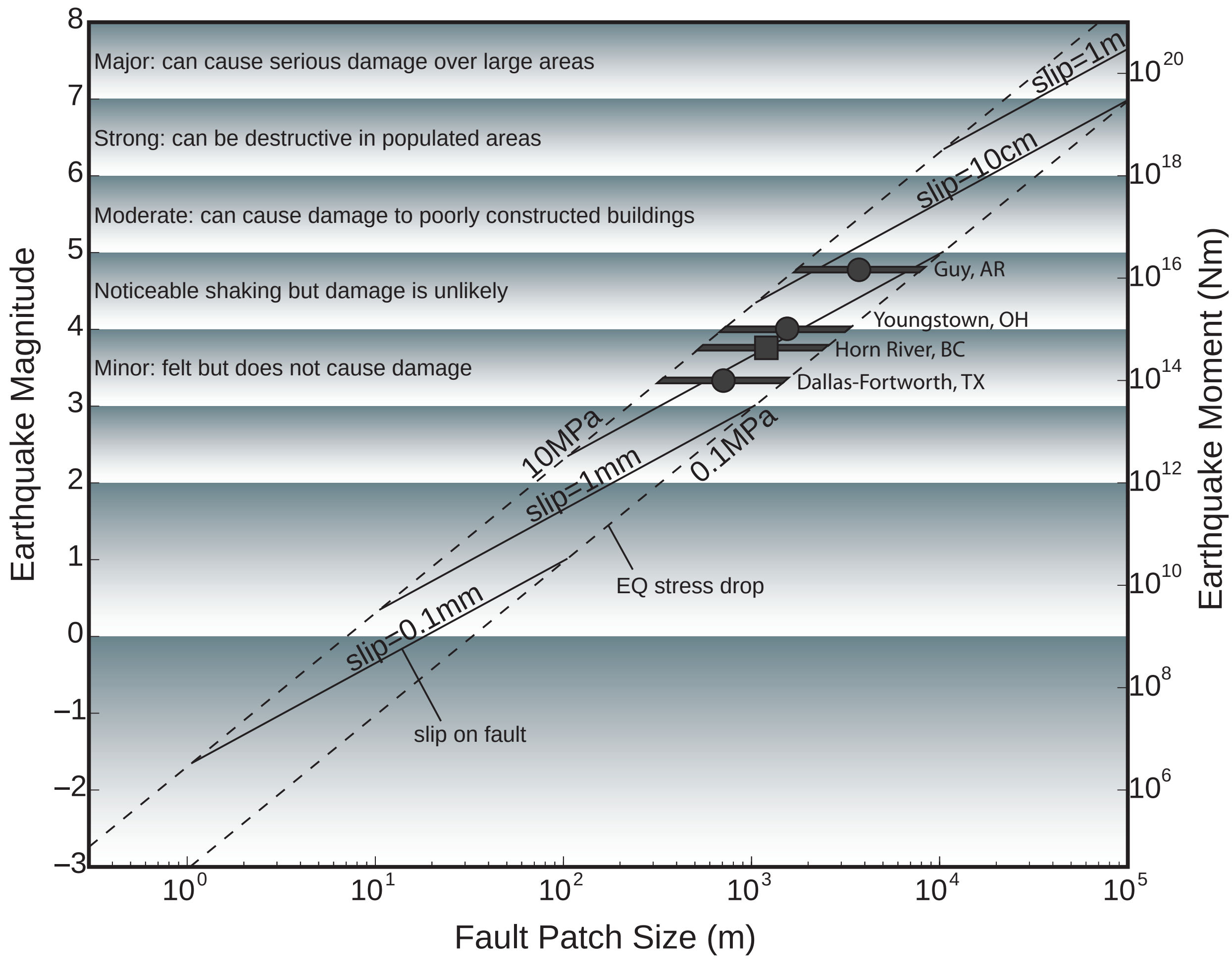

Figure 7. Scaling of earthquake source parameters showing the relationship between earthquake magnitude, the size of the fault patch that slips in the earthquake and the amount of fault slip using principles summarized in Stein and Wysession (2009). Triggered earthquakes are plotted based on their reported magnitudes using circles for saltwater disposal and a square for hydraulic fracturing (Horton, 2012; Kim, 2013; BCOGC, 2012; Frohlich et al., 2011).

As fluids are injected into the subsurface and microseismic events are monitored, there are two observations that may indicate of the presence of active faults. First, events may migrate farther from the injection zone than expected, indicating that fluid is potentially migrating through a permeable, active fault. Second, small earthquakes may illuminate a planar feature suggesting the presence of a potentially active fault. Further analysis and a degree of caution would be appropriate, either through a continued examination of historical seismic data, microseismic data, or any available 3D seismic data. If an illuminated feature is preferentially oriented for failure then the seismic hazard may increase and the operational factors may need to be adjusted accordingly, with the option of well abandonment considered in severe cases.

The proposed traffic light system is divided into two columns; one focusing on saltwater disposal and one focusing on hydraulic fracturing. For the two project types, different observations may cause operators to transition between the green and amber zones of the traffic light; however, we suggest that the same observations may cause injection operations for both saltwater disposal and hydraulic fracturing to move into the red zone of the traffic light.

Ideally, all injection operations will begin in the green zone of the risk tolerance matrix and the traffic light system, where operations and monitoring would be carried out as planned based on the outcome of the initial risk assessment. For saltwater disposal, as long as no earthquakes are detected, the project remains in the green zone. For hydraulic fracturing, we would expect to observe very small magnitude earthquakes, but if an anomalous seismic event(s) was detected the project may transition to the amber zone. Anytime a project moves out of the green zone and into the amber or red zone, it would be beneficial to quickly evaluate to what extent operation practices might be adjusted or halted and what analysis might be performed (CAPP, 2012; AXPC, 2013; NRC, 2012). Operators and regulators may then work together to do a preliminary analysis of the event(s) and maintain open communication with each other and nearby operators (CAPP, 2012).

If a project begins in the amber zone of the risk tolerance matrix and traffic light system, or moves into it due to the occurrence of unexpected events, then caution should be exercised at all times in the form of heightened awareness, enhanced monitoring and/or the real-time data analysis. We stress that the amber zone of the traffic light may not necessarily be interpreted as a disadvantageous phase nor should it be thought that a project would inevitably move to the red zone of the traffic light. Example actions are slightly different for saltwater disposal and hydraulic fracturing. In the case of saltwater disposal, it may be reasonable to decrease injection rates, volumes, and pressures, while for hydraulic fracturing, avoiding pre-existing faults during individual fracture stages and utilizing 3D seismic data to identify faults in the subsurface may be considered.

Observations that may cause a project to move into the red zone of the traffic light system for both saltwater disposal and hydraulic fracturing projects include the detection of unacceptable levels of ground shaking or magnitudes, events defining a fault capable of producing a potentially damaging earthquake, and events migrating into the basement rock. Actions that could be considered if any of the above observations occur include limiting injection and considering well abandonment, continuing earthquake monitoring for the duration of the examination or, in severe cases, sometime after the injection has ceased, and reporting observations and operational practices to area regulators and neighboring operators.

It is important to note that after a project moves to amber or red it may be possible to transition back to a lower risk level after a thorough evaluation of changes to the hazard and risk at the site. This may include engaging engineers and subsurface geological and geophysical experts to review available subsurface data and, if necessary, to design and conduct engineered trials to adjust operating procedures as appropriate with respect to injection volumes, rates, and locations (CAPP, 2012). It would be critical to re-evaluate the tolerance for risk at the site in light of the observations that caused the project to transition to the amber or red portion of the traffic light system.

If triggered events occur, all area operators and regulators have the opportunity to increase their understanding of the potential to trigger or induce events in the future. Sharing information such as the time, location, magnitude, the focal mechanism (if the operator is able to calculate this information given their monitoring), and the injection history leading up to this event with regulators and other area operators may be necessary. Enhancing the seismic monitoring at a particular site, even if a project moves into the amber or red zone of the traffic light or if a project is abandoned, allows for a more detailed evaluation of any future events (SEGW, 2014; AXPC, 2013).

Summary

To date, there are many different guidelines, regulations, and studies that have been published or put into practice. Many of these are *ad hoc*, prescriptive, and reactionary. We present here a framework for risk assessments for triggered seismicity associated with saltwater disposal and hydraulic fracturing and offer systematic recommendations for factors to be considered. This framework includes an assessment of the site characteristics, seismic hazard, operational factors, exposure, and tolerance for risk. The process is intended to be site-specific, adaptable, and updated as new information becomes available. We describe factors that are not currently included in standard earthquake hazard and risk assessment procedures, including considering the necessary anthropogenic factors that are inherent in fluid injection operations. We use risk tolerance matrices as a means for including all aspects that influence the tolerance for risk regulators, operators, stakeholders, and the public have for triggered earthquakes. The hazard and risk assessment workflow includes the use of a traffic light system that focuses on geologic and geophysical observations, rather than only earthquake magnitudes or ground motions, as the determining factors for whether a particular site needs to consider enhanced monitoring and decreased injection practices or possible injection well abandonment.

Acknowledgements

Funding for this work came from the Stanford Center for Induced and Triggered Seismicity. We thank Abhineet Gupta of the Department of Civil and Environmental Engineering at Stanford University for beneficial discussions focusing on the development of the risk tolerance matrices.

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CASES NO. 20313, 20314, 20472, 20463 and 20465
Index of Division Exhibit No. 4

Exhibit No.	Exhibit Name
4-A	Oklahoma Corporation Commission, 2017, "*Earthquakes in Oklahoma*"; website download; Oil & Gas Conservation Division.
4-B	Oklahoma Corporation Commission, 2015, Media Advisory – Oil and Gas Disposal Well Volume Reduction Plan; Oil & Gas Conservation Division, 8 p.
4-C	Oklahoma Corporation Commission, 2017, Looking Ahead - *New Earthquake Directive Takes Aim at Future Disposal Rates*; Oil & Gas Conservation Division, 24 p.
4-D	Oklahoma Corporation Commission, 2018, Earthquake Response Summary; Oil & Gas Conservation Division, 4 p.
4-E	McNamara, D., *et.al.*, 2015, *Efforts to monitor and characterize the recent increasing seismicity in central Oklahoma*; The Leading Edge (Society of Exploration Geophysicists), Special Section: Injection-induced seismicity; p. 628-639.

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 4-A

"EARTHQUAKES IN OKLAHOMA"

as provided by the Oklahoma Corporation Commission at the following website:

HTTPS://EARTHQUAKES.OK.GOV/WHAT-WE-ARE-DOING/OKLAHOMA-CORPORATION COMMISSION/

OKLAHOMA CORPORATION COMMISSION

The Oklahoma Corporation Commission (OCC) is the state's regulatory agency charged with overseeing Oklahoma's oil and gas industry.

Latest Developments

OCC has taken numerous actions related to disposal wells in specific zones around the state based on seismic events, under its statutory authority to oversee oil and gas operations in the state. Oklahoma statutes grant the OCC "exclusive jurisdiction" to regulate Class II underground injection wells.

OCC regularly updates its website "Hot Topics" with developments in its seismicity response.

A summary of Oklahoma Corporation earthquake actions thru February 24, 2017 can be **found here.**

See the links below for a chronological listing of OCC actions related to seismicity:

2017

- February 24, 2017 news release, "Looking Ahead" New Earthquake Directive Takes Aim at Future Disposal Rates
- March 1, 2017 joint Oklahoma Corporation Commission Oil and Gas Division and Oklahoma Geological Survey (OGS) Statement on 2017 USGS assessment of continued seismic hazard in Oklahoma
- June 27, 2017 news release, "Managing Risk Oklahoma Geological Survey, Oklahoma Corporation Commission, Industry Collaboration Bears Fruit
- July 14, 2017 Oklahoma Corporation Commission Earthquake Advisory

2016

- January 4, 2016 plan in response to Edmond area seismicity
- January 13, 2016 plan in response to Fairview area seismicity
- January 20, 2016 media advisory regarding Sandridge Energy
- February 16, 2016 media advisory regarding regional earthquake response plan for western Oklahoma
- March 7, 2016 media advisory regarding expanded regional earthquake response
- September 12, 2016 Earthquake Response Summary
- November 3, 2016 media advisory regarding Pawnee
- November 8, 2016 media advisory regarding Cushing
- November 18, 2016 Earthquake Response Summary
- December 20, 2016 news release, New Year, New Plays, New Plans

2015

- April 21, 2015 statement on Oklahoma Geological Survey finding regarding Oklahoma's seismicity
- July 17, 2015 update to the March, 2015 directive outlining an Area of Interest and requiring operators to prove operations are not in communication with the "basement" rock
- Area of Interest Map
- July 28, 2015 actions in the Crescent area
- August 3, 2015 disposal volume reduction plan in Oklahoma and Logan Counties
- September 18, 2015 plan for the Cushing area
- October 19, 2015 additions to the Cushing area plan
- November 10, 2015 plan in response to Medford area seismicity
- November 16, 2015 plan in response to Fairview area seismicity
- November 19, 2015 plan in response to Cherokee-Carmen area seismicity
- December 3, 2015 plan in response to Byron/Cherokee area and Medford area seismicity

Traffic Light System

The Commission has adopted a "traffic light" system for disposal well operators, as recommended by the National Academy of Sciences, which directs staff to review disposal well permits for proximity to faults, seismicity in the area and other factors. All proposed disposal wells, regardless of location, now undergo a seismicity review.

As the science around disposal wells continues to evolve, the Oklahoma Corporation Commission will also evolve the application of the "traffic light" system. The "yellow light" permitting system is in place for proposed disposal wells that do not meet automatic "red light" criteria, but for which there are still concerns regarding seismicity. Yellow light permit requirements may include the following:

- Any permit granted under "yellow light" is temporary (6 months)
- Permit criteria is based on induced seismicity concerns
- Wells must shut down every 60 days and take bottom hole pressure readings
- The language governing the permit can be made more stringent at any time
- The operator must monitor for background seismicity
- Permit criteria includes mandatory shut down in the event of defined seismic activity
- Permit process is done through public court process (rather than administrative approval)

Disposal Well Monitoring and Reporting

The Corporation Commission also adopted new rules, which Governor Fallin approved and were effective September 2014. The rules increase from monthly to daily the required recording of well pressure and volume of disposal wells that dispose into the Arbuckle formation. The rules also require all disposal wells permitted for 20,000 barrels/day to conduct Mechanical Integrity Tests.

All disposal wells with an Area of Interest, regardless of size or formation, must record volume and pressure daily and report weekly to the Commission. The information is then placed on an FTP site that allows researchers access to the data.

Bob Anthony
Commissioner

Todd Hiett
Commissioner

Dana Murphy
Commissioner

CASES NO. 20313, 20314, 20472, 20463 and 20465
Exhibit No. 4-B

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OIL & GAS CONSERVATION DIVISION

Tim Baker, Director

August 3, 2015

Contact: Matt Skinner
405-521-4180
m.skinner@occemail.com

MEDIA ADVISORY – OIL AND GAS DISPOSAL WELL VOLUME REDUCTION PLAN

The Oklahoma Corporation Commission's Oil and Gas Conservation Division (OGCD) has put in place a plan to reduce oil and gas wastewater disposal well volume in an proscribed area of northern Oklahoma County and southern Logan County. Under the plan, operators will have a 60 day period during which volume will be reduced 38 percent, or about 3.4 million barrels under the 2014 total. Such a reduction will bring total volume for the area to a level under the 2012 total by about 2.4 million barrels. The area saw its sharpest rise in seismicity start in late 2012.

An example of the letter that is being sent out to operators is attached, Also attached is a graphic of what is called the "Logan County trend" area (the impacted area), a listing of the wells and operators involved, and a statement from Commission Vice Chairman Dana Murphy on the matter.

Also attached is the latest report on the April and July "plug-back" actions taken by the OGCD.

This is the latest development under the "traffic light" system". The system was first put in place in 2013 in response to the concerns over the possibility of earthquake activity being caused by oil and gas wastewater disposal wells in Oklahoma. It has been in a state of constant evolution since then, as new data becomes available.

Other elements of the traffic light system include:

- A "plug-back" program covering more than 500 disposal wells. Wells are reducing their depth if found to be at a depth that sharply increases the risk of induced seismicity.
- Required seismicity review for any proposed disposal well.
  - Those proposed wells that do not meet "red light" (stop) standards but are still of concern:

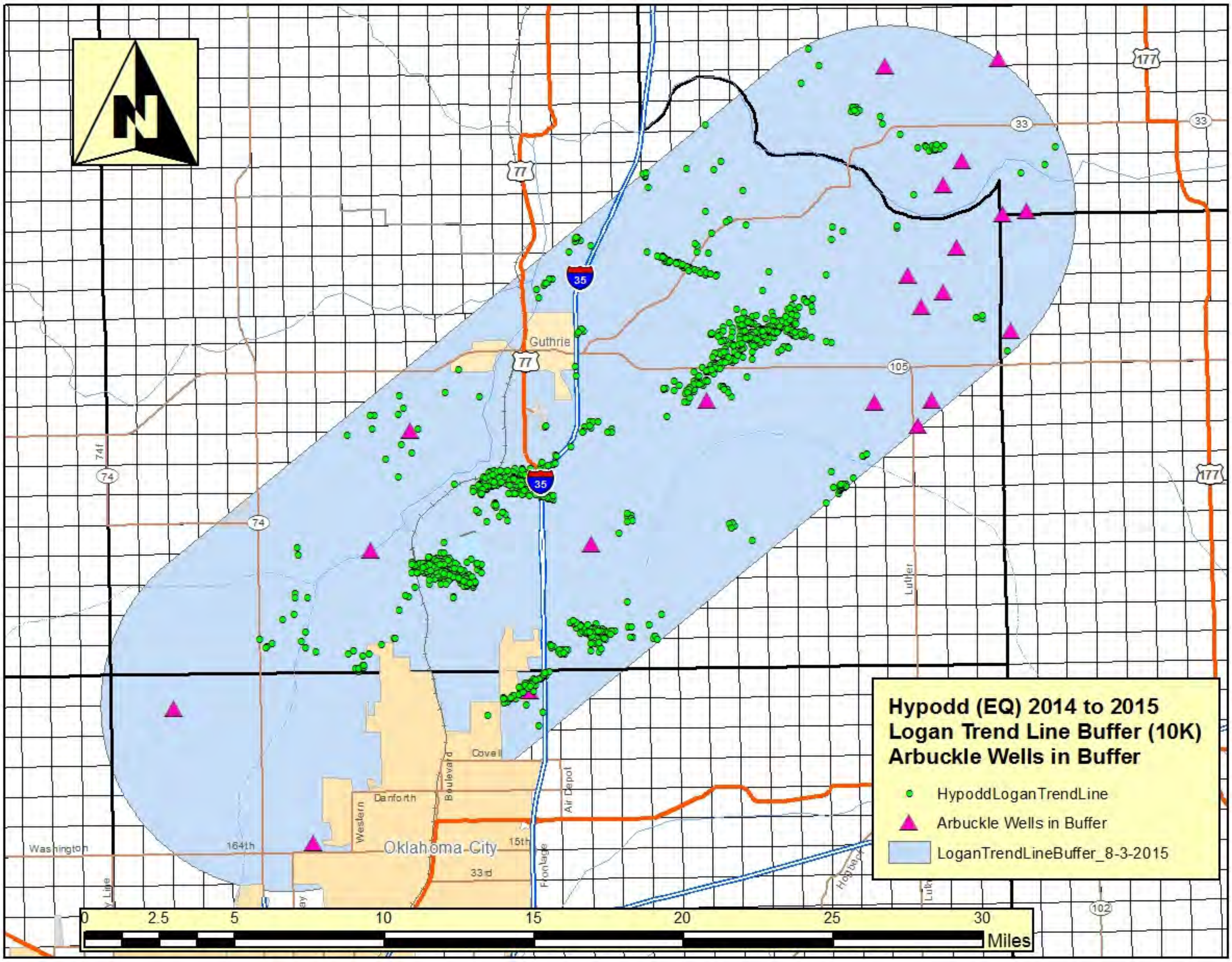
1. Must have public review
2. Permit is temporary (six months)
3. Permit language requires**
    1. Seismometers
    2. Shut down if rise in background seismicity or there is a defined seismic event
    3. Shut in and perform reservoir pressure testing every 60 days.
    ** Applicant agreement to conditions does not guarantee approval

- Weekly volume reporting requirements for and close scrutiny of all disposal wells in an Area of Interest (AOI):
    - AOI now defined as a 10 kilometer (about 122 square miles) area surrounding the center mass of an earthquake "cluster"
- Rules increasing from monthly to daily the required recording of well pressure and volume from disposal wells that dispose into the Arbuckle formation (the state's deepest injection formation)
- Rules requiring Mechanical Integrity Tests for wells disposing of volumes of 20,000 barrels a day or more have increased from once every five years to every year, or more often if so directed by the Commission

-OCC-

All OCC advisories and releases are available at www.occeweb.com

Editors, Producers: See www.occeweb.com and www.earthquakes.ok.gov for maps, directives and other information on earthquake response


Hypodd (EQ) 2014 to 2015
Logan Trend Line Buffer (10K)
Arbuckle Wells in Buffer
HypoddLoganTrendLine
Arbuckle Wells in Buffer
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Guthrie
Oklahoma City
Covell
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Boulevard
Air Depot
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Washington
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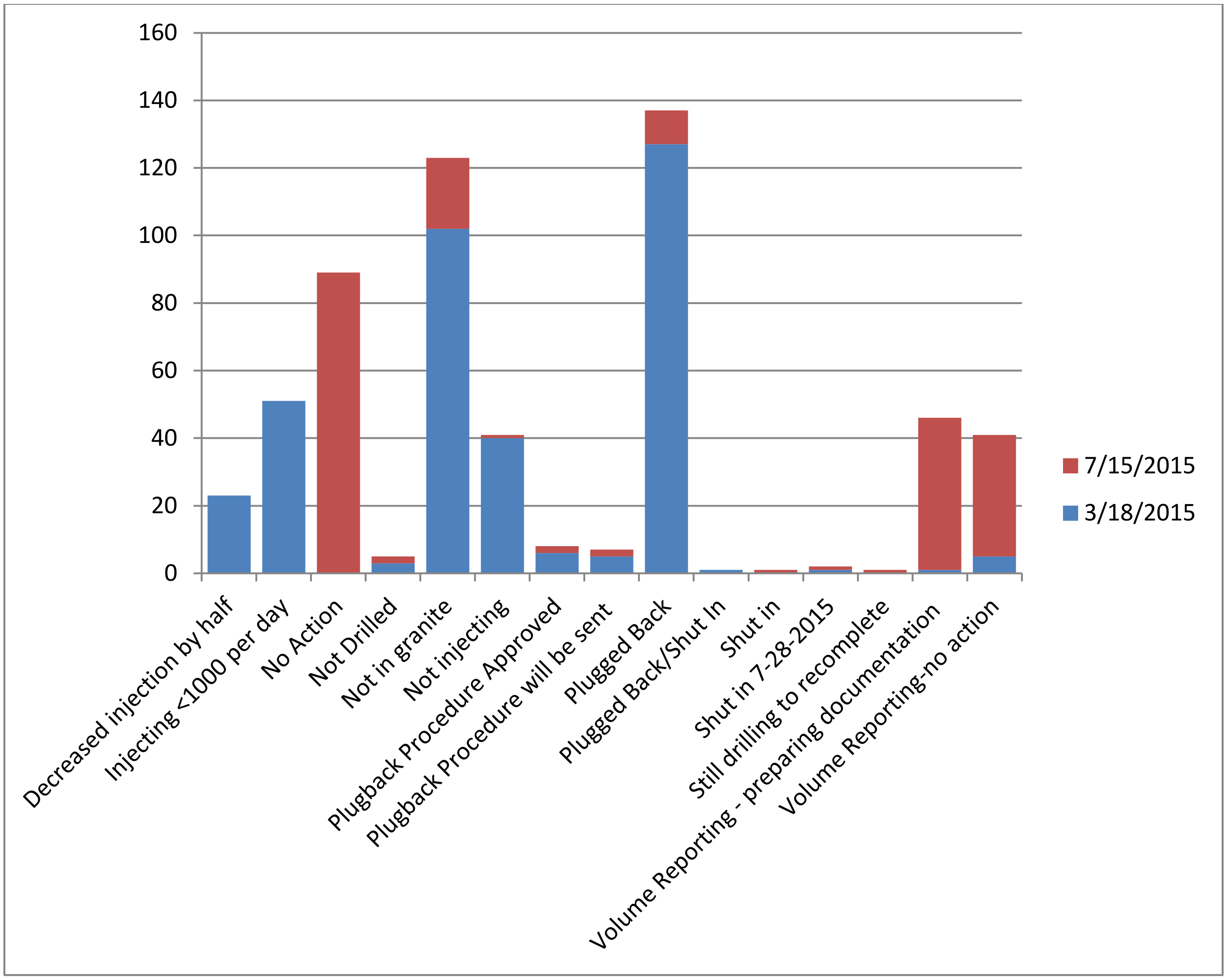

Company	(All)

Count of Wells	**Date Added**		
Current Status	**3/18/2015**	**7/15/2015**	**Grand Total**
Decreased injection by half	23		23
Injecting <1000 per day	51		51
Not Drilled	3	2	5
Not in granite	102	21	123
Not injecting	40	1	41
Plugback Procedure Approved	6	2	8
Plugback Procedure will be sent	5	2	7
Plugged Back	127	10	137
Plugged Back/Shut In	1		1
Shut in		1	1
Shut in 7-28-2015	1	1	2
Still drilling to recomplete		1	1

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News from Commissioner Dana Murphy

For Further Information, Contact: Teryl Williams (405) 521- 2267

August 3, 2015

STATEMENT OF CORPORATION COMMISSIONER DANA MURPHY REGARDING LATEST STAFF DIRECTIVE ON SEISMICITY

I fully support going forward with a plan based on volume cuts, and am pleased to see a real beginning in that regard. This is an issue completely outside the scope of the experience of not only this agency, but all our partner agencies and stakeholders as well. There was a time when the scientific, legal, policy and other concerns related to this issue had to first be carefully researched and debated in order to provide a valid framework for such action. That time is over. Based on the research and analysis of the data compiled, we must continue to take progressive steps, and do so as quickly as possible as part of the continuing efforts to resolve this complex and challenging issue.

-OCC-
All OCC advisories and releases are available at www.occeweb.com

BOB ANTHONY
Commissioner

Todd Hiett
Commissioner

Dana Murphy
Commissioner

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OIL & GAS CONSERVATION DIVISION

Tim Baker, Director

TO:

FROM: Tim Baker, Director, Oil and Gas Conservation Division

RE: Reduction in Volumes for Wells Located in Area of Interest for Induced Seismicity

DATE: August 3rd, 2015

The Commission's Oil and Gas Conservation Division (OGCD) is expanding its efforts to reduce the risk of earthquakes potentially triggered by saltwater disposal wells. The following addresses the reduction of volumes being disposed in the Arbuckle formation within the defined area of interest. Any company that has been identified as operating one or more Arbuckle disposal well(s) located within the defined area will need to reduce volumes disposed into such well(s).

The area highlighted on the attached map has been designated based upon the dramatic increase in earthquakes within the immediate area. The OGCD has reviewed the earthquake activity of magnitude 2.5 mm and greater, as reported by the Oklahoma Geological Survey (OGS). The earthquake activity from the last three years and seven months is summarized below and is also reflected in the attached map:

Earthquake activity in 2012:	2
Earthquake activity in 2013:	14
Earthquake activity in 2014:	359
Earthquake activity in 2015: (as of 7/31/15)	253

Total volumes of produced water disposed of in the Arbuckle formation, by wells within the designated area, as reported on OCC Forms 1012A beginning in 2012 are as follows:

2012 volumes: 7,788,710 Bls.

2013 volumes: 6,039,802 Bls.

2014 volumes: 8,847,093 Bls.

As part of an effort to decrease the risk of induced seismicity, you will need to complete reduction of disposal volumes in accordance with the following schedule and as indicated for the wells below. All disposal well volumes shall be calculated on a daily basis. In addition, gauges and flow meters should be placed on such wells on or before August 14, 2015 so that Commission Field Inspectors can verify pressures and volumes. As has been the practice, pressures and volumes for such wells should continue to be supplied to the Commisson on a weekly basis at ogvolumes@occemail.com.

Using the daily average of the total volume reported on the 2014 1012A Annual Fluid Injection Report, disposal volumes need to be reduced in accordance with the following schedule:

(a) On or before August 23rd, 2015, daily volumes should be reduced by thirteen percent (13%) of the daily average of the total volume reported on the 2014 1012A Annual Fluid Injection Report.

(b) On or before September 12th, 2015, daily volumes should be reduced by an additional thirteen percent (13%), for a total volume reduction of twenty-six percent (26%) of the daily average of the total volume reported on the 2014 1012A Annual Fluid Injection Report.

(c) On or before October 2nd, 2015, daily volumes should be reduced by an additional twelve percent (12%), for a total volume reduction of thirty-eight percent (38%) of the daily average of the total volume reported on the 2014 1012A Annual Fluid Injection Report.

Contact Charles Lord of the OGCD at 405-522-2751 or c.lord@occemail.com if you have any questions.

Thank you in advance for your continued cooperation and attention to this matter

CASES NO. 20313, 20314, 20472, 20463, and 20465
Division Exhibit No. 4-C

OKLAHOMA
Corporation Commission
P.O. BOX 52000
OKLAHOMA CITY OKLAHOMA 73152-2000

255 Jim Thorpe Building
Telephone: (405)521-2302
FAX: (405)521-3099

OIL & GAS CONSERVATION DIVISION **Tim Baker, Director**

February 24, 2017

Contact: Matt Skinner
405-521-4180
m.skinner@occemail.com

Looking Ahead

New Earthquake Directive Takes Aim at Future Disposal Rates

The Oklahoma Corporation Commission's Oil and Gas Conservation Division (OGCD) has issued a new directive for the Earthquake Area of Interest (AOI) aimed at limiting the growth in future disposal rates into the Arbuckle formation in the AOI.

"The data from the Oklahoma Geological Survey shows the earthquake rate has been dropping since we issued various directives reducing the then-current volume within the AOI," OGCD Director Tim Baker said. "The continued drop in earthquakes, as well as new data and input from the Oklahoma Geological Survey have caused a change in our orientation from focusing on current disposal volumes within the AOI to looking ahead to try and ensure there isn't a sudden, surprise jump in those disposal volumes. This directive includes not only those Arbuckle disposal wells within the AOI already restricted in volume, but also the few potentially high-volume disposal wells that previously were not under a volume reduction directive because there has been no seismicity in their area. In all, it will cover 654 Arbuckle disposal wells in the AOI."

Baker says the directive will not reduce current volumes, but will keep future volume increases in check.

"We have a few Arbuckle disposal wells in the AOI that without this directive could add more than 2 million barrels a day in disposal to the Arbuckle. They are currently operating at a fraction of their permitted volume, and the new cap will be based on the much lower last 30 day average of their disposal volumes," Baker said. "Other wells are already operating under a reduction directive with volumes that are lower than even those allowed. We don't want to see them jump drastically in one day, even if they are within their directive limits. So they will have a cap to limit how much they can increase volume at once."

The directive also allows operators more flexibility in handling their wastewater.

"We have set up a system under which the operator will have a 30 day allowance, based on the particular directive, for how much he can dispose. Operators will be allowed, on a limited basis, to increase the volumes in certain wells and, if necessary, offset with lower volumes in others, so long as the 30 day allowance that encompasses total disposal of all his wells is not exceeded," Baker explained. "It is important to note that all directives remain in effect, and all wells currently shut in by directive will remain that way."

Baker called the directive a "data driven" approach.

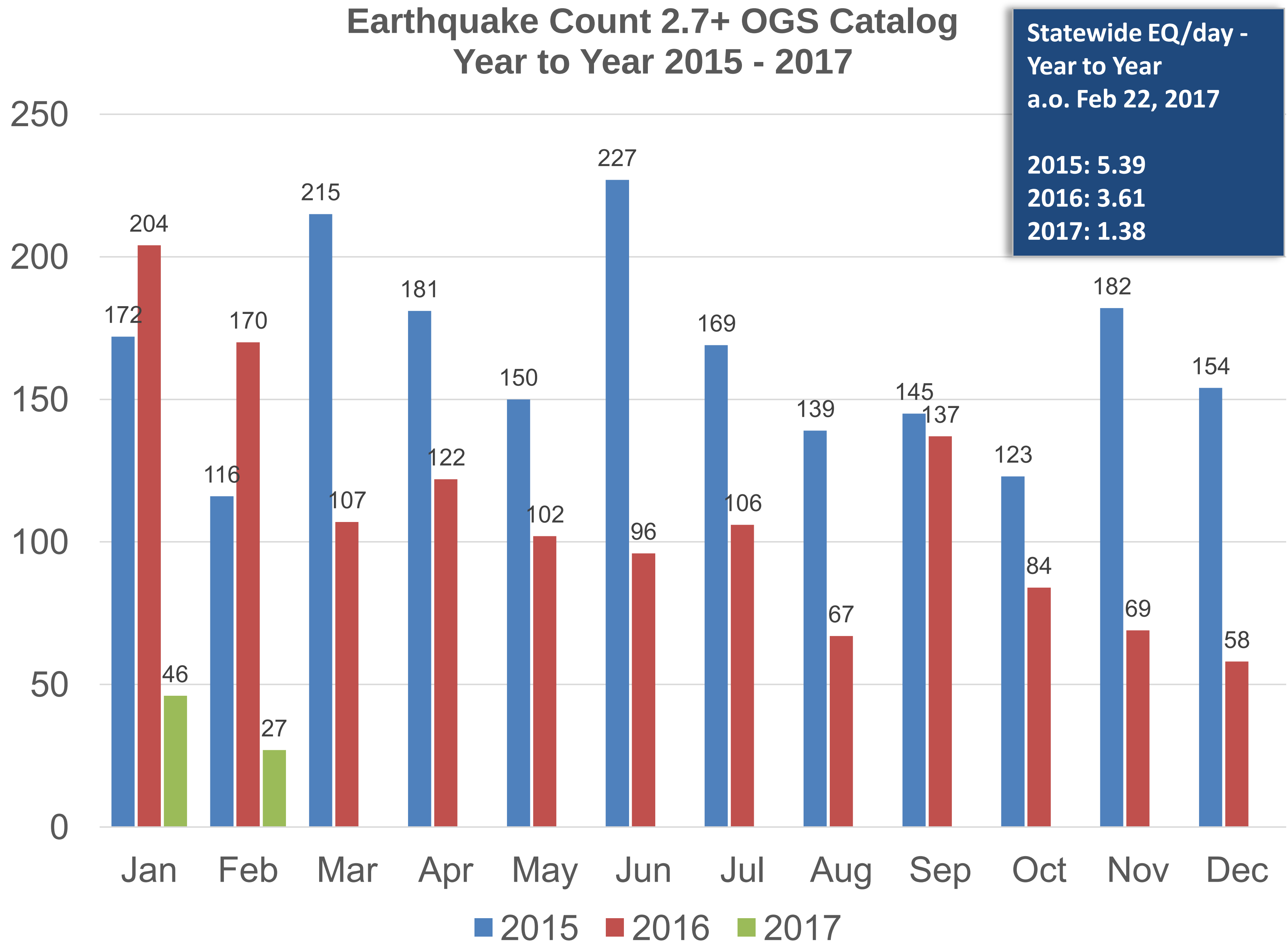
(more)

“The amount and quality of the data now available to us is far ahead of where we were a year ago,” Baker said. “We can make decisions on a much timelier basis. Given that, operators need to be aware that we will take action if that data indicates further volume reductions should be put in place. The earthquake rate is headed in the right direction, but this remains our most critical issue.”

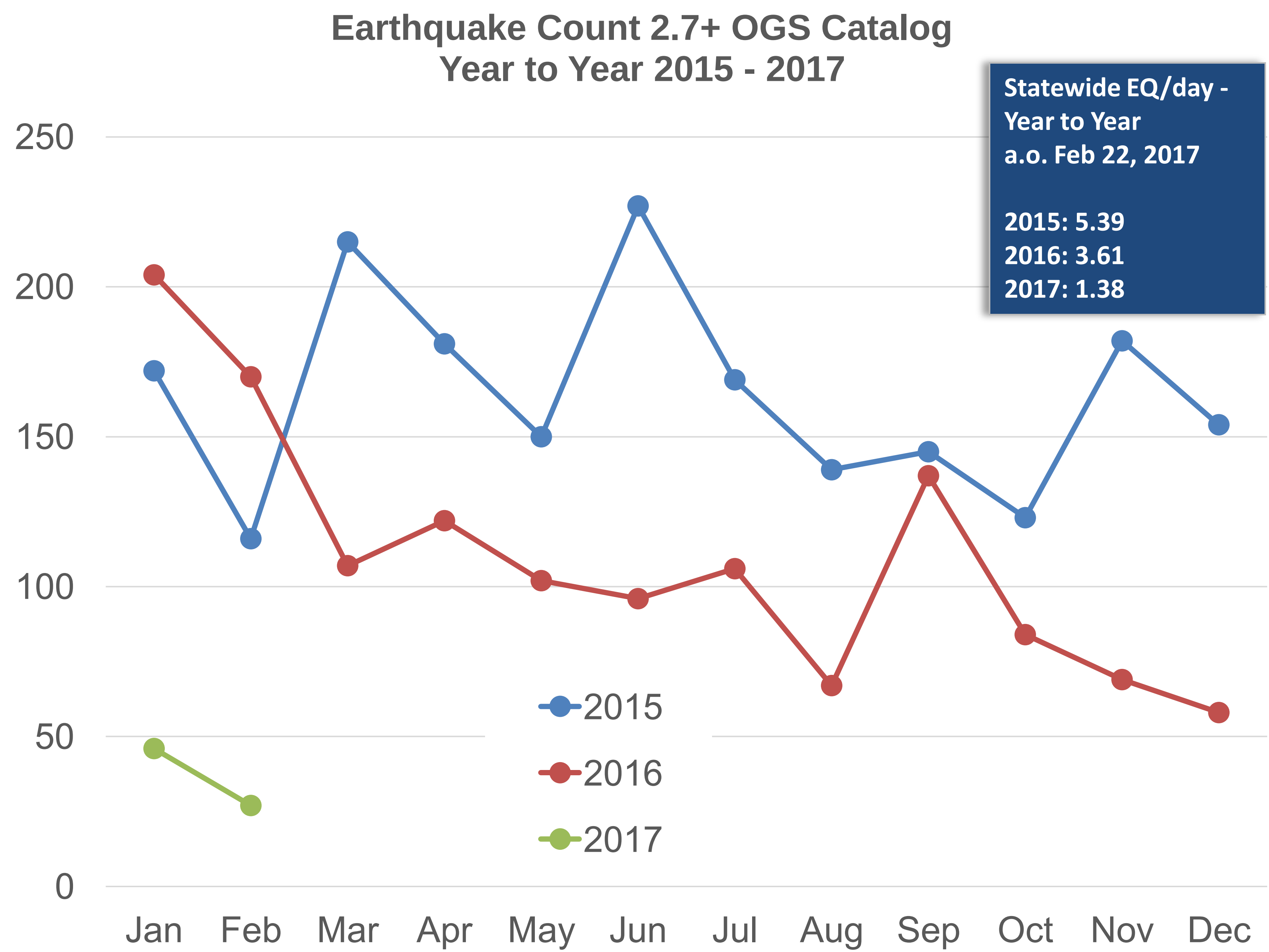
-occ-

****Editors, producers note: Graphs of the earthquake rate, a mapof the AOI, letter to operators, and a list of wells are attached.**

***** A summary of OCC earthquake actions can be found at www.occeweb.com under “Hot Topics”**



Earthquake Count 2.7+ OGS Catalog
Year to Year 2015 - 2017
Statewide EQ/day -
Year to Year
a.o. Feb 22, 2017
2015: 5.39
2016: 3.61
2017: 1.38
250
200
150
100
50
0
172
204
46
116
170
27
215
107
181
122
150
102
227
96
169
106
139
67
145
137
123
84
182
69
154
58
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2015
2016
2017


Earthquake Count 2.7+ OGS Catalog
Year to Year 2015 - 2017
Statewide EQ/day -
Year to Year
a.o. Feb 22, 2017
2015: 5.39
2016: 3.61
2017: 1.38
250
200
150
100
50
0
2015
2016
2017
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

BOB ANTHONY
Commissioner

TODD HIETT
Commissioner

DANA MURPHY
Commissioner

OKLAHOMA
CORPORATION COMMISSION
P.O. BOX 52000
OKLAHOMA CITY, OKLAHOMA 73152-2000

253 Jim Thorpe Building
Telephone: (405) 521-2240
FAX: (405) 521-3099
www.occeweb.com

OIL & GAS CONSERVATION DIVISION

Tim Baker, Director

TO:

From: Tim Baker

RE: Review of Area of Interest (AOI) for Triggered Seismicity

Date: February 22, 2017

The Commission's Oil and Gas Conservation Division (OGCD) is exercising its authority pursuant to 17 O.S. Sec. 52, 52 O.S. Sec. 139 (D) (1) and OAC 165:10-5-7(g) to respond to an emergency situation having potentially critical environmental or public safety impact resulting from the operation of saltwater disposal wells.

The OGCD has reviewed recent earthquake activity, as reported by the Oklahoma Geological Survey (OGS). The combined reported earthquake activity constitutes an emergency situation.

After consultation with researchers and the Oklahoma Geological Survey, adjustments have been made to the distribution of volume allotments outlined in directives issued before December 5, 2016 ("Prior Directive Action"). Additional limits have also been set for wells within the AOI, but not under any Prior Directive Action.

This action is aimed at limiting future growth of disposed volume into the Arbuckle within the AOI, while allowing operators with multiple Arbuckle disposal wells within the AOI more flexibility in water management.

The following applies to all Operators with wells within the defined zone in the Area of Interest (AOI):

All Arbuckle disposal wells currently shut in by a Prior Directive Action shall remain shut in.

All Arbuckle disposal wells operated by an entity (Operator) and within a Directive Area contribute to the total Arbuckle disposal well volume allowed for that Operator within that Directive Area. This total will be the cumulative volume allotment from the most recent Prior Directive Actions applied to a given well. The total volume within a designated Directive Area may be distributed at the discretion of the Operator, with the following requirements:

Arbuckle disposal wells within the Oklahoma Central Reduction Area (OCRA) not currently injecting at a rate higher than a ten-thousand (10,000) barrels per day (bpd) rolling 30-day average will have a limit of the lesser of ten-thousand (10,000) barrels per day (bpd) rolling 30-day average or the permitted daily volume. Arbuckle disposal wells within the Oklahoma Central Reduction Area (OCRA) currently injecting at a rate higher than a ten-thousand (10,000) barrels per day (bpd) rolling 30-day average will have a limit of the higher of the last two 30-day averages, based on volumes reported through the 1012D efile system. For operators using the cumulative volume method, the single day volume for a well will be limited to the lesser of five-thousand (5,000) bpd above the new 30-day average limit or the permitted daily volume. The total volume distributed within the Directive Area for any Operator must not exceed the total allowed for that Operator, as indicated in the table included with this letter.

Arbuckle disposal wells within the Oklahoma Western Reduction Area (OWRA) not currently injecting at a rate higher than a fifteen-thousand (15,000) barrels per day (bpd) rolling 30-day average will have a limit of the lesser of fifteen-thousand (15,000) barrels per day (bpd) rolling 30-day average or the permitted daily volume. Arbuckle disposal wells within the Oklahoma Western Reduction Area (OWRA) currently injecting at a rate higher than a fifteen-thousand (15,000) barrels per day (bpd) rolling 30-day average will have a limit of the higher of the last two 30-day averages, based on volumes reported through the 1012D efile system. For operators using the cumulative volume method, the single day volume for a well will be limited to the lesser of five-thousand (5,000) bpd above the new 30-day average limit or the permitted daily volume. The total volume distributed within the Directive Area for any Operator must not exceed the total allowed for that Operator, as indicated in the table included with this letter.

All Arbuckle disposal wells within the AOI, but not under a Prior Directive Action, not currently injecting at a rate higher than a fifteen-thousand (15,000) barrels per day (bpd) rolling 30-day average will have a limit of the lesser of fifteen-thousand (15,000) barrels per day (bpd) rolling 30-day average or the permitted daily volume. All Arbuckle disposal wells within the AOI, but not under a Prior Directive Action, currently injecting at a rate higher than a fifteen-thousand (15,000) barrels per day (bpd) rolling 30-day average will have a limit of the higher of the last two 30-day averages, based on volumes reported through the 1012D efile system. For operators using the cumulative volume method, the single day volume for a well will be limited to the lesser of five-thousand (5,000) bpd above the new 30-day average limit or the permitted daily volume. The total volume distributed within the Directive Area for any Operator must not exceed the total allowed for that Operator, as indicated in the table included with this letter.

These adjustments must be completed within 30 days of the date of this letter.

Operators wishing to open additional formations for disposal, while still disposing in the Arbuckle, will be required to install the necessary equipment to ensure that no more than the allowed maximum barrels per day of disposal fluid are delivered to the Arbuckle zone. A technical meeting will be required prior to beginning the multi-zone disposal. An initial injection profile must be provided to the OCC when the multi-zone injection begins. Thereafter, an annual injection profile will be required to verify all equipment is still operating according to design parameters.

Operators not currently submitting reports through the e-file system, but included in this action will be required to submit daily disposal volumes for December 27, 2015 through the present, utilizing the e-file system. Contact ogvolumes@occemail.com for more information on e-filing 1012D reports.

These instructions are mandatory and are to be implemented immediately. Failure to comply may result in legal action by the OGCD.

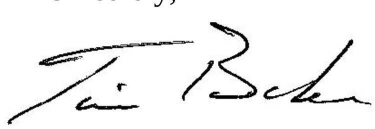
The actions directed in this letter will be reviewed as more information becomes available. Review shall occur on a yearly basis or more frequently if the data so warrants. Subsequent actions or directives may be necessary if the data and seismic activity warrants such action. Likewise, actions or directives may be cancelled if supported by the data.

Objections to this action must be submitted in writing by email to Charles Lord or Jim Marlatt at the email address listed below, or at the address or facsimile number indicated in the letterhead by March 15th 2017.

If you have any questions, or to request a technical conference, contact the OGCD:

Charles Lord	or	Jim Marlatt
405- 522-2751		405- 522-2758
c.lord@occemail.com		j.marlatt@occemail.com

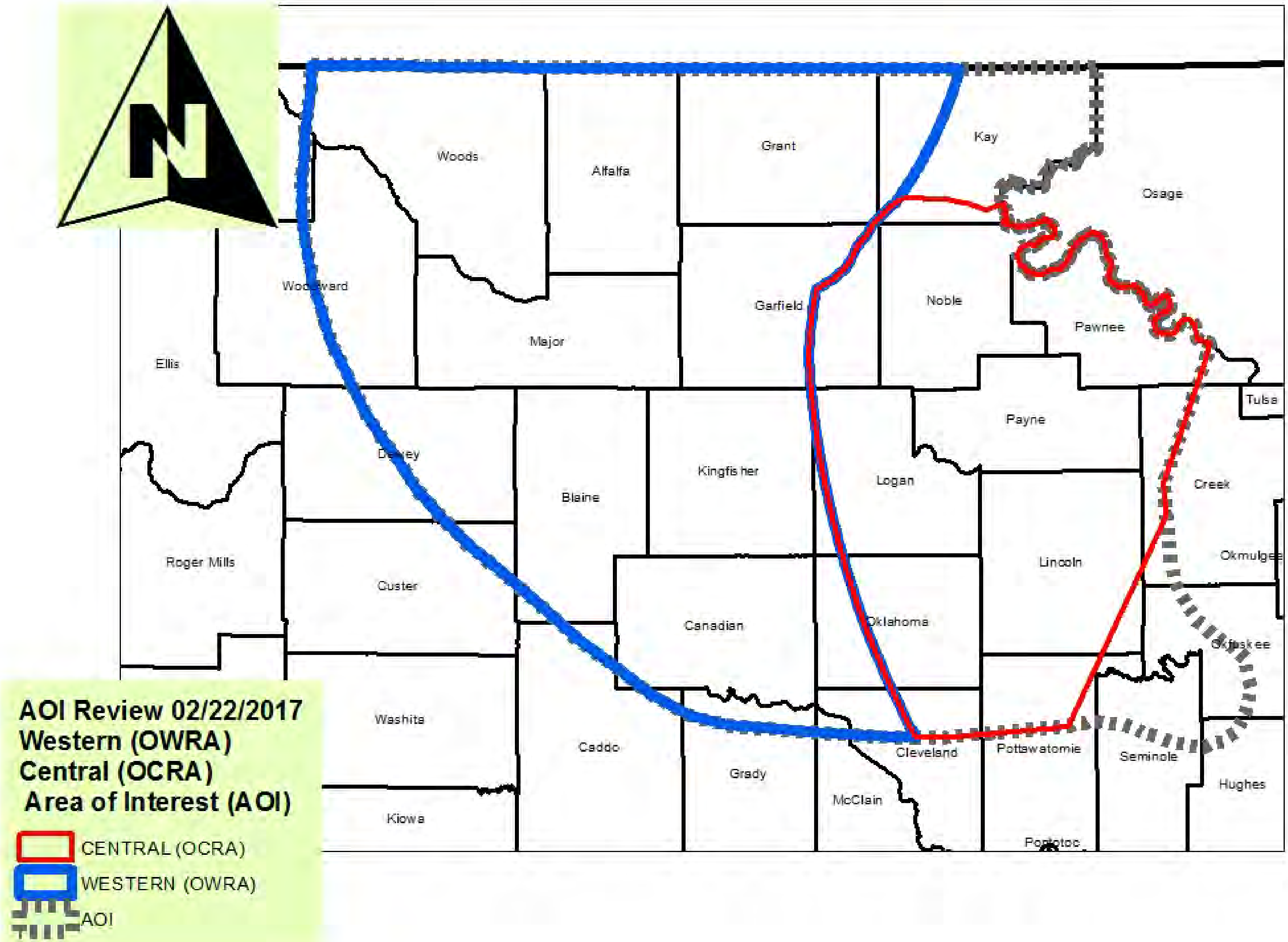
Sincerely,



Tim Baker, Director
Oil and Gas Conservation Division

Attachments:

List of wells with Directive Area
List of Operators with Total Allowed Volume by Directive Area



AOI Review 02/22/2017
Western (OWRA)
Central (OCRA)
Area of Interest (AOI)
CENTRAL (OCRA)
WESTERN (OWRA)
AOI
Woods
Alfalfa
Grant
Kay
Osage
Woodward
Garfield
Noble
Pawnee
Major
Ellis
Tulsa
Payne
Dewey
Kingfisher
Logan
Creek
Blaine
Roger Mills
Lincoln
Okmulgee
Custer
Canadian
Oklahoma
Okfuskee
Washita
Caddo
Cleveland
Pottawatomie
Seminole
Grady
McClain
Hughes
Kiowa
Pontotoc

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
2	ABC OIL COMPANY INC	PARKS 8	1		
3	ADVANCE OIL CORPORATION	VANCE 2		1	
4	AEXCO PETROLEUM INC	ORR SWD 1-16		1	
5		SNYDER SWD 1-32	1		
6	ANTHIS LAND COMPANY LLC	ANDERSON 15-1		1	
7	ARP OKLAHOMA LLC	DALMATIAN SWD #1			1
8		JACKDAW SWD #1			1
9		K-9 1			1
10		K-9 2			1
11		OTTERHOUND SWD 1			1
12	ARROWHEAD ENERGY INC	VENCI SWD 2-26			1
13	ATCHLEY RESOURCES INC	SANGO 1-A	1		
14	BARON EXPLORATION COMPANY	CARLSON SWD 1-20			1
15		COMMANDER SWD 2-17			1
16	BAUGH ALLAN L	FOUNTAIN SWD 1		1	
17	BEAR ENERGY LLC	BUCKET SWD 1		1	
18		GOODNIGHT SWD 1		1	
19		GOODNIGHT SWD 3		1	
20		GOODNIGHT SWDW 4		1	
21		GOODNIGHT SWDW 5		1	
22		SUN SWD 1		1	
23		WEST CARNEY SWDW 1		1	
24		WEST CARNEY SWDW 2		1	
25	BEARD OIL COMPANY	FITZGERALD 18-1			1
26		JOHNS 20-1	1		
27		THIRSTY ONE 18-1			1
28		THIRSTY-TOO SWDW 18-2			1
29	BECCA OIL LLC	MILLER 1		1	
30	BEDFORD ENERGY INC	MERICK 19-W-1		1	
31	BENSON MINERAL GROUP INC	CARTMELL 15-1D		1	
32	BEREXCO LLC	BEN VANCE 35		1	
33		EMMA COKER 36		1	
34		HENN 5		1	
35		JEMINA 6		1	
36		LONG 21W		1	
37		MUSSELLEM 31		1	
38		POWELL 15		1	
39		POWELL C31 SWD		1	
40		S LONG 2		1	
41		STARR 34		1	
42		VANCE, BEN 33		1	
43		VANCE, SAM 8		1	
44		VIDA M. WAY 26A		1	
45		WAY, VIDA M. 27		1	
46	BSO INC	HORINE C C-1		1	
47	CALLIE OIL COMPANY LLC	MCCOON 3		1	
48	CAPSTONE OILFIELD DISPOSAL SERVICE LLC	RING 3-7			1
49	CEI OPERATING LLC	BOSTIAN 1		1	
50		CUNDIFF SWD 1		1	
51		MANY DRINKS 1 SWD		1	
52		MINNICH 1		1	
53	CENTREX OPERATING COMPANY	CARMICHEAL 2-15	1		
54	CHAPARRAL ENERGY LLC	BLACK HOLE SWD 1		1	
55		CLIFFORD SWD 1			1
56		DOVER UNIT HOOVER SWD 1			1
57		ELSIE 1D			1
58		ERIKSON 1 SWD			1

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
59		FREEDOM 26 SWD			1
60		KINETIC SWD 1			1
61		KOKOJAN SWD 1			1
62		MENO SWD 5			1
63		MESSENGER "A" 1			1
64		OL' FAITHFUL SWD 13			1
65		PHILLIPS 15 SWD 1			1
66		ROOMBA SWD 1			1
67		SUPLEX SWD 1-19		1	
68		TURKEY CREEK SWD 1			1
69		WESSEL SWD #1			1
70		WHITLOCK-DIEHL 4	1		
71	CHER OIL COMPANY LTD	STATE SCHOOL LAND 1-16R		1	
72		TUCKER 12-1D		1	
73	CHESAPEAKE OPERATING LLC	AMAZON SWD 1-25			1
74		AR-KANSAS 11-28-15 SWD 1			1
75		BULLET 25-28-14 SWD 1			1
76		CAPRON SWD 1-15			1
77		CHUPA 1-12			1
78		CLAY 7-25-10 SWD 1			1
79		DONOVAN YOST 1-15		1	
80		EUPHRATES 11-27-12 SWD 1			1
81		GERKEN 1-21		1	
82		GIANT 1-7			1
83		GIDEON 1-32			1
84		HARDROW 1		1	
85		HDW 1-2			1
86		HOLLOW LOG 1-35			1
87		JORDAN 20-25-13 SWD 1			1
88		JUSTIN 10-28-14W SWD 1			1
89		MULLINS 1-33			1
90		NILE 14-28-12 SWD 1			1
91		OLD FAITHFUL 20			1
92		O'NEIL 1-16		1	
93		PISTOL 31-28-14 SWD 1			1
94		PULLER 7-26-10 SWD 1			1
95		RIO GRANDE 16-27-12 SWD 1			1
96		ROGUE SWD 1-27			1
97		SARA YOST 7-22		1	
98		SCOUT 12-28-17 SWD 1-X			1
99		SOUTH ALVA 18-26-13 SWD 1			1
100		SPENCER 14-27-17 SWD 1			1
101		TIGRIS 24-24-11 SWD 1			1
102		WEST EDMOND 1-24			1
103		WISE 1-11			1
104		YELLOW 30-27-10 SWD 1			1
105		YOST 1-15		1	
106	CHIEFTAIN OIL CO INC	ERMA SWD 1			1
107	CHOATE DISPOSAL SERVICES LLC	CHOATE SWD 1			1
108	CIMARRON RIVER OPERATING CO	E. YAHOLA 2A		1	
109		RIVERBED A SWD-1		1	
110	CIRCLE 9 RESOURCES LLC	DEER CREEK SWD 1-27	1		
111		GAINEY RANCH SWD 17-1	1		
112		HOKE 1-1		1	
113		LOUISE 1		1	
114		MVN 1		1	
115	CISCO OPERATING LLC	ALICE 32-1 SWD			1

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
116		BOLSER 33-1 SWD			1
117		DZ 29-1 SWD			1
118		HEPPLER 8-1 SWD		1	
119		JAMES 18-2 SWD			1
120	CONCORDE RESOURCE CORPORATION	CARNES #1-6 SWD		1	
121		NGR SWD 1H-20		1	
122	CONTINENTAL RESOURCES INC	DOROTHY 1-20			1
123	CROWN ENERGY COMPANY	HANNAH JO A1 10 SWD		1	
124		LINDA A1 1 SWD		1	
125	CUESTA PETROLEUM INC	RAINEY (SWD) 1	1		
126		SANGO SWD 1	1		
127	D & J OIL COMPANY INC	DENNIS SWD 1-6			1
128		JAMES 1-20			1
129		MYERS 1-34 SWD			1
130	D & J TANK TRUCKS INC	SANDERS 3-SWD		1	
131	DAKOTA EXPLORATION LLC	HOFFMAN 21-SWD1		1	
132		OBERLENDER 23-SWD1		1	
133		PLC 2-SWD#1		1	
134	DARLING OIL CORPORATION	BUXTON 1			1
135		MOLLY 2			1
136	DAVIS F OIL & GAS LLC	GRAY 19-1	1		
137	DEAD FERN RESOURCES INC	OVERMAN 1	1		
138	DEM OPERATIONS INC	DIXON 1			1
139	DEMCO OIL & GAS COMPANY	EFFIE MEYERS 2			1
140		EVANS 2			1
141	DEXXON INC	YARHOLA ROYALTY UNIT (C KEY WSW-1) WSW-1		1	
142	DONRAY PETROLEUM LLC	ALLEN 4		1	
143	DORADO E & P PARTNERS LLC	BILLY REX SWD 1			1
144		BRORSEN 1-10 SWD		1	
145		BUSH SWD 1-7			1
146		HARTSUCK SWD 1-9		1	
147		POLLARD 1-35 SWD			1
148		VADDER 1-9X SWD			1
149		VONDA 1-6		1	
150	DRYES CORNER LLC	SAFAIR 1-28		1	
151	DUNCAN RONALD R	LOWERY 1 SWD	1		
152	E O K OPERATING LLC	HOLT SWD 1		1	
153		ICONIUM SWD 1		1	
154		JEFFREY HORTON 1		1	
155		KAREN 1		1	
156		MERIDIAN SWD 1		1	
157		NORTH LUTHER SWD 1-4		1	
158	EAGLE EXPLORATION PRODUCTION LLC	REITZ 1 SWD			1
159		REITZ 2 SWD			1
160	EAGLE ROAD OIL LLC	CARTER 1-5SWD		1	
161		MANUEL 2	1		
162		RIPLEY SWD 1		1	
163		WILL 1-28 SWD		1	
164	EASTOK PIPELINE LLC	EASTOK 1-24		1	
165		EASTOK-CABERNET 1-35 SWD		1	
166		EASTOK-DRUMMOND 1-19		1	
167		EASTOK-PALM 1-12 SWD		1	
168		EASTOK-PEMBERTON 1-22 SWD		1	
169		EASTOK-RIEMAN 1-35 SWD		1	
170		EASTOK-RUARK 1-29 SWD		1	
171		EASTOK-STEICHEN 1-10 SWD		1	
172		HOLLAND 1-21		1	

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
173		MOEBIUS 2-28		1	
174	EMPIRE PETROLEUM LLC	HOFMEISTER SWD 21-1	1		
175		O&G REICHERS SWD 3-1	1		
176		R-JENT SWD 3-1	1		
177	ENERSOURCE PETROLEUM INC	JONES-COUNCIL 1		1	
178	EQUAL ENERGY US INC	CD 1		1	
179		CD 2		1	
180		MELSON 1-23		1	
181		TWIN CITIES 1		1	
182		TWIN CITIES 2		1	
183		TWIN CITIES 3		1	
184		TWIN CITIES NORTH 1-24		1	
185		TWIN CITIES NORTH SWD 2		1	
186	GILLHAM PAUL OIL COMPANY	CALHOUN 31-1 SWD		1	
187		JT 1-25		1	
188	GLM ENERGY INC	KODESH 1-3		1	
189		O'HARA 4			1
190	HALL GREG OIL & GAS LLC	SCHOOLLAND 2-16		1	
191	HALLCO PETROLEUM INC	CONKLIN 3	1		
192	HIGHTOWER ENERGY LLC	CALDWELL-LIONEL HARRIS 1		1	
193	HINKLE OIL & GAS INC	HELLER SWD 1			1
194		POOL SWD 1			1
195	HULEN OPERATING COMPANY	THREATT 18-3		1	
196	INTERNATIONAL ENERGY COMPANY LLC	BLUBAUGH 20-D1		1	
197		BONFY 24-D1		1	
198		FATH 28-D1		1	
199		SOBER 4-D1	1		
200	JEFFRIES PUMPING SERVICE INC	AUTWINE 1-WS	1		
201	JONES L E OPERATING INC	ENDICOTT 2		1	
202		GOLTRY 1		1	
203	KAY PRODUCTION COMPANY	SLOCUM-MOORE 3			1
204	KIRKPATRICK OIL COMPANY INC	LITTLE BEAVER SWD 1-26			1
205		MARSHALL EAST SWD 1		1	
206		OTTER SWD 1-4		1	
207		THOMAS SWD 1			1
208	KLO LLC	JAMISON 9			1
209		N. KLINTWORTH 6		1	
210		OTSTOT 19-1			1
211	KROTZER OIL COMPANY	GLASS/REED 1-C		1	
212	LAWCO HOLDINGS LLC	CLINE 1-23	1		
213		NAN 1	1		
214	LINN OPERATING INC	GROUTCHY 1-22		1	
215		HUTTON 2			1
216	LONGFELLOW ENERGY LP	CAROLYN 27-1SWD			1
217		HLADICK 14-1 SWD			1
218		J & J 7-1 SWD			1
219		WEBER 19-1 SWD			1
220	M M ENERGY INC	GREGG 1		1	
221		HAYES B-2		1	
222		SCHOOL LAND 64 77		1	
223		SHOFFNER 1			1
224		SHOFFNER 2-28			1
225	MACKEY CONSULTING & LEASING LLC	PAGE SWD 1-24	1		
226	MAR-BAR ENTERPRISES INC	BRUMFIELD 1B		1	
227	MARBET LLC	GRAGG (DUAL COMP. SEE ORDER) 1		1	
228	MARJO OPERATING MID-CONTINENT LLC	CHANDLER 1		1	
229		PEARL SWDW 1		1	

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
230		VINCO 1		1	
231		VINCO SWDW 2		1	
232		WEST CARNEY EXTENSION 1		1	
233	MEADOWBROOK OIL CORPORATION OF OK INC	MCGREW 1-A SWD			1
234	MEASON PETROLEUM LLC	DONALDSON 1-21 SWD		1	
235	MID-CON ENERGY OPERATING LLC	AMY SIMPSON 29		1	
236		B. WILSON 25		1	
237		BRINTON D-09		1	
238		CUSHING CO-OP WFS S-1		1	
239		E. WILSON 1		1	
240		FARRIS 29-SWD		1	
241		FARRIS M 31		1	
242		FISHER, G.W. SWD 27		1	
243		G.W. FISHER 29		1	
244		MCBRIDE 35		1	
245		MILLER 13		1	
246		MULLENDORE 2		1	
247	MIDSTATES PETROLEUM COMPANY LLC	ALFALFA 1			1
248		CHASE 1		1	
249		CHUCKAHO 1		1	
250		COOK SWD 1H-12			1
251		DACOMA 1			1
252		DENTON SWD 1-28			1
253		EAST WELLSTON 1		1	
254		FIRE 1		1	
255		HAZEL 1		1	
256		LOHMANN SWD 1-16			1
257		LONGHURST 1			1
258		MEIER 2614 1-21 SWD			1
259		MOREHART SWD 1-6			1
260		MURROW SWD 1-10			1
261		RED ROCK 1		1	
262		ZAHORSKY SWD 1-8			1
263	MID-WAY ENVIRONMENTAL SERV INC	A.N. TERRY 1		1	
264	MONTCLAIR ENERGY LLC	MONTCLAIR SWD 1		1	
265	MONTGOMERY EXPLORATION CO LTD	DUNCAN SWD	1		
266	MORAN-K OIL LLC	FAGAN 1		1	
267	MUEGGE CLAY A	PAUL KIRBY 1			1
268	MUSGROVE CASEY OIL CO INC	BYERS 4A		1	
269	MUSTANG FUEL CORPORATION	KAW LAND & CATTLE 1-8 SWD		1	
270		MAT SWD 1-36		1	
271		RED ROCK RANCH 1-18 SWD		1	
272		SUPERMAN 1-13 SWD		1	
273	MYSTIQUE RESOURCES COMPANY	HORINEK 1	1		
274	NATURAL RESOURCES OP LLC	SCHOOLTON 1	1		
275		VINCO 1		1	
276	NBI SERVICES INC	TIGER "H" 5		1	
277	NEILSON INC	KERRI ANN SWD 1-5			1
278	NEW DOMINION LLC	BOOMTOWN 1	1		
279		CHAMBERS 1		1	
280		CORAL SWD 1-26	1		
281		DECKER 1	1		
282		DEEP THROAT 1		1	
283		FLOWER POWER 1		1	
284		HATCHER 1-31	1		
285		HOWARD 1-15	1		
286		HUC 34-1	1		

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
287		JADYN 1-7	1		
288		JESSE 1	1		
289		KOLAR 1	1		
290		LUTHER 2		1	
291		NORTH PARADIGM 1	1		
292		PARADIGM 1-SWD	1		
293		PARADIGM 2-SWD	1		
294		PARADIGM SWD 3	1		
295		PARADIGM TARPEY 1	1		
296		PARADOX 1	1		
297		PEYTON SWD 1-15		1	
298		RIVER BEND 1A-25	1		
299		RIVER CREST 1	1		
300		SIKEACEPE 1-18H SWD	1		
301		STOUT 1	1		
302		SWEETHEART 1		1	
303		TOMMY 1	1		
304		TRIXIE SWD 1-3	1		
305		TURNER 1	1		
306		WEST PARADIGM 1	1		
307		WILZETTA 1 SWD		1	
308		WISHON SWD 1		1	
309	OAK VALLEY SWD LLC	OAK VALLEY SWD 1-26			1
310	OAKLAND PETROLEUM OPERATING CO INC	FIXICO N1		1	
311	O'BRIEN OIL CORPORATION	LIBERTY 2-18		1	
312	OEX-1 LLC	HODGES 5-20	1		
313		STEFFEN SWD 1-5	1		
314	ONEOK HYDROCARBON LP	KOCH FEE SWD 39			1
315	OPTIMA EXPLORATION LLC	OLD HADSON OHIO WALKER 1		1	
316	ORCA OPERATING COMPANY LLC	CARTER SWD 1-23			1
317		NORTHCUT SWD 21-1		1	
318	ORION EXPLORATION PARTNERS LLC	HERCYK SWD 1-31	1		
319	PETCO PETROLEUM CORP	MANUEL 42		1	
320		WACOCHE, BENJAMINE 4		1	
321	PETRO WARRIOR LLC	WILDHORSE SWDW 1		1	
322	PRESSURE PUMPING SERVICES LLC	GERALDEAN BUMGARDNER 2			1
323	PRIMEXX OPERATING CORPORATION	PRIMEXX SWD 1 3			1
324		PRIMEXX SWD 15 2			1
325		PRIMEXX SWD 31-1			1
326	PULLERS OIL COMPANY LLC	MURET (WARREN #1) 1	1		
327		SQUIRES SWD 1			1
328	RAINBO SERVICE COMPANY	BRADY - TELLIER 1		1	
329		PESTHOUSE 1-1			1
330	RAM ENERGY LLC	EAST CHANDLER 1		1	
331	RANGE PRODUCTION COMPANY LLC	BADLANDS SWD 1-24		1	
332		BILLY SWD 1-26		1	
333		BRAKE SWD 1-9	1		
334		COPPERHEAD SWD 1-19		1	
335		DAKOTA SWD 1-9		1	
336		DARKHORSE 1-26			1
337		FOUNTAIN SWD 1-14		1	
338		HOBSON 1		1	
339		JAMES DAVIS 1		1	
340		KANDI SUE SWD 1		1	
341		LINNAEUS 1		1	
342		MARLAND SWD 1-19		1	
343		OAKLAND SWD 1-11	1		

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
344		ROSS SWD 1		1	
345		STRECKER SWD 1		1	
346		TOWER SWD 1-29	1		
347		WHITE EAGLE SWD 1-21		1	
348		WHITE EAGLE SWD 1-26		1	
349		WILSON 1		1	
350		YEARLING SWD 1-33		1	
351	RED HAWK DISPOSAL LLC	REDHAWK SWD 1-17		1	
352	RED RIVER ROYALTY PRODUCTION LLC	OLSON 1-20		1	
353	RED ROCKS OIL & GAS OPERATING LLC	LEVISAY 1-11	1		
354	SAND CREEK OPERATING LLC	KRAFT 1			1
355	SANDRIDGE EXPLORATION & PRODUCTION LLC	ALLISON SWD 1-22			1
356		AMANDA LYNN SWD 1-33			1
357		AMANDA LYNN SWD 2-33			1
358		APALOOSA SWD 1-3			1
359		AQUARIUS SWD 1-22			1
360		ASHLEY SWD 2-36			1
361		AUSTIN SWD 1-16			1
362		BAILAR SWD 1-35			1
363		BAILEY SWD 1-1			1
364		BAKER SWD 2810 1-20			1
365		BELLA SWD 1-15			1
366		BETTY ELLEN SWD 1-20			1
367		BETTY ELLEN SWD 2909 2-20			1
368		BIG BEAR SWD 2506 1-34			1
369		BILLY SWD 2505 1-14			1
370		CALLIE SWD 1-7			1
371		CARA SWD 1-31			1
372		CASH SWD 1-32			1
373		CASH SWD 2-32			1
374		CAVIN SWD 1-31			1
375		CHARLY SWD 2407 1-9			1
376		CHARLY SWD 2407 2-9			1
377		CHRISSY SWD 1-35			1
378		CLARK W SWD 2811 1-27			1
379		CLAUDE SWD 1-13			1
380		CONSTANCE SWD 1-18			1
381		COTTONWOOD SWD 2411 1-19			1
382		COUNTY LINE SWD 1-2		1	
383		COUNTY LINE SWD 2-2		1	
384		CRICKET SWD 1-21			1
385		DIAMONDBACK SWD 2710 1-5			1
386		DIAMONDBACK SWD 2710 2-5			1
387		DONNA FAYE SWD 1-19			1
388		DONNA FAYE SWD 2708 2-19			1
389		DONNIE SWD 1-15			1
390		DORADO SWD 1-32			1
391		DOTTY SWD 2-27			1
392		DUSTIN SWD 2709 1-6			1
393		DUSTIN SWD 2709 2-6			1
394		ELY SWD 2703 1-5			1
395		FIERO SWD 1-23			1
396		FIERO SWD 2-23			1
397		FIONA SWD 2610 1-5			1
398		FRANZ SWD 2816 1-24			1
399		FRIDA SWD 2305 1-2			1
400		GATILLO SWD 1-34			1

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
401		GATILLO SWD 2-34			1
402		GRISWOLD SWD 2811 1-25			1
403		HADLEY SWD 1-15			1
404		HAN SWD 2816 1-27			1
405		HARLEY SWD 1-11			1
406		HARLEY SWD 2-11			1
407		ISABELLA SWD 2407 1-28			1
408		ISABELLA SWD 2407 2-28			1
409		JAKE SWD 2406 1-18			1
410		JAKE SWD 2406 2-18			1
411		JESSICA SWD 1-12			1
412		JESSICA SWD 2-12			1
413		JUDY SWD 1-12			1
414		JUDY SWD 2-12			1
415		KAYLEE RAE SWD 2305 1-15			1
416		KIARA SWD 1-34			1
417		KIMBERLY SWD 1-32			1
418		KOPPITZ SWD 1-31			1
419		LANDRY SWD 1-5			1
420		LAUREN SWD 2609 1-3			1
421		LIDIA SWD 2710 1-7			1
422		LILY SWD 1-27			1
423		LISA H SWD 2408 1-34			1
424		LIZZIE SWD 2711 1-33			1
425		LOMA SWD 1-1			1
426		LOUIE SWD WELL 1			1
427		LYNCH SWD 1-10			1
428		LYNCH SWD 2-10			1
429		MANDI JO SWD 1-5			1
430		MARLEY SWD 2511 1-25			1
431		MARLEY SWD 2511 2-25			1
432		MARY CHARLENE SWD 2706 1-25			1
433		MIGUEL SWD 2611 1-9			1
434		MIGUEL SWD 2611 2-9			1
435		MILA SWD 2610 1-28			1
436		MILLIE SWD 2810 1-9			1
437		NANA SWD 1-27			1
438		NATHANIEL SWD 2806 1-27			1
439		OLIVIA KATE SWD 2603 1-26			1
440		ORION SWD 1-22			1
441		OWEN SWD 1-13			1
442		PAINT 1-11			1
443		PHILLIPS SWD 1-7			1
444		PHIN SWD 2811 1-11			1
445		PHIN SWD 2811 2-11			1
446		PINTO SWD 1-11			1
447		POPPINS SWD 2810 2-21			1
448		PRESLEY SWD 2-27			1
449		PROTEUS 17-1			1
450		RISITA SWD 1-27			1
451		ROBYN SWD 1-14			1
452		ROSE KELLY SWD 1-3			1
453		ROSE KELLY SWD 2-3			1
454		ROSE SWD 2810 1-26			1
455		ROSE SWD 2810 2-26			1
456		ROXY SWD 1-30			1
457		SARAH ANNE SWD 2916 1-26			1

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
458		SEEBE SWD 2713 1-23			1
459		SEEBE SWD 2713 2-23			1
460		SHARON SWD 1-22			1
461		SHARON SWD 2-22			1
462		SIDNEY SWD 1-3			1
463		SOLO SWD 2815 1-16			1
464		SOPHIE SWD 1-14			1
465		TATUM ROSE SWD 2710 1-17			1
466		TAYLOR SWD 1-21			1
467		TIBURON SWD 1-1			1
468		TIBURON SWD 2-1			1
469		TROY SWD 2408 1-1			1
470		WALLEY SWD 1-29			1
471		WOODBRIDGE SWD 1-27			1
472		WOODY SWD 1-4			1
473	SHERMAN LARRY OIL LLC	BUCK 1		1	
474		CARNEY 1		1	
475		COUNTY LINE 1	1		
476		GRACE 4		1	
477	SHIELDS OPERATING INC	CROCKETT 1-D		1	
478		REBOUND 1-22D		1	
479	SHORELINE OPERATING LLC	R.E. WELSH 9-A	1		
480	SHORT OIL COMPANY	SCOTT, LOUISA 5		1	
481	SK PLYMOUTH LLC	NIAGARA FALLS 1-22 SWD			1
482		TOEWS SWD 1-15			1
483		TRENT 1-35 SWD			1
484		ZALOUDEK 1-34 SWD			1
485	SOUTHWEST PETROLEUM CORP	ANNIE ROBERTS 1		1	
486		SARAH DEERE 7-7		1	
487		SUSIE CROW 1-A		1	
488	SPECIAL ENERGY CORPORATION	BOWLING SWD 2-32	1		
489		CALES 1-4 SWD	1		
490		CARMICHAEL 23-26N-1E 1SWD	1		
491		CONRADY 19-28N-6W 1 SWD			1
492		DOWNING 1-7 SWD			1
493		FERDA 21-28N-4W 1SWD			1
494		FRIEOUF 1-7 SWD			1
495		KIRBY 1-8 SWD			1
496		OPLOTNIK 1-3 SWD			1
497		PAN GALACTIC GARGLE BLASTER 1-35		1	
498		PEPPER CREEK 1SWD		1	
499		POLECAT 1-15 SWD			1
500		POSTLEWAIT 1-7 SWD			1
501		RAMSEY 1-19		1	
502		RAMSEY UNIT 1-17		1	
503		RAMSEY UNIT 1-18		1	
504		SCHIEBER 21-28N-4E 1SWD	1		
505		SHARON 1		1	
506		SUBERA 1-19 SWD			1
507		TOEWS 34-25N-4W 1SWD			1
508	SPESS OIL COMPANY INC	CAUDILLO-WOOD 2	1		
509		CLARA MAY 2	1		
510		NORTH 5			1
511	STEPHENS ENERGY GROUP LLC	FUXA 1-15SWD		1	
512	STEPHENS PRODUCTION CO	HOPFER BROTHERS SWD 1		1	
513	STILL A B WELL SERVICE INC	E.G. SHARP 5		1	
514	STORY OIL AND GAS INC	BUFFALO 1 SWD	1		

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
515	SUMMIT RESOURCES MANAGEMENT LLC	PRUCHA 1-23 SWD		1	
516	SUNDANCE ENERGY OKLAHOMA LLC dba SEO LLC	BERG TRUST 16-3-23 1 SWD		1	
517		BRANSON 17-4-23 1 SWD		1	
518		BROWN TRUST 19-3-17-1 SWD		1	
519		CORNFORTH 15-3-9 1 SWD		1	
520		ROTHER 16-4-11 1 SWD		1	
521		WHITENECK TRUST 20-3-12 1 SWD		1	
522	SUNDOWN ENERGY LP	SUNDOWN 1		1	
523	TAG PETROLEUM INC	NASH 1		1	
524		OVERHOLT 1		1	
525	TALL OAK MIDCON LLC	CIRCLE SWD 1			1
526	TARKA ENERGY LLC	COOPER "D" 1		1	
527		LARIAT 4-2D		1	
528		SECHRIST SWD 1		1	
529		WATERS 9-1D		1	
530		WOODS SWDW 1		1	
531	TAYLOR R C OPERATING CO LLC	DAHL SWD FACILITY 1			1
532	TERRITORY RESOURCES LLC	A.M. THOMAS 15		1	
533		CAGE SWD 1-17		1	
534		ENDICOTT "D" 1		1	
535		HEGCO BRETT 2	1		
536		NEMAHA 7		1	
537		OCTAGON SWD 1-35		1	
538		OLDHAM 6		1	
539		REAR NAKED CHOKE 1-17 SWD		1	
540		TRIANGLE 1-23 SWD		1	
541		TRUEBLOOD 1-2		1	
542		WHIZZER 1-18 SWD	1		
543	TNT OPERATING COMPANY INC	BAKER-TOWNSEND (NO MIT NEEDED) 6			1
544	TONKAWA SALTWATER DISPOSAL LLC	TONKAWA SWD 1	1		
545	TOOMEY OIL COMPANY INC	RUTH 1		1	
546	TRANS PACIFIC OIL CORPORATION	GREG THURMAN SWD #1			1
547	TREK RESOURCES INC	STATE 16-2			1
548	TRIAD ENERGY INC	MARY ANNE SWD 1-22			1
549		WILLIAMS SWD 1-6			1
550	TRINITY OPERATING (USG) LLC	ADOBE 1-10 SWD			1
551		BLACKWELL 1-34 SWD			1
552		SCROGGINS 1-33SWD		1	
553		STRICKER 9D		1	
554	TRIPOWER RESOURCES LLC	PARAGON 1	1		
555	TRU OPERATING LLC	HARRINGTON 1 SWD		1	
556	TURNTABLE ENERGY INC	JENKINS 2	1		
557	U S ENERGY DEVELOPMENT CORPORATION	CAT IN THE HAT 2-19 SWD		1	
558		CHAMBERS 1-8 SWD		1	
559		DAVIS FARMS 1-5 SWD		1	
560		ESTILL 8-SWD			1
561		KRITTENBRINK 1-36 SWD		1	
562		MORRISETT SWD 2		1	
563	UNION VALLEY PETROLEUM CORP	BONNIE JEAN SWD 1-22			1
564		WESLEY SWD 1-8			1
565	VENTURA ENERGY SERVICES LLC	ASHTON 2		1	
566	WEST PERKINS COMMERCIAL DISPOSAL LLC	WEST PERKINS SWD 1		1	
567	WHITE OPERATING COMPANY	CLAUDE YOUNT 1			1
568		HEMMER 2			1
569		MARY UNSELL 7			1
570		WALNUT GROVE D-2			1
571		WALNUT GROVE(COMMUNITY#6) SWD-1			1

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
572		WINSTEAD 1			1
573	WHITE STAR PETROLEUM LLC	ADKISSON 1-33SWD		1	
574		B & W WEATHERS SWD 1-7		1	
575		BIG IRON 4-21N-1E 1SWD		1	
576		BODE SWD 1-2		1	
577		BONTRAGER 1-21X SWD		1	
578		BOSTIAN SWD 17-2		1	
579		BOYCE SWD 21-2		1	
580		BUCKNER 24-19N-1W SWD		1	
581		BUFFINGTON 29-22N-1E 1SWD		1	
582		CEDAR GROVE 21-20N-2E 1SWD		1	
583		CHLOUBER 35-19N-3E 1 SWD		1	
584		CLARY 35-1 SWD		1	
585		CLAY 21-1SWD		1	
586		COMBS 8-18N-3E 1SWD		1	
587		COOLEY 24-19N-1E SWD		1	
588		CUNNINGHAM 23-18N-2W 1SWD		1	
589		DADDY DON 1-30 SWD		1	
590		DALLAS 1-6 SWD		1	
591		DEAN SWD 3-1		1	
592		DOBERMAN 1-25 SWD		1	
593		DUDEK 12-18N-3W 1SWD		1	
594		EAVENSON 24-19N-3W 1SWD		1	
595		EDWARDS 32-21N-3W 1 SWD		1	
596		ELAINE 10-18N-2W 1SWD		1	
597		ELINORE 1-18SWD		1	
598		ETHRIDGE 25-3 SWD		1	
599		FRANK SWD 1-33		1	
600		FUXA 25-19N-4W 1SWD		1	
601		GEIHSLER 6-21N-4W 1SWD		1	
602		GILBERT 1-17 SWD		1	
603		H. VOISE 14-21N-1E 1SWD		1	
604		HARRISON 22-18N-2E 1SWD		1	
605		HARTING 1-1 SWD		1	
606		HARVEY 1-11 SWD		1	
607		HC RYAN 15-18N-6E 1 SWD		1	
608		HEDGES 6-21N-5W 1SWD			1
609		HICKS 1-21 SWD		1	
610		HILDEBRAND 6-1 SWD		1	
611		HILL 29-1SWD		1	
612		HOPFER 1-20 SWD		1	
613		HOPKINS SWD 1-32		1	
614		JANICE 7-21N-3W 1SWD		1	
615		JOYCE 1-5 SWD		1	
616		JUDGE SOUTH 33-18N-2E SWD		1	
617		KATZ 31-2 SWD		1	
618		KING 2		1	
619		LEIGH 8-19N-3E 1 SWD		1	
620		LEMMONS 14-19N-3W 1SWD		1	
621		LENA 15-19N-3W 1SWD		1	
622		LENORA 29-18N-1W 1SWD		1	
623		LIMESTONE SWD 24-1		1	
624		LIMESTONE SWD 27 1		1	
625		LOUIS 6-3 SWD		1	
626		METCALF 24-2 SWD		1	
627		MITCHELL 4-1 SWD		1	
628		NELSON 33 18N 3E 1SWD		1	

	A	B	C	D	E
1	Op_Name	WellNamNum	AOI	OCRA	OWRA
629		NEWTON 1-7 SWD		1	
630		OLMSTEAD 21-21N-3W 1SWD		1	
631		PEACH 1-19 SWD		1	
632		PENNY 29-1SWD		1	
633		RAINS 5-20N-2E 1 SWD		1	
634		RUNNING GUN 28-21N-2W 1SWD		1	
635		SEBRANEK 1-21N-3W 1SWD		1	
636		SINGLETON SWD 1-35		1	
637		SMITH 1-14D SWD		1	
638		THOMASON 15-20N-3E 1SWD		1	
639		VARGAS 3-20N-1E 1SWD		1	
640		VITEK 1-24 SWD		1	
641		VOISE 1-10 SWD		1	
642		WHEELER 11-1 SWD		1	
643		WILLIAMS 1-24 SWD		1	
644		WILLIAMS 5-1 SWD		1	
645		WILMA SWD 1-16		1	
646		WILSON 11-2SWD		1	
647		WINNEY 1-8 SWD		1	
648		WISEMAN 36-21N-1E 1 SWD		1	
649		WOODARD 1-33 SWD		1	
650		WOSMEK 23-20N-1W 1SWD		1	
651	WHITEHEAD ROSS E	LOJO 1 CDW 1			1
652	WICKLUND PETROLEUM CORPORATION	Bolenbaugh SWDW 1-27		1	
653	WISE OIL & GAS COMPANY LLC	MARBET 28		1	
654	XANADU EXPLORATION COMPANY	FALLIS 1		1	
655	YARHOLA PRODUCTION COMPANY	MIKEY 14		1	

Op_Name	AOI	OCRA	OWRA
ABC OIL COMPANY INC	6,000		
AEXCO PETROLEUM INC	15,000	3,500	
ARP OKLAHOMA LLC			32,467
ARROWHEAD ENERGY INC			75
ATCHLEY RESOURCES INC	9,500		
BARON EXPLORATION COMPANY			-
BAUGH ALLAN L		159	
BEAR ENERGY LLC		4,572	
BEARD OIL COMPANY	15,000		35,000
BECCA OIL LLC		11	
BEDFORD ENERGY INC		180	
BENSON MINERAL GROUP INC		-	
BEREXCO LLC		5,672	
BSO INC		640	
CALLIE OIL COMPANY LLC		-	
CAPSTONE OILFIELD DISPOSAL SERVICE LLC			317
CEI OPERATING LLC		3,554	
CENTREX OPERATING COMPANY	1,000		
CHAPARRAL ENERGY LLC	3,500	6,848	28,071
CHER OIL COMPANY LTD		797	
CHESAPEAKE OPERATING LLC		16,883	157,289
CHIEFTAIN OIL CO INC			660
CHOATE DISPOSAL SERVICES LLC			2,850
CIRCLE 9 RESOURCES LLC	30,000	2,869	
CISCO OPERATING LLC		516	5,256
CONCORDE RESOURCE CORPORATION		1,702	
CONTINENTAL RESOURCES INC			3,153
CROWN ENERGY COMPANY		2,830	
CUESTA PETROLEUM INC	16,000		
D & J OIL COMPANY INC			1,586
D & J TANK TRUCKS INC		55	
DAKOTA EXPLORATION LLC		1,413	
DARLING OIL CORPORATION			3,235
DAVIS F OIL & GAS LLC	15,000		
DEAD FERN RESOURCES INC	1,000		
DEM OPERATIONS INC			3,575
DEMCO OIL & GAS COMPANY			2,000
DONRAY PETROLEUM LLC		3,140	
DORADO E & P PARTNERS LLC		2,908	3,025
DRYES CORNER LLC		2,339	
DUNCAN RONALD R	1,100		
E O K OPERATING LLC		347	
EAGLE EXPLORATION PRODUCTION LLC			8,631
EAGLE ROAD OIL LLC	15,000	-	
EASTOK PIPELINE LLC		11,263	
EMPIRE PETROLEUM LLC	19,500		

Op_Name	AOI	OCRA	OWRA
ENERSOURCE PETROLEUM INC		624	
EQUAL ENERGY US INC		40,814	
GILLHAM PAUL OIL COMPANY		91	
GLM ENERGY INC		128	2,000
HALL GREG OIL & GAS LLC		-	
HALLCO PETROLEUM INC	15,000		
HIGHTOWER ENERGY LLC		40	
HINKLE OIL & GAS INC			15,854
HULEN OPERATING COMPANY		-	
INTERNATIONAL ENERGY COMPANY LLC	15,000	3,465	
JEFFRIES PUMPING SERVICE INC	1,500		
JONES L E OPERATING INC		1,320	
KAY PRODUCTION COMPANY			1,000
KIRKPATRICK OIL COMPANY INC		2,210	1,519
KLO LLC		456	10,000
KROTZER OIL COMPANY		89	
LAWCO HOLDINGS LLC	9,500		
LINN OPERATING INC		218	5,000
LONGFELLOW ENERGY LP			8,533
M M ENERGY INC		15,207	20,000
MACKEY CONSULTING & LEASING LLC	15,000		
MAR-BAR ENTERPRISES INC		2,647	
MARBET LLC		110	
MARJO OPERATING MID-CONTINENT LLC		2,970	
MEADOWBROOK OIL CORPORATION OF OK INC			255
MEASON PETROLEUM LLC		393	
MID-CON ENERGY OPERATING LLC		101	
MIDSTATES PETROLEUM COMPANY LLC		8,908	136,371
MID-WAY ENVIRONMENTAL SERV INC		705	
MONTCLAIR ENERGY LLC		4,487	
MONTGOMERY EXPLORATION CO LTD	15,000		
MORAN-K OIL LLC		78	
MUEGGE CLAY A			1,500
MUSGROVE CASEY OIL CO INC		-	
MUSTANG FUEL CORPORATION		-	
MYSTIQUE RESOURCES COMPANY	10,000		
NATURAL RESOURCES OP LLC	15,000	291	
NBI SERVICES INC		508	
NEILSON INC			477
NEW DOMINION LLC	330,814	85,170	
OAK VALLEY SWD LLC			7,125
O'BRIEN OIL CORPORATION		121	
OEX-1 LLC	30,000		
ONEOK HYDROCARBON LP			325
OPTIMA EXPLORATION LLC		-	
ORCA OPERATING COMPANY LLC		1,611	-

Op_Name	AOI	OCRA	OWRA
ORION EXPLORATION PARTNERS LLC	15,000		
PETCO PETROLEUM CORP		3,638	
PETRO WARRIOR LLC		870	
PRESSURE PUMPING SERVICES LLC			4,500
PRIMEXX OPERATING CORPORATION			3,735
PULLERS OIL COMPANY LLC	2,000		49
RAINBO SERVICE COMPANY		500	1,144
RAM ENERGY LLC		166	
RANGE PRODUCTION COMPANY LLC	45,000	60,322	10,000
RED HAWK DISPOSAL LLC		-	
RED RIVER ROYALTY PRODUCTION LLC		250	
RED ROCKS OIL & GAS OPERATING LLC	15,000		
SAND CREEK OPERATING LLC			38
SANDRIDGE EXPLORATION & PRODUCTION LLC		2,749	492,539
SHERMAN LARRY OIL LLC	15,000	1,250	
SHIELDS OPERATING INC		6,000	
SHORELINE OPERATING LLC	2,000		
SHORT OIL COMPANY		599	
SK PLYMOUTH LLC			24,419
SOUTHWEST PETROLEUM CORP		-	
SPECIAL ENERGY CORPORATION	60,000	8,449	15,908
SPESS OIL COMPANY INC	5,000		1,000
STEPHENS ENERGY GROUP LLC		225	
STEPHENS PRODUCTION CO		1,319	
STILL A B WELL SERVICE INC		130	
STORY OIL AND GAS INC	15,000		
SUMMIT RESOURCES MANAGEMENT LLC		387	
SUNDANCE ENERGY OKLAHOMA LLC dba SEO LLC		2,031	
SUNDOWN ENERGY LP		-	
TAG PETROLEUM INC		400	
TALL OAK MIDCON LLC			1,619
TARKA ENERGY LLC		7,052	
TAYLOR R C OPERATING CO LLC			3,928
TERRITORY RESOURCES LLC	30,000	13,707	
TNT OPERATING COMPANY INC			5,334
TONKAWA SALTWATER DISPOSAL LLC	15,000		
TOOMEY OIL COMPANY INC		780	
TRANS PACIFIC OIL CORPORATION			695
TREK RESOURCES INC			738
TRIAD ENERGY INC			3,320
TRINITY OPERATING (USG) LLC		-	30,000
TRIPOWER RESOURCES LLC	15,000		
TRU OPERATING LLC		-	
TURNTABLE ENERGY INC	2,000		
U S ENERGY DEVELOPMENT CORPORATION		3,047	7,113
UNION VALLEY PETROLEUM CORP			721

Op_Name	AOI	OCRA	OWRA
VENTURA ENERGY SERVICES LLC		500	
WEST PERKINS COMMERCIAL DISPOSAL LLC		679	
WHITE OPERATING COMPANY			13,309
WHITE STAR PETROLEUM LLC		153,096	1,421
WHITEHEAD ROSS E			3,198
WICKLUND PETROLEUM CORPORATION		738	
WISE OIL & GAS COMPANY LLC		69	
XANADU EXPLORATION COMPANY		311	
YARHOLA PRODUCTION COMPANY		-	
Grand Total	840,414	514,225	1,121,876

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 4-D

Earthquake Response Summary

- Researchers largely agree that wastewater injection into the Arbuckle formation, the state's deepest formation, poses the largest potential risk for induced earthquakes in Oklahoma. Most of the wastewater comes not from hydraulic fracturing operations, but rather from producing wells. The water exists in the producing formation and comes up with the oil and natural gas.

- The Oklahoma Corporation Commission's Oil and Gas Conservation Division (OGCD) took its first action on Arbuckle disposal wells regarding earthquakes concerns in September 2013, resulting in one well shutdown and the prevention of the startup of another.

- In early 2015, new research and data provided the basis for a switch from isolated actions on individual Arbuckle disposal wells to larger plans covering more square miles and wells. This resulted in plans that, when taken in conjunction with previous actions, reduced total disposed volume in earthquake areas by approximately 800,000 barrels a day from 2014 levels. About 700 Arbuckle disposal wells were covered.

- The volume reduction area currently covers about 11 thousand square miles, and a 15 thousand square mile "Area of Interest" (AOI) has been established. All Arbuckle wells in the AOI must report disposal volumes at least weekly. New applications for Arbuckle disposal wells in the AOI are no longer eligible for administrative approval.

- More recently, earthquake events outside the main earthquake area have been linked to hydraulic fracturing. These events are rarer, accounting for less than 4 percent of the earthquake activity, and tend to be of lesser magnitudes. More information on the protocols developed to deal with this risk can be found below.

Recent Actions

May 23, 2018 – Directive issued for some disposal wells to shutdown and others to decrease volume in Crescent area. http://www.occeweb.com/News/2018/05-23-18CRESCENTWEB.pdf

April 27, 2018 – Directive issued for further disposal well volume reductions in Covington/Douglas area. http://www.occeweb.com/News/2018/05-08-18CovingtonDirective.pdf

April 19, 2018 – Directives issued for disposal well shutdown in Hennessey area and further volume reductions in Enid area. http://www.occeweb.com/News/2018/04-19-18HennesseyEnidDirectives.pdf

April 9, 2018 – Directive for disposal well in Covington area to reduce volume by 70 percent. Well is the School Land 64-77 (M M Energy)

March 29, 2018 - OCC/OGS statement on new predictive seismic risk model for Oklahoma http://www.occeweb.com/News/2018/03-29-18Statement-SeismicMap.pdf

February 27, 2018 – New protocol issued to mitigate earthquake risk linked to hydraulic fracturing operations in the SCOOP and STACK plays.
http://www.occeweb.com/News/2018/02-27-18PROTOCOL.pdf

October 31, 2017 – Directive for 2 Arbuckle disposal wells in the Hennessey area to reduce volume 25 percent. (At OCC's recommendation, operators of the wells agree to work toward ending all disposal into the Arbuckle.) Wells in question are the Choate SWD1 (Choate Disposal Services) and the Dover Unit Hoover SWD1 (Chaparral Energy).

October 18, 2017 – Wilzetta #1 (New Dominion) in Lincoln County directed to stop all disposal into the Arbuckle formation.

August 9, 2017 - Further Arbuckle disposal well volume reductions in the Edmond area.
http://www.occeweb.com/News/2017/08-09-17ADVISORY.pdf

June 27, 2017 – Report on progress of actions taken in relation to seismicity activity potentially related to well completion operations. http://www.occeweb.com/News/2017/06-27b-17Seismicity-well%20completion.pdf

March 1, 2017 – OGS/OCC joint statement regarding seismicity hazard map.
http://www.occeweb.com/News/2017/03-01-17OCC-%20OGS%20JOINT%20STATEMENT.pdf

February 24, 2017 – Area of Interest (AOI) – Directive restricting future volume disposal rates.
http://www.occeweb.com/News/2017/02-24-17%20FUTURE%20DISPOSAL.pdf

December 20, 2016 – Statewide: Directive regarding seismicity that may be linked to hydraulic fracturing operations. http://www.occeweb.com/News/2016/12-20-16SCOOP-STACK.pdf

November 8, 2016 – Cushing area: Directive modifying operations of 54 Arbuckle disposal wells.
http://www.occeweb.com/News/2016/11-08-16CUSHING%20PLAN.pdf

November 3, 2016 – Pawnee area: Directive covering 38 Arbuckle disposal wells under OCC jurisdiction and 26 Arbuckle disposal wells under sole EPA jurisdiction.
http://www.occeweb.com/News/2016/11-03-16PAWNEE%20POSTING.pdf

September 12, 2016 – Pawnee area: Directive modifying operations at 48 Arbuckle disposal wells under OCC jurisdiction in a 1,116 square mile area. 32 to shut in, remainder to reduce volume. EPA follows OCC lead in its area of jurisdiction (Osage County), shutting down 5 Arbuckle disposal wells, and reducing volumes at 14 others. http://www.occeweb.com/News/2016/09-12-16Pawnee%20Advisory.pdf

September 3, 2016 – Pawnee area: 37 wells directed to shut in (cease operations) under emergency directive as immediate response to Pawnee-area 5.8 magnitude earthquake. (Superseded by September 12, 2016 directive).

August 19, 2016 – Luther/Wellston area: 2 wells shut in, 19 wells to further reduce volume. Actions are in addition to the earlier 40 percent volume cutback that includes area.
http://www.occeweb.com/News/2016/08-19-16LUTHER-WELLSTON%20(3).pdf

March 7, 2016 – Central Oklahoma Regional Volume Reduction Plan and Expansion of Area of Interest
http://www.occeweb.com/News/2016/03-07-16ADVISORY-AOI,%20VOLUME%20REDUCTION.pdf (Note: On the advice of seismologists, plan is being phased in over a two month period. Completion is scheduled for the end of May).

February 16, 2016 – Western Oklahoma Regional Volume Reduction Plan:
http://www.occeweb.com/News/2016/02-16-16WesternRegionalPlan.pdf (Completed on April 30)

January, 20, 2016 – Medford, Byron-Cherokee areas: Sandridge Energy - 8 wells to stop disposal, 9 wells to be used by researchers. 36 wells to reduce volume. Total volume reduction: 191,327 barrels/day, (40 percent). A barrel is 42 gallons.**

****Supersedes Sandridge Energy portion of plans issued 12/3/15.**

http://www.occeweb.com/News/01-20-16SANDRIDGE%20PROJECT.pdf

January 13, 2016 - Fairview area: 27 disposal wells to reduce volume. Total volume reduction for the area in question: 54,859 barrels a day or (18 percent).

http://www.occeweb.com/News/01-13-16ADVISORY.pdf

January 4, 2016 - Edmond area: 5 disposal wells to reduce volumes by 25 to 50 percent. Wells 15 miles from epicenter to conduct reservoir pressure testing. (Two disposal wells ceased operation as part of the action). http://www.occeweb.com/News/01-04-16EQ%20ADVISORY.pdf

December 3, 2015 – Byron/Cherokee area: 4 disposal wells shut-in, volume cuts of 25 to 50 percent for 47 other disposal wells. http://www.occeweb.com/News/12-03-15BYRON-CHEROKEE_MEDFORD%20EARTHQUAKE%20RESPONSE.pdf

December 3, 2015 – Medford area: 3 disposal wells shut-in and f cuts of 25 to 50 percent in disposed volumes for 19 other wells. The total net volume reduction for the area in question is 42 percent.
http://www.occeweb.com/News/12-03-15BYRON-CHEROKEE_MEDFORD%20EARTHQUAKE%20RESPONSE.pdf

November 20, 2015 – Crescent: 4 disposal wells shut-in, 7 others reduce volume 50 percent.

http://www.occeweb.com/News/11-20-15CRESCENT%20ADVISORY.pdf

November 19, 2015 – Cherokee: 2 disposal wells shut-in, 23 others reduce volume 25 to 50 percent.

http://www.occeweb.com/News/CHEROKEE%20ADVISORY-VOLUME,%20OPERATOR.PDF

November 16, 2015 – Fairview: 2 wells reduce volume 25 percent, 1 well stop operations and reduce depth.

http://www.occeweb.com/News/11-16-15FAIRVIEW%20and%20MAP.pdf

November 10, 2015 – Medford: 10 wells reducing volume disposed 25 to 50 percent.
http://www.occeweb.com/News/11-10-15MEDFORD02.pdf

October 19, 2015 – Cushing: 13 wells either ceasing operations or cutting volume disposed 25 percent.

http://www.occeweb.com/News/10-19-15CUSHING%202.pdf

August 3, 2015 – Volume cutback plan for area that includes portions of northern Oklahoma, Logan, Lincoln, and Payne counties. Goal is to bring total disposed volume in area to 30 percent below 2012 total (pre seismicity). Plan covers 23 wells.

http://www.occeweb.com/News/08-03-15VOLUME%20ADVISORY%20RELEASE.pdf

July 28, 2015 – Crescent: 2 wells shut in, 1 reducing volume 50 percent.
http://www.occeweb.com/News/Crescent%20wells.pdf

**** July 17, 2015 – Directive for 211 disposal wells in the Arbuckle to check depth. Must prove that that depth is not in communication with basement rock, or a plug back operation is completed to bring the bottom of the well at least 100 feet up into the Arbuckle.**
http://www.occeweb.com/News/DIRECTIVE-2.pdf

**** March 25, 2015 – Directive for 347 wells in the Arbuckle to check depth, etc.**
http://www.occeweb.com/News/2015/03-25-15%20Media%20Advisory%20-%20TL%20and%20related%20documents.pdf

**** To date, the July 17 and March 25 directives have resulted in 227 wells plugging back (i.e., reducing depth).**

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 4-E

Efforts to monitor and characterize the recent increasing seismicity in central Oklahoma

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Abstract

The sharp increase in seismicity over a broad region of central Oklahoma has raised concerns regarding the source of the activity and its potential hazard to local communities and energy-industry infrastructure. Efforts to monitor and characterize the earthquake sequences in central Oklahoma are reviewed. Since early 2010, numerous organizations have deployed temporary portable seismic stations in central Oklahoma to record the evolving seismicity. A multiple-event relocation method is applied to produce a catalog of central Oklahoma earthquakes from late 2009 into early 2015. Regional moment tensor (RMT) source parameters were determined for the largest and best-recorded earthquakes. Combining RMT results with relocated seismicity enabled determination of the length, depth, and style of faulting occurring on reactivated subsurface fault systems. It was found that the majority of earthquakes occur on near-vertical, optimally oriented (northeast-southwest and northwest-southeast) strike-slip faults in the shallow crystalline basement. In 2014, 17 earthquakes occurred with magnitudes of 4 or larger. It is suggested that these recently reactivated fault systems pose the greatest potential hazard to the region.

Introduction

It is well established that in 2009, the earthquake rate significantly increased throughout the central United States and that it is not an artifact of improved seismic-network monitoring capabilities (Ellsworth, 2013; Ellsworth et al., 2015). More than 50% of these earthquakes since 2009 have occurred in central Oklahoma, and in the past few years (2013–2015), earthquake rates have increased even more, thus raising concerns for potential hazard to local communities and energy-industry infrastructure in central Oklahoma (McNamara et al., 2015).

Here we review collaborative efforts by the United States Geological Survey (USGS), the Oklahoma Geological Survey (OGS), the University of Oklahoma (OU), Oklahoma State University (OSU), and the Incorporated Research Institutions in Seismology (IRIS) to monitor and characterize the evolving earthquake sequences in central Oklahoma. We describe ongoing seismic-station deployments, quantify the recent earthquake rate increase, compute detailed earthquake source parameters, and place constraints on the spatial distribution of reactivated fault zones (Figure 1). Based on characteristics of the November 2011 Prague, Oklahoma, M_W 5.6 earthquake sequence, we suggest that 12 separate recently reactivated fault systems pose the greatest potential hazard to the region (Figure 1). Results from this study are an update of McNamara et al. (2015) and can contribute to the assessment of earthquake hazard for the short-term "traffic-light" system implemented by the Oklahoma Corporation Commission (OCC) and the long-term USGS National Seismic Hazard Map (NSHM) (Petersen et al., 2014; Petersen et al., 2015; Ellsworth et al., 2015).

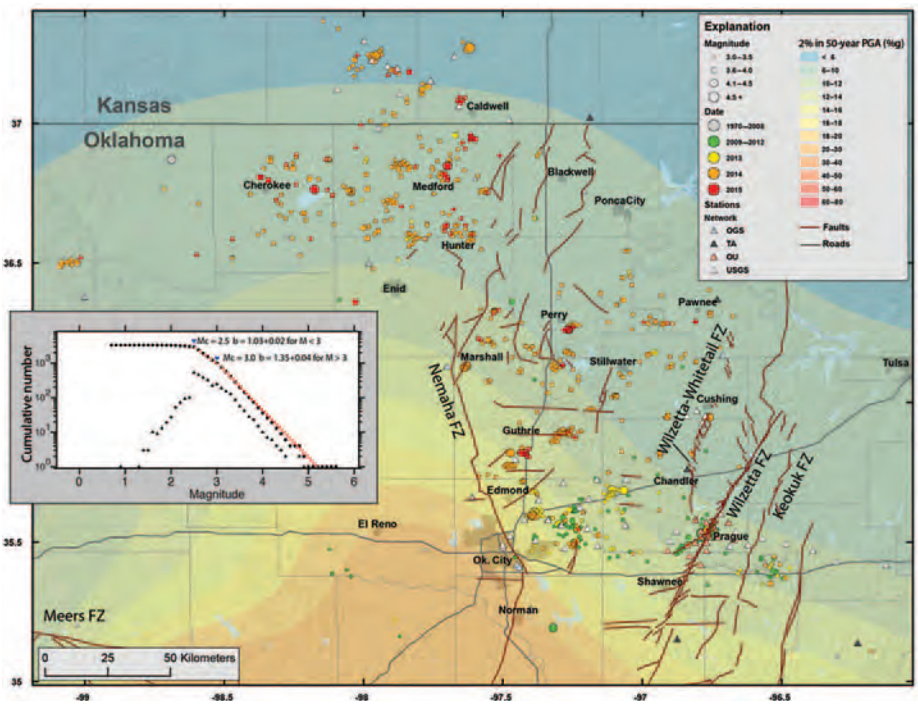

Figure 1. Map showing the original (M ≥ 3) USGS National Earthquake Information Center (NEIC) single-event epicenters from 1974 through February 2015, colored by year and sized by magnitude. Color contours represent peak ground acceleration (in percent g) with 2% probability of being exceeded in 50 years from the 2014 update of the USGS National Seismic Hazard Map (Petersen et al., 2014). Brown lines represent known subsurface faults from numerous sources (Miser, 1954; Bennison, 1964; Chenoweth, 1983; Joseph, 1987; Northcutt and Campbell, 1995; McBee, 2003). The inset panel shows the magnitude of completeness (M_c = 3) and *b*-value fit for the catalog from 1974 through 2015.

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[5]Department of Geosciences, Colorado State University.
[6]Global Seismological Services.
[7]Oklahoma Geological Survey.
http://dx.doi.org/10.1190/tle34060628.1.

Recent increase in Oklahoma seismicity

The recent increase in seismicity is illustrated best as the rate changes observed in cumulative seismic moment versus time (Figure 2), which show a steady increase in cumulative moment from 2009 to late 2011. In 2011, a sharp step in cumulative-moment release occurred because of the Prague sequence in November 2011, which includes an M_W 5.6 and three $M_W > 4$ earthquakes. After the Prague sequence, cumulative-moment release rose moderately until late 2013, when it began to rise sharply because of a significant increase in the number of higher-magnitude earthquakes over an expanded region of active seismicity (McNamara et al., 2015) (Figures 1 and 2). In 2014, 608 magnitude 3 and greater earthquakes occurred in central Oklahoma (more than in California), including 17 earthquakes with magnitudes of 4 or larger (a rate of 1.4/month). This year, 2015, shows no sign of decline in earthquake rate, with more than 200 M 3 and nine M 4 earthquakes by late March — a rate of three M 4 and larger earthquakes per month (Figure 2).

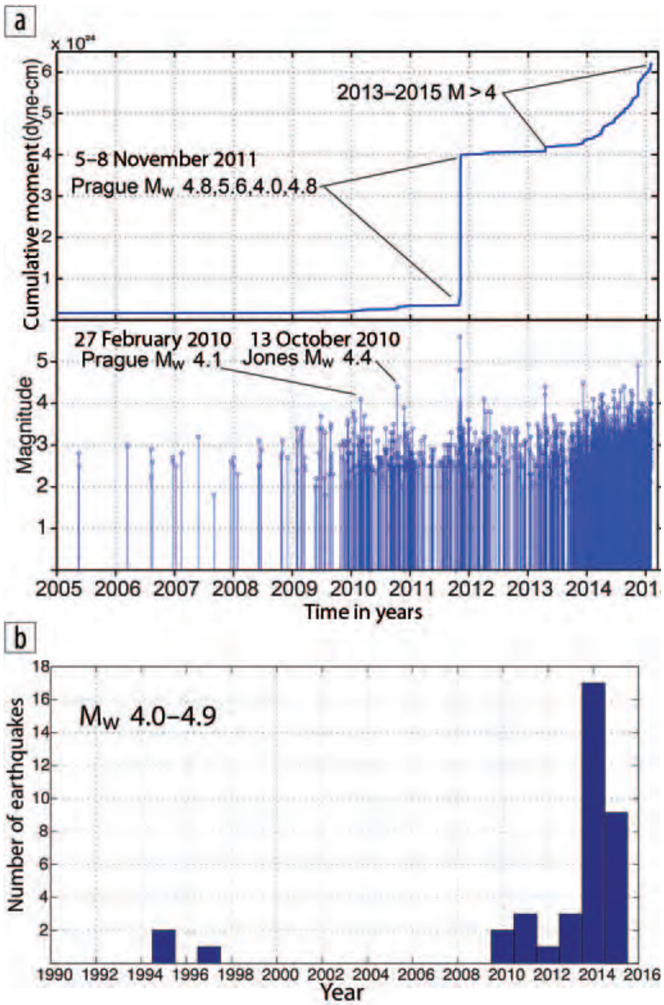

Figure 2. Central Oklahoma earthquake characteristics from the USGS COMCAT online system. (a) Earthquakes from the NEIC COMCAT system from 2005 through February 2015. Plot showing cumulative-moment release (top panel). Timeline showing earthquake magnitude versus time (bottom panel). (b) The number of magnitude 4 earthquakes per year from 1990 through 2015.

Rubinstein et al. (2014b) show that the earthquake rate change observed in the Raton Basin of Colorado and New Mexico is highly improbable for random fluctuations in a constant background. We applied the same methods to a declustered catalog of $M \geq 3.2$ earthquakes in central Oklahoma and southern Kansas (Figure 1) and found that for any individual year since the earthquake rates increased (i.e., 2009–2014), the rates observed in that year are highly improbable, given an earthquake catalog from 1974 through that year (probability maximum $P_{max} = 0.03$). The same test applied to 2007 and 2008 yields $P_{max} = 0.65$ for both years, indicating that given earlier seismicity, the rates observed during those years were likely. Using the previous year to predict the seismicity shows that the earthquake rates in 2009, 2013, and 2014 are highly improbable ($P_{max} = 0.03$, $P_{max} = 0.0007$, and $P_{max} = 0.00004$, respectively), indicating that earthquake rates increased significantly in those years. For 2010–2012, the rates observed were not improbable ($P_{max} = 0.28$, $P_{max} = 0.99$, and $P_{max} = 0.50$, respectively), indicating that the earthquake rate did not change significantly in those years relative to the previous year's rate. The observed earthquake-rate increase, combined with an increase in earthquake clustering in time (Llenos and Michael, 2013), indicates that a fundamental change in the earthquake-triggering process has occurred (McNamara et al., 2015).

Since settlement of the region, Oklahoma has had a well-documented history of felt earthquakes. Prior to the recent increase in seismicity, the largest events in central Oklahoma were two earthquakes in the range of magnitude 5 (10 September 1918 and 8 April 1952) (Von Hake, 1976; Luza and Lawson, 1982). Paleoseismology studies have identified the Meers fault as a Holocene thrust fault with a surface rupture and scarp in south-central Oklahoma and a history of earthquakes dating back more than 1100 years (Luza et al., 1987). In contrast, recent Oklahoma seismicity is well to the northeast of the Meers fault zone and is distributed over a much broader region of ancient reactivated structures associated with the Nemaha and Wilzetta fault zones (Figure 1).

The 2014 update of the USGS NSHM did not include most of the recent seismicity, and as a consequence, the highest predicted shaking in Oklahoma is well to the southwest and centered on earthquakes that occurred on the Meers fault zone (Figure 1). The recent earthquakes were not included because several studies have raised suspicion that they are induced because of anthropogenic activity (Holland, 2013; Keranen et al., 2013; Llenos and Michael, 2013), and therefore, long-term earthquake hazard in central Oklahoma is currently underestimated (Figure 1) (Petersen et al., 2014).

USGS earthquake monitoring and characterization efforts

A significant scientific issue for the USGS earthquake-hazard program is to consider how to incorporate the recent earthquakes in central Oklahoma into the calculation of the NSHM (Ellsworth et al., 2015; McGarr et al., 2015; McNamara et al., 2015; Petersen et al., 2015). The USGS National Earthquake Information Center (NEIC) is responsible for characterizing felt earthquakes in the United States and throughout the world. This characterization includes rapid determination of hypocenter location, magnitude estimation, moment tensors, fault-rupture modeling, and impact assessment (USGS Prompt Assessment of Global Earthquakes for

Response [PAGER]). In addition, earthquake source parameters determined by the USGS NEIC are used to determine long-term earthquake hazard throughout the United States (Petersen et al., 2014). The USGS is working on several fronts to understand better the mechanisms that drive the increase in earthquake rate and to estimate the changing earthquake hazard in Oklahoma (Hough, 2014; Keranen et al., 2014; Sumy et al., 2014; Sun and Hartzell, 2014; Ellsworth et al., 2015; McNamara et al., 2015; Petersen et al., 2015; H. M. Benz, R. McMahon, D. Aster, D. McNamara, and D. Harris, personal communication, 2015).

Oklahoma seismic-station deployments

Beginning in early 2010, the USGS, in cooperation with the Oklahoma Geological Survey, began to deploy temporary portable strong-motion seismic stations northeast of Oklahoma City to improve monitoring of the increasing seismicity and potentially to capture ground shaking from a large event (Figure 1). Immediately after the M_W 4.8 earthquake of 5 November 2011 in the Prague region, the University of Oklahoma rapidly installed three broadband seismograph stations near the epicenter of the earthquake. The stations were deployed in time to record the M_W 5.6 Prague earthquake on the following day (5 November 2011) (Keranen et al., 2013; McNamara et al., 2015). The unprecedented occurrence of two significant earthquakes in the area prompted the USGS and IRIS to assist OU and the OGS in the deployment of additional seismograph stations. Field teams from OU added an additional five seismograph stations within three days of the main shock, while IRIS completed the installation of 10 stations by 9 November 2011. In the same time frame, the USGS added three combined strong-motion/broadband stations in the epicentral area and 10 broadband stations in a pseudolinear array approximately 100 km long (Sumy et al., 2014).

Since the November 2011 Prague sequence, numerous additional stations have been deployed by OGS and the USGS to monitor the northwest migration of seismicity (Figure 1). In 2013–2014, the USGS-deployed stations in southern Kansas have contributed to improved earthquake-monitoring capability in northern Oklahoma (Rubinstein et al., 2014a). Complementing the portable deployments were temporary, regionally distributed stations in the Earthscope Transportable Array and permanent stations operated by the OGS seismic network (McNamara et al., 2015) and the USGS Advanced National Seismic System (ANSS) backbone network. The combined network of permanent and temporary seismic-station deployments provided high-quality waveforms in real time to the USGS NEIC for seismic-phase picks that are analyzed routinely in real time to determine detailed earthquake-source parameters that can be used to characterize regions of reactivated faulting in central Oklahoma (McNamara et al., 2015).

NEIC earthquake characterization

NEIC single-event hypocenter determination. Earthquake source characteristics (hypocenter location, depth, and magnitude) for most detectable earthquakes (M > 2.5) in the United States are computed routinely at the USGS NEIC and displayed online at http://earthquakes.usgs.gov. Initial earthquake locations were determined with a standard "single-event" approach using a stand-alone version of the main real-time processing and analysis system used by the USGS NEIC (Buland et al., 2009). This system allowed us to identify and locate individual earthquakes and to compute network-averaged regional magnitudes (e.g., M_L, mbLg, M_d) and M_W from RMT waveform modeling of earthquakes larger than approximately M 3.5.

A three-step approach was used for initial processing of the waveform data. First, all publicly available waveform data were loaded into an instance of the USGS NEIC operational processing system. Earthquake P-wave and S-wave phases were picked automatically and associated into common events, and source parameters (location, magnitude) were determined. Second, the automatic locations and magnitudes were reviewed manually to improve the seismic-phase arrival-time picks and to add new secondary phases as available. This primarily included first arriving S-waves that the automatic process did not identify. Finally, the continuous waveform data were reviewed visually to find small events that the automatic process missed. Seismic-phase traveltimes were computed using the AK135 1D global velocity model (Kennett et al., 1995). We did not locate all observed earthquakes — only those events for which there was a sufficient number of arrival-time observations and good azimuthal coverage to ensure a well-constrained hypocenter. Typically, smaller earthquakes were recorded on only a few stations, making it difficult to determine location and depth accurately. For regions in Oklahoma in which a dense network of seismic stations was available (Guthrie, Cushing, Prague), subspace detection was applied to lower the magnitude of completeness (H. M. Benz, R. McMahon, D. Aster, D. McNamara, and D. Harris, personal communication, 2015).

Hypocentroidal decomposition multiple-event relocation. After initial single-event earthquake locations and magnitudes were determined using the procedures described above, they were reanalyzed to refine further source locations using a multiple-event approach based on the hypocentroidal decomposition algorithm (HD) (Jordan and Sverdrup, 1981).

Hypocentroidal decomposition is a multiple-event procedure in the same class of methods that includes joint hypocentral determination (Dewey, 1972) and double difference (Waldhauser and Ellsworth, 2000). The HD relocation method provides improved hypocenter locations with minimized location bias and realistic estimates of location uncertainty for each earthquake (McNamara et al., 2015). When a dense network of local seismic stations is available (Prague, Guthrie, and Cushing), location uncertainty is reduced to < 1 km (McNamara et al., 2015). In other regions where only a few stations are located within 10 to 20 km (Cherokee, Stillwater, Medford, and Renfro), uncertainty is reduced to < 2 km (Figure 3). In addition, relocating earthquakes using HD can reduce by a factor of two the scatter in hypocenter locations determined using single-event methods (Figure 3). Another advantage of this method is the ability to relocate a poorly recorded main shock by tying it to clusters of aftershocks that often are recorded on a dense local network (McNamara et al., 2015). These advantages have motivated the USGS NEIC to implement multiple-event hypocenter location methods to improve hypocenter accuracy and uncertainty for earthquake sequences of interest to the nation.

Figure 3 shows the uncertainty ellipses of the epicenters and the direction and length of the changes in location relative to the final HD location for recent (2013–2014) seismicity near Guthrie and Langston, Oklahoma. Epicentral errors are reduced significantly relative to the original NEIC single-event location. Good constraints on older epicentral locations can be attributed directly to well-constrained locations of more recent earthquakes recorded at both the temporary and permanent stations in the area, which establish the traveltime corrections needed to relocate those events properly. In the Guthrie-Langston sequences, station density is not as high as in the other regions (Prague, Cushing, and Jones), so uncertainty ellipses are generally larger (> 1.0 km). Recent examples of HD applications and method details can be found in Hayes et al. (2013), Hayes et al. (2014), McNamara et al. (2014), Rubinstein et al. (2014b), and McNamara et al. (2015).

Regional moment tensors. Focal-mechanism solutions for U. S. earthquakes are computed routinely at the USGS NEIC for M > 3.5 earthquakes, using the RMT method described in Herrmann et al. (2011) (Figure 4). Successful waveform modeling of regional body and surface waves depends on selecting a frequency band in which the signal-to-noise ratio is high and filtered waveforms are relatively simple, which requires evaluation of the RMT modeling for each earthquake. With few exceptions, we find that most Oklahoma regional earthquakes that are well recorded regionally (generally with M > 3.5) can be modeled in the period band of 16 to 50 s. This period band is below the microseismic noise, with periods that are long enough to minimize effects from scattering but are short enough to improve depth estimates. Green's functions were computed using the western U. S. model of Herrmann et al. (2011), a model that fits the observed local and regional P-wave traveltimes and surface-wave amplitude and dispersion in the period band of 10 to 100 s for Oklahoma earthquakes. RMT calculations provide good estimates of the earthquake depth, magnitude, and faulting style (McNamara et al., 2015), allowing characterization of reactivated fault structures that pose the greatest hazard to the region.

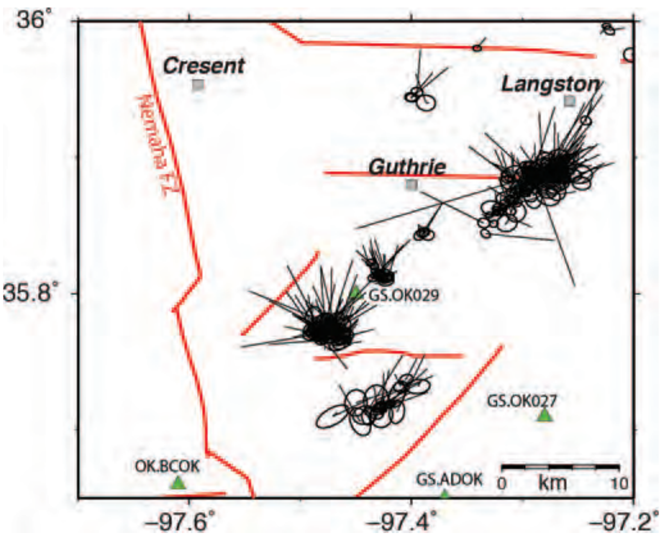

Figure 3. Uncertainty ellipses and location change vectors for earthquakes in the sequences near Guthrie and Langston, Oklahoma. Green triangles show portable seismometers deployed to monitor the seismicity in the region. Structures associated with the Nemaha fault zone are shown as red lines.

Reactivated structures pose a potential hazard to communities and infrastructure

The specific earthquake sequences observed in central Oklahoma in recent years do not behave with a typical main-shock–aftershock progression. Instead, they are swarmlike, similar to volcanic sequences, with large- and small-magnitude events interspersed in time, and most of the larger earthquakes are preceded by numerous moderate foreshocks. The November 2011 Prague, Oklahoma, sequence is a good example, with an equal number of magnitude 4 foreshocks and aftershocks.

Combined analysis of the spatial distribution of multi-event relocated seismicity and RMT focal-mechanism nodal planes allows us to place constraints on the location, orientation, and style of reactivated fault structures. The majority of the recent earthquakes in central Oklahoma occur along reactivated ancient subsurface faults at shallow depths in the crust (< 6 km); these faults cut through the Cambro-Ordovician Arbuckle Group and extend down into the crystalline basement (McNamara et al., 2015). In some cases, earthquake sequences are associated clearly with known fault systems. In most cases, the earthquake sequences occur away from known faults but align within a similar fabric. Figure 4 shows subsurface faults inferred from the combined analysis of the spatial distribution of seismicity and focal-mechanism nodal planes as dashed black lines; however, for clarity, only RMT focal mechanisms for earthquakes with $M_W \geq 4$ are mapped.

The RMT focal mechanisms determined in central Oklahoma are predominantly strike-slip, with one nodal plane oriented northeast to southwest and the other oriented northwest to southeast (McNamara et al., 2015) (Figure 4). A small number of RMTs, in the Prague and Cushing sequences, have nodal planes that strike east-west and north-south. The three dominant RMT nodal-plane orientations are aligned approximately with the known subsurface fault fabric identified in numerous geologic maps and reports (Miser, 1954; Bennison, 1964; Chenoweth, 1983; Joseph, 1987; Northcutt and Campbell, 1995; McBee, 2003). Most RMT nodal planes are oriented optimally relative to the approximately east-west maximum horizontal compression direction for reactivating earthquake activity on ancient faults (Holland, 2013; Alt and Zoback, 2014; McNamara et al., 2015).

Since the earthquake rate increase in 2009 to early 2015, there has been a clear southeast-to-northwest migration of the seismically active regions (Figure 1), 12 of which have produced earthquakes with magnitudes greater than 4 (Figure 4). Based on characteristics of the November 2011 Prague M_W 5.6 earthquake sequence (Keranen et al., 2013; McNamara et al., 2015) and the circumstances detailed below, we suggest that recently reactivated fault systems with earthquakes greater than magnitude 4 pose the greatest potential hazard to communities and infrastructure in the region.

Earthquake sequences in south-central Oklahoma along the Nemaha and Wilzetta fault zones

South-central Oklahoma is the most populated region of the state, with more than one million inhabitants in the Oklahoma City metropolitan area. It is also the location of significant energy-industry and national strategic infrastructure such as the

Cushing crude-oil storage facility. Earthquake sequences in this region are associated with the Nemaha and Wilzetta fault zones that bound a broad region of uplift originally formed as a result of the Ancestral Rocky Mountains Orogeny during the Pennsylvanian period (Figure 4a) (Luza and Lawson, 1982; Joseph, 1987). The uplifted region is a complex belt of ancient, buried high-angle faults that hosts reservoirs of oil and gas (Dolton and Finn, 1989; McNamara et al., 2015). Most recent earthquake sequences occurred on reactivated conjugate strike-slip structures that are structurally similar to reactivated faults that produced the 2011 Prague, Oklahoma, M_W 5.6 earthquake sequence.

November 2011 Prague earthquake sequence. The M_W 5.6 Prague earthquake of 6 November 2011 was the largest earthquake in Oklahoma's recorded history. It was felt widely in the neighboring states of Texas, Arkansas, Kansas, and Missouri and as far away as Tennessee and Wisconsin. The M_W 5.6 earthquake was preceded by many foreshocks, including an M_W 4.0 in February 2010 and an M_W 4.8 earthquake the previous day (5 November 2011). The sequence also included two $M \geq 4.0$ aftershocks (M_W 4.0 on 6 November 2011 and M_W 4.8 on 8 November 2011). The USGS PAGER system (U. S. Geological Survey, 2011) estimated that more than 3000 people in an area of approximately 65 km^2 in the immediate vicinity of the M_W 5.6 epicenter experienced severe shaking of intensity levels MMI VIII = 34% to 65% g.

Shaking in the epicentral region was significantly stronger than peak acceleration shaking levels predicted in the 2014 USGS NSHM when suspected induced earthquakes were not included in the model (2% probability of exceedance in 50 years = 10% to 12% g, MMI V–VI) (Petersen et al., 2014) (Figure 1) and more consistent with shaking levels when all earthquakes are included (0.04% probability of exceedance in one year = 50% to 200% g MMI VIII–X) (Petersen et al., 2015; Ellsworth et al., this issue). This shaking destroyed six houses, 20 homes sustained major damage (averaging \$80,000 per home for repairs), and 38 homes had minor damage (estimated repair costs of \$13,000 per home) (Branstetter and Killman, 2015). Fortunately, the earthquake sequence occurred in a relatively sparsely populated region of central Oklahoma, and widespread damage was avoided. However, several residents are pursuing

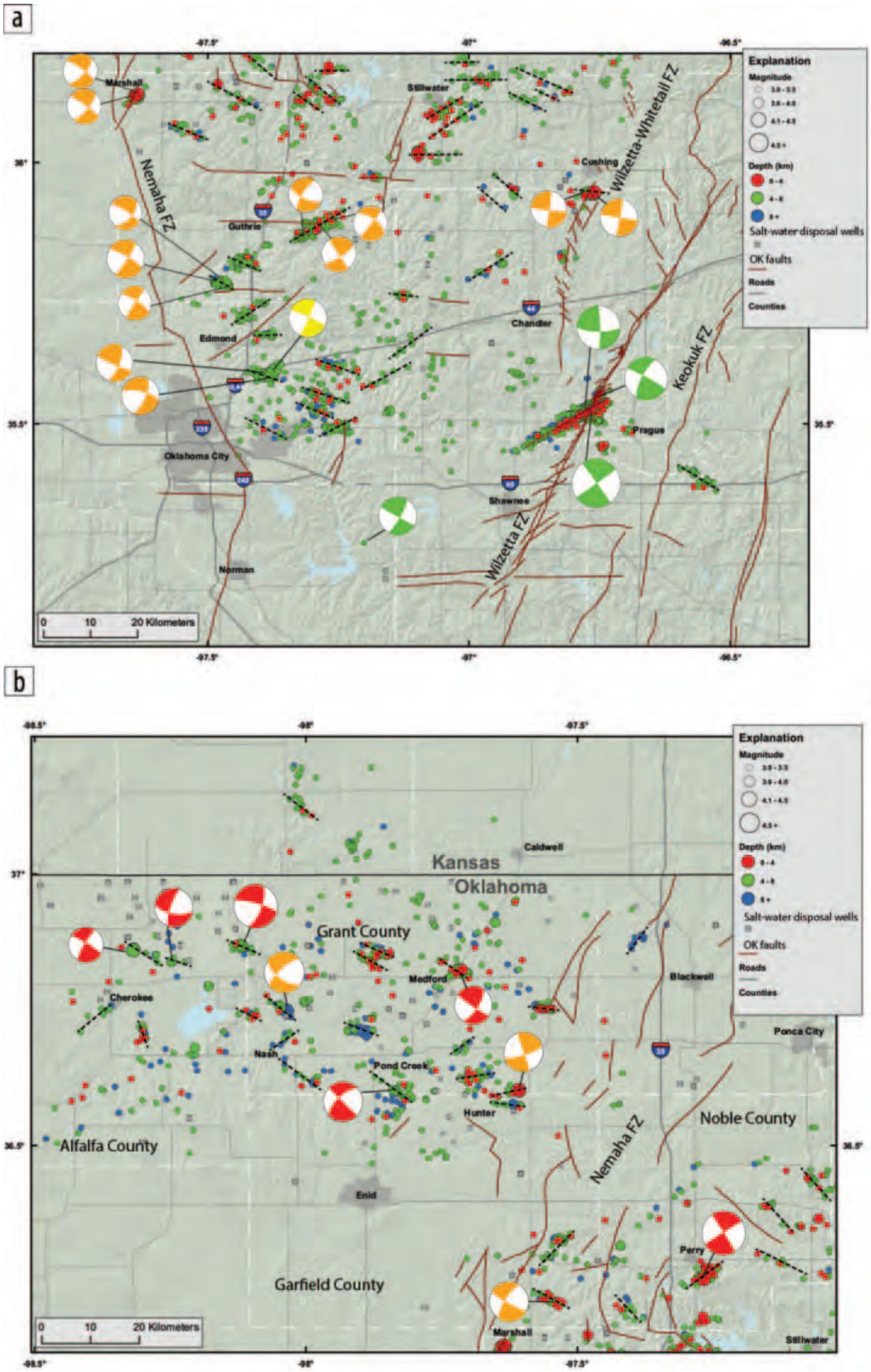

Figure 4. Central Oklahoma regional maps. Earthquakes relocated by hypocentroidal decomposition (HD) are shown as circles colored by depth and sized by magnitude. Also shown are known subsurface faults (solid brown lines), inferred faults (dashed black lines), and injection wells (gray squares). Subsurface faults are inferred from the combined analysis of the spatial distribution of seismicity and focal mechanism nodal planes. Also shown are RMT focal mechanisms for earthquakes with $M_W \geq 4$. Regional moment tensors are colored by year (green occurred in 2012–2013, yellow in 2013, orange in 2014, and red in 2015). (a) South-central Oklahoma, including the Oklahoma City metropolitan area and the Nemaha-Wilzetta uplift region. (b) Northwest-central Oklahoma region, including Alfalfa and Grant counties.

reimbursement through the Oklahoma state court system for damage to their homes (Wertz, 2015).

The sequence of earthquakes occurred at a complex intersection of conjugate strike-slip faults within the Wilzetta fault zone (Figure 4a) (McNamara et al., 2015). This intersection of reactivated fault segments within the Wilzetta fault zone includes a relatively long main branch (approximately 20 km), along with several shorter conjugate structures (2 to 4 km). The RMT analysis for the M_W 4.8 foreshock and M_W 5.6 main shock defines a near-vertical northeast-striking nodal plane with right-lateral strike-slip mechanism that aligns with trends in the relocated seismicity (Figure 4a). The 8 November 2011 M_W 4.8 aftershock also has a near-vertical strike-slip mechanism but is left lateral with an east-west-this striking nodal plane that aligns with an approximately 5-km splay of aftershock seismicity. The seismicity and focal mechanisms combined indicate activity on conjugate strike-slip faults, likely activated in response to the stress changes from the cascading sequence of earthquakes (Sumy et al., 2014; McNamara et al., 2015).

Elevated hazard for Oklahoma City. Beginning in 2010 and continuing to the time of writing (late February 2015), earthquake rates have shown a significant increase in the region northeast of Oklahoma City. The HD relocation hypocenters define several discrete sequences with linear trends consistent with the general fabric of known faults within the Nemaha and Wilzetta fault zones (Figure 4a). Most relocated earthquake depths (3 to 8 km) are within the Arbuckle disposal formation and in the deeper basement structures (McNamara et al., 2015).

Of particular concern for residents of Oklahoma City are active earthquake sequences associated with long fault structures that might be capable of supporting large earthquakes (M 5 to 6). Examples include the approximately 12-km-long sequence east of Guthrie (Figure 4a), the sequence south of Marshall along a reactivated segment of the Nemaha fault zone, and smaller sequences throughout the region that might be connected at depth to optimally oriented splays of the Nemaha fault zone (McNamara et al., 2015) (Figure 4a). As defined by the recent seismicity, the uplifted region between the Nemaha and Wilzetta fault zones hosts numerous previously unknown associated subfaults which, if connected at depth to the main branch of the Nemaha fault zone, could cause a cascade of earthquakes in the same manner as the Prague sequence in November 2011 (Sumy et al., 2014). An earthquake of similar magnitude to the Prague M_W 5.6 would produce severe shaking in a broad region around the epicenter (MMI VIII) and would pose significant hazard to the higher-population-density region of the Oklahoma City metropolitan area.

October 2014 Cushing earthquake sequence: Elevated hazard for national strategic infrastructure. In October 2014, two moderate-sized earthquakes (M_W 4.0 and 4.3) struck immediately south of Cushing, Oklahoma, 5 km beneath the site of the largest crude-oil storage facility in the conterminous United States and a major hub of the U. S. oil-and-gas pipeline transportation system (Pipeline and Hazardous Materials Safety Administration, 2015). The earthquakes occurred on an unnamed left-lateral strike-slip fault that intersects with other recently reactivated segments of the right-lateral Wilzetta-Whitetail fault zone (Bennison, 1964; McBee, 2003) (Figure 4a). Minor damage was reported throughout Cushing, including cracked plaster, broken window glass, and items thrown from shelves.

Shortly after the 7 October 2014 Cushing M_W 4.0 event, the OCC halted injection operations at three wells within a six-mile radius around the main-shock epicenter. This was the first implementation of the OCC's traffic-light system since its inception in late 2013. Inspectors found that the Wildhorse wastewater-disposal well was injecting into the basement below the disposal formation (Arbuckle) which, because of the likely presence of subsurface faults, can increase greatly the potential for inducing earthquakes (Zoback, 2012; Ellsworth, 2013). The OCC ordered the Wildhorse disposal well to halt operations and plug with cement back up to the depth of the Arbuckle Formation. Two additional wells in the vicinity (Calyx, Wilson) also experienced short periods of halted operations after the largest earthquakes in the Cushing sequence. Once injection operations resumed, two days after shutdown and plug-in, the sequence drastically died off, with no recorded earthquakes since late November 2014. With the plummeting price of crude oil, the Cushing storage facility was expected to approach peak capacity (80 million barrels) by April 2015 (Wilmoth, 2015), exposing critical resources and infrastructure to elevated earthquake hazard. The OCC implementation of the traffic-light system has been a success so far in this case for mitigating potential damage to the Cushing facility and possibly avoiding an environmental disaster for the residents of nearby Cushing and costly cleanup for the energy industry.

Recent seismicity in northwest-central Oklahoma. Northwestern central Oklahoma has experienced the most recent seismicity as a result of northwest migration of active earthquake sequences (Figures 1 and 4b). The recent earthquakes are dispersed over several northern Oklahoma counties (Alfalfa, Grant, Garfield, and Noble), with sequences of the most potential hazard ($M_W \geq 4$) located near the towns of Perry, Medford, and Cherokee (Figure 4b). In 2013, Alfalfa County had only three earthquakes with a maximum M_W of 2.8, whereas Grant County to the east experienced approximately 35, with a maximum magnitude of M_W 3.6. In 2014, as wastewater injection increased to some of the highest levels in the state (Soraghan, 2015), the frequency and magnitude of local earthquakes greatly increased, introducing the first M > 4.0 earthquakes to these northern counties (M_W 4.0 and M_W 4.3 in Grant County) (Figure 4b).

This trend continued into February 2015, with 48 earthquakes in Alfalfa County and 85 in Grant County since the beginning of the year. Grant County has already experienced three earthquakes of at least M_W 4.0, as has Alfalfa County, each within 20 km of Cherokee and operational wastewater-disposal wells. The most recent of these larger events occurred within six days of each other, 30 January and 5 February 2015, within 10 km of Cherokee. After the M_W 4.0 on 30 January 2015, injection operations at the SandRidge Energy Miguel well were halted. This marks the second implementation of the OCC traffic-light system. Less than a week after this decision was made, a second large earthquake occurred (M_W 4.2), less than 8 km from the first, with multiple smaller accompanying aftershocks.

Similar to the active earthquake sequences near Oklahoma City, RMT nodal planes align with trends in the relocated seismicity and define a series of near-vertical reactivated strike-slip faults. The reactivated structures are a mix of northwest-to-southeast-striking left-lateral and northeast-to-southwest-striking right-lateral strike-slip faults that generally align with the regional fabric of the Nemaha fault zone (Figure 4a). Earthquake sequences near Perry and Marshall clearly are associated with the Nemaha fault zone. In contrast, earthquake sequences farther to the west near Medford and Cherokee (McNamara et al., 2015) occur away from known faults but align within a similar general fabric observed throughout central Oklahoma. The combined analysis of RMTs and relocated earthquake sequences enables the characterization of these previously unknown and unmapped fault structures that pose elevated hazard to communities and infrastructure in the region.

Conclusions

Traditionally, it has been difficult to develop spatial correlations between earthquakes and specific faults in the central United States. This has resulted primarily from low seismicity rates and few well-constrained earthquake locations and moment-tensor solutions. The combination of the recent increased earthquake rate and good seismic-station coverage over a broad region of central Oklahoma allowed us to build a catalog of calibrated earthquake hypocenters and regional moment-tensor solutions. Combining RMT results with relocated seismicity enabled us to determine the length, depth, and style of faulting occurring on reactivated subsurface fault systems.

Using the catalog of earthquake-source parameters determined in this study, we delineate numerous reactivated subsurface faults throughout central Oklahoma and are working to provide guidance on which faults pose the highest hazard. The majority of the reactivated faults in the region is oriented favorably for earthquake rupture relative to the regional compressive- stress field. Earthquakes are shallow and are constrained primarily to the upper portion of the crystalline basement (a depth of less than 6 km), with some seismicity reaching into the overlying sedimentary bedrock. Many of the earthquakes relocated in this study coalesce from diffuse and scattered locations into discontinuous sequences with fault lengths of 1 to 12 km. Most of these discontinuous sequences are aligned consistently with the general fabric of the Nemaha and Wilzetta fault zones, but we are uncertain whether there are longer fault structures that tie these independent clusters together. Many earthquake sequences are associated directly with well-known structures of the Nemaha and Wilzetta fault zones. However, most earthquakes occur in the broad region of uplift and are not associated with known fault zones.

Recently, the Oklahoma Geological Society and the Oklahoma Corporation Commission have been collaborating on building an enhanced fault database for Oklahoma. This type of product will be valuable for understanding the faulting process and will help with mitigation efforts. Access to proprietary well and reflection data also could aid in understanding the relationship between recent seismicity and reactivated fault zones. In addition, new OCC regulations for reporting and monitoring of wastewater disposal wells will help to improve our understanding of the earthquake process. These are necessary first-order observations required to assess the potential hazards of individual faults in Oklahoma. Results from this study are important parameters required to assess both short-term (traffic-light) and long-term (NSHM) earthquake hazard. We suggest that the increased rate and occurrence of earthquakes near optimally oriented and long fault structures has raised the earthquake hazard in central Oklahoma and has increased the probability for a damaging earthquake. TLE

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Oil Conservation Division
Energy, Minerals and Natural Resources Department
State of New Mexico

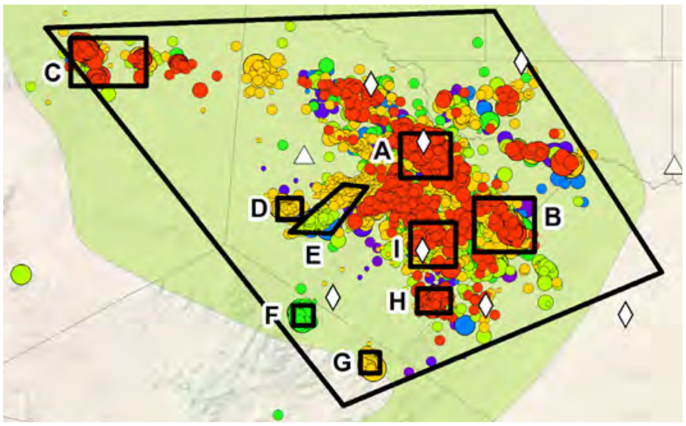
CASES NO. 20313, 20314, 20472, 20463 and 20465
Index of Division Exhibit No. 5

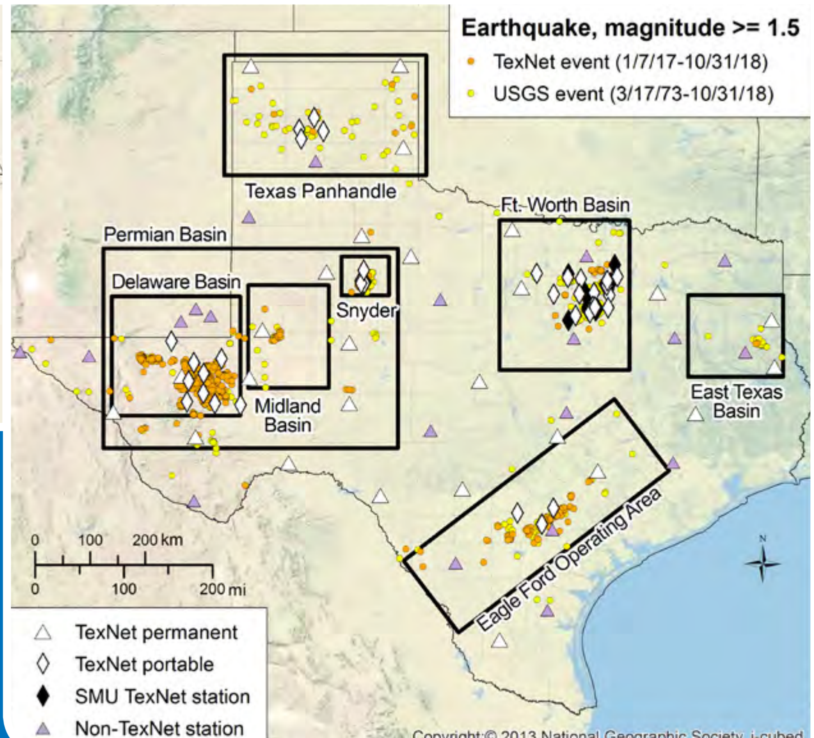
Exhibit No.	Exhibit Name
5-A	Rathje, E., Hennings, P., Savvaidis, A., and Young, M., 2018, 2018 Biennial report on seismic monitoring and research in Texas; TexNet and the Bureau of Economic Geology, University of Texas at Austin, 26 p.
5-B	Railroad Commission of Texas, 2019, Attachments for new injection/disposal wells; Commission website guidance for application content for injection permit.
5-C	Center for Integrated Seismicity Research (CISR), 2019, Summary list of research projects; TexNet and the Bureau of Economic Geology, University of Texas at Austin.
5-D	Hornbach, M., *et.al.*, 2016, Ellenburger wastewater injection and seismicity in North Texas; Physics of the Earth and Planetary Interiors, vol. 261, p. 54-68.
5-E	U. S. Environmental Protection Agency, 2016, Fiscal Year 2015 - EPA Region 6 End-of-Year Evaluation, Railroad Commission of Texas, Underground Injection Control Program; USEPA correspondence dated August 15, 2016 to the Director, Oil and Gas Division; 61 p.

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 5-A

2018 Biennial Report on Seismic Monitoring and Research in Texas

November 28, 2018





The University of Texas at Austin
Bureau of Economic Geology
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TexNet | Bureau of Economic Geology

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Executive Summary

In 2008, the rate of seismicity began to significantly increase across the southern Midcontinent of the United States, including parts of Texas. This increase led to the 2016 creation of the Texas Seismic Monitoring Program (TexNet) at the Bureau of Economic Geology (Bureau), The University of Texas at Austin (UT Austin), with a $4.471 million appropriation from the State of Texas. For the 2018–19 biennium, $3.4 million of funding was made available to TexNet. With these funds, TexNet completed the deployment of the network, operated the network to detect and locate earthquakes, and performed research to better understand seismicity in Texas. The following list represents key points from the work performed by TexNet over the last 2 years and summarized in this report:

- Texas now has a state-of-the art seismic network with a consistent ability to monitor earthquakes statewide. We can detect earthquakes across Texas below the felt level and locate these events with improved accuracy. A continuously updated, publicly available catalog of seismicity across the state is available at **http://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog**, providing near real-time earthquake information to all Texas residents.

- Increased seismicity began before the installation of the TexNet seismic network, with the seismicity ramping up in key areas around 2008–9.

- Most of the state is not experiencing earthquakes, but seismic activity *is* occurring in four main areas: the Delaware Basin in West Texas, Dallas–Fort Worth area, Eagle Ford Shale area of South Texas, and Cogdell Field near Snyder. Additionally, on October 20, 2018, a magnitude 4.4 (M 4.4) event occurred in the Panhandle near Amarillo. Although seismic activity has been recorded, almost all earthquakes are below the level commonly felt by people. No damage to date has been reported in these areas (to our knowledge), and currently the risk is deemed to be low to moderate.

- Ongoing research by TexNet is dedicated to understanding the causes of earthquakes in Texas, identifying mitigation strategies, and evaluating the potential seismic risk to, or impact on, Texans. Research takes advantage of state resources at UT Austin, Texas A&M University (TAMU), Southern Methodist University (SMU), The University of Texas at El Paso (UTEP), The University of Texas at Dallas (UT Dallas), and the University of Houston.

- TexNet leadership meets regularly with the TexNet Technical Advisory Committee and the Railroad Commission of Texas to discuss data collection and research outcomes, both of which are important for regulatory decision making. Leadership also meets with various stakeholder groups, including city councils, citizen groups, and oil and gas operators.

- Of the $3.4 million allocated for operation and maintenance of TexNet and associated research activities, approximately 45 percent has been spent through August 31, 2018. We anticipate full spend-out for both TexNet Operations and TexNet Research by the end of the 2019 fiscal year.

Recommendations: TexNet and its associated research program provide improved monitoring of seismicity across the State of Texas and enable research that advances our understanding of seismicity in Texas. This work provides a basis for assessing earthquake hazards, minimizing earthquake activity associated with human activities, and reducing the impact of possible future earthquakes on the people and infrastructure of Texas. It is critical to fund TexNet on an ongoing basis and as a stand-alone item in the state budget. **Continued funding of $3.4 million for the 2020–21 legislative cycle will allow the State of Texas to maximize its current investment in the earthquake monitoring network and extend our understanding of earthquake risk in the state.**

Table of Contents

1.0 Introduction

Summary: The main goals of TexNet are to provide high-quality earthquake data and to perform research to understand the causes of earthquakes in Texas. As of August 2018, TexNet has deployed 58 new seismic stations across the state. From January 2017 through October 2018, a total of 4,638 earthquakes have been reported by TexNet, with the vast majority (97 percent) being smaller than M 2.5, the magnitude above which events are typically felt by people. TexNet collaborates broadly with entities statewide and nationally to maintain a state-of-the art seismic network and ensure high-quality research.

1.1 Overview of TexNet Seismic Monitoring and Research

The goal of TexNet is to provide high-quality data and information to evaluate the location, frequency, and likely causes of earthquakes in Texas. As of August 2018, TexNet has deployed a total of 58 new seismic stations (25 permanent, 33 portable) across the State of Texas. These stations, along with 18 existing stations, form an evenly spaced, backbone seismic network across the state that allows for the accurate detection of earthquakes. The 33 portable stations have been specifically deployed across four areas of the state that have recently experienced clustered seismicity and represent regions of high socioeconomic importance. A data management system is used to detect, analyze, and locate earthquake events. A continuously updated, publicly available catalog of seismicity across the state is available at **http://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog**.

The research being conducted with TexNet funding is focused on understanding the potential causes of these earthquakes, including the potential relationship with subsurface industrial activity such as the injection of fluids. The TexNet seismic network, the foundational component of this research program (Figure 1.1),

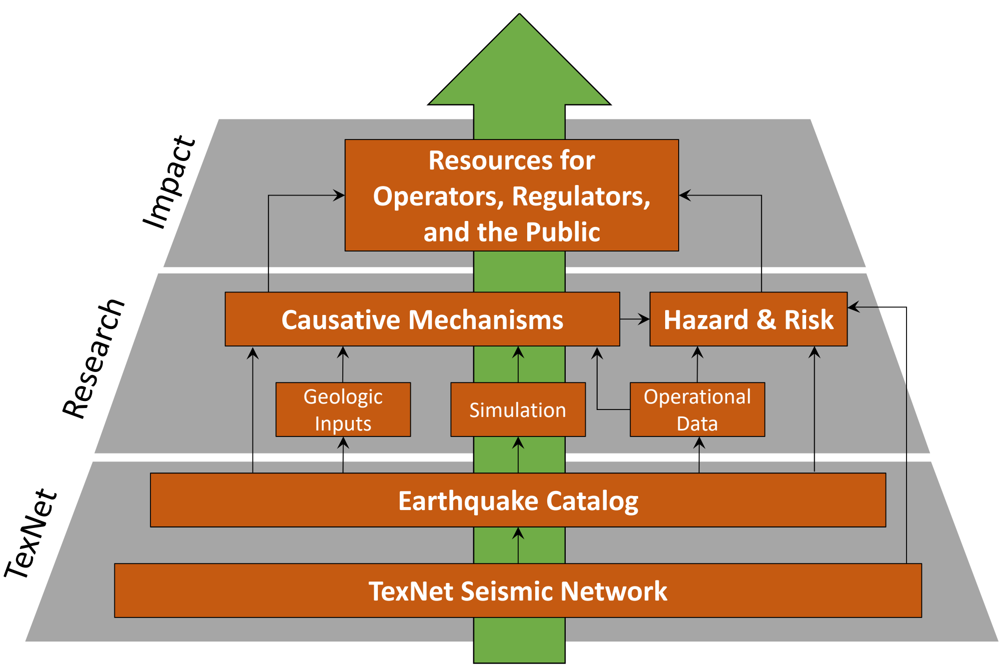

Figure 1.1 Integration of TexNet seismic network and TexNet research.

records ground shaking from earthquakes, which allows for the determination of the location and size of the earthquakes. The resulting catalog of earthquake locations/sizes is used throughout the research program. Integrating geologic inputs, coupled geomechanical/reservoir modeling, and operational data from oil/gas activities with the earthquake catalog allows for research related to the potential causative mechanisms of earthquakes in Texas. The research on causative mechanisms is integrated with operational data and earthquake data to better quantify seismic hazard and risk to the people and infrastructure of Texas. Together, the various research components provide resources and knowledge used by operators, regulators, and the general public to minimize the impact of earthquakes in Texas. The goals of the TexNet seismic network and associated research program have been endorsed by the Academy of Medicine, Engineering and Science of Texas in their Shale Development Report (TAMEST, 2017).

TexNet was established and funded in Section 16 of House Bill 2 (HB2) of the 84th Texas Legislature (2016–17). This legislation provided $4,471,800 over the 2016–17 biennium to the UT Austin Bureau of Economic Geology to establish and operate the TexNet seismic monitoring network, to perform research related to the modeling of reservoir behavior for wells in the vicinity of faults, and to establish a Technical Advisory Committee (TAC). During the 85th Texas Legislature (2018–19), House Bill 2819 (HB2819) revised the makeup of the TexNet Advisory Committee and described the committee's role in overseeing the operation of the TexNet seismic monitoring network and associated research related to seismicity in Texas. However, no funds were directly appropriated to the Bureau in 2018–19 for continued operation of the TexNet seismic network or to support the associated research program. Rather, $3.4 million of funding was made available to TexNet by the Office of the President of UT Austin via the "hold harmless" funding provided to the university by the 85th Legislature.

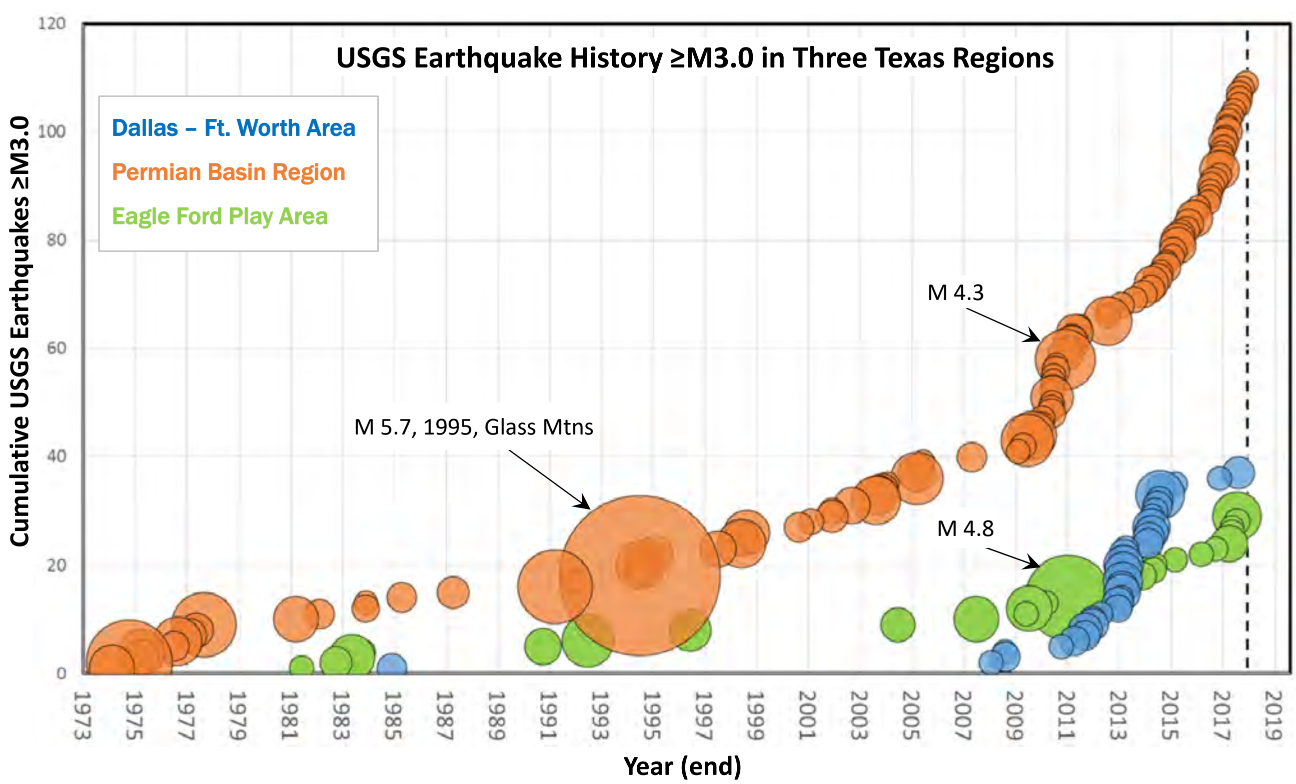

Figure 1.2 Cumulative seismicity for M ≥ 3.0 in the Dallas–Fort Worth area, Permian Basin region, and Eagle Ford area since 1973. Data from USGS/ANSS ComCat. Size of symbols correlates to recorded magnitude of event. The 1995 "Glass Mtns" event depicted in figure was a natural event occurring near Alpine, Texas.

1.2 Overview of Seismicity in Texas

A clear increase in the rate of recorded seismicity in Texas was observed beginning around 2008 (Frohlich et al., 2016). Prior to that time, an average of one to two earthquakes per year of M ≥ 3.0 were recorded. Since 2008, the rate has increased to approximately 15 events per year, on average.

Figure 1.2 shows the cumulative number of earthquakes greater than M 3.0 recorded in three specific areas of Texas (Dallas–Fort Worth, Permian Basin, and Eagle Ford play) from 1973 to 2018, as reported in the USGS Advanced National Seismic System (USGS/ANSS) Comprehensive Catalog (ComCat). Based on the data shown in Figure 1.2, seismicity rates started to increase in the Dallas–Fort Worth area around 2008, in the Permian Basin area around 2010, and in the Eagle Ford play area around 2017. The increase in seismicity in the Dallas–Fort Worth area is what initiated the creation of TexNet.

TexNet became operational in January 2017. The earthquakes detected by TexNet (Figure 1.3) are mainly clustered around four areas: the Fort Worth Basin, the Delaware Basin in West Texas, the Eagle Ford area,

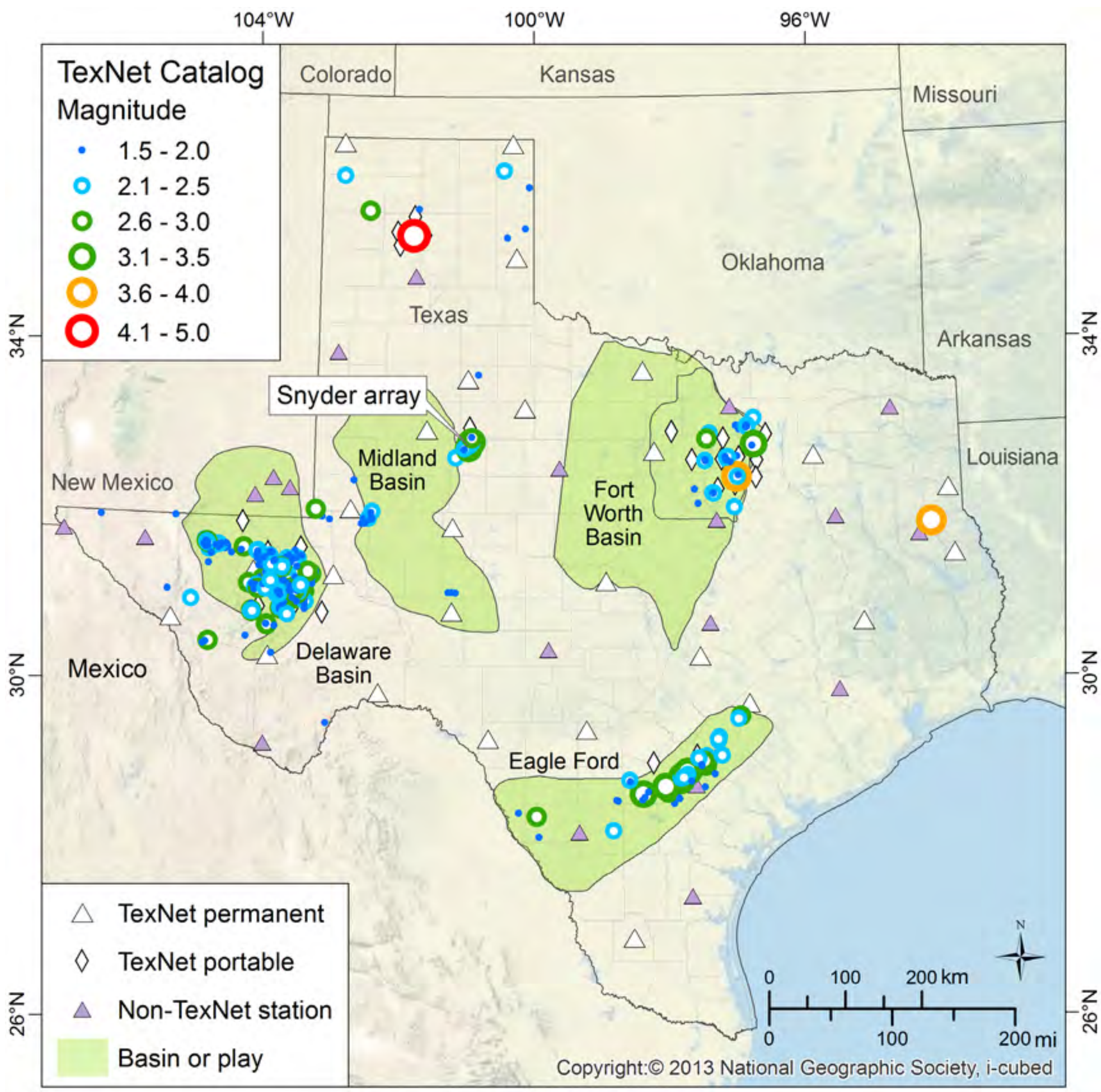

Figure 1.3 Earthquakes larger than M 1.5 recorded by TexNet between January 2017 and September 2018. Deployed TexNet permanent and portable seismic stations as of September 2018 are shown.

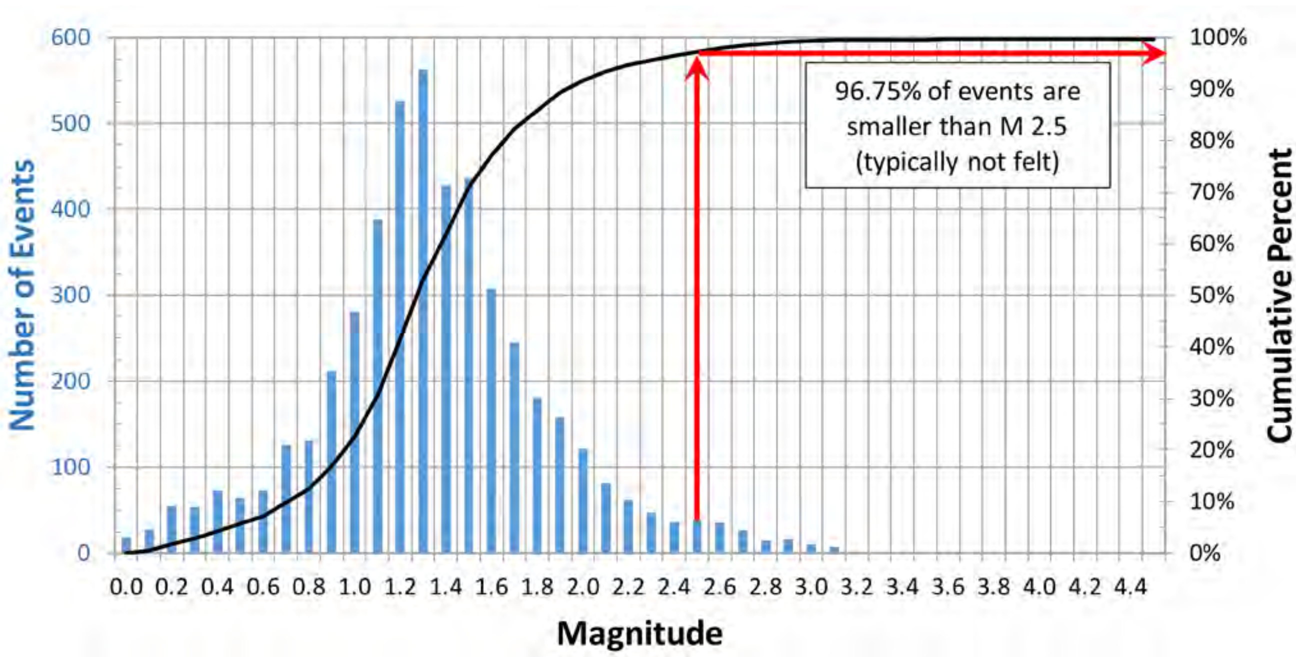

Figure 1.4 Magnitude distribution of earthquakes publicly available from TexNet.

and Cogdell Field near Snyder. The Delaware Basin has generated the largest number of earthquakes. The largest event, however, was an M 4.4 earthquake that occurred on October 20, 2018, near Amarillo—outside of the main areas of clustered seismicity.

From January 2017 through October 2018, a total of 4,638 earthquakes were reported through TexNet, with 1,835 events above M 1.5 and 148 events above M 2.5. These values are consistent with the understanding that the number of earthquakes generally increases about 10 times as the magnitude decreases by one unit. The magnitude distribution of the events publicly available from TexNet is shown in Figure 1.4. As expected, there are considerably more small earthquakes than large earthquakes; the vast majority (97 percent) are smaller than M 2.5, the magnitude above which events are typically felt by people.

1.3 TexNet Collaborations

TexNet is currently collaborating with SMU to support the operation of their network. In return, TexNet has real-time access to SMU data and uses it in earthquake detection and location. Similarly, TexNet has, at no cost, access to data from monitoring networks in neighboring states (e.g., Oklahoma and New Mexico) for use in earthquake detection/location. Data sharing occurs through the Data Management Center at the Incorporated Research Institute for Seismology (IRIS).

TexNet is also collaborating with specific groups across the state and nationally on seismology research to investigate seismicity in different parts of Texas. TexNet works with SMU to study the Dallas–Fort Worth area, the University of Houston to study the Midland Basin, UTEP to study the Delaware Basin, and the UT Austin Institute for Geophysics (UTIG) to study the Eagle Ford area. In addition, TexNet collaborates with TAMU, the Southwest Research Institute (SWRI), and Golder Associates on geomechanical analysis and reservoir modeling in the Fort Worth Basin. These collaborations are all supported by the TexNet research budget.

Research on seismicity is also funded through the Bureau's Center for Integrated Seismicity Research (CISR), which is sponsored by oil and gas operators in Texas who are keen to understand the causes of seismicity in

Texas and the steps that can be taken for mitigation. CISR funding broadens and deepens TexNet research, and improves earthquake monitoring in the border areas adjacent to neighboring states by collecting data for locating earthquakes in Texas. These sponsors interface with Bureau researchers and their collaborators through the CISR Science Advisory Committee, which meets quarterly for updates and annually for a comprehensive review. Sponsors provide access to proprietary data and collaborate on research, as appropriate, further boosting the comprehensive research program.

Various collaborations take place between TexNet and other entities that do not entail funding through TexNet. For example, TexNet collaborates with the Stanford Center for Induced and Triggered Seismicity to characterize the seismicity potential of subsurface faults in the Fort Worth Basin. TexNet also collaborates with the USGS on seismicity analyses and generation of different seismic-related products, such as ShakeMaps. TexNet leadership meets regularly with the Railroad Commission of Texas to discuss data collection and research outcomes, both of which are important for regulatory decision making. Leadership also meets with various stakeholder groups, including city councils, citizen groups, and oil and gas operators, to educate this broad constituency on earthquakes and their implications for Texas.

Finally, TexNet collaborates with the states of Oklahoma, Kansas, New Mexico, and Arkansas—in cooperation with the U.S. Department of Energy and the Ground Water Protection Council—through the recently created Regional Induced Seismicity Collaborative (RISC). RISC focuses on facilitating research already being conducted by these states by creating more effective pathways to move information and insights between the research groups, to the states' regulatory communities, and to the public.

2.0 TexNet Budget and Ongoing Cost

Summary: The FY 2018–19 TexNet budget included $1.4 million to operate the seismic network and $2.0 million to support research. Operation costs support the deployment and maintenance of the network, as well as the detection and reporting of earthquakes. Research includes projects that improve understanding of the causes of earthquakes in Texas and their potential effect on the people and infrastructure of the state. For the FY 2020–21 biennium, we request funding of $3.4 million to continue network operations and TexNet research, building on the existing infrastructure investment and supporting the mitigation of earthquake effects on the citizens of Texas.

2.1 Budget and Spending for TexNet Operations

TexNet operations (Project 1) include deployment and maintenance of sensors; telecommunications; operation of TexNet Hub servers; and the detection, location, and reporting of earthquakes across the state. The majority of TexNet operations are housed in the Bureau, with a small subcontract ($104,660) with SMU initiated to help link data from their 19 stations in the Fort Worth Basin to the TexNet network.

Table 2.1 shows a breakdown of costs for specific TexNet elements. As indicated, equipment spending in FY18 was nominal and limited to equipment and servers. We anticipate that equipment costs in FY19 will remain nominal, resulting in a total cost this biennium of $100,000. The majority of spending has been on deployment and operations. These costs include personnel to operate and maintain existing seismometer stations; redeploy portable seismometers to locations of clustered seismicity (in consultation with the TexNet TAC); and analyze data collected from seismometer stations to detect, locate, and report events in Texas. Note that FY18 costs are actual spending amounts; FY19 costs are expected.

Table 2.1 Costs for TexNet Operations during the 2018–19 biennium

TexNet Seismic Network	Equipment	Deployment and Operations					Subtotals by Cost
	TexNet Hardware	SMU Subcontract	Materials & Services	Personnel	Computer Usage	Travel	
TexNet FY18 Cost (actual)	$ 34,467	$ 14,820	$ 166,366	$ 357,942	$ 5,071	$ 34,467	$ 613,133
TexNet FY19 Cost (expected)	$ 65,533	$ 89,840	$ 110,734	$ 486,240	$ 10,729	$ 25,603	$ 788,679
Subtotals by Category	**$ 100,000**	**$ 104,660**	**$ 277,100**	**$ 844,182**	**$ 15,800**	**$ 60,070**	
Totals	**$ 100,000**	**$ 1,301,812**					**$ 1,401,812**

2.2 Budget and Spending for TexNet Research

Research conducted under TexNet during the 2018–19 biennium includes a portfolio of projects designed to investigate topics needed to better understand the causes of earthquakes and their potential effect on the people and infrastructure of the state. These research activities were developed and funded in consultation with the TexNet TAC and were categorized into technical themes—Seismology, Geologic Characterization, Fluid Flow and Geomechanics, Seismic Hazard and Risk Assessment, and Results/Info Distribution—that effectively mirrored the workflow of raw-data collection to data analysis to geologic research/insight to communication.

Research activities and budgets are itemized in Table 2.2. Summaries of the research associated with the projects are included in Section 4 of this report. The research portfolio includes projects at several research

Table 2.2 Costs for TexNet Research during the 2018–19 biennium

Theme	Project Title	Institution/ Unit	Personnel	Materials & Services	Sub-contracts	Computer Charges	Tuition	Travel	Special Equipment	FY18/19 Project Total	FY19 Remaining
Seismology	**Project 2:** Texas Seismology Studies	UT-BEG	$ 250,952	$ 19,000	$ -	$ 14,011	$ 3,000	$ 35,000	$ 15,000	$ 336,963	$ 225,270
	Project 2a: Fort Worth Basin Seismicity and Integrated Studies	SMU			$ 210,874					$ 210,874	$ 183,446
	Project 2c: Midland Basin Seismicity Monitoring and Analysis	U Houston			$ 110,094					$ 110,094	$ 103,838
	Project 2d: Delaware Basin Seismicity Monitoring and Analysis	UT El Paso			$ 194,974					$ 194,974	$ 194,974
	Project 2e: High-Resolution Crustal Imaging in the Delaware Basin	UT Dallas			$ 70,489					$ 70,489	$ 70,489
	Project 2b: West Texas Seismicity Using Lajitas Array	UT-IG	$ 62,946	$ -	$ -	$ -	$ -	$ 5,776	$ -	$ 68,722	$ 37,500
Geologic Characterization	**Project 3:** Texas Injection and Production Analytics	UT-BEG	$ 33,961	$ 2,140	$ -	$ 1,000	$ -	$ 5,000	$ 8,085	$ 50,186	$ 15,467.0
	Project 4: Ft Worth Basin Geologic/Mechanistic Characterization	UT-BEG	$ 135,777	$ 3,084	$ -	$ 5,278	$ -	$ 8,172	$ -	$ 152,310	$ 11,014.8
		SWRI			$ 39,966					$ 39,966	$ -
	Project 5: Permian Region Geological Characterization	UT-BEG	$ 117,122	$ 9,070	$ -	$ 10,700	$ -	$ 4,000	$ -	$ 140,892	$ 24,220
Fluid Flow and Geomechanics	**Project 6:** Ft Worth Basic Hydrogeologic Modeling	UT-BEG	$ 165,120	$ 38,705	$ -	$ 4,480	$ -	$ 4,355	$ 6,227	$ 218,886	$ 12,116
		GOLDER			$ 50,000					$ 50,000	$ 17,701
	Project 7: Azle Coupled Geomechanical Modeling	UT-TAMU			$ 104,495					$ 104,495	$ 6,545
	Project 8: Ft Worth Basin Fast Marching Pore Pressure Simulation	UT-TAMU			$ 50,000					$ 50,000	$ 50,000
	Project 9: Geomechanics of Fault Reactivation	UT-BEG-PGE	$ 115,564	$ 4,557	$ -	$ 5,007	$ -	$ 6,115	$ -	$ 131,243	$ 4,812
	Project 10: Fluid Injection and Earthquake Size in Faulted Reservoirs	UT-PGE	$ 37,874	$ 77	$ -	$ -	$ 17,119	$ 4,237	$ -	$ 59,308	$ 3,541
Seismic Hazard and Risk Assessment	**Project 11:** Time Dependent Seismic Hazard	UT-CAEE	$ 105,905	$ 790	$ -	$ -	$ 4,973	$ 6,000	$ -	$ 117,668	$ 107,428
	Project 12: Refining Texas Velocity Models over the Top 500 m	UT-CAEE	$ 70,005	$ 12,578	$ -	$ -	$ 18,933	$ 17,500	$ -	$ 119,016	$ 82,018
	Project 13: Infrastructure Vulnerability	UT-CAEE	$ 88,921	$ -	$ -	$ 9,000	$ 31,402	$ 1,000	$ -	$ 130,323	$ 85,938
Results and Info Distribution	**Project 14:** Geodatabase	UT-BEG	$ 45,159	$ 5,000	$ -	$ -	$ -	$ -	$ -	$ 50,159	$ 42,490
									TOTAL	$ 2,406,571	$ 1,278,808

units within UT Austin—including Petroleum and Geosystems Engineering (PGE) and Civil, Architectural and Environmental Engineering (CAEE)—as well as projects with SMU, TAMU, UT Dallas, UTEP, and the University of Houston. The SWRI and Golder Associates are subcontractors on two of the research projects, totaling $39,966 and $50,000, respectively. The total research budget of $2,406,571 exceeds the $2 million allocated for the 2018–19 biennium by residuals following the 2016–17 biennium. As of August 31, 2018, approximately 47 percent of the research budget has been spent; we expect to fully spend out the research budget by the end of FY19.

2.3 Request for FY 2020–21 Funding

The costs to continue operating and maintaining the TexNet seismic network over the 2020–21 biennium will remain at $1.4 million. Funding requested to maintain the complementary TexNet research program is $2.0 million.

Table 2.3 provides projected costs for the 2020–21 biennium. Costs requested for Equipment assume replacement/expansion of two stations per year. Operations and Maintenance are calculated for the biennium for the four categories shown, which are similar to those presented in Table 2.1 for the 2018–19 biennium.

As summarized in Table 2.2 and discussed later in Section 4, the TexNet research program spans an array of geologic and engineering topics that increase understanding of all of the following: subsurface conditions in geologic basins in Texas, which can help to explain earthquake processes across the state; geomechanical properties of faults and how they reactivate; pore-pressure conditions needed to rupture existing faults, including reservoir-modeling approaches to simulate complex dynamic subsurface processes; and how earthquakes could impact infrastructure. Specific research projects that will be undertaken with future TexNet funding will be discussed and agreed upon by the researchers and the TexNet TAC.

This integrated research program takes maximum advantage of the data acquired by the seismic network, as well as of the subsidiary geologic data, and provides the basis for understanding seismicity in Texas, mitigating the results of this activity, and minimizing the financial and social impacts of these events to the State of Texas.

Table 2.3 Costs for TexNet, 2020–21 biennium: Equipment, Operations and Maintenance, and Research

TexNet Seismic Network	Equipment	Operations and Maintenance				TexNet Operations	TexNet Research	Subtotals
		Materials & Services	Personnel	Computer Usage	Travel			
TexNet FY20	$ 50,000	$ 110,000	$ 500,000	$ 7,500	$ 35,000	$ 702,500	$1,000,000	$ 1,702,500.00
TexNet FY21	$ 50,000	$ 95,000	$ 510,000	$ 7,500	$ 35,000	$ 697,500	$1,000,000	$ 1,697,500.00
Subtotals by Category	**$ 100,000**	**$ 205,000**	**$ 1,010,000**	**$ 15,000**	**$ 70,000**	**$ 1,400,000**	**$2,000,000**	
							Biennium Total	**$3,400,000**

3.0 TexNet Seismic Monitoring Network

Summary: The TexNet seismic network is a system of permanent and portable stations deployed across the State of Texas. The permanent stations form a backbone network while the portable stations are deployed in areas where seismicity is spatially clustered, requiring more detailed characterization. The presence of TexNet generally allows earthquakes above approximately M 1.2 to be detected in areas with portable array deployments and their location to be assessed with low uncertainty, 1.5 km (0.9 miles) in the horizontal direction and 2.5 km (1.5 miles) in the vertical direction. The location and characterization of small earthquakes is critical to understanding larger earthquakes.

3.1 Network Configuration

The TexNet seismic network includes a total of 58 new broadband seismic stations across the State of Texas: 25 permanent stations and 33 portable stations (Figure 3.1). The 25 permanent stations, along with 18 existing stations operated by others (e.g., the USGS), form an evenly spaced backbone seismic network across the state that allows for the accurate detection of earthquakes. Permanent station installations consist of a highly sensitive broad frequency band seismometer, placed within a 20-ft-deep cased and cemented borehole. Each location is permitted under a 10-year license agreement with the landowner. A critical component of high-performance seismic stations is the identification of low-noise sites—a guiding principle for TexNet that is now reflected in the high-quality data that the network is returning.

Portable stations are deployed in areas of seismicity to enhance data quality and earthquake detectability, reducing location uncertainties and, in particular, allowing for better estimates of earthquake depth. TexNet deployed and maintains 33 portable stations and partially supports SMU's 19 stations, as well. Portable stations consist of direct-burial broadband seismometers and accelerometers to characterize ground motion from nearby events. These stations have shorter-term lease agreements (2 years) to more quickly relocate stations in case of shifts in seismicity. As of October 2018, TexNet portable stations are deployed in the following areas of spatial-cluster seismicity (Figure 3.1):

- 15 stations in the Fort Worth Basin, Dallas–Fort Worth area
- 8 stations in the Delaware Basin
- 3 stations in the Eagle Ford operating area
- 7 stations in the vicinity of Cogdell Field, northeast of Snyder

Additionally, following the M 4.4 event on October 20, 2018, near Amarillo, four portable stations were deployed to the Panhandle (Figure 3.1). These instruments were taken from the set of reserve instruments maintained at the Bureau for rapid deployment after notable events.

A continuously updated, publicly available catalog of seismicity across the state is available at **http://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog**.

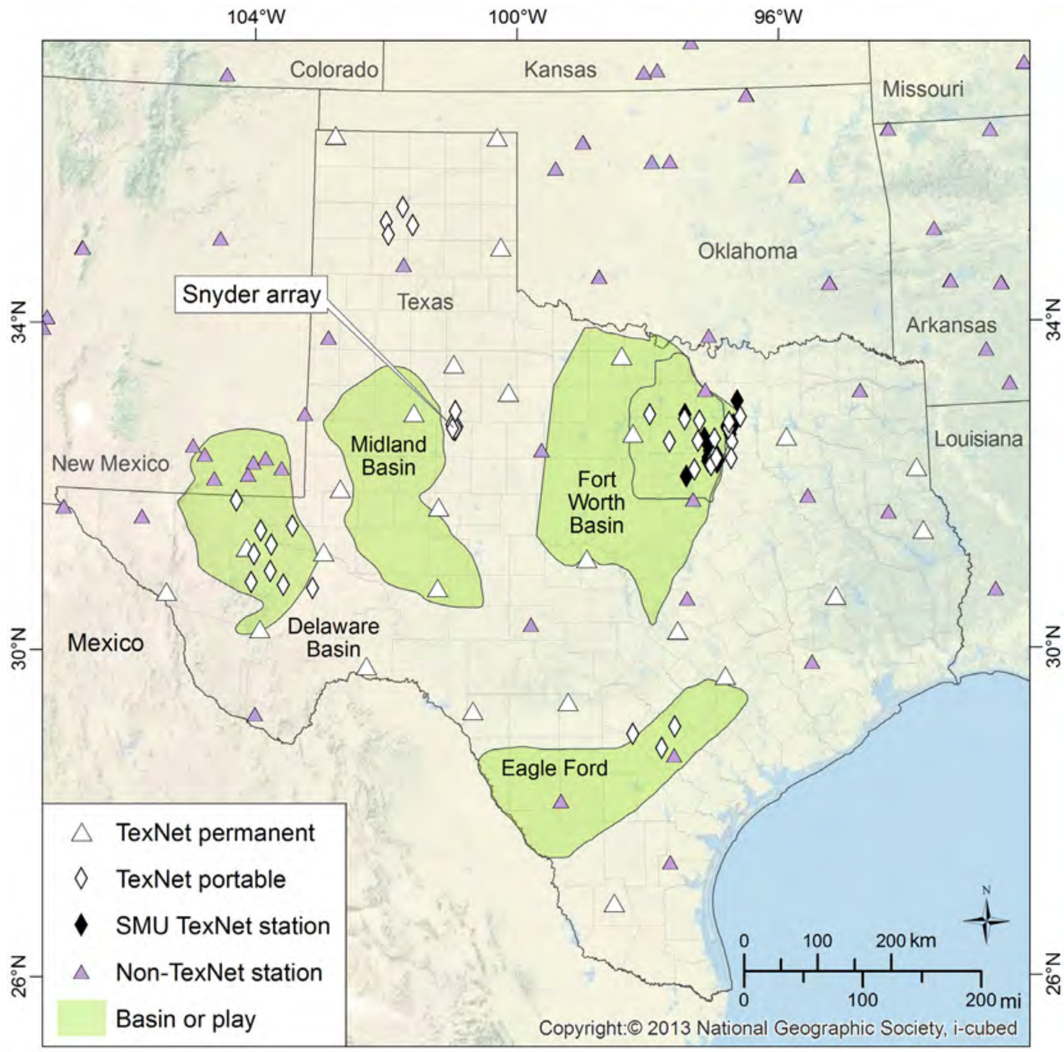

Figure 3.1 Map of TexNet permanent and portable stations, along with TexNet-supported SMU stations and non-TexNet stations that are used in detection and analysis of earthquakes by TexNet staff.

3.2 Network Performance

Magnitude of Completeness (Mc)

A key characteristic of a seismic monitoring network is the magnitude above which one can confidently state that all earthquakes were detected. This threshold is known as the *magnitude of completeness* (Mc). A lower Mc enhances the assessment of current and future seismicity. Generally, more closely spaced stations and more sensitive instruments lead to a smaller Mc. Before TexNet was deployed, the Mc across Texas was estimated to be between 2.7 and 3.0. The full deployment of TexNet and its portable stations has significantly reduced the Mc to between 1.1 and 1.2, as shown by the magnitude-frequency distribution in Figure 3.2.

General Statistics of Location Uncertainty

Earthquakes locations are reported in terms of their horizontal location on Earth's surface (i.e., epicenter) and their depth below the surface (i.e., hypocenter). Similar to Mc, more-accurate earthquake locations are obtained with a denser network of sensors. Reducing uncertainties is vital for accurately identifying

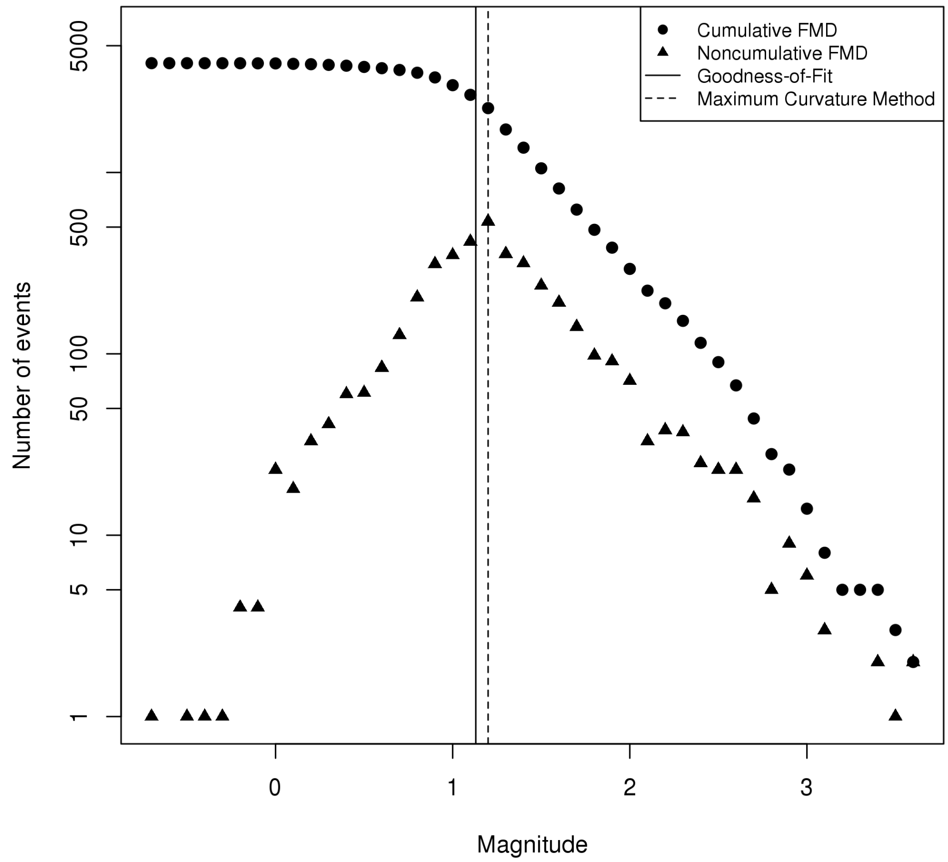

Figure 3.2 Estimated Mc for TexNet, based on the noncumulative frequency magnitude distribution (FMD) of earthquakes with magnitudes identified between January and September 2018.

earthquake location; accurate earthquake locations are critical for relating specific earthquakes to potential geologic faults, wastewater disposal wells, or other factors and for assessing their proximity to communities and critical infrastructure.

During the 2017–18 period of TexNet operations, the largest number of earthquakes were recorded in the Delaware Basin in West Texas (Figure 3.1). Therefore, we use Delaware Basin seismicity to illustrate how network density affects the horizontal and depth uncertainties in the earthquake locations. For this assessment, the total number of detected earthquakes for the Delaware Basin (2,248 events) provided by the TexNet catalog were reanalyzed for their location using (1) only pre-TexNet stations; (2) pre-TexNet stations and TexNet backbone stations; or (3) pre-TexNet stations, TexNet backbone stations, and TexNet portal stations.

The analysis shows that, when using only pre-TexNet stations, only 1,468 of the 2,248 events could be located; for these events (Figure 3.3a) most of the horizontal uncertainties were larger than 5 km (3.1 miles) and depth uncertainties were larger than 7 km (4.3 miles), making it difficult to associate the earthquakes with specific subsurface faults. The addition of the TexNet backbone stations (Figure 3.3b) reduced horizontal uncertainty to a median of 2.6 km (1.5 miles) and depth uncertainty to a median of 4.2 km (2.5 miles); the number of events that could be located increased to 2,210. Finally, the further addition of portable stations (Figure 3.3c) reduced median horizontal uncertainty to 1.5 km (0.9 miles) and median depth uncertainty to 2.6 km (1.5 miles), and increased the number of located events to 2,248. These smaller uncertainties and larger numbers of located earthquakes (even though most are too small to be felt by people) illustrate the value of increasing the number of seismometer stations in the state.

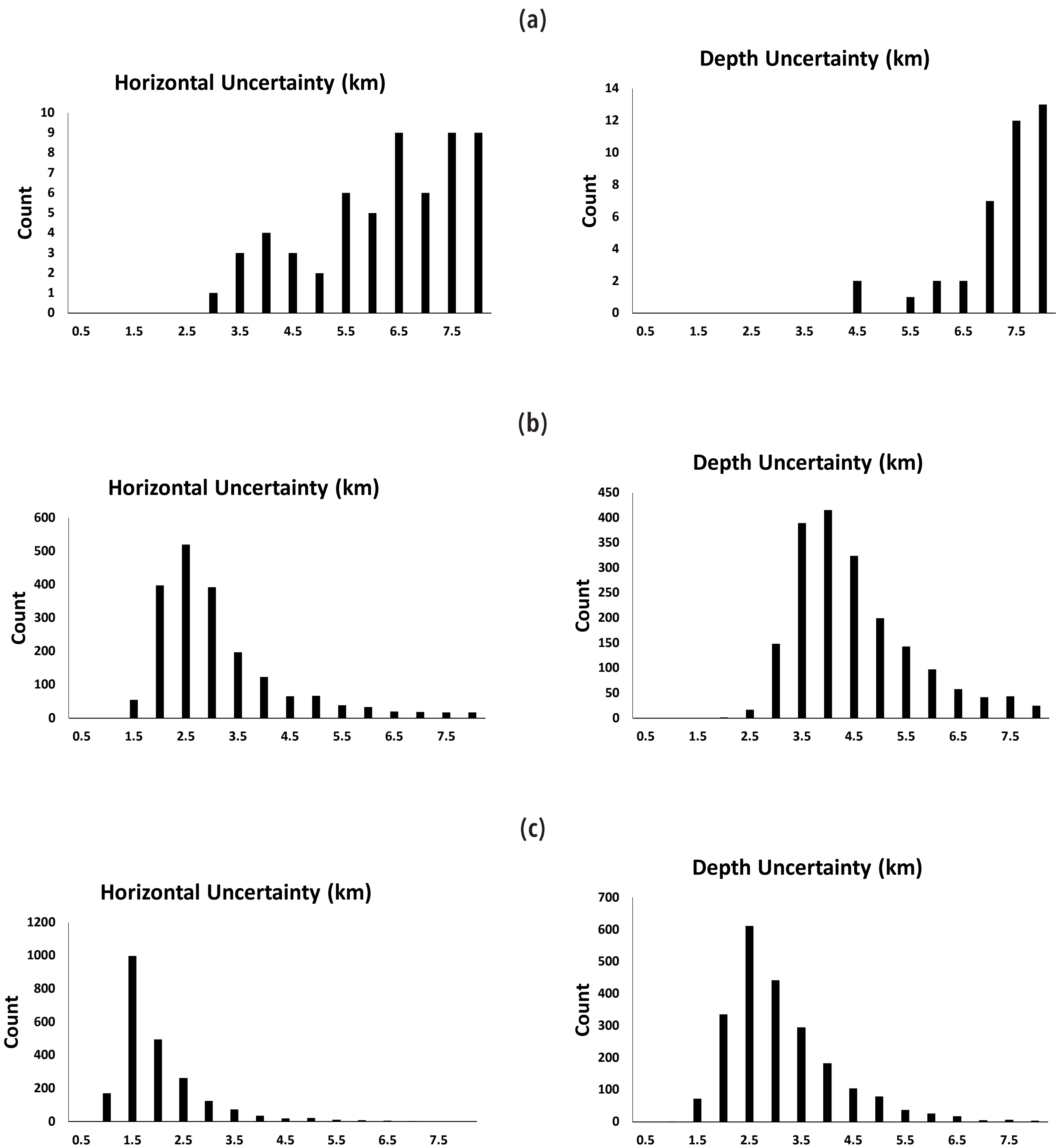

Figure 3.3 Histograms of horizontal and depth uncertainty of earthquake locations in the Delaware Basin for earthquakes analyzed using **(a)** only pre-TexNet stations; **(b)** pre-TexNet stations and TexNet backbone stations; and **(c)** pre-TexNet stations, TexNet backbone stations, and TexNet portal stations.

4.0 Summary of TexNet-Funded Research

Summary: TexNet research integrates TexNet earthquake information and complementary data into analyses and models that provide a better understanding of the causes of seismicity in Texas and its potential impact on the people and infrastructure of the state. As integrated analyses in the Dallas-Fort Worth area—where earthquake rates have diminished but active clusters persist—are nearing completion, it is becoming clear that deep injection of wastewater is the most likely cause of the earthquakes, although production may play a role in some cases. The Panhandle of North Texas has both natural and induced earthquakes. The geologic and operational habitat of earthquakes in other areas—such as West Texas and South Texas, where earthquake rates have increased compared to historic norms—is considerably more complex, but the TexNet research plan takes this into account and integrated studies are underway. The pace of delivery of quality data on earthquakes, and the publication of research findings, has increased over the current biennium and will continue to accelerate as per the developed research plan.

4.1 Introduction

Individual projects in the TexNet research portfolio form an integrated strategy to contribute leading science to better understand earthquakes in Texas. These studies are working to assess whether subsurface operations may be contributing to seismicity and, if so, the extent of this contribution. Two vital goals of this research are to use the results to devise appropriate mitigation strategies, when possible, and to better understand the seismic risk. In this section, we review the composition and progress of TexNet-funded research, providing a summary of composition and progress of the projects.

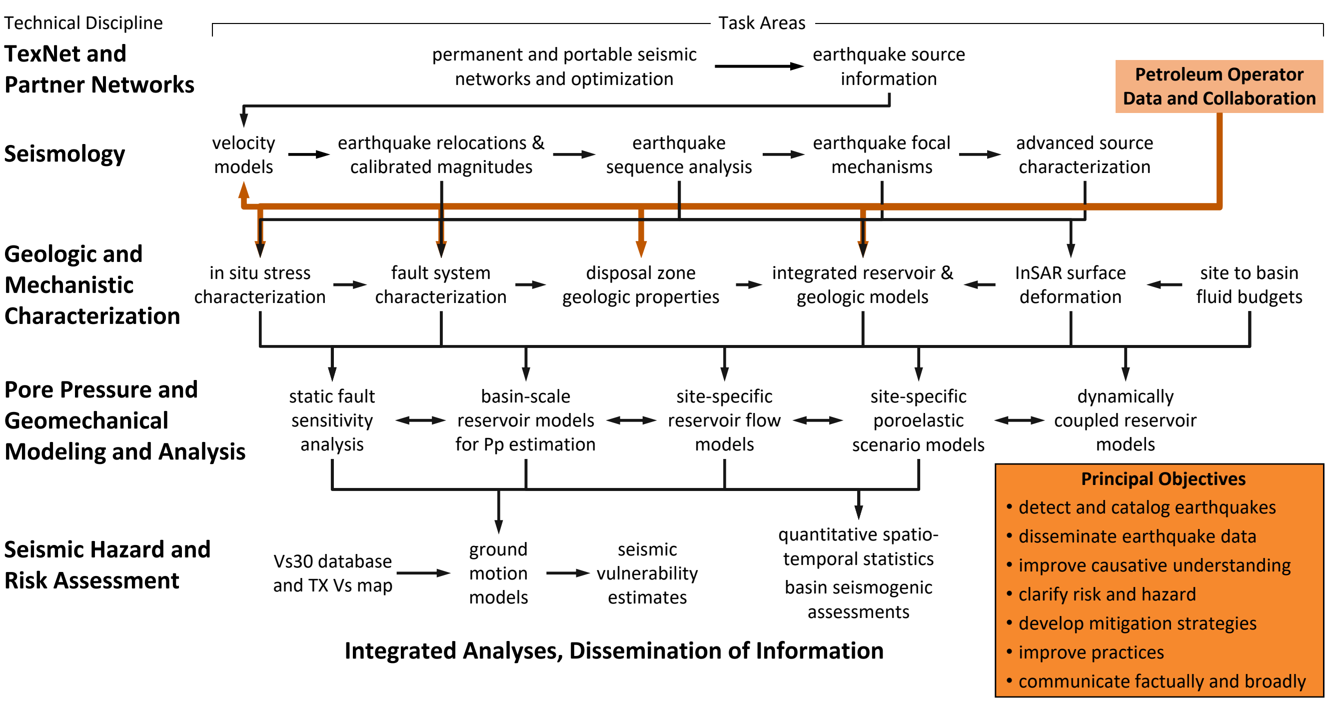

Figure 4.1 Chart showing how technical areas and projects are connected.

The principal products of TexNet projects are (1) high-quality data, and (2) analyses and models that explain subsurface behavior and aboveground consequences. Once finalized, data for individual earthquakes are made available publicly through the TexNet Earthquake Catalog. Analyses and models, however, must undergo independent scientific peer review before being made public, a process that typically involves presenting and vetting material at technical conferences and workshops, and publishing research findings in peer-reviewed scientific journals. The publication process can often take 1–2 years to complete. A partial listing of publications from research funded by TexNet can be found in Section 6.

The TexNet research portfolio is defined by technical areas that include **Seismology, Geologic and Mechanistic Characterization, Pore Pressure and Geomechanical Modeling and Analysis,** and **Seismic Hazard and Risk Assessment** (Figure 4.1), as well as tasks that add value to the information needed to pursue the following principal objectives: (1) cataloging earthquakes, (2) disseminating earthquake data, (3) improving causative understanding, (4) clarifying risk and hazard, (5) developing mitigation strategies, (6) improving practices, and (7) communicating facts and findings to different stakeholders. Figure 4.1 shows connections between the technical subdisciplines and the 14 specific research projects that are listed in Table 2.2 of Section 2. Some TexNet projects are applied statewide and others are focused geographically (Figure 4.2).

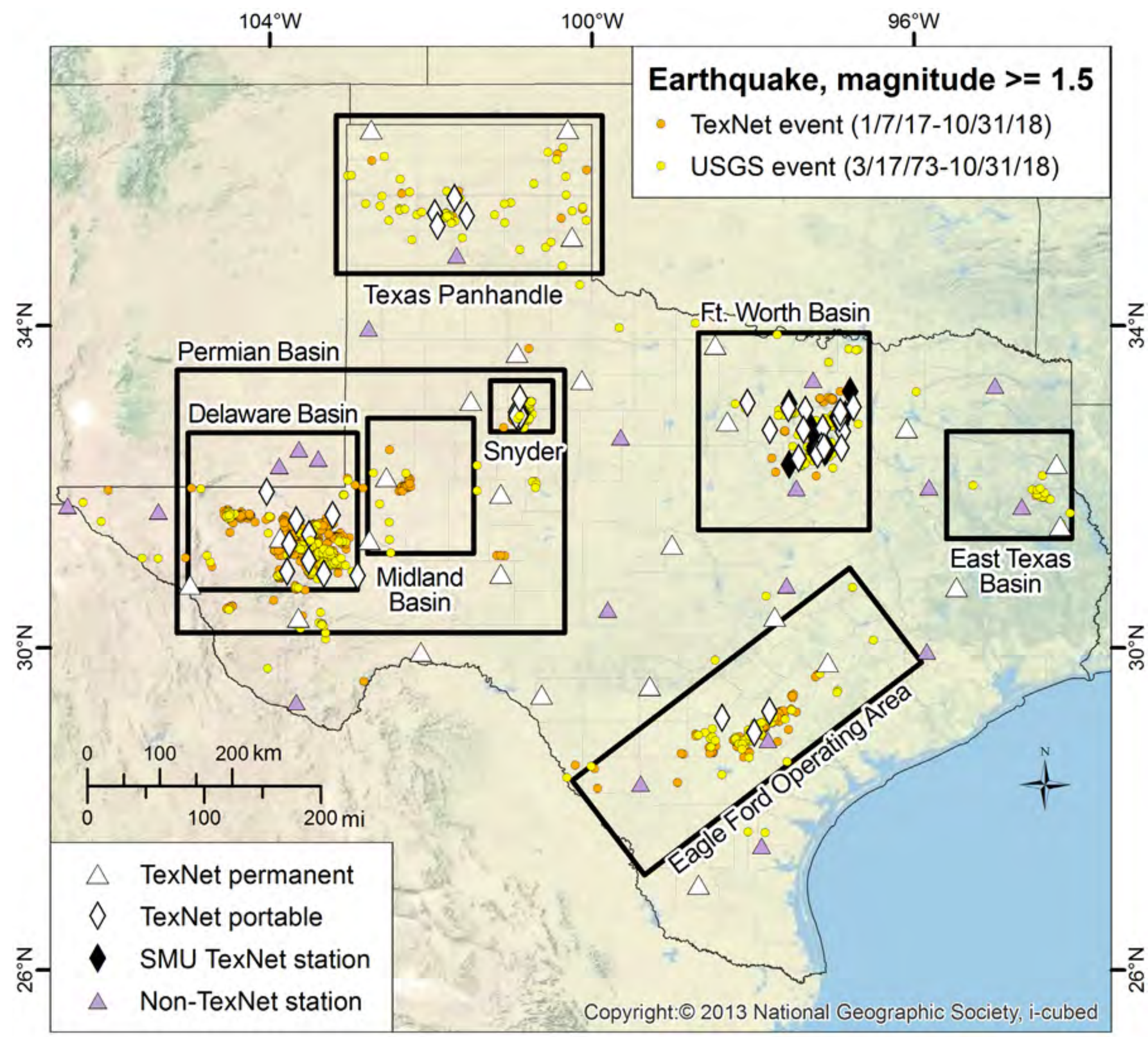

Figure 4.2 Seismicity in Texas as cataloged by the USGS and TexNet, deployed seismic stations, and TexNet research study areas.

Seismology Research Projects

Project 1 describes the statewide development and maintenance of the TexNet seismic network and the operational elements required to detect and locate earthquakes and distribute the data to the public (Table 2.1). See Section 3 for a summary of Project 1 progress. Project 2 and its subprojects represent a suite of seismologic studies, in partnership with other universities in Texas, that include earthquake monitoring in specific regions using dense local seismic networks.

Geologic and Mechanistic Characterization Research Projects

Projects 3, 4, and 5 focus on characterizing subsurface geology as it pertains to earthquakes: Texas Injection and Production Analytics (Project 3), and two separate projects characterizing geologic/mechanical properties (i.e., state of stress, faulting, permeability) of strata in the Fort Worth Basin (Project 4) and of the Delaware Basin area of the greater Permian Basin (Project 5). These projects clarify the potential hazard of fault reactivation and provide information for comprehensive models used for dynamic analysis.

Pore Pressure and Geomechanical Modeling and Analysis Research Projects

Assessing the potential relationship between earthquakes and subsurface oil and gas operations requires understanding the extent to which these operations change subsurface fluid pressures and the stress state acting on faults, as well as understanding the depths/locations of the oil/gas operations relative to those of the earthquakes. This work includes hydrogeologic and geomechanical reservoir modeling and analysis. Projects in this area include regional-scale analyses of the Fort Worth Basin (Projects 6 and 8), smaller-scale analyses of specific earthquake sequences (Project 7), and theoretical analyses designed to assess the subsurface conditions of geologic faults that are more likely to slip and cause an earthquake (Projects 9 and 10).

Seismic Hazard and Risk Assessment Research Projects

Projects in the area of seismic hazard and risk are designed to better understand the potential impacts of earthquakes on the people and infrastructure of Texas. This work involves developing models describing the time-dependent nature of observed seismicity and associated level of ground shaking (Project 11), refining the near-surface velocity structure that affects the levels of ground shaking and earthquake event location (Project 12), and evaluating the vulnerability of typical infrastructure in Texas (Project 13).

Dissemination Projects

As TexNet research projects accelerate in producing data, analyses, and models, it is critical to organize that information so that the public can easily retrieve it. Thus, the goal of Project 14 is to develop a digital repository where all TexNet data, and peer-reviewed models and publications, can be rapidly shared and integrated into other research.

A summary of research progress is provided in the section that follows; scientific peer-reviewed publications are listed in Section 6.

4.2 Summary of Research Progress

Research Progress for Dallas–Fort Worth Area and Fort Worth Basin

- Injection of wastewater into deep disposal layers is the most likely cause of earthquakes in the region. Withdrawal of fluids, both water and hydrocarbons, also contributed to increased seismicity in the region.
- Earthquake characterization for 2014–18 is complete; advanced studies continue.
- SMU has developed a comprehensive earthquake catalog for the region from 2008 to the present, which has been provided to TexNet for inclusion in its historical earthquake catalog.
- Analysis of saltwater injection and hydrocarbon production is complete and available upon request.
- Geologic characterization of injection zone is complete and pending publication.
- Fault interpretation and fault-slip-potential analyses are complete and pending publication.
- Integrated geologic model is complete and pending publication.
- Coupled geomechanical models for the Azle sequence are complete. Results from TAMU are published and results from the Bureau are pending publication.
- Hydrogeologic modeling by the Bureau and TAMU will be finalized in FY19.

The five largest earthquake sequences in the basin that have been studied and presented in the peer-reviewed scientific literature are (1) the 2008–09 DFW International Airport; (2) the 2009–10 Cleburne; (3) the 2013–present Azle–Reno; (4) the 2014–present Irving–Dallas; and (5) the 2015–present M 4.0 Venus sequences. During 2017 and 2018, seismicity occurred broadly across the Fort Worth Basin region. The 2018 M 3.4 earthquake in Venus and the 2017 M 3.0 earthquake in Irving–Dallas were the largest events in the reporting period (Figure 4.3). This seismicity included continued activity of the Azle–Reno, Irving–Dallas, and Venus sequences, with small $M < 3.5$ earthquakes between 2017 and 2018 but seismicity rates notably reduced compared to 2015–16. The 2018 Venus earthquake and 2017 Irving–Dallas earthquake led to 343 and 574 felt reports (reported by the USGS “Did You Feel It?” program), respectively. The 2017 M 2.8 earthquake in the Azle–Reno region led to 117 felt reports. In addition to these three sequences, a significant number of earthquakes have occurred near the cities of Fort Worth and Lake Lewisville, and to the west of Cleburne (Figure 4.2). These events have been preliminarily interpreted to represent new sequences on newly active faults. Additional stations have been recently deployed in those areas to better resolve location and depth.

Scientific consensus indicates that the increase in the rate of seismicity in the Fort Worth Basin beginning in 2008 and continuing through the present has been most likely caused by saltwater disposal (SWD) and oil and gas production. Injection of wastewater into deep disposal layers is the most likely cause, but withdrawal of fluids, both water and hydrocarbons, has also contributed to the increased seismicity. Monitoring has shown a decrease in the rate of seismicity since 2015, as the monthly rate of SWD decreased to pre-2007 levels, concurrent with a slowdown in the rate of development of the Barnett Shale. In work that is pending publication, we explain that the basin has many more faults than previously recognized and that many of the faults are sensitive to dynamic changes in the reservoir due to fluid injection and withdrawal. In some cases, faults in close proximity to wells with high rates and volumes of wastewater injection have caused earthquakes. In other cases that remain poorly understood, faults at greater distances from injection and production have reactivated, causing earthquakes; while faults located near areas of high-rate and high-volume injectors have not been reactivated.

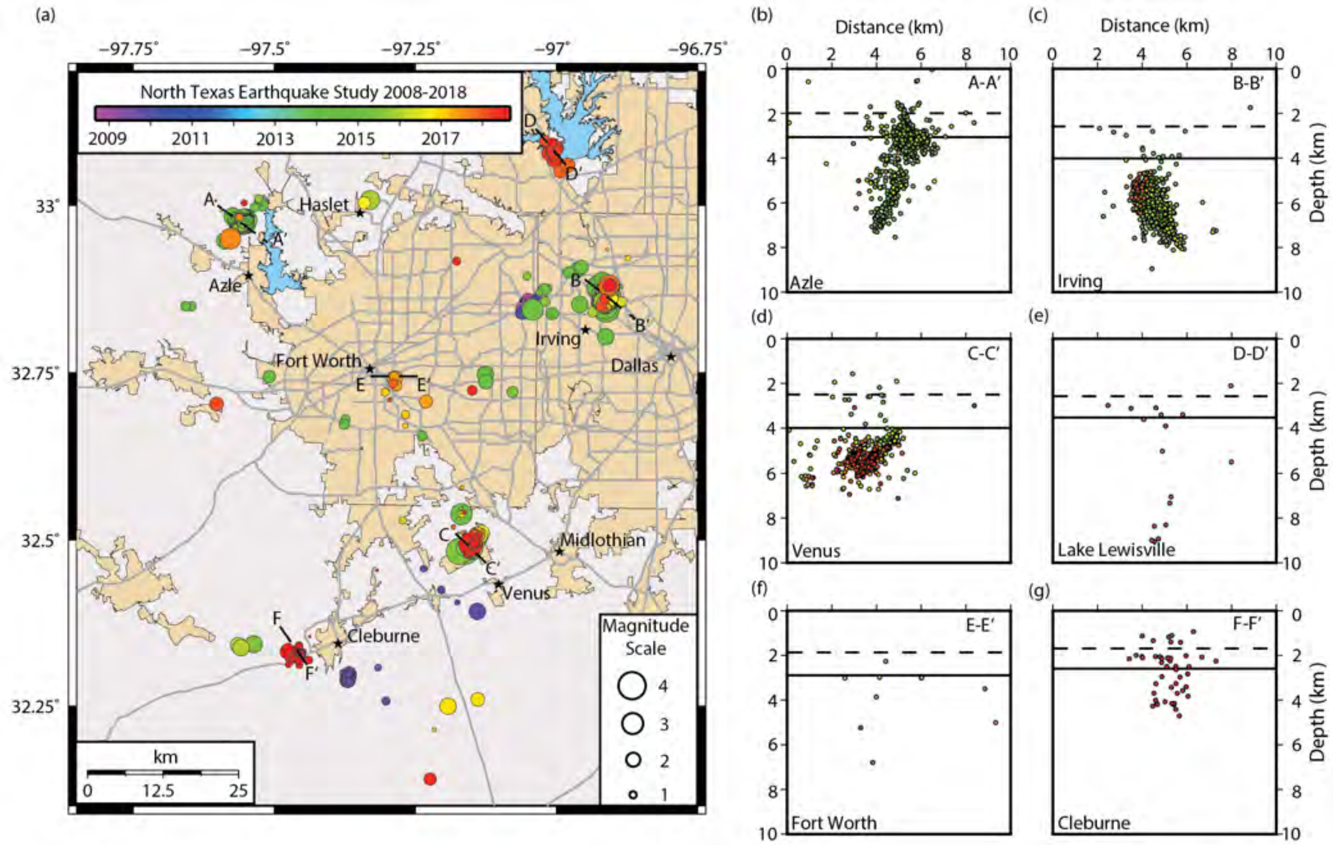

Figure 4.3 (a) Map view of SMU earthquake catalog showing locations of earthquakes (circles) scaled by their magnitudes and colored by origin times. Also shown are locations of injection wells (brown diamonds) active during period of observation. **(b–g)** Cross-sectional views of seismically active portions of basin, with their given sequence names shown at bottom left and cross-section line designations shown at top right. Cross-section lines are labeled on map view (a) and shown as dashed black lines (Quinones et al., in review).

Significant questions currently being addressed by ongoing TexNet research projects:

- What magnitudes of fluid-pressure change are most closely linked to earthquakes?
- What is the nature of the seismogenic faults?
- What are the most likely mechanisms for the inducement of earthquakes at great distances from areas of injection and production?
- What is the spatiotemporal change in earthquake hazard and what areas of the basin are the most sensitive to hydrocarbon operations using current practices?

Research Progress for West Texas

- The Permian Basin region of West Texas is geologically and operationally complex, with 11 active earthquake clusters: 9 in the Delaware Basin, 1 in Snyder, and 1 in Midland.
- The rate of earthquakes in the Delaware Basin increased in 2010 and again in 2017.
- Each earthquake cluster may have a unique mix of operational and natural influences.

- Detailed earthquake analysis is underway in the region using data from TexNet, and the number of monitoring stations being placed in strategic locations continues to grow.
- Locally dense monitoring of key earthquake clusters is either underway or planned.
- A new 3D velocity model will soon further reduce earthquake hypocenter uncertainty.
- Analysis of saltwater injection and hydrocarbon production is complete and available upon request.
- Work supporting integrated earthquake assessment is focused on the Delaware Basin.
    - Preliminary geologic characterization of shallow injection and shallow earthquakes is complete and being used for hydrogeologic modeling and geomechanical analysis.
    - A new 3D model of Delaware Basin structure and faults will be complete in FY19 and will be used for analysis of fault stress and fault-slip potential.
    - Site-specific assessment of key earthquake clusters will commence in FY19.

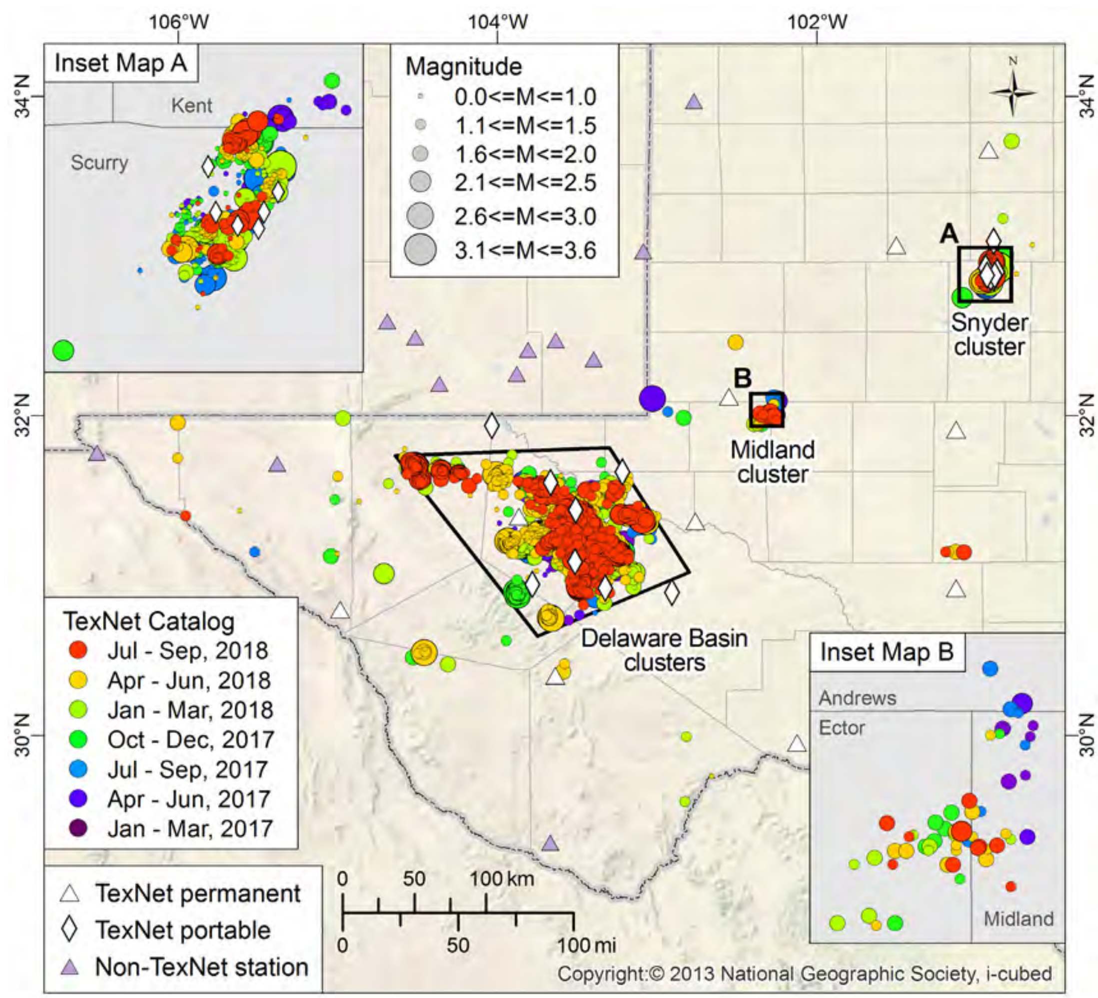

Figure 4.4 Map of the over 4,000 earthquakes cataloged by TexNet in West Texas from January 1, 2017, to September 30, 2018. Circles represent earthquakes, and color and size correspond to time and magnitude of event, respectively.

In contrast to the less-complicated earthquake situation of the Fort Worth Basin, where injection is primarily in Ordovician intervals and earthquakes are primarily in the Precambrian basement along NE-striking faults, the Permian Basin region of West Texas is far more complex, with 11 active earthquake clusters (Figures 4.4 and 4.5). The areas are each distinct with regard to geology and operational history. Natural earthquakes also occur in the region. The Snyder cluster is being monitored by a local TexNet monitoring array. The Midland cluster and Delaware Basin "A" cluster will also be monitored by local arrays beginning in FY19. Earthquake depth estimates still carry considerable uncertainties, but a new 3D velocity model for the region and more instruments will reduce uncertainty.

Even with the current uncertainty in depth, some Delaware Basin earthquake clusters likely are occurring dominantly in the shallow sedimentary realm (e.g., "A" cluster, Figure 4.5). Others are occurring in the deeper geologic basement along previously identified faults (e.g., "B" cluster, Figure 4.5). Soon-to-be-published data in the Delaware Basin region suggest that the ramp-up of seismic activity began in 2010 and increased markedly in 2017. Information with higher confidence will become available for these clusters in FY19 as more TexNet stations are added, local arrays are put into service, and controls on velocity structure are improved. At present, different causative mechanisms, each with a mix of operational and natural influences, may be needed to explain each earthquake cluster.

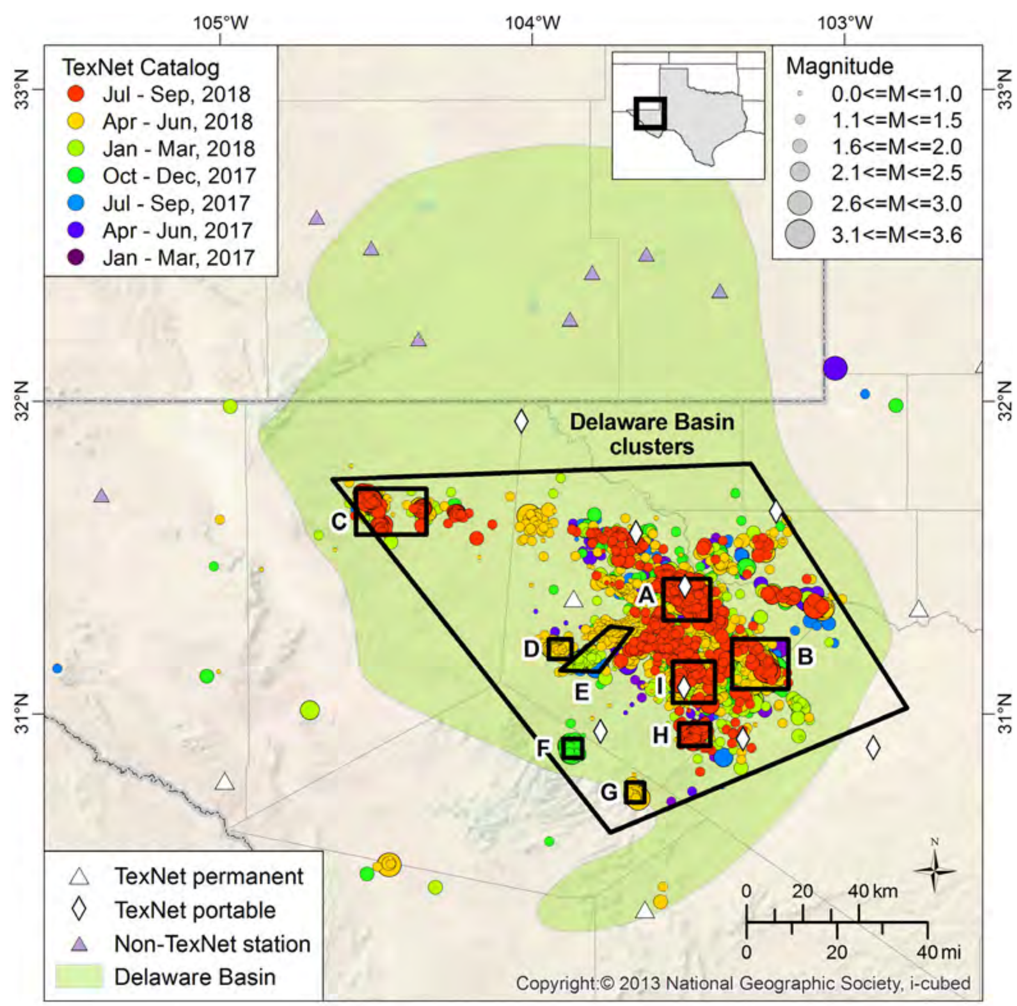

Figure 4.5 Enlarged area (from Figure 4.4) showing primarily Delaware Basin. Areas labeled with letter represent spatial clusters of seismicity.

The research study plan for 2019–20 will focus on the Delaware Basin, where the rate of seismicity is the greatest in the region. Here, geologic data sets are being assembled, integrated models are being constructed, and scoping-level hydrogeologic and geomechanical models have begun. The goals of the first phase of work are to identify the most likely factors contributing to earthquakes in each studied cluster area and to then use those preliminary results to determine the most appropriate research strategies to gain quantitative understanding. Significant questions remain:

- What is the recent history of earthquakes in the region, and how might it change in the future?
- What is the depth of the various earthquake clusters, and are the depth ranges limited or broad?
- What are the most likely mechanisms for inducing earthquakes, and how do natural causes fit in?
- What data and information will be most beneficial to inform steps for mitigation?

Research Progress for South Texas (Eagle Ford Area)

- Earthquakes in South Texas occur along a NE-trend broadly spanning the Eagle Ford area (Figure 4.6).
- Currently, an insufficient number of monitoring stations are available for reliable information on earthquake depth, though we are confident that earthquakes cataloged by TexNet have occurred in both the geologic basement and the overlying sediment.
- Saltwater injection and hydrocarbon production data sets are complete and available for use.
- An integrated geologic model is being developed and will achieve preliminary status in 2019.
- A locally dense seismic-monitoring network will become active in 2019.

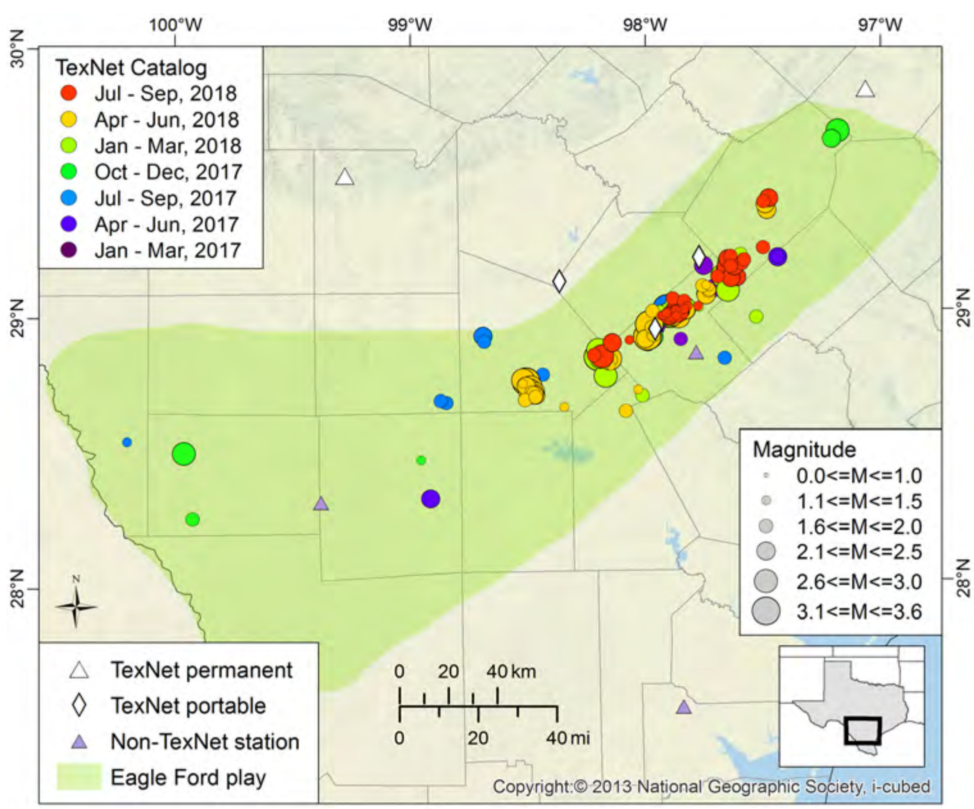

Figure 4.6 Map of the 132 earthquakes cataloged by TexNet in southern Texas from January 1, 2017, to September 30, 2018. Circles represent earthquakes, and color and size correspond to time and magnitude of event, respectively.

The research plan for South Texas in 2019–20 is to acquire more-detailed data on earthquake location, depth, and characteristics using the current TexNet seismic network and locally dense monitoring; build and maintain a database of operational activity for both oil and gas production and SWD; and construct an integrated geologic model with increasing completeness and capability over time. Mechanistic analyses to assess earthquake cause and mitigation options will begin in 2020 when earthquake and geologic data sets are satisfactorily complete.

Research Progress for Texas Panhandle

- The strongest earthquake cataloged thus far by TexNet occurred in the Texas Panhandle on October 20, 2018.
- The region is moderately seismically active, with both natural and possibly induced earthquakes.

The M 4.4 earthquake event indicated above occurred 12 miles northeast of Amarillo, adjacent to other studied clusters (Walter et al., 2018) (Figure 4.7). Within a week of that event, TexNet deployed four temporary monitoring stations in the region surrounding the event location to monitor for aftershocks. No further study is planned at this time.

Research Progress for East Texas

After a period of quiescence since the 2012–13 Timpson sequence, two earthquakes have been recently cataloged by TexNet, including an M 3.6 event recorded on September 4, 2018, approximately 5 miles west of Timpson, Texas. TexNet researchers are monitoring this area to determine if a more concerted study should be prioritized.

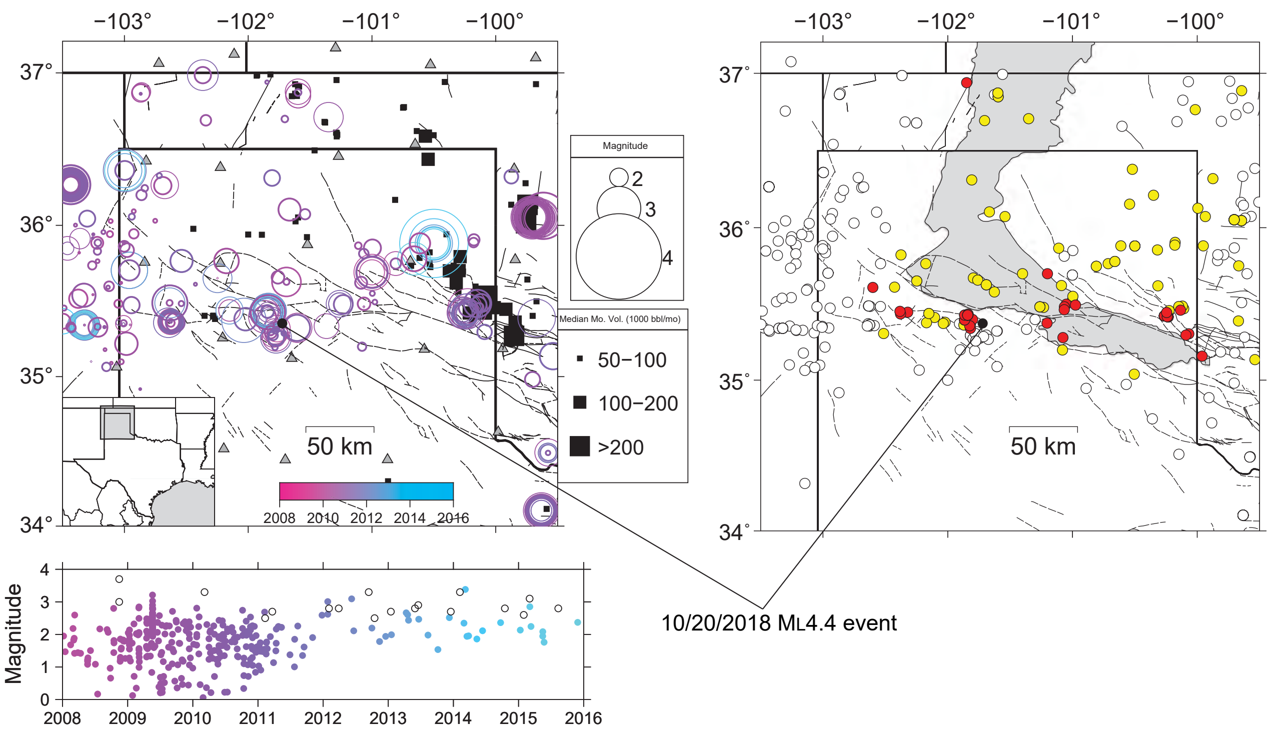

Figure 4.7 (Left) Earthquakes (circles) and wastewater injection wells (filled squares) in the Panhandle region. (Right) Map of earthquakes ranked by the method of Frohlich et al. (2016), with colors showing the strength of available evidence of inducement: white, score 0.0–1.0 (event not induced, or very little evidence available); yellow, score 1.5–2.0 (event possibly induced); red, score 2.5–3.0 (event probably induced). From Walter et al. (2018).

5.0 Future Plans for TexNet

Summary: TexNet will continue to improve network quality by repositioning, adding, and upgrading stations. TexNet will collaborate with other universities in Texas to deploy local dense arrays in areas of clustered seismicity. TexNet funded research will continue to focus on seismicity in the Dallas–Fort Worth, Permian Basin, and South Texas priority areas.

5.1 TexNet Seismic Monitoring Network

The earthquake locations provided by TexNet from 2017 through 2018 have quantified temporal changes in seismicity across Texas to a degree never previously understood. These results motivate the need to assess network performance with the capability to reposition individual stations as our understanding of Texas seismicity improves. TexNet has quantified the dynamic characteristic of seismicity in Texas, fueling the need for a flexible instrumentation plan going forward that will leverage the portable instrumentation component of the program. To continually improve the network, stations will be repositioned and added as needed to enhance data quality, improve earthquake detectability, and minimize uncertainties in earthquake location. Some examples of current plans for changes to the network are provided below.

Delaware Basin: Five additional stations, procured with funding from internal sources, will be installed to better locate events in this area of clustered seismicity. Specific sites will be chosen as close as possible to locations directly above the centers of specific seismicity clusters in the region. Additionally, UTEP will be installing an array of dense, portable stations over the next year to better understand the seismicity.

Fort Worth Basin: Results have shown that three existing sites in the region are too noisy; therefore, more-suitable sites are being evaluated that are closer to the active earthquake clusters. SMU will continue to operate their stations.

Eagle Ford Area: A portable station installed near detected seismicity was recently reinstalled. The sensor was initially installed in a 23-ft (7-m) deep borehole to reduce ambient noise but will be deepened to 47 ft (12 m) in 2019 to further improve data quality. This portable station will then become part of the TexNet permanent seismic network.

TexNet collaborations with the following Texas academic institutions involved in managing local dense arrays will continue in 2019:

- SMU, which operates 19 stations in the Fort Worth Basin close to active earthquake clusters
- UTEP, which will deploy 25 portable stations in late 2018 in the Delaware Basin near Pecos, Texas
- The University of Houston, which will deploy 7 seismic stations in late 2018 and early 2019 in the Midland Basin
- UTIG (with Bureau personnel), which will install an additional 25 stations in the Eagle Ford area

5.2 Research

TexNet-funded research will continue to focus on Dallas–Fort Worth, Permian Basin, and South Texas as priority areas (Figure 5.1). These priorities will be reevaluated as earthquake trends evolve and our understanding of the earthquakes improves.

Research work in the Dallas–Fort Worth area is entering concluding phases, with numerous publications submitted, or soon to be, and summary analyses and reporting scheduled for 2019 (see Section 6). Interim research products are available now for operators, regulators, and the public; final versions will become available beginning in 2019.

Concerted research work in the Permian Basin began in 2018 with a focus on improving the regional velocity model for locating earthquakes and integrating geologic analysis of the Delaware Basin, centered on the city of Pecos. The current focus of analysis in this area will include the shallow earthquake clusters; subsequent analysis of deeper earthquake clusters will begin in 2019.

Research on other seismically active areas of Texas such as the Midland Basin; the area northeast of Snyder, Texas; and the Eagle Ford area will also begin in coming years. However, background work for research in these additional areas is already underway, including local seismic monitoring, analysis of operational data on oil and gas production and wastewater injection, and assembly of geologic data and 3D models.

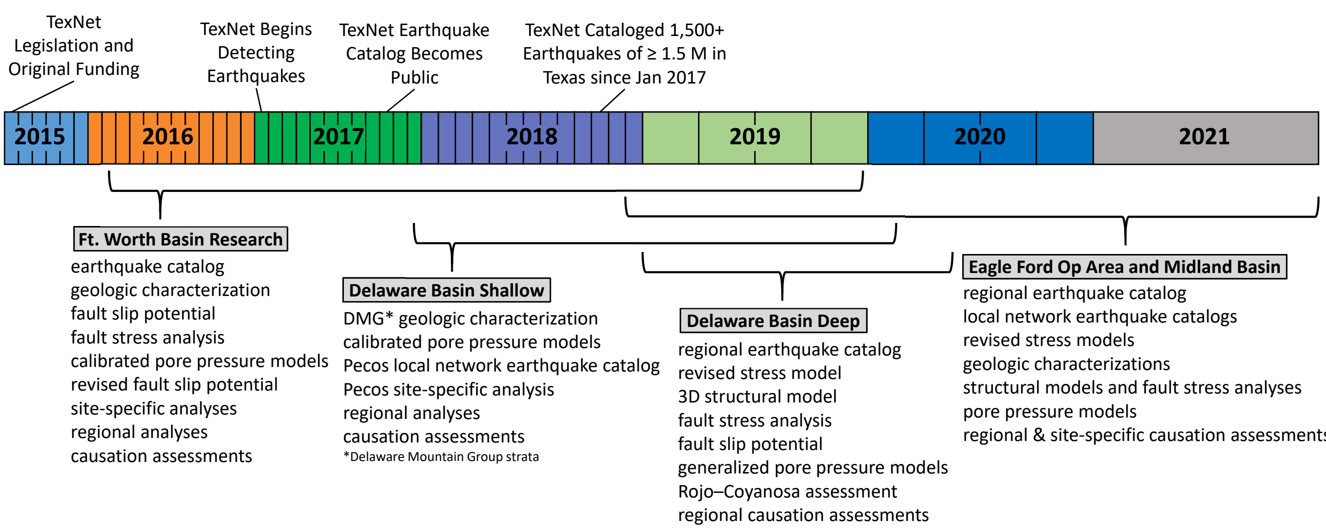

Figure 5.1 Generalized timeline for principal geographic application areas of TexNet research.

6.0 TexNet Research Publications

Summary: TexNet is funding high-quality research that receives independent, scientific peer review in an effort to provide the best research products for the State of Texas. Over 100 separate scientific conference presentations and peer-reviewed publications have resulted thus far from work funded or co-funded by TexNet. Table 6.1 lists peer-reviewed conference and journal papers published, accepted, or submitted. A list of conference abstracts from TexNet work can be found at the TexNet website.

Table 6.1 Peer-reviewed conference papers and journal papers from TexNet-supported research, published and planned. Project numbers listed are defined in Section 2.

No	Year	Type	Status	Project	Authorship, Title, and Publishing Information
1	2016	Journal Paper	Published	9	Fan, Z., Eichhubl, P., and Gale, J. F. W., 2016, Geomechanical Analysis of Fluid Injection and Seismic Fault Slip for the MW4.8 Timpson, Texas, Earthquake Sequence, Journal of Geophysical Research-Solid Earth, 121 (4), p. 2798–2812, doi:10.1002/2016JB012821.
2	2017	Journal Paper	Published	11	Zalachoris, G., Rathje, E., and Paine, J. 2017, VS30 Characterization of Texas, Oklahoma, and Kansas Using the P-Wave Seismogram Method, Earthquake Spectra, Earthquake Engineering Research Institute, 33 (3), p. 943–961, doi:10.1193/102416EQS179M.
3	2018	Journal Paper	Published	2a	Ogwari, P. O., DeShon, H. R., and Hornbach, M. J., 2018, The Dallas-Fort-Worth Airport Earthquake Sequence: Seismicity Beyond Injection Period, Journal of Geophysical Research, 123, p. 553–563, doi:10.1002/2017JB015003.
4	2018	Journal Paper	Published	2a	Quinones, L. A., DeShon, H. R., Magnani, M. B., and Frohlich, C., 2018, Stress Orientations in the Fort Worth Basin, Texas, Determined from Earthquake Focal Mechanisms, Bulletin Seismological Society of America, 108 (3A), p. 1124–1132, doi:10.1785/0120170337.
5	2018	Journal Paper	Published	2	Walter, J., Frohlich, C., and Borgfeldt, T., 2018, Natural and Induced Seismicity in the Texas and Oklahoma Panhandles, Seismological Research Letters, 89 (6), p. 2437–2446, doi:10.1785/0220180105.
6	2018	Journal Paper	Published	1	DeShon, H. R., Hayward, C. T., Ogwari, P. O., Quinones, L., Sufri, O., Stump, B., and Magnani, M. B., 2018, Summary of the North Texas Earthquake Study Seismic Networks, 2013–2018, Seismological Research Letters, doi:10.1785/0220180269.
7	2019	Journal Paper	Accepted	11	Zalachoris, G., and Rathje, E., in press, Ground Motion Model for Small-to-Moderate Earthquakes in Texas, Oklahoma, and Kansas, Earthquake Spectra, doi:10.1193/022618EQS047M.
8	2018	Journal Paper	Submitted	9	Fan, Z., Eichhubl, P., and Newell, P., in review, Basement Fault Reactivation by Fluid Injection into Sedimentary Reservoirs: Poroelastic Effects, Journal of Geophysical Research-Solid Earth.
9	2018	Journal Paper	Submitted	2a	Jeong, S.-J., Stump, B. W., and DeShon, H. R., in review, Spectral Ground Motion Characteristics for Induced Earthquakes in the Fort Worth Basin, Texas, Bulletin of the Seismological Society of America.
10	2018	Journal Paper	Submitted	13	Khosravikia, F., Clayton, P., and Nagy, Z., in review, An Artificial Neural-Network Based Framework for Ground Motion Prediction Equations for Small to Moderate Earthquakes in Texas, Oklahoma, and Kansas, Seismological Research Letters.

No	Year	Type	Status	Project	Authorship, Title, and Publishing Information
11	2018	Journal Paper	Submitted	4	Smye, K. M., Lemons, C. R., Eastwood, R., McDaid, G., and Hennings, P. H., in review, Stratigraphic Architecture and Petrophysical Characterization of Formations for Deep Disposal in the Fort Worth Basin, TX, Interpretation.
12	2018	Journal Paper	Submitted	1	Quinones, L. A., DeShon, H. R., Jeong, S.-J., Ogwari, P., Scales, M. M., and Kwong, K. B., in review, Tracking Induced Earthquakes in the Fort Worth Basin: A Summary of the 2008–2018 North Texas Earthquake Study Catalog, Bulletin of the Seismological Society of America.
13	2018	Journal Paper	Submitted	4	Hennings, P. H., Lund Snee, J.-E., Osmond, J. L., DeShon, H. R., Dommisse, R., Horne, E. A., Lemons, C. and Zoback, M. D., in review, Slip Potential of Faults in the Fort Worth Basin of North-Central Texas, USA, Geophysical Research Letters.
14	2018	Journal Paper	Submitted	1	Savvaidis, A., Young, B., Huang, D.-G., and Lomax, A., in review, TexNet: A Statewide Seismological Network in Texas, Seismological Research Letters.
15	2018	Journal Paper	Submitted	2	Huang, G.-C. D., Savvaidis, A., and Walter, J. I., in review, Mapping the 3D Lithospheric Structure of the Greater Permian Basin in West Texas and Southeast New Mexico for Earthquake Monitoring, Journal of Geophysical Research.
16	2017	Conference Paper	Presented	11	Zalachoris, G. and Rathje, E., 2017, Ground Motion Models for Earthquake Events in Texas, Oklahoma, and Kansas, 3rd International Conference on Performance-Based Design in Earthquake Geotechnical Engineering (PBD-III), Vancouver, Canada, July.
17	2017	Conference Paper	Presented	11	Zalachoris, G., Rathje, E., Cox, B., and Cheng, T., 2017, Application of the P-Wave Seismogram Method for Vs30 Characterization of Texas, Oklahoma, and Kansas, 3rd International Conference on Performance-based Design in Earthquake Geotechnical Engineering (PBD-III), Vancouver, Canada, July.
18	2018	Conference Paper	Presented	2	Savvaidis, A., Rathje, E., Cox, B., Zalachoris, G., Tiwari, A., Yust, M., and Young, B., 2018, Site Characterization of TexNet Seismic Stations Using Different Geophysical Approaches, Geotechnical Earthquake Engineering and Soil Dynamics V, Austin, Texas, June.
19	2018	Conference Paper	Presented	12	Yust, M. B., Cox, B. R., and Cheng, T., 2018, Epistemic Uncertainty in Vs Profiles and Vs30 Values Derived from Joint Consideration of Surface Wave and H/V Data at the FW07 TexNet Station, Geotechnical Earthquake Engineering and Soil Dynamics V, Austin, Texas, June.
20	2019	Conference Paper	Presented	7	Chen, R., Xue, X., Yao, C., Datta-Gupta, A., King, M. J., Hennings, P., and Dommisse, R., 2018, Coupled Fluid Flow and Geomechanical Modeling of Seismicity in the Azle Area North Texas, SPE 191623, Presented at 2018 Annual Technical Conference, Dallas, Texas.
21	2018	Conference Paper	Presented	11	Grigoratos, I., Bazzurro, P., Rathje, E., and Savvaidis, A., 2018, A Framework to Quantify Induced Seismicity Due to Wastewater Injection in Oklahoma, 11th US National Conference on Earthquake Engineering, EERI, Los Angeles, June.
22	2019	Conference Paper	Submitted	13	Khosravikia, F., Clayton, P., and Faust, K., 2019, Evaluation of Seismic Resilience of Highway Bridge Networks: An Agent-Based Modeling Framework, Proc., ASCE/SEI Structures Congress, Orlando, Fla., April.
23	2019	Conference Paper	Submitted	13	Kurkowski, J., and Clayton, P., 2019, Vulnerability of Masonry Veneers to Induced Seismic Events in Central United States, Proc., ASCE/SEI Structures Congress, Orlando, Fla., April.

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CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 5-B

Attachments for New Injection/Disposal Wells

| Well Log | Groundwater Depth Letter | Area of Review | Historical Seismic Events | Notice | Fresh Water Injection | Requests for Exception |

Well Log

The well log is needed to identify the top and bottom of the proposed injection zone and overlying formations.

1. A complete electric log or similar well log of the proposed injection/disposal well is required.
   - The log must include a header and show the proposed disposal/injection zone.
   - Driller's logs, caliper logs and collar logs are not adequate. If a well log is not available for the proposed injection/disposal well, the applicant may submit a log of a nearby well and identify the logged well on one of the plats submitted with the application.
2. If a well log is not available for the proposed injection/disposal well, the applicant may submit a log of a nearby well and identify the logged well on one of the plats submitted with the application.
3. If multiple wells are covered by one Form H-1 within the same application, only one well log is required.

Groundwater Depth Letter

The groundwater depth letter is needed to evaluate the level of groundwater protection present in the proposed injection well.

1. With Forms H-1/H-1A, provide Form GW-2 stating the depth to which usable quality groundwater must be protected is required. This form is commonly referred to as a "surface casing letter" and "water board letter." Information to obtain the RRC Webpage in the Quick Links Section under the Groundwater Advisory Unit.
2. With Form W-14, a letter stating that the proposed injection will not endanger usable quality groundwater is required. An applicant may request this letter from the RRC Groundwater Advisory Unit by filing two copies of the Form W-14, a plat showing the location of the well with surveys marked, and a representative electric log.

Area of Review

The purpose of this requirement is to identify any wells near the proposed injection well which may provide an avenue for migration of injected fluids out of the proposed disposal/injection zone.

1. A map of all wells of public record within a 1/4-mile radius of the proposed injection/disposal well showing the total depth of each well is required. Click here for an example.

MAP GUIDELINES:

- Use a current map.
- Use a legible map clearly showing operator names, lease names, and well numbers.
- Draw 1/4 mile radius around the well, wells (multi-well applications), or lease (area permit applications).
- Always provide map scale.
- Be able to distinguish wells with same numbers.

2. The RRC Public GIS Map Viewer is the map that RRC staff will use to verify that all wells within a 1/4-mile radius have been examined.

RRC MAPPING DATABASE:

- The interface allows you to locate the well by API number, Lease Id number, Survey or GPS coordinates.
- You may also navigate by zooming in using landmarks such as cities and highways.
- You may use the "MAP TOOLS" function to to either navigate, identify wells, surveys or draw a 1/4 or 1/2 mile circle around the subject well.

3. A table of wells within the 1/4-mile radius that penetrate the top of the injection/disposal zone is required. Click here for an example. For each well, list the well name and number, date drilled, and current status, including the date plugged if applicable.

TABLE OF WELLS GUIDELINES:

- List all wells within 1/4 mile radius around the well, wells (for multi-well applications), or lease (for area permit applications) that penetrate the top of the proposed injection zone.
- For each well, show the well names, well numbers, API numbers and Total Depth.
- For each well, show date drilled, current status, and date plugged (if applicable).
- Include a copy of the plugging report for any wells plugged prior to January 1, 1967.
- If records are not readily available for any plugged wells, include copies of the plugging report to expedite processing.

4. If space allows, the Map and Table of wells within the 1/4-mile radius can be combined.
5. For area permit applications, the Area of Review consists of the entire lease area, plus a 1/4-mile radius outside the lease boundary.

Historical Seismic Events

Any application for a new disposal well permit or an amendment of an existing disposal wellpermit for pressure, injection rate, or interval must include a survey of historical seismic events.

A survey of historical seismic events is a printed copy or screenshot showing the input parameters and results of a survey of information from the United States Geological Survey (USGS) regarding the locations of any historical events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the disposal well location. The USGS Earth Archive Search may be found at the following link: (http://earthquake.usgs.gov/earthquakes/search/).

To use the USGS Earth Archive Search, enter the following parameters:

- DATE & TIME: Start (UTC); 1973-01-01 00:00:00
- MINIMUM MAGNITUDE: 2
- CIRCLE: Center Latitude and Center Longitude; Enter the location of the proposed Disposal Well using a WGS84 or NAD83 datum
- CIRCLE: Inside Radius; Leave blank or enter 0
- CIRCLE: Outside Radius; Enter 9.08

Notice

The notification process ensures that all affected parties are informed and have opportunity to protest the permitting of the proposed injection well.

1. Map of all wells of public record within the 1/2-mile radius of the proposed injection/disposal well clearly labeled showing each Commission designated operator of any well or active drilling permit location.
2. Mail or deliver a copy of the application form(s), both front and back, to:

    - the owner "of record" of the surface of the tract on which the well is located.. Owner "of record" is the owner that is listed on deed and tax records
    - each Commission designated operator of any well or active drilling location within 1/2-mile of the proposed disposal/injection well (excluding permanently plugged wells)
    - the county clerk for the county where the well is located
    - the city clerk if the well is located within corporate city limits

If the application is for commercial disposal, notice must also be given in the same manner to owners "of record" of each surface tract that adjoins the proposed disposal tract. If the tract has been subdivided, then notify all surface owners of record within a 1/2-mile radius of the wellbore. Although not required, we recommend that you include a cover letter to briefly explain the nature of the application.

3. Provide a signed statement listing name, address, and relation to the application (i.e. offset operator, surface owner, etc.) and the date that a copy of the application (*front & back*) was mailed or delivered to each of the required recipients. If there is no active operators within the 1/2-mile indicate that on the signed statement.
4. Notice of the application must be published once by the applicant in a form approved by the Commission for Form W-14 or Form H-1 in a newspaper of general circulation in the county where the well is located. Notice instructions and forms may be obtained from the Commission's Austin office, district offices, or downloaded from this website. The following information must be submitted with the application:

- Affidavit of publication. The affidavit must be notarized and must state that the newspaper has general circulation in the county where the well is located.
- Newspaper clipping.

PUBLICATION GUIDELINES:

- Indicate that the formation is productive or non-productive of oil and gas.
- Include Formation Name(s).
- Inlcude the Field and Lease Name(s).
- Include the Well Number(s).
- The direction/miles from the nearest town must be consistent with the information in the application.
- The injection interval/disposal zone must be consistent with the information in the application.
- For H-1 applications where several wells are involved, use the top of the shallowest and the bottom of the deepest interval for the subsurface depth interval.
- Notice must be published (once for injection or disposal under Rules 9 or 46 and once a week for three consecutive weeks for hydrocarbon storage under Rule 95, 96, or 97) at your expense on or before the day the application is filed.
- The newspaper need not be in the same county as the well, but must have general circulation in that county.
- The legal authority paragraph must be included in the publication.
- The notice must contain instructions for persons who wish to protest the application or who wish to request further information concerning the application.
- The published notice for commercial disposal wells shall include the language "Application for Commercial Oil and Gas Waste Disposal Well."
- The published notice for an area permit shall include the language "Area Permit Application."

5. For commercial applications, submit a plat showing the legal tract of land on which the well is located and clearly label the adjoining offset landowners.

LAND OWNERSHIP MAP GUIDELINES:

- Clearly show the location of all wells of public record within one-half mile radius of the proposed injection/disposal well.
- Identify the commission designated operators of wells within one-half mile of the proposed injection/disposal well.
- For a commercial disposal well application, show the owners of record of the surface tracts that adjoin the proposed disposal well tract.

6. Include a list of the names and addresses of the surface owners or record, operators or wells within one-half mile, county clerk, and, if applicable, city clerk.
7. Submit a signed statement indicating the date that a copy of the application form(s) was mailed or delivered to each person on the list.

NOTE:

Operators of wells or wells with active drilling permits withink one-half mile must be notified regardless of the status of the wells. The only wells that may be excluded are wells that have been permanently plugged and abondoned.

Fresh Water Injection

The injection of fresh water as a make-up fluid is restricted to cases where there is no technically or economically viable alternative. This part of the permit review verifies that all alternatives have been investigated.

1. Fresh water questionnaire to justify use of fresh water.
2. Form H-7 (Fresh Water Data Form)

    - Chemical analysis of fresh water to be injected.
    - Plat outlining fresh water rights.

NOTE:

If fresh water is purchased, only the fresh water questionnaire is required.

The Commission is required by statute to forward a copy of an application involving injection of fresh water to the RRC Groundwater Advisory Unit for comment. The GAU has up to 30 days to respond.

Requests for Exception

Requests to construct and operate a well in a manner other than that specified in the rules requires an exception to the specific requirement.

1. Types.

    - Tubing and packer - to inject down casing without tubing and packer.
    - Packer setting depth - to allow the packer to be set higher than normally allowed.
    - Pressure observation valves - to waive the requirement for wellhead pressure valves on the tubing and each annulus.

2. Request must be in writing and include the $375 filing fee.

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Research

The 2017-2019 Research Project Portfolio is undergoing final edits and will be posted very soon.

Theme	#	Project Title
TexNet Seismic Network	1	Network Operations
Seismology	2	Texas Seismology Studies
	3	Seismicity Studies in Texas and New Mexico
	4	Ft Worth Basin Seismicity and Poroelastic Studies
	5	West TX Seismicity using Lajitas Array and EDT Pre-TexNet
	6	Midland Basin Seismicity Monitoring and Analysis
Geologic Characterization	7	Texas Injection and Production Analytics
	8	Ft Worth Basin Geological and Mechanistic Characterization
	9	Permian Region Geological and Mechanistic Characterization
	10	Geological Characterization (Eagle Ford and Cogdell)
Fluid Flow and Geomechanics	11	Ft Worth Basin Hydrogeologic Modeling
	12	Ft Worth Basin Fast Marching Pore Pressure Simulation
	13	Delaware Basin Hydrogeologic Modeling
	14	Geomechanics of Fault Reactivation
	15	Site-Specific Fault Reactivation Models (FWB and Permian Region)
	16	Mechanical Framework of Induced Seismicity in the Delaware Basi
	17	Fluid Injection and Earthquake Size in Faulted Reservoirs
Seismic Hazard and Risk Assessment	18	Time Dependent Seismic Hazard
	19	Refining Velocity Models to 500m using Surface Wave Profiling
	20	Infrastructure Vulnerability
Results and Info Distribution	21	Geodatabase
	22	Summary of Findings, Reporting, and Outreach
Overhead: PIs and Directorship	23	Program Development, Direction, Government/Industry Interface

Once finalized this page will show the details of the 2017-2019 research projects.

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Ellenburger wastewater injection and seismicity in North Texas

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ABSTRACT

North Texas has experienced a roughly exponential increase in seismicity since 2008. This increase is primarily attributable to wastewater injection into the Ellenburger Formation—a carbonate formation located within and just above seismically active zones. To our knowledge, there has been no previous comprehensive ~10 year analysis comparing regional seismicity with basin-wide injection and injection pressure of wastewater into the Ellenburger, even though monthly injection/pressure records have been made publically available for nearly a decade. Here we compile and evaluate more than 24,000 monthly injection volume and pressure measurements for the Ellenburger formation. We compare Ellenburger injection pressures and volumes to basin-wide injection pressures and volumes, and to earthquake locations and rates. The analysis shows where cumulative injection volumes are highest, where injection pressures and formation pressures are increasing, how injection volumes have changed regionally with time, and how Ellenburger injection volumes and pressures correlate in space and time with recent seismicity in North Texas. Results indicate that between 2005 and 2014 at least 270 million m^3 (~1.7 billion barrels) of wastewater were injected into the Ellenburger formation. If we assume relative homogeneity for the Ellenburger and no significant fluid loss across the 63,000 km^2 basin, this volume of fluid would increase pore fluid pressure within the entire formation by 0.09 MPa (~13 psi). Recent spot measurements of pressure in the Ellenburger confirm that elevated fluid pressures ranging from 1.7 to 4.5 MPa (250–650 psi) above hydrostatic exist in this formation, and this may promote failure on pre-existing faults in the Ellenburger and underlying basement. The analysis demonstrates a clear spatial and temporal correlation between seismic activity and wastewater injection volumes across the basin, with earthquakes generally occurring in the central and eastern half of the basin, where Ellenburger wastewater injection cumulative volumes and estimated pressure increases are highest. The increased seismicity correlates with increased fluid pressure, which is a potential cause for these earthquakes. Based on these results, we hypothesize it is plausible that the cumulative pressure increase across the basin may trigger earthquakes on faults located tens of kilometers or more from injection wells, and this process may have triggered the Irving-Dallas earthquake sequence. We use these results to develop preliminary forecasts for the region concerning where seismicity will likely continue or develop in the future, and assess what additional data are needed to better forecast and constrain seismic hazard.

1. Introduction

The Bend Arch-Fort Worth Basin in North Texas has experienced a rapid increase in the number of earthquakes beginning in 2008 (Fig. 1). This basin includes the largest metropolitan area in the southern United States–the Dallas-Fort Worth Metroplex. Prior to 2008, no confirmed felt earthquakes had occurred in the basin despite more than 160 years of settlement and more than 40 years of seismic monitoring (Frohlich and Davis, 2002; Frohlich et al., 2011, 2016). Since 2008, however, earthquakes in the Fort Worth Basin have generally increased in number, magnitude, and hence moment release, with the basin experiencing its largest (M4.0) earthquake in 2015 (Fig. 2).

There have been numerous investigations concerning the cause of recent earthquakes in North Texas and most conclude that the injection of oil and gas flowback brine water into deep sedimentary formations is probably responsible for reactivating faults and causing seismicity in the basin (Frohlich et al., 2011, 2016, 2012; Justinic et al., 2013; Gono et al., 2015; Hornbach et al., 2015). All

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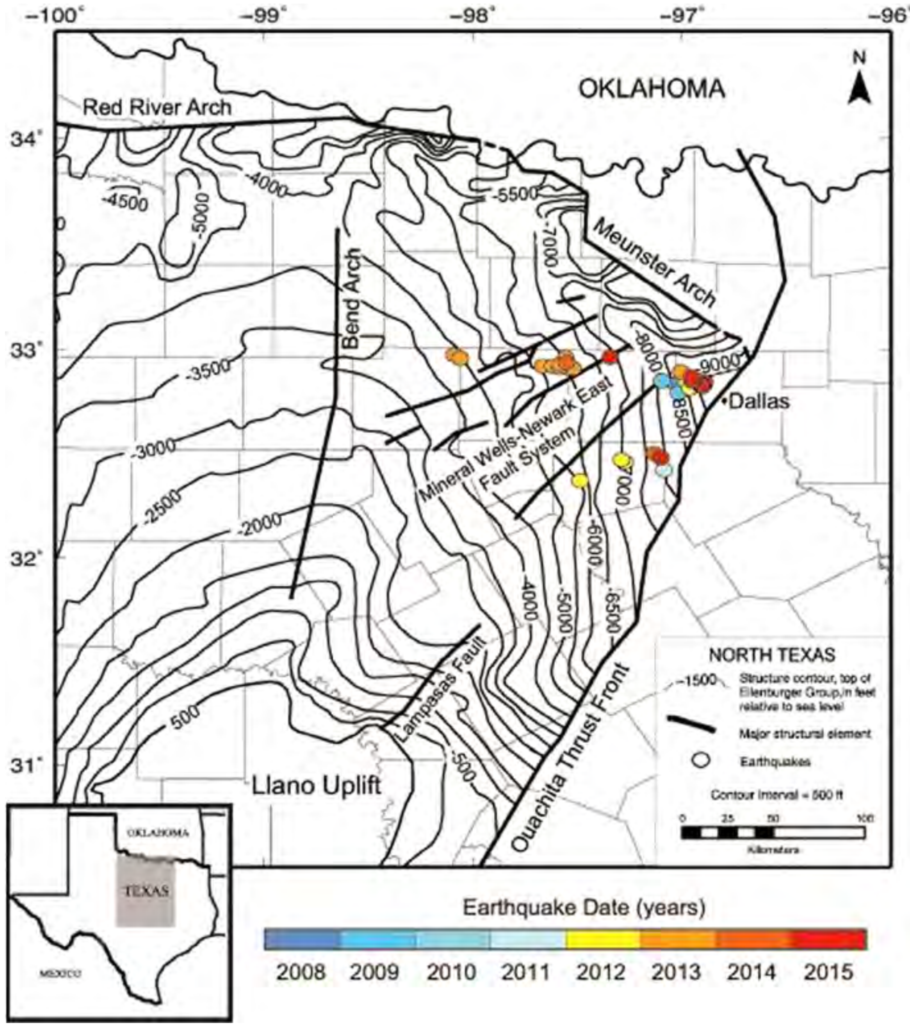

Fig. 1. Map of the Bend-Arch Fort Worth Basin showing earthquake epicenters reported in the USGS ANSS Catalog (location uncertainty of ~10 km). Contours indicate the top of the Ellenburger formation based on Pollastro et al. (2007). The basin depocenter is below the cities of Irving and Dallas in western Dallas County, where a significant increase in seismicity occurred in the past 3 years.

of these investigations focus on discreet relationships between regional wastewater injection sites and earthquakes. An important unanswered question is why some high volume injection sites induce earthquakes while others do not. Fully addressing the induced seismicity hazard requires understanding not only subsurface pressure changes but also the local stress regime. Although the stress regime in the Fort Worth Basin is only marginally constrained, published earthquake focal mechanism across the basin (e.g. Justinic et al., 2013; Hornbach et al., 2015) suggest the maximum principal stress direction extends in a northeast to southwest direction consistent with regional stress studies (e.g. Zoback and Zoback, 1980).

Two of the investigations assessing the cause of earthquakes in the Fort Worth basin (Gono et al., 2015; Hornbach et al., 2015) modelled subsurface permeability, pressure, and structure to estimate pore fluid pressure changes over time. Although both studies concluded regional seismicity is most likely induced by wastewater injection, a limitation of these modeling studies is their inability to fully account for subsurface complexity, and thus to constrain completely how pressures and volumes of injected wastewater influence subsurface stress. Specifically, significant uncertainties concerning fault locations, fault orientations, fault permeability, fluid flow paths, and regional stress regimes often limit the applicability of such modeling investigations. Limitations of these studies, combined with a decade of pressure and injection data made available by the Texas Railroad Commission, motivate us to explore alternative methods for forecasting where future seismicity might occur as wastewater injection continues in the basin.

In the present investigation we apply an alternative statistical approach that avoids the uncertainties associated with detailed 3D fluid flow modeling; we make straightforward statistical comparisons between wastewater injection practices, subsurface pressures, and regional seismicity. Statistical methods comparing seismicity and injection have found a correlative relationship in other large basins, especially in Oklahoma (e.g. Walsh and Zoback, 2015; Weingarten et al., 2015). In the Fort Worth Basin, Frohlich (2012) compared wastewater injection locations with regional seismicity during the two years when the US Earthscope Transportable Array was deployed across the area. Additionally, for 13 of the 28 counties located in the Fort Worth Basin, Gono et al. (2015) produced a nearly basin-scale fluid model noting the relationship between modeled subsurface pressure in the Ellenburger and regional seismicity. While both of these investigations found a spatial association between wastewater injection, subsurface injection pressure, and regional seismicity, neither evaluated the complete publically available pressure/volume data for all wastewater injection wells in the Ellenburger for the entire ~ 10 year period when seismicity has increased significantly (Fig. 2).

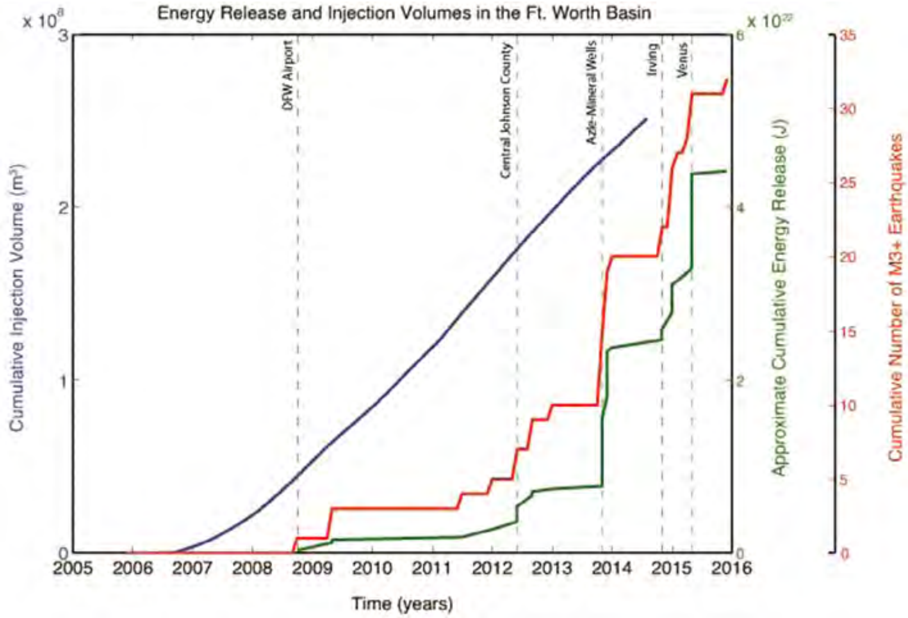

Fig. 2. Cumulative injection volumes, number of earthquakes at magnitude 3 and greater, and scalar moment which we use as a proxy for seismic energy release in the Ft. Worth Basin since 2005. Injection data were taken from the Texas Railroad Commission and earthquakes are M3.0 and above from the USGS Catalog. The energy is calculated by multiplying the scalar moment by a constant using the approach of Hanks and Kanamori (1979). Dashed lines represent the beginning of a sequence containing two or more magnitude 3 earthquakes.

For all 28 counties within the Fort Worth Basin, the present investigation compiles and analyzes earthquake locations for all USGS-reported earthquakes of magnitude 3 or greater, as well as more than 24,000 monthly injection volume and pressure measurements for the years 2005–2014 using data available online and archived by the Texas Railroad Commission. We use these data to assess the relationship between wastewater injection, time, pressure, and seismicity in North Texas over a ~10 year period and to generate forecasts for seismicity in the region.

2. Geologic background

2.1. Tectonic setting

The Bend Arch-Fort Worth Basin is an Ordovician age (greater than400 Ma) sedimentary basin covering an area of ~63,000 km^2 in North Central Texas. The basin is an asymmetric feature bounded by the Ouachita thrust and fold belt to the east, the Muenster Arch and Amarillo Uplift to the north, the Bend Arch structural fold belt to the west, and the Llano uplift to the south (Fig. 1) (e.g. Montgomery et al., 2005; Pollastro et al., 2007). Sediments in the basin dip east-northeast with the deepest part of the basin located below the city of Dallas at a depth of ~3700 m below sea level (Fig. 1) (Core Laboratories Inc, 1972; Pollastro et al., 2007). Although only a few large faults are mapped in the basin, nearly all follow a similar strike that extends along a southwest-northeast trend (e.g. Budnik et al., 1990; Ewing, 1991), consistent with regional seismic reflection studies (e.g. Sullivan et al., 2006) and the estimated current maximum horizontal stress direction (e.g. Zoback and Zoback, 1980; Huffman, 2003; Heidbach et al., 2008). Regional fault studies indicate the basin has not experienced widespread or significant tectonic activity for the past ~300 Ma (e.g. Muehlberger, 1965; Rozendal and Erskine, 1971; Huffman, 2003). Thus considering these observations, the occurrence of frequent felt earthquakes since 2008 within the basin is highly anomalous (Sullivan et al., 2006; McDonnell et al., 2007; Frohlich, 2012; Hornbach et al., 2015).

2.2. Recent seismicity

In the Fort Worth Basin since 2008, the cumulative number of earthquakes having magnitudes of 3 or more increases roughly exponentially, with discreet increases associated with individual earthquake sequences (Fig. 2). Many North Texas earthquake sequences do not follow typical mainshock-aftershock patterns but consist of swarms of small earthquakes. These include sequences in eastern Tarrant County near the Dallas-Fort Worth (DFW) airport beginning in 2008 (Frohlich et al., 2011), in Johnson County near Cleburne beginning 2009 (Justinic et al., 2013), in central Johnson County in 2012 and near Venus in eastern Johnson County in 2011(Frohlich, 2012) and again in 2015, in Dallas and Irving beginning in 2012 and continuing intermittently up to the present, and in Parker and Palo Pinto Counties near Azle and Mineral Wells beginning in 2013 and continuing intermittently up to the present (e.g. Hornbach et al., 2015). All these earthquakes occur either within the deepest and oldest sedimentary formations of the basin (primarily the Ellenburger), or in the basement Precambrian granite immediately underlying, and likely in direct pressure communication with, the Ellenburger (Frohlich et al., 2011; Justinic et al., 2013; Hornbach et al., 2015). The published investigations of all these sequences concluded that it was plausible or probable that they were induced by increased subsurface fluid pressures associated with the injection of wastewater. These results are also consistent with numerous recent studies that suggests fluid injection into formations directly above basement faults, such as the Ellenburger, increases the likelihood of earthquake activity (e.g. Frohlich, 2012; Ellsworth, 2013; National Research Council, 2013; McGarr, 2014; Walsh and Zoback, 2015; Rubinstein and Mahani, 2015).

2.3. The source of wastewater injected into the Ellenburger

The wastewater injected into the Fort Worth Basin is a byproduct of gas production mostly from the Barnett Shale (Montgomery et al., 2005; Bowker, 2007; Jarvie et al., 2007), an organic rich but geologically tight formation. Although the Barnett has high hydrocarbon production potential, its low permeability (typically less than 10^{-18} m^2) makes it difficult to exploit using conventional methods. The Barnett Shale unconformably overlies the Viola limestone and Ellenburger dolomite/limestone formations and underlies the Marble Falls Limestone formation (Fig. 3). The low permeability of the Barnett forms a natural seal, separating the Marble Falls and Ellenburger limestone aquifers from each other. Gas production for the Barnett Shale requires hydraulic fracturing, and a byproduct of this practice is wastewater (also called brine) that usually contains high concentrations of total dissolved solids. This brine is produced as a result of both flowback from hydraulic fracturing and from extraction of naturally occurring formation water. Brine produced in typical oil and gas fields can have total dissolved solids in excess of 250,000 ppm (Gregory et al., 2011), ~10x saltier than seawater. To avoid environmental surface damage, oil and gas companies typically reinject brines into deep, isolated saltwater formations that are not in communication with shallower, fresh water aquifers.

We estimate that a majority of the water being injected into the Ellenburger is flowback water associated with the hydraulic fracturing process. According to the Texas Railroad Commission website, at least 15,000 unconventional wells have been drilled in the Barnett Shale. The average well in the Barnett shale that is hydraulically fractured uses between 11,000 and 19,000 m^3 (69,000–119,000 bbls) of water (Nicot et al., 2014). If injected

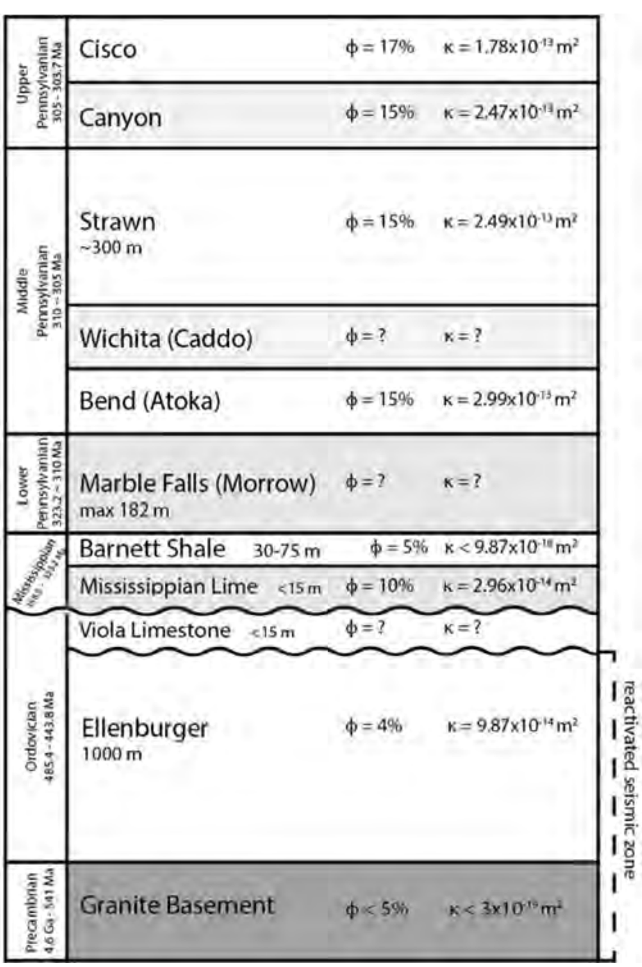

Fig. 3. The main formations used for wastewater injection in the Fort Worth Basin with respective porosities (ϕ) and permeabilities (κ). Figure shows approximate relatively thicknesses in the center of the basin. (Core Laboratories Inc. 1972; Gale et al., 2007; Montgomery et al., 2005; Loucks et al., 2009; Pollastro et al., 2003; Brace et al., 1968; Skoczylas and Henry, 1995; Geraud, 1994).

water is ultimately recovered from each well during production, then the total amount of flowback water from Barnett production ranges from 175 to 285 million m^3 (1.1–1.8 billion bbls). As we will show, this amount is equivalent to ~65–106% of the total volume of water injected into the Ellenburger since 2005. Thus, the amount of water used to hydraulically fracture the Barnett from 2006 to 2014 is consistent to first-order with the amount of wastewater injected into the Ellenburger during that same time.

2.4. The fate of oilfield wastewater

Currently, oil and gas companies reinject wastewater into several different formations in the Fort Worth Basin. These formations, from shallowest to deepest, include (but are not limited to) the Cisco, Canyon, Strawn, Caddo, Atokan, Marble Falls, and the Ellenburger formations (Fig. 3). The age of the youngest formation outcropping at the surface of the basin is no younger than 65 Ma. The Ellenburger is the oldest (age >450 Ma), deepest, and thickest: it is a massive, ~1 km thick karsted dolomite/limestone formation that extends across the entire basin (e.g. Core Laboratories Inc, 1972; Pollastro et al., 2007; see also Fig. 1). The Ellenburger overlies basement granite wash and unconformably underlies the Viola Limestone and Barnett Shale (Fig. 3) (e.g. Montgomery et al., 2005; McDonnell et al., 2007). The top of the Ellenburger formation is shallowest in the west, averaging a depth of ~1000 m near the Bend Arch, but steadily deepens to the east, toward the formation depocenter and lowest potential drainage point at a depth of ~2800 m below sea level under the cities of Irving and Dallas (Core Laboratories Inc, 1972) (Fig. 1).

The Ellenburger is the single largest aquifer in Texas, and it contains waters ranging in salinity from fresh at its shallow locations to hyper saline (150,000 ppm, ~5x seawater) at greater depths (Core Laboratories Inc, 1972). Despite its significant volume, some physical properties of the Ellenburger are not ideal for wastewater storage: it has generally lower porosity (Φ) and permeability (κ) than other shallower Fort Worth Basin aquifers (Fig. 3), and although thick and therefore voluminous, regional seismic surveys indicate the Ellenburger is at many locations in direct contact with basement faults. Some of these basement faults extend through the Ellenburger and into the Barnett, providing connectivity between the units (e.g. Khatiwada et al., 2013). The Ellenburger formation porosity ranges between 2% and 12% but averages only 4% (Core Laboratories Inc, 1972). Regional studies combined with pressure fall-off tests indicate the formation has moderate permeability (0.1–500 mD) and, since it directly overlies the basement, fluids in the Ellenburger formation are likely in direct communication with basement faults at many sites.

The Ellenburger is largely a non-productive formation and, unlike many other formations in the basin where oil and gas have been produced extensively, has experienced only very limited fluid extraction for hydrocarbon production in the Fort Worth Basin. Some fluids have been intentionally extracted from the Ellenburger on the far western edge of the basin on top of the Bend Arch anticline or outside the basin entirely (e.g. Autry, 1940; Bradfield, 1964; Loucks and Anderson, 1985) and in limited instances, hydraulic fracturing has caused fracturing into the Ellenburger (Pollastro et al., 2007). For the vast majority of hydraulic fractures within the Barnett shale, however, there is little or no evidence of significant water flowback from the Ellenburger, with annual water production (G-1 and G-10) test reports provided by the Texas Railroad Commission typically indicating no significant flowback occurring within a year of the onset of production. Previous studies also suggest significantly more brine is injected into the Ellenburger than is produced from the Ellenburger in a particular region (e.g. Hornbach et al., 2015). Thus, while the Ellenburger is one of the largest brine sinks in the region, it has experienced only

Table 1
Total Ellenburger and total injection volumes by county, compiled from all available data accessible through the Texas RRC website, from December 2005 to November 2015.

County	County Area in Fort Worth Basin (sq.km)	Ellenburger - Total Volume (cubic m)	Total Volume (cubic m) *TRRC reports date back no further than 2005*	Ellenburger Volume/ Total Volume	Ellenburger - Total Volume per County Area (cubic m per sq. km)	Ellenburger - Total Volume per County Area (meters)	Total Volume per County Area (cubic m per sq.km) *TRRC reports date back no further than 2005*	Ellenburger Volume per Area/Total Volume per Area	# Inj Permits	# Inj Permits Ellenburger Only	# Inj Permits with H-10 data Ellenburger Only	# Inj Permits w/H-10 data in Ellenburger/ # Inj Permits
Archer	2357	43,147	2,17,31,269	0.199%	18	0.000018306	9220	0.199%	2716	5	2	0%
Bosque	2561	0	0	–	0	0.000000000	0	–	2	2	0	–
Brown	2445	0	16,49,521	0.000%	0	0.000000000	675	0.000%	540	0	0	0%
Burnet	2577	0	0	–	0	0.000000000	0	–	0	0	0	–
Clay	2683	1,35,601	96,30,627	1.408%	51	0.000050535	3589	1.408%	981	9	2	0%
Comanche	2429	0	34,031	0.000%	0	0.000000000	14	0.000%	43	0	0	0%
Coryell	2562	0	0	–	0	0.000000000	0	–	3	0	0	–
Dallas	801	0	0	–	0	0.000000000	0	–	0	0	0	–
Denton	1541	63,03,866	64,45,431	97.804%	4090	0.004089793	4182	97.804%	40	5	3	8%
Eastland	2398	8,81,730	1,80,92,628	4.873%	368	0.000367694	7545	4.873%	831	7	4	0%
Erath	2813	11,65,433	14,05,908	82.895%	414	0.000414302	500	82.895%	36	13	6	17%
Hamilton	2165	0	26,424	0.000%	0	0.000000000	12	0.000%	9	2	0	0%
Hill	1023	30,77,541	30,79,829	99.926%	3008	0.003007999	3010	99.926%	10	3	3	30%
Hood	1093	1,93,55,818	2,19,76,196	88.076%	17,709	0.017708891	20,106	88.076%	31	20	13	42%
Jack	2375	1,04,86,081	2,56,86,745	40.823%	4415	0.004415192	10,815	40.823%	1129	41	25	2%
Johnson	1888	11,22,01,133	11,38,80,566	98.525%	59,429	0.059428566	60,318	98.525%	39	39	27	69%
Lampasas	1844	0	0	–	0	0.000000000	0	–	0	0	0	–
Mills	1937	0	0	–	0	0.000000000	0	–	0	0	0	–
Montague	2107	1,32,58,069	6,83,20,137	19.406%	6293	0.006293035	32,429	19.406%	947	17	8	1%
Palo Pinto	2468	71,14,911	1,27,58,373	55.767%	2883	0.002882865	5170	55.767%	378	33	15	4%
Parker	2341	3,54,16,831	3,77,59,218	93.797%	15,129	0.015128933	16,130	93.797%	65	19	16	25%
San Saba	2937	0	0	–	0	0.000000000	0	–	0	0	0	–
Somervell	484	1,00,52,570	98,43,163	102.127%	20,770	0.020769772	20,337	102.127%	6	6	5	83%
Stephens	2318	14,93,560	30,66,97,456	0.487%	644	0.000644331	1,32,311	0.487%	1621	11	9	1%
Tarrant	2238	3,10,02,071	3,60,51,412	85.994%	13,853	0.013852579	16,109	85.994%	14	13	9	64%
Wichita	1462	46,338	10,25,40,669	0.045%	32	0.000031685	70,116	0.045%	4931	4	2	0%
Wise	2344	1,68,39,841	3,32,19,943	50.692%	7184	0.007184232	14,172	50.692%	287	18	8	3%
Young	2388	9,39,788	2,54,35,266	3.695%	394	0.000393546	10,651	3.695%	1938	23	10	1%
TOTAL	58,580	26,98,14,329	85,62,64,812	32%	1,56,682	0.15668226	4,37,410	36%	16,597	290	167	1%

limited fluid removal that might reduce formation pressures, particularly near the depocenter of the Fort Worth Basin.

3. Methodology

3.1. Data compilation

Wastewater injection/pressure data for Class II injection wells in Texas are collected and archived by the Texas Railroad Commission and publically available online. Since 2006, monthly pressure and injection volumes for each well site have been compiled annually at the end of each fiscal year on H-10 forms and provided publically online by the Texas Railroad Commission. Of a total of 290 verified disposal well permits for the Ellenburger in the Fort Worth Basin, we found 167 wells with H-10 reports, providing detailed injection volumes and well-head pressures from as early as late 2005 through September 2014 (Texas Railroad Commission, last accessed December 2015). To determine which formation wells inject into, we analyzed injection disposal permits. In instances where the injection formation is not specified explicitly, we identified it from the injection depth interval combined with regional subsurface formation tops (e.g. Pollastro et al., 2007). We compile and summed monthly Ellenburger injection volumes and pressures at all locations throughout the Bend-Arch Fort Worth Basin, spanning a total of 28 counties (Table 1).

We analyzed broad-scale pressure and injection trends by estimating (1) the volume injected per unit area, by county, over time, (2) the mean change in formation compressibility (see below), (3) the relative number and location of Ellenburger injectors, by volume, compared to the total number of injectors and the total injection volume in the basin, and (4) the spatial and temporal relationship between Ellenburger injection volumes, pressures/volume ratios, and regional seismicity. H-10 reports indicate how often pressure measurements were made at each well site. To ensure temporal consistency for injection pressure measurements, we only analyze pressures at wells where H-10 reports indicate daily pressure measurements were made to estimate an average monthly injection pressure. The full analysis, incorporating more than ~24,000 monthly data points, is used to make basic observations regarding wastewater injection, injection pressure, and seismicity in and below the Ellenburger.

3.2. Calculation of pressure and apparent compressibility

Assessing changes in relative formation compressibility provides important insight into subsurface fluid pressures changes, and in particular, allows us to identify locations where fluid pressure increases with time, promoting seismicity. For a given geological formation, if fluids are added faster than fluids leave, the formation pressure increases, and will continue to increase until there is failure via either plastic deformation, hydraulic fracture, or fault slip. It is well established that increasing fluid pressures increases the risk of seismicity and rock fracturing (e.g. Terzaghi, 1943; McLatchie et al., 1958; Zoback and Hickman, 1982), and that faulting may help relieve pressures in some areas, while increase stress in other areas (e.g. Stein, 1999). For each injector site where daily pressure measurements were made, we calculate changes over time in the formation as apparent compressibility, β

$$\beta = \frac{1}{V_e}\frac{\mathrm{dV}}{\mathrm{dP}} \tag{1}$$

here dV is the change in monthly volume injected at each injector site, dP is the change in mean monthly injector pressure at each injector site, and V_e is the approximate volume of the Ellenburger formation, which we estimate from isopach maps to be ~63,000 km^3 (Core Laboratories Inc, 1972). β represents an apparent compressibility and not a true compressibility because the calculation is local and uses pressures measured at the well head, not within the formation. Although this approach does not provide the true compressibility, the value calculated provides insight into whether compressibility, and therefore subsurface pressure, is increasing, decreasing, or holding steady with time at each injection site. One way to visualize or characterize what we are assessing is revealed in the $\frac{\mathrm{dV}}{\mathrm{dP}}$ term of the equation. If more pressure is required to inject the same volume of wastewater in a given time, then the pressure in the formation near the well site is increasing and the compressibility of the formation is decreasing.

We can calculate the average, basin-wide pressure change in the Ellenburger formation by recasting the compressibility equation in terms of a change in pressure, dP:

$$dP = \frac{1}{V_f}\frac{\mathrm{dV}}{\beta_f} \tag{2}$$

here dP is the average change in fluid pressure in the pores in the Ellenburger formation; V_f, the pore fluid volume for the Ellenburger for the basin, is calculated assuming an average porosity of 4% (Core Laboratories Inc, 1972) and a formation volume of 63,000 km^3, yielding an average pore volume of 2520 km^3; β_f, the average formation compressibility, estimated directly by studies commissioned by the Texas Railroad Commission for the Ellenburger, is 1.2×10^{-3} MPa^{-1} (http://www.rrc.state.tx.us/about-us/resource-center/research/special-studies/johnson-county/); and dV is the fluid volume injected as wastewater into the Ellenburger starting in 2006 and totaling 270 million m^3 through September, 2014. Using these data, we calculate an average increase in fluid pressure throughout the entire basin of 0.09 ± 0.02 MPa (~13 ± 3 psi), where uncertainties here are attributed only to uncertainties in basin formation area and volume (Pollastro et al., 2007; Core Laboratories Inc, 1972).

4. Results and analysis

4.1. Ellenburger injection volumes

As noted above, since 2006 approximately 270 million cubic meters (1.7 billion barrels) of wastewater have been injected into the Ellenburger formation in the basin (Fig. 2). The total volume of injected fluid increases between 2006 and 2009 and has since held relatively steady at approximately 35 million m^3 per year (Figs. 4A and 4B). Between 2006 and 2008, monthly volumes increased by more than a factor of 10, averaging less than 160 thousand m^3 a month in 2006 but more than 2 million m^3 per month by the end of 2008, with injection volume rates sustained near these values since 2009. Peak monthly injection of 3.5 million m^3 per month occurred at the end of 2011 and early 2012, and since then, injection volumes have sustained high values, typically exceeding 2.5 million m^3 per month through 2014 (see Table 2).

Geographically, the most significant injection occurs in the central-eastern half of the basin, near and surrounding the basin depocenter (Figs. 1 and 5). Ten of the 28 counties within the Bend-Arch Fort Worth Basin had no injection into the Ellenburger (Table 1). There is wide variability among the 18 counties with injection reports into the Ellenburger. The counties with the five highest Ellenburger injection volumes per unit area are, in decreasing order, Johnson, Sommervell, Hood, Parker and Tarrant counties, all in the central eastern portion of the Basin near the Dallas-Fort Worth-Arlington Metroplex. These counties, which represent only 12.75% of the surface area of the basin, accommodated more than 81% of all wastewater injected into the Ellenburger formation. In addition, the highest volume individual injectors are in these

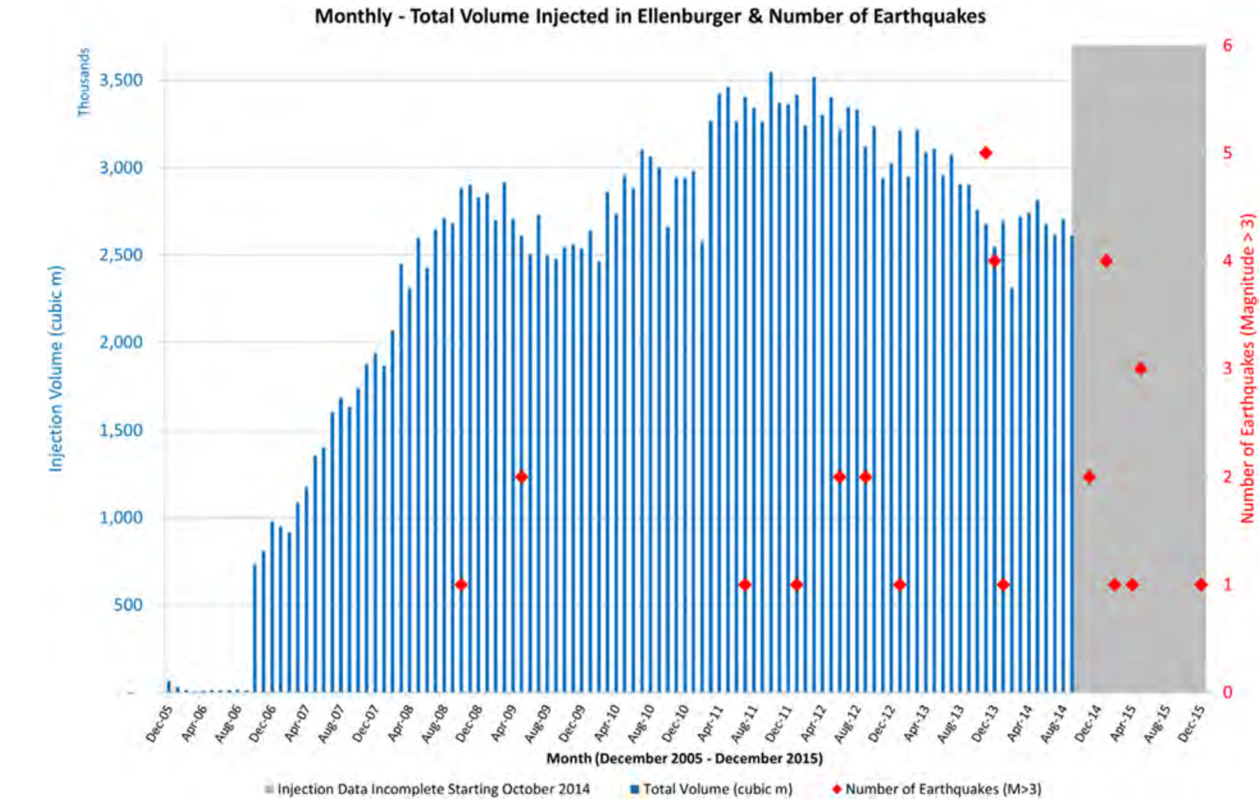

Fig. 4A. Earthquakes with magnitudes greater than 3 (red diamonds) and monthly injection rates into the Ellenburger in the Fort Worth Basin (blue bars) from December 2005 to October 2014. After October 2014 injection data is incomplete (gray box). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

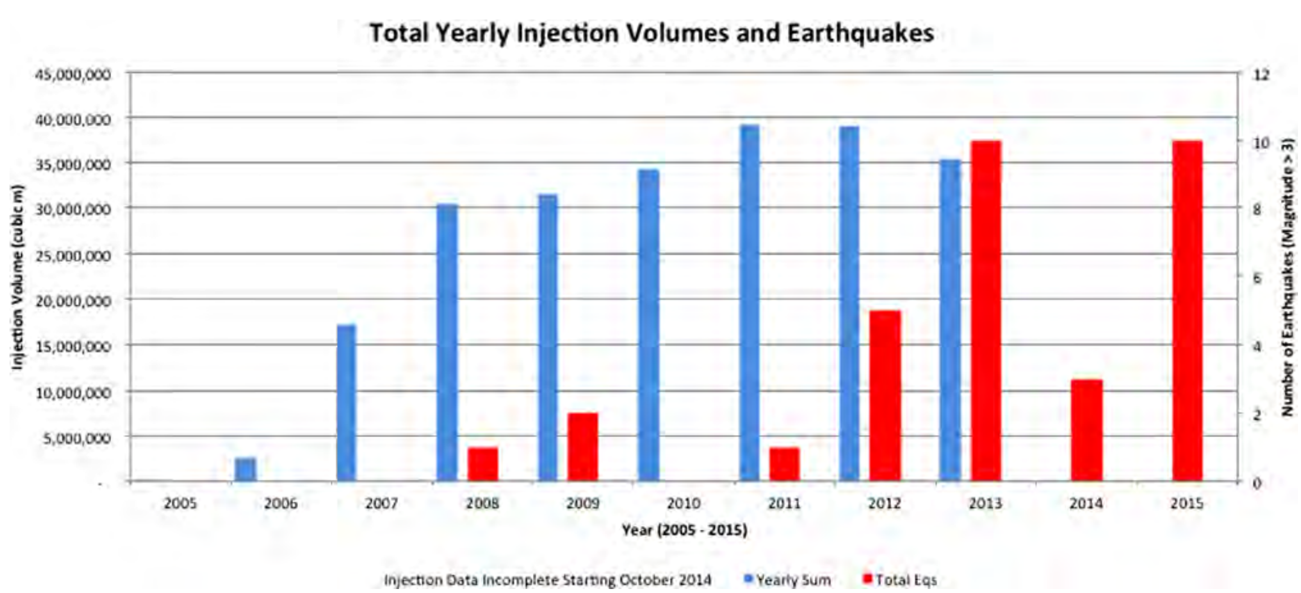

Fig. 4B. Bar chart showing the total yearly injection volume into the Ellenburger throughout the entire basin (blue) and the total number of earthquakes per year of magnitudes greater than 3.0 (red). Injection data is incomplete starting October 2014, so complete annual data are unavailable for 2014. The most rapid increases in injection volume occur from 2005 to 2008, and continues to steadily increase by 4–15% per year until 2011. From 2011 to 2013 yearly injection volumes decrease by 9–15% per year. A phase shift of two years gives the highest correlation coefficient (0.75) between annual seismicity and annual Ellenburger injection volume, however the analysis is clearly limited by available seismic data, as only earthquakes having magnitude 3.0 or greater are used. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

counties, with the largest (in Tarrant County) injecting approximately 8 million m^3 of brine into the Ellenburger between 2006 and 2014 (see Table 3). Of the 10 largest injectors, all are in three counties: Johnson (6), Tarrant (2), and Parker (2) (Table 3). These 10 wells represent only 6% of all wells in the basin injecting into the Ellenburger, but they accepted 25% of all Ellenburger

Table 2
Wastewater injection into the Ellenburger by year showing percent change and USGS reported seismicity for Magnitude 3 earthquakes by year. Annual injection volumes into the Ellenburger are based on all downloadable H-10 reports made publicly available on the Texas Railroad Commission web site.

Year	Total Injection Volume (cubic m)	% Change in Injection Volume	Total Eqs (M>3)
2005	62,627	–	0
2006	2,638,753.87	+4113%	0
2007	17,332,805.14	+557%	0
2008	30,363,307.59	+75%	1
2009	31,629,742.23	+4%	2
2010	34,244,309.21	+8%	0
2011	39,262,619.16	+15%	1
2012	39,090,310.47	-0.04%	5
2013	35,391,447.41	-9%	10
2014	–	–	3
2015	–	–	10

wastewater. If we interpolate injection volume for wells across the basin, we observe the highest injection volumes per unit area below the central and eastern portion of the basin (Fig. 6).

Temporal analysis of injection volume per unit area, aggregated by county, indicates the central-eastern half of basin experienced the highest cumulative injection volumes, and that only recently (2010–2014) has injection volume increased significantly to the north and west (Fig. 7). High injection volumes began in Johnson, Sommervell, Tarrant, Parker, and Hood counties in 2005–2008, and high annual injection volumes have since been generally sustained. From 2008 to 2010, Palo Pinto, Jack, Wise, and Denton Counties experienced significant increases in annual injection volume. More recently (from 2010 to 2014), these injection volumes increased in Wise and Montague Counties.

Although the Texas Railroad Commission does not provide total injection rates for individual formations, it does provide the total

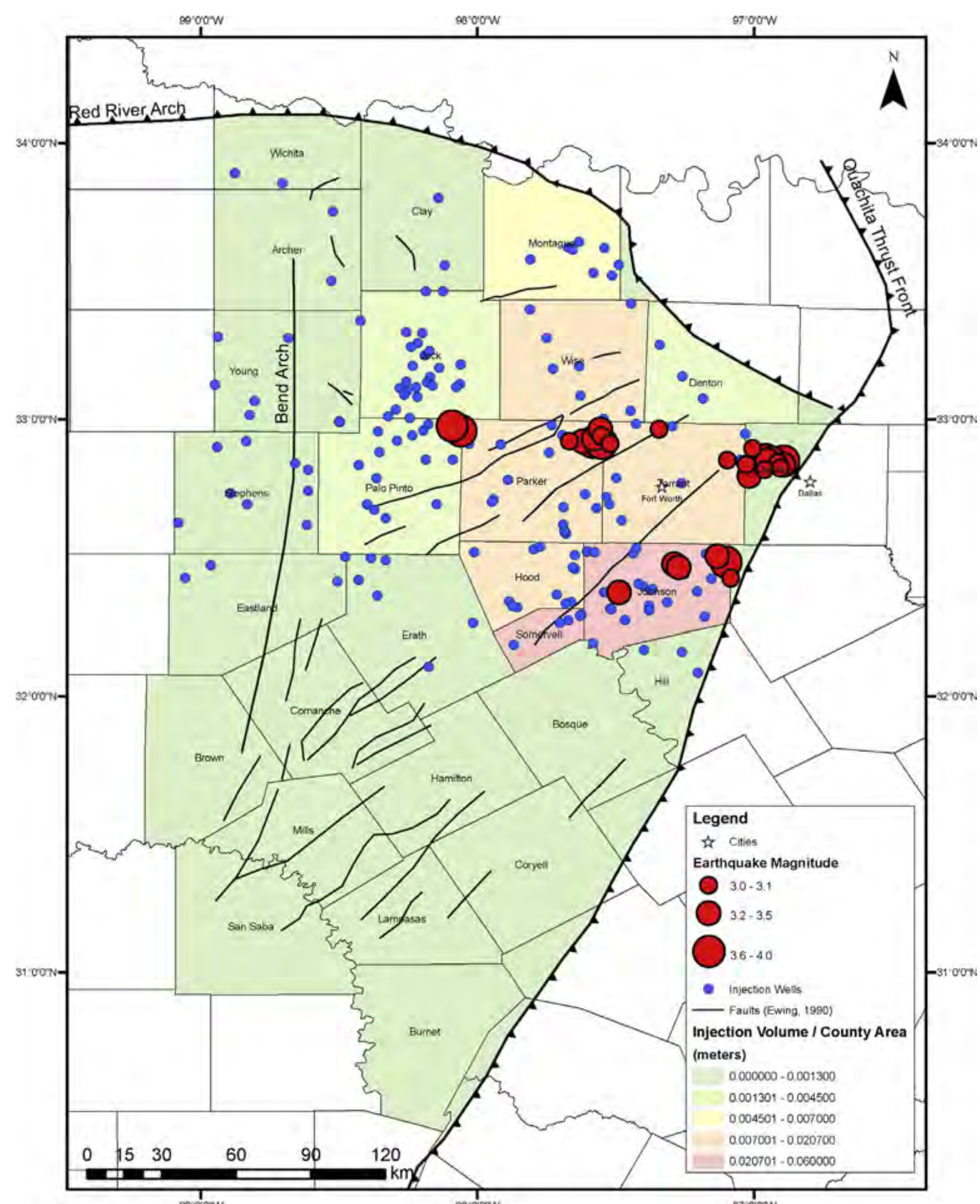

Fig. 5. The location of earthquakes (red) injection wells (blue) and injection volume per unit area, aggregated by county (colored counties). Earthquakes generally occur within or adjacent to counties where the injection volumes are highest. Our analysis of formation compressibility and subsurface pressures indicates the same areas where injection volumes are highest also experience the most significant subsurface pressure increases with time. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Table 3
Top 20 Ellenburger injectors by volume in the Fort Worth Basin from 2005 to 2014. Magnitude 3 or greater earthquakes have occurred within 10 km of 46% of the top 20 injectors, and 50% of the top 10 injectors. For the remaining 147 smaller volume injector wells in the basin, only 6% have experienced earthquakes within 10 km of their injection sites.

County	Total Volume (bbls)	Total Volume (cubic m)	No. EQs (M>3) within 10 km	Date of EQ
Tarrant	50,112,720	79,67,286.05	1	17-12-2015
Johnson	49,559,591	7,879,345.56	0	
Tarrant	47,269,368	7,515,229.19	0	
Parker	45,263,623	7,196,341.21	0	
Johnson	44,255,812	7,036,112.06	2	11/30/14, 5/7/15
Johnson	43,863,439	6,973,729.74	1	18-01-2012
Johnson	40,506,255	6,439,980.12	1	18-01-2012
Johnson	37,360,019	5,939,768.55	0	
Johnson	36,743,655	5,841,774.50	2	6–24-12, 6-15-12
Parker	35,559,264	5,653,471.37	0	
Johnson	34,468,836	5,480,107.17	0	
Johnson	33,551,658	5,334,287.52	3	5/7/15, 11/30/14, 7/17/11
Denton	33,459,656	5,319,660.37	0	
Johnson	32,680,831	5,195,837.08	0	
Tarrant	32,244,615	5,126,484.28	0	
Johnson	31,364,464	4,986,551.45	0	
Johnson	31,221,778	4,963,866.19	0	
Johnson	31,188,357	4,958,552.67	2	6/24/12, 6/15/12
Parker	29,689,424	4,720,241.36	2	11/25/13, 11/9/13
Johnson	29,076,663	4,622,820.14	2	11/30/14, 5/7/15

monthly wastewater volumes injected into all formations (not just the Ellenburger). The total volume injected for the entire basin 2006–2014 is 795 million m^3 ($\sim$5 billion barrels). Our analysis therefore indicates that approximately 1/3 of all wastewater injected into the Bend-Arch Fort Worth Basin is injected into the Ellenburger.

4.2. Comparison of Ellenburger injection volumes with basin seismicity

When earthquakes occur they generally have been in the counties with the highest injection volumes (Parker, Johnson or Tarrant Counties), or in counties immediately adjacent to these counties (Dallas, Ellis, and Palo Pinto counties). For example, Johnson, Tarrant, and Parker Counties, the three counties where wastewater disposal rates are highest, have also experienced a disproportionately large number of earthquakes, with 47% of all USGS-reported earthquakes greater than M3 occurring in these counties. Since 2005 the total volume of wastewater injected into the Ellenburger in these counties exceeds 178,600,000 m^3; this is $\sim$67% of all wastewater injected into the Ellenburger in the Fort Worth Basin. Thus, Counties that have experienced the highest injection rates since 2005 are also the counties with high earthquake concentrations. Although no wastewater injection occurs in Dallas and Ellis counties, both counties are immediately adjacent to two counties with very high wastewater injection rates (Johnson and Tarrant). Additionally, subsurface structural maps based on well logs show that in the Fort Worth basin the Ellenburger dips northward and eastward toward the Ouachita Front, reaching its deepest depth and largest thickness beneath Dallas and Ellis counties (Core Laboratories Inc, 1972; Fig. 1). Since the Ellenburger is a permeable formation, it is likely that heavier injection fluids will naturally gravitate eastward towards Dallas and Ellis counties, potentially increasing fluid pressure in this region.

Earthquakes also occur disproportionately near large injection wells, just as previous studies suggest (e.g. Frohlich, 2012). For example, of the 10 largest injection wells by volume in the basin, 50% have had a M3 or greater earthquake occur within 10 km (Table 3). Similarly, of the 20 largest injector wells by volume in the county, 46% have had a M3 or greater earthquake occur within 10 km. Indeed, the M 3.0 earthquake near Haslet, Texas, on December 17, 2015 represents the most recent example of this pheonomenon: the Haslet earthquake epicenter was within $\sim$1 km from the single largest injection well (by cumulative volume) in the entire basin. In contrast, if we exclude the top 20 injector wells by volume, only 6% of the remaining 147 injector wells have had a M3 or greater earthquake occur within 10 km. Thus, for areas within 10 km of a a large injector well, the earthquake probability appears significantly (nearly a factor of ten) greater. This result is consistent with previous investigations in the Fort Worth Basin noting spatial and temporal relationships between seismicity and wastewater injection (e.g. Frohlich, 2012).

4.3. Changes in Ellenburger compressibility with time

We calculated the monthly apparent compressibility for 84 wells where pressure measurements were made consistently on a daily basis. Of these, 43 (51%) showed evidence for reduced compressibility (increased formation pressure) with time, 21 (24%) showed evidence for increased compressibility (reduced formation pressure) with time, and 20 (24%) show no significant change in compressibility (no clear pressure change) with time. It is important to recognize that apparent reduction in compressibility (and increase in pressure) may simply be the result of increased friction as more fluids are injected into the well with time. We note however that 39 of the 43 wells (91%) with reduced compressibility have monthly injection volumes that remain either *constant* or systematically *decrease* with time while injection pressure increased. This implies that for at least 39 wells, reduced compressibility is not due to increased injection rates and that other factors must be involved. Increased compressibility (reductions in pressure) that we observe in 24% of the wells could be caused by fluid loss in the formation near a particular well due to natural fluid migration, unintentional removal by adjacent oil and gas production, or by fault reactivation that generates more accommodation space for fluids via increased fracture porosity. Currently, there is no significant oil and gas production in the Ellenburger in the central part of the basin. It is therefore perhaps more likely that pressure reductions are caused by natural fluid migration out of the formation. The analysis thus indicates that a majority of wells show an apparent reduced compressibility over time. Counties with the most wells showing reduced compressibility are Parker and Jack counties (6 wells each, 14% of the total), Johnson, Erath, and Hood counties (5 wells each, 12% of the total), followed by Palo Pinto (3 wells), Somervell (2 wells), and Tarrant county (2 wells). These counties are all located in or near areas of high seismicity (Fig. 5). These results therefore demonstrate that there is more than a simple correlation in time and space between high injection volumes and recent seismicity—the injection also provides a mechanism for triggering earthquake activity. Specifically, reduced formation compressibility and increased subsurface pressures below these well sites provide a clear and plausible cause for recent earthquakes: increased subsurface fluid pressures resulting from wastewater injection that is coincident in time and space with regional seismicity provide a simple, direct, observable, and easily explainable mechanism for triggering these seismic events.

4.4. Estimating the average change in Ellenburger formation pressure

For the entire Ellenburger formation, we calculate an average pressure change dP of 0.09 MPa (13 psi) attributable to wastewater injection totaling 270 million m^3 between 2006 and September 2014 (see methods section above). This value is consistent with pressures typically associated with seismic triggering (Reasenberg and Simpson, 1992; Stein, 1999). Our calculation

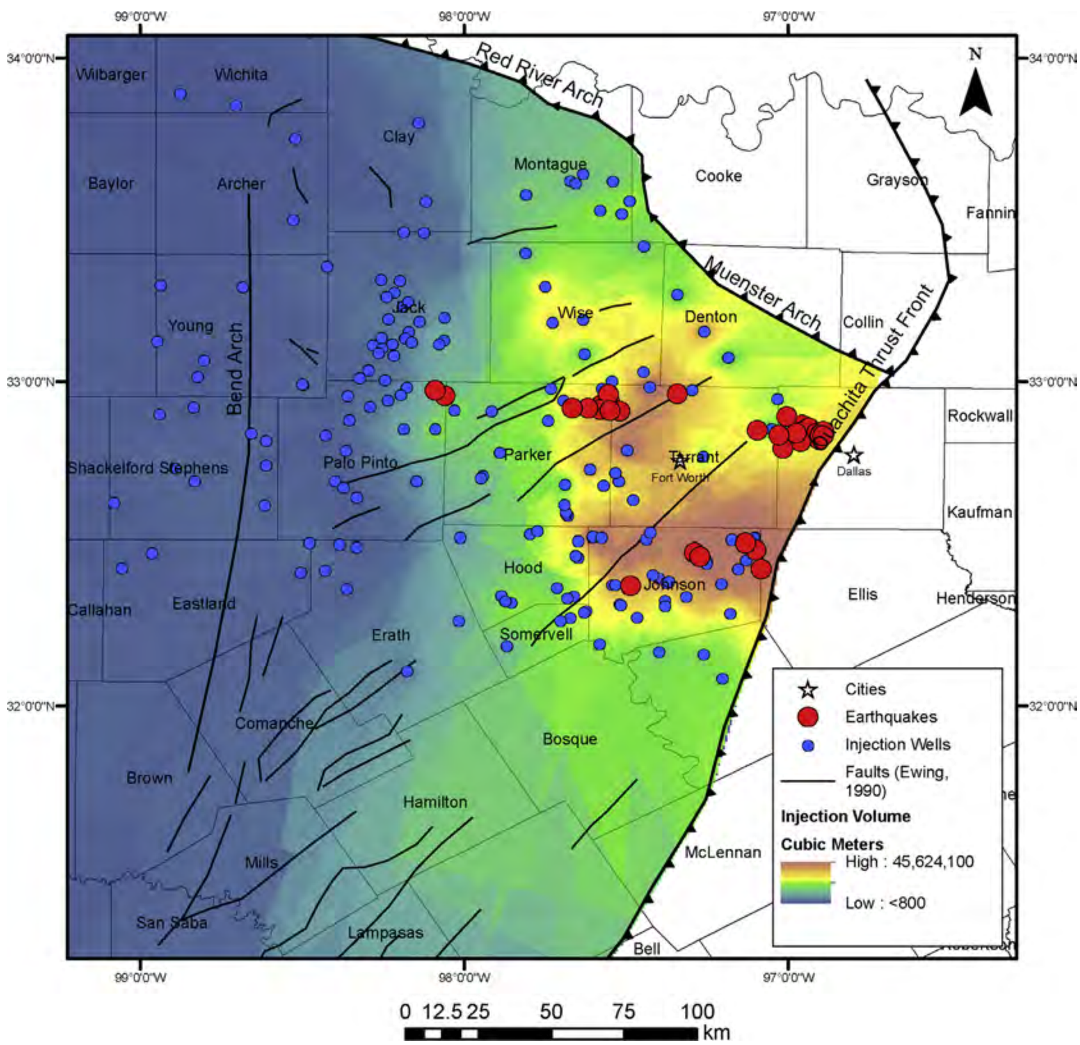

Fig. 6. Map showing an interpolated surface grid of injection volumes per unit area for Ellenburger wells, calculated using the inverse distance weighting (IDW) deterministic method. The interpolation uses the total injection volume of all 167 wells injecting into the Ellenburger formation. The interpolation consists of ~100,000 cells each with an area 817×817 m^2. Areas are assigned volumes calculated by a weighted average of the known volumes of the injection wells. Using the weighting approach, approximately 50% of the injected volume is accounted for within 25% of the distance to the next nearest well. The highest injection volumes are generally concentrated in the same regions where we see clusters of earthquakes. Additionally, the Dallas County earthquake sequence lies just southeast and down dip of the high injection volumes in Johnson county. Detailed fault maps will ultimately provide better constraints on how fluids might flow through the basin.

assumes uniform characteristics for the entire Ellenburger, when in fact there is undoubtedly significant heterogeneity (e.g. Core Laboratories Inc, 1972; Loucks et al., 2009). As a result, areas where the reservoir is confined and isolated from regions where injection occurs may have lower fluid pressure, at the expense of areas where wells inject into confined reservoirs that may have significantly higher pressure. For example, if fluids were confined by county, the highest pressure increases would generally occur in counties with the highest injection volumes per unit area (Fig. 8).

Compressibility will be higher (and pressures lower) if gas is present in the Ellenburger formation; however, it is unlikely that much free gas is present in the formation, particularly in the deepest part of the basin. Four lines of evidence support this conclusion. First, there is no significant oil or gas production from the Ellenburger in the basin. Second, the pressures at depths where the Ellenburger exists are not conducive to free gas, as natural gas is significantly more soluble at high pressure and is more dependent on pressure than temperature changes. This suggests that the lowest compressibilities (and the highest pressures) will preferentially occur in the deepest part of the basin, where pressure is highest, methane is more soluble, and the least amount of gas is present.

Third, if significant gas were present, the estimate of 0.09 MPa would be an over-prediction of subsurface pressure. To date, however, all measured pressures in the Ellenburger (provided by shut-in pressure tests) indicate excess fluid pressures higher than 0.09 MPa. For example, recent studies conducted by the Texas Railroad Commission to address the potential cause of recent seismicity in Johnson County, near Venus, Texas, indicate fluid pressures above hydrostatic in all wells tested across the region, with values ranging between 1.7 and 4.5 MPa (250–650 psi) above hydrostatic (http://www.rrc.state.tx.us/about-us/resource-center/research/special-studies/johnson-county/). Similarly, shut-in pressure measurements made at a well in Parker County near the Azle/Reno earthquake sequence also show pressures above hydrostatic (Hornbach et al., 2015). Fourth, it should be noted that the compressibility value used in the calculation is provided directly by engineers assessing subsurface pressures in the Ellenburger, and therefore, if accurate, should properly account for any free gas in the pore fluid. The Ellenburger pressure estimate presented here indicates elevated fluid pressures, just as spot measurements made at well sites suggest, but under-predicts actual observed subsurface pressures in the region. The analysis presented here is

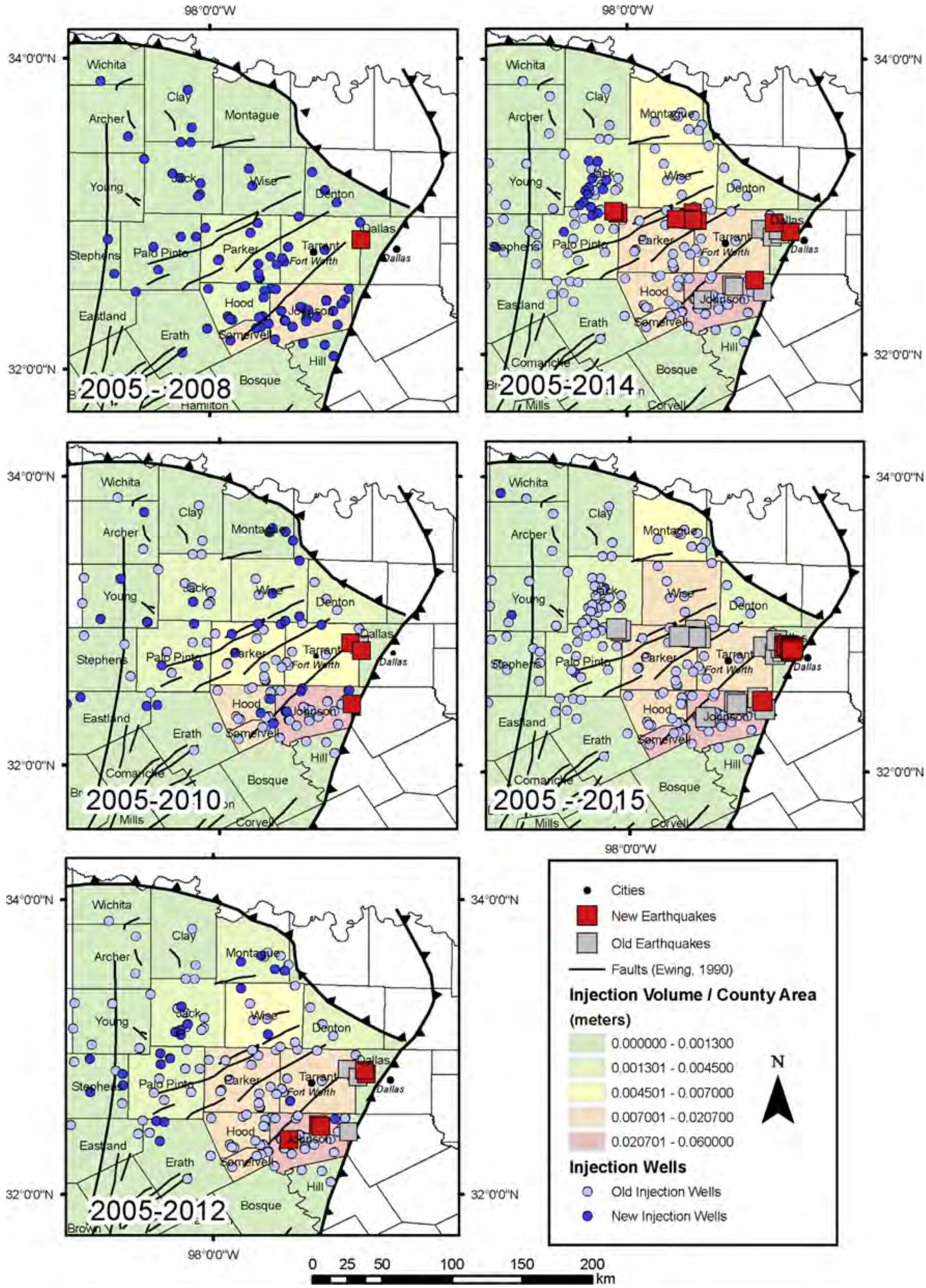

Fig. 7. Time lapse of injection volume per unit area, aggregated by county, and regional seismicity for events of magnitude 3 or greater. Seismicity begins in Eastern Tarrant and Johnson counties, both regions of initially high injection, and spreads both east and west into other areas where injection increases. Note in the last 4 years an increase in permitted injection wells to the north and west.

therefore consistent with regional observations indicating elevated fluid pressures exist and supports previous conclusions suggesting wastewater injection into Ellenburger elevates fluid pressures, promoting seismicity in the region.

4.5. Apparent seismic outliers

The previous investigations (Frohlich et al., 2011; Frohlich, 2012; Justinic et al., 2013; Hornbach et al., 2015) did not provide

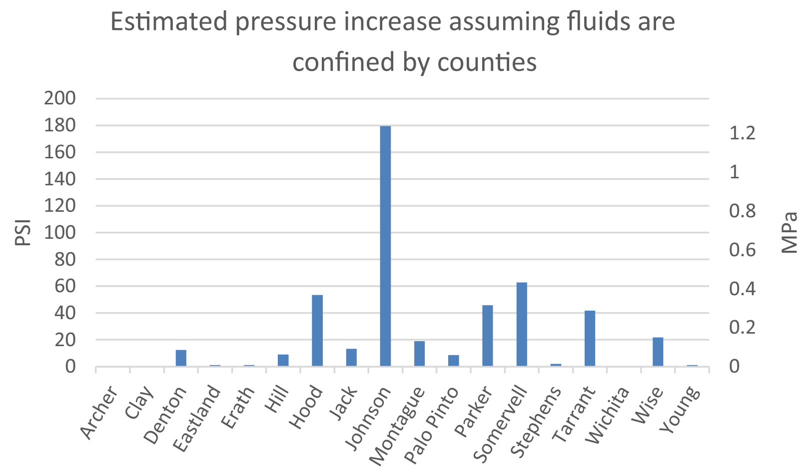

Fig. 8. Estimate of the expected pressure increase in the Ellenburger assuming all injected fluids are confined to the county of injection. In reality, fluid confinement is poorly constrained, and fluids are undoubtedly confined to larger or smaller volumes than those used here, with confinement often leaky. The analysis indicates fluid pressures are highest in Johnson County, but also high in Tarrant, Hood, Somervell, and Parker counties. The only regions where Ellenburger fluid pressures have been measured directly and made publically available are in Johnson and Parker Counties. In both instances, fluid pressures were elevated above values suggested here, with Johnson county measurements 250–650 psi above hydrostatic and Parker county measurements indicating ~70 psi above hydrostatic. Thus the elevated fluid pressures present here are consistent with, but lower than measured values.

an explanation for the occurrence of earthquakes in areas adjacent to, but more distant than a few km from higher-volume injection wells. These include earthquakes in Dallas and Ellis Counties, where no injection wells currently exist, and Palo Pinto County, where injection volumes are moderately low compared to adjacent seismically active counties. Although injection volumes are moderate in Palo Pinto County, the largest injector in the county is located near the two earthquakes in this region (Fig. 6). This, combined with regional fault maps indicating the Mineral Wells Fault may be optimally orientated for failure, with a similar strike to the Newark East Fault near Azle (Hornbach et al., 2015), may explain why earthquakes began in this region in 2013. For the Dallas and Ellis County earthquakes, there are several reasons why these events might not be natural, and instead, induced by wastewater injection:

1. The relatively shallow depths of the earthquakes (<8 km) placing them in the Ellenburger and underlying basement are similar to the depths of likely induced earthquakes near Azle, DFW, and Cleburne. In general, induced earthquakes have shallower hypocenters than natural earthquakes (e.g. Simpson et al., 1988; Ellsworth et al., 2015).
2. Often, induced earthquakes propagate away from an injection well over time, typically over the course of months to years (e.g. Ake et al., 2005; Keranen et al., 2014; Block et al., 2014; Hornbach et al., 2015), and there are documented cases of induced earthquakes more than 10–20 km distant from an injection site (e.g. Healy et al., 1968; Block et al., 2014). Earthquakes were first reported in the basin in 2008 and 2009 in eastern Tarrant and Johnson Counties, with seismicity occurring elsewhere across the region as time passed. The Dallas and Ellis county earthquakes are generally located 10 km or more away from the nearest injector well and did not begin until 6 years after large-scale injection commenced in the surrounding counties. Both counties are located just north and east of Johnson County— the county experiencing by far the largest volume of wastewater injection into the Ellenburger.
3. Large regional faults generally trend in a south-southwest to north-northeast direction across the basin, potentially providing direct pressure communication pathways from high injection zones in Johnson, Somervell, and Tarrant County to Dallas and Irving (Fig. 1, 6 and 7) (e.g. Rozendal and Erskine, 1971; Ewing, 1991; Pollastro et al., 2007; Hentz et al., 2012). Importantly, previous studies indicate critically stressed faults can act as long-distance fluid conduits that have higher permeability than the formation rock (e.g. Hsieh and Bredehoeft, 1981; Barton et al., 1995; Townend and Zoback, 2000). Thus, the idea of km-scale fluid flow along such fault systems is not new. Analysis of regional seismic reflection data revealing fault location and orientations combined with pressure/stress tests in regional wells could rule out or confirm this possibility.
4. Denser fluids will naturally gravitate towards the deepest accessible point, the basin structural axis or localized fault-bounded depocenters, increasing pressure in these areas. Dallas and Ellis counties rest directly above the Ellenburger's deepest point (Core Laboratories Inc, 1972) (Fig. 1). Thus it is plausible that denser brines injected in Parker, Johnson, and Tarrant counties will tend to migrate downslope to Ellis and Dallas counties, and over time increase fluid pressures in the Ellenburger formation there. These increased fluid pressures might trigger earthquakes on faults located in the deepest part of the basin. As noted above, it appears faults with the appropriate orientation already exist to provide high-permeability flow paths for these brines that generate pressure fronts towards Dallas and Ellis County.
5. Unlike the counties where the largest injections volumes occur (Johnson, Parker, and Tarrant counties), the Ellenburger in both Ellis and Dallas Counties is situated down-dip from injection, but is bounded to the east by the Ouachita fold and thrust belt, a massive, nearly impermeable geological boundary (Figs. 1, 5 and 6). The sediments in the Ouachita belt that the Ellenburger terminates against in the eastern edge of the basin consist of low-grade metamorphosed rock, most notably marble, metaquartzite, and quartz diorite (Rozendal and Erskine, 1971). These rocks are significantly less permeable than the Ellenburger. This suggests that fluids cannot easily migrate out of the depocenter below Dallas County since it is bounded by an impermeable feature to the east. Thus once fluids reach the deepest part of the basin below the Dallas-Irving area, they have nowhere else down-dip to migrate, except perhaps along faults. As a result, fluids injected into the Ellenburger in nearby counties may cause pressures to increase steadily over time in the Dallas/Irving area.

We can estimate the permeability necessary for more distant wastewater injection wells to affect faults below the city of Dallas and Irving. Felt earthquakes began in the Irving-Dallas area in early 2014, approximately six years after high injection rates began. We estimate the permeability necessary for the pressure wave to reach Dallas from injectors in both Johnson and Tarrant Counties by solving the characteristic time-pressure diffusion equation for permeability (e.g. Hettema et al., 2002):

$$k = \frac{d^2 \varphi \mu C}{t} \tag{3}$$

Here, d, the distance from a well in Johnson (or Tarrant) county to the center of Dallas county, is 40 (or 15) km; φ, the porosity of the Ellenburger is assumed 4% (Core Laboratories Inc, 1972), μ, the fluid viscosity of the brine, is 4×10^{-4} ($\pm 5 \times 10^{-3}$) Pa s (Texas Railroad commission website); C, the total compressibility of the Ellenburger, is 1.5×10^{-9} ($\pm 0.5 \times 10^{-9}$) Pa^1 (Texas Railroad commission website); and t, the characteristic time it takes for the pressure front to travel 40 and 15 km respectively, is 6 years. Using the 40 km distance for wells in Johnson county to earthquakes in Dallas County, we calculate a permeability of $1–3 \times 10^{-13}$ m^2 (100–300 mD) is necessary for fluid pressures to travel this distance over 6 years. If we use 15 km, the approximate distance from the Irving-Dallas earthquake sequence to the nearest active injection well in Tarrant county, a permeability of $1–4 \times 10^{-14}$ m^2 (10–40 mD) is necessary for the pressure wave to travel to the area of seismicity over six years. Measured permeability values for the Ellenburger vary greatly, but usually range between 5×10^{-13} and 1×10^{-15} m^2 (0.1–500 mD) (e.g. Archie, 1952; Core Laboratories Inc, 1972; Hornbach et al., 2015). Our estimated permeability values fall within observed measurements. It therefore is plausible that pressure fronts generated by injectors in neighboring counties could impact Dallas County.

5. Conclusions

Analysis of seismicity, injection volume and pressure measurements for the period 2005–2014 shows that within the Bend-Arch Fort Worth basin, areas where the largest fluid volumes were injected into the Ellenburger were also the areas where compressibility generally decreased, subsurface pressures increased, and earthquakes most often occurred (Figs. 2 and 5–7). The analysis shows not only correlation but causation: lower formation compressibility and higher pressures generally develop at the same time and location where earthquakes occurred. This interpretation is consistent with multiple previous studies conducted decades ago noting both correlation and causation between increased fluid injection volumes, increased pressures, and increased probability of structural failure and associated seismicity with time (e.g. Terzaghi, 1936; Kisslinger, 1976; Talwani and Acree, 1984; Ellsworth et al., 2015).

Of the eight counties in the basin where seismicity has occurred, two (Dallas and Ellis) have no reported injection wells. However, both counties (1) are immediately adjacent to counties where injection volumes are high, (2) are down-dip of the injection zone where denser fluids will flow, (3) are bounded by low permeability sediments of the Ouachita fold and thrust belt that prohibit fluid escape, (4) only began experiencing seismicity after injection began, and (5) are in areas structurally favorable (down-dip) for significant pressure increase. Furthermore, the timing and location of seismicity, developing several years after injection began and more than 10 km from the nearest injector, is similar to induced seismicity observed elsewhere attributed to pressure diffusion across a basin (e.g. Hsieh and Bredehoeft, 1981; Zoback and Hickman, 1982; Simpson et al., 1988; Block et al., 2014) and requires permeabilities consistent with values observed in the Ellenburger. Thus, it is plausible that the seismicity in Dallas and Ellis counties is induced.

In addition, we observe that (1) previous studies suggest the basin has been tectonically inactive for at least 250–300 million years, (2) no earthquakes had been reported in the Dallas-Fort Worth-Arlington area for the past 160 years prior to wastewater injection activity, (3) Dallas-Area earthquake focal depths are in the Ellenburger or the shallow basement beneath, and (4) the seismicity in the basin has spread with time. All these observations are consistent with the hypothesis that earthquakes in the Fort Worth Basin are induced by pressure changes linked to wastewater injection.

Because the subsurface pressure front continues to migrate even after injection ceases, past studies show that it often takes a significant amount of time (months to years) for pressure, and associated seismicity, to reduce to pre-injection levels (e.g. Hsieh and Bredehoeft, 1981; Zoback and Hickman, 1982; Block et al., 2014). Thus, if injection continues into the Ellenburger at rates observed from 2008 to 2014, the analysis broadly suggests that seismicity will continue to occur in Parker, Johnson, Tarrant, Ellis and Dallas Counties along faults optimally oriented for failure. Since not only this study but several others (e.g. Frohlich, 2012; Gono et al., 2015; Frohlich et al., 2016) show a correlation in space and time with large injection volumes and seismicity, one might anticipate seismicity to develop in other areas of the basin with time in locations where injection volumes have been recently increasing (such as Montague and Wise counties) or where the Ellenburger is down-dip of increasing injection volumes or bounded by the Ouachita fold and thrust belt, such as Denton county. Indeed, more detailed microseismicity studies in Montague, Wise, and Denton counties indicate earthquakes have already occurred that are too small to be felt or noticed by local residents (Frohlich, 2012). Nonetheless, injection that increase fluid pressures and reduce effective stress is only one factor influencing induced seismicity. To gain a better understanding of the link between wastewater injection and seismicity, it would be useful to have better information about the locations and orientations of subsurface faults across the basin, and the regional stress regime, especially in areas that are seismically inactive but where future injection is proposed. To assess future hazard, it would also be useful to have measurements of the stress on regional faults. Currently, the orientation of faults with respect to the subsurface stress regime in the basin is only marginally constrained in the public literature (Fig. 5) and this represents an important area of future research for further quantifying the induced seismicity hazard.

Finally, to assess regional seismic hazard—especially in dense urban environments like the Dallas-Fort Worth-Arlington Metroplex—it would be extremely valuable to closely monitor subsurface pressures with time, especially in areas where subsurface pressures may be increasing. As our analysis indicates, injected fluids have the potential to affect subsurface pressures at distances as great as tens of kilometers, with wells in different counties potentially impacting subsurface pressure under the cities of Dallas and Irving. Testing this hypothesis and determining the potential seismic hazard in the DFW area ultimately requires more detailed stress and fault maps combined with high-quality pressure monitoring within and below the Ellenburger formation. Currently, no standard or routine formation pressure monitoring program exists in the Ellenburger. Monthly well head injection pressures provided to the Texas Railroad Commission are only a rough proxy for understanding changes in formation compressibility, and currently, there are no baseline or time-dependent pressure measurements in the deepest part of the basin, directly below the cities of Dallas and Irving where seismicity could be most damaging. The recommendation to monitor subsurface pressure is a not a new idea; it was made nearly 50 years ago by both industry and academic researchers (e.g. Van Everdingen, 1968; Galley, 1968, and references therein) when injection strategies were first considered. It is a recommendation that remains even more valid and relevant today than it was 50 years ago.

Acknowledgments

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CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 5-E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TEXAS 75202 – 2733

AUG 15 2016

CERTIFIED MAIL -- RETURN RECEIPT REQUESTED: 7004 1160 0003 0358 5306

Ms. Lori Wrotenbery, Director
Oil and Gas Division
Railroad Commission of Texas
1701 N. Congress
P.O. Box 12967
Austin, Texas 78711-2967

Dear Ms. Wrotenbery:

This letter transmits the Environmental Protection Agency's (EPA) end-of-year evaluation (EOY) of the Texas Underground Injection Control (UIC) program implemented by the Railroad Commission of Texas (RRC) for Fiscal Years 2010 through 2015. EPA's last evaluation of the RRC's UIC program covered Fiscal Year 2009. The RRC provided comments on our draft EOY via letter from Mr. David Hill, RRC's Manager of Injection-Storage, dated July 21, 2016; our EOY report includes Mr. Hill's letter in Appendix III. The comments were considered in the finalization of the report.

We wish to thank you and your staff for your work in protecting underground sources of drinking water from underground injection activities under your authority. We look forward to working with you to resolve our oversight issues outlined in the enclosed report. As always, we offer our technical support and cooperation to you and your staff as we move forward.

If you wish to discuss any aspect of this EOY evaluation, call me at (214) 665-7101, or you or your staff may call Mr. Philip Dellinger at (214) 665-7150. If your staff has specific questions about UIC grant performance, please contact Mr. Michael Vaughan at (214) 665-7313 or Mr. Mike Frazier at (214) 665-7236, for questions regarding EPA's program oversight.

Sincerely yours,

for

William K. Honker, P.E.
Director
Water Division

Enclosure

cc: Leslie Savage, RRC Chief Geologist, w/encl.
David Hill, RRC UIC Manager, w/encl.

FISCAL YEAR 2015
EPA REGION 6 END-OF-YEAR EVALUATION
RAILROAD COMMISSION OF TEXAS
UNDERGROUND INJECTION CONTROL PROGRAM

Introduction

Since 1982, the Railroad Commission of Texas (RRC) has maintained its Underground Injection Control (UIC) primacy enforcement responsibility for Class II oil and gas related injection wells authorized by the federal Environmental Protection Agency (EPA) pursuant to Safe Drinking Water Act (SDWA) requirements. EPA later approved RRC's primacy program for Class III brine mining wells and energy related Class V injection wells. The RRC implements State UIC primacy permitting and enforcement programs for Class II wells through an alternative demonstration under SDWA Section 1425 and for their limited Class III and V primacy program under SDWA Section 1422.

As part of the EPA/RRC primacy agreements, EPA Region 6 retains oversight responsibilities that includes an annual end-of-year evaluation. This annual oversight report summarizes RRC activities since EPA's last end-of-year evaluation for FY2009, as reported by the RRC in fulfillment of its primacy program and Federal UIC grant and workplan commitments. Specific RRC comments on the draft of this report dated June 30, 2016, is included in Appendix III.

Section 1 FY2015 Grant Workplan

Pursuant to receiving federal assistance through SDWA Part C authorization, the RRC submitted and EPA approves an annual grant application and associated workplan that outlines goals, expected milestones for key program activities, and estimated funding to toward achieving those goals and milestones. The grant application and workplan for FY2015 were approved by Region 6 on July 1, 2014.

Section 1.1 FY2015 Grant Award and Allocation

The federal FY2015 grant allotment for the Texas Railroad Commission's (RRC) UIC program was $631,720 in UIC programmatic funds; these funds are determined annually based on the annual well inventory numbers submitted by State UIC Primacy programs. In addition, the RRC received $8,900 in UIC special project funds during FY2015.

Section 1.2 Grant Delivcrables

Pursuant EPA regulations and policies, environmental programs conducted on behalf of EPA will establish and implement effective quality systems. The Quality Management Plan (QMP) and Quality Assurance Project Plan (QAPP) must be up dated annually. If both the QMP and QAPP are current and valid, EPA requires each state to annually certify that both plans are current by submitting updated signatory pages and organizational charts as applicable. The FY2015 QMP [QTRAK #15-326] was approved by Region 6 on 7/17/2015, and expires on 7/17/2016. The FY2015 QAPP [QTRAK #16-036] was approved by Region 6 on 11/12/2015, and expires on 11/12/2016. Table 1 includes the workplan due dates and date of receipt for documents submitted by RRC as specified in the grant workplan.

Table 1. Grant deliverables in FY2015 UIC Workplan.

Grant Deliverable	Due Date	Date Received
Quarterly Reports (EPA Forms 7520)	4/30/2015; 10/31/2015	Submitted on schedule
FY2014/2015 Grant Application FY2014/2015 Grant Workplan	7/01/2014	Application received-5/16/2014 Workplan received-5/16/2014 Approved - 5/20/2014
Final Financial Status Report (FY15)	11/30/2015	The Final FSR reviewed and processed 2/01/2015. Grant is closed.
Annual UIC Program Report (FY15)	10/31/2015	9/28/2015
Update on Program, Regulatory or Statutory Changes	10/31/2015	9/28/2015
Annual QMP/QAPP Updates*	QMP QAPP	Received- 6/23/15 Approved- 7/17/15 Expires- 7/17/16 Received- 11/06/15 Approved-11/12/15 Expires- 11/12/16
UIC Well Inventory for FY15	12/18/2014	12/18/2014

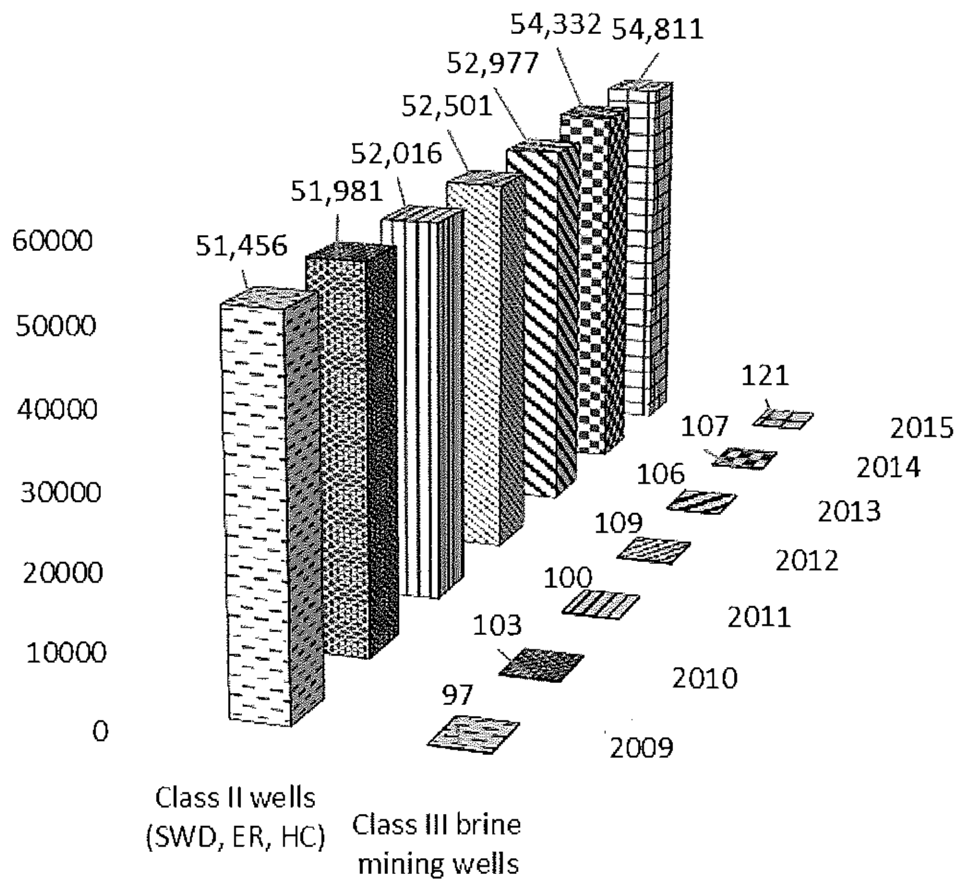
* The Quality Management Plan (QMP) and Quality Assurance Project Plan (QAPP) are updated annually.

Section 2 Inventory

Chart 1 illustrates the number of injection wells reported by class to EPA annually by the RRC from 2009 through 2015; the State UIC program annual inventory numbers are usually submitted during or near December each year. These values (along with values reported by other

State and EPA UIC programs) are used by EPA to calculate the annual grant funds allocated to each State UIC program. Since SDWA regulation of underground injection wells began, the RRC UIC program is still the nation's largest State Class II program based on the total number of Class II injection wells [salt water disposal (SWD), enhanced recovery (ER), and hydrocarbon storage wells (HC) combined] reported annually. Injection wells used in natural gas storage operations are regulated by the RRC, but are exempt from regulation under the SDWA and not generally subject of EPA UIC oversight.

Chart 1. Annual well inventory by well class 2009-2015



The annual number of Class II wells (all types) reported since 2009 has increased by 3,355, an approximate 6.5 percent increase during the six-year period. Between 2009 and 2013, the number of Class II wells increase by less than 1 percent annually; in 2014 and 2015, the reported number increase by 2.6 percent and 1.6 percent, respectively.

The number of Class III brine mining wells increased from 97 in 2009 to 121 in 2015, an increase of 24 or an approximate 25 percent increase during the six-year period. In 2015 alone, the number of authorized Class III brine mining wells increased by 14, a 13 percent increase from 2014.

In addition to the inventory submitted to EPA annually, the RRC also includes inventory values in their annual narrative report pursuant to the EPA/State UIC grant workplan; the inventory values in the narrative report seem to include all types of injection wells, Class II, III, and possibly V, based on the larger numbers. Those inventory numbers are not used in this evaluation. The RRC annual narrative reports between 2009 and 2015 are attached to this annual evaluation as Appendix I.

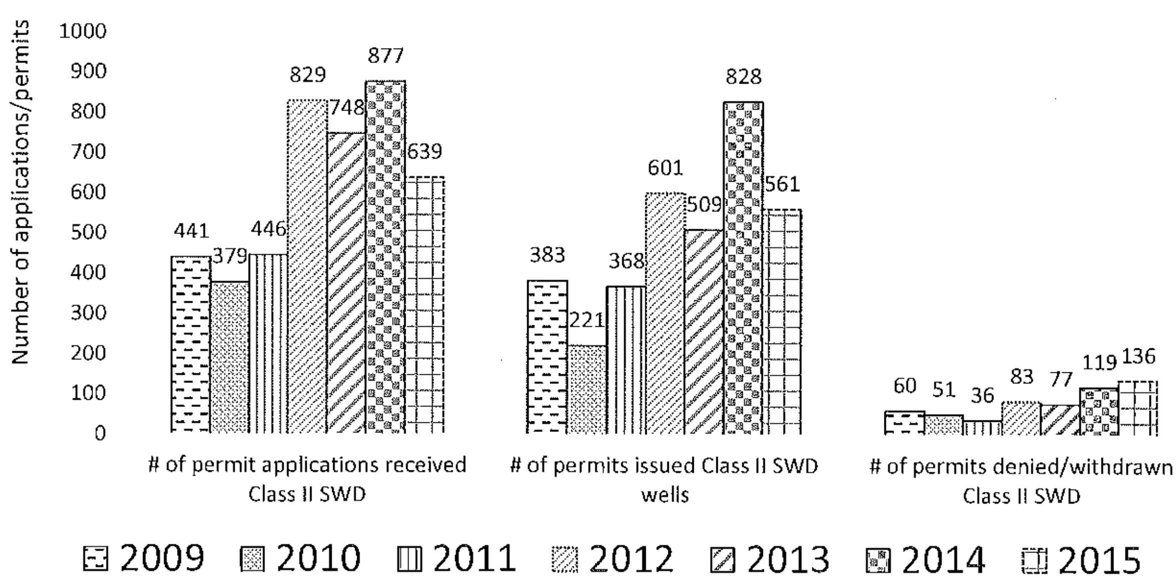
Section 3 Key Program Activities

This section includes an evaluation of key program measures as reported annually to EPA by the RRC through EPA's Forms 7520 and the annual narrative required in the annual UIC grant workplan. The charts in this section includes information submitted by the RRC from 2009 through 2015.

Section 3.1 Permitting

The previous Section 2 includes information on permitted wells regulated by the RRC; all injections wells authorized by the RRC are authorized by RRC permit. There are no authorized-by-rule injections wells regulated by the RRC. Chart 2 presents the number of Class II UIC permit applications received for salt water disposal (SWD), the number of new Class II SWD UIC permits issued, and the number of SWD UIC permit applications either denied or withdrawn from 2009 through 2015, and also include applications to amend existing permits (see RRC letter dated July 21, 2016, in Appendix III). The values were taken from EPA Forms 7520 submitted by the RRC annually since 2009.

Chart 2. Reported number of permit applications received/issued/denied or withdrawn for Class II Salt Water Disposal wells 2009-2015

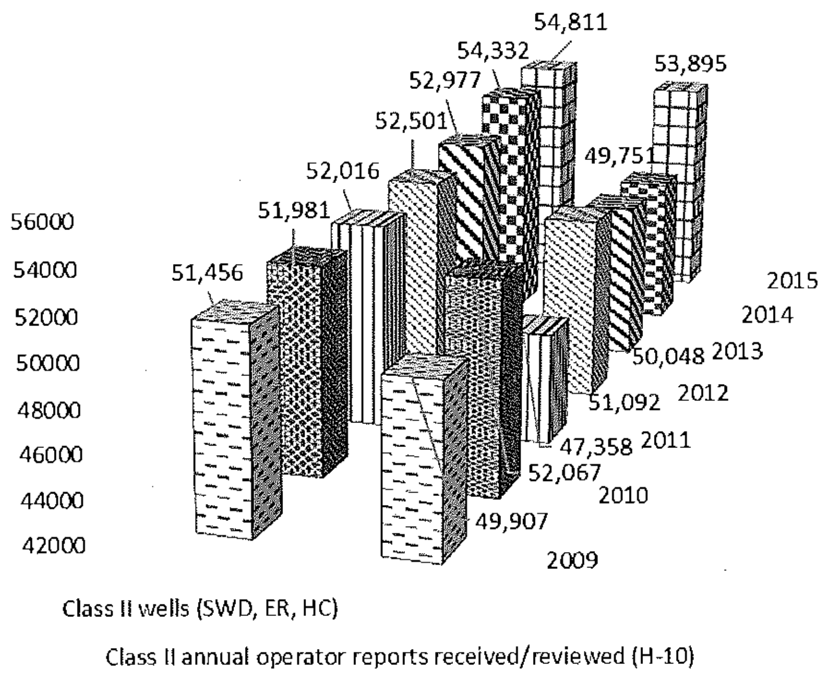


The number of permits received increased in 2012 by about 85 percent from 2011 numbers, remains relatively constant during 2013 and 2014 and declines approximately 27 percent in 2015; that same decline is not reflected in the number of permits denied or withdrawn in 2015.

Section 3.2 Annual UIC Operator Reports

Chart 3 illustrates the annual Class II well inventory graphed with the number of annual monitoring reports submitted by operators for Class II injection wells (SWD, ER, and HC) since 2009.

Chart 3. Class II well inventory and number of operator annual reports received and reviewed 2009-2015

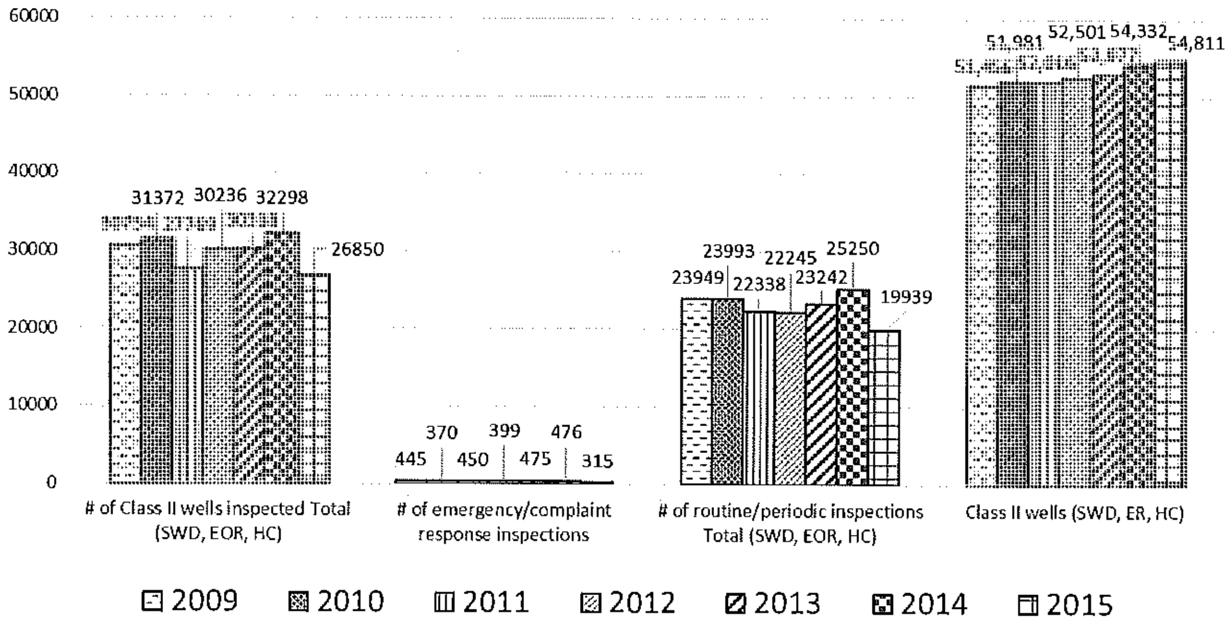


The RRC requires operators of injection wells to complete and submit Form H-10 annually; Form H-10 includes specific well identification information and monthly measurements of injection pressures, injected volumes, and casing/tubing annulus pressures. During the last seven annual reporting periods included in this report, the RRC received and reviewed annual reports of almost 97 percent of all Class II permitted injection wells. Annually, the percentage of H-10s collected ranged from over 100 percent in 2010 to almost 91 percent in 2011. The annual numbers of H-10s received and reviewed were taken from the RRC's annual narrative report, while the Class II inventory values throughout this report were taken from annual well inventory report submitted annually by RRC to EPA near the end of each calendar year. The annual narrative reporting period is the state fiscal year, July 1-June 30; while the annual well inventory report is the number of regulated wells near the end of each calendar year as requested by EPA. For this reason, the comparison percentage of Class II well inventory and operator annual monitoring reports is an approximation. The low number of wells for which the operators of record did not submit a form H-10 may be a result of the operator being no longer in business or non-reported wells being either transferred, plugged, or abandoned.

3.3 Class II Injection Well Inspections, Mechanical Integrity Testing, and Enforcement

For Class II wells, Chart 4 compares the annual inventory with the number of wells inspected, number of routine/periodic inspections, and number of inspections in response to emergencies or complaints. From 2009 through 2015, the average number of inventoried Class II injection wells inspected for compliance in the field was near 57 percent, with the lowest percentage of about 49 percent in 2015. Based on the reported values, more than half of the reported number of authorized injection wells in Texas are inspected annually, and from Chart 3, the RRC collects and reviews operator-submitted monitoring information of approximately 97 percent of the Class II well inventory annually. Those numbers assure more than adequate inspection and monitoring surveillance actions.

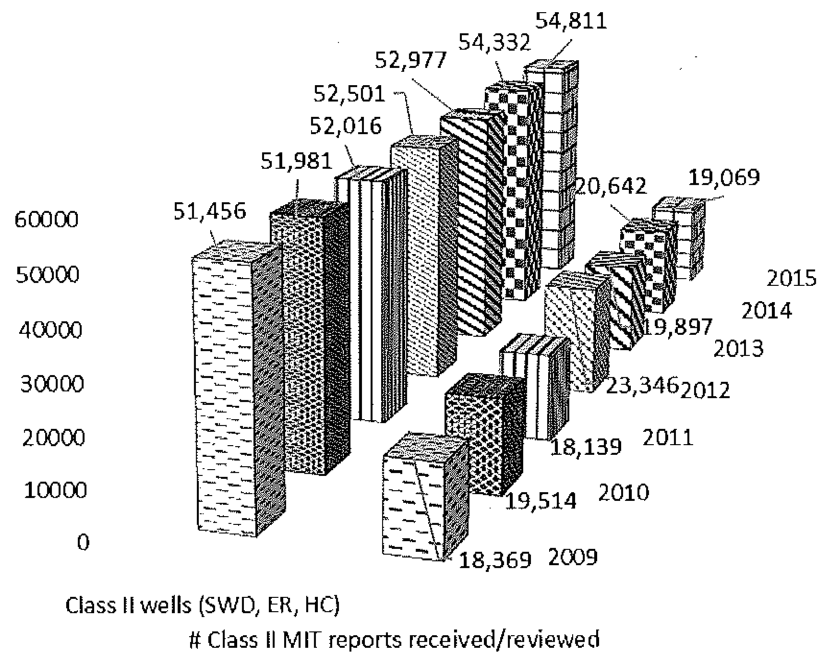
Chart 4. Class II well inventory, wells inspected, routine/periodic inspections, and emergency/complaint response inspections 2009-2015



Most of the reported inspections are performed as routine or periodic injection wells inspections. On average, inspections performed under emergency or complaint response conditions comprise just over 1 percent of all Class II inspections (2,930 of 209,597 from 2009-2015). These values reflect an outstanding enforcement monitoring program.

The most important indicator of ground water protection in any UIC program is the mechanical integrity testing program, or MIT. A properly conducted MIT evaluates the condition of the well casing, tubing and packer to assure acceptable operating conditions. In most cases, an MIT is a pressure test of the casing/tubing annulus and the associated packer; a test failure indicates a possible pathway for injected fluid to move out of the approved injection zone into or toward an underground source of drinking water. This procedure is fundamental in any UIC program and is required at least every five years for Class II wells. Chart 5 shows the number of Class II MIT reports received and reviewed by the RRC compared to the inventory of Class II wells from 2009-2015.

Chart 5. Class II well inventory and number of mechanical integrity test reports received and reviewed 2009-2015

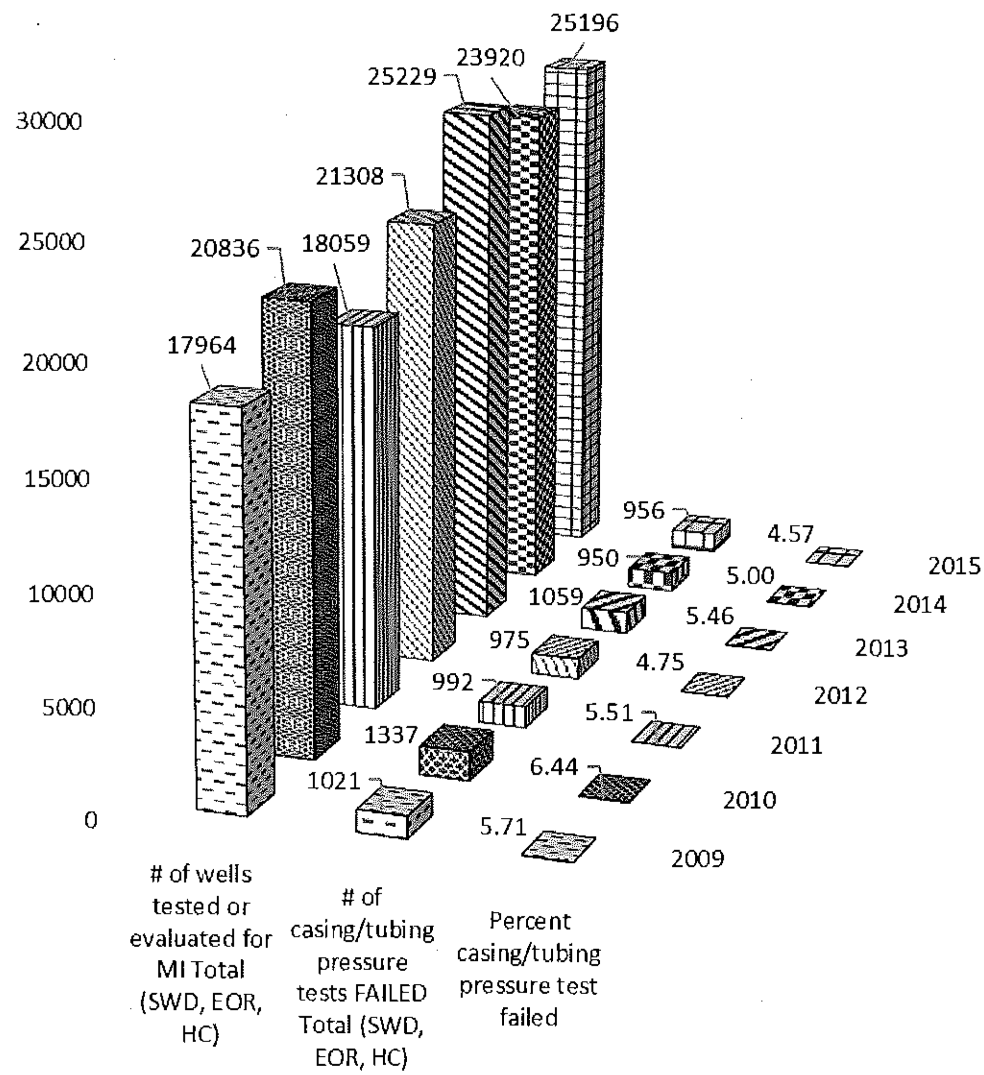


On average, the number of injection wells tested for mechanical integrity annually equals about 37 percent of the reported annual inventory of Class II wells, with the greatest frequency, 45 percent, reported for 2012. In summary, these MIT values indicate that over one-third of the reported annual inventory of Class II wells are likely tested for mechanical integrity annually. Based on these reported MIT values, the RRC testing and surveillance program exceeds the testing requirement for the MIT five-year performance measure.

If any injection well fails MIT, the applicable regulatory agency, whether State or EPA, disallows further operation until the operator shows the well has been repaired and passes a subsequent MIT. MIT failures are reported to EPA annually through Forms 7520 and may also be included in the State UIC program's annual narrative; the reporting period for Forms 7520 is the Federal fiscal year, October 1 – September 30, while a State's annual narrative generally covers the State fiscal year. A large percentage of Class II wells are tested for mechanical integrity by a pressure test of the casing/tubing annulus; the RRC states that more than 95 percent of RRC injection well permits require pressure testing to determine mechanical integrity (see RRC letter dated July 21, 2016, in Appendix III).

Chart 6 below illustrates the number of wells reported by the RRC through the annual Forms 7520s for the number of Class II wells tested for mechanical integrity and the number that failed casing/tubing pressure testing from 2009 through 2015. Other MIT evaluations may include cement record evaluations and geophysical logging techniques including radioactive tracer surveys, temperature or noise logs, and oxygen activation logs.

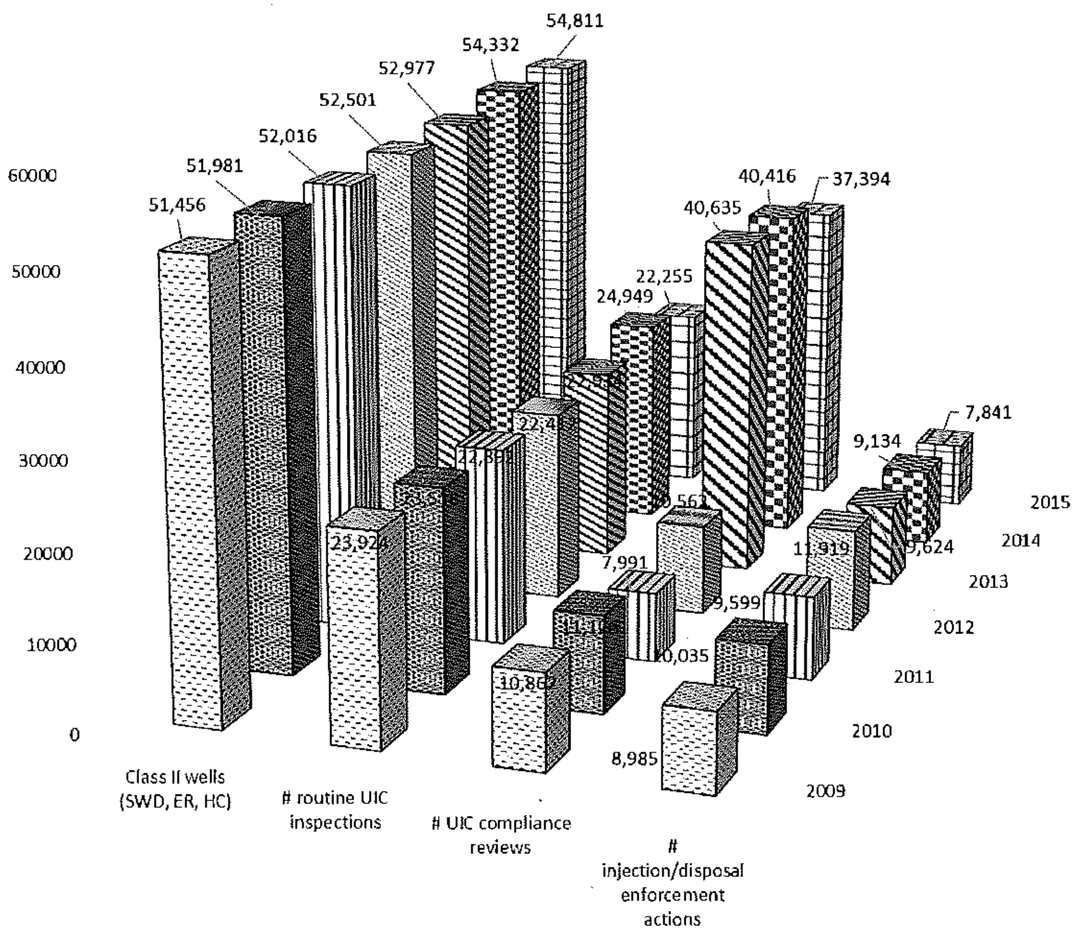
Chart 6. Number of Class II wells tested for mechancial integrity and number that failed testing 2009-2015



Since 2009, the percentage of MIT failures reported by the RRC ranges between 4 and 7 percent of the Class II wells tested. This failure percentage range is consistent with the percentage in other State Class II UIC programs in Region 6.

Most Class II State UIC programs strive toward inspecting all their wells at least annually to assure proper surface operations and monitor for any pressure related issues. Chart 7 compares the number of routine UIC inspections, compliance reviews, and enforcement actions with the annual reported Class II well inventory submissions. The inspections, compliance reviews, and enforcement actions values were taken from the RRC's annual narratives from 2009 through 2015. Based on these data, approximately 44 percent of Class II injection wells undergo routine UIC inspections annually. Prior to 2013, the RRC reports show approximately 20 percent of Class II wells were reviewed for compliance with applicable State UIC requirements; beginning in 2013, the number of reported Class II compliance reviews increased approximately 300 percent from 10,000 plus in 2012 to over 40,000 in 2013. In the last three years approximately 75 percent of Class II wells in Texas were reviewed for compliance annually.

Chart 7. Number of Class II wells inventory, number inspected, number reviewed for compliance, and number with enforcement actions 2009-2015



The number of Class II enforcement actions from 2009 through 2015 range from under 8,000 in 2015 to almost 12,000 in 2012. On average, the number of injection/disposal enforcement actions reported during this period represent about 18 percent of Class II wells in Texas.

In total, EPA Region 6 believes the RRC compliance surveillance and enforcement program appears responsive to operator reports and received complaints based on the information provided by the RRC. A summary of specific oversight issues are summarized in the remainder of this evaluation.

Section 4 Specific Oversight Issues

Since 2009, EPA Region 6 has communicated with the RRC about three primary UIC program concerns:

1. Increased seismic activity related to authorized Class II disposal,

2. Apparent formation pressure increases in East Texas associated with authorized Class II disposal, and

3. Identification and delineation of aquifers exempted at Class II program primacy in 1982, and any aquifers exempted by the RRC since 1982 related to oil and gas operations.

Section 4.1 Seismic Activity Correlated with Class II Disposal Injection

The EPA/State UIC National Technical Workgroup report on injection induced seismicity was released in February 2015. The report provides recommendations and strategies to injection well regulators for managing and minimizing suspected injection induced seismicity, and is available at the following website: http://www.epa.gov/sites/production/files/2015-08/documents/induced-seismicity-201502.pdf. Among other things, development of the report involved a comprehensive review of scientific literature, detailed analysis of four recent case examples (including North Texas) and exploring the applicability and value of petroleum engineering methods in the assessment of potential induced seismicity. RRC was one of the state agencies that participated in this effort and is commended for its influential involvement. RRC is also commended for establishing new regulations specific to seismicity, including solidifying RRC authority to take appropriate action related to injection well operations. A summary of related injection well permitting developments since these regulations took effect are described in Appendix III.

Although several areas in Texas experienced potential injection induced seismicity over the last several years, recent public, media and regulator interests have focused on the North Texas activity, specifically the Dallas-Ft Worth area. This includes activity in and around the cities of Azle, Cleburne, as well as near DFW Airport. The strategies RRC employed in these cases included early engagement of disposal well operators near the seismic activity. This action resulted in successful voluntary closure or injection volume reduction for several Class II disposal wells. Seismic activity in these three areas substantially diminished in frequency and magnitude; however, earthquake events continue in other areas of North Texas, most notably, frequent events in and near the city of Irving in Dallas County.

RRC representatives have publicly indicated that available scientific data do not sufficiently support a causal relationship between Class II waste disposal wells in North Texas and recorded earthquakes. In light of findings from several researchers, its own analysis of some cases, and the fact that earthquakes in some areas diminished following shut-in or reduced injection volume in targeted wells, EPA believes there is a significant possibility that North Texas earthquake activity is associated with disposal wells.

As indicated in the EPA/State workgroup report mentioned above, naturally fractured injection formations may transmit pressure buildup from injection for miles. The Ellenberger Formation, a deep naturally fractured formation, is the preferred disposal zone for most disposal wells in North Texas. This geophysical characteristic of the Ellenberger may allow pressure from authorized injection activities to follow existing fracture pathways toward existing fault zones miles away. These fractures may also be transmitting pressure buildup downward to basement rock along faults that were previously dormant.

EPA is concerned with the level of seismic activity during 2015 in the Dallas/Ft. Worth area because of the potential to impact public health and the environment, including underground sources of drinking water. EPA recommends close monitoring of injection activity through daily recording and reporting of accurate injection pressures and volumes from area disposal wells, coupled with appropriate data analysis methods, in a coordinated effort to detect possible correspondence with seismic activity.

Section 4.2 East Texas Formation Pressure Increases Related to Class II Disposal

A large volume of produced brine in East Texas is injected underground into authorized Class II disposal wells. Many of those wells are permitted commercial facilities that receive exploration and production (E&P) oilfield wastes produced from East Texas and Northwest Louisiana. The volume of produced oilfield wastewater historically increases as hydrocarbon reservoirs produce less oil and gas proportionate to associated formation salt water brine. Injection of the increasing volumes of produced brine into Class II disposal wells in East Texas is believed to be the cause of documented pressure increases in some geologic formations, primarily the late-Cretaceous Rodessa Formation. RRC records indicate that many production wells in East Texas lack cement between the well casing and Rodessa Formation; this cement void may provide a pathway for pressure transfer into another zone. Such pressure transfer could cause the observed high bradenhead pressures in some production wells in the area.

In 1991, EPA first authorized the disposal of restricted hazardous waste into a Class I hazardous disposal well at the current Pergan Marshall LLC facility near Marshall in Harrison County, a county in the East Texas area of focus. This authorization is required under Section 3004 of the Resource Conservation and Recovery Act. As early as 2006, the regulatory required annual pressure fall-off well tests that monitor pressure changes began to show a significant increase in formation pressure; the Pergan Marshall disposal well injects waste fluid into the Rodessa

Formation. In 2014, the pressure fall-off tests showed pressures non-compliant with EPA-approved conditions. In September 2014, EPA published its denial decision for continued operation of the Pergan Marshall Class I hazardous disposal well (see Appendix II). During the time of the observed significant increases in the Pergan Marshall Class I well, the RRC also authorized a large number of Class II wells in Harrison County to dispose of produced brine. EPA believes the recorded pressure build-up in the Rodessa Formation in the area is a direct result of authorized Class II disposal in a large number of authorized injection wells.

As early as 2012, the RRC recognized a regional increase in geologic formations used to dispose of produced brine associated with oil and gas production. The RRC documented an increase of bradenhead pressure for a large number of production wells in a three county area in East Texas: Harrison, Panola, and Shelby.

Beginning in 2012, RRC's Oil and Gas Division requested bottom-hole pressure (BHP) data from operators of 86 commercial disposal wells in those East Texas counties; in April 2014, the RRC modified permitted injection pressures for many of those wells and required continuing annual pressure fall-off testing and BHP monitoring to assure protection of underground sources of drinking water. The BHP data received and analyzed ranged from approximately 0.106 pounds per square inch per foot of depth (psi/ft) to 0.92 psi/ft. Most of these data are from disposal in the Rodessa Formation for which a salt water gradient of 0.46 psi/ft is often used by the RRC. Based on historical and the new operator data including pressure fall-off test reports, the RRC found areas with elevated pressures and areas where pressure is not a problem, but no clear trend has emerged as nearly all operators have reported only once.

RRC staff are using all available data when reviewing new disposal well applications for both commercial and non-commercial Class II disposal wells in the three county area. Factors considered in the RRC permitting process include:

1. The construction and completion of all wells within a ½-mile area of review,
2. The BHP of the proposed disposal formation, if available, and
3. The proposed injection rate of wastewater, both volume and pressure.

Permits have been issued for some wells where application data indicate that pressures will not be a problem; those permits contain special monitoring and reporting conditions that will help the RRC determine how formation pressures change over time. The RRC expects additional data from identified operators in late 2015 and early 2016; after analysis of these new data, the RRC will update Region 6 on this issue.

Section 4.3 Identification and Delineation of Aquifer Exemptions, Pre and Post-Primacy

The RRC 1982 UIC primacy documents contain correspondence between EPA Region 6 and then RRC Director of Underground Injection Control, Jerry Mullican, specifically addressing aquifers proposed for exemption related to oil and gas production activities. Ultimately, an executed letter agreement between Region 6 Administrator, Dick Whittington, and Mr. Mullican dated March 29, 1982, crystallized proposed actions by both agencies at UIC primacy (see Appendix II).

In an effort to determine the historical outcome of this agreement, EPA Region 6 UIC staff met with RRC staff in Austin in December 2014; agreements reached in that meeting are documented in a letter dated July 14, 2015, from Bill Honker, Water Division Director, Region 6) to Leslie Savage, Assistant Director of Technical Permitting, Oil and Gas Division, RRC (see Appendix II). On November 10, 2015, Region 6 UIC staff again met with RRC representatives in Austin on this and other issues. RRC reported the effort is very resource intensive and staff continue to gather information in their records. The RRC is moving forward with identifying and delineating historical and current aquifer exemption areas which are considered exempt from full UIC regulation. Once the RRC completes its research, EPA anticipates further actions to document the areas of exemption. EPA recommends continued high prioritization of this effort.

CASES NO. 20313, 20314, 20472, 20463 and 20465
Index of Division Exhibit No. 6

Exhibit No.	Exhibit Name
6-A	Sanford, A., and Toppozada, T., 1974, Seismicity of proposed radioactive waste disposal site in southeastern New Mexico; New Mexico Bureau of Geology and Mineral Resources Circular 143, 22 p.
6-B	Sanford, A., *et. al.*, 2006, Earthquake catalogs for New Mexico and bordering areas II: 1999–2004; New Mexico Geology; v. 28, no. 4; p. 99-109.
6-C	Pursley, J., Bilek, S., 2013, Earthquake catalogs for New Mexico and bordering areas: 2005–2009; New Mexico Geology; v. 35, no. 1; p. 3-12.
6-D	Herzog, M., 2014, *Investigation of possible induced seismicity due to wastewater disposal in the Delaware Basin, Dagger Draw Field, New Mexico-Texas, USA*; undergraduate honor theses; University of Colorado Boulder; p. 26-31, 44-46.
6-E	Dagger Draw Field: Summary of Disposal Wells; 2019 Oil Conservation Division database; compiled by P. Goetze.
6-F	Rubinstein, J., Ellsworth, W., McGarr, A., and Benz, H., 2014, *The 2001–present induced earthquake sequence in the Raton Basin of northern New Mexico and southern Colorado*; Bulletin of the Seismological Society of America, v.104, no. 5; 20 p.

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 6-A

CIRCULAR 143

Seismicity of Proposed Radioactive Waste Disposal Site in Southeastern New Mexico

by
Allan R. Sanford
and
Tousson R. Toppozada

1974

New Mexico Bureau of Mines & Mineral Resources
A DIVISION OF
NEW MEXICO INSTITUTE OF MINING & TECHNOLOGY

Circular 143

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ABSTRACT

Seismicity was determined for the area within a 300-km radius from the proposed nuclear waste disposal site in southeastern New Mexico. The primary data used to establish seismic risk were: reports of felt shocks prior to 1961; instrumental epicenters and magnitudes from 1961 through 1972; and lengths, displacements, and ages of fault scarps cutting Quaternary geomorphic surfaces. The prinicpal results of this study were: 1) earthquakes exceeding local magnitude 3.5 have not occurred within 40 km of the site in the past 12 years; probably not in the past 50 years, 2) on the average of once every 50,000 years major earthquakes (magnitude 7.8) are possible within 115 km of the site, but these events will produce accelerations of only about 0.07 g at the site; and 3) some evidence indicates that earthquakes located on the Central Basin Platform, 80 to 100 km southeast of the site, could be related to water injection for secondary recovery of oil.

INTRODUCTION

This study was undertaken to determine the seismicity at the proposed radioactive waste disposal site in southeastern New Mexico. The site is centered at lat. 32.41° N. and long. 103.76° W. about 42 km (25 mi) east of Carlsbad. Algermissen's (1969) seismic risk map of the United States, fig. la, indicates that the region around the site has a relatively low Zone 1 seismicity classification. The maximum expected seismic intensities from local or distant shocks in a Zone 1 region is V-VI (modified Mercalli Intensity Scale of 1931, see Appendix 1). On an earlier seismic risk map (fig. lb) Richter (1959) places the Carlsbad region within a seismic zone where the probable maximum intensity is expected to be VIII.

Both of these seismic risk maps are based on essentially the same data. The differences are due to varying interpretations. Most of these data are non-instrumental, simply reports of felt or damaging shocks. Our evaluation of the seismic risk of the region is based not only on the non-instrumental data, but on a substantial amount of instrumental data not available to Richter or Algermissen. In addition, they did not attempt to incorporate geologic evidence of recent crustal movements into their estimates of seismicity. This type of data, accounting for geologic features, especially fault scarps offsetting Quaternary geomorphic surfaces, is essential to accurate estimates of seismic risk over the planned lifetime of the disposal facility

ACKNOWLEDGMENTS

The authors are indebted to the following people and organizations for providing data used in this report: Stuart A. Northrop, Professor Emeritus of the University of New Mexico; Lt. Col. H. E. Wakitsch of AFTAC/VELA Seismological Center; D. H. Shurbet of Texas Tech University; Jerald McIntyre of University of Texas at El Paso;. John Kosovich of Trinidad Junior College; Kenneth Olsen of Los Alamos Scientific Laboratory; and John Hoffman of the Albuquerque Seismological Center (USGS). Omer Alptekin and Mark Dee, graduate assistants at New Mexico Institute of Mining and Technology, assisted the authors on some phases of the research.

This study of the seismicity of the proposed nuclear waste disposal site in southeastern New Mexico was requested and supported by the Oak Ridge National Laboratories under Contract No. AT-(40-1)-4423.

DATA

The seismicity study was restricted to an area within 300 km (180 mi) of the proposed site (fig. 2 on page vi). The basic data collected were: reports of felt shocks prior to January 1, 1961; instrumental locations and magnitudes of earthquakes from January 1, 1961 through December 31, 1972; and locations of fault scarps offsetting Quaternary

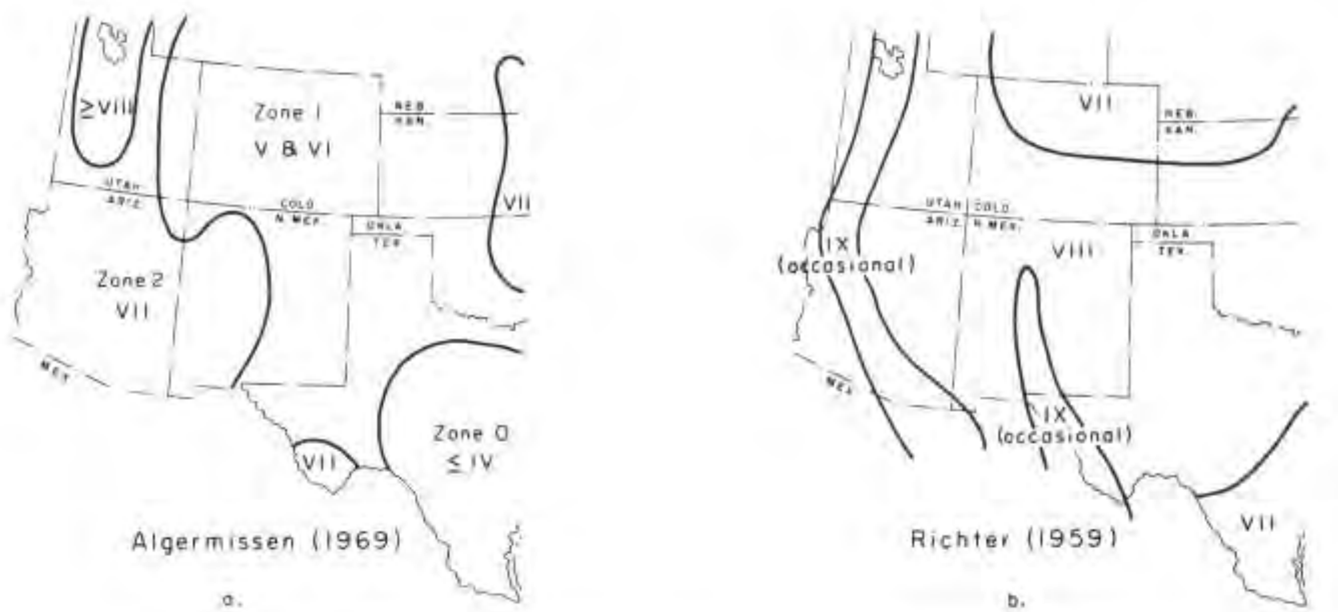

FIGURE 1–*Seismic risk maps for southwestern U.S. (map "a" by Algermissen, 1969, and map "b" by Richter, 1959)*

TABLE 1 – *Reports of felt earthquakes within 300 km of disposal site prior to 1961*

No.	Date Yr/Mo/Day	Time GMT	Location of Max. Reported Intensity	Distance(km) & Direction from Site	Maximum Reported Intensity[1]	References[2]	Remarks
1	1923 Mar 7	04:03	El Paso, Tex.	260, S75W	V	(1), (2), (3)	Felt in Sierra Blanca (166 km to SE), Columbus (130 km to W), Alamogordo (135 km to N). Newspaper accounts suggest epicenter in northern Chihuahua.
2	1926 July 17	22:00	Hope and Lake Arthur, N. M.	90, N54W	III	(4)	Earth sounds heard in NE direction at Hope; windows rattled at Lake Arthur.
3	1930 Oct 4	03:25	Duran, N. M.	280, N32W	(IV)	(5)	Moderate shock felt by many. Rolling motion, rumbling sound, rattled windows. No damage.
4	1931 Aug 16	11:40	Valentine, Tex.	210, S20W	VIII	(5), (6), (7)	Strong damaging earthquake. Felt over 1,250,000 sq. km. See discussion in text.
5	1931 Aug 16	19:33	Valentine, Tex.	210, S20W	(V)	(5)	Strong aftershock.
6	1931 Aug 18	19:36	Valentine, Tex.	210, S20W	V	(5)	Strong aftershock.
7	1931 Aug 19	01:36	Valentine, Tex.	210, S20W	(V)	(5)	Strong aftershock.
8	1931 Oct 2	?	El Paso, Tex.	260, S75W	(III)	(5)	Feeble shock.
9	1931 Nov 3	14:50	Valentine, Tex.	210, S20W	(V)	(5)	Strong aftershock of Aug. 16, 1931 earthquake.
10	1935 Dec 20	05:30	Clovis, N. M.	230, N13E	III-IV	(8)	Two shocks. Tile wall in creamery cracked.
11	1936 Jan 8	06:46	Carlsbad, N. M. ?	40, N89W	(IV)	(3), (5)	Newspaper account indicates this earthquake was probably centered near Ruidoso, N. M.
12	1936 Aug 8	01:40	El Paso, Tex.	260, S75W	(III)	(3), (5)	Weak shock not felt elsewhere.
13	1936 Oct 15	~18:	El Paso, Tex.	260, S75W	(III)	(5)	Slight shock.
14	1937 Mar 31	22:45	El Paso, Tex.	260, S75W	(IV)	(3), (5)	Felt by many.
15	1937 Sept 30	06:15	Ft. Stanton, N. M.	200, N53W	(V)	(5)	Awakened many.
16	1943 Dec 27	04:00	Tularosa, N. M.	220, N70W	IV	(9)	Rattled windows.
17	1949 Feb 2	23:00	Carlsbad, N. M.	40, N89W	(IV)	(5), (9)	Press reported two distinct shocks which were felt by several, and a few frightened. Windows, doors, dishes rattled.
18	1949 May 23	07:22	East Vaughn, N. M.	280, N28W	VI	(5), (9)	Felt area 33 km strip connecting East Vaughn and Pastura. At E. Vaughn few things fell from shelves, loose objects rattled.
19	1952 May 22	04:20	Dog Canyon, N. M.	158, N79W	IV	(5), (9)	Felt by two in ranch house. Windows, doors, dishes rattled.
20	1955 Jan 27	00:37	Valentine, Tex.	210, S20W	IV	(5), (9)	Felt by many. Houses shaken.

[1] Based on Modified Mercalli Intensity Scale of 1931 (see Appendix I). Intensities given in parentheses were assigned by the authors of this paper.

[2] The numbers in this column are for the references listed below.

(1) Woollard (1968)
(2) Bull. Seismol. Soc. Amer. (1923)
(3) Newspaper account
(4) Northrop (1973)
(5) U. S. Earthquakes
(6) Sellards (1933)
(7) Byerly (1934)
(8) Northrop and Sanford (1972)
(9) Abstracts of Earthquake Reports for the Pacific Coast and Western Mountain Region.

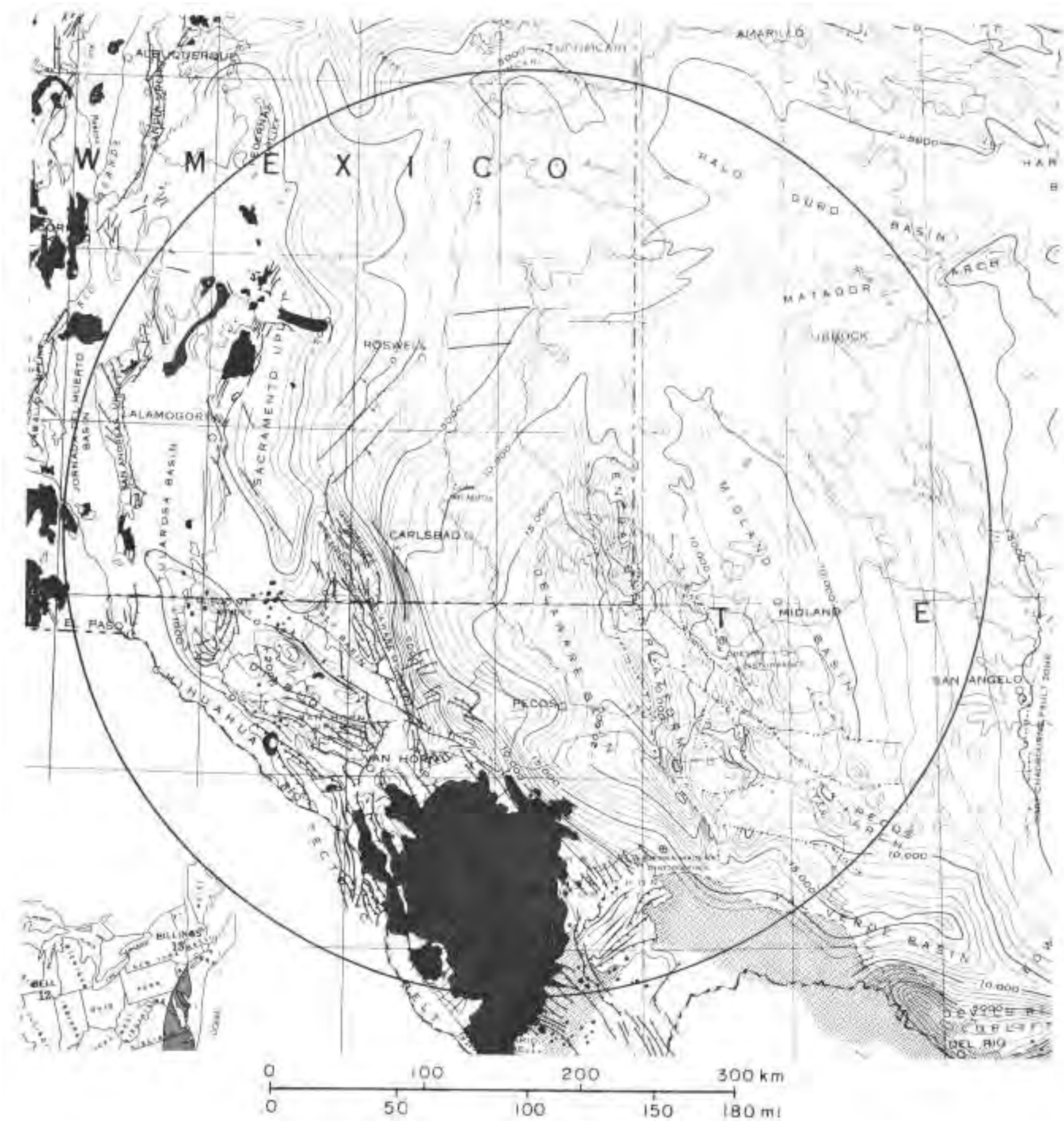

FIGURE 2—*Tectonic map of the region surrounding the proposed disposal site. The radius of the circle centered on the site is 300 km (180 mi) (from U.S. Geological Survey and American Association of Petroleum Geologists).*

geomorphic surfaces. These data are presented in tables 1 and 2 and in figs. 3 and 6.

Felt Earthquakes Prior to Jan. 1, 1961

Table 1 lists earthquakes within 300 km of the site prior to 1961. Information on locations and strengths of earthquakes listed in table 1 is based on values of earthquake intensity. Intensity values (Appendix 1) are assigned on the basis of reactions and observations of people during a shock and the degree of damage to structures. Given many intensity observations, the maximum intensity and limit of perceptibility can be established. Both quantities can be related approximately to the earthquake magnitude (Richter, 1958; Slemmons and others 1965; Wiegel, 1970).

In addition to sources listed in table 1, we contacted a number of historical societies, museums, and longtime residents in southeastern New Mexico and West Texas to determine if some shocks had been overlooked. This effort did not reveal any earthquakes not already in our listings (tables 1 and 2).

TABLE 2 – *Instrumentally located earthquakes within 300 km of disposal site from 1961 through 1972*

No.	Date Yr/Mo/Day	Origin Time GMT	Location Lat°N	Long°W	Distance from Site in Km.	Azimuth from Site	Magnitude[1] M_B	M_L	Reference[2]	Area
21	62 Mar 3	18:16:48.1	33.8	106.4	288	N57W		1.7	(1)	Bingham, N. M.
22	62 Mar 6	09:59:09.7	31.2	104.8	166	S36W		3.5	(2)	Van Horn, Tex.
23	64 Jun 18	20:20:18.4	33.1	106.1	230	N70W		1.8	(1)	Tularosa, N. M.
24	64 June 19	05:28:39.4	33.1	106.1	230	N70W		2.1	(1)	Tularosa, N. M.
25	64 Nov 8	09:25:59.0	31.9	103.1	82	S48E		~3.0	(2)	Kermit, Tex.
26	64 Nov 21	11:21:22.5	31.9	103.1	82	S48E		~3.3	(2)	Kermit, Tex.
27	65 Feb 3	19:59:31.5	31.9	103.1	82	S48E		3.9	(3)	Kermit, Tex.
28	65 Apr 13	09:35:46.0	30.3	105.1	265	S29W	4.2	3.2	(4)	Chihuahua, Mex.
29	65 Aug 30	05:17:37.9	32.1	102.3	140	S76E	3.5	3.3	(4)	Midland, Tex.
30	66 Aug 14	15:25:44.1	31.7	103.1	98	S40E	3.4	4.1	(3)	Wink, Tex.
31	66 Aug 17	18:47:13	30.5	105.6	272	S40W		3.2	(2)	Chihuahua, Mex.
32	66 Aug 19	04:15:44.6	30.3	105.6	292	S37W	4.1	5.3	(4)	Chihuahua, Mex.
33	66 Aug 19	08:38:21.9	30.3	105.6	292	S37W	4.0	4.3	(4)	Chihuahua, Mex.
34	66 Sept 17	21:30:14.0	34.9	103.9	278	N3W		2.7	(3)	Quay, N. M.
35	66 Nov 26	20:05:41	30.8	105.5	240	S43W		3.3	(2)	Chihuahua, Mex.
36	66 Nov 28	02:20:57.3	30.4	105.4	270	S35W	3.8	4.0	(4)	Chihuahua, Mex.
37	66 Dec 5	10:10:37.8	30.4	105.4	270	S35W	4.2	4.0	(4)	Chihuahua, Mex.
38	67 Sept 29	05:49:39.0	32.1	106.9	296	S84W		3.2	(3)	La Mesa, N. M.
39	68 Mar 9	21:54:23.3	32.5	106.0	208	N86W		3.2	(4)	Orogrande, N. M.
40	68 Mar 23	11:53:37.1	32.5	106.0	208	N86W		2.4	(2)	Orogrande, N. M.
41	68 May 2	02:56:43.8	33.1	105.2	154	N60W		3.0	(5)	Elk, N. M.
42	68 Aug 22	02:22.25.5	34.3	105.8	282	N42W		2.1	(2)	Cedarvale, N. M.
43	69 May 12	08:26:18.7	31.9	106.4	254	S78W		3.8	(6)	El Paso, Tex.
44	69 May 12	08:49:16.3	31.8	106.4	255	S75W	4.3	3.5	(6)	El Paso, Tex.
45	69 June 1	17:18:24.8	34.2	105.2	238	N33W		2.3	(2)	Corona, N. M.
46	69 June 8	11:36:02.3	34.2	105.2	238	N33W		2.7	(5)	Corona, N. M.
47	69 Oct 19	11:51:34.4	30.8	105.7	254	S47W	3.8	3.9	(6)	Chihuahua, Mex.
48	71 July 30	01:45:50.9	31.7	103.1	98	S40E	3.0	4.5	(2), (6)	Wink, Tex.
49	71 July 31	14:53:48.6	31.7	103.1	98	S40E	3.4	4.2	(2), (6)	Wink, Tex.
50	71 Sep 24	01:01:53.6	31.7	103.1	98	S40E		3.8	(2)	Wink, Tex.
51	72 Feb 27	15:50:01.9	32.9	105.8	198	N74W		2.3	(2)	Cloudcroft, N. M.
52	72 Dec 9	05:58:00.7	31.8	106.4	254	S75W		3.0	(2)	El Paso, Tex.
53	72 Dec 10	14:37:49.8	31.8	106.4	254	S75W		3.0	(2)	El Paso, Tex.
54	72 Dec 10	14:58:01.6	31.8	106.4	254	S75W		2.7	(2)	El Paso, Tex.

[1] M_B is reported by CGS, M_L is calculated by NMIMT from ALQ and SNM seismograms.

[2] Numbers in this column are for the references listed below.

(1) Sanford (1965)
(2) New location by NMIMT, not previously published.
(3) Sanford and Cash (1969)
(4) U.S. Dept. of Commerce, Seismological Bulletin
(5) Toppozada and Sanford (1972)
(6) U.S. Dept. of Commerce, Earthquake Data Report

FIGURE 3–*Locations of earthquakes within 300 km of the disposal site. Locations shown with square symbols are based on reports of felt earthquakes prior to 1961. Epicenters shown with circles were determined instrumentally and cover the period 1961 through 1972. Opposite the squares and circles are the numbers of shocks in tables 1 and 2.*

The principal weakness of the seismic data prior to 1961 is that they are partly a function of population density. In sparsely settled areas like the mountainous regions of southeastern New Mexico and southwestern Texas (population density of about 1 person per sq. mi), moderate shocks could have gone completely unreported, or, at best, reported at low intensity levels not indicating true strengths of the earthquakes. With few exceptions, shocks listed in table 1 are moderate and only reported felt at one locality. Converting this intensity into a magnitude results in values too low in most cases. Only for the earthquake of August 16, 1931 are intensity observations sufficient to estimate magnitude with reasonable accuracy.

Imperfect noninstrumental data were incorporated into this study because they are available for a much longer period of time than the instrumental data. Strong earthquakes are rare events. Therefore the longer the earthquake history available, the more probable the report of an earthquake that may be the largest the region is likely to experience.

The apparent epicenters of the shocks listed in table 1 appear as squares on the map in fig. 3. With the exception of the weak shock at Hope, New Mexico (no. 2 in table 1) and the 2 reported earthquakes at Carlsbad (numbers 11 and 17 in table 1), all shocks prior to 1961 occurred to the west of the site and at distances greater than 160 km. The shock of January 8, 1936, almost certainly did not occur at Carlsbad as reported by *U. S. Earthquakes.* A story in a Carlsbad newspaper *The Daily Current-Argus,* January 8, 1936, p. 1, states that the shock was centered near Ruidoso 170 km northwest. The earthquake was felt by only a few persons in Carlsbad. We have not been able to confirm the location of the January 8, 1936 earthquake, but if Ruidoso is the true location, the shock must have been quite strong to have been felt in Carlsbad. The second shock, February 2, 1949, occurred near the city of Carlsbad (Appendix 2).

Locations and Magnitudes after Jan. 1, 1961

After 1961, the number of seismic stations in southwestern U. S. became sufficient for the National Earthquake Information Center of NOAA (formerly U. S. Coast and Geodetic Survey) to locate most of the moderately strong earthquakes ($M_L > 3.5$) in the region of study. Weak as well as moderately strong earthquakes also have been located by New Mexico Institute of Mining and Technology (Sanford, 1965; Sanford and Cash, 1969; Toppozada and Sanford, 1972).

Table 2 lists all instrumentally located shocks within 300 km of the site from January 1, 1961 through December 31, 1972. Epicenters for these earthquakes appear as circles on the map in fig. 3. The greatest number of shocks in the 12-year period of instrumental data occurred in the SW quadrant (fig. 2) from the site-15 shocks with magnitudes (M_L) exceeding 3.0. The number of shocks with $M_L > 3.0$ in the other quadrants in fig. 2 was 8 in the SE quadrant, 2 in the NW quadrant, and none in the NE quadrant. The large number of weak shocks ($M_L < 3.0$) in the NW quadrant is the result of the geographic locations and periods of operations of the seismic stations from 1961 through 1972 (table 3). Because seismic stations north and west of the site were more numerous and in operation longer periods of time than elsewhere, location of weak shocks near these stations was possible. If stations had been in operation south of the site during the entire 12-year period, many shocks with $M_L < 3.0$ would have been located in the SW and SE quadrants from the site.

With the exception of the activity southeast of the site, the distribution of instrumental epicenters from 1961 through 1972 differed little from the distribution of felt shocks prior to 1961. Both distributions indicate seismic activity has been most intense southwest of the site.

The 8 earthquakes located instrumentally to the southeast of the site are important because of their strengths (M_L as great as 4.5) and nearness to the site (as little as 82 kin). These shocks are associated with the Central Basin Platform, a highly faulted Early Permian structure (Meyer, 1966), in recent years the site of many major oil fields.

TABLE 3 — *Locations and periods of operation of seismic stations within 750 km of proposed disposal site*

Station	Nearest Population Center	Location Lat°N Long°W	Elevation Meters	Period of Operation
ALQ	Albuquerque, N.M.	34.94 106.46	1853	Oct. 1961 to Present
EPT	El Paso, Tex.	31.77 106.51	1186	1963 to Present
FOTX	Ft. Stockton, Tex.	30.90 102.70	880	June 21, 1964 to April 12, 1965
JCT	Junction, Tex.	30.48 99.80	591	March 1965 to Present
LC	Las Cruces, N.M.	32.40 106.60	1590	Jan. 1962 to Nov. 1965 Aug. 1967 to Dec. 1967
LUB	Lubbock, Tex.	33.58 101.87	979	Dec. 1961 to Present
SNM	Socorro, N.M.	34.07 106.94	1511	July 1961 to Present
TFO	Payson, Ariz.	34.27 111.27	1402	1963 to Present
TJC	Trinidad, Colo.	37.22 104.69	2103	1966 to Present
TUC	Tucson, Ariz.	32.31 110.78	985	Pre-1961 to Present
WMO	Ft. Sill, Okla.	34.72 98.59	505	1962 to 1969

Before the present study, earthquakes prior to February 3, 1965 were not known to have occurred on the Central Basin Platform area. Queries of local historical societies and newspapers confirmed an absence of any reports prior to 1965. However, this region of low population at the present time was sparsely populated prior to the beginning of oil development in 1920.

To learn more about earthquakes on the Central Basin Platform, a 10-month seismogram from a temporary LRSM (Long Range Seismic Measurements) station near Ft. Stockton, Texas was examined. Apparently, this is the only high-magnification station (350-400 K at 1 Hz) to have operated for any substantial period of time within 120 km of the Central Basin Platform activity. Fortunately, the period of operation of the Ft. Stockton station (FOTX), from June 21, 1964 to April 12, 1965, included the date of the then earliest known earthquake on the Central Basin Platform—February 3, 1965.

Table 4 lists earthquakes (observed on FOTX seismograms) we believe originated in the same region of the Central Basin Platform as shocks 25, 26, 27, 30, 48, 49, and 50 in table 2 and fig. 3. Table 4 includes shocks 25, 26, and 27 listed in table 2. Prior to the examination of the FOTX records, the strong and locatable earthquakes of November 8, 1964 (25) and November 21, 1964 (26) in the Central Basin Platform were unknown.

All of the measured S-P intervals on the FOTX seismograms yield an epicentral distance corresponding to the distance between the FOTX station and the area of activity on the Central Basin Platform. For some of the stronger shocks in table 4, P arrival times were available from the Las Cruces station (LC). The difference between P arrival times at stations LC and FOTX in table 4 is the same (34.7±0.5 seconds) for the unlocated shocks as for the located shocks on November 8 and November 21, 1964 and February 3, 1965.

The FOTX records indicate the Central Basin Platform was seismically active during mid-1964. The fact that the rate of activity at the beginning of the 10-month period equalled the rate of activity at the end of the period suggests earthquakes occurred prior to June, 1964. Unfortunately, the date of onset of seismic activity on the Central Basin Platform cannot be determined from available seismological data. Thus, the question of whether shocks in this region are natural or related to water injection for secondary recovery of oil, can probably be resolved only by determining depths of focus for earthquakes. Central Basin Platform earthquakes are discussed in more detail later.

Strongest Reported Earthquake in Region

The strongest reported earthquake to occur within 300 km of the disposal site was the "Valentine, Texas" earthquake on August 16, 1931 (event no. 4 in table 1). Valentine, Texas reported the maximum intensity for this shock—VIII on the Modified Mercalli Scale of 1931 (Appendix 1). Reports of earthquake intensity were gathered from a large number of localities by the USCGS (U.S. Earthquakes, 1931 and Sellards, 1933). Intensities at the time of this shock were based on the Rossi-Forel Intensity Scale, subsequently abandoned in favor of the Modified Mercalli (M.M.) Intensity Scale of 1931. We have assigned M.M. intensities on the basis of descriptions of earthquake effects (primarily damage to structures) given by Sellards (1933), and plotted the isoseismal map shown in fig. 4. Close to the source, the isoseismals are elongated northwest-southeast conforming to the structural grain of the region (fig. 2). Further from the epicenter, the earthquake had higher intensities to the east than west due to lower topographic relief to the east.

TABLE 4 – *Central Basin Platform earthquakes recorded at Ft. Stockton station (FOTX) from June 21, 1964 through April 12, 1965*[1]

Date Yr/Mo/Day	FOTX-P Arrival Time GMT	FOTX-S-P Interval Secs.	LC-P Arrival Time GMT	Other Stations Recording Shock
64 June 22	07:07:47	14	07:08:22	
64 Jul 13	12:20:03	14		
64 Jul 13	16:18:17	14		
64 Jul 19	02:34:16	13		
64 Aug 14	14:56:37	14	14:57:11	
64 Sep 7	13:42:36	14	13:43:10	
64 Sep 8	22:06:20	15		
64 Sep 11	12:33:08	14		
64 Nov 8	09:26:19	S[2]	09:26:53	SNM
64 Nov 16	02:06:05	15		
64 Nov 17	08:05:14	14		
64 Nov 18	10:20:30	14		
64 Nov 19	11:39:59	14		
64 Nov 19	11:40:30	14		
64 Nov 21	11:21:42	S[2]	11:22:17	SNM, ALQ
64 Nov 23	03:10:18	14		
64 Nov 25	23:18:43	14		
64 Nov 26	00:03:13	14		
64 Nov 27	16:29:53	14	16:30:28	
64 Nov 28	23:46:55	14		
64 Dec 1	20:59:50	13		
64 Dec 1	06:49:47	13		
64 Dec 5	23:09:43	14		
64 Dec 7	06:24:12	14		
64 Dec 7	06:31:40	14		
64 Dec 8	17:16:02	14		
64 Dec 13	19:19:19	13		
64 Dec 14	15:20:26	14		
64 Dec 26	00:08:29	14		
65 Jan 8	14:01:13	14		
65 Jan 12	20:35:19	14		
65 Jan 12	20:49:38	14		
65 Jan 21	11:51:51	14		
65 Feb 2	09:59:19	13		
65 Feb 3	19:59:52	S[2]	20:00:27	SNM, ALQ, WMO, UBO
65 Mar 8	21:00:01	14		
65 Mar 9	03:46:18	14		
65 Apr 2	07:30:58	14		

1 Listing of shocks restricted to events whose maximum peak to peak amplitudes exceeded 20 mm.

2 Earthquake too strong on the seismogram to read S-P interval

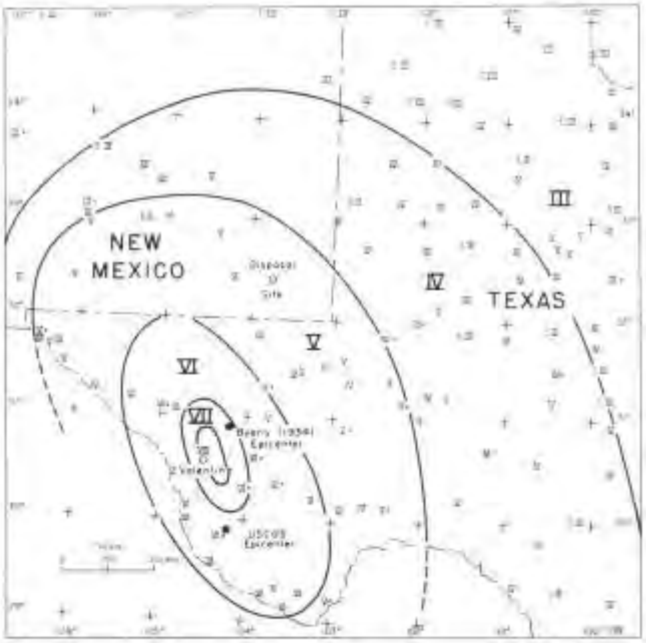

FIGURE 4–*Isoseismal map for the Valentine, Texas earthquake on August 16, 1931.*

Region	Equation	No.
Western (Wiegel, 1970)	$M=2.3\log_{10}(A+3{,}000)-5.1$	(1)
Rocky Mountain and Central (Wiegel, 1970)	$M=2.3\log_{10}(A+14{,}000)-6.6$	(2)
Eastern (Wiegel, 1970)	$M=2.3\log_{10}(A+34{,}000)-7.5$	(3)
Nevada (Slemmons and others, 1965)	$M=1.4\log_{10}(A/2)$	(4)

In all of the equations, A is the area of perceptibility in square miles. The main problem in determining the magnitude of the Valentine quake is deciding which equation applies. The epicenter lies near the boundary of two physiographic provinces, the Basin and Range to the west, and the High Plains to the east. The area affected by this shock is much greater to the east than the west.

The equation for the Rocky Mountain and central region appears most applicable. Substituting the felt area reported by USCGS, 450,000 square miles, yields a magnitude of 6.4. This result appears reasonable and is compatible with the maximum intensity reported for the shock (VIII at Valentine).

Two instrumental locations and origin times have been published for this earthquake. USCGS places the epicenter at 29.9° N. and 104.2° W. and the origin time at 11:40:15 GMT. On the other hand, Byerly (1934), who made a detailed instrumental investigation of this earthquake, found the epicenter to be 30.9° N. and 104.2° W. and the origin time 11:40:21 GMT. Byerly's epicenter, 110 km (66 mi) north of the USCGS epicenter, is closer to the region of highest reported intensities, thus, probably the most accurate of the two locations.

Byerly listed the direction of first motions on seismograms of the Valentine earthquake recorded at distances ranging from 5.8° (550 km) to 104.8° (11,500 km). Applying the recent techniques of first motion analysis, we obtained a surprisingly good fault-plane solution (fig. 5) considering the doubtful quality of the seismograms in 1931. The solution indicates predominantly dip-slip motion along a normal fault striking N. 40° W. and dipping 74° southwest. This type of fault motion is consistent with the known structure in the epicentral region.

The area over which an earthquake is perceptible can be used to estimate its magnitude (Slemmons and others, 1965; Wiegel, 1970). The area of perceptibility for a shock of prescribed strength varies considerably with location. For example, the extent of the felt region is much greater for a shock of given magnitude in the eastern conterminous U. S. than the western. Equations applicable to certain regions of the country are listed below:

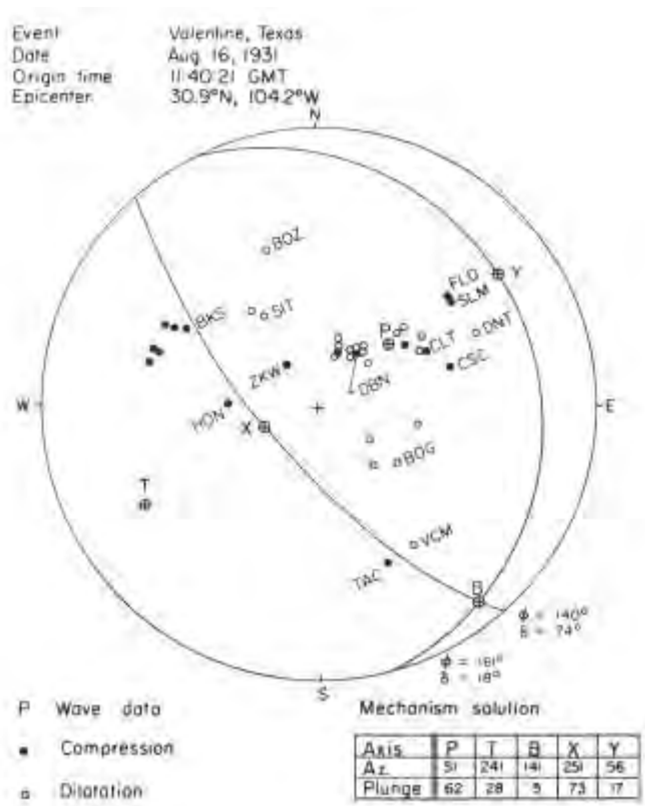

FIGURE 5–*Fault-plane solution for the Valentine, Texas earthquake on August 16, 1931.*

FIGURE 6 – *Map showing location of fault scarps cutting Quaternary alluvial surfaces. After Talmage (1934), Reiche (1938), Kelley (1971), Dake and Nelson (1933), King (1948), King (1965), Kottlowski (1960), Kottlowski and Foster (1960), and Pray (1961).*

Quaternary Fault Scarps

An estimate of the seismicity of the region can be obtained from the lengths, displacements, and ages of faults offsetting Quaternary geomorphic surfaces (Sanford and others, 1972). The principal advantage of this method is that it incorporates a much longer span of seismic history than other techniques. However, this advantage is offset by difficulties in applying the method, in particular, obtaining reliable ages for the fault scarps.

Investigation of fault scarps was confined to the region within 300 km of the disposal site exclusive of the Permian basin (fig. 6). (Bachman, 1973, has completed a detailed investigation of surface features of the Permian basin which indicates recent fault scarps do not exist in that area.) The study was restricted to fault scarps that offset Quaternary alluvial surfaces because these are the only fault displacements whose age can be estimated with any degree of certainty. Some Quaternary tectonic movements in the area may have occurred along faults cutting older rocks, but detection of recent offsets along these faults is nearly impossible.

The first phase of the investigation was a search of the literature for references to fault scarps of recent age. The literature as well as an earlier detailed investigation of fault scarps along the Rio Grande rift (Sanford and others, 1972) indicated nearly all scarps are located in the basins near the escarpments of the tilted fault-block mountains. For this reason, the second phase of the investigation, an examination of aerial photographs, was restricted to the boundaries between the basins and the mountain escarpments. Photographs covering a total area of 10,000 sq. km in New Mexico were examined. The study of aerial photographs did not reveal any major fault scarps not already reported in the literature. On the other hand, details of the known faulting were obtained as well as an indication of a recent age from the general youthful appearance of the scarps.

All of the fault scarps shown in Texas were taken from geologic maps but were not confirmed by an examination of aerial photographs. Because the New Mexico study indicated areas of recent faulting had been identified on published geologic maps, we believe that few scarps were missed in Texas. The fault scarp on the east side of the Salt Basin graben, 55 km south of the New Mexico border, was visited. Judging from its sharpness, this feature originated recently.

The fault scarps, particularly along the margins of the San Andres and Sacramento Mountains, indicate major earthquakes have occurred in the region within the past 500,000 years. The length of the faulting in these two areas (about 60 to 100 km) and the maximum displacements (up to 30 m) suggest earthquakes comparable in strength to the Sonoran earthquake of 1887 (Aguilera, 1920). This major earthquake (probable magnitude of about 7.8) produced 80 km of fault scarp with a maximum displacement of about 8.5 m extending southward from the United States-Mexico border at about long. 109° W.

SEISMIC RISK MAP

Earthquake and fault-scarp data (figs. 3 and 6), indicate that damaging shocks probably will not occur at or within 40 km of the disposal site during the lifetime of the installation. The disposal site, however, will be subjected to ground motions generated by major earthquakes located in the mountainous regions to the west and possibly by moderate earthquakes with epicenters on the Central Basin Platform.

In fig. 7, the region surrounding the disposal site has been zoned on the basis of the severest seismic conditions likely to occur in 500,000 years, the approximate lifetime of the installation. The primary data used to generate the seismic risk map in fig. 7 were the lengths, displacements, and ages of the fault scarps.

All fault scarps shown in fig. 6 offset Quaternary surfaces that are less than 500,000 years in age. The lengths and displacements of the scarps are indicative of major earthquakes comparable in size to the 1887 Sonoran earthquake (magnitude of about 7.8). Inasmuch as the evidence points to major earthquakes in the past 500,000 years, a reasonable expectation is that they will occur in the next 500,000 years.

The positions of existing scarps as well as the general tectonic framework of the region suggest that a major earthquake is not likely to occur any closer than the Salt Basin graben, a distance of about 115 km. For

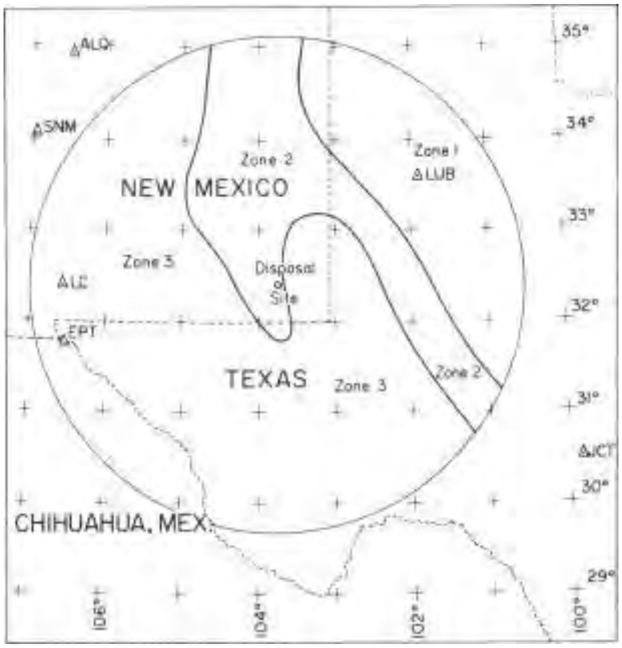

FIGURE 7—*Seismic risk map for the region surrounding the proposed waste disposal site (time period 500,000 years).*

the seismic risk map in fig. 7, magnitude 7.8 shocks were assumed to be possible in a 500,000-year period west of the eastern margins of the Tularosa Basin and Salt Basin graben. Zoning was determined in the following manner. First, maximum accelerations as a function of distance from the epicenter were found from the work of Schnabel and Seed (1973). Second, accelerations were converted to intensities using Richter's (1958) empirical relation. Third, the map was subdivided into the following risk zones, corresponding closely to those used by Algermissen (fig. 1a):

Zone	Accelerations cm/sec^2	Intensities M.M.
3	>150	>VIII
2	35 to 150	VI to VIII
1	<35	<VI

If only major shocks west of the site had to be considered, the seismic risk map would be relatively simple—three zones running roughly northwest-southeast through the region with the disposal site toward the center of Zone 2. However, if moderate earthquakes are considered possible anywhere along the Central Basin Platform, the seismic risk map becomes more complex. In fig. 7, a magnitude 6 earthquake was considered possible along this structure, and zoning was determined in the same manner as described above. The siesmic risk map in fig. 7 is the result of combining the zoning for major earthquakes west of the site with zoning for moderate earthquakes on the Central Basin Platform. The site can be affected more by moderate earthquakes on the Central Basin Platform than by major earthquakes in the Tularosa Basin or Salt Basin graben. The assumption that shocks can be as large as magnitude 6 on the Central Basin Platform may not be correct, particularly if these shocks are associated with water injection for secondary recovery of oil.

RECURRENCE RATES

The number of times in a 500,000-year period the disposal site will be subjected to the degree of shaking indicated on the seismic risk map can be found from the earthquake data in tables 1 and 2. Recurrence rates can be calculated from the empirically determined relation between number of shocks and magnitude (Richter, 1958)

$\log_{10}$åN= a-b M_L, (5)

where EN is the number of shocks having magnitudes of M_L or greater, and "a" is the logarithm to the base 10 of the number of shocks with $M_L > 0$. If the values for "a" and "b" are known for a seismic region, then equation (5) can be used to estimate the strongest earthquake anticipated in that region during a specified period of time, or the time interval between shocks of prescribed strength.

Fig. 8 is a graph of magnitude versus $\log_{10}$ åN for the earthquakes listed in tables 1 and 2, exclusive of shocks from the Central Basin Platform and aftershocks of the 1934 Valentine earthquake. Curve AB is based on instrumental data only from table 2, and curve CD is based on data from both tables. Maximum reported intensities in table 1 were converted to magnitudes using the relations established for California by Richter (1958). Recent studies (Sanford and others, 1972) indicate these relations are applicable to New Mexico earthquakes.

The sharp break in curves AB and CD indicates that data are incomplete for magnitudes less than 3.2 to 3.4. The linear portion of the curves for $M_L > 3.4$ can be extrapolated to estimate the strongest earthquake to expect in a 100-year period. For AB, this shock is magnitude 6.8; and for curve CD, the shock is magnitude 6.3.

The slope of both curves, 0.6, is substantially smaller than previously observed in the region. For the Rio Grande rift near Socorro, Sanford and Holmes (1962) obtained a value for "b" of 0.99. Algermissen (1969) reports a "b" value of 1.02 for the central and southern Rocky Mountains. Because the number of shocks used to establish the linear portions of curves AB and CD is small (16 and 25, respectively) an error in "b" is quite possible. An alternate computation of the strongest earthquake in a 100-year period can be made by assuming a line with a slope of 1.0 passing through the ML equal to 5.3 point (curves EF and GH in fig. 8). For line EF, the strongest earthquake will have a magnitude of 6.2, and for line GH, the magnitude will be 5.9.

The recurrence rate for the strongest earthquake the region is ever likely to experience (magnitude 7.8) can also

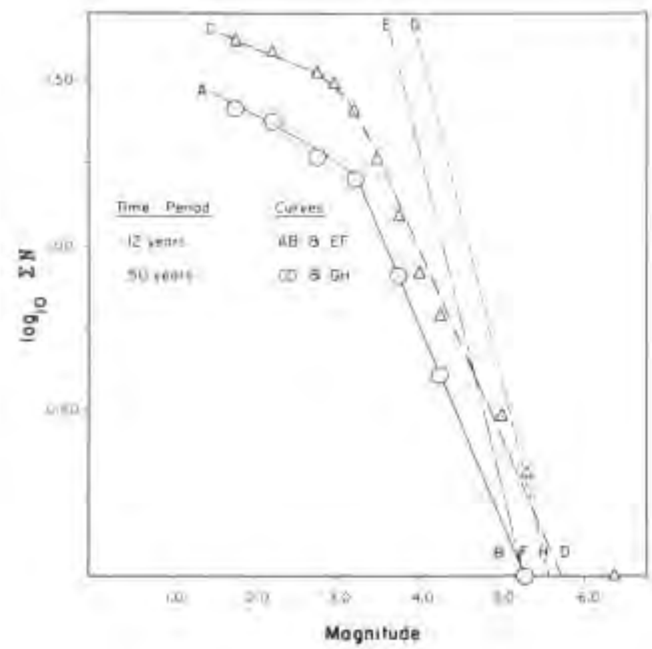

FIGURE 8 — *A graph of the logarithm of the cumulative number of earthquakes versus the magnitude. Curve AB is based on shocks listed in table 2 exclusive of earthquakes located on the Central Basin Platform. Curve CD is based on curve AB data plus earthquakes listed in table 1 exclusive of the aftershocks of the Valentine, Texas earthquake.*

be estimated by extrapolation of the curves in fig. 8. For curves AB, CD, EF, and GH, a 7.8 earthquake will occur once every 400, 900, 4,000, and 8,000 years, respectively. Data on fault scarps in the region do not indicate major earthquakes are occurring as frequently as once every 400 to 1,000 years. This observation suggests that the slopes of the linear portions of curves AB and CD in fig. 8 may be incorrect; consequently, many shocks with $M_L < 4.5$ (maximum intensity < VI) in the region may have gone unreported or undetected. An alternate explanation is that the actual relation between the $\log_{10}$åN and ML becomes nonlinear for large values of ML. Therefore, an extrapolation of equation (5) based on smaller earthquakes cannot be used to estimate recurrence rates for major earthquakes.

Nevertheless, magnitude 7.8 earthquakes could be occurring in the western half of the study region at a rate of once every 5,000 years. Major earthquakes that could affect the disposal site at the level shown on the seismic risk map (fig. 7) would occur less frequently. These shocks must have epicenters in the Salt Basin graben, a structure that covers only about 10 percent of the area considered in calculating the recurrence intervals. Therefore, major earthquakes to the west could produce Zone 2 effects (maximum intensity VI-VIII) at the disposal site only about once every 50,000 years. Calculation of recurrence rates for moderate earthquakes on the Central Basin Platform is not meaningful until the question of their origin is settled.

CENTRAL BASIN PLATFORM EARTHQUAKES

Shurbet (1969) was the first to suggest that seismic activity on the Central Basin Platform is related to water injection for secondary recovery of oil. His suggestion was based on the clearly established association between earthquakes and waste injection into crystalline bedrock at the Rocky Mountain Arsenal near Denver (Healy and others, 1968). Subsequently, a direct association between earthquakes and fluid injection for secondary recovery of oil was established at the Rangely field in northwestern Colorado (Healy and others, 1972). As the fluid pressure builds up during injection, the effective stress across pre-existing fractures diminishes. Frictional resistance to sliding is directly proportional to the effective stress.

The principal observations supporting an association between earthquakes and water injection on the Central Basin Platform are:

Felt earthquakes on the Central Basin Platform were not reported prior to August 14, 1966.

The Central Basin Platform is an old structure (Early Permian) with no evidence at the surface of being rejuvenated.

All but one of the known Central Basin Platform shocks occurred near, or in, a major oil field being subjected to massive water injection.

The oil field referred to above is the Ward-Estes North, operated by the Gulf Oil Corporation. The center of the field is 31.57° N. and 102.98° W. and it is 28 km long and 5 km wide with a N. 10° W. trend (the structural trend of the Central Basin Platform). The locations of shocks 25, 26, and 27 in table 2 are 22 km north of the field and shocks 30, 48, 49, and 50 are on its northern boundary. Considering the uncertainties in the instrumental epicenters, all of these shocks could have occurred within the boundaries of the field.

The Ward-Estes North field is a prime candidate for earthquakes because of the enormous quantities of water injected. The cumulative total of water injected to 1970 was 1,158,550,000 barrels. Water injection began in 1944 but more than three-quarters has occurred since 1955. This field alone accounts for 42 percent of all the water injected in Ward and Winkler Counties, Texas. These two counties straddle the western margin of the Central Basin Platform just south of the New Mexico border. The water injected in the Ward-Estes North field is about 3 times the total amount injected in all the oil fields in the southeastern corner of New Mexico (Tps. 18 to 26 S.; Rs. 27 to 38 E.; 10,000 sq. km).

Central Basin Platform earthquakes may be related to water injection, but the evidence certainly is not conclusive. Natural earthquake activity could have been occurring long before injection commenced, but not reported because of the low population density of the region. Rejuvenation of the Central Basin Platform structure could be so recent that surface manifestations are slight or absent. Old buried structures in northeastern New Mexico, where there is no oil production, are seismically active. The apparent association of the seismic activity with the Ward-Estes North field may be coincidence; perhaps a degree of certainty could be established by determining depths of focus of current seismic events.

SUMMARY

Reports of felt shocks prior to 1961 indicate the region near the proposed disposal site is not seismically active.

Instrumental data since 1961 do not give any evidence for earthquakes with $M_L > 3.5$ in the immediate vicinity of the site.

Fault scarps west of the disposal site indicate major earthquakes, M_L — 7.8, have occurred in the past 500,000 years.

The location of known fault scarps and the general tectonic framework of the region suggest that a major earth quake is not likely to occur any closer than 115 km west of the site. Major earthquakes ($M_L = 7.8$) at this distance will produce ground accelerations of about 0.07 g.

An analysis of earthquake statistics since 1923 indicates the site will be subjected to shaking at the 0.07-g level about once every 50,000 years from earthquakes located west of the site, particularly along the Salt Basin graben.

The earthquakes on the Central Basin Platform south-east of the site have epicenters in, or near, an oil field undergoing massive water injection for secondary recovery. Also the Central Basin Platform is an old structure, lacking surface evidence of rejuvenation; and earthquakes were not reported felt prior to August 14, 1966. These points suggest a direct link between earthquakes and water injection, but the evidence is not conclusive.

If the Central Basin Platform shocks are natural and can attain a magnitude of 6.0 anywhere on the structure, then the maximum acceleration from these shocks at the site will be about 0.1 g.

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APPENDICES

Appendix 1 — Modified Mercalli Intensity Scale of 1931 (Abridged)

From Abstracts of Earthquake Reports for the Pacific Coast and Western Mountain Region

I Not felt except by a very few under especially favorable circumstances. (Rossi-Forel Scale.)

II Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing. (I to III Rossi-Forel Scale.)

III Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motorcars may rock slightly. Vibration like passing truck. Duration estimated. (III Rossi-Forel Scale.)

IV During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, and doors disturbed; walls make creaking sound. Sensation like heavy truck striking building. Standing motorcars rocked noticeably. (IV to V Rossi-Forel Scale.)

V Felt by nearly everyone; many awakened. Some dishes, windows, etc., broken; a few instances of cracked plaster; unstable objects overturned. Disturbance of trees, poles, and other tall objects sometimes noticed. Pendulum clocks may stop. (V to VI Rossi-Forel Scale.)

VI Felt by all; many frightened and run outdoors. Some heavy furniture moved; a few instances of fallen plaster or damaged chimneys. Damage slight. (VI to VII Rossi-Forel Scale.)

VII Everybody runs outdoors. Damage negligible in buildings of good design and construction; slight to moderate in well built ordinary structures; considerable in poorly built or badly designed structures. Some chimneys broken. Noticed by persons driving motorcars. (VIII Rossi-Forel Scale.)

VIII Damage slight in specially designed structures; considerable in ordinary substantial buildings, with partial collapse; great in poorly built structures. Panel walls thrown out of frame structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected in small amounts. Changes in well water. Persons driving motorcars disturbed. (VIII+ to IX Rossi-Forel Scale.)

IX Damage considerable in specially designed structures; well designed frame structures thrown out of plumb; great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked conspicuously. Underground pipes broken. (IX + Rossi-Forel Scale.)

X Some well built wooden structures destroyed; most masonry and frame structures destroyed with foundations; ground badly cracked. Rails bent. Landslides considerable from river banks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks. (X Rossi-Forel Scale.)

XI Few, if any (masonry), structures remain standing. Bridges destroyed. Broad fissures in ground. Underground pipelines completely out of service. Earth slumps and land slips in soft ground. Rails bent greatly.

XII Damage total. Waves seen on ground surfaces. Lines of sight and level distorted. Objects thrown upward into the air.

Appendix 2 — Field Report of Carlsbad Earthquake Feb. 2, 1949

From Abstracts of Earthquake Reports for the Pacific Coast and Western Mountain Region, 1949, MSA 61, USCGS, p. 29.

2 February, 16:00. State of New Mexico.

Following up press reports that an earthquake had been felt in Carlsbad, a coverage was made by Prof. Stuart A. Northrop, Collaborator in Seismology for New Mexico. The press reported two distinct shocks; woman and several neighbors alarmed; thought something had run into house; several ran outside. Comment by Prof. Northrop: Probably a slight subsidence.

Carlsbad. IV. Motion rapid, lasted a few seconds. Felt.in several homes; frightened few people. Rattled windows, doors, dishes; house creaked.

Carlsbad. IV. Lasted 30 seconds. Rattled windows, doors, dishes. Frightened observer. Ground: Soil, level.

Carlsbad. III. Lasted about 1 or 2 seconds. Felt by several in home. House seemed to shudder momentarily. Ground: Soil, compact, level.

Reported not felt: Artesia, Carlsbad Caverns Nat'l Park, Lakewood.

Type Faces: Camera-ready copy composed at
N.M. Bureau Mines on IBM MT
Text in 10 pt. Press Roman leaded
two points
Subheads in II pt. Press Roman

Presswork: Text printed on 38" single color Miehle and 22 1/2" MGD
Cover printed on 29" single color Harris

Paper: Cover on 65# white Antique
Body on-60# white offset

Earthquake catalogs for New Mexico and bordering areas II: 1999–2004

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This latest report on earthquake activity in New Mexico and bordering areas by New Mexico Institute of Mining and Technology (NMT) investigators covers the 6-yr period 1999–2004[1]. It is a continuation of catalogs for 1962 through 1998 published as Circular 210 by the New Mexico Bureau of Geology and Mineral Resources in 2002. (Data are available online at http://geoinfo.nmt.edu/publications/circulars/210/.) Earthquake research centered at NMT is appropriate because a small region surrounding Socorro produces a disproportionate share of the state's activity and has generated the strongest historical earthquakes. A primary goal of the research at NMT has been to establish an accurate earthquake database for the Socorro area and all of New Mexico from which reliable estimates of earthquake hazard can be obtained. To this end, it has been important to eliminate quakes arising from explosions and those that have been induced by human activity, for example, collapse of underground mines and disposal of large volumes of waste water generated in development of energy resources.

Abstract

Earthquakes in New Mexico and bordering areas have been instrumentally located since 1962 at New Mexico Institute of Mining and Technology. Catalogs of these earthquakes for the period 1962 through 1998 were published in 2002. This report extends the cataloging of earthquakes for the region through 2004. For this 6-yr period 198 earthquakes with magnitudes of 2.0 or greater were located. An unusual feature of the seismicity 1999 through 2004 is that 63% of the earthquakes were concentrated in two swarms, one near water disposal wells on the western edge of the Dagger Draw oil field in southeastern New Mexico, and the other within and bordering the coalbed methane fields of the Raton Basin in northeastern New Mexico. We suggest that the proximity of these swarms to oil and gas fields may indicate that the earthquakes are induced by destabilization of the crust through production and waste disposal practices. The remaining 37% of the earthquakes 1999 through 2004 were concentrated near Socorro and west Texas. Except for the Socorro area, activity along the Rio Grande rift was low.

Introduction

The earthquake catalogs presented here for New Mexico and bordering areas are for the 6-yr period 1999 through 2004. They are a continuation of catalogs published for the same region over a 37-yr period 1962 through 1998 (Sanford et al. 2002). Procedures followed in generating the catalogs here are identical to those used by Sanford et al. (2002); however, they are restricted to shocks of magnitude 2.0 or greater. The earlier catalogs listed events with magnitudes as low as 1.3. Another difference for the 1999–2004 listings of quakes is the addition of epicenter error and maximum station azimuthal gap to the parameters date, origin time, epicenter location, and magnitude.

For 1999 through 2004, 198 earthquakes of magnitude 2.0 or greater were located in New Mexico and bordering areas, a region extending from 31.0° to 38.0° N latitude and from 101.0° to 111.0° W longitude (Fig. 1). In the preceding 6-yr interval, 123 quakes of magnitude 2.0 or greater occurred in the same region. This suggests a near doubling of activity in 1999 through 2004. However, an unusual feature of this latest 6-yr period is the onset of two vigorous earthquake swarms located in small areas of New Mexico. Some observations suggest the two swarms are induced: (1) in the Delaware Basin of southeast New Mexico by disposal of large quantities of water produced along with oil, and (2) in the Raton Basin of northeast New Mexico by the removal and/or injection of water associated with production of coalbed methane. Because these two tight clusters of earthquakes account for 123 of the quakes from 1999 through 2004, each will be described separately in this paper. Following Sanford et al. (2002), the remaining 75 earthquakes are divided between two areas: a 5,000-km^2 region surrounding Socorro that is designated the Socorro Seismic Anomaly (SSA; Balch et al. 1997), and the other, the remainder of New Mexico and bordering areas designated RNM. The justification for the separation into two areas is that the SSA occupies only 0.7% of the area covered in the study but contributes a disproportionately large fraction of the total activity, 23% in the 37-yr period 1962 through 1998 (Sanford et al. 2002) and 15% in the 6-yr period covered by this study.

Procedures

Earthquake data

Most of the data used to determine origin times, epicenters, and magnitudes came from two networks operated by New Mexico Institute of Mining and Technology (NMT): (1) nine stations surrounding Socorro (Fig. 2) and (2) nine stations surrounding the Waste Isolation Pilot Project (WIPP) near Carlsbad (Fig. 3). Data from these NMT networks were augmented by arrival times from stations operated by the U.S. Geological Survey, the U.S. Bureau of Reclamation, the University of Texas–El Paso, and the University of Texas–Dallas. The appendix has a table of coordinates for stations used to locate earthquakes from 1999 through 2004 and a map of the station locations.

Earthquake magnitudes

All magnitudes in this study were determined from the New Mexico duration magnitude scale:

$$M_d = 2.79 \log \tau_d - 3.63,$$

where τ_d is the duration of recorded ground motion in seconds (Newton et al. 1976; Ake et al. 1983). This relation was first developed by Dan Cash of Los Alamos National Laboratory (LANL) for quakes in northern New Mexico. Later an essentially identical relation was obtained by a group at NMT for earthquakes throughout New Mexico. Both the NMT and LANL duration magnitude scales are tied to local magnitudes obtained from Wood-Anderson seismograms (Richter 1958) of New Mexico earthquakes. Hanks and Kanamori (1979) showed that local magnitude is equivalent to moment magnitude.

Earthquake locations

Earthquake origin times and epicenters were obtained from the inverse method computer program SEISMOS (Hartse 1991). Slightly different versions of the program were used to locate earthquakes within the SSA and those in RNM and the Raton Basin and Delaware Basin swarms.

The velocity model used with SEISMOS to locate earthquakes outside the SSA was a simple half-space with a velocity of 6.15 km/sec and a Poisson's ratio of 0.25. (An exception was the Raton Basin swarm when a Poisson's ratio of 0.235 produced smaller epicenter errors.) Because of the model adopted, only P_g and S_g arrival times were used in the location procedure. For earthquakes within the SSA, a relatively complex and tightly constrained crustal velocity model obtained from inversion of reflection data was used (Hartse et al. 1992)[2].

Focal depths were not calculated for any of the earthquakes listed in the catalogs of this paper. Even in the case of SSA events, where readings from several relatively close stations were available (see Fig. 2), attempts to obtain reliable focal depths failed because focal depth errors were exceedingly large. Better estimates of

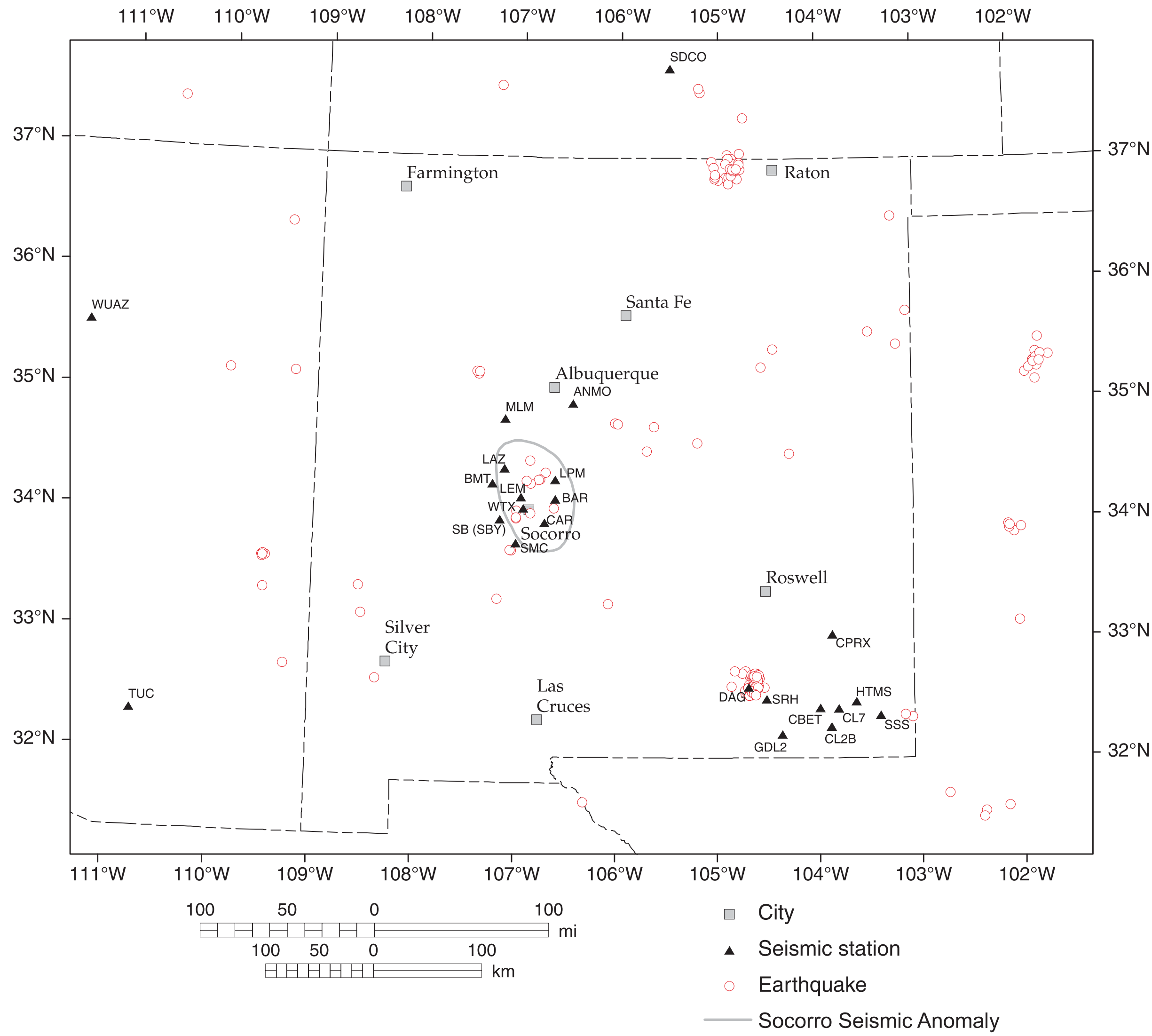

FIGURE 1—Earthquakes in New Mexico and bordering areas, 1999–2004 with magnitudes of 2.0 or greater. A total of 198 earthquake epicenters are plotted, 123 of which occurred in two tight clusters of activity, one in northeastern New Mexico and the other in the southeastern corner of the state. The remaining 75 earthquakes are located throughout the region, including 11 within the Socorro Seismic Anomaly (the elliptical area outlined (Balch et al. 1997)), a small region that contributes a disproportionate fraction of the activity.

epicenter locations and origin times were obtained by fixing the focal depth at 5 km, the approximate middle of the seismogenic zone.

For events occurring outside the SSA, calculation of focal depths was impossible because of the large distances to the recording stations and the half-space crustal structure used in the SEISMOS location program. The result of these two conditions is that the location program is unable to determine any difference in focal depths that occur within a reasonable depth range of 1.0–10.0 km. Therefore, although we fixed focal depths at 5 km for most of the earthquakes in the study, the use of other fixed depths between 1.0 and 10.0 km for individual events produced locations well within one standard deviation of each other.

Accuracy of epicenters

Epicenter accuracy is defined as how close the locations calculated by SEISMOS are to the true epicenters. A primary factor influencing accuracy is how near the adopted crustal velocity model matches the true velocity structure. For the SSA, the match is close (Hartse 1991) and the recording distances short. For the remainder of New Mexico and bordering areas, the adopted half-space crustal model has a velocity that is an average for the entire study area. Some cataloged epicenters may be less accurate because paths to the recording stations were long and passed through crust that has a velocity different from the average. Except for earthquakes in the SSA, the epicenter error listed in the catalogs may not adequately reflect deviations from the true locations arising from crustal velocity variations from the average.

Other factors influencing accuracy of epicenters are: (1) number of stations, (2) distance of stations, (3) azimuthal distribution of stations, (4) quality of P and S arrivals, and (5) number of paired P and S arrivals. The program SEISMOS estimates a one standard deviation epicenter error in kilometers, but this estimate can be affected by either overestimating or underestimating the timing errors of the P and S arrivals. Also, the estimated error does not appear to incorporate the effect of large gaps (the maximum azimuthal separation between adjacent stations). Calculated locations with gaps of 270°or more that have estimated epicenter errors as low as 2.5–7.0 km are listed in the catalogs. Inasmuch as this appears unrealistic, gap has been included in the catalogs so that it can be used as a parameter in assessing the most accurate epicenters.

Socorro Seismic Anomaly (SSA)

Earthquakes of magnitude 2.0 or greater that occurred in the 5,000-km^2 SSA surrounding Socorro in 1999 through 2004

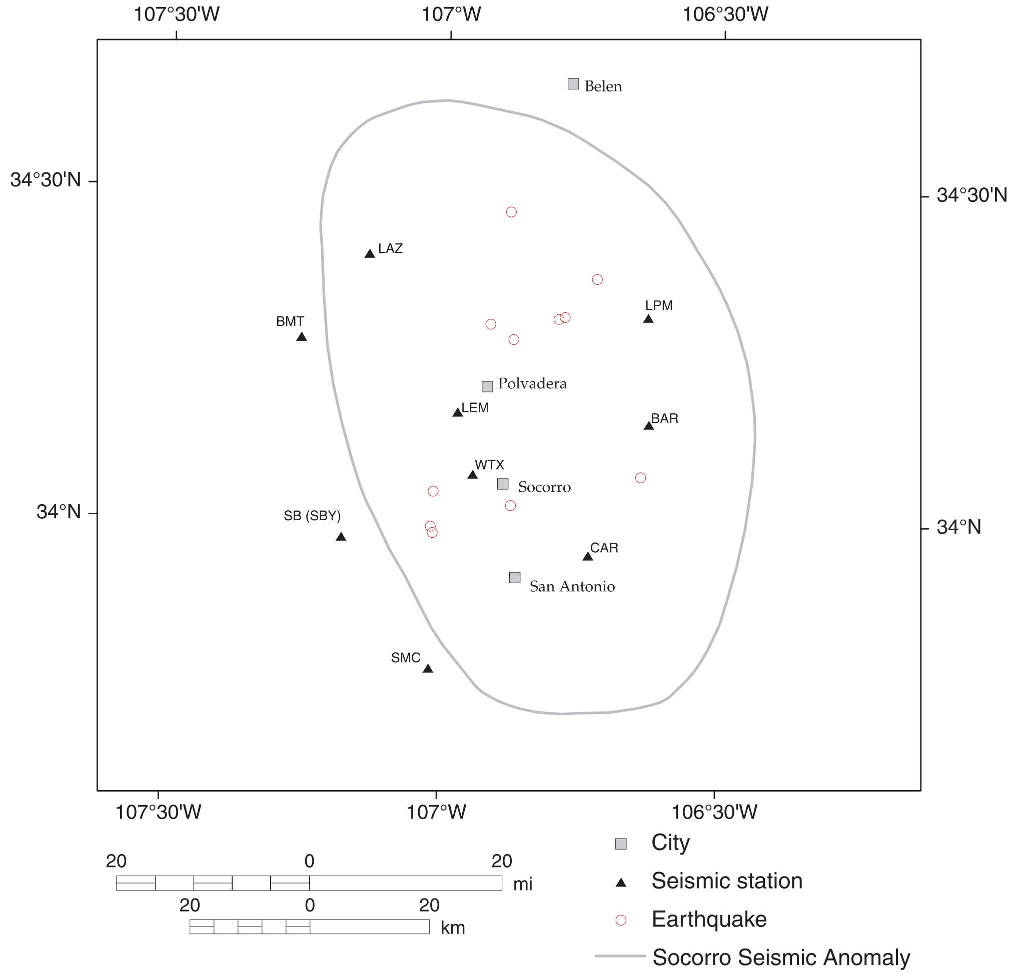

FIGURE 2—Socorro, New Mexico, seismograph network stations. Epicenters for 11 earthquakes of magnitude 2.0 or greater for the period 1999–2004 are shown within the Socorro Seismic Anomaly (the outlined elliptical area; Balch et al. 1997).

TABLE 1—Socorro Seismic Anomaly earthquakes with magnitudes of 2.0 or greater: 1999–2004.

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1std (km)	Gap (degrees)	Magnitude
1	1999	8	1	12	12	41.48	34	22.07	106	43.55	0.50	138	2.1
2	1999	12	9	12	39	12.09	34	2.71	107	0.94	0.45	76	2.6
3	1999	12	13	4	17	46.13	34	18.62	106	46.99	0.79	214	2.1
4	1999	12	13	10	58	46.36	34	18.41	106	47.64	0.42	95	2.0
5	1999	12	13	23	24	16.43	34	4.23	106	38.50	0.62	205	2.3
6	2001	5	5	6	29	10.19	33	58.97	107	1.00	0.53	104	2.1
7	2001	5	7	17	38	3.10	33	59.52	107	1.20	0.54	110	2.8
8	2001	11	18	14	22	59.87	34	16.52	106	52.53	0.30	87	2.2
9	2001	12	12	16	44	17.82	34	17.90	106	55.07	0.58	110	2.1
10	2003	11	2	11	58	8.94	34	1.53	106	52.57	0.45	84	2.0
11	2004	5	24	21	36	28.42	34	28.06	106	53.03	0.48	90	2.9

are listed in Table 1, and epicenters are mapped in Figure 2. Earthquake activity in this region is attributed to crustal extension arising from inflation of a mid-crustal magma body—the Socorro Magma Body (Fialko and Simons 2001). This thin (~150 m), extensive (~3,400 km^2) magma body is at a depth of ~19 km (Ake and Sanford 1988; Hartse et al. 1992; Balch et al. 1997; Schlue et al. 1996).

The 11 quakes in 1999 through 2004 are scattered throughout the SSA region (Fig. 2). The number each year ranged from zero in 2000 and 2002 to five in 1999. The average yearly rate of 1.8 is just slightly higher than the previous 6-yr period 1993 through 1998. However, the annual rate for the 12-yr interval before 1993 was 11.5, which illustrates the highly irregular nature of the SSA seismicity. Despite the relatively low level of seismic activity from 1999 through 2004, SSA earthquakes contributed 15% of the earthquakes of magnitude 2.0 or greater, exclusive of shocks in the Raton Basin and Delaware Basin swarms.

Remainder of New Mexico and bordering areas (RNM)

Earthquakes of magnitude 2.0 or greater that occurred in the RNM from 1999 through 2004 are listed in Table 2 except for those in the Raton Basin and Delaware Basin swarms. Epicenter locations are mapped in Figure 1. The number of earthquakes is only one-half the total for the previous 6-yr period. An analysis of the number of quakes versus magnitude indicates that the 64-event data set for RNM is com-

TABLE 2—Remainder of New Mexico and bordering areas earthquakes with magnitudes of 2.0 or greater: 1999–2004. Asterisks indicate locations by the U.S. Geological Survey.

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1std (km)	Gap (degrees)	Magnitude
1	1999	2	9	20	28	18.18	35	43.43	103	5.37	5.49	133	2.0
2	1999	2	25	0	32	11.72	36	50.05	104	55.12	8.08	178	2.0
3	1999	8	6	7	0	1.02	34	32.17	104	16.75	6.97	244	2.0
4	1999	9	1	16	35	15.18	33	42.81	107	3.78	1.17	306	2.3
5	1999	9	4	3	35	43.91	33	43.14	107	4.51	0.92	294	2.2
6	1999	10	9	12	9	39.31	31	32.66	102	22.68	10.71	332	2.0
7	2000	1	23	16	27	53.94	35	24.19	104	26.58	9.57	338	2.0
8	2000	4	6	18	39	4.26	35	26.46	103	11.55	4.75	126	2.1
9	2000	4	24	9	41	30.26	33	7.73	102	0.29	3.93	141	2.0
10	2000	8	2	12	21	30.24	35	21.59	101	46.61	4.44	140	2.1
11	2000	8	7	17	19	6.55	35	17.01	101	48.05	4.78	137	2.8
12	2000	8	7	18	34	7.48	35	16.85	101	48.24	7.57	197	2.4
13	2000	8	7	21	36	19.84	35	18.44	101	46.43	5.02	138	2.5
14	2000	8	10	13	39	48.78	35	14.27	101	45.84	13.45	309	2.3
15	2000	8	17	1	8	5.55	35	7.76	101	47.27	4.76	192	3.6
16	2000	10	31	13	19	16.98	33	18.68	107	11.68	4.17	260	2.1
17	2000	11	4	13	13	30.29	35	28.85	101	44.85	6.70	183	2.1
18	2000	12	7	9	38	51.68	34	45.42	105	38.62	3.52	213	2.0
19	2000	12	16	22	8	54.51	35	20.04	101	38.56	10.44	306	3.3
20	2000	12	27	12	51	37.31	33	23.86	108	34.51	7.14	178	2.2
21	2001	1	2	10	21	34.42	34	33.30	105	42.73	2.55	192	2.1
22	2001	1	20	10	4	22.81	33	10.11	108	32.53	11.44	181	2.0
23	2001	6	1	20	29	43.16	32	20.30	103	4.83	4.26	307	2.0
24	2001	6	2	1	56	54.39	32	21.50	103	9.02	3.31	205	3.0
25	2001	9	3	21	54	22.26	31	0.36	107	19.83	9.89	298	2.1
26	2001	11	22	0	7	9.60	31	41.96	102	43.70	8.67	331	2.5
27	2001	11	23	13	47	10.57	31	29.78	102	23.68	9.69	338	2.4
28	2002	1	11	12	32	20.80	36	24.58	109	21.50	7.32	285	2.4
29	2002	1	16	15	25	32.21	35	11.39	101	53.39	10.11	308	2.6
30	2002	1	19	11	51	14.13	35	13.50	101	50.66	11.10	303	2.2
31	2002	3	31	2	54	6.01	35	16.21	101	48.06	10.73	304	2.8
32	2002	4	30	4	37	15.89	35	10.19	109	16.70	4.69	174	2.3
*33	2002	6	18	11	4	47.78	37	35.40	107	14.40			2.9
34	2002	6	19	12	14	22.26	36	30.69	103	13.90	4.83	217	3.3
*35	2002	9	26	10	32	10.00	37	24.60	110	31.80			3.0
36	2002	10	4	8	36	14.62	33	51.98	102	2.35	6.06	159	2.3
37	2002	10	4	9	23	26.63	33	55.95	102	5.61	5.29	160	2.5
38	2002	10	4	9	31	13.15	33	53.90	102	5.19	8.75	193	2.1
39	2002	10	18	15	46	14.83	33	55.27	102	4.74	4.55	160	2.4
40	2002	11	12	13	37	19.57	34	37.52	105	12.15	4.11	217	2.0
41	2002	11	17	12	47	39.45	33	54.44	101	57.97	5.09	159	2.5
42	2003	2	22	7	40	52.02	32	37.73	108	23.04	3.09	164	2.3
43	2003	5	22	22	24	52.77	34	47.10	106	2.12	1.73	126	2.0
44	2003	5	23	12	59	22.76	34	46.67	106	0.51	1.80	83	2.2
45	2003	8	5	5	42	24.11	35	15.21	104	33.95	2.96	107	2.6
46	2003	8	12	6	43	59.20	31	35.06	102	8.71	6.58	255	2.4
47	2003	9	5	20	21	4.28	35	11.07	107	25.02	3.10	295	2.4
48	2003	9	24	15	2	7.43	35	20.39	101	43.60	4.04	140	3.0
49	2003	10	20	0	15	54.08	35	32.85	103	28.47	7.12	205	2.7
*50	2003	10	28	23	20	13.00	35	16.80	101	44.40			2.4
51	2003	12	13	9	16	3.13	31	37.53	106	19.27	3.51	210	2.2
52	2003	12	21	16	1	39.69	33	37.54	109	32.55	3.42	133	2.6
53	2003	12	21	16	8	54.96	33	37.51	109	30.48	2.73	134	2.6
54	2003	12	21	16	12	56.66	33	38.08	109	31.89	2.93	133	2.5
55	2003	12	21	16	19	36.77	33	36.56	109	32.48	3.64	134	2.0
56	2003	12	21	19	32	55.53	33	37.27	109	32.19	2.94	133	2.2
57	2003	12	28	2	55	1.99	37	32.48	105	11.25	4.34	103	3.5
58	2003	12	28	3	57	2.17	37	34.56	105	12.14	5.03	83	3.0
59	2004	3	5	18	28	20.75	35	10.42	109	56.18	4.94	111	2.4
60	2004	3	12	8	37	26.51	33	21.50	109	31.41	10.17	193	2.3
61	2004	4	15	1	16	48.47	32	43.75	109	17.52	12.63	78	2.1
62	2004	11	14	21	27	50.35	33	16.83	106	5.26	2.43	130	3.2
63	2004	11	24	10	16	38.94	35	12.24	107	26.17	3.57	296	2.0
64	2004	12	13	9	43	7.30	35	12.06	107	24.70	3.30	295	2.2

plete down to magnitude 2.0. A surprisingly large fraction of the 64 earthquakes are located in the Great Plains of west Texas with a prominent concentration near Amarillo. These events as well as others outside the boundaries of New Mexico generally have large epicenter errors, frequently on the order of 10 km. Similar to the results of the 1962–1998 study (Sanford et al. 2002), some epicenters in 1999–2004 extend in a diffuse band northeastward from the SSA to the New Mexico–Texas border, and like the earlier study, the Rio Grande rift is not defined by the earthquake activity.

Delaware Basin earthquake sequence

The Delaware Basin earthquake sequence is located on the western margin of the Dagger Draw oil field 40 km northwest of Carlsbad. Because of its location, this earthquake sequence has been designated the Dagger Draw swarm. Magnitude 2.0 or greater earthquakes in the Dagger Draw swarm began as early as 20 March 1998. (Weaker shocks occurred earlier, certainly by July 1997, and perhaps as early as December 1996.) The latter earthquake and three others in 1998 (Sanford et al. 2002) are included in the Table 3 listing of Dagger Draw swarm events to the end of 2004. An analysis of the 94 Dagger Draw swarm earthquakes in Table 3 indicates the data are complete down to magnitude 2.0.

For most of the 6.75 yrs of Dagger Draw swarm activity in Table 3, locations were poorly constrained. Although the original seven stations of the WIPP network were located 50–120 km distance from the Dagger Draw swarm, the azimuthal distribution of stations was poor. Even with the addition of readings from the Socorro network, gaps remained large. Locations improved greatly in the summer of 2003 with the installation of station DAG located 6–10 km west to southwest of the Dagger Draw swarm events. Further improvement occurred with the installation in March 2004 of another close station (SRH) at a distance of 12–22 km southeast of the Dagger Draw swarm.

Despite the addition of stations DAG and SRH, direct calculation by SEISMOS of focal depths yielded very unrealistic values. Selection of reasonable fixed depths between 1.0 and 10.0 km yielded epicenters very near a tight cluster of disposal wells (Fig. 3). As a result, we elected to use the depth of injection at the disposal wells, 3.4 km, as the fixed focal depth for the location of all Dagger Draw swarm events. This choice appeared to produce epicenters with the smallest errors.

The map of epicenters for the Dagger Draw swarm (Fig. 3) is restricted to 15 events in Table 3 with epicenter errors of 3.0 km or less and gaps of 140° or less. All but one of these 15 quakes occurred after station DAG went into operation. Nine of the epicenters define a rectangular area 3.4 km east-west and 2.4 km north-south. From this 8-km^2 region, the other six epicenters extend northward for a distance of ~10 km.

An analysis of time differences between station arrivals indicates the epicenter distribution in Figure 3 applies throughout the 6.75 yrs of the Dagger Draw swarm, at least for the strong quakes. The magnitude 3.9 earthquake on 14 March 1999 is one of the 15 events in Figure 3 that is located in the 8-km^2 area of highest activity. Time differences between stations recording the 14 March 1999 earthquake were compared with the same differences for strong earthquakes on 17 March 1999 (3.5), 30 May 1999 (3.9), 17 September 2002 (3.5), and 23 May 2004 (3.9). The comparison showed that these four strong shocks also had epicenters within the area of highest activity in Figure 3.

Additional evidence supporting the epicenter distribution in Figure 3 are clearly defined S-P intervals observed on ~50 seismograms of weak Dagger Draw swarm quakes recorded at station DAG. The S-P intervals yield distances of 6–10 km, distances that are in agreement with the distribution of epicenters in Figure 3.

The eastern margin of the most active region in Figure 3 lies within a tight cluster (radius ~500 m) of three disposal wells located in sec. 4 T20S R24E and centered at 32.599° N latitude and 104.590° W longitude. The volume of water disposed of by injection in the three wells is very large. At the end of April 2003, the monthly disposal rate was 150,000 m^3. The cumulative disposal on the same date for the three wells was ~11,500,000 m^3. The cumulative volume by the end of 2004 is estimated to have been 14,500,000 m^3, equivalent to a cube of water ~245 m on a side.

The proximity of the earthquake epicenters to three wells that have injected very large amounts of water at a depth of ~3.4 km suggests that the earthquakes are induced. The classic example of earthquakes produced by injection of fluid occurred in the Denver area (Healy et al. 1968). From 8 March 1962 to 20 February 1966 ~550,000 m^3 of fluid was injected in a well at the Rocky Mountain Arsenal, an amount only ~3.8% of the estimated quantity of fluid injected into the three Dagger Draw oil field disposal wells by the end of 2004. Earthquakes in the Denver swarm ranged up to magnitude 5.5, and epicenters extended over a distance of ~10 km.

Healy et al. (1968) were able to establish that the Denver swarm was triggered by the fluid injection by using a careful analysis of daily fluid pressure variations and the temporal behavior of the earthquakes. For the Dagger Draw swarm, short-term comparisons between well-head pressures, fluid injected, and earthquake numbers and strengths have not been made for lack of the necessary data. For this reason, an absolutely conclusive connection between the Dagger Draw swarm and the very large volumes of injected water cannot be established.

Raton Basin earthquake sequence

The Raton Basin earthquake sequence is a tight cluster of shocks that straddles the New Mexico–Colorado border from approximately 36.75° to 37.25° N latitude (Fig. 1). From the beginning of the Raton Basin earthquake sequence on 28 August 2001 to 15 October 2001, the earthquakes were located north of the 37.00° N latitude border. On or shortly before 15 December 2001, epicenters for nearly all quakes shifted south of the border. Table 4 lists earthquakes that occurred in the Raton Basin earthquake sequence from 15 December 2001 to the end of 2004. Earthquake activity that preceded 15 December 2001 is described in an excellent and detailed U.S. Geological Survey investigation (Meremonte et al. 2002).

The New Mexico Tech Raton Basin earthquake sequence catalog (Table 4) lists 33 earthquakes, not a particularly impressive number of events. However, an analysis of number of earthquakes versus magnitude for the 33 earthquakes indicates many earthquakes below magnitude 3.0 were not detected because stations close to the activity did not exist (Fig. 4 or Appendix). An analysis of the 15 earthquakes with magnitudes of 3.0 or greater indicates that the number of earthquakes is increasing by about a factor of 10 for each unit decrease in magnitude. Extrapolation of this rate of increase to shocks with magnitudes less than 3.0 shows the data would be complete for earthquakes of magnitude 2.0 or greater if ~160 earthquakes had been detected and located in the approximately 36-month period. By comparison, this is two times the activity for any 36-month interval in the SSA (Sanford et al. 2002). By New Mexico standards, the Raton Basin earthquake sequence after 15 December 2001 is a remarkable seismic event.

Many locations of Raton Basin earthquakes are poorly constrained because the station nearest to the swarm events was in Albuquerque (ANMO), ~260 km to the southwest. A new U.S. Geological Survey station was installed in June 2003, station SDCO located ~110 km to the northwest of the Raton Basin earthquake sequence. When readings from this station were available, epicenter error decreased significantly.

The map of Raton Basin earthquake sequence epicenters (Fig. 4) after 15 December 2001 is restricted to the 18 events in Table 4 that have epicenter errors of 5 km or less and gaps of 140° or less. Most of these best-constrained locations are for earthquakes that occurred after station SDCO went into operation. However, even with readings from SDCO, distances from the Raton Basin earthquakes to seismograph stations ranged from approximately 100 to 600 km. Because of these very long paths, deviations of crustal structure from the 6.15 km/sec half-space model in SEISMOS can have a significant effect on epicenter locations. Therefore, the calculated locations can differ from the true locations in a manner dependent on the mix of stations used. Despite the uncertainty in epicenter locations, their distribution in Figure 4 indicates a very small geographic area is generating an exceptionally large number of earthquakes. Proving conclusively that this very unusual Raton Basin swarm has a natural origin may be as difficult as proving conclusively that its events are induced.

The major observation suggesting Raton Basin earthquake activity may be induced is the large quantity of water removed and disposed of by injection in the devel-

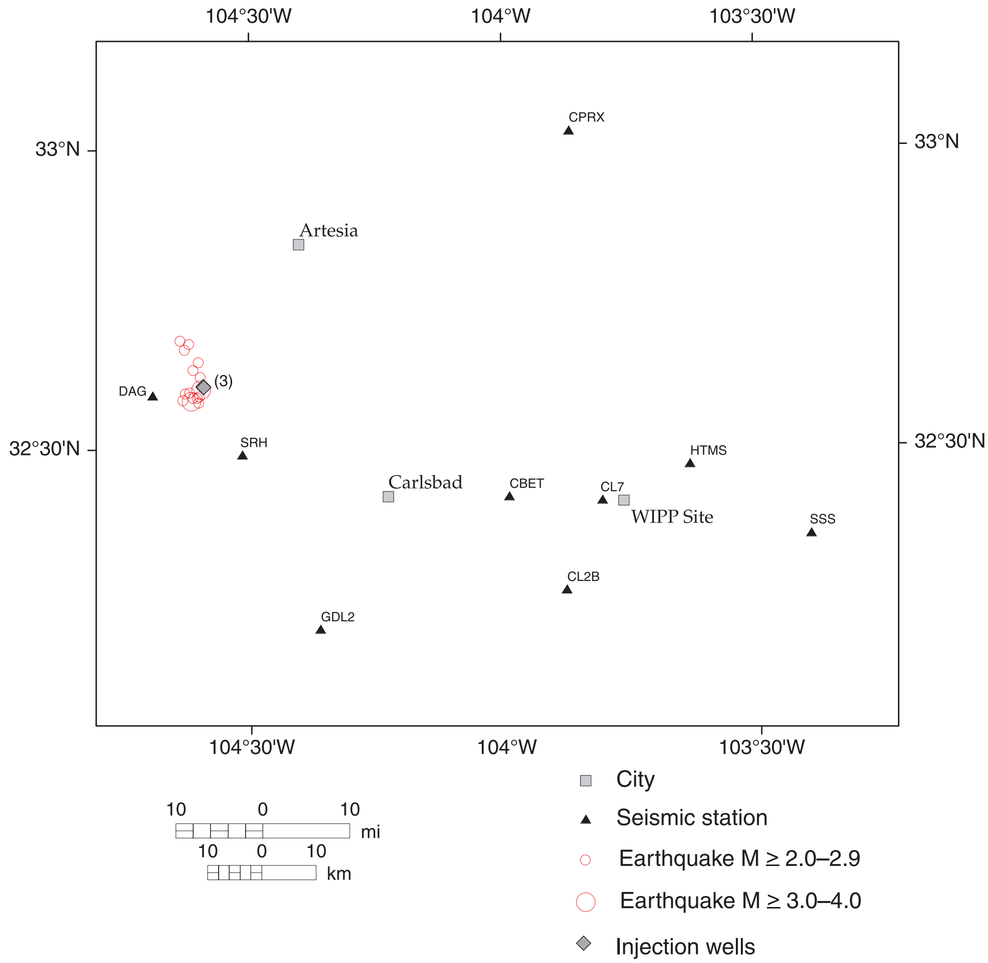

FIGURE 3—Southeastern New Mexico seismograph network stations. Epicenters shown for 15 earthquakes in the Dagger Draw swarm, 1999–2004, with magnitudes of 2.0 or greater, epicenter errors of 3.0 km or smaller, and gaps of 140° or smaller. The location of a tight cluster of three waste water disposal wells is also shown.

TABLE 3—Dagger Draw swarm earthquakes with magnitudes of 2.0 or greater: 1998–2004. Asterisks indicate earthquakes with epicenter errors less than or equal to 3.0 km and gaps less than or equal to 140°.

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1std (km)	Gap (degrees)	Magnitude
1	1998	3	20	1	42	12.93	32	35.83	104	40.38	6.00	162	2.0
2	1998	6	16	5	52	19.68	32	35.10	104	37.76	4.48	158	2.0
3	1998	7	8	5	17	40.78	32	36.62	104	37.70	4.44	162	2.7
4	1998	7	27	12	47	23.25	32	35.66	104	41.49	2.65	273	2.0
5	1999	3	1	8	0	23.54	32	34.37	104	39.12	3.18	155	2.7
6	1999	3	14	1	10	15.73	32	41.06	104	37.39	4.17	143	2.2
*7	1999	3	14	22	43	18.09	32	34.84	104	36.94	2.58	84	3.9
8	1999	3	15	8	17	29.73	32	34.07	104	40.97	3.74	158	2.3
9	1999	3	17	12	29	23.17	32	34.52	104	39.90	3.40	156	3.5
10	1999	3	23	17	0	10.28	32	33.99	104	37.88	5.21	163	2.6
11	1999	4	20	4	39	6.99	32	34.41	104	37.97	3.96	153	2.1
12	1999	5	30	19	4	26.36	32	34.72	104	39.24	3.39	102	3.9
13	1999	5	30	20	47	42.18	32	35.65	104	41.26	4.28	156	2.7
14	1999	6	1	21	42	24.44	32	39.76	104	35.06	3.93	153	2.0
15	1999	6	7	22	28	46.78	32	35.00	104	41.57	4.62	170	2.3
16	1999	8	9	6	51	22.51	32	34.98	104	39.49	3.98	165	2.9
17	1999	8	9	19	28	42.59	32	32.02	104	43.47	4.25	178	2.0
18	1999	8	24	11	43	1.27	32	32.86	104	40.01	4.80	171	2.2
19	1999	9	6	16	39	24.11	32	33.54	104	39.73	4.90	169	2.7
20	1999	11	25	18	4	0.02	32	40.73	104	36.71	5.38	155	2.2
21	2000	2	2	7	14	19.30	32	33.49	104	42.45	4.50	174	2.5
22	2000	6	18	15	28	49.10	32	35.17	104	39.69	3.04	155	2.1
23	2000	12	1	4	9	42.06	32	33.66	104	43.74	4.12	102	2.1
24	2000	12	15	18	50	14.54	32	31.38	104	39.45	5.00	270	2.1
25	2001	3	19	16	18	36.62	32	41.48	104	39.10	3.56	145	2.4
26	2001	7	28	11	35	28.82	32	34.26	104	41.32	3.95	165	2.6
27	2002	1	9	10	23	1.97	32	35.26	104	38.32	5.08	159	2.0
28	2002	1	19	8	13	49.67	32	35.15	104	32.16	21.59	252	2.1

TABLE 3—continued

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1std (km)	Gap (degrees)	Magnitude
29	2002	2	9	1	35	1.83	32	32.69	104	40.91	3.43	160	2.1
30	2002	2	11	5	20	33.94	32	33.41	104	39.03	6.13	106	2.1
31	2002	6	13	9	15	7.38	32	36.70	104	41.28	6.81	118	2.0
32	2002	8	12	23	28	30.67	32	35.14	104	39.86	4.49	162	2.8
33	2002	8	12	23	36	29.80	32	32.48	104	41.59	9.30	314	2.1
34	2002	8	14	23	17	33.01	32	34.34	104	38.36	3.66	160	2.9
35	2002	8	19	18	51	52.87	32	34.75	104	40.36	5.30	163	2.1
36	2002	8	22	20	19	0.90	32	34.40	104	40.04	3.75	148	2.2
37	2002	8	23	10	21	17.75	32	33.55	104	40.77	4.80	165	2.2
38	2002	8	30	7	7	55.55	32	40.09	104	36.59	4.99	156	2.1
39	2002	9	17	15	45	14.92	32	35.46	104	38.91	3.71	143	3.5
40	2002	9	17	23	34	19.32	32	34.87	104	38.81	4.59	160	3.2
41	2002	9	22	22	58	10.20	32	40.85	104	41.13	5.98	111	2.1
42	2002	9	25	5	15	5.54	32	38.22	104	38.60	10.58	153	2.0
43	2002	10	28	2	15	38.61	32	36.03	104	39.43	2.96	160	2.0
44	2002	10	28	14	4	31.28	32	33.87	104	38.97	3.31	162	2.6
45	2002	10	28	16	55	42.24	32	33.85	104	38.06	4.22	161	2.1
46	2003	1	19	15	31	32.76	32	35.75	104	39.48	11.02	160	2.2
47	2003	1	20	16	34	23.35	32	34.25	104	39.77	4.00	163	2.2
48	2003	1	20	18	47	39.79	32	34.78	104	38.46	3.58	153	2.5
49	2003	2	11	13	13	59.69	32	41.56	104	39.92	3.73	154	2.2
50	2003	2	13	0	28	19.95	32	41.68	104	38.20	5.01	156	2.3
51	2003	2	14	7	25	39.50	32	41.53	104	38.03	4.74	111	2.1
52	2003	2	20	17	24	26.97	32	43.39	104	43.49	6.24	277	2.4
53	2003	2	20	17	27	42.33	32	42.19	104	36.94	4.23	149	2.2
54	2003	2	23	0	14	11.02	32	42.24	104	45.20	6.16	280	2.0
55	2003	2	24	19	47	15.40	32	43.37	104	49.74	34.09	286	2.0
56	2003	2	27	13	10	0.40	32	41.00	104	39.15	6.47	159	2.0
57	2003	3	19	8	35	12.36	32	39.06	104	36.44	3.22	151	3.0
58	2003	3	28	17	58	27.49	32	35.08	104	41.76	5.38	170	2.1
59	2003	4	15	21	48	54.24	32	33.24	104	38.32	7.05	309	2.0
60	2003	5	8	13	0	32.11	32	40.96	104	39.88	4.30	158	2.7
61	2003	5	18	2	34	33.78	32	34.20	104	39.09	4.21	162	2.1
62	2003	6	13	18	37	18.14	32	41.65	104	39.92	4.44	159	2.0
63	2003	6	17	12	27	37.94	32	35.68	104	51.81	6.53	289	2.0
64	2003	6	21	2	3	9.00	32	42.32	104	37.86	2.84	150	3.3
65	2003	6	21	3	24	39.81	32	41.09	104	38.87	4.57	158	2.3
*66	2003	9	15	11	27	6.23	32	35.15	104	36.77	2.22	124	2.9
67	2003	10	19	3	41	2.16	32	42.21	104	37.85	3.13	112	2.3
68	2003	11	13	19	59	17.23	32	41.47	104	36.79	2.55	154	2.1
69	2003	11	19	7	11	15.44	32	32.12	104	38.22	2.89	164	2.2
70	2003	12	23	12	40	35.26	32	41.33	104	35.75	2.76	201	2.1
*71	2004	1	5	22	20	43.80	32	40.53	104	37.24	1.86	106	2.1
*72	2004	1	30	7	50	27.03	32	37.96	104	36.74	1.82	103	2.1
73	2004	2	12	15	12	38.33	32	31.29	104	41.34	5.25	171	2.1
*74	2004	2	19	11	27	26.74	32	37.23	104	35.90	2.47	104	2.3
75	2004	2	24	20	57	21.20	32	33.98	104	37.55	3.46	146	2.4
*76	2004	3	3	23	14	20.99	32	39.96	104	37.75	2.42	106	2.6
*77	2004	3	14	15	6	37.06	32	34.93	104	37.96	2.12	132	2.4
78	2004	3	21	23	12	47.05	32	34.45	104	38.39	3.06	144	2.1
*79	2004	3	29	3	35	17.65	32	35.62	104	37.68	2.54	117	2.1
80	2004	4	20	17	41	57.70	32	31.28	104	40.94	3.31	163	2.2
*81	2004	4	24	22	40	27.20	32	40.90	104	38.23	1.56	99	2.0
*82	2004	5	23	9	22	4.83	32	35.96	104	35.76	1.80	111	3.9
*83	2004	5	23	12	9	49.10	32	35.15	104	36.26	2.30	122	2.0
*84	2004	5	29	2	46	1.57	32	38.71	104	36.11	2.85	106	2.1
*85	2004	6	22	8	55	2.62	32	34.70	104	36.08	2.62	136	3.0
86	2004	6	22	9	14	3.63	32	35.05	104	35.90	2.55	162	2.1
*87	2004	7	2	19	41	34.45	32	35.70	104	37.16	2.68	136	2.5
88	2004	7	18	19	19	38.65	32	32.70	104	39.68	2.15	158	2.2
89	2004	7	19	0	42	45.65	32	40.75	104	36.72	3.53	251	2.0
90	2004	7	19	9	51	6.90	32	32.34	104	38.17	2.23	156	2.0
91	2004	8	26	18	45	17.26	32	33.78	104	38.67	2.17	155	2.7
*92	2004	10	28	2	59	3.73	32	35.29	104	36.02	2.38	120	3.0
93	2004	11	1	16	24	22.14	32	32.01	104	38.35	2.37	169	2.0
94	2004	12	20	20	42	52.43	32	31.41	104	37.44	2.20	169	2.0

opment of coalbed methane in the Raton Basin of New Mexico (Hoffman and Brister 2003). Water is removed from producing zones at depths of ~300 m to ~900 m and injected into disposal wells at depths of ~1,800 m to 2,100 m . The cumulative volume of water removed and then injected from the beginning of coalbed methane development in October 1999 to 1 January 2005 was 6,072,125 m^3, equivalent to a lake with a depth of 2 m and a diameter of 2 km. By comparison, this amount is 11 times the fluid injected during the induced Denver earthquake swarm from 1962 through 1967 (Healy et al. 1968).

The observation that suggests the Raton Basin earthquake sequence is the result of injection of large volumes of water is the

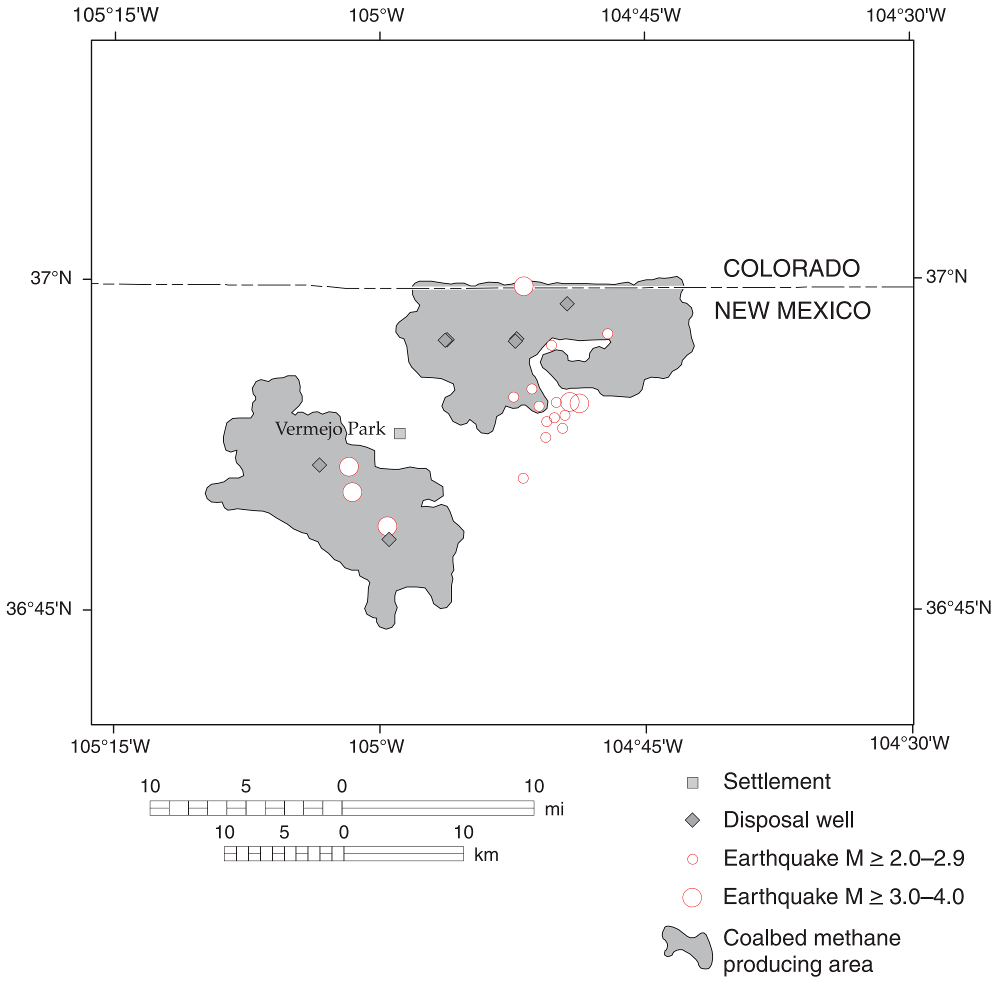

FIGURE 4—Epicenters of 18 earthquakes in the Raton Basin swarm, 2001–2004 with magnitudes of 2.0 or greater, epicenter errors of 5.0 km or smaller, and gaps of 140° or smaller. The locations of five waste water disposal wells and the outline of the coalbed methane fields are also shown.

proximity of earthquake epicenters to disposal wells. The average epicenter errors for the 18 earthquakes in Figure 4 are 4.1 km (1 s.d.) and 8.2 km (2 s.d.). Considering these errors, the earthquakes could have occurred at or near the five disposal wells. Earthquakes can be generated if the disposal of water increases pore pressure, which then reduces the frictional resistance to faulting because the effective normal stress across the fault plane is decreased (Healy et al. 1968). The authors do not have critical information, for example, on injection pressures at disposal wells that would indicate conclusively that disposal of large volumes of water is generating the earthquakes within the coalbed methane fields.

The diffuse distribution of epicenters in Figure 4 might suggest two additional mechanisms for inducing earthquakes in the coalbed methane fields: (1) sudden subsidence of overburden because of removal of water and (2) hydro-fracturing to increase production of methane. Rapid ground subsidence over areas of gas and petroleum production has been observed (Fielding et al. 1998) and can induce earthquakes (Richter 1958; Kanamori and Hauksson 1992). The authors do not know whether subsidence is actually occurring in the coalbed methane producing areas of the Raton Basin, but Synthetic Aperture Radar might be able to answer the question (Fielding et al. 1998). Hydro-fracturing is being used in the coalbed methane fields of the Raton Basin to enhance the production of methane (EPA 2004), and it can induce earthquakes (Kanamori and Hauksson 1992; Fehler et al. 2001).

Preliminary studies indicate that the Raton Basin earthquake sequence in New Mexico continued through 2005 at the same intensity as observed from 2002 through 2004 and with the same general epicenter distribution as shown in Figure 4. About 12 earthquakes of magnitude 2.0 or greater occurred, one of these was magnitude 4.5, probably the strongest of the Raton Basin swarm.

Summary and conclusions

The number of magnitude 3.0 or greater earthquakes for the 6-yr 1999–2004 period is fairly impressive: 15 for the Raton Basin swarm, 10 for the Dagger Draw swarm, and nine for the remainder of New Mexico. This level of activity for a 6-yr period is comparable to other active 6-yr periods, for example, 1965–1970, 1971–1976, and 1990–1995 (Sanford et al. 2002). However, what makes the 1999–2004 period different from the earlier periods is that 75% of the magnitude 3.0 or greater earthquakes were generated in two very small regions located close to where very large amounts of water are being produced and disposed of by injection, a necessary procedure accompanying the production of gas and oil. Comparable periods of intense activity over several years from small areas did not occur anytime during the period 1962 through 1998. The 6-yr 1999–2004 interval is a truly unique period in the region's earthquake history.

Another characteristic of earthquake activity from 1999 through 2004 is a continuation of abnormally low activity in the Socorro Seismic Anomaly that commenced in 1993. Important characteristics of seis-

TABLE 4—Raton Basin swarm earthquakes with magnitudes of 2.0 or greater: 2001–2004. Asterisks indicate earthquakes with epicenter errors less than or equal to 5.0 km and gaps less than or equal to 140°.

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1std (km)	Gap (degrees)	Magnitude
1	2001	12	15	7	58	30.63	36	57.97	105	3.98	11.81	304	3.0
2	2002	1	26	1	6	4.62	36	49.37	104	48.13	8.69	297	3.0
3	2002	2	7	5	19	54.30	37	1.37	104	54.43	13.36	313	2.4
4	2002	3	20	14	33	7.87	36	50.25	104	53.16	11.80	313	2.3
5	2002	3	20	23	16	55.37	36	46.88	104	53.47	8.23	309	2.0
6	2002	6	18	9	12	37.20	36	55.91	104	50.03	5.61	92	3.0
*7	2002	11	14	3	44	39.97	36	53.71	104	50.14	4.68	133	2.6
8	2002	11	14	4	56	52.73	36	54.96	104	48.51	5.43	129	3.0
*9	2002	12	9	17	30	41.35	36	55.02	104	51.42	3.86	134	2.0
*10	2002	12	31	19	2	30.03	36	59.69	104	51.86	4.84	131	3.6
*11	2002	12	31	19	34	45.25	36	56.99	104	50.30	4.73	78	2.2
12	2003	4	28	7	32	25.78	36	55.16	105	2.40	8.93	218	3.3
*13	2003	6	3	18	9	28.05	36	57.52	104	47.11	3.94	106	3.0
*14	2003	6	15	0	22	18.70	36	54.43	104	49.27	4.21	120	3.3
*15	2003	6	20	3	10	20.89	36	52.81	104	50.62	3.28	111	2.4
*16	2003	8	14	0	11	9.28	36	53.24	104	49.67	4.03	91	2.7
17	2003	9	8	11	2	50.32	37	19.93	104	44.77	7.02	178	2.7
*18	2003	9	13	15	22	41.63	36	48.79	104	59.57	4.44	75	3.6
19	2003	9	19	18	14	25.15	36	59.55	104	53.70	6.91	211	2.5
20	2003	9	19	18	18	34.60	36	54.07	104	46.48	6.17	210	2.4
21	2003	10	25	12	55	57.77	37	2.08	104	46.67	6.39	99	3.1
*22	2003	11	5	20	17	39.55	36	53.81	104	49.55	4.91	133	2.1
23	2003	11	24	7	5	59.17	36	56.86	104	55.27	6.06	136	3.2
24	2003	12	12	17	24	12.85	36	49.36	105	1.86	12.24	313	2.3
*25	2004	1	10	4	7	11.29	36	50.98	104	51.90	3.96	115	2.1
26	2004	1	14	1	14	15.07	36	56.65	104	47.17	5.09	91	3.1
*27	2004	2	3	14	34	22.80	36	53.53	104	50.57	4.34	78	2.7
*28	2004	3	22	12	9	56.38	36	50.35	105	1.54	3.16	81	3.6
*29	2004	3	30	1	2	55.30	36	54.66	104	52.43	3.74	77	2.8
*30	2004	3	30	2	23	37.85	36	54.41	104	50.02	3.79	78	2.7
*31	2004	3	30	2	41	5.79	36	54.24	104	51.01	3.71	78	2.9
*32	2004	5	31	3	27	43.38	36	54.37	104	48.73	3.16	78	3.1
*33	2004	8	1	6	50	46.79	36	51.50	105	1.75	4.19	101	3.8

mic activity exclusive of the Socorro Seismic Anomaly, the Raton Basin swarm, and the Daggar Draw swarm are: (1) an unusually large percentage of quake epicenters in the Great Plains of west Texas, (2) a diffuse band of earthquakes extending from the SSA to the New Mexico–Texas border, and (3) the near absence of earthquakes in the Rio Grande rift except for the Socorro Seismic Anomaly.

Acknowledgments

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We would like to thank the following individuals for providing data useful in the location of some of the earthquakes in the catalogs: Diane Doser (University of Texas–El Paso) and Hans Hartse (Los Alamos National Laboratory). As noted in this report, we used data available from seismograph stations operated by the U.S. Geological Survey, the Incorporated Research Institutions for Seismology (IRIS Consortium), and the U.S. Bureau of Reclamation. Finally we wish to thank Gretchen Hoffman and Brian Brister for information on the development of coalbed methane in the Raton Basin of New Mexico, and Susan Bilek for her assistance in generating the figures for this report.

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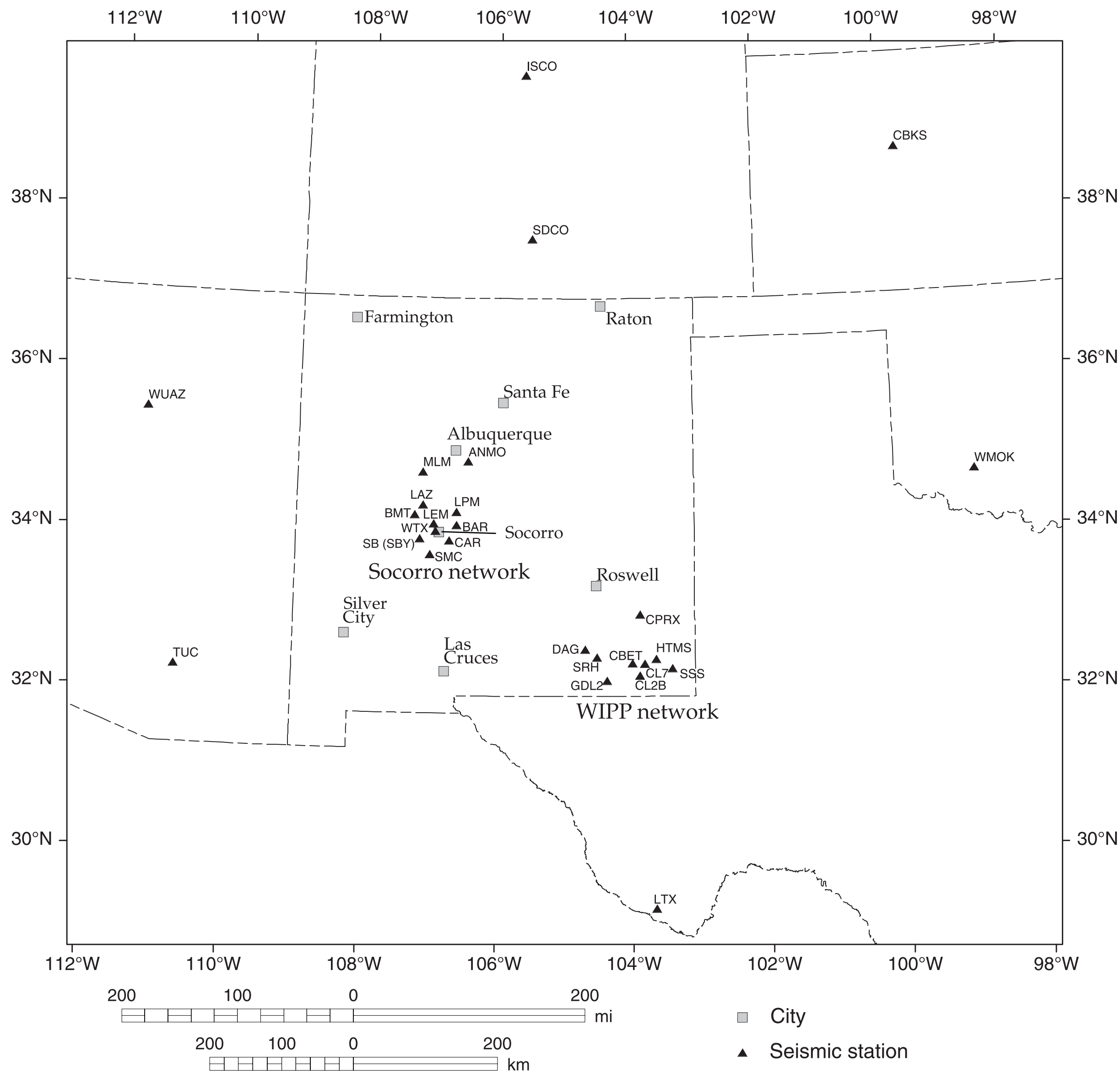
Notes to page 99

[1]Data are not currently available online but will be available online in the future.

[2]The model has four layers: the first a thickness of 10 km, a P-wave velocity of 5.95 km/sec, and a Poisson's ratio of 0.256; the second has a thickness of 8.75 km, a P-wave velocity of 5.80 km/sec, and a Poisson's ratio of 0.228; the third has a thickness of 14.75 km, a P-wave velocity of 6.50 km/sec, and a Poisson's ratio of 0.250; and the fourth has an infinite thickness with a P-wave velocity of 8.10 km/sec, and a Poisson's ratio of 0.250.

Appendix

Location of seismograph stations used for the study of earthquakes in New Mexico and bordering areas for the period 1999–2004. Code names for the stations in tight clusters near Socorro and in southeastern New Mexico are also shown in Figures 2 and 3.



Code names and coordinates of seismograph stations used to locate earthquakes in New Mexico and bordering areas during the 1999 through 2004 period. The organizations operating the stations and network designations are also listed.

Station code	Latitude	Longitude	Elevation	Network	Network code
ANMO	34.9502	-106.4602	1743.0	Global Seismic Network - IRIS/USGS	IU
TUC	32.3097	-110.7842	906.0	Global Seismic Network - IRIS/USGS	IU
BAR	34.1502	-106.6278	2121.0	New Mexico Tech Seismic Network - Socorro	SC
BMT	34.2750	-107.2602	1972.0	New Mexico Tech Seismic Network - Socorro	SC
CAR	33.9525	-106.7345	1662.0	New Mexico Tech Seismic Network - Socorro	SC
LAZ	34.4020	-107.1393	1853.0	New Mexico Tech Seismic Network - Socorro	SC
LEM	34.1655	-106.9742	1698.0	New Mexico Tech Seismic Network - Socorro	SC
LPM	34.3117	-106.6318	1737.0	New Mexico Tech Seismic Network - Socorro	SC
MLM	34.8142	-107.1450	2088.0	New Mexico Tech Seismic Network - Socorro	SC
SB (SBY)	33.9752	-107.1807	3230.0	New Mexico Tech Seismic Network - Socorro	SC
SMC	33.7787	-107.0193	1560.0	New Mexico Tech Seismic Network - Socorro	SC
WTX	34.0722	-106.9458	1555.0	New Mexico Tech Seismic Network - Socorro	SC
CBET	32.4205	-103.9900	1042.0	New Mexico Tech Seismic Network - WIPP	SC
CL2B	32.2642	-103.8787	1045.0	New Mexico Tech Seismic Network - WIPP	SC
CL7	32.4132	-103.8075	1033.0	New Mexico Tech Seismic Network - WIPP	SC
CPRX	33.0308	-103.8667	1356.0	New Mexico Tech Seismic Network - WIPP	SC
DAG	32.5913	-104.6918	1277.0	New Mexico Tech Seismic Network - WIPP	SC
GDL2	32.2003	-104.3635	1213.0	New Mexico Tech Seismic Network - WIPP	SC
HTMS	32.4725	-103.6342	1192.0	New Mexico Tech Seismic Network - WIPP	SC
SRH	32.4918	-104.5153	1270.0	New Mexico Tech Seismic Network - WIPP	SC
SSS	32.3547	-103.3968	1073.0	New Mexico Tech Seismic Network - WIPP	SC
CBKS	38.8140	-99.7374	677.0	USGS Seismic Network	US
ISCO	39.7997	-105.6134	2743.0	USGS Seismic Network	US
LTX	29.3339	-103.6669	1013.0	USGS Seismic Network	US
SDCO	37.7456	-105.5012	2569.0	USGS Seismic Network	US
WMOK	34.7379	-98.7810	486.0	USGS Seismic Network	US
WUAZ	35.5169	-111.3739	1592.0	USGS Seismic Network	US

Earthquake catalogs for New Mexico and bordering areas: 2005–2009

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This latest report on earthquake activity in New Mexico and bordering areas by New Mexico Institute of Mining and Technology (NMT) investigators covers the 5-yr period 2005–2009. It is a continuation of catalogs for 1962 through 1998 published as Circular 210 by the New Mexico Bureau of Geology and Mineral Resources in 2002 and for 1999 through 2004 published in New Mexico Geology (v. 28, no. 4, pp. 99-109) (Data are available online at ***http://geoinfo.nmt.edu/publications/circulars/210/.)***

Abstract

The earliest documented records of large earthquakes in New Mexico go back to the early 1900s, and seismicity has been monitored instrumentally since the early 1960s. This catalog is a continuation of previous catalogs spanning 1962 through 2004 and includes 165 earthquakes $M_d \geq 2.0$. In addition it also includes all located events with $M_d \geq 0$ in New Mexico. Similar to the 1999–2004 catalog, we found that a large number of earthquakes $M_d \geq 2.0$ were located in two distinct regions. One of these regions is in southeastern New Mexico near the Dagger Draw oil field (32% of all events with $M_d \geq 2.0$), and the other is in northeastern New Mexico within and surrounding the coalbed methane fields near Raton (44% of all events with $M_d \geq 2.0$). Only 5% of the larger earthquakes occurred in the Socorro Seismic Anomaly region. The remaining events were scattered throughout New Mexico, southeastern Colorado, eastern Arizona, northern Mexico, and western Texas.

Introduction

This catalog summarizes earthquake activity in New Mexico and surrounding regions from 2005 through 2009. It is a continuation of the earthquake catalogs for the 42-yr period 1962–2004 (Sanford et al. 2002, 2006). We include here all locatable events that occurred in New Mexico and surrounding regions with $M_d \geq 0$, as well as a subset of events magnitude 2.0 and greater for direct comparison with the previous catalogs. The signal processing and reported earthquake location parameters are defined in Sanford et al. (2006). In addition to signal processing from our local seismic network (network code SC), we were able to improve locations of events that occurred during the Earthscope USArray deployment in New Mexico due to the denser seismic station coverage all over the state during the 2008–2009 time period.

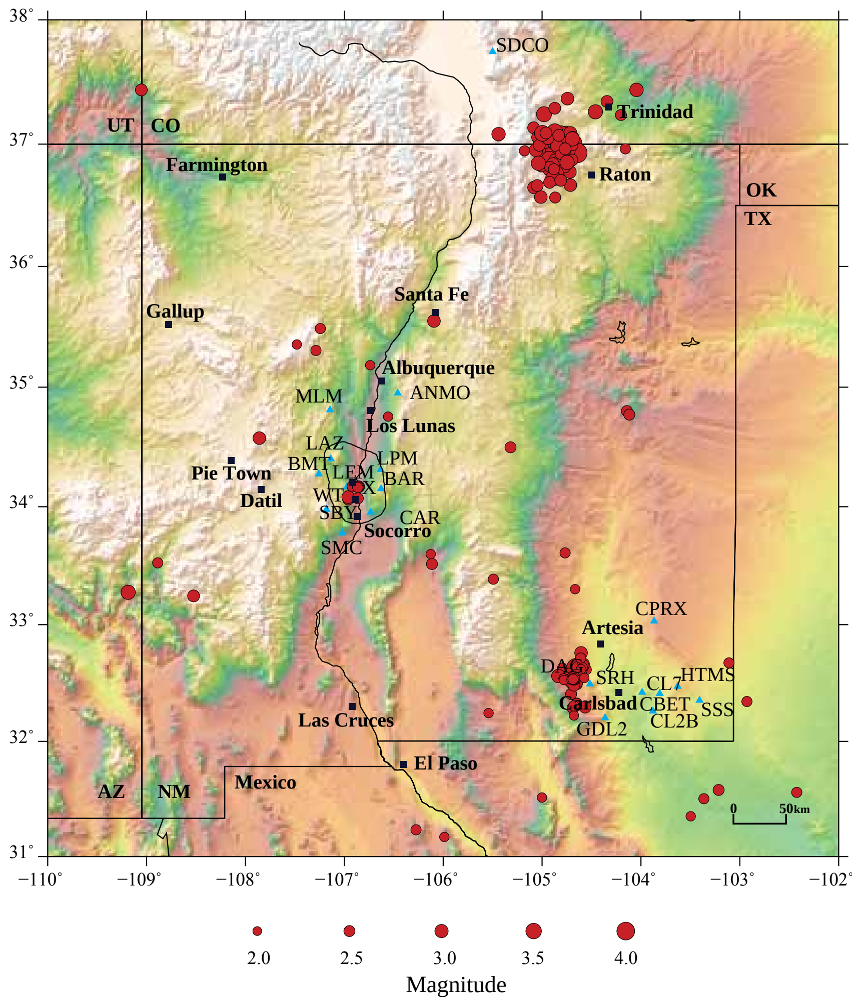

FIGURE 1—$M_d \geq 2.0$ earthquakes that occurred in New Mexico and surrounding regions during the 2005–2009 time period (165 events, red circles, scaled by magnitude). The two large clusters are focused in the Raton area (73 earthquakes) and near Carlsbad (53 earthquakes in the Delaware Basin). Also shown are major cities (squares) and the seismic station locations (blue triangles). The Socorro Seismic Anomaly (SSA, black outline [Balch et al. 1997]) in the central Rio Grande rift contains a cluster of eight $M_d \geq 2.0$ events.

Earthquakes with $M_d \geq 2.0$

From 2005 through 2009 there were 165 earthquakes of $M_d \geq 2.0$ in New Mexico and surrounding regions within an area spanning 31°–38° N latitude and 101°–111° W longitude (Fig. 1). Most of these events were in three distinct clusters with 32% (53 earthquakes) of all earthquakes located in southeastern New Mexico, 44% (73 events) near Raton, northern New Mexico, and 5% (8 events) in the Socorro Seismic Anomaly (SSA), which is an approximately 5,000 km² region in central New Mexico. The remaining 19% of $M_d \geq 2.0$ earthquakes (31 events) were scattered throughout New Mexico and the border areas of Arizona, Texas, and Colorado.

Past catalogs suggest that the two largest clusters, the Dagger Draw sequence in southeast New Mexico and the Raton sequence in northern New Mexico, are induced (Sanford et al. 2006). In southeast New Mexico, the oil production in the Delaware Basin might be responsible for most of the seismic activity near the Dagger Draw oil field. In the Raton area many earthquakes might be the result of injecting

New Mexico Geology, v. 35, no. 1, pp. 3–12; Data Repository 20130001.

TABLE 1—Socorro Seismic Anomaly earthquakes with magnitudes of 2.0 or greater: 2005–2009.

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1 std (km)	Gap (degrees)	Magnitude
1	2005	10	30	2	57	35.79	34	3.66	106	57.59	0.41	70	2.3
2	2007	5	23	5	16	58.85	34	4.80	106	57.67	0.42	68	2.8
3	2008	9	29	15	32	36.51	34	10.16	106	55.00	0.93	75	2.4
4	2009	8	20	1	57	24.86	34	4.26	106	51.78	0.26	39	2.3
5	2009	8	27	6	51	45.85	34	10.05	106	51.25	0.27	51	2.0
6	2009	8	30	0	31	1.11	34	9.92	106	51.28	0.26	45	2.5
7	2009	8	30	6	39	48.54	34	9.85	106	51.54	0.36	72	2.3
8	2009	8	30	7	9	44.63	34	9.68	106	51.77	0.37	72	2.3

and/or removing large quantities of water associated with the production of coalbed methane. The remaining 39 earthquakes are separated into the SSA region events and the remainder of New Mexico and bordering area events (RNM). To be consistent and for comparison purposes, we follow the division into these regions used in the past catalogs.

In the previous catalogs, SSA contained 23% of $M_d \geq 2.0$ events during the 1962–1998 time period (Sanford et al. 2002) and 15% of the earthquakes in the 1999–2004 time period (Sanford et al. 2006). In this catalog, the SSA contributes 21% of the earthquakes (8 out of 39 events) if we ignore the induced seismicity in the two largest clusters.

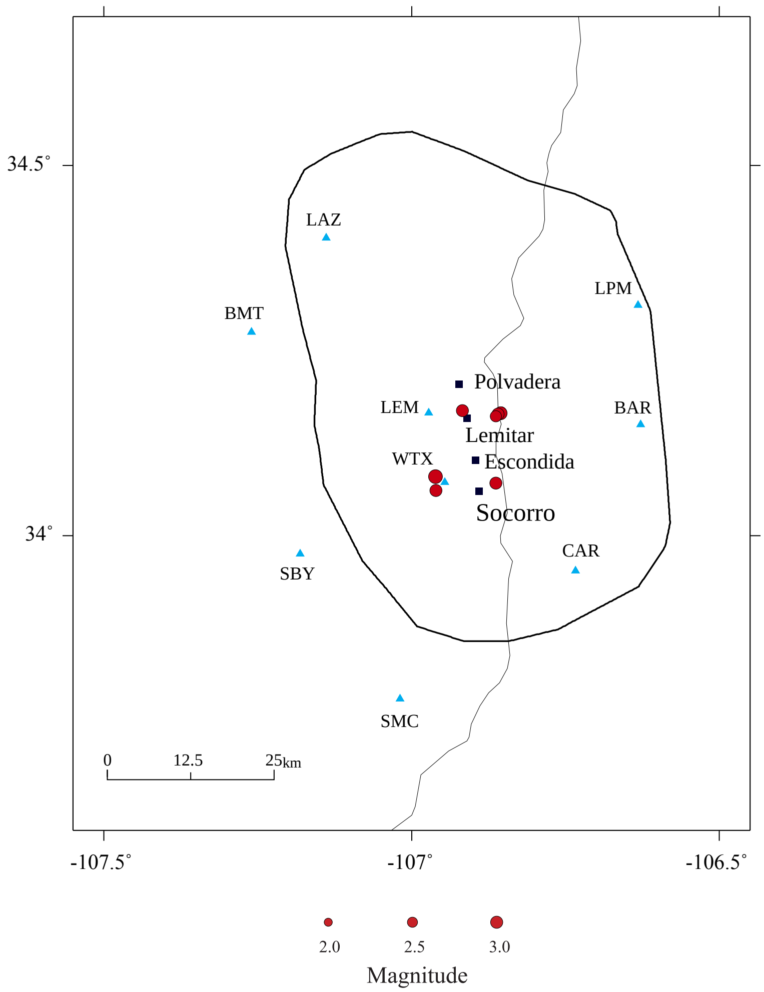

FIGURE 2—Locations of eight $M_d \geq 2.0$ earthquakes (red circles scaled by magnitude) that occurred within the Socorro Seismic Anomaly (SSA, solid line [Balch et al. 1997]) from 2005 through 2009. Also shown are station locations of the Socorro Seismic Network (blue triangles).

Earthquakes with $M_d \geq 0.0$

We also publish the results of $M_d \geq 0.0$ events in Appendix A of this catalog (available online at **http://geoinfo.nmt.edu/repository/index.cfm?rid=20130001**). This group consists of 1,375 instrumentally located earthquakes from 2005 through 2009. Slightly more than one-half of these events (735 earthquakes, 53%) were within the SSA region (Fig. A1). There were 271 events located in the Dagger Draw region bounded by 32.5°–32.75° N latitude and 104.4°–104.8° W longitude (20%, Fig. A2). The remainder of the events (369 earthquakes, 27%) were just outside of the boundaries for SSA and Dagger Draw, or were scattered throughout New Mexico and bordering states. There were no detectable events in the Raton–Trinidad area with $0.0 \leq M_d < 2.0$ recorded on our network, due to the large distance between the area and our seismic stations. We detect events with very small magnitudes (as small as −1.5) in the Dagger Draw and SSA areas due to the station proximity. However, events near the west and especially north borders of New Mexico need to be at least M_d 1.5 for us to locate them.

Procedures

Earthquake data

The Socorro Seismic Network (SC) provided most of the data used for earthquake location. This network consists of nine short-period stations located in southeast New Mexico surrounding the Waste Isolation Pilot Plant (WIPP) and 10 short-period stations located in central New Mexico bordering the SSA. Data are also obtained from nearby stations located in Arizona, Colorado, and Texas (the Arizona Seismic Network, network code AE; the Global Seismograph Network, network code IU; and the United States National Seismic Network, network code US). In late 2009 the New Mexico Tech geophysics group adopted a broadband USArray station Y22A, which is now also a part of the SC network. In addition to the permanent stations, data from several 120 sec to 50 Hz broadband Earthscope Transportable Array stations were available

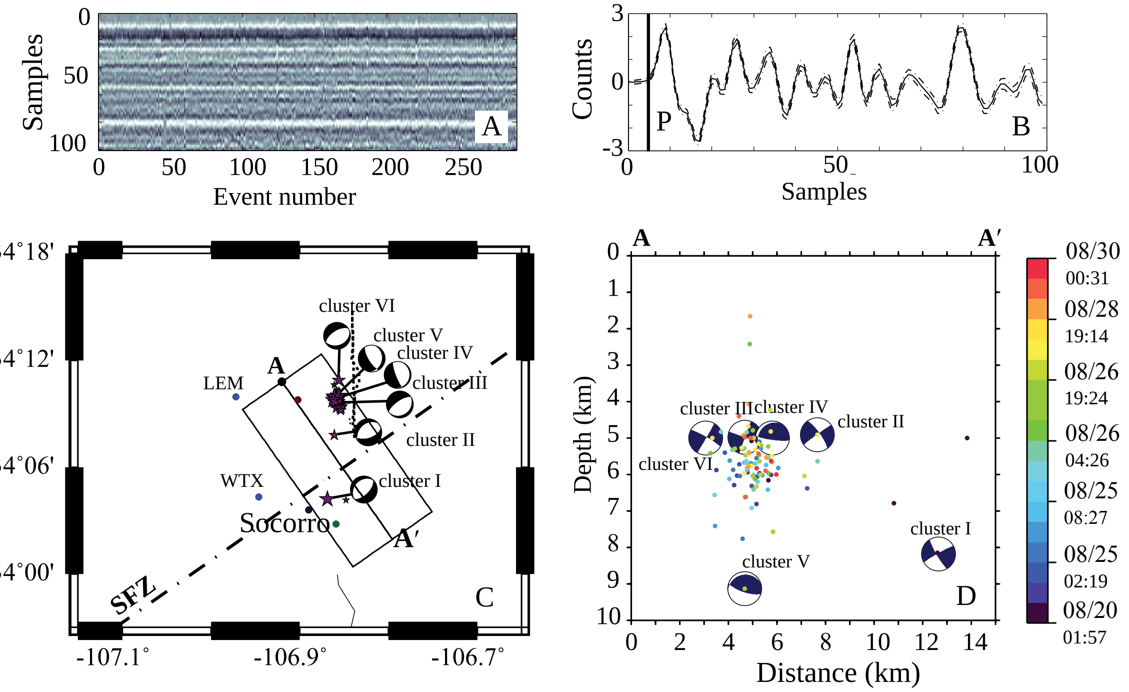

FIGURE 3—Lemitar earthquake sequence details (modified from Ruhl et al. 2010): **A**—Waveforms of 298 earthquakes recorded at station BAR, aligned on first arriving P (at 0 samples, y-axis). All waveforms meet cross-correlation threshold of 0.55. **B**—Stack of the 298 cross-correlated waveforms from station BAR. **C**—Plane view of the largest 105 cross-correlated events with focal mechanisms (white quadrangle represents dilatation, black compression) for each subcluster. Socorro Fracture Zone (SFZ, Sanford and Lin 1998) is approximated with a dash-dot line. The Veranito fault is shown with a dotted line (Cather et al. 2004). **D**—Cross section (A–A′ from panel C) of the events and focal mechanisms in C. Note that event symbols are color-coded based on relative time since the first event in the data set.

for most of 2008–2009. The data from these additional stations helped greatly to improve event location parameters and quality, especially for the Raton earthquakes.

Earthquake size and location

The magnitudes for all the events within these catalogs were determined using a local duration-based magnitude formula (Ake et al. 1983):

$$M_d = 2.79 \log(\tau_d) - 3.63,$$

where τ_d is the manually selected duration of the earthquake signal in seconds. The magnitude of an event is determined using signal duration recorded on the short-period (100 samples/sec) stations only.

Hypocenters and origin times were estimated using direct and reflected phase arrivals off the Socorro Magma Body (SMB) in the SEISMOS location algorithm (Hartse et al. 1992). This algorithm uses regionally tailored velocity models for events within the SSA, near Raton, and for the remainder of New Mexico. Direct P- and S-wave arrivals were used in all of the regions; the reflected arrivals were used only in the SSA area. Focal depths are generally unconstrained with default depth fixed at 5 km (e.g., Sanford et al. 2006). Only events with reflected phases in the SSA region have a constrained depth solution.

Socorro Seismic Anomaly (SSA)

Earthquakes in the SSA are very likely caused by the extensional tectonic system of the Rio Grande rift, largely because the SSA region overlies a thin and extensive magma body (the Socorro Magma Body, SMB) at a depth of approximately 19 km (Balch et al. 1997). The $M_d \geq 2.0$ events within the SSA region from 2005 through 2009 are listed in Table 1, and locations are shown in Figure 2 ($M_d \geq 0.0$ events are listed in Table A1, and plotted in Fig. A1). The median of earthquake epicentral errors was 0.36 km, and the median of the station coverage gap was 69°. These values are about 25% lower than the median values for the 1999–2004 catalogs, which we attribute to the additional station coverage from the Earthscope USArray network. Six out of the eight events with $M_d \geq 2.0$ that were located within the SSA borders occurred during the deployment period of these additional stations. All eight events within the SSA region with magnitude 2.0 or greater were between Socorro and Polvadera. Four out of the eight events located near Lemitar occurred within a 10-day period in 2009. These events were part of an extended earthquake sequence during the August–September 2009 period described below. The other four events were near Socorro Peak (two events), near Escondida (one event), and near Polvadera (one event).

2009 Lemitar earthquake sequence

As most of the $M_d \geq 2.0$ events in the SSA region occurred during a continuous earthquake sequence, we describe that sequence in more detail here. This sequence started with a magnitude 2.3 event near Escondida, just north of Socorro, on 20 August 2009 (event #4, Table 1). Two days later seismicity shifted north of this initial event by approximately 10 km; however, this shift lacks a clear migration pattern. Between 23 August and 15 September 2009, 431 events were located in proximity to the second location (e.g., event #5, Table 1) within a 34.5 km^3 volume (Ruhl et al. 2010).

These events were at shallow depths (1.1–8.9 km), with magnitude 2.0 and greater earthquakes occurring on average 1.5 km shallower than the smaller events. The depth errors ranged between 0.31 and 1.68 km, with an average of 0.51 km (median 0.43 km). Focal mechanisms computed using on average 22 first-motions (data from the SC and TA networks) of seven earthquakes from this sequence suggest that these events occurred along north-to northwest-striking normal faults. Some of the earthquakes intersect the nearby north-striking Veranito fault at depth (dotted line in Fig. 3C, Cather et al. 2004). The fault's most recent surface rupture is weakly constrained, but it is older than early to middle

TABLE 2—Remainder of New Mexico and bordering areas earthquakes with $M_d \geq 2.0$: 2005–2009.

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1 std (km)	Gap (degrees)	Magnitude
1	2005	1	13	22	13	3.45	34	48.02	104	8.50	4.30	251	2.4
2	2005	1	30	11	32	37.73	31	33.42	102	25.42	10.39	331	2.2
3	2005	7	29	5	8	49.85	33	23.25	105	29.55	12.74	324	2.2
4	2005	9	27	11	42	32.11	31	34.91	102	18.27	4.77	249	2.0
5	2006	6	15	6	13	4.25	30	60.00	105	32.77	7.04	40	2.0
6	2006	6	23	12	13	18.62	35	18.44	107	17.28	3.82	299	2.3
7	2006	7	17	8	42	16.33	33	36.47	104	45.96	3.35	186	2.2
8	2007	4	3	6	19	59.72	32	40.26	103	6.47	6.88	310	2.2
9	2007	8	15	6	53	2.17	35	32.97	106	5.51	2.89	142	2.7
10	2007	9	8	7	15	36.06	33	16.43	109	11.14	5.81	289	3.1
11	2007	9	10	10	27	37.80	31	30.84	105	00.01	4.63	265	2.1
12	2007	9	15	5	26	28.12	33	31.40	108	53.34	6.15	299	2.2
13	2007	11	3	9	30	47.06	33	14.65	108	31.57	5.14	292	2.5
14	2007	12	21	17	38	18.52	33	18.11	104	39.91	2.91	174	2.0
15	2008	4	16	9	6	7.89	33	30.82	106	6.80	2.93	158	2.4
16	2008	5	23	21	21	41.70	32	14.51	105	32.34	6.62	229	2.1
17	2008	6	6	20	10	7.69	37	26.15	109	3.07	12.22	288	2.6
18	2008	11	2	13	57	25.00	33	35.87	106	7.55	2.27	187	2.0
19	2008	11	24	9	12	14.09	34	29.87	105	19.22	8.70	218	2.4
20	2009	3	3	22	58	14.60	34	46.35	104	7.07	5.69	268	2.4
21	2009	6	5	17	17	1.86	31	14.03	106	16.44	7.23	281	2.3
22	2009	6	5	18	10	25.61	31	10.26	105	59.35	6.76	279	2.0
23	2009	6	30	13	51	37.14	31	34.63	103	12.86	9.38	325	2.3
24	2009	7	1	15	9	6.93	31	30.07	103	21.72	8.63	312	2.1
25	2009	7	3	16	20	26.33	31	20.97	103	29.83	8.91	313	2.0
26	2009	7	17	5	26	10.64	35	21.26	107	28.78	5.82	224	2.0
27	2009	8	12	0	12	43.14	35	29.13	107	14.52	6.52	211	2.2
28	2009	9	23	13	3	17.60	34	34.55	107	51.51	3.59	240	2.7
29	2009	9	29	3	43	41.52	34	45.23	106	33.27	3.14	227	2.0
30	2009	10	25	14	5	24.08	32	20.48	102	55.74	8.65	323	2.2
31	2009	11	28	18	13	50.20	35	10.98	106	44.25	3.20	159	2.1

Pleistocene (S. Cather, pers. comm., 2012). The earthquake locations form a generally flat volume at depth, which suggests that this fault becomes listric with depth (Fig. 3).

Due to the similar waveform character of events in this swarm, we applied a cross-correlation technique to improve user picks and refine earthquake locations (e.g., Shearer 1997; Rowe et al. 2002). Cross-correlation techniques compute differential P-, S- or reflected-wave travel-times for well-correlated waveforms on a station-by-station basis (e.g., Shearer 1997). These differential times were used to adjust the manual arrival time picks and resulted in better constrained locations for 298 out of 341 events with a correlation threshold of 0.55 (Figs. 3A and 3B). The cross-correlation results of the 105 largest events with a correlation threshold of 0.60 also suggest that instead of one large cluster, there were several distinct clusters with slight waveform shape variations. Four of these clusters have north-northeast-striking fault plane solutions, whereas two strike roughly north (Figs. 3C and 3D).

Remainder of New Mexico and bordering areas (RNM)

There were 31 earthquakes of $M_d \geq 2.0$ that occurred in New Mexico and the bordering areas, excluding those that were located near Raton, the Delaware Basin, or in the Socorro Seismic Anomaly (Fig. 1, Table 2). These events cover the Rio Grande rift, Great Plains, Mogollon–Datil region, and the borders of the Colorado Plateau. In the last 5-yr catalog (Sanford et al. 2006) there were 64 events located in RNM regions, which is more than double the number of events during 2005–2009 time period.

Delaware Basin earthquake sequence

This sequence consists of closely located and relatively frequent earthquakes near the Dagger Draw oil field region (Table 3). The Dagger Draw oil field (Dagger Draw north pool and Dagger Draw south pool) is approximately 40 km northwest of Carlsbad, New Mexico. The Delaware Basin sequence, also known as the Dagger Draw swarm, started with the initiation of production at this field, which suggests that these earthquakes are most likely induced (Sanford et al. 2006).

There is large temporal variation in the frequency of these events within a year

TABLE 3—Dagger Draw sequence earthquakes with $M_d \geq 2.0$: 2005–2009.

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1 std (km)	Gap (degrees)	Magnitude
1	2005	4	4	7	56	12.90	32	35.63	104	37.00	2.01	117	2.3
2	2005	5	4	6	22	11.49	32	35.05	104	37.26	2.62	127	2.3
3	2005	5	13	12	27	7.28	32	34.15	104	36.57	2.30	137	2.4
4	2005	6	15	4	7	1.14	32	19.67	104	38.90	1.76	188	2.2
5	2005	6	15	4	33	57.92	32	18.14	104	40.01	2.07	195	2.6
6	2005	6	15	22	48	55.23	32	18.32	104	39.82	2.68	206	2.0
7	2005	6	19	9	53	40.53	32	17.25	104	41.46	4.46	200	2.4
8	2005	6	29	21	49	5.82	32	19.06	104	39.14	2.78	197	2.3
9	2005	7	1	13	41	35.41	32	19.24	104	38.96	2.89	201	2.3
10	2005	7	20	2	16	49.65	32	37.84	104	47.76	2.79	108	2.1
11	2005	10	11	8	29	53.93	32	35.35	104	37.54	1.71	122	2.1
12	2005	11	4	18	9	13.85	32	30.62	104	38.44	1.46	138	2.2
13	2005	12	19	20	27	38.60	32	37.94	104	39.44	2.82	150	3.8
14	2005	12	19	20	41	18.87	32	33.68	104	50.11	4.13	103	2.9
15	2005	12	19	20	41	42.00	32	45.49	104	36.34	10.58	174	2.7
16	2005	12	19	21	14	55.35	32	33.70	104	44.28	3.18	274	2.0
17	2005	12	19	21	55	46.98	32	36.93	104	33.16	3.47	210	2.3
18	2005	12	20	4	46	38.27	32	35.30	104	43.60	3.50	110	2.1
19	2005	12	20	4	51	18.79	32	33.63	104	41.40	2.81	166	2.0
20	2005	12	22	14	30	10.89	32	37.24	104	37.20	3.08	156	3.4
21	2006	1	27	10	4	55.75	32	39.77	104	34.99	2.03	148	2.5
22	2006	1	27	16	7	45.12	32	38.91	104	35.16	1.91	147	2.5
23	2006	2	4	19	55	10.21	32	38.08	104	35.47	1.91	146	2.0
24	2006	3	20	17	55	28.87	32	42.78	104	36.45	2.11	110	2.3
25	2006	11	2	0	42	39.78	32	33.76	104	38.70	3.45	155	2.3
26	2006	11	21	8	23	29.78	32	24.31	104	42.41	2.70	180	2.4
27	2006	11	26	11	57	14.11	32	37.00	104	36.44	1.90	100	2.1
28	2007	3	21	8	47	25.19	32	29.45	104	42.32	3.48	206	2.0
29	2007	8	11	0	7	35.73	32	32.42	104	46.99	3.43	177	2.0
30	2008	5	23	18	3	6.40	32	29.39	104	38.70	2.55	163	2.2
31	2008	6	26	20	32	33.08	32	30.18	104	38.46	7.74	161	2.3
32	2008	6	27	13	43	49.69	32	13.32	104	40.81	3.76	220	2.0
33	2008	6	30	5	58	8.24	32	17.63	104	34.03	3.79	187	2.5
34	2009	1	29	23	50	27.27	32	33.68	104	38.95	2.27	163	2.0
35	2009	1	30	1	41	21.23	32	33.31	104	39.72	2.53	165	2.5
36	2009	7	24	10	30	55.62	32	18.26	104	40.70	2.51	195	2.2
37	2009	9	6	3	38	14.06	32	31.00	104	42.64	2.43	172	2.8
38	2009	9	6	5	54	48.24	32	32.87	104	39.68	2.99	160	2.1
39	2009	9	6	9	24	30.30	32	33.70	104	38.66	2.51	155	2.0
40	2009	9	7	5	22	7.22	32	28.80	104	40.59	2.43	167	2.6
41	2009	9	23	23	54	48.19	32	33.33	104	40.41	2.39	159	2.3
42	2009	9	23	23	58	56.76	32	32.67	104	40.70	2.92	160	3.1
43	2009	9	24	20	55	45.62	32	32.39	104	40.47	2.71	168	2.0
44	2009	10	9	6	42	1.93	32	32.52	104	40.00	2.90	159	2.1
45	2009	10	14	16	31	45.34	32	32.30	104	40.75	2.70	165	2.5
46	2009	10	18	2	45	33.52	32	33.67	104	39.50	2.57	139	2.4

TABLE 3—continued

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1 std (km)	Gap (degrees)	Magnitude
47	2009	11	17	7	27	23.71	32	34.07	104	38.87	2.83	155	2.6
48	2009	11	17	18	53	6.46	32	32.87	104	40.39	2.78	166	2.6
49	2009	11	17	19	7	36.94	32	32.44	104	40.38	2.45	160	2.3
50	2009	11	27	5	35	1.66	32	31.54	104	46.68	3.55	104	2.0
51	2009	12	10	4	44	20.89	32	31.85	104	41.97	2.62	164	2.2
52	2009	12	11	15	29	47.68	32	32.00	104	41.12	2.71	162	2.2
53	2009	12	24	19	41	38.75	32	32.52	104	34.45	2.50	144	2.0

TABLE 4—Raton Basin earthquakes with $M_d \geq 2.0$: 2005–2009. Asterisks indicate earthquakes with USGS location only.

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1 std (km)	Gap (degrees)	Magnitude
1*	2005	1	10	10	14	59.15	37	0.60	104	40.80	n/a	n/a	3.4
2	2005	4	1	10	14	33.82	97	7.87	105	5.04	7.90	175	2.6
3*	2005	4	6	8	45	24.57	36	52.80	104	47.40	n/a	n/a	2.9
4	2005	4	24	11	2	37.84	36	48.38	104	55.86	4.67	193	2.5
5	2005	7	4	10	45	27.14	36	47.76	104	55.27	4.05	174	3.0
6	2005	7	8	6	24	1.78	36	55.18	104	54.57	5.80	175	3.0
7	2005	7	8	6	25	55.78	36	54.07	105	.50	7.26	173	2.1
8	2005	8	10	22	8	20.40	36	55.71	104	38.73	4.77	182	4.3
9	2005	8	10	22	24	38.08	36	52.24	104	46.24	4.00	179	2.8
10	2005	9	30	2	12	31.78	37	5.60	104	45.59	5.44	212	2.7
11	2005	10	20	8	15	41.45	36	48.98	105	.62	4.39	175	2.3
12	2005	11	16	3	11	33.67	37	5.70	104	48.50	5.03	207	2.7
13	2006	1	27	18	48	51.46	36	56.29	104	46.69	4.05	179	2.9
14*	2006	2	11	13	3	50.48	37	4.80	105	26.40	n/a	n/a	2.9
15	2006	5	6	17	7	3.42	37	2.33	104	45.46	4.19	180	3.1
16*	2006	5	14	10	16	33.86	36	50.40	104	45.00	n/a	n/a	2.5
17	2006	5	26	6	14	28.33	36	46.28	104	43.16	4.15	179	2.7
18	2006	7	11	11	53	39.73	37	4.90	104	59.60	5.29	177	2.9
19	2006	8	8	13	41	59.65	36	56.69	105	1.44	6.58	173	2.6
20	2006	8	24	14	4	28.79	37	1.15	104	57.95	3.91	175	2.9
21	2006	9	9	9	54	15.92	37	5.24	104	34.99	2.03	148	2.5
22	2006	9	9	12	53	15.75	37	26.31	104	2.81	5.75	202	2.8
23	2006	9	9	18	5	46.30	37	22.08	104	44.52	4.50	183	2.8
24	2006	9	9	23	14	40.01	37	14.44	104	58.74	4.65	176	3.2
25*	2006	9	10	12	2	59.70	37	17.40	104	52.20	n/a	n/a	2.6
26*	2006	9	14	13	3	24.26	37	0.60	104	52.20	n/a	n/a	3.0
27*	2006	9	28	9	56	37.81	36	57.60	104	46.80	n/a	n/a	2.6
28	2006	9	30	12	40	3.29	37	1.88	105	1.69	4.51	173	2.7
29	2006	10	30	2	35	19.51	36	38.74	105	4.82	3.44	179	2.7
30	2006	11	24	23	22	27.03	37	3.25	105	2.37	4.52	173	2.7
31*	2006	12	24	11	50	21.47	36	56.40	104	45.00	n/a	n/a	3.6
32	2007	1	3	14	34	41.14	37	4.24	104	53.80	3.96	201	3.8
33*	2007	1	14	5	17	36.69	36	52.80	104	55.80	n/a	n/a	3.2
34	2007	2	25	11	24	28.05	36	51.18	104	50.01	4.66	177	2.6

TABLE 4—continued

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1 std (km)	Gap (degrees)	Magnitude
35*	2007	3	12	6	32	14.59	37	3.60	104	56.40	n/a	n/a	3.4
36*	2007	6	9	10	45	44.71	36	55.80	104	47.40	n/a	n/a	3.3
37	2007	10	27	5	32	17.90	36	52.48	104	52.49	5.56	176	2.2
38*	2007	12	17	4	30	29.10	36	57.00	105	3.60	n/a	n/a	2.9
39	2008	1	29	2	30	30.08	36	33.79	104	52.08	4.12	174	2.4
40	2008	2	14	3	60	10.96	36	50.98	104	50.74	5.71	177	2.5
41	2008	2	15	8	4	1.49	36	53.63	105	6.48	5.14	170	n/a
42	2008	4	5	7	13	25.21	36	52.87	104	45.57	5.32	179	2.3
43	2008	4	20	9	39	54.42	36	59.12	104	51.09	4.80	200	2.8
44	2008	4	21	9	36	31.93	36	52.09	104	41.79	6.70	206	2.5
45	2008	4	24	2	21	52.37	37	3.08	104	41.54	5.90	182	2.7
46	2008	7	17	10	34	44.32	36	57.68	104	49.18	5.95	194	2.2
47	2008	7	18	14	59	43.25	36	54.89	104	49.18	7.68	178	2.1
48*	2008	8	24	22	48	31.50	37	6.00	104	52.20	n/a	n/a	3.4
49	2008	9	6	14	34	2.89	36	59.17	104	41.34	5.17	208	2.2
50	2008	9	22	13	55	23.30	37	13.98	104	12.25	7.31	201	2.4
51	2008	9	25	16	55	36.93	37	20.65	104	20.58	4.55	193	2.6
52	2008	10	4	12	41	28.67	37	2.37	104	41.74	4.45	210	3.0
53	2009	2	3	23	27	15.41	36	50.19	104	53.54	4.94	175	2.7
54	2009	2	13	11	2	33.77	36	48.57	104	46.13	4.57	178	2.3
55	2009	3	15	14	21	45.94	36	48.89	104	55.07	5.87	175	2.4
56*	2009	3	22	11	14	40.10	37	15.60	104	27.60	n/a	n/a	3.0
57	2009	5	1	1	34	10.89	36	39.93	104	42.82	4.22	179	2.7
58	2009	6	27	6	44	46.81	36	45.78	104	50.74	4.75	193	2.7
59	2009	6	27	8	24	33.19	36	34.09	105	.84	5.20	181	2.6
60	2009	7	29	9	60	42.67	36	43.29	104	53.16	4.27	175	3.3
61	2009	7	29	14	31	54.22	36	47.76	104	52.72	6.41	180	2.3
62	2009	8	3	23	15	11.82	36	41.31	104	55.44	4.70	174	2.5
63	2009	8	21	11	46	3.61	36	59.27	105	1.72	13.96	215	2.5
64	2009	9	29	11	20	33.91	36	50.53	105	2.09	4.79	172	3.0
65	2009	9	29	22	54	12.64	37	2.82	104	56.60	7.21	181	2.7
66	2009	10	3	18	45	34.73	37	5.24	104	59.84	5.11	175	3.3
67*	2009	10	29	11	23	2.92	37	5.40	104	57.60	n/a	n/a	2.5
68*	2009	10	29	11	38	9.08	37	4.20	104	49.80	n/a	n/a	2.6
69	2009	11	4	19	52	25.03	36	57.61	104	46.03	7.66	203	2.5
70	2009	11	16	1	46	8.64	36	56.64	105	10.74	15.41	221	2.1
71	2009	11	19	8	31	14.15	36	39.67	105	2.90	6.26	170	2.5
72	2009	11	20	14	54	31.08	36	50.96	104	44.88	7.09	206	3.0
73	2009	12	11	20	32	31.91	36	42.18	104	48.72	3.82	195	2.6

as well as between years. For example, in 2005 there were 20 $M_d \geq 2.0$ earthquakes near Dagger Draw, which suggest on average 1.6 events per month. However, five of these events occurred in June (25%) and seven occurred in December (35%) alone. In comparison, during the first quarter of 2005 we did not observe any $M_d \geq 2.0$ events in this region. There is also a large yearly variation in earthquake occurrence. Out of all 53 $M_d \geq 2.0$ events in the Dagger Draw sequence during the 2005–2009 time period, 20 earthquakes (38%) occurred in 2005, seven in 2006 (13%), two in 2007 (4%), four in 2008 (7%), and 20 in 2009 (38%).

Raton Basin earthquake sequence

This earthquake sequence is a cluster of events in the Raton Basin along the northeastern border of New Mexico. This sequence started in late 2001 (Sanford at al. 2006) and continues through the present. The events in this group are relatively large

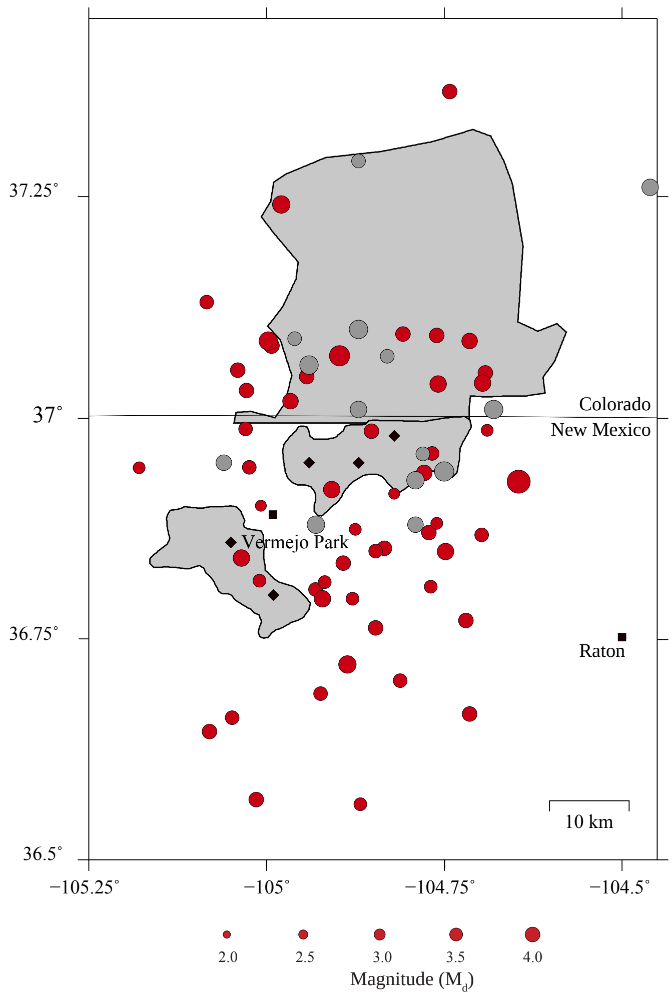

FIGURE 4—Earthquakes near Raton during 2005–2009 time period located using the SC network (57 events, red circles), locations from the USGS only (16 events, gray circles). Also shown are the coalbed methane-producing areas (gray regions) and the waste water disposal wells (black diamonds) in New Mexico, obtained from the New Mexico Bureau of Geology and Mineral Resources. The oil and gas-producing area in Colorado (gray polygon) was obtained from the Colorado Oil and Gas Conservation Commission.

($M_d \geq 2.0$) and generally poorly located by the SC network, as the closest station is a broadband site ANMO near Albuquerque. We were able to improve the location parameters for a group of 23 earthquakes that occurred during the Earthscope USArray station deployment in New Mexico.

From 2005 through 2009 there were 73 earthquakes in the Raton Basin (Table 4). Compared to the last catalogs spanning the period 1999–2004, the frequency of earthquakes in the Raton Basin has more than doubled in the last 5 yrs. This increase is independent of the larger seismic station pool in the area; even without the USArray sites, the earthquakes in the Raton Basin during this time were locatable by our network. Most of the events are concentrated around the coalbed methane fields (Fig. 4); however, we do not have enough information at this time to discuss whether these events are the results of production or natural motion along existing faults.

The Earthscope USArray Transportable Array seismic network (TA) was located in New Mexico during most of 2008 and 2009. We relocated 23 of the 73 Raton Basin earthquakes using the local network (SC) and the nearby USArray stations that were operational when events occurred (red circles, Figs. 5A and 5B; Table 5), and four earthquakes for which we only had a USGS location (blue circles, Figs. 5A and 5B). The location errors, the RMS (root mean square), and azimuth gap values decreased significantly when using data from these additional stations. The locations do cluster closer together; however, not all of the events were within or near the coalbed methane-producing region represented by the gray areas in Figures 5A and 5B. Thus, we suggest that either the coalbed methane production spans larger regions than shown on the map, or that these events occur on nearby faults unrelated to the industrial development. The location parameters, azimuth gaps (Fig. 5C), and epicenter standard deviations (Fig. 5D) improved greatly after relocation.

Conclusions

From 2005 through 2009 we have located 165 $M_d \geq 2.0$ earthquakes and 1,375 $M_d \geq 0.0$ earthquakes in New Mexico and the surrounding regions. The earthquakes were located mainly in three distinct clusters: Dagger Draw region, southeast New Mexico; Raton region, northeast New Mexico; and the SSA region, central Rio Grande rift area. In August and September 2009 there was a swarm of more than 400 earthquakes in the SSA region, which is associated with extensional movement near the Veranito fault. The activity near Dagger Draw region is likely caused by produced water disposal in the nearby wells. In the Raton Basin area, seismicity has been attributed to coalbed methane production; however, the relocated earthquakes with improved location parameters fall outside of the industrial boundaries.

Acknowledgments

These catalogs include the work of several undergraduate and graduate students. They helped with maintaining the seismological observatory and creating the earthquake catalogs. We are also grateful for Hans Hartse's and Kuo-wan Lin's location program that was used for all of the data processing. The USArray program allowed us to greatly improve earthquake locations, especially in the Raton region. We also used data from several stations in the U.S. National Seismic Network (network code US) and the Global Seismograph Network (network code IU). The location of the Veranito fault was provided by the New Mexico Bureau of Geology and Mineral Resources. This manuscript was greatly improved by reviews from Allan Sanford, Kuo-wan Lin, and Noel Barstow.

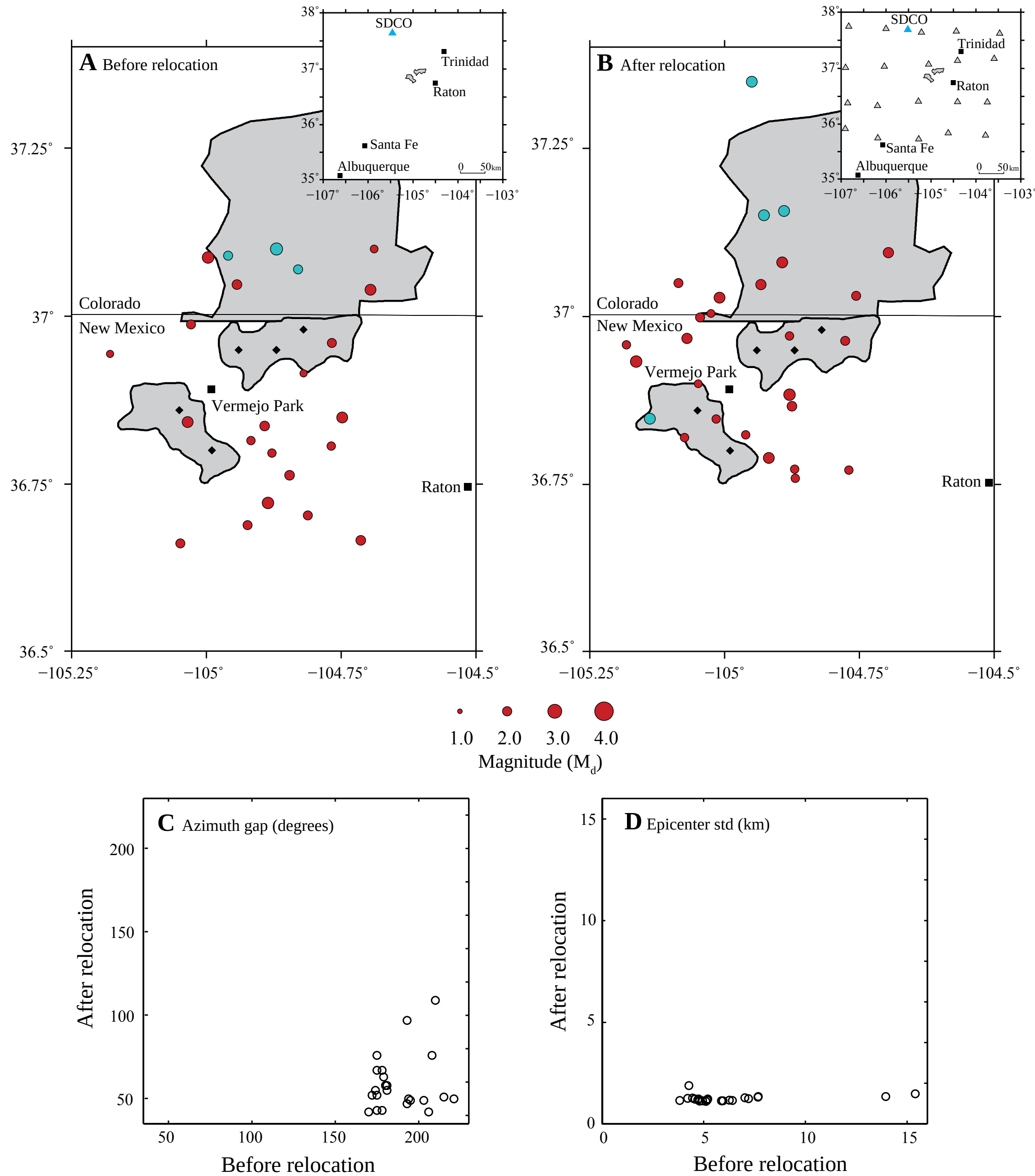

FIGURE 5—**A**—Original locations for 27 events in the New Mexico–Colorado border area. Red circles represent earthquakes located using the SC network (23 events), blue circles are events with a USGS location only (four events. Note one of these events lies out of the map boundaries in the original location). **B**—Earthquakes relocated using the SC network and the USArray stations (gray triangles) in the New Mexico–Colorado border area. Comparison of azimuth gap values (**C**) and the standard deviation of epicenters (**D**) for 23 relocated earthquakes. The original values are on the x-axis, the improved values after relocation using USArray stations are on the y-axis.

TABLE 5—Locations of 23 earthquakes in the Raton Basin relocated using data from the SC network and the USArray stations.

No.	Year	Month	Day	Hour	Minute	Seconds	Lat N	Minutes	Long W	Minutes	1 std (km)	Gap (degrees)	Magnitude
1	2008	7	17	10	34	47.59	37	0.29	105	1.51	1.15	50	2.2
2	2008	7	18	14	59	46.01	36	45.53	104	52.13	1.35	67	2.4
3	2008	9	6	14	34	9.26	36	46.26	104	46.19	1.16	76	2.4
4	2008	9	25	16	55	41.00	37	5.72	104	41.79	1.23	97	2.8
5	2008	10	4	12	41	31.48	37	4.84	104	53.58	1.27	109	3.1
6	2009	2	3	23	27	15.77	36	49.18	105	4.48	1.13	52	2.4
7	2009	2	13	11	2	36.05	36	57.48	105	10.94	1.22	43	2.4
8	2009	3	15	14	21	48.65	36	46.35	104	52.22	1.14	67	2.3
9	2009	5	1	1	34	11.87	36	51.98	104	52.52	1.25	63	2.7
10	2009	6	27	6	44	49.70	36	58.04	105	4.19	1.22	47	2.8
11	2009	6	27	8	24	29.61	37	1.86	104	45.38	1.22	58	2.6
12	2009	7	29	10	0	44.36	36	53.03	104	52.79	1.89	76	3.2
13	2009	7	29	14	31	55.40	36	49.44	104	57.68	1.15	58	2.4
14	2009	8	3	23	15	10.47	36	58.26	104	52.77	1.18	55	2.3
15	2009	8	21	11	46	6.14	37	2.99	105	5.15	1.35	51	2.5
16	2009	9	29	11	20	32.98	37	1.69	105	0.57	1.12	52	3.0
17	2009	9	29	22	54	11.64	37	2.86	104	56.00	1.24	55	2.8
18	2009	10	3	18	45	39.44	36	55.98	105	9.86	1.11	43	3.2
19	2009	11	4	19	52	30.99	36	59.93	105	2.73	1.31	49	2.5
20	2009	11	16	1	46	10.93	36	53.99	105	2.96	1.48	50	2.2
21	2009	11	19	8	31	13.07	36	50.84	105	0.95	1.16	42	2.4
22	2009	11	20	14	54	34.65	36	47.37	104	55.09	1.28	42	3.0
23	2009	12	11	20	32	31.00	36	57.83	104	46.59	1.15	49	2.6

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Some abbreviations used in this paper

AE	Arizona Seismic Network
IU	Global Seismograph Network
RMS	root mean square
RNM	remainder of New Mexico and bordering states
SC	Socorro Seismic Network
SFZ	Socorro Fracture Zone
SMB	Socorro Magma Body
SSA	Socorro Seismic Anomaly
TA	Earthscope USArray Transportable Array seismic network
US	United States National Seismic Network
USGS	U.S. Geological Survey
WIPP	Waste Isolation Pilot Plant

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 6-D

Spring 2014

Investigation of possible induced seismicity due to wastewater disposal in the Delaware Basin, Dagger Draw Field, New Mexico-Texas, USA

Mariel Herzog
University of Colorado Boulder

Investigation of possible induced seismicity due to wastewater disposal in the Delaware Basin, Dagger Draw Field, New Mexico-Texas, USA

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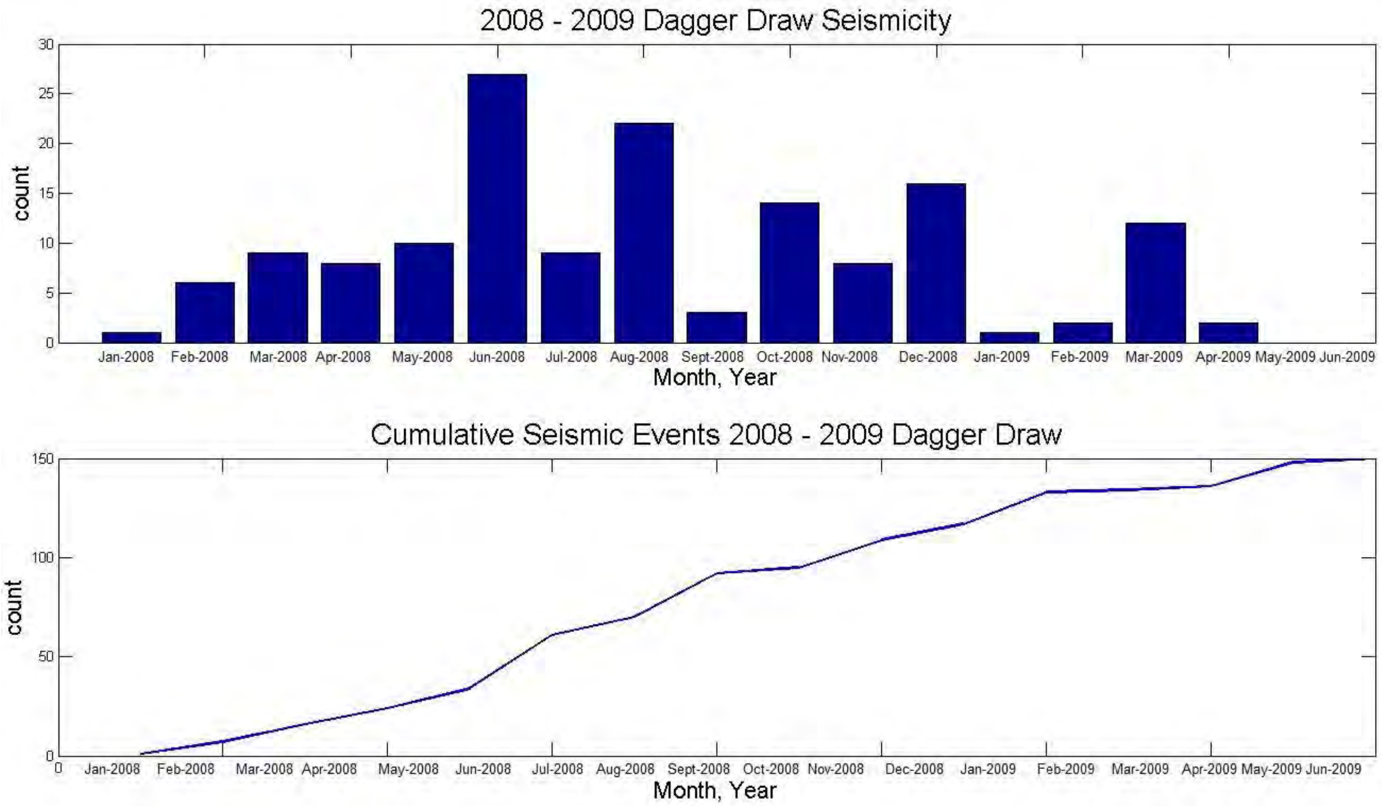
Figure 17: 2008 – 2009 Seismicity in the Dagger Draw Area: [Upper] Monthly display of seismicity shows periods of increased and decreased seismicity. [Lower] Cumulative earthquakes since January 2008 show a consistent increase.

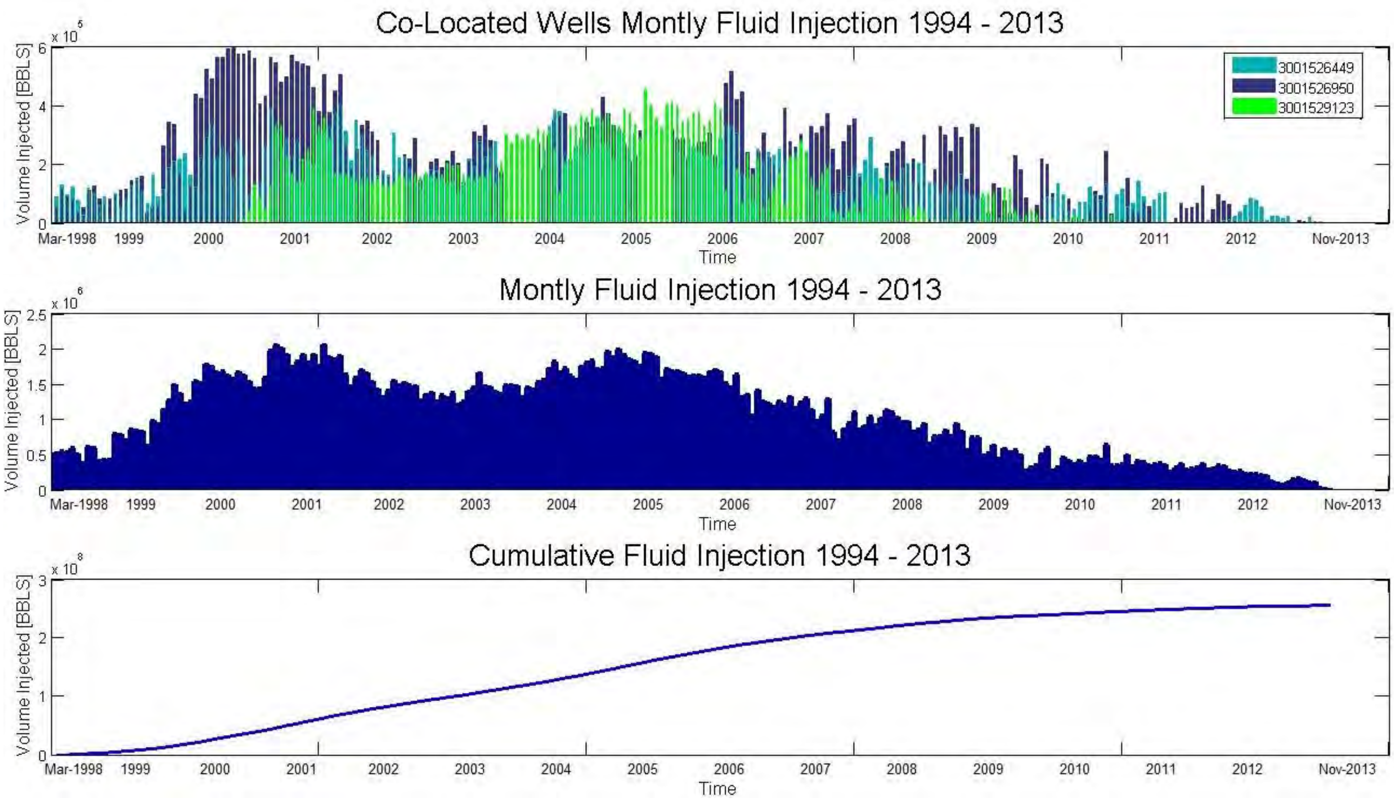


ii. Injection Data

Three wells (3001526449, 3001526950, 3001529123) co-located with previously observed earthquakes (Figure 18 [Upper]) provide a better understanding of the activity and volume of fluids present near where the earthquakes are observed. Well 3001526449 and 3001529123 inject into the Ellenburger (4.7 km, UIC). 3001526950 injects into Denovian sandstone. All three wells inject into the deepest sedimentary formations close to basement rock.

Data from each of the nine New Mexico deep wastewater injection wells used in this study shows a consistent increase in volume from 1998 – 2000. Activity fluctuated from 2000 – 2008 before finally decreasing (Figure 18 [Middle]). Cumulative fluid injection (Figure 18 [Lower]) shows that injected fluid has leveled off which is consistent with a decline in activity. However, the amount of injected fluid within the formations will take time to dissipate and the majority will remain within the rock structure [Simpson 1986]. An understanding of the amount of fluid present in a formation is essential to understanding pore pressure and in situ stress. The likelihood of remote triggering could bring the structure to failure despite the end of injection activity [Van der Elst, 2013].

Figure 18: Well Injection Data for the Dagger Draw Area. [Upper] Monthly fluid injection for three wells co-located to previously observed seismicity. Each well varies in monthly volume injected, however, all three show the onset and decline of production. [Middle] Monthly fluid injection for the sum of all nine wells used in the study. This also shows the same onset and decline of activity. [Lower] Cumulative volume of wastewater injected. Volume becomes constant after 2009.



iii. <u>Anthropogenic Source</u>

Increases in observed seismicity with increasing injection activity suggest induced seismicity (Figure 19). Additions to the Dagger Draw earthquake catalog support this. As expected, [Simpson, 1986] seismic events still occur despite declines in injection activity. It is important to look at the entire injection history when considering the earthquakes found in Table 1 as previously injected fluid within the formation will affect the likelihood of triggered seismic events. Cumulative injection data (Figure 19, Lower) levels off while cumulative earthquakes continues to increase. Earthquakes observed from 1998 to 2007 (Figure 19, Upper) fluctuate consistently with injection activity. Both catalogs suggest that the amount of seismic events was a product of injection volume.

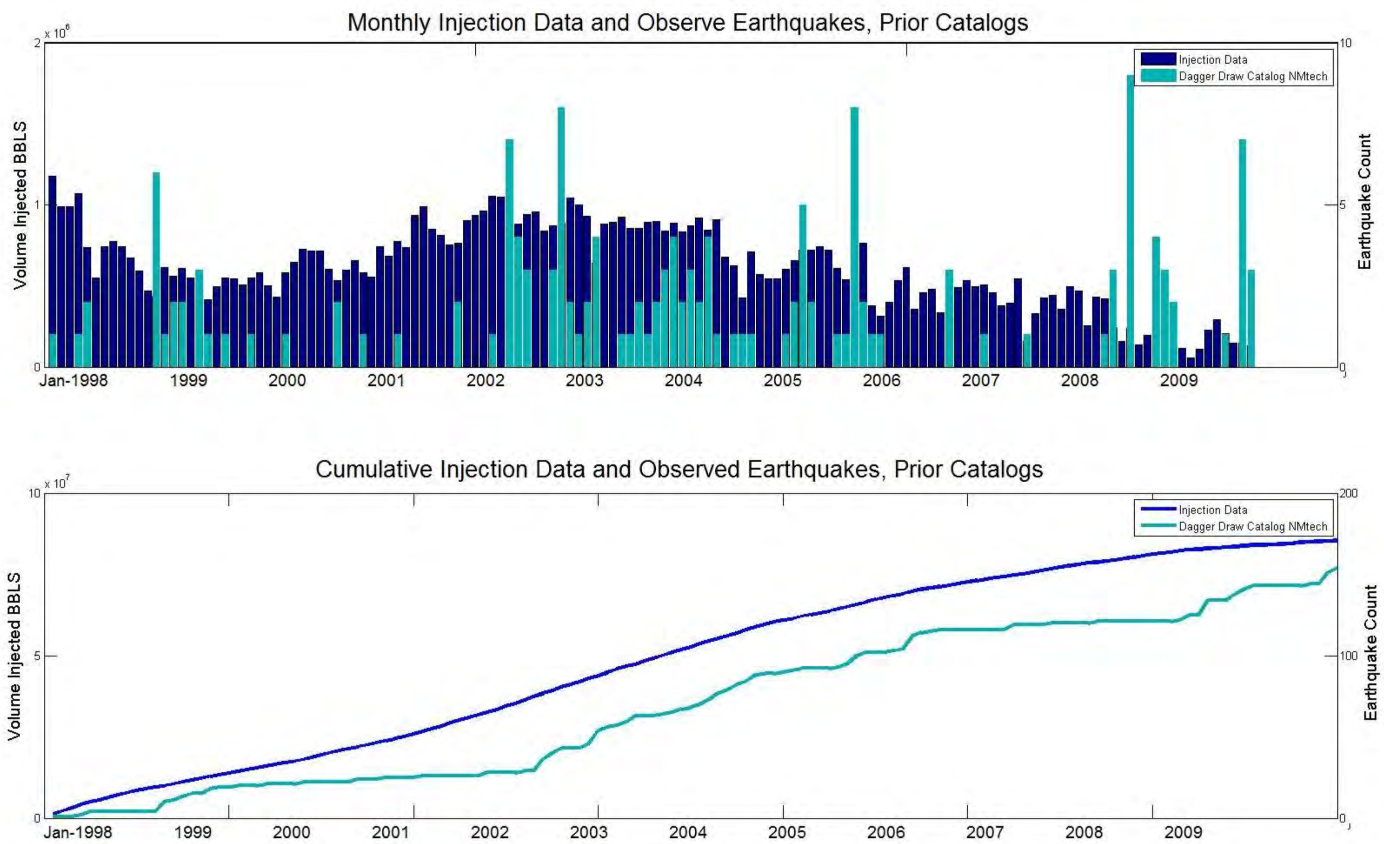


Figure 19: Injection History and Observed Earthquakes: [Upper] Injection history for all nine wells and earthquakes. [Lower] Earthquakes found in this study (Table 1, spans 2008 - 2009) and injection history of three co-located wells to Dagger Draw seismicity.

Due to the brevity of TA seismometer deployment in the Dagger Draw basin, the match filter catalog only spans from 2008 – 2009. Figure 20 shows the historical injection volume and the results from the match filter (table 1). Despite a time lag of approximately four months, the earthquakes are consistent with injection data. We expect that expanding the timespan of the match filter analysis to other continuous seismometer networks would agree with the trends observed from the TA station outputs. Regardless, the current catalog does support the possibility that these earthquakes were triggered by injection activity.

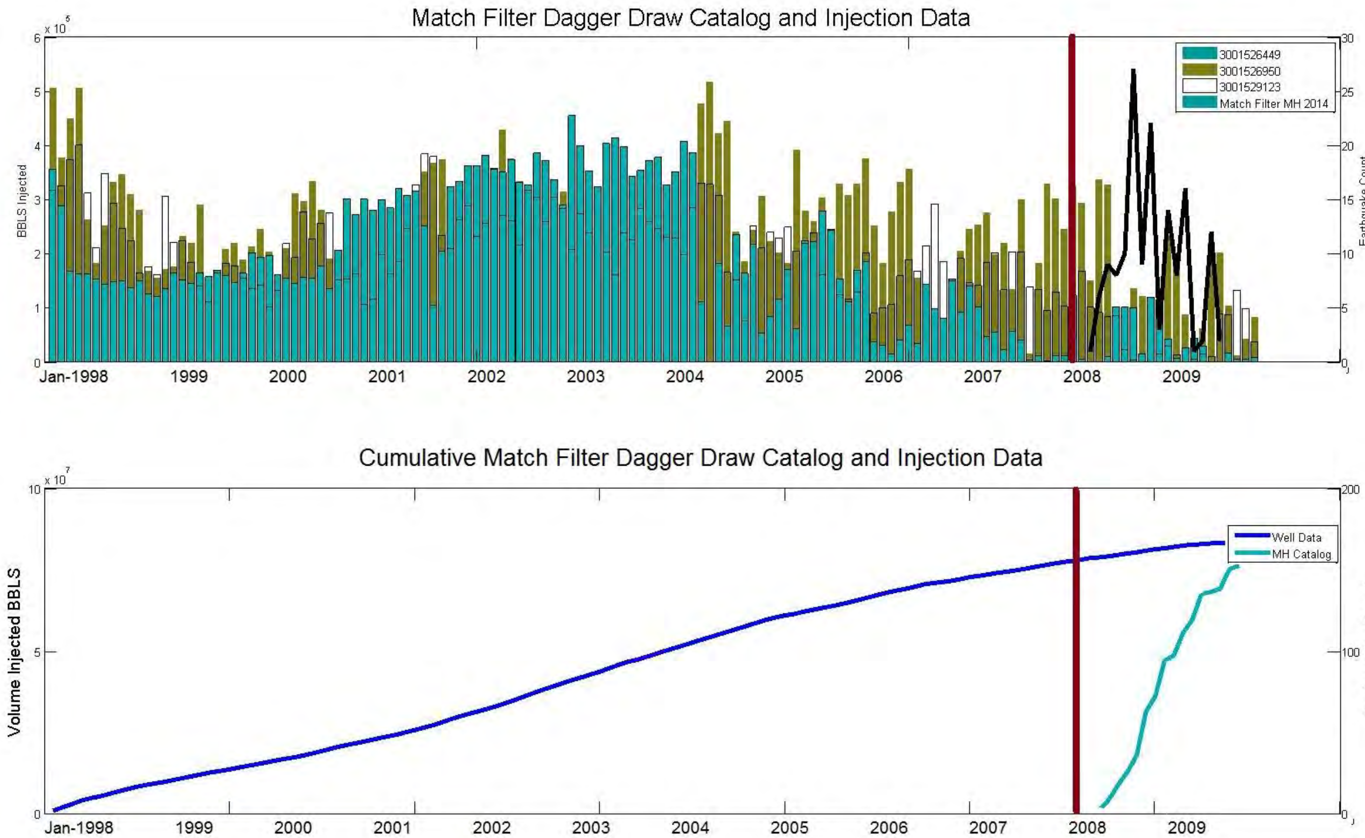


Figure 20: Found Earthquakes and Injection Data: Red line indicates beginning of match filter analysis in the seismic record [Upper] Monthly injection data and earthquake count as a result of the match filter (Table 1). [Lower] Cumulative volume of injected fluid and found earthquakes shows an increase in seismicity and declining injection volumes.

Conclusion

Using the match filter technique, this study found a significant number of previously unidentified earthquakes that are likely induced by anthropogenic activity. The match filter increased the existing catalog (Table 2 and Table 3) by a factor of 1.5. The timing of these events follows well data both close to and within a larger region of where the earthquakes are observed. Due to the relatively small magnitude of these earthquakes, they are difficult to identify at seismometers far from the epicenter. This study shows the results of two seismometers. It is likely that there are more events that could be added to our catalog by earthquakes triggered from injection activity in the area may extend further spatially than the range of the two seismometers.

Constant activity of high volume deep injection of wastewater fluid brings structures closer to failure. Such great increases in pore pressure leave formations susceptible to triggers such as additional injection activity or a remote earthquake. It is challenging to determine the exact spatial and temporal consequence this practice has in a regional formation. By identifying these events and extending existing earthquake catalogs, we can be more confident in this link.

Further Research

A velocity model of the Dagger Draw field would provide the ability to determine the focus, epicenter, and magnitude of the cataloged earthquakes. This would be found using methods of inversion with seismic data. An understanding of the depth and magnitude of these earthquakes would help to confirm whether or not these earthquakes were induced by local energy production. An investigation of changes of earthquake magnitude with amount of fluid injected into the formations would provide better insight to the stress conditions of the rock.

The TA array provides continuous seismic data, however it is constrained to a two year time period. Injection activity has decreased slowly since 2004. Earthquakes from three New Mexico Tech Catalogs [Pursley et al., 2013], [Sanford et al., 2006] , and [Sanford et al., 2002], Table 1, and Table 2 suggest an increase in seismicity. However, these additions are limited by the availability of seismic data.

Since the TA record spans 2008 – 2009, several questions still remain about the temporal relation of these earthquakes to wastewater injection. Simpson 1986 notes that it is not uncommon that when injections stop, earthquakes are observed at shallower depths. Seismic data from any time beyond when the formations were actively injected with wastewater does not yet exist. It is possible that observed earthquakes beyond the period of activity could still be associated with injection. A velocity model of the region and an extension of the seismic record would enrich our results greatly.

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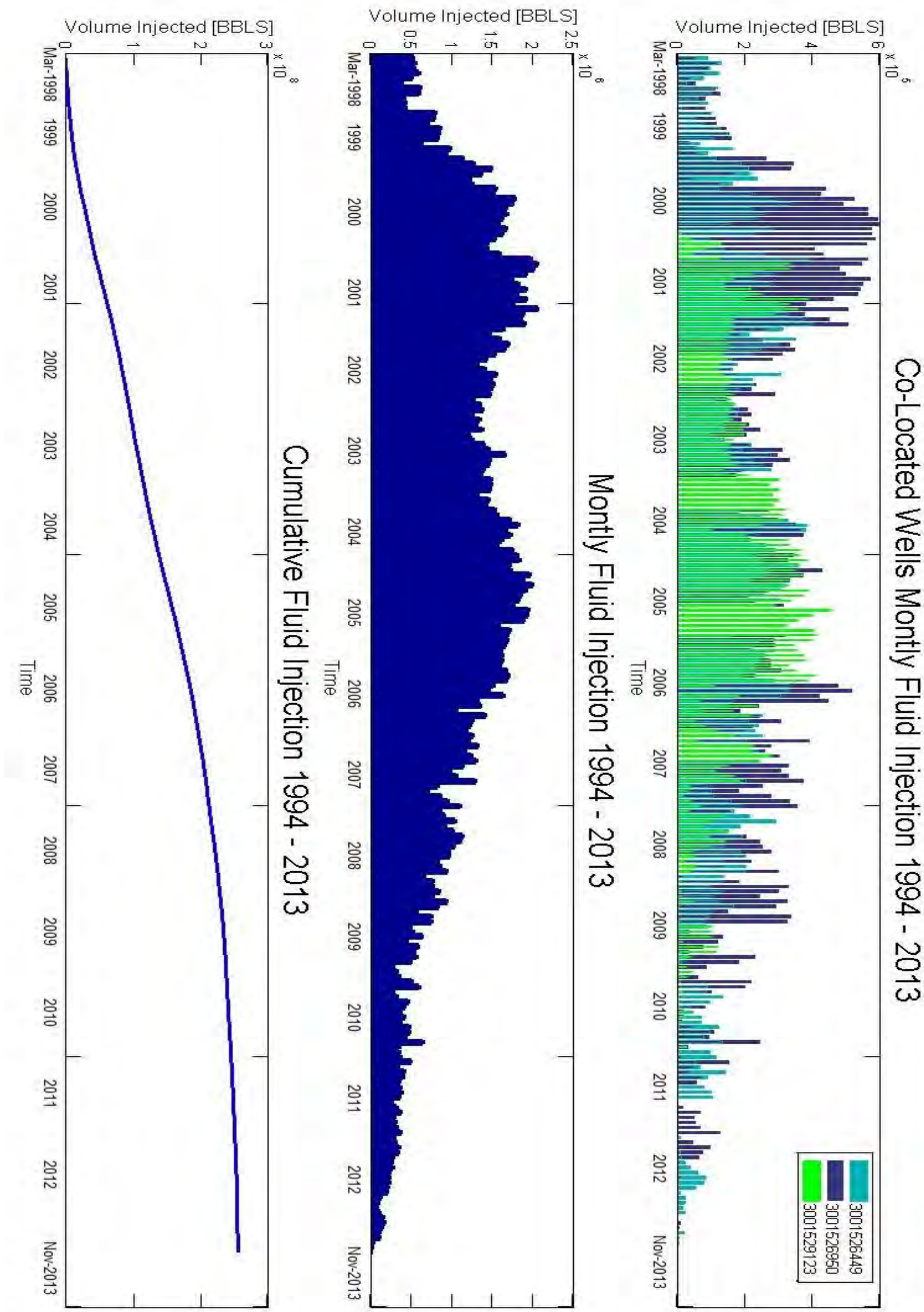
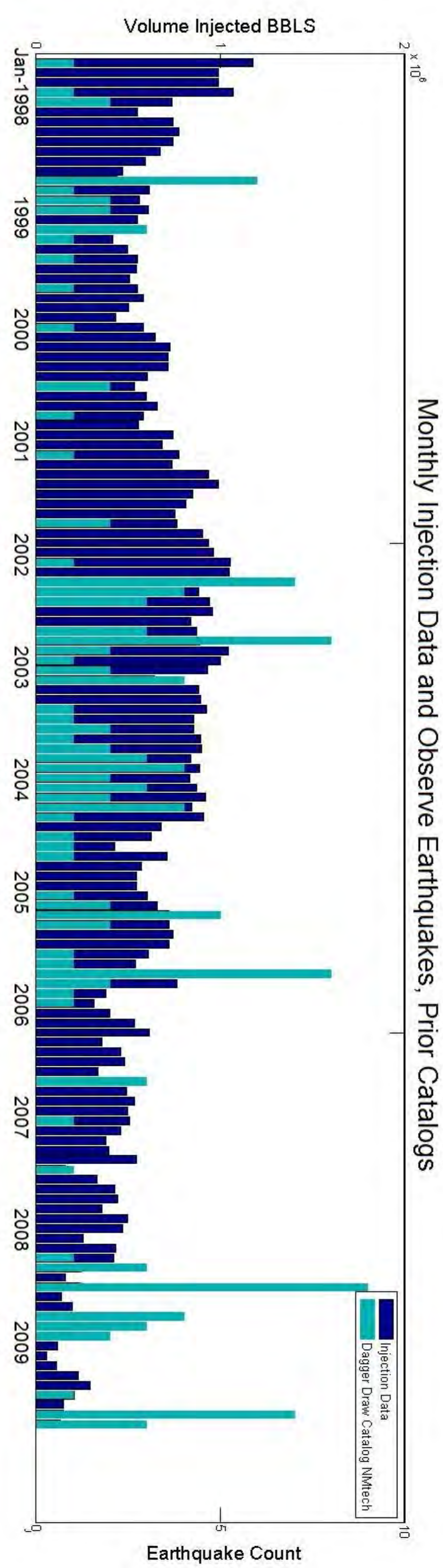
Larger Figures




Monthly Injection Data and Observe Earthquakes, Prior Catalogs
Volume Injected BBLS
x 10^6
Earthquake Count
Injection Data
Dagger Draw Catalog NMtech
Jan-1998
1999
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2002
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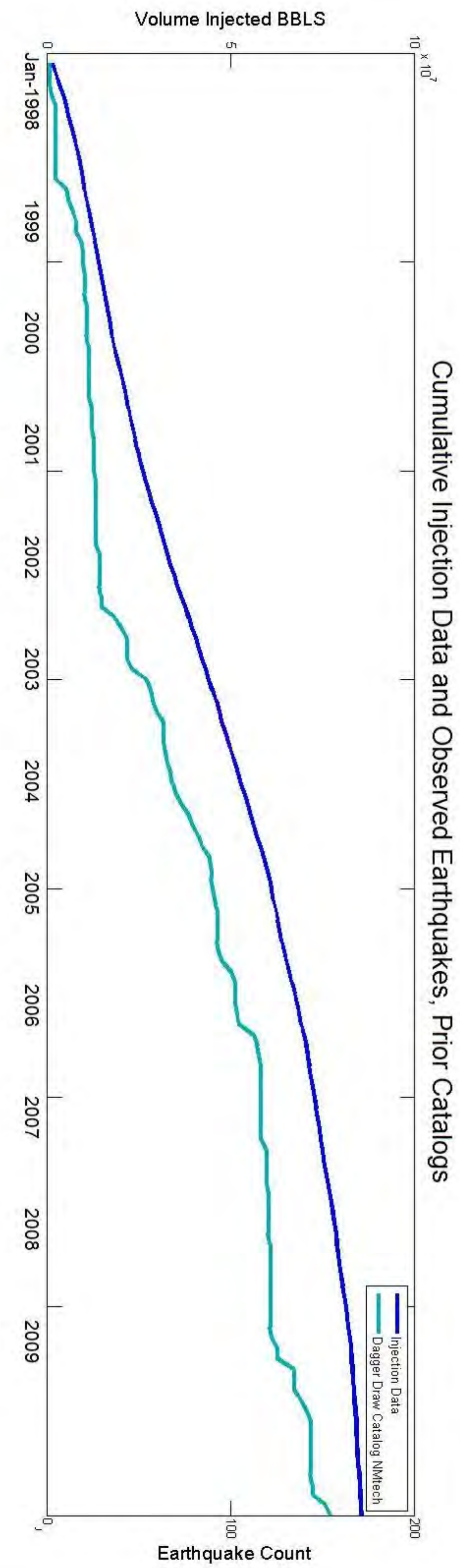
2006
2007
2008
2009


Cumulative Injection Data and Observed Earthquakes, Prior Catalogs
Volume Injected BBLS
x 10^7
Earthquake Count
Injection Data
Dagger Draw Catalog NMtech
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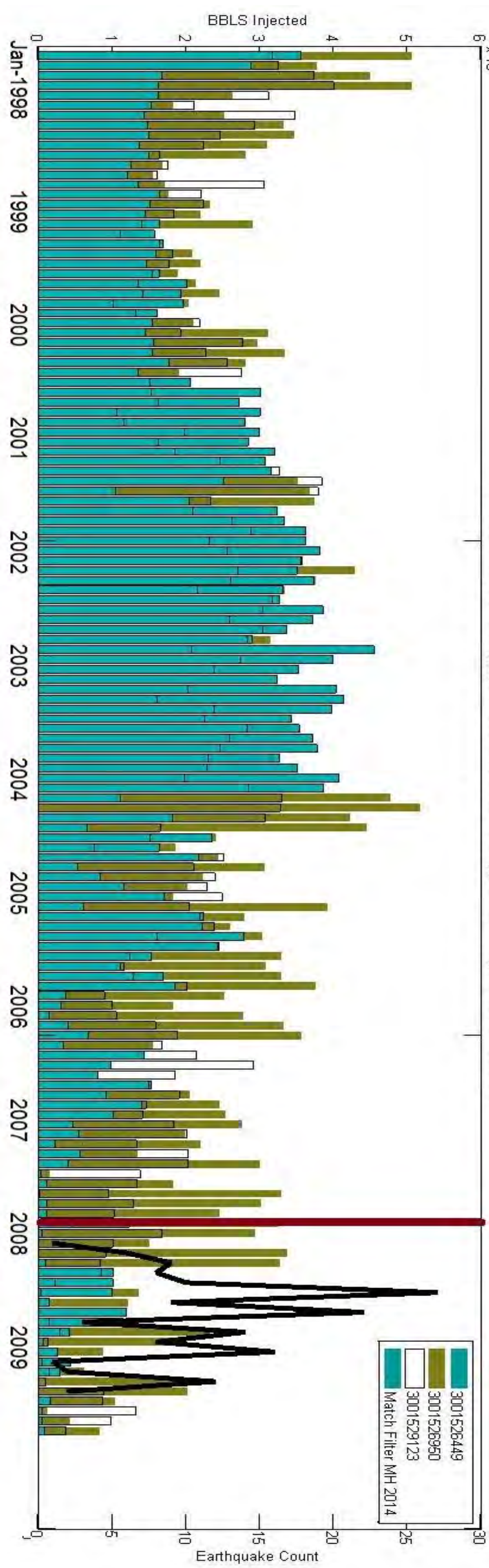
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BBLS Injected
x 10^5
Earthquake Count
Jan-1998
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3001526449
3001526950
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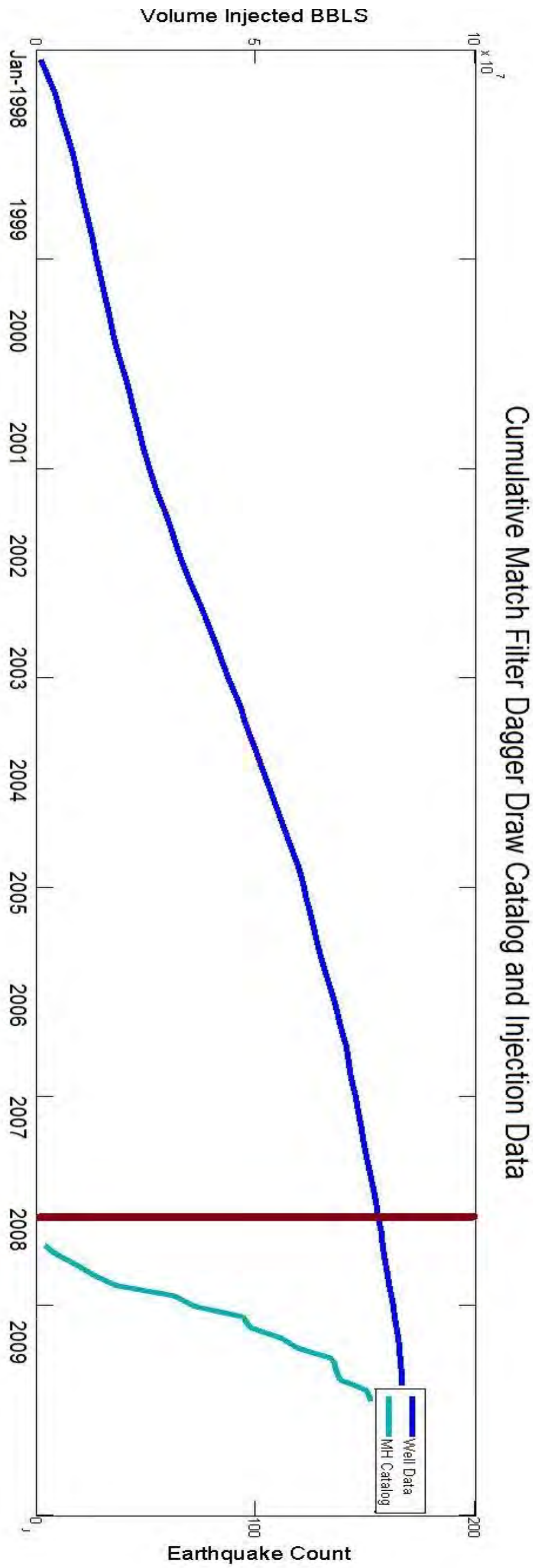
Match Filter MH 2014


Cumulative Match Filter Dagger Draw Catalog and Injection Data
Volume Injected BBLS
x 10^7
Earthquake Count
Jan-1998
1999
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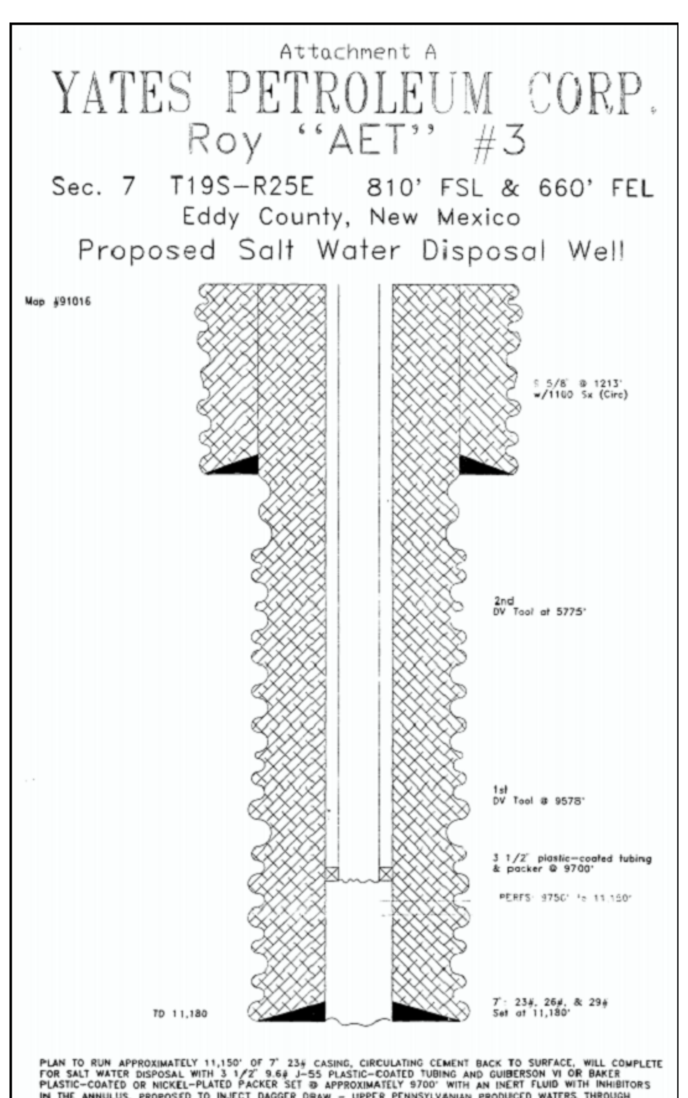
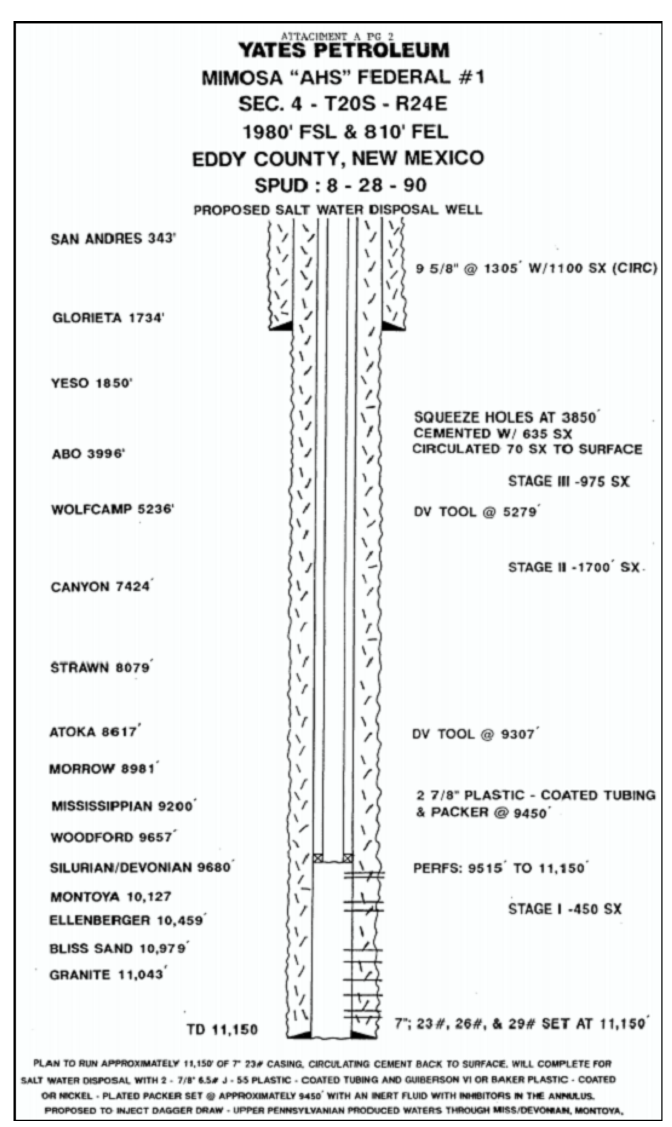
Well Data
MH Catalog

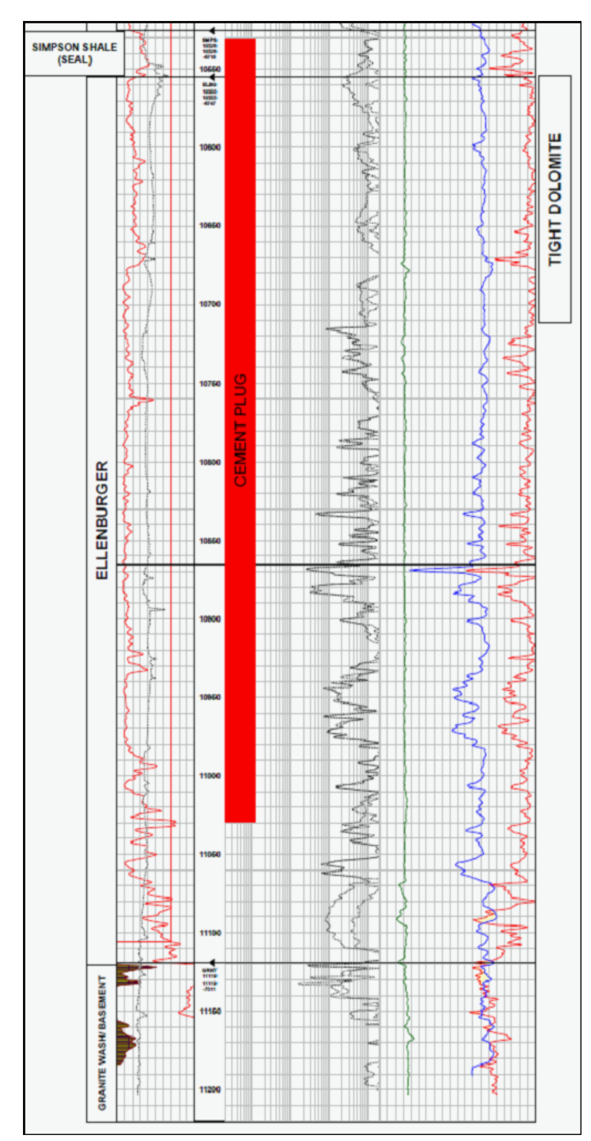
CASES NO. 20313, 20314, 20472, 20463 and 20465 Division Exhibit No. 6-E

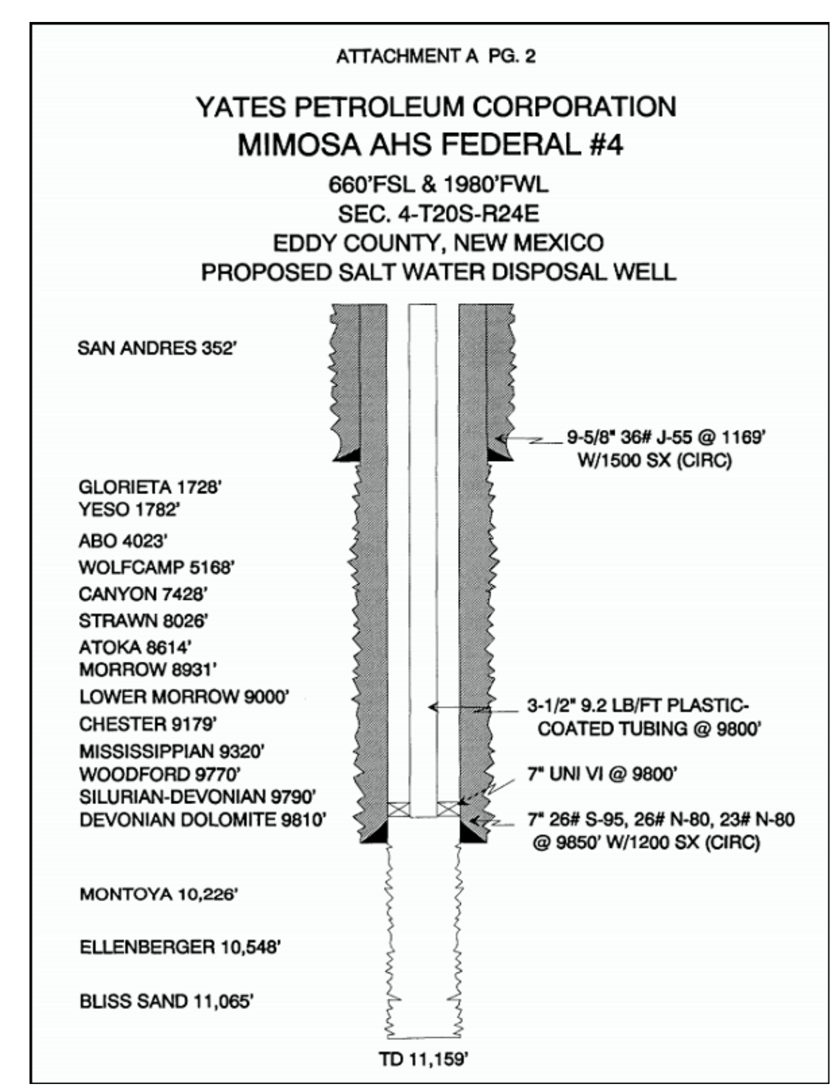
Summary Table of Salt Water Dispoosal Wells in Vicinity of Dagger Draw Field

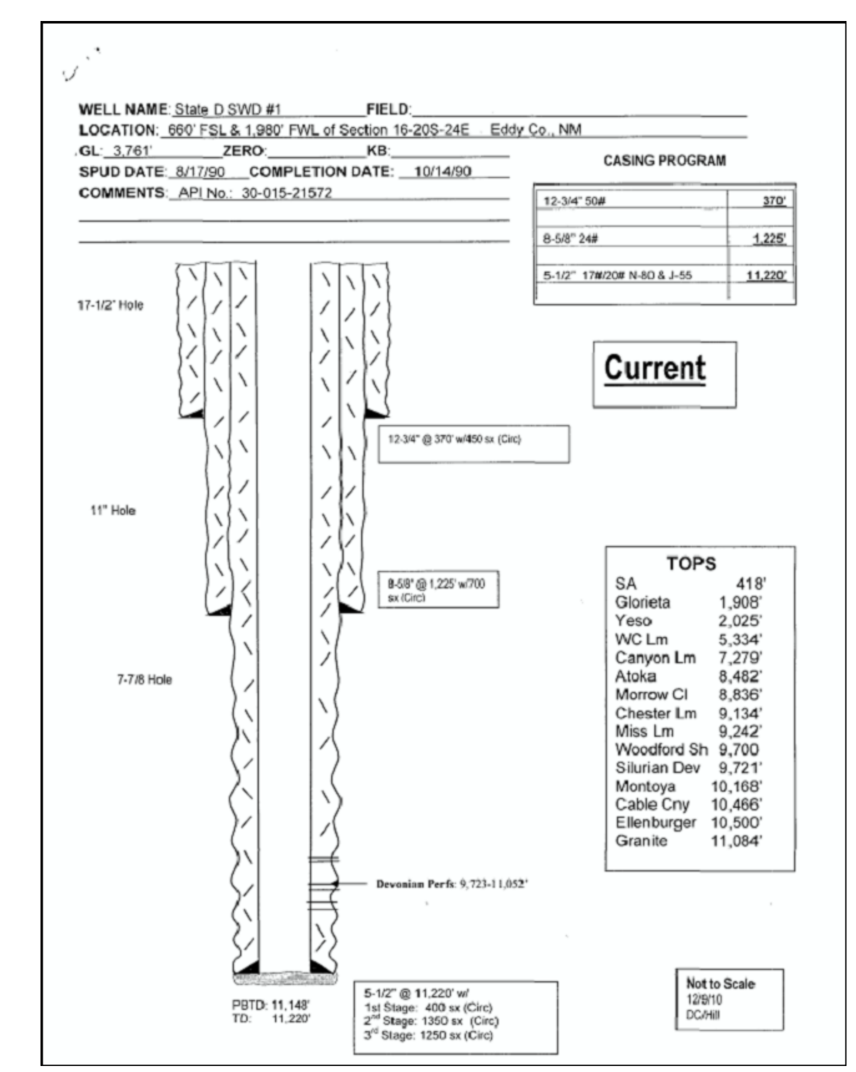
	API	Well Name	Type	Status	UL-Sec -T-R	Injection Authority (Approval Date)	Approved Interval in Order	Completion Comments	Year to Date Cumulative (BW)	Total Injection Prior to 2006 (BW)	Last Monthly Report (BW)	Spud Date
1	30-015-23585	ROUTH DEEP SWD #002	Salt Water Disposal	Active	B-14-19S-24E	SWD-399 (August 29, 1990)	Devonian	9,570'-9,900'; open hole with shoe in Mississippian; unnumbered IPI (November 30, 1993) increase MASIP to 2630 psi.	29,700,142	28,317,078	0	1/13/1981
2	30-015-23315	COTTON MX FEDERAL COM #001	Salt Water Disposal	Active	C-14-19S-25E	SWD-370 (July 18,1989)	Upper Penn	7,680'-8,000'; unnumbered IPI (December 12, 1991) increase MASIP to 2000 psi.				5/16/1980
3	30-015-26562	**ROY SWD #003**	Salt Water Disposal	Active	**P-07-19S-25E**	SWD-437 (August 16, 1991)	**Devonian-Ellenburger**	**9,750'-11,150'; Precambrian at 11,198'; perfs 10,029'-11,110'; unnumbered IPI order increases MASIP to 2600 psi (0.26 psi/ft)**	13,151,689	**12,183,722**	0	4/3/1991
4	30-015-29729	FAIRCHILD 13 SWD #001	Salt Water Disposal	Active	M-13-19S-25E	R-13412 (June 23, 2011)	Canyon	TD at 8,223', plug back to 8,204'				7/25/2011
5	30-015-21045	AIKMAN SWD STATE #001	Salt Water Disposal	Active	N-27-19S-25E	SWD-417 (May 10, 1991)	Devonian	10,300'-10,700'; completed 10,205'-10,520' open hole;	40,398,289	30,661,867	157,941	1/10/1974
6	30-015-29258	MORRIS ARCO 26 #002	Salt Water Disposal	New	B-26-19S-25E	SWD-1731 (August 8, 2018)	Devonian-Silurian	10,200'-10,600'; operator only	21,513	0	1,748	11/19/1996
7	30-015-28992	OSAGE BOYD 15 SWD #001	Salt Water Disposal	Active	F-15-19S-25E	SWD-1717 (March 27, 2018)	Cisco-Canyon	7,640'-7,916'				6/18/1996
8	30-015-27457	ROSS RANCH 22 #001	Salt Water Disposal	Active	L-22-19S-25E	SWD-1843 (December 10, 2018)	Cisco-Canyon	7,615'-8,005'				8/8/1996
9	30-015-25003	DAGGER DRAW SWD #001	Salt Water Disposal	Active	E-22-19S-25E	R-7637 (December 26, 1995) [also R-7637-B]	Cisco-Canyon	7,800'-8,040'				10/9/1984
10	30-015-00087	DONAHUE FEDERAL SWD #001	Salt Water Disposal	Active	E-10-20S-24E	SWD-377 (September 7, 1989)	Abo	4,200'-4,664'				10/24/1956
11	30-015-26449	**MIMOSA FEDERAL SWD #001**	Salt Water Disposal	Active	**I-04-20S-24E**	SWD-408 (January 4, 1991)	**Mississippian, Devonian, Ellenburger**	**9515'-11,150'; granite at 11,043'; perfs 9515' to 11,011'**	38,563,201	**29,254,291**	0	8/28/1990
12	30-015-29123	**MIMOSA FEDERAL SWD #003Y**	Salt Water Disposal	Active	**P-04-20S-24E**	SWD-645 (October 22, 1996)	**Devonian-Ellenburger**	**9,700'-11,300' open hole; plugged back from Cambrian granite in 2016**	38,563,201	**29,571,105**	0	8/3/1996
13	30-015-26950	**MIMOSA FEDERAL SWD #004**	Salt Water Disposal	Active	**N-04-20S-24E**	SWD-474 (May 6, 1992)	**Devonian, Ellenburger, Bliss Sandstone**	**9860'-11,159'; granite at 11,112'; TD at 11159; not plug backed**	52,921,759	**41,645,113**	0	3/3/1992
14	30-015-21572	**STATE D SWD #001**	Salt Water Disposal	Active	**N-16-20S-24E**	SWD-395 [Amended] (September 27, 1990)	**Devonian**	**9,723'-11,052'; perfed same interval; granite at 11,084'; unnumbered IPI order increases MASIP to 2750 psi (0.28 psi/ft)**	36,132,705	**32,380,113**	0	6/26/1975
15	30-015-27465	**INDIAN HILLS STATE COM #007**	Salt Water Disposal	Active	**F-36-20S-24E**	SWD-570 (September 20, 1994)	**Siluro-Devonian**	**10,000'-11,000'; 10,380'-10,885' open hole; Form C-105: Devonian (?) at 10,248' [no logs on record with OCD]**	28,600,245	**25,462,725**	307	3/30/1995
16	30-015-21669	**MOC SWD #001**	Salt Water Disposal	Active	**K-07-20S-25E**	SWD-448 (November 18, 1991)	**Devonian**	**10,200'-11,000'; 10,277'-10,800' open hole; Woodford at 10,225' and Devonian at 10,252' [no logs for deeper well on record with OCD]**	54,446,670	**37,153,413**	8,799	1/28/1992
17	30-015-21141	HOLSTUN SWD #001	Salt Water Disposal	Active	2-04-20S-25E	R-9269 (August 21, 1990)	Devonian	10,274'-10,600' open hole	15,486,563	11,386,538	164,357	6/20/1974
18	30-015-20257	KING SWD #001	Salt Water Disposal	Active	C-09-20S-25E	R-5250 (August 3, 1976)	Devonian	10,300'-10,550; 10,333'-10,555' open hole	18,235,299	10,658,906	0	9/30/1969
19	30-015-28763	TWEEDY 9 SWD #001	Salt Water Disposal	Active	J-09-20S-25E	SWD-1276 (May 1, 2011)	Devonian	10,300'-10,600'; 10,410'-10,600' open hole	7,128,914	0	24,392	7/9/2011
20	30-015-31294	AGI SWD #001	Salt Water Disposal	Active	E-23-21S-23E	SWD-784 [Corrected] (August 17, 2000)	Devonian	650-foot open hole; treat acid gas not injected, water only	60,975,691	33,457,535	35,095	8/28/2000
21	30-015-30701	BUNNELL FEDERAL #003	Salt Water Disposal	Active	J-18-21S-23E	SWD-762 (December 30, 1999)	Devonian	9,500'-10,000'; 500-foot open hole	2,576,291	438,828	0	8/10/1999
22	30-015-10414	ARCHIMEDES SWD #001	Salt Water Disposal	Active	J-18-21S-24E	SWD-814-A [Amended] (February 18, 2003)	Devonian	10,660'-10,800'; casing failure in 2013 with repairs	230,916,612	14,081,936	50	2/3/1964
23	30-015-22717	SHELL FEDERAL #002	Salt Water Disposal	Active	13-05-21S-24E	SWD-1252-A (February 6, 2012)	Devonian	10678'-11450'; 10,622'-11,458' open hole; only Mississippian at 10,188' reported	2,155,629	0	11,902	1/6/2012
24	30-015-30112	ROCKY HILLS SWD #001	Salt Water Disposal	Active	O-19-21S-24E	SWD-692 (February 11, 1998)	Devonian	10,000'-10,800'; 10,240'-10,900' open hole; Form 3160-5: Woodford at 10,158' and Devonian at 10,230' [no logs on record with OCD]	69,753,308	**43,727,506**	0	2/14/1998
25	30-015-30600	ROCKY HILLS SWD #002	Salt Water Disposal	Active	K-20-21S-24E	SWD-738 (March 3, 1999)	Devonian	10,300-11,300'; 10,343'- 11,307' open hole; Form 3160-5: Woodford at 10,288' and Devonian at 10,342'	101,075,384	**70,564,858**	1	3/30/1999
26	30-015-30337	WINSTON SWD #004	Salt Water Disposal	Active	2-31-21S-24E	SWD-723 [Corrected] (February 22, 1999)	Devonian	10,600'-11,400'; 10,200'-11,000' open hole; Form C-105: Woodford at 10,145' and Devonian at 10,203'	38,863,872	21,746,510	0	12/12/1998











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The 2001–Present Induced Earthquake Sequence in the Raton Basin of Northern New Mexico and Southern Colorado

by Justin L. Rubinstein, William L. Ellsworth, Arthur McGarr, and Harley M. Benz

Abstract We investigate the ongoing seismicity in the Raton Basin and find that the deep injection of wastewater from the coal-bed methane field is responsible for inducing the majority of the seismicity since 2001. Many lines of evidence indicate that this earthquake sequence was induced by wastewater injection. First, there was a marked increase in seismicity shortly after major fluid injection began in the Raton Basin in 1999. From 1972 through July 2001, there was one M $\geq$4 earthquake in the Raton Basin, whereas 12 occurred between August 2001 and 2013. The statistical likelihood that such a rate change would occur if earthquakes behaved randomly in time is 3.0%. Moreover, this rate change is limited to the area of industrial activity. Earthquake rates remain low in the surrounding area. Second, the vast majority of the seismicity is within 5 km of active disposal wells and is shallow, ranging between 2 and 8 km depth. The two most carefully studied earthquake sequences in 2001 and 2011 have earthquakes within 2 km of high-volume, high-injection-rate wells. Third, injection wells in the area are commonly very high volume and high rate. Two wells adjacent to the August 2011 **M** 5.3 earthquake injected about 4.9 million cubic meters of wastewater before the earthquake, more than seven times the amount injected at the Rocky Mountain Arsenal well that caused damaging earthquakes near Denver, Colorado, in the 1960s. The August 2011 **M** 5.3 event is the second-largest earthquake to date for which there is clear evidence that the earthquake sequence was induced by fluid injection.

Online Material: Gutenberg–Richter plots for varying decade-long catalogs.

Introduction

Earthquakes induced by deep underground injection of fluids were first recognized in the 1960s during the Rocky Mountain Arsenal earthquake sequence that was induced near Denver, Colorado (Evans, 1966; Healy *et al.*, 1968). As proposed by Hubbert and Rubey (1959), fluid injection can raise pore pressure within nearby fault zones, thus lowering the effective stress and frictional resistance on faults. The lowered frictional resistance makes earthquake slip more likely. Earthquakes can be induced in this way if there is hydraulic communication between the injection interval and a seismogenic fault zone. The injection of fluids causes a pore pressure increase, which is transmitted into a seismogenic fault zone to induce earthquakes, even though the injected fluid itself may not reach the fault. Study of injection-induced earthquakes has been extensive, including a field experiment in earthquake control (Raleigh *et al.*, 1976). This experiment demonstrated that fluid pressure controlled the rate of earthquake occurrence in part of the Rangely Oil Field in northwestern Colorado. Raleigh *et al.* (1976) found that when they increased the pressure within a portion of the field, earthquake rates increased; and, when it was decreased, the earthquake rate dropped. This was the first demonstration of controlling earthquakes by adjusting pore pressure at depth.

Since these studies in the 1960s and 1970s, many other earthquakes have been identified as having been induced by fluid injection, including earthquakes in Ashtabula, Ohio (Seeber and Armbruster, 1993; Seeber *et al.*, 2004), Dallas–Fort Worth, Texas (Frohlich *et al.*, 2011), and El Dorado, Arkansas (Cox, 1991). There was a recent spate of earthquakes believed to be induced, including the 2011 M 5.7 Prague, Oklahoma, earthquake (Keranen *et al.*, 2013; Llenos and Michael, 2013; Sumy *et al.*, 2014), the 2011 M 4.0 Youngstown, Ohio, earthquake (Kim, 2013), the Paradox Valley, Colorado, earthquakes (M_{max} 4.4; Block *et al.*, 2014), and the 2011 Guy–Greenbrier, Arkansas, earthquake sequence (M_{max} 4.7; Horton, 2012). These are part of a larger trend of increased seismicity in the central and eastern United States since 2001, much of which is believed to be induced by wastewater injection (Ellsworth, 2013). All of these earthquakes occurred in areas with little or no previous seismicity, and, assuming that they are induced, this indicates that earthquake hazard needs to be reassessed in these areas as well as other areas where wastewater is injected.

It is often difficult to determine with certainty whether a specific earthquake was induced or not. Many kinds of data are needed to describe the physical state of the focal volume; for example, initial stress state, location and static strength of faults, hydrogeologic structure, fluid injection volumes, injection rates, injection pressures, and precise earthquake locations. Without these kinds of data, it is very difficult to determine whether earthquakes are induced or natural. Seismologists are often left looking for correlations in time and space between injection activities and earthquakes. To deal with this problem, Davis and Frohlich (1993) offered a set of seven criteria that help to determine whether or not earthquakes are induced. They were intended as guidance to help determine whether earthquakes were induced and not as a decision tool. Although these criteria provide a good framework, the lack of data may preclude answering one or more of the questions, thus limiting the utility of the criteria. Additionally, studies of induced earthquakes in the past 20 years have shown that these criteria can be too restrictive, such that some clearly induced earthquakes would show attributes inconsistent with an affirmative answer to some of the Davis and Frohlich (1993) criteria.

In this work, we focus on an extended earthquake sequence in the Raton Basin of southern Colorado and northern New Mexico (Fig. 1). Historical and instrumental data show that the Raton Basin had a low level of seismic activity until August 2001. This changed with an earthquake sequence that started in August 2001, followed by increased seismicity in the vicinity of the initial sequence that has continued to the present. This includes an **M** 5.3 earthquake that occurred on 23 August 2011.

Here, we address the question of whether this earthquake sequence is related to wastewater injection and find multiple lines of evidence supporting this hypothesis. To evaluate this, we first examine the industrial activities and seismicity of the broader region and explore the relationship between them. Statistical analysis of the earthquake rate change that occurred in 2001 indicates that it is highly unlikely the rate change could arise from random fluctuations of the ambient seismicity, given a constant background rate. These earthquakes are limited to the area of fluid injection, they occur shortly after major fluid injection activities began, and the earthquake rates track the fluid injection rates in the Raton Basin. We also examine earthquake sequences in 2001 and 2011 in detail. These sequences lie very close (≤2 km) to high-volume, high-injection-rate wells, which shows that these sequences, specifically, were induced by nearby wastewater injection.

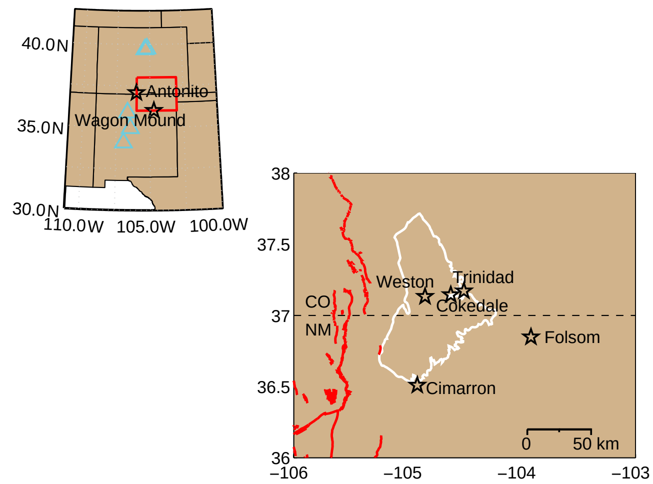

Figure 1. Generalized map of the Raton Basin. The box in the regional map (upper left) indicates the area shown in enlarged view to the right. Triangles indicate the locations of permanent seismic stations that recorded more than five earthquakes prior to 2001. Stars are locations of towns discussed in the text. (Right) Map zoomed in to show: outline of the Raton Basin (solid, white line) and the Colorado–New Mexico state line (dashed line). Faults known to be active in the quaternary are indicated with solid lines (USGS Quaternary Fault and Fold Database; see Data and Resources). The color version of this figure is available only in the electronic edition.

Regional Tectonics and Deformation

The Raton Basin is a coal-bearing sedimentary basin situated along the Colorado–New Mexico border, between the western edge of the Great Plains to the east and the Sangre de Cristo Range and Rio Grande rift to the west. It is approximately 150 km long (north–south) and 75 km wide at its maximum. On a regional scale, the Raton Basin lies within a broad crustal zone of east–west extension astride the Rio Grande rift (Heidbach *et al.*, 2008; Berglund *et al.*, 2012).

Geologic mapping within the Raton Basin reveals little evidence for faulting. Maps commonly show that the basin is bounded by thrust faults on the western edge of the basin and a west-dipping normal fault striking northwest that runs the length of the eastern side of the basin (Fig. 1). In addition to the basin-bounding faults identified by many maps, one map also identifies faults lying within the basin (Robson and Banta, 1987). This map includes two normal faults striking to the northeast within the southeastern portion of the Colorado side of the basin. These faults are believed to be buried in the Precambrian basement and are not seen to outcrop within the Raton formation, which lies at the surface above these mapped faults (upper Cretaceous/lower Paleocene). We could not identify any seismicity associated with these faults. They are also not found within the U.S. Geological Survey (USGS) Quaternary Fault and Fold Database (see Data and Resources), so we do not believe them to be active. The closest faults that are known to be active within the Quaternary Period are west of the basin in the Rio Grande Rift (Fig. 1).

Industrial Activities in the Raton Basin

Coal mining began in the Raton Basin in 1862 and continued through 2002, although production greatly decreased in the early 1960s. In 1994, energy companies began producing coal-bed methane from the same formations. Methane production was initially in the Colorado portion of the basin and expanded to New Mexico in 1999. The production formations are the Raton, Vermejo, and Trinidad formations, with production wells typically drilled to the top of the underlying Pierre formation, which ranges from 200 to 800 m depth.

Along with methane, there is considerable formation water produced at the same time. Some of this formation water is injected deep underground for disposal. Wastewater injection in Colorado began in 1994, expanding into New Mexico in 1999 and is primarily in the Dakota formation, a buff, conglomeratic sandstone (Johnson, 1969), with injection intervals ranging between 1250 and 2100 m below the ground surface, depending on location in the Raton Basin (Colorado Oil and Gas Information System [COGIS]; see Data and Resources).

The Dakota formation has a large lateral extent. The closest outcrops of the Dakota formation to the Raton Basin are 40 km north of Trinidad and 5 km south of the southwestern limit of the Raton Basin (Johnson, 1969; New Mexico Bureau of Mines and Mineral Resources, 2003). East–west hydraulic continuity in the Dakota formation is believed to be on the order of 80 km in the Raton Basin, with the exception of the northwestern portion of the basin, which appears to be hydrologically isolated (Nelson *et al.*, 2013). There are no disposal wells in the northwestern portion of the basin because the produced formation water there meets water-quality standards for surface discharge.

Many of the hydrologic units within the Raton Basin are underpressured, including the Dakota sandstone (Johnson and Finn, 2001; Nelson *et al.*, 2013). On average, the hydraulic head within the Dakota unit lies approximately 500 m below the surface, which is approximately 4.9 MPa underpressured (Nelson *et al.*, 2013). Because the Dakota unit is underpressured, injection throughout much of the Colorado portion of the Raton Basin can be done with gravity feed (D. Onyskiw, personal comm., 2012). Of 21 injection wells in the Colorado portion, only 5 have ever injected under pressure, 2 of which have been operating under gravity feed since 2005. In the case of gravity feed, even when there is no injection pressure, the weight of the water column in the well bore still causes a stress change at depth. This is not the only source of stress changes due to fluid injection. Other sources of stress change come from the redistribution of fluids at depth upon injection and poroelastic effects whereby the medium is forced to accommodate the injected fluids. Information on injection pressures on the New Mexico side of the basin indicates that the wells have always injected under gravity feed.

The Dakota sandstone lies anywhere between 800 and 1400 m below the bottom of the Trinidad formation (the lower production unit; Johnson and Finn, 2001). Given that both the production and injection formations are believed to be hydrologically isolated from adjacent geologic units (Nelson *et al.*, 2013), we expect little or no hydrologic communication between them. Likewise, without a fluid pathway (e.g., a fault), we would expect little communication between the injection formation (Dakota) and underlying geology. This includes the Precambrian basement, where the majority of the earthquakes have occurred. Between the Dakota hydrologic unit and the basement, there is a Jurassic hydrologic group that is primarily sandstones, below which is a Permian–Pennsylvanian hydrologic unit composed of limestones, sandstones, and shales (Geldon, 1989). This is underlain by Miocene metamorphics and volcanics, which lie on top of the Precambrian basement. Given the numerous seals between these hydrologic units, communicating hydraulic pressures to depth would require a connecting fluid pathway, like a fault.

Table 1
Injection Wells in the Colorado Portion of the Raton Basin

Well Name	Latitude (°)	Longitude (°)	Start of Injection (yyyy/mm)
Apache Canyon 10	37.10	−104.99	1995/01
Apache Canyon 19	37.07	−104.93	1995/01
Beardon	37.25	−104.66	2001/01
Cimarron	37.26	−104.93	2005/03
Cottontail Pass	37.22	−104.78	1994/11
Del Aqua	37.28	−104.74	2005/07
Ferminia	37.29	−104.83	2007/09
Hill Ranch	37.09	−104.74	2005/07
Jarosa	37.30	−104.78	2007/05
La Garita	37.16	−104.80	2001/08
Long Canyon	37.10	−104.62	2001/04
Lopez Canyon	37.15	−104.89	2010/09
PCW	37.12	−104.68	1997/07
Polly	37.23	−104.70	2009/07
Sawtooth	37.20	−104.67	2000/04
Southpaw	37.30	−104.73	2009/04
VPRC 14	37.02	−104.78	1999/09
VPRC 204	37.02	−104.83	2012/03
VPRC 39	37.02	−104.78	2000/05
Weston	37.15	−104.86	2004/01
Wild Boar	37.13	−104.70	2000/08

Wastewater Injection in Colorado

The Colorado Oil and Gas Conservation Commission (COGCC) regulates wastewater injection wells in Colorado and maintains the COGIS online database with all the records for these wells. Wastewater injection began in the Raton Basin in November 1994 at the Cottontail Pass well in Colorado (Table 1). Two months later, in January 1995, two additional injection wells came online: Apache Canyon 10 and Apache Canyon 19. The field rapidly expanded from 1997 to 2001, with eight additional injection wells coming online. Six of these wells are located in the eastern portion of the production field. Since 2001, 10 more injection wells have opened, giving a total of 21 presently active injection wells in the Colorado portion of the Raton Basin.

Prior to the rapid expansion of production and injection activities in the Colorado portion of the Raton Basin (in mid-

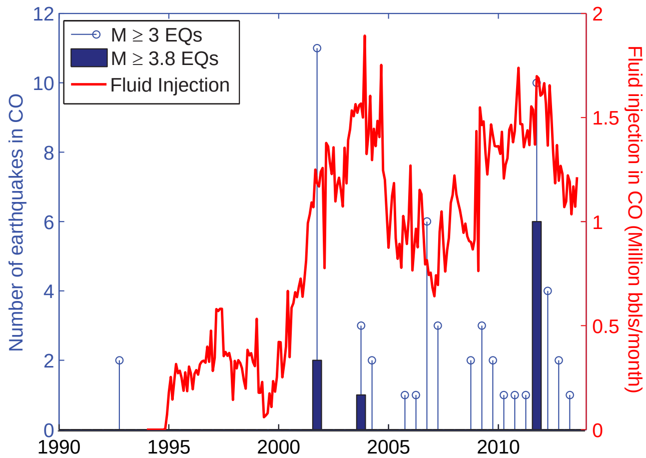

Figure 2. Number of earthquakes per six months (stem and bar graph) and monthly injection rates in the Colorado portion of the Raton Basin (line). The increase in earthquake rate appears to occur shortly after there is a large increase in injection rates. The earthquake catalog is complete for earthquakes M 3.8 and larger. The color version of this figure is available only in the electronic edition.

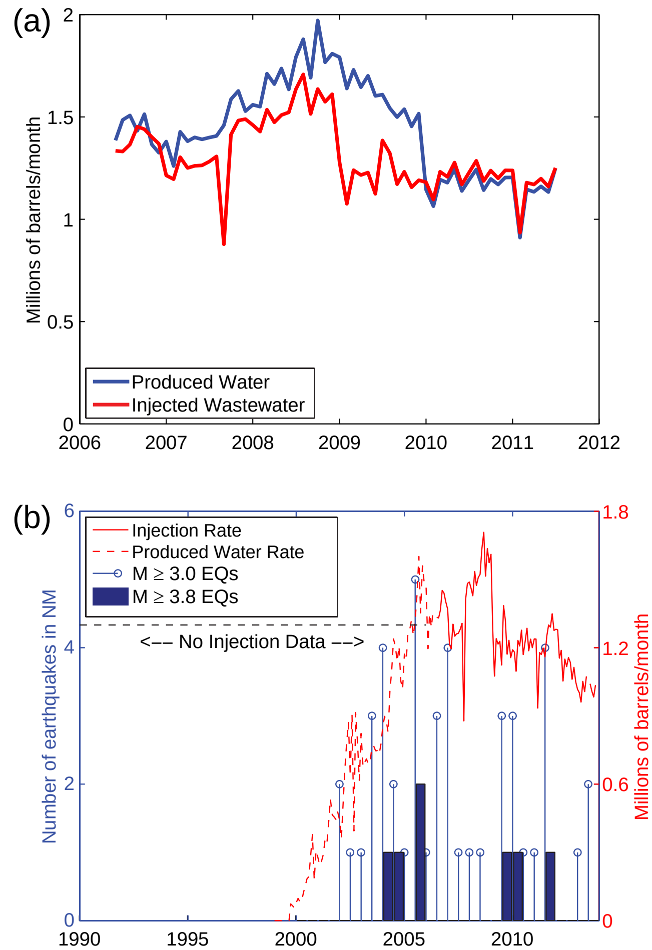

Figure 3. (a) Water production and wastewater injection in New Mexico. Monthly wastewater injection rates and produced-water rates follow each other reasonably well for much of this time period, but differences can be as large as 580,000 barrels in an individual month. It is unclear why at some points the rates match each other very well and other times there are large differences. (b) Number of earthquakes per six months (bars/stems) and monthly injection rates in the New Mexico portion of the Raton Basin (line). The earthquake catalog is complete for earthquakes $M \geq 3.8$. One can see that the earthquakes start shortly after injection rates increase. No information is available on injection in New Mexico before June 2006, so produced-water data is used as a proxy. The color version of this figure is available only in the electronic edition.

2000), injection rates remained under 600,000 barrels/month (Fig. 2). These rates began to rise with the expansion of the field; and, since mid-2000, monthly injection rates have ranged between 600,000 and 1.9 million barrels/month. With increasing production, there has been a corresponding increase in the number of disposal wells in the area.

Because barrels are the standard measure of volume used within the oil and gas industry, we have elected to use barrels as the measure of volume in this article instead of the metric measure of cubic meters. For reference, there are approximately 6.29 barrels/m^3.

Wastewater Injection in New Mexico

In New Mexico, the Oil Conservation Division of the Energy Minerals and Natural Resources Department regulates wastewater injection wells and maintains an online database with records pertaining to wastewater injection wells.

Injection data prior to June 2006 are unavailable for New Mexico. We are able to get a field-wide sense of injection prior to June 2006 by using produced-water data as a proxy for injection, but associating injection rates and total volumes with individual wells is not possible. The production records for the Raton Basin in New Mexico extend back to the beginning of production in the Raton Basin in 1999, and these data include produced-water rates. We believe that water production is an appropriate proxy for injection for two reasons: (1) for the period when both injection and production values are available, the totals match each other fairly well (Fig. 3a); (2) essentially 100% of all produced water is injected in this area by requirement of the landowner (personal comm. with a local operator, 2012). Based on well permitting and drilling information, there was an apparent lag between the initiation of production and the initiation of injection in the New Mexico portion of the basin. The first injection well that was completed was VPRA042, with a completion date of May 2000. It is unclear what happened to the water prior to the completion of this well, but certainly production rates prior to this are not an appropriate proxy for injection rates in the New Mexico portion of the Raton Basin. Given that these rates are quite small, we do not expect it to strongly influence later analysis.

Injection rates in New Mexico, inferred from produced-water rates, slowly climbed from the start of injection in 1999 until early 2004 when rates began to level off (Fig. 3). Since

2004, the median injection rates have been approximately 1.2 million barrels/month.

Seismicity of the Raton Basin

Here, we discuss the seismicity of the Raton Basin in a broader context. A more detailed discussion of the earthquake sequences that began in August 2001 and August 2011 is provided below in the Case Study: The August–September 2001 Earthquake Sequence and Case Study: The August–September 2011 Earthquake Sequence sections.

Historical Seismicity

To provide historical context, we review the historical seismicity for a broad region centered on the Raton Basin. We define this region as between 103° and 106° W longitude and 36° and 38° N latitude (Fig. 1).

Our review of the earthquake history of the region relies on sources published in the scientific literature (Northrop and Sanford, 1972; Stover and Coffman, 1994; Kirkham and Rogers, 2000; Sanford *et al.*, 2002) and annual summaries (see Data and Resources) of U.S. seismicity (U.S. earthquakes) published by the Department of Commerce and covering the years from 1928 through 1975. Studies of earthquakes in the preinstrumental period commonly rely heavily on newspapers and other written accounts. Settlements in the Colorado portion (Fig. 1) of the basin include the towns of Weston (founded in the late nineteenth century) and Cokedale (founded in 1906). There are no towns in the New Mexico portion of the basin where coal-bed methane is being produced today.

Our search of historical reports through 1970 did not identify any earthquakes that could be associated with the Raton Basin. Given that *The Chronicle-News* (based in Trinidad, Colorado, 10 km east of the coal-bed methane field) has been in continuous publication since 1877 and that the 10 August 2005 **M** 5.0 earthquake was widely felt at modified Mercalli intensity (MMI) IV in Trinidad (USGS “Did You Feel It?” system; see Data and Resources), we expect historic accounts to be complete throughout the Raton Basin at M ≥ 5.0 since 1877.

The earliest reported earthquake in this general region occurred on 14 June 1878 and was reported to have broken windows at Cimarron, New Mexico (Stover and Coffman, 1994). An earthquake with a maximum reported MMI of V occurred on 13 August 1924, about 20 km east of Wagon Mound, New Mexico (Northrop and Sanford, 1972). On 12 July 1936, an earthquake with a magnitude of 3.4 occurred near the New Mexico–Oklahoma border (Neuman, 1938). An MMI V earthquake was felt near Cimarron, New Mexico, on 4 August 1952 (Murphy and Cloud, 1952). Later that year (7 October 1952), an earthquake with MMI V occurred, with strongest intensities observed at Antonito, Colorado (Murphy and Cloud, 1952; Kirkham and Rogers, 2000). Locations of these towns are shown in Figure 1.

Spatiotemporal Evolution of Instrumentally Recorded Seismicity

For the purposes of examining the instrumentally recorded seismicity, we narrow our study region so it contains little more than the Raton Basin. We nominally select a box with the following bounds: 36.7° N to the south, 37.6° N to the north, 105.2° W to the west, and 104.4° W to the east. This covers the boundaries of the Raton Basin fairly well, only omitting small portions of the basin at its edges (Fig. 4). This region extends 20 km or more beyond every injection well in the area, so it is an appropriate size to examine the relationship between earthquakes and wastewater injection wells.

The earthquake catalog is primarily composed of earthquakes listed in the Advanced National Seismic System (ANSS) Comprehensive Catalog (ComCat; see Data and Resources). ComCat contains earthquake hypocenters, magnitudes, phase picks, moment tensor solutions, macroseismic information, tectonic summaries, and maps, which are produced by contributing seismic networks. ComCat replaces the ANSS composite catalog. This catalog is supplemented by catalogs from the *International Seismological Centre* (*ISC*) *Bulletin*, the Los Alamos Scientific Laboratory seismic array (1973–1984), a catalog produced by Meremonte *et al.* (2002) to study the August 2001 earthquake sequence, and a catalog we prepared for this study that examines the August 2011 earthquake sequence. Earthquake locations in the ComCat, *ISC Bulletin*, and the Meremonte *et al.* (2002) catalogs have been refined using an updated velocity model. Further details on the location methodologies can be found in Appendix A. Analysis of the complete catalog indicates a magnitude of completeness of M_c 3.8 from 1970 to present (Appendix B).

Before August 2001, seismicity in the Raton Basin was widely distributed and infrequent (Fig. 4a). Seismicity was primarily found near the northeastern margin of the basin. Additional seismicity could also be seen outside the basin to the northeast and to the west.

Since 2001, the behavior of seismicity in the Raton Basin has changed significantly. Earthquakes are far more frequent than they were in the preceding 30 years. Sixteen M ≥ 3.8 earthquakes occurred in the period August 2001–2013, as opposed to one in the preceding 31 years and 7 months. This represents a 40-fold increase in earthquake rate, from 0.032 earthquakes/year to 1.27 earthquakes/year (Fig. 5). The spatial distribution of the seismicity also changed in 2001. Most of the recent seismicity is concentrated near the center of the Raton Basin, whereas earlier seismicity was located on the periphery of or outside the basin (Fig. 4).

Notable Earthquakes and Earthquake Sequences

Three notable earthquake sequences have occurred since August 2001: the August–September 2001 earthquake sequence; the August–September 2005 earthquake sequence that included an **M** 5.0 event; and the August–September 2011 earthquake sequence that included the largest recorded earthquake in the area, the 23 August 2011 **M** 5.3 earthquake. All

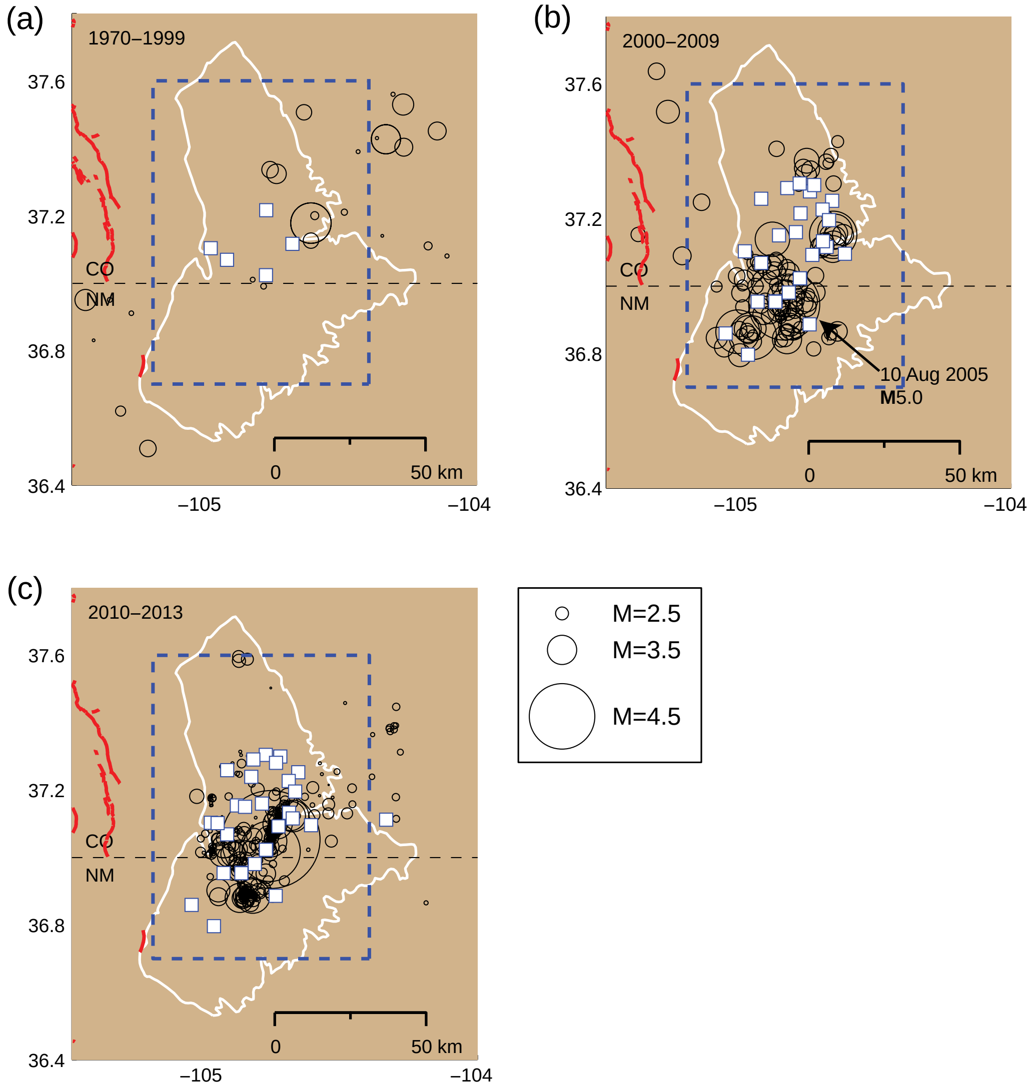

Figure 4. Seismicity in the Raton Basin. Circle size indicates magnitude of the earthquakes. Locations are of varying quality, depending on whether there was a temporary network installed. This figure includes all earthquakes detected. White boxes are the locations of wastewater injection wells that were active in the time period shown. White solid line indicates the boundaries of the Raton Basin. Thick, dark lines are faults with known quaternary activity (USGS Quaternary Fault and Fold Database; see Data and Resources). The dashed boxes indicate the area used to study earthquake rates (a) 1970–1999 seismicity, (b) 2000s seismicity, (c) 2010–2013 seismicity. The 10 August 2005 **M** 5.0 earthquake is indicated in (b) with an arrow. The M 4.1 is the next largest circle and is entirely within the **M** 5.0 earthquake's circle. The color version of this figure is available only in the electronic edition.

of these sequences are located near the center of the Raton Basin (Figs. 4, 6, and 7).

The 2001 earthquake sequence occurred in the Colorado portion of the basin and included an M_{bLg} 4.0 event that occurred on 4 September 2001 and an M_{bLg} 4.5 event that occurred on 5 September 2001. This earthquake sequence marks the beginning of a higher seismicity rate in the Raton Basin. To better understand these events, the USGS responded by deploying a 12-station temporary seismic network. From precise hypocenter locations, Meremonte *et al.* (2002) identified a plane of seismicity striking to the northeast and dipping steeply to the southeast (approximately N37°E). Our relocations are consistent with this finding (Fig. 6). Focal mechanisms of the two largest earthquakes in this sequence indicate east–west extension, although the inferred fault planes do not dip as steeply as the plane imaged by the well-located hypocenters (Fig. 8). Generally, this evidence is consistent with the regional extensional tectonics (Heidbach *et al.*, 2008; Berglund *et al.*, 2012). More details about this earthquake sequence can be found in the Case Study: The August–September 2001 Earthquake Sequence section.

The 2005 earthquake sequence includes the second-largest instrumentally recorded earthquake in the Raton Basin, the 10 August 2005 **M** 5.0 earthquake (Fig. 4b). This earthquake sequence was located in the New Mexico portion of the basin, about 10 km south of the state line. No temporary instruments were deployed at this time, limiting station coverage to permanent stations (of which there were nine stations

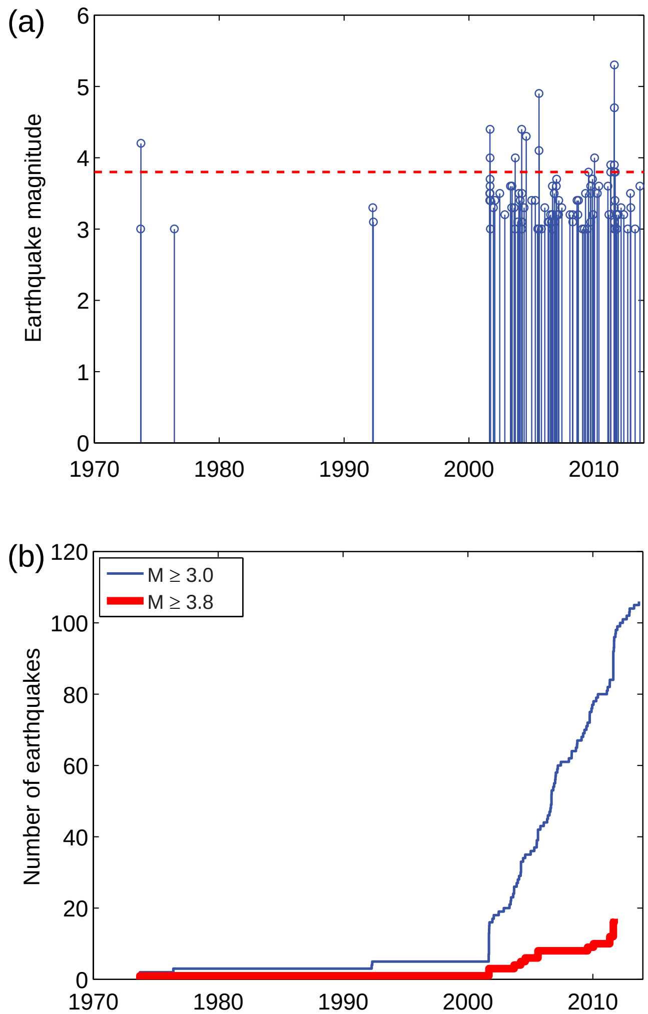

Figure 5. (a) Time progression of earthquakes in the Raton Basin. Dashed line indicates the earthquake detection threshold for the Raton Basin over the entire study period. (b) Cumulative number of earthquakes in the Raton Basin. This shows a large increase in M ≥3 and M ≥3.8 earthquakes occurring in August 2001. The station distribution in the area did not change significantly in the area from 1970 to 2008, so we do not anticipate that the reason there are more M 3 earthquakes arises from improved detection capabilities. The color version of this figure is available only in the electronic edition.

within 200 km) and a maximum azimuthal gap of 146°, using stations up to 350 km from the event. There is no apparent structure to the seismicity in this earthquake sequence, probably owing to earthquake locations with uncertainties of about 15 km or more. An M_b 4.1 foreshock occurred 6 s before the mainshock, and an M_L 3.0 aftershock occurred 16 min later. There were no other M ≥3 earthquakes within one month of these earthquakes. The magnitude of completeness is $M_c = 3.0$ (Appendix B). The moment tensor for the mainshock indicates normal faulting on a nodal plane striking north–south (Fig. 8). As already noted, this is consistent with the regional east–west extension (Heidbach *et al.*, 2008; Berglund *et al.*, 2012).

The 2011 earthquake sequence began on August 21 and included an **M** 4.6 earthquake on August 22, which was followed by the **M** 5.3 mainshock 6 hr later on 23 August. The largest aftershock was an **M** 4.0 earthquake that occurred later in the day on 23 August. The 2011 earthquake sequence immediately abuts the 2001 earthquake sequence, extending to the southwest, with virtually no spatial overlap between the epicenters of the 2001 and 2011 sequences (Fig. 7a). Like the 2001 sequence, the epicenters form a steeply dipping tabular structure striking northeastward. As with the August 2001 and August 2005 sequences, mainshock focal mechanisms are consistent with normal faulting on northeast-striking structures (Fig. 8). The USGS responded to the earthquake sequence by deploying a four-station temporary seismic network to record the aftershocks. An extended discussion of this earthquake sequence can be found in the Case Study: The August–September 2011 Earthquake Sequence section.

The Relationship between Fluid Production and Seismicity in the Raton Basin

We do not believe that the production of gas or water is directly related to the earthquakes in the Raton Basin. Given that the oil production in the area is minimal, and water is far heavier than natural gas, the extraction of water will have the largest stress effect. Examining the Colorado portion of the basin through June 2012, we find that the maximum amount of produced water in 2012 in a 5 km × 5 km square (25 km^2) within 20 km of the 2011 earthquake sequence was approximately 66 million barrels, or approximately 10 million cubic meters. Assuming the production is uniform across the 25 km^2, this would give a withdrawal of approximately 40 cm of fluid across the area, which is equivalent to a 4 kPa stress change. Because fluid withdrawal is likely to be uneven, we consider a factor of 5 uncertainty in the stress change, giving a 20 kPa stress change, which is of the same order of magnitude as the minimum threshold for natural earthquake triggering.

Studies of static stress triggered earthquakes typically only see earthquakes triggered at static stresses of 10 kPa or more (Hardebeck *et al.*, 1998), although Ziv and Rubin (2000) saw triggering at smaller stresses given specific criteria. Earthquakes dynamically triggered by the passage of teleseismic waves are typically triggered at 30 kPa or greater (Gomberg and Johnson, 2005), but triggering stresses have been seen to be as small as 5 kPa in areas particularly susceptible to earthquake triggering (Brodsky and Prejean, 2005). Because the stress changes from the production of water are at the lower end of stresses where earthquakes are triggered by natural processes (i.e., earthquakes are not triggered in the vast majority of locations experiencing these stress changes), we find it unlikely that fluid production contributes to the occurrence of the earthquakes in the Raton Basin. Additionally, the maximum stress change that we observe is located 15–20 km to the northwest of the seismicity in the 2011 sequence.

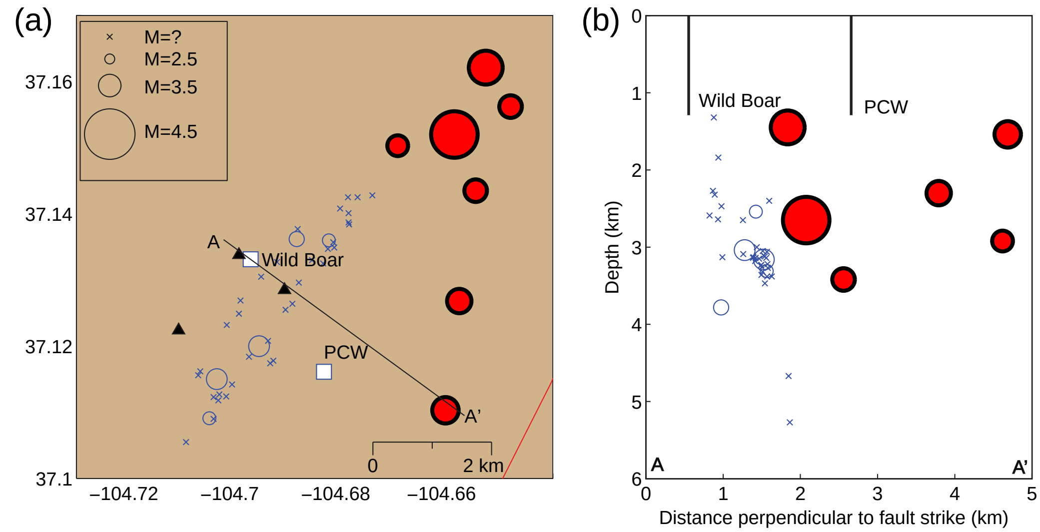

Figure 6. (a) Map and (b) cross section of the seismicity in the August–September 2001 earthquake sequence. Circle size is indicative of earthquake magnitude. Earthquakes where no magnitude was computed are indicated with "'×". Filled circles are earthquakes that occurred prior to the installation of the temporary seismic network and have absolute location uncertainties on the order of ±15 km. Unfilled circles are events located with the temporary network and have location uncertainties of ±200 m. Triangles are locations of temporary network stations. Squares are the locations of injection wells that were active in 2001. Fault strike is determined under the assumption that the earthquakes define the fault, and a line is then fit to the seismicity. The line in the lower right corner is a small piece of a fault mapped by Robson and Banta (1987). The full fault can be seen most clearly in Figure 7a running from the words Wild Boar to VPRC 14/39. No faults with known Quaternary slip are found in this area (USGS Quaternary Fault and Fold Database; see Data and Resources). One of the larger events seen in (a) is not visible in (b) because it lies below 6 km. The color version of this figure is available only in the electronic edition.

The Relationship between Wastewater Injection and Seismicity in the Raton Basin

Following the August–September 2001 earthquake sequence, there have been questions regarding whether the seismicity in the Raton Basin is related to the wastewater injection in the area. Meremonte *et al.* (2002) considered this question for the August–September 2001 earthquake sequence. Meremonte *et al.* (2002) applied the criteria proposed by Davis and Frohlich (1993) to this earthquake sequence but were equivocal as to whether the earthquake sequence was related to the wastewater injection in the region. It is worth noting, however, that Meremonte *et al.* (2002) stated that if the earthquake sequence were natural, they would expect the seismicity to tail off and return to the lower background seismicity rate. Instead, the seismicity rate in the Raton Basin has continued at a much higher rate than the pre-2001 period. In this section, we examine the seismicity in the Raton Basin in its entirety with respect to wastewater injection activities across the Raton Basin. We find strong evidence that this earthquake sequence is induced by fluid injection in the area.

Statistical Analysis of the Seismicity Rate

Beginning in August 2001, earthquakes have become much more frequent in the Raton Basin. There has been a 40-fold increase in the rate of $M \geq 3.8$ earthquakes since August 2001 (1 earthquake 1970–July 2001 versus 16 earthquakes August 2001–2013; Table 2). In this section, we examine the likelihood that the change in earthquake rate that we observe could occur as a random fluctuation in earthquake rate given a constant, long-term background rate of seismicity (i.e., earthquake occurrence follows a uniform Poisson process).

Although we are confident that the catalog is complete for earthquakes $M \geq 3.8$ (Appendix B), we use a catalog of the $M \geq 4$ earthquakes in the Raton Basin to be even more certain that no events are missing. In this catalog, we find 1 $M \geq 4$ earthquake from 1970–July 2001 and 12 $M \geq 4$ earthquakes from August 2001–2013 (Table 2).

With this catalog, we apply the binomial test to determine how likely it is that the earthquake rate change that we observe could be produced by random variation in earthquake rate, given a constant, background seismicity rate. The binomial test takes the background rate of seismicity and, given this rate, determines how likely it is to get X number of earthquakes within a time period Y. One must be careful with the binomial test, because it assumes that earthquake behavior is random and not clustered as earthquakes commonly are (e.g., aftershocks). This can be addressed by declustering the catalog with respect to time and space. Declustered catalogs have been shown to be Poissonian (Gardner and Knopoff, 1974), and thus the binomial test is appropriate. Given that there are clear foreshock–aftershock sequences in our catalog (Table 2), we decluster our catalog using the Gardner and Knopoff (1974) method and identify four different sequences of potentially related earthquakes (Table 2). In the declustered catalog, we count each cluster as only one earthquake. This yields a catalog of seven earthquake sequences.

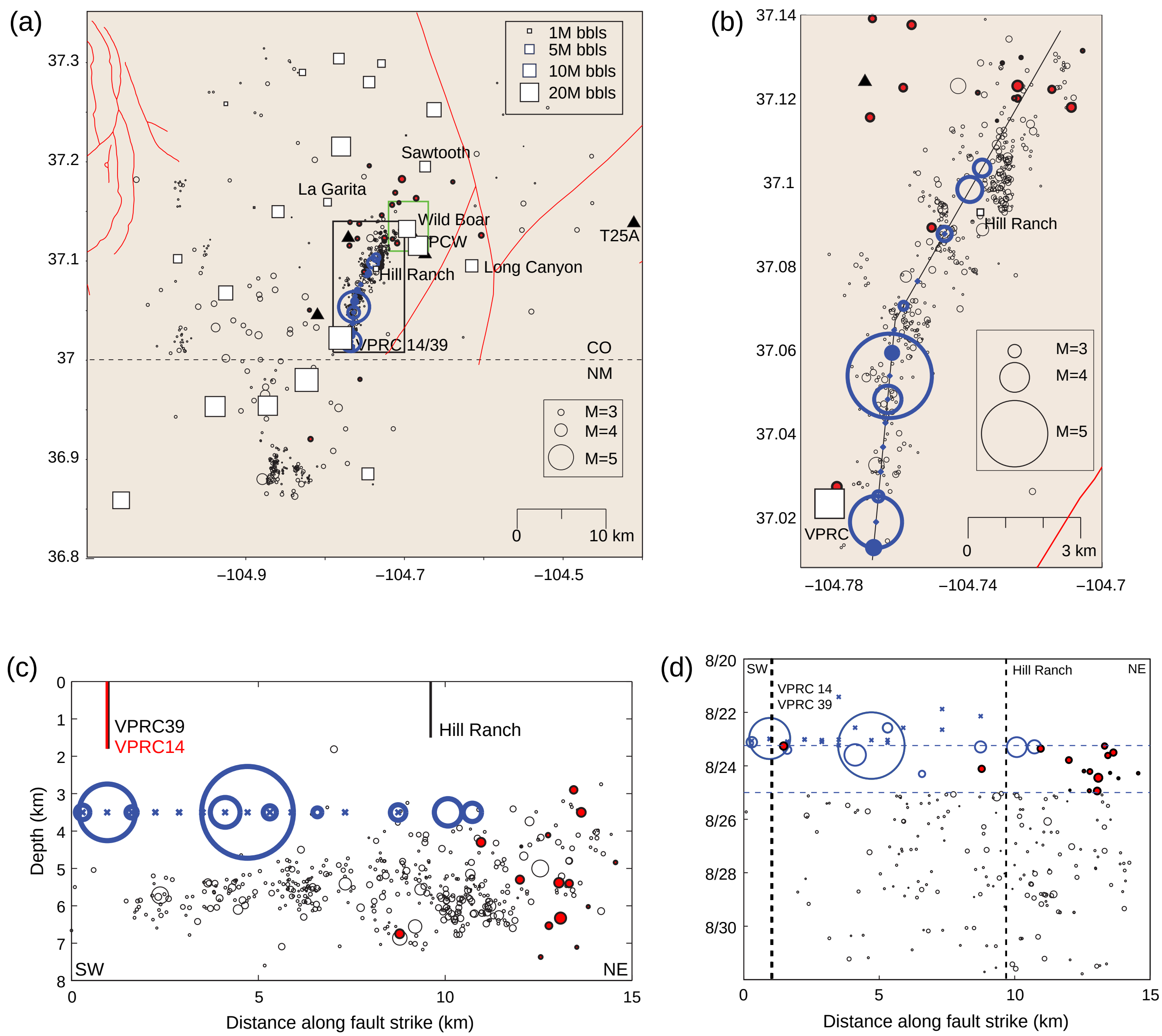

Figure 7. Seismicity from August 2011 to 15 December 2011. Circles represent earthquakes, sized according to earthquake magnitude. Filled circles with thick borders are earthquakes that occurred before the temporary network was installed and have location uncertainties of ±2.3 km. Thin, unfilled circles are earthquakes that occurred after the temporary network was installed and have relative location uncertainties of ±300 m. Thick, unfilled circles are the **M** 5.3 mainshock, foreshocks, and early aftershocks located using the polarization method. Relative uncertainty for polarization locations is ±2 km. The ×'s are early foreshocks and aftershocks for which no magnitude has been computed. (a) A broader picture of seismicity during this period. Squares are injection wells sized according to the cumulative volume of fluid injected through August. The lines show mapped faults in or near the Raton Basin (Johnson, 1969; Robson and Banta, 1987; Scott and Pillmore, 1993; USGS Quaternary Fault and Fold Database [see Data and Resources]). More detailed mapping has been conducted in the Colorado portion of the basin than on the New Mexico side, hence there are more mapped faults. We do not expect there to be a significant difference in the faulting on either side of the border, we just have more detailed knowledge of faults on the Colorado side. The large box in (a) is the study area shown in (b), and the smaller box is the study area for the 2001 earthquake sequence in Figure 6. (b) Expanded view of the 2011 earthquake sequence. Intersecting lines indicate the two-strand model of the fault used for polarization locations. (c) Cross section of the seismicity looking to the northwest. Vertical lines are injection wells in the area. Events located using the polarization location method are set to 3.5 km depth based on synthetics computed for the M_L 2.9 foreshock on 22 August 2011 and the **M** 4.0 aftershock on 23 August 2011. Fault strike is determined under the assumption that the lineation of the seismicity defines a fault, and a line is fit to this lineation. (d) Timing of the beginning of the 2011 earthquake sequence. The dashed horizontal lines indicate the timing of the mainshock (upper line) and the date when earthquakes began to be located using the temporary network (lower line). The dashed vertical lines indicate the location of the injection wells in the area. VPRC 14 and VPRC 39 appear as the thicker line to the left because they are adjacent to each other. Hill Ranch is the line to the right. Some of the foreshocks identified by examining the records from T25A are not plotted because polarization analysis could not be reliably performed due to low signal to noise ratios. The color version of this figure is available only in the electronic edition.

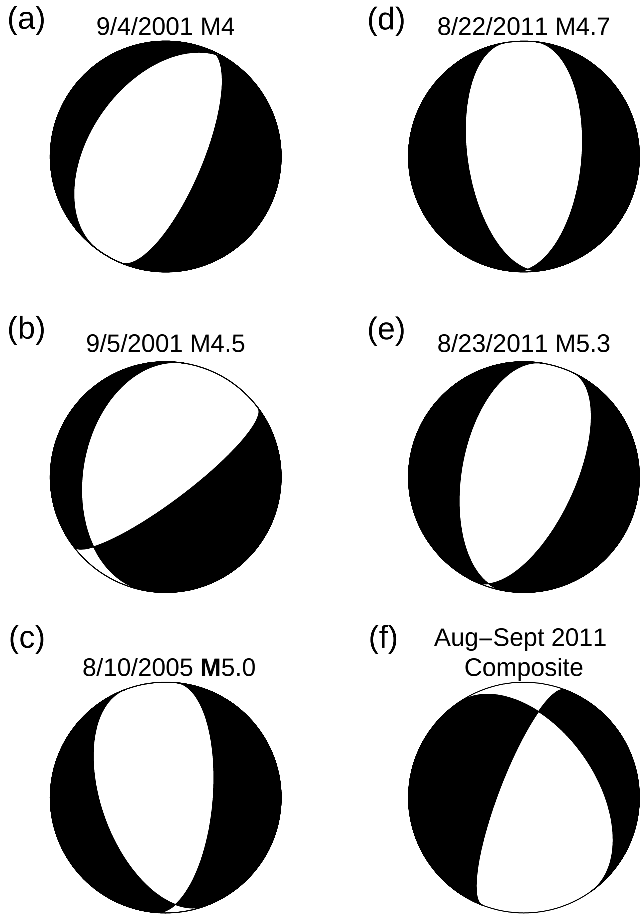

Figure 8. Focal mechanisms for the (a) 4 September 2001 M_{bLg} 4 earthquake, (b) 5 September 2001 M_{bLg} 4.4 earthquake, (c) 10 August 2005 **M** 5.0 earthquake, (d) 22 August 2011 **M** 4.7 earthquake, and (e) 23 August 2011 **M** 5.3 earthquake. (f) The composite focal mechanism for the August–September aftershocks of the 23 August 2011 **M** 5.3 earthquake.

With the declustered catalog, we treat the background rate as seven earthquakes occurring in the 44-year study period. Assuming earthquakes occur randomly in time, we can determine the likelihood that an individual earthquake would occur in a period of time as simply the length of that period divided by length of the entire study (1970–2013, or 44 years). Here, we are interested in whether the earthquake rate change that occurred at the time fluid injection commenced could be produced by random fluctuations in the background rate. Thus, the likelihood that any individual earthquake would occur in the coinjection period (November 1994–December 2013) is approximately 44%. There were six independent earthquakes within this time period and one in the preinjection period. We use combinatorics to determine the likelihood that six or seven earthquakes would occur in the coinjection period (Appendix C). This analysis yields that it is unlikely (3% probability) that the observed seismicity rate change can be the result of random fluctuations in earthquake rate, given a constant, long-term background seismicity rate.

Although large earthquake rate changes have been seen to be correlated to industrial activities (e.g., Healy *et al.*, 1968; Horton, 2012), natural causes for earthquake rate changes have also been observed. The most common causes of prolonged, large earthquake rate changes are fluids and fluid movement in volcanic, geothermal, and hydrothermal systems (e.g. Hill, 2006). Thus, this earthquake rate change alone is not sufficient evidence to demonstrate that these earthquakes are caused by fluid injection.

Spatial Relationship between Seismicity and Wastewater Injection Wells

Seismicity before 2001 was concentrated at the edges of the Raton Basin (Fig. 4a). From 2001 forward, most of the seismicity is found in the center of the basin, in the area of the injection wells (Fig. 4b,c). In fact, the earthquake rate change appears to be solely coming from the area of the wells. No earthquakes larger than the magnitude of completeness ($M_c = 3.8$) are found outside the area of the wells before or after injection began, thus the increased rate occurs in the center of the basin near the wells. The broadscale coincidence of the location of increased seismicity and location of the increased injection activity suggests that the injection activities are related to the increased seismicity rate.

Since the start of injection, one can see that most of the seismicity is located quite close to active injection wells, whereas earlier seismicity is not (Fig. 4a–c). The majority of this seismicity was located without the benefit of dense seismometer deployments, giving high epicentral uncertainties (2σ of approximately ± 15 km). Thus, the absence of a precise spatial correlation for these earthquakes with wells does not mean that they are not related to the wells. Additionally, there is evidence that induced earthquakes can occur at distances of greater than 10 km from causative injection wells (Herrmann *et al.*, 1981; Horton, 2012; Ellsworth, 2013; Keranen *et al.*, 2014).

Although for much of this extended earthquake sequence, location uncertainties are large, when uncertainties are lower (as with the 2001 and 2011 sequences), we see that their epicenters lie within 2 km of high-volume, high-injection-rate wells (Figs. 6 and 7). The well-located seismicity is situated at depths extending downward from approximately 1 km below the bottom of the injection wells.

Fluid Injection Volumes, Injection Rates, and Seismicity Rates

In this section, we examine the fluid injection history on both sides of the Colorado–New Mexico border and compare this history to the temporal variations in seismicity. Overall, we find that both earthquake rates and fluid injection rates have remained high over the last 10 years. Injection rates are known in Colorado extending back to the beginning of methane production in the field (1994), but in New Mexico the corresponding data are only available beginning in June 2006. For this reason, we separate the Colorado and

Table 2
Magnitude 3.8 and Greater Earthquakes in the Raton Basin from 1972 through 2013

Date (yyyy/mm/dd)	Time (hh:mm:ss.ss)	Latitude (°)*	Longitude (°)	Depth (km)	Magnitude†
1973/09/23	03:58:54.5	37.178	−104.61	1.05	4.2
2001/09/04‡	12:45:52.1	37.162	−104.65	1.45	4.0
2001/09/05‡	10:52:07.5	37.152	−104.66	2.65	4.5
2003/09/13	15:22:47.9	37.139	−104.88	2.99	3.8
2004/03/22§	12:09:54.9	36.852	−104.96	5.43	4.4
2004/08/01§	06:50:44.8	36.865	−105.01	2.41	**4.3**
2005/08/10‖	22:08:14.6	36.963	−104.83	2.77	4.1
2005/08/10‖	22:08:20.9	36.946	−104.84	5.95	**5.0**
2007/01/03	14:34:37.17	37.009	−104.911	5.17	**4.4**
2009/07/29	10:00:35.7	36.843	−104.83	13.33	**4.1**
2010/01/18	08:41:06.6	36.886	−104.83	10.04	**3.8**
2011/05/11	19:06:12.6	37.123	−104.69	1.1	**3.8**
2011/08/22#	23:30:18.1	37.019	−104.77	3.5	**4.7**
2011/08/23#	05:46:17.8	37.054	−104.76	3.5	**5.3**
2011/08/23#	14:11:13.0	37.048	−104.76	3.5	**4.0**
2011/09/13#	05:24:37.26	36.880	−104.869	3.58	4.0
2011/09/16	14:51:50.0	36.880	−104.88	2.25	**3.9**

*2σ location uncertainties are ±15 km for all events except the earthquakes on 22 and 23 August 2011.

†Magnitude is the authoritative magnitude in ComCat. Moment magnitudes (**M**) are indicated with the magnitude printed in boldface type. The other magnitudes are a combination of amplitude based measures: M_b, M_{bLg}, and M_L.

‡Cluster of M ≥4 earthquakes in 2001. These earthquakes are located close in space and time, such that they cannot be considered to be independent in space and time. As such, they are counted as an individual earthquake sequence in the statistical calculations.

§Cluster of M ≥4 earthquakes in 2004.

‖Cluster of M ≥4 earthquakes in 2005.

#Cluster of M ≥4 earthquakes in 2011.

New Mexico portions of the Raton Basin in the following analysis.

Raton Basin in Colorado. From the start of injection in November 1994 through July 2001, no earthquakes were detected in the Colorado portion of the Raton Basin. During much of this period, fluid injection rates in this area were fairly low. From 1994 through February 2001, the maximum rate was 725,000 barrels/month, and the median rate was 300,000 barrels/month (Fig. 2). From the start of 2001 until the first earthquakes in this sequence were felt (August 2001), injection rates in the Colorado portion of the field dramatically increased, rising from a median rate of 500,000 barrels/month in the year 2000 to 1.2 million barrels/month in August 2001 (Fig. 2). The earliest earthquakes were located in the eastern portion of the gas field, shortly after six wastewater injection wells were put into operation.

The level of seismicity, although quite variable, has been fairly high in the Colorado portion of the field since injection increased in March 2001 (Fig. 2). Examining the cumulative injection volumes and number of earthquakes in the Colorado portion of the field, we can see, from a broad perspective, that total injection volumes and the number of earthquakes roughly track each other (Fig. 9a). There is a fairly constant injection rate on the Colorado side of the border. Likewise, the earthquake rate is roughly constant with considerable temporal clustering.

Raton Basin in New Mexico. We use water production in New Mexico as a proxy for injection from 1999 to May 2006. Production rates slowly increase from the start of production in 1999 through mid-2005. At the time of the first M ≥3.0 earthquakes detected in the New Mexico portion of the Raton Basin (January 2002), injection rates were low (~250,000 barrels/month). By the time earthquakes became more frequent (early 2004), injection rates had risen to 750,000 barrels/month (Fig. 3). Since mid-2005, injection rates have remained largely constant (median: 1.2 million barrels/month). Similarly, earthquake rates have been generally constant since this time and closely track the injection rates (Fig. 9b).

The total volumes injected in New Mexico and Colorado since 1999 are comparable, with ~110 million barrels on both sides between June 2006 and September 2013. During the time period of the increased seismicity (2001–present), Colorado and New Mexico also had similar numbers of M ≥ 3 earthquakes (54 and 45, respectively).

Mechanics of Injection-Induced Seismicity

The mechanics of injection-induced earthquakes have been long established (e.g., Healy *et al.*, 1968; Raleigh *et al.*, 1976). Injection increases the pore fluid pressures in the fault, reducing the normal stress and hence frictional resistance, and in turn facilitating slip under the ambient tectonic shear stress (Hubbert and Rubey, 1959).

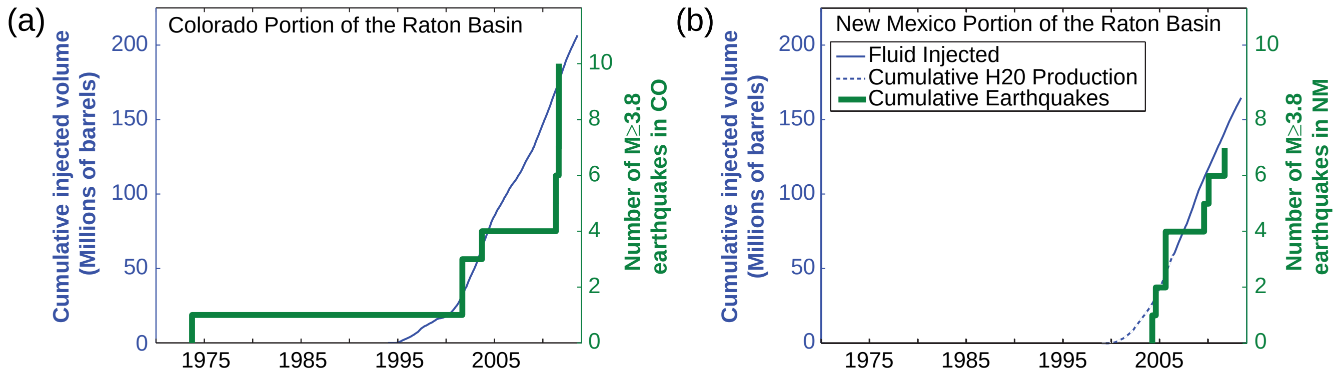

Figure 9. Cumulative fluid injection and earthquakes on the Colorado and New Mexico sides of the Raton Basin. When injection information is unavailable in New Mexico, cumulative produced-water volumes are used as a proxy for cumulative injection volumes. A dashed, thin line indicates cumulative produced-water volumes. Once injection volumes become available, a solid, thin line is used. Earthquake data is from 1970–2013, injection data is from 1970–September 2013. The color version of this figure is available only in the electronic edition.

Even in an underpressured, extensional system like the Raton Basin, where fluids can typically be injected with no wellhead pressure, earthquakes can still be induced. In these cases, pore pressure still increases at the injection interval as a result of the excess hydraulic head in the well bore. In fact, the fluid pressures from hydraulic head alone have been observed to both hydraulically fracture and cause slip on faults in wells in underpressured, extensional environments (Stock *et al.*, 1985; Moos and Morin, 1991). When the increased fluid pressure from the water column alone is large enough to induce failure, fluid injection need not require wellhead pressure to cause slip. The critical stress hypothesis (Townend and Zoback, 2000), which states that the crust is everywhere near failure, also supports the notion that small stress changes can be enough to induce an earthquake.

In addition to stresses coming directly from the wellhead, there are other, more broadscale stress changes that come from fluid injection. With the injection of fluids, there will be significant fluid movement to accommodate the increase in fluid volume. This fluid redistribution will change the stress field. Poroelastic effects are also important, as pore spaces will get filled and additional pores may be opened or closed due to the increased fluid pressures.

Case Study: The August–September 2001 Earthquake Sequence

Description of the Earthquake Sequence

The first earthquake observed in the August–September 2001 earthquake sequence was an M_{bLg} 3.4 earthquake on 28 August 2001. At the time, the detection threshold was approximately M 3.0 (Appendix B). The sequence lasted several months, with the most vigorous seismicity ending in September. The largest earthquakes in the sequence, M_{bLg} 4.0 and 4.5, occurred on 4 September 2001 and 5 September 2001, respectively. The sequence included 11 M $\geq$3 earthquakes in the 24-day period between 28 August 2001 and 21 September 2001.

In response, members of the USGS Geologic Hazards Team from Golden, Colorado, deployed a temporary array of 12 seismometers to record the ongoing earthquake sequence. The stations were deployed beginning 8 September 2001 (Meremonte *et al.*, 2002), after the two largest earthquakes in the sequence. A total of 39 earthquakes, that occured between 10 September 2001 and 15 October 2001, were located by Meremonte *et al.* (2002). The hypocenters of these earthquakes define a northeast-striking plane of seismicity spanning approximately 7 km in length and dipping steeply to the southeast.

We relocate this seismicity using an updated velocity model. Our locations for the 2001 hypocenters are much the same as those of Meremonte *et al.* (2002). Details on the location methodology can be found in Appendix A. Our locations also define a northeast-striking, steeply dipping fault between 1.5 and 6 km depth, centered below the Wild Boar UIC Class II disposal well (Fig. 6b). The plane imaged by the seismicity runs parallel to a fault mapped by Robson and Banta (1987) but lies approximately 5 km to the northwest of it (Fig. 6a).

Uncertainties for the relative earthquake locations when the temporary network was running are approximately $\pm$200 m (2σ). Absolute uncertainties (2σ) are approximately $\pm$2 km. Earthquakes that occurred before 10 September 2001 were located using the regional seismic network, which has interstation spacing of hundreds of kilometers. Consequently, the 2σ location uncertainty of these earlier earthquakes is approximately $\pm$15 km.

The depth to basement beneath the Wild Boar well is estimated to be between 2 and 3 km, based on seismic reflection sections (personal comm. with a local oil and gas operator, 2012). Thus, it appears that the earthquakes during the late stages of the sequence were in the lower sedimentary section and uppermost basement (Fig. 6b).

Regional moment tensors were computed for the two largest earthquakes in this sequence by Saint Louis University (SLU; Herrmann *et al.*, 2011). Both earthquakes are normal-faulting events striking approximately northeast (Fig. 8a,b). This is consistent with the regional tectonics of the area, which are east–west extension, dominated by the Rio Grande rift system.

Evidence that the 2001 Earthquake Sequence was Induced by Wastewater Injection

The August 2001 earthquake sequence is effectively centered below the Wild Boar injection well (Fig. 6) with many epicenters within hundreds of meters of the injection well. Most events in the 6 km lineation of seismicity lie between 1 and 3 km below the injection depth (Fig. 6b). At the time of the 2001 sequence, there were four other active injection wells within 10 km of the earthquake sequence: PCW (2 km), Sawtooth (4.5 km), Long Canyon (8 km), and La Garita (8.3 km).

The injection rates at Wild Boar in the months leading up to the earthquake sequence were higher than any of the other wells listed above. Injection rates at Wild Boar routinely exceeded 200,000 barrels/month in 2001, whereas rates at the PCW well averaged 150,000 barrels/month and rates at Sawtooth, Long Canyon, and La Garita never exceeded 93,000, 52,000, and 36,000 barrels/month, respectively. Wild Boar also began injecting in August 2000, one year before felt earthquakes began. PCW, the other high-injection-rate, high-volume well began injection three years before Wild Boar without any detected earthquakes. Sawtooth, Long Canyon, and La Garita also began injection shortly before the first felt earthquakes (April 2000, August 2001, and April 2001, respectively). All of these wells have always injected under gravity feed only.

Given that Wild Boar is the highest-rate well, began injecting shortly before earthquakes started in the area, and is the closest well to the earthquakes, it is the most likely well to have induced the earthquakes. Because PCW is a high-injection-rate well and the other wells began injecting shortly before the earthquakes started, we cannot rule out these wells as contributing to inducing the earthquakes.

Case Study: The August–September 2011 Earthquake Sequence

The largest earthquake documented in the Raton Basin is an **M** 5.3 earthquake that occurred on 23 August 2011. This earthquake was preceded by several foreshocks, including an **M** 4.7 earthquake approximately 6 hr before the mainshock. The aftershock sequence decayed quickly, with most aftershocks ending within approximately one month of the mainshock. The USGS Geologic Hazards Science Center in Golden, Colorado, installed a four-station, temporary seismic network the day after the mainshock to record and locate the aftershocks. It would have been desirable to install additional instruments, but this was not possible due to the need to respond to the **M** 5.8 central Virginia earthquake that occurred later on the same day.

Earthquake location quality varies for this earthquake sequence. Because the temporary seismic network was not installed at the time of foreshocks, mainshock, and early aftershocks, we applied standard location techniques with the permanent regional stations. Location uncertainties were similar to those of the preceding 10 years (~15 km). Fortunately, we were able to reduce the uncertainty in epicenters of these early temblors to approximately ±0.9 km. We do this by measuring the *P*-wave polarization and *S–P* time at station T25A and finding the intersection of this ray with two fault segments defined by the well-located aftershocks of the 2011 earthquake. Smaller, early aftershocks were located using a hypocentral decomposition approach and have 2σ epicentral uncertainties of ±2.3 km. Aftershocks recorded by the temporary network have 2σ relative epicentral uncertainties of ±300 m, relative depth uncertainties of ±250 m, and absolute uncertainties of ±2 km. Further details on the methods used can be found in Appendix A.

Foreshocks

The 23 August 2011 **M** 5.3 Trinidad earthquake was preceded by a number of foreshocks. Within ComCat, three earthquakes were identified in the 24 hr preceding the mainshock: the previously mentioned **M** 4.7 earthquake and events of M_L 2.9 and 3.0. To identify additional foreshocks, we manually scanned the continuous seismic records at station T25A for July and August 2001. This analysis revealed a foreshock sequence with 36 events that began with an M ~ 1.1 event at 10:05 UTC on 21 August, which is the smallest foreshock that we detected. Although there are not enough earthquakes to conduct a formal analysis, Gutenberg–Richter statistics suggest that the magnitude of completeness is 2.1 or greater for the period during which we manually scanned the waveforms. For 2001–2013, the overall magnitude of completeness is approximately 3.0 (Appendix B).

The early foreshock sequence (prior to the **M** 4.7) is largely centered on the first foreshock (Fig. 7d). The earliest foreshocks were in the north. Following the **M** 4.7 earthquake, foreshocks were largely concentrated to the south. The **M** 4.7 is very close (< 2 km) to two high injection-rate wells, VPRC 14 and VPRC 39. The later foreshocks extend further south than the majority of the aftershocks (Fig. 7d).

Many of the largest events produced prominent phases on the seismograms that are diagnostic of earthquakes occurring at shallow depth. We were able to confirm this shallow depth of the foreshocks by comparing seismograms recorded at T25A (Fig. 10a) with synthetic seismograms computed for varying depths. We find the best match for surface waves (which are the waves most diagnostic of earthquake depth) and the *P* and *S* arrival times (which are also diagnostic of depth) for the M_L 2.9 foreshock at 13:52 UTC on 22 August 2011 is with the synthetic seismograms for hypocentral depths of 3–4 km. We find hypocentral depths of 3–4 km are also appropriate for the M_L 3.0 earthquake foreshock that occurred on 23 August 2011 at 02:48 UTC.

The Mainshock

The **M** 5.3 mainshock occurred on 23 August 2011 at 05:46 UTC. It is located near the center of the foreshock sequence, approximately 5 km north of the southern end of the sequence and 10 km south of the northern end (Fig. 7). Regional waveform modeling indicates that it is a normal-faulting earthquake, with fault planes striking to the north-northeast and dips ranging between 40° and 50° (Herrmann *et al.*, 2011). The lineation of seismicity of both the foreshocks and the aftershocks is consistent with the strikes of the two nodal planes defined by the moment tensor. The lineation is also roughly consistent with the strike of a normal fault identified by Robson and Banta (1987) (Fig. 7a,b). Considering that the closest part of the seismicity is approximately 4.5 km from the mapped fault, we do not expect that this similarity reflects a direct physical connection between the two structures. Both structures, though, are consistent with the ambient state of stress. The focal mechanism is also consistent with the regional tectonic setting of east–west extension (Heidbach *et al.*, 2008; Berglund *et al.*, 2012)

Standard arrival-time location techniques place the mainshock hypocenter at 4.3 km depth, with an uncertainty of ±15 km but we assume that the earthquake lies within the aftershock zone, extending over 2.5–8 km depth. The USGS/SLU regional moment tensor places the centroid depth at 3 km.

To add an additional constraint on the depth of the mainshock, we compute synthetic seismograms for two smaller earthquakes that were close to the mainshock and well recorded at T25A. We examine the seismograms of these earthquakes instead of the mainshock because the shorter source duration of these events results in simpler seismograms that more clearly show the effects of depth on wave propagation. Computing synthetic seismograms for the M_L 2.9 foreshock discussed in the Foreshocks section and the **M** 4.0 aftershock at 14:11 UTC on 23 August 2011 confirms the above estimate of 3 km, whereby the surface waves and body-wave arrival time in the synthetics best match the observed waveforms at T25A for depths of 3 and 4 km (Fig. 10). This places both earthquakes in the uppermost crystalline basement.

Analysis of Interferometric Synthetic Aperture Radar (InSAR) image pairs that span the earthquake confirms these shallow hypocentral depths (W. Barnhart, personal comm., 2013). W. Barnhart identified deformation associated with the earthquake sequence that indicates a normal-faulting earthquake occurred with a similar strike and dip as seen in the seismic moment tensor. Results of analyzing the InSAR images indicate that slip is concentrated within a zone of approximately 2.5–6 km in depth.

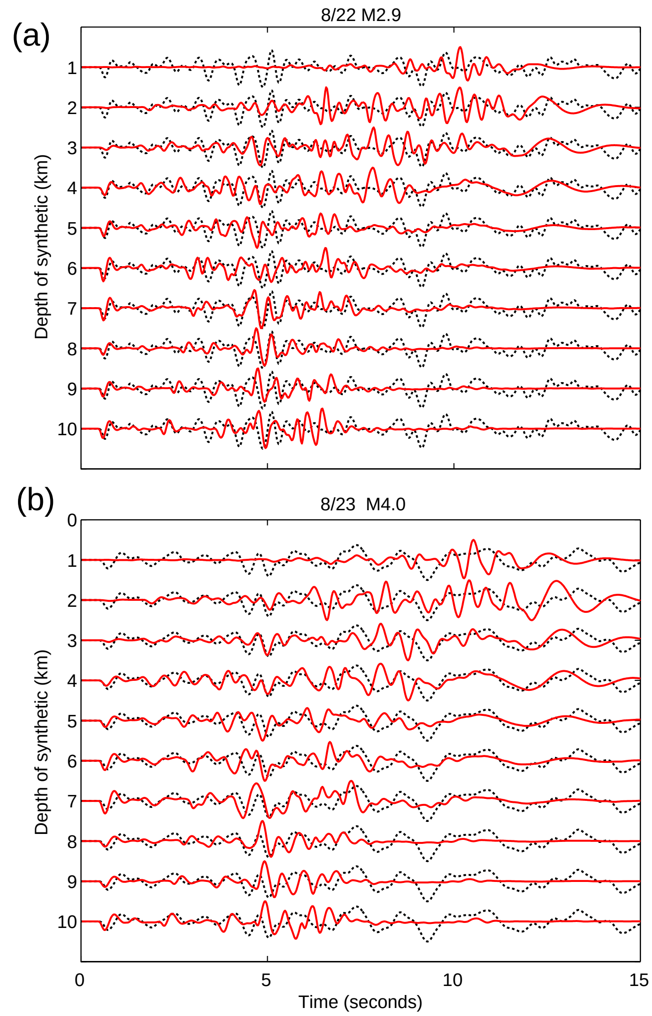

Figure 10. Observations and synthetics for the (a) 22 August 2011 13:52 UTC M_L 2.9 foreshock and the (b) 23 August 2011 14:11 UTC **M** 4.0 aftershock. Observations are shown as dotted lines, and synthetics are shown as thick lines. The surface waves match best with the synthetics for earthquakes having depths of 3 and 4 km. Surface waves are the waves that are most diagnostic of earthquake depth, so this match is more important that a good body-wave match. Synthetics computed for depths greater than 5 km do not generate strong surface waves, which are evident in both earthquakes. Thus, we infer the earthquakes to lie between 3 and 4 km depth. Additionally, we find that the best *P*- and *S*-arrival time match is for depths of 3 and 4 km earthquake depth. Similar results are found for other early aftershocks and foreshocks. The color version of this figure is available only in the electronic edition.

Postmainshock Seismicity: 23 August–15 December 2011

We analyzed the seismicity in the Raton Basin following the **M** 5.3 earthquake primarily using the temporary seismic network that was deployed by the USGS Geologic Hazards Team in Golden, Colorado. This network was fully operational by 25 August 2011. We examine the data through 15 December 2011, because we are most interested in the aftershocks of the **M** 5.3 mainshock, which had largely abated by then.

Aftershocks. From the time of the mainshock through 2013, there have been 10 M $\geq$3.0 earthquakes in the vicinity. Seven of these events occurred within the first 48 hr, including the largest aftershock, an **M** 4.0 earthquake that occurred 8.5 hr after the mainshock. The three other M $\geq$3 earthquakes occurred in October 2011, December 2011, and May 2012. These three later events all occurred at least 4 km to the northeast of the mainshock hypocenter.

Examining the distribution of the seismicity, we find two intersecting lineations (Fig. 7b). The southern lineation strikes nearly north–south, and the northern lineation strikes approximately northeast–southwest. We infer that these semiplanar zones of seismicity represent faults. Although we were unable to find any discussion of these faults in the scientific literature, the strong alignment of the seismicity indicates that they are faults. The faults cover a region approximately 14 km in length. Although these lineations describe the general trend of seismicity, precisely located hypocenters from the temporary network do not define a simple plane for either trend. Rather, the lineations appear to be composed of en echelon subfaults 2–3 km in length that strike anywhere from slightly west of north to northeast (Fig. 7b). This contrasts with the seismicity in the 2001 earthquake sequence, which forms a single 7 km long, steeply dipping plane. It is also possible that the segmentation of the earthquakes may arise from an insufficient number of instruments that recorded these earthquakes, such that earthquakes appear to be preferentially moved toward the station closest to the earthquake instead of their true location.

The majority of the seismicity in the 2011 earthquake sequence lies at depths between 4 and 8 km below ground level, with the deepest seismicity appearing at the southern end of the aftershock zone. This increase in depth may be an artifact of bias in the location process, as there are no stations close to these events.

A composite focal mechanism (Snoke *et al.*, 1984) from the aftershock sequence indicates normal faulting on a north–south-trending fault plane (Fig. 8). This is consistent with the focal mechanisms for the larger earthquakes in the 2001 and 2011 sequences, the tectonic regime, and the lineations of seismicity in the area. As with the 2001 sequence, the east-dipping nodal plane implied by the composite mechanism appears to have a shallower dip than the plane defined by the seismicity.

Seismicity Outside the Aftershock Zone. In addition to the aftershocks of the **M** 5.3 mainshock, two smaller sequences occurred elsewhere in the Raton Basin between 25 August 2011 and 25 October 2011. One is about 20 km to the west of the August 2011 earthquake sequence, and the other is approximately 20 km to the southwest (Fig. 7a). The sequence to the southwest is notable in that it includes an **M** 3.9 earthquake that occurred 16 September 2011. We believe that neither of these additional earthquake sequences are related to the seismicity near the **M** 5.3 mainshock, given that its aftershock sequence diminished greatly after three weeks and because these earthquake sequences are ~20 km from the obvious aftershocks of the 23 August mainshock.

Evidence that the 2011 Earthquake Sequence Was Induced by Wastewater Injection

The August–September 2011 earthquake sequence lies within 10 km of five injection wells in the Raton Basin: VPRC 14, VPRC 39, Hill Ranch, PCW, and Wild Boar (Fig. 7a). With the exception of Hill Ranch, these are high-injection-rate, high-volume wells. Cumulative injection volumes ranged between 15.1 million and 22.5 million barrels of wastewater through the end of August 2011 for all but Hill Ranch. Monthly injection rates at the same wells between January and August 2011 range from 220,000 to 262,000, 177,000 to 217,000, 78,000 to 91,000, and 88,000 to 124,000 barrels per month at VPRC 14, VPRC 39, PCW, and Wild Boar, respectively. The low-volume, low-rate Hill Ranch well injected 5000–46,000 barrels per month in the previous eight months.

Because the two VPRC wells are nearly colocated, we treat them as a single well for our analysis. At the time of the earthquake sequence, these wells were individually injecting at higher rates than the other wells in the area, and when summed they were injecting at far higher rates than any of the other wells. In the eight months preceding the earthquake sequence, the summed injection rate of the VPRC wells ranged between 408,000 and 479,000 barrels/month, whereas the well with the next highest injection rate in the same time period was Wild Boar, which injected 124, 000 barrels/month at most. Since 2005, the VPRC wells have been operating under gravity feed.

The proximity of the VPRC wells to the 2011 earthquake sequence also suggests that they are the wells most likely to have induced the earthquake sequence. The VPRC wells are the closest wells to the mainshock (3.7 km) and foreshock sequence (2.6 km from the first identified foreshock). The other wells (PCW, Wild Boar, and Hill Ranch) lie significantly further from the mainshock and foreshocks than the VPRC wells (9.9, 10.6, and 4.9 km from the mainshock, respectively). It is worth noting that Wild Boar and PCW lie closer than the other wells to the northernmost aftershocks of the earthquake sequence, so they may have played a role in inducing these earthquakes. The northernmost events could also be typical aftershocks, which commonly extend well beyond the initial mainshock rupture zone (Mendoza and Hartzell, 1988). Although we prefer the model whereby the VPRC wells are primarily responsible for this earthquake sequence, the cumulative effect of all or a subset of the nearby wells may have induced these earthquakes.

Summary

The Raton Basin of southern Colorado and northern New Mexico has seen a dramatic rise in the seismicity rates, beginning in 2001. In the past 13 years, there have been 16 M $\geq$3.8 earthquakes. In the previous 30 years only one

$M \geq 3.8$ earthquake occurred. The seismicity in the last 12 years includes **M** 5.3 and 5.0 earthquakes; the former caused damage to some unreinforced masonry buildings in the Colorado towns of Segundo and Valdez and minor damage in Cokedale and Trinidad (Morgan and Morgan, 2011). Based on the three broad lines of evidence below, we argue that the majority of these earthquakes have been induced by wastewater injection activities in the area.

1. We observe a large increase in earthquake rate in the Raton Basin shortly after major wastewater injection began in the area. This rate increase is limited to the area of industrial activity, with no significant change to earthquake behaviors outside the basin. Statistical analysis of the seismicity shows that the activity from 1970 to 2013 is unlikely to result from a constant-rate Poisson process. Comparing the rate of earthquakes before and after the initiation of wastewater injection into the basin, there is a 3.0% probability that the observed activity could be produced by random variations in the background seismicity rate.
2. The vast majority of the seismicity lies within 5 km of wastewater injection wells. Careful investigation of two locally recorded earthquake sequences places them in close proximity to high-volume, high-injection-rate wells. The 2001 earthquake sequence epicenters surround the Wild Boar injection well, and the precisely located aftershocks are primarily less than 3 km below the injection interval. The 2011 earthquake sequence initiated within 2.6 km of two high-volume, high-injection-rate wells: VPRC 14 and VPRC 39. Combined, these wells were injecting more than 400,000 barrels of wastewater per month in the 16 months of injection prior to the **M** 5.3 mainshock. The injection intervals of these wells lie within 2 km depth of the shallowest hypocenters of the 2011 earthquake sequence.
3. The wells in the area are high volume and high injection rate. Individual wells greatly exceed the injection rates and cumulative volumes at the classic case of injection-induced seismicity at the Rocky Mountain Arsenal. On a field-wide basis, injection in the Raton Basin is orders of magnitude larger still. Across the field, wastewater injection rates and earthquake rates show similar time histories. In particular, the seismicity starts shortly after injection rates increased significantly. Within the Colorado portion of the basin, both injection rates and rates of earthquake occurrence have remained fairly consistent since 2001. Beginning in 2006, when injection data becomes available, injection rates and earthquake rates in the New Mexico side of the basin are also constant. We also note that the total injection volumes since 2006 on both sides of the border are similar, and the numbers of detected earthquakes that have occurred on both sides are similar. This suggests that the volume of injected fluid or injection rate has some control on the seismicity that occurs.

Although there are many lines of evidence showing that the seismicity in the Raton Basin has been induced by wastewater injection activities in the area, it is very difficult to say whether an individual earthquake was caused by injection because natural seismicity has also been recorded there. Unfortunately, earthquakes that occurred when there was no local network deployed cannot be located with much accuracy, so the probability of fully describing these is low. For future research, a longer-term study with dense network coverage on both sides of the border would be especially useful in understanding the inducing relationship between the earthquakes and fluid injection in the Raton Basin.

It is also difficult to disentangle whether injection rate or cumulative volume controls if and when earthquakes are induced in the area. We expect that both cumulative injection volume and injection rates affect the rate and maximum magnitude of induced earthquakes, as has been suggested previously (McGarr, 2014; McGarr and Rubinstein, 2014).

Data and Resources

Los Alamos Seismic Laboratory catalog data is found in Los Alamos Progress Reports (LA-8579-PR, LA-8580-PR, LA-8614-PR, LA-8687-PR, LA-8745-PR, LA-9036-PR, LA-8846-PR, LA-9307-PR, LA-9467-PR, LA-9679-PR, LA-10139-PR, LA-10313-PR, LA-9782-PR, LA-9899-PR, LA-9900-PR, LA-10033-PR, LA-10314-PR, and LA-10598-PR). The *International Seismological Centre* (*ISC*) *Bulletin* (catalog) and waveform data can be obtained from http://www.isc.ac.uk/iscbulletin/search/ (last accessed January 2014; ISC, 2011). ComCat is maintained by the U.S. Geological Survey (USGS) and can be found at http://earthquake.usgs.gov/earthquakes/search/ (last accessed January 2014). Annual summaries of United States Earthquakes from the Department of Commerce can be found at http://openseismo.org/public/Lee/United_States_Earthquakes/ (last accessed December 2013).

The facilities of the Incorporated Research Institutions for Seismology Data Management System (IRIS-DMS), and specifically the IRIS-DMS, were used for access to waveform, metadata, or products required in this study. The IRIS-DMS is funded through the National Science Foundation, specifically the GEO Directorate through the Instrumentation and Facilities Program of the National Science Foundation under Cooperative Agreement EAR-1063471. Some activities are supported by the National Science Foundation EarthScope Program under Cooperative Agreement EAR-0733069. Data from the USArray Transportable Array were made freely available as part of the EarthScope USArray facility, operated by IRIS and supported by the National Science Foundation under Cooperative Agreements EAR-0323309, EAR-0323311, and EAR-0733069. Waveform data from the 2011/2012 USGS temporary deployment can be accessed at IRIS. Additional waveform data used in the location of the 2011 earthquake sequence came from the Advanced National Seismic System backbone network and the USGS Albuquerque Seismological Laboratory Network (IU). IU stations are the part of the Global Seismic Network that are installed, maintained, and operated by the USGS Albuquerque Seismological Laboratory (http://earthquake.usgs.gov/regional/asl/ and http://www.liss.org; last accessed January 2014). The latest information on U.S. stations and data availability may be viewed at http://earthquake.usgs.gov/monitoring/anss/ (last accessed January 2014).

The Colorado Oil and Gas Information System (COGIS) is maintained by the Colorado Oil and Gas Conservation Commission (COGCC) and has well data for the state of Colorado (http://cogcc.state.co.us/COGIS/LiveQuery.html; last accessed January 2014). The Oil Conservation Division of the New Mexico Energy Minerals and Natural Resources Department also maintains an online database of well data (http://ocdimage.emnrd.state.nm.us/imaging/WellFileCriteria.aspx; last accessed January 2014).

The Quaternary Fault and Fold Database, supported by the USGS, Colorado Geological Survey, and New Mexico Bureau of Mines and Mineral Resources, is available at http://earthquake.usgs.gov/hazards/qfaults (last accessed May 2014).

"Did You Feel It?" data is available at http://earthquake.usgs.gov/earthquakes/dyfi/events/us/2005bpcu/us/index.html, last accessed December 2013.

Upon publication, catalog data for the earthquakes located in this paper and pick data for the 2001 temporary seismic deployment will be inserted into ComCat. USGS/Saint Louis University regional moment tensor data comes from http://www.eas.slu.edu/eqc/eqc_mt/MECH.NA/index.html (last accessed January 2014).

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Appendix A

Earthquake Location Methodologies

Most of the earthquakes studied in this article were located using the program VELEST and standard procedures described by Kissling *et al.* (1994). Some parts of the seismicity were located using other methods. These are described in the following subsections. The quality of the earthquake locations varies highly, depending on the number and proximity of seismometers to the earthquakes in the area. An estimate of uncertainty is reported in each section. The velocity model that we use is 1D and was determined using the VELEST program. The initial velocity model was provided by P. Friberg (with permission from Pioneer Natural Resources), but we updated it using the data from the U.S. Geological Survey (USGS) temporary deployment in 2011.

For the time periods outside the two temporary, dense seismic deployments in 2001 and 2011 (i.e., 1963–August 2001 and November 2001–July 2011), we use pick data from the *International Seismological Centre Online Bulletin*, supplemented by readings provided by Jim Dewey (written comm., 2012). We then use VELEST to compute the earthquake locations. Bootstrap resampling methods give horizontal uncertainties of ±15 km. Varying the velocity model and earthquake starting locations suggests that location uncertainties may be even larger.

For those earthquakes that occurred during the temporary deployment in 2001, we use pick data from these stations. Bootstrap resampling methods give relative horizontal uncertainties of ±200 m. Varying starting locations and velocity models gives absolute uncertainties of ±2 km.

For those events that occurred while the temporary network was deployed in 2011, we use VELEST to locate these events. We compute a 1000 realization bootstrap analysis (Efron, 1979) of the VELEST locations and find a 1σ uncertainty across the entire region, located ±300 m horizontally and ±250 m in depth. We explored using the double-difference earthquake relocation algorithm *hypoDD* (Waldhauser and Ellsworth, 2000) to refine our locations, but we found that it did not significantly reduce uncertainties in earthquake locations, nor did the locations reduce to more planar features, so we chose to use the VELEST locations as our final locations.

We use locations from the Comprehensive Catalog (ComCat) for earthquakes that occurred after the dense seismometer deployment in 2011 (i.e., events between 15 December 2011 and 31 December 2013). Location uncertainties are likely on the order of 10–15 km.

Polarization Location Method: August 2011 Mainshock and Foreshocks

We use a method based upon *P*-wave polarization and *S*–*P* time to determine the location of the 2011 mainshock and its foreshocks. We use this method because we only have one station (T25A) that is within 30 km of the earthquake sequence at the time it initiated. T25A is located approximately 30 km to the east-northeast of the earthquake sequence (Fig. 10).

In this method, we first rotate the seismograms to identify the direction of *P*-wave polarization to establish the direction of wave propagation. For the mainshock, the initial *P*-wave motion is rectilinear on the horizontal components at a back azimuth of S73°W, implying that the earthquake lies to the south-southwest of T25A. It should be noted that the orientation of the components at T25A are N1°E and S89°E, instead of north and east (G. Ekström, personal comm., 2013). We then determine where a ray with that back azimuth intersects a two-segment model of the fault defined by the well-located aftershocks. Under the assumption that these earthquakes lie within the area defined by the aftershocks, the intersection between the ray described by the *P*-wave polarization and the simple fault model is deemed to be the epicenter of the earthquake. Observed *S*–*P* times at T25A are consistent with this assumption, with most events lying within 3 km of the fault segments.

In this analysis, epicentral uncertainty is controlled by (1) uncertainties in the polarity analysis, (2) uncertainty in the orientation of the horizontal components of T25A, and (3) uncertainty in the location of the fault segments. We are also making the assumption that these earthquakes lie on the same fault planes as the later aftershocks that were recorded by the temporary network. As noted above, *S*–*P* times indicate that these earthquakes are close to these fault planes. A conservative estimate of the uncertainty in the polarization analysis is ±3°. Given an average source–receiver distance of 30 km, this gives an epicentral uncertainty of ±1.5 km. After correcting for the slight misorientation of the horizontal components of T25A, the uncertainty in their orientation was determined to be 1.2° (Ekström and Busby, 2008). This gives an epicentral uncertainty associated with the orientation of the sensor of ±0.6 km. The maximum width of the aftershock zone is approximately 2.8 km; therefore, given that the faults are projected to the center of the seismicity, this gives an epicentral uncertainty of ±1.4 km. It should also be noted that the uncertainty in the aftershock locations, and thus the location of the faults that are used to locate the earthquakes, is approximately ±300 m. In a worst-case scenario, in which all of the possible errors are additive, epicentral errors for the events located using the polarization method should not exceed ±3.8 km. We expect that the errors are much smaller than this.

To assess the polarization method, we compare its locations with those from VELEST. We test it on the six earthquakes in the USGS Preliminary Determination of Epicenters (PDE) catalog that are M ≥2.5 during the period of the temporary deployment for which we computed VELEST locations (25 August 2011–15 December 2011). The VELEST locations have uncertainties on the order of ±300 m in epicentral location. For the earthquakes examined, we find the mean distance between the VELEST locations and the polarization locations is 0.9 km, and the maximum is 1.4 km. Thus, a conservative estimate of the epicentral uncertainty of the polarization locations would be ±2 km. This is likely a more accurate estimate of the uncertainty in the *P*-wave polarization locations than just summing all the possible sources of error.

Early Aftershocks of the 2011 Earthquake Sequence and Earthquakes in 2011 Prior to the August 2011 Earthquake Sequence

We use a hypocentral decomposition location method (Jordan and Sverdrup, 1981; Hayes *et al.*, 2013; McNamara *et al.*, 2014) for two populations of earthquakes: (1) earthquakes that occurred in 2011 prior to the foreshock sequence that began 21 August 2011 and (2) early aftershocks that were recorded prior to the installation of the temporary seismic network. The uncertainty in these locations is ±2.3 km, determined by the mean difference between these locations and the polarization locations used for the foreshocks and mainshock. Although the polarization method that we used to locate the foreshocks has lower uncertainties than the hypocentral decomposition event method, we do not use it because it became too time intensive, given the dramatic increase in earthquake rate following the mainshock.

Appendix B

Magnitude of Completeness

To statistically analyze the seismicity in the Raton Basin, it is important to be certain that the earthquake catalog is complete. Effectively, we need to compute the magnitude threshold for which all earthquakes are found within the earthquake catalog. We use the entire-magnitude-range (EMR) method (Woessner and Wiemer, 2005) and the maximum curvature method (Wiemer and Wyss, 2000) to compute the magnitude of completeness for our earthquake catalogs. We utilized the ZMAP software package to compute these values (Wiemer, 2001). For each computation, we treat the larger minimum magnitude from the EMR and maximum curvature methods as the magnitude of completeness.

The earthquake catalog that we use is a combination of the PDE, the U.S. National Hazard Map (Petersen *et al.*, 2008), ComCat, and Los Alamos Scientific Laboratory seismic array catalogs. We also add in supplementary data from the temporary seismometer deployments in 2001 and 2011. Because we are concerned with the variation of the magnitude of completeness with time (i.e., if the magnitude of completeness is higher at earlier points in the catalog), we divide the catalog into 10-year increments and compute magnitudes of completeness. We compute this for each 10-year period beginning in 1970, with the last period extending through the end of 2013. For example, for a catalog beginning in 1970, we would examine the periods 1970–1979, 1980–1989, 1990–1999, and 2000–2013. We also increment the time periods by years, such that we examine every possible starting year, for example, 1971–1980, 1972–1981, 1973–1982, etc. We examine these time periods using catalogs with radii of 100, 200, 300, and 500 km surrounding a point in the center of the Raton Basin. We use these large radii to ensure that there is enough seismicity to compute a magnitude of completeness for the early years of the catalog when there was little seismicity in the region. Ⓔ Gutenberg–Richter plots are shown for each of the catalog combinations in Figures S1–S10 (available in the electronic supplement to this article).

For the different decade and distance-defined catalogs, we find that the magnitude of completeness varies from 2.7 to 3.8. Thus, a conservative approach for examining the seismicity would be to only consider earthquakes of M 3.8 and larger in our statistics. We also examine the catalog completeness for 2000–present. We find that the magnitude of completeness for this most recent period is 3.0.

Appendix C

Statistical Testing of Earthquake Rate Change

To determine the likelihood that six or seven independent earthquakes would occur in the time period November 1994–December 2013, we use combinatorics. After declustering the catalog, we assume the earthquakes occur randomly in time. The probability that they would occur in any given time period is simply the length of that time period divided by the length of the full study period. We are interested in the coinjection period of November 1994–December 2013 (19 years, 2 months), which is approximately 44% of the full study duration of 44 years (January 1970–December 2013). Thus, the likelihood that any individual earthquake would occur in the coinjection period P_{co} is 44%. The likelihood that an individual earthquake occured prior to the coinjection period P_{pre} is $1 - P_{\mathrm{co}}$, or 56%. To compute the likelihood that all seven earthquakes would occur in that period is P_{co}^7 (0.3%). The likelihood that six earthquakes occur in the coinjection period is P_{co}^6. For this to be coincident with an additional earthquake prior to the coinjection period, we need to multiply the probability of six earthquakes in the coinjection period with the probability that a seventh earthquake occured in the preinjection period (P_{pre}), giving $P_{\mathrm{co}}^6 \times P_{\mathrm{pre}}$. Because each of the seven earthquakes could be the earthquake outside the injection period, there are seven different possibilities. Thus, the probability that six of the seven earthquakes occured in the coinjection period and one earthquake occured in the preinjection period is $P_{\mathrm{co}}^6 \times P_{\mathrm{pre}} \times 7$, giving 2.7%. The likelihood that six or seven of the earthquakes occured in the coinjection period is the sum of the likelihood that all seven earthquakes occured in the coinjection period (0.3%), with the likelihood that six of the seven earthquakes occur in the period (2.7%) or 3.0%.

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Manuscript received 9 January 2014

CASES NO. 20313, 20314, 20472, 20463 and 20465
Index of Division Exhibit No. 7

Exhibit No.	Exhibit Name
7-A	Oil Conservation Division, 1981, New Mexico State Demonstration for Class II Wells Appendix II; *Aquifer Evaluation for UIC: Search for a Simple Procedure*; December 31, 1980.
7-B	New Mexico Oil and Gas Association Presentation Concerning Disposal in the Delaware Mountain Group; February 26, 2018; New Mexico UIC Technical Work Group; 17 p.
7-C	Goetze, P., 2018, Current Status of the New Mexico underground injection control (UIC) Class II program; Oil Conservation Division; presentation for the New Mexico Produced Water Conference 2018; 26 p.
7-D	Lund Snee, J. and Zoback, M., 2018, *State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity*; The Leading Edge (Society of Exploration Geophysicists), Special Section: Injection-induced seismicity; p. 127-134.

CASES 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 7-A

AQUIFER EVALUATION FOR UIC:
SEARCH FOR A SIMPLE PROCEDURE

Submitted to:

Oil Conservation Division
Department of Energy and Minerals
State of New Mexico

Prepared by:

Mike Holland, Oil Conservation Division
Tom Parkhill, Oil Conservation Division
Lee Wilson, Lee Wilson & Associates, Inc.
Mark Logsdon, Lee Wilson & Associates, Inc.
Mike Stahl, Lee Wilson & Associates, Inc.

December 31, 1980

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The initial irregular movement of fresh water, and its subsequent isolation, make it difficult to define a boundary for a protected aquifer. One may encounter oil and water at the same depth within close lateral proximity. A plot of the 175 wells with fresh water shows that some occur in total isolation from the main trends described above. For example, a few oil wells in northern Lea County produce fresh water; almost all are in rocks older than the San Andres Formation and Artesia Group (e.g. Abo Formation). Nothing in the literature or log data accounts for this fresh water, although conceivably it has migrated northward from the Hobbs Channel. For purposes of UIC, these occurrences are so isolated that there is no basis for concluding that a fresh-water aquifer exists.

A fresh-water aquifer does exist in the Capitan Formation and associated San Andres Formation and Artesia Group. Most of the fresh water is produced from wells which occur in clusters within the trend of the Capitan Reef and Hobbs Channel. However, within such clusters there are almost always wells producing saline water from the same depth. Neither data nor geologic theories allow the delineation of a boundary for fresh water.

NEED TO CONSIDER EXEMPTIONS

The Capitan Formation, San Andres Formation and Artesia Group aquifers of Lea County contain localized fresh water and therefore are subject to UIC protection. The Artesia Group and, especially, the San Andres Formation are used for brine disposal and waterflood in the study area. Table 1 lists major salt-water disposal wells in the area which inject brines in the general area of deep fresh water. Perhaps one-fifth to one-quarter of all brine disposal in southeastern New Mexico occurs into zones which are potentially protected aquifers. If injection to these aquifers is disallowed, then all the wells listed in Table 1 would be out of compliance with UIC regulations. The alternative to injection in the San Andres (4,000 - 5,000 feet deep) would be to use Devonian strata, at depths of up to 10,000 feet. A change in injection practices will be expensive and should not be undertaken without further analysis.

The State has one obvious alternative to protecting the deep aquifers of Lea County and phasing out injection into those units. This option is to apply UIC provisions for exemptions.

EVALUATION OF EXEMPTION CRITERIA

Steps 5-8 of Figure 1 indicate the procedure for determining whether the deep aquifers of Lea County may be exempt from UIC regulations. Although EPA personnel were able to provide assistance in application of the regulations, the Agency has developed no formal guidance to assist in the interpretation of the exemption criteria. Therefore, in this study a significant effort was made to develop basic concepts which might apply to the exemption procedures. The conclusions presented are preliminary and may be revised when EPA criteria are established.

TABLE 1.

MAJOR SALT-WATER DISPOSAL WELLS WHICH OCCUR IN FRESH-WATER AREA OF LEA COUNTY, NEW MEXICO.

Location = section, township (south), range (east).

Operator	Location	Injection Interval	Barrels Injected/month	Cumulative Injection
Rice	25-18-37	4446-4527	97,285	27,134,667
Rice	29-18-38	4469-4522	228,627	43,096,101
Rice	30-18-39	5105-5188	31,951	4,967,482
Rice	33-18-37	4500-4975	128,952	35,133,435
Rice	15-19-38	4634-4826	242,138	47,027,165
Rice	1-20-36	4300-4935	127,916	32,282,168
Rice	5-20-37	4515-4920	173,066	40,706,962
Rice	9-20-37	4396-4845	327,309	72,412,835
Rice	20-20-37	4451-4939	98,937	29,012,203
Rice	33-20-37	4500-5077	243,520	36,037,613
Rice	21-21-36		298,109	29,174,043
S & M Oil	5-18-39	5300-5854	17,390	646,793
Conoco	23-20-37	4547-4700	Disconnected	615,979
Truckers	6-21-36	4395-4435	25,170	1,086,652
McCasland	31-21-36		32,343	1,944,331
McCasland	6-22-36	3140-3295	32,343	1,805,883
Conoco	5-23-36	3710-52	Disconnected	70,444

Total injection = 2,105,056 barrels per month (for July 1980); 403,154,756 barrels cumulative in these wells. This is 18.5% of all 1979 injection in southeastern New Mexico.

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 7-B

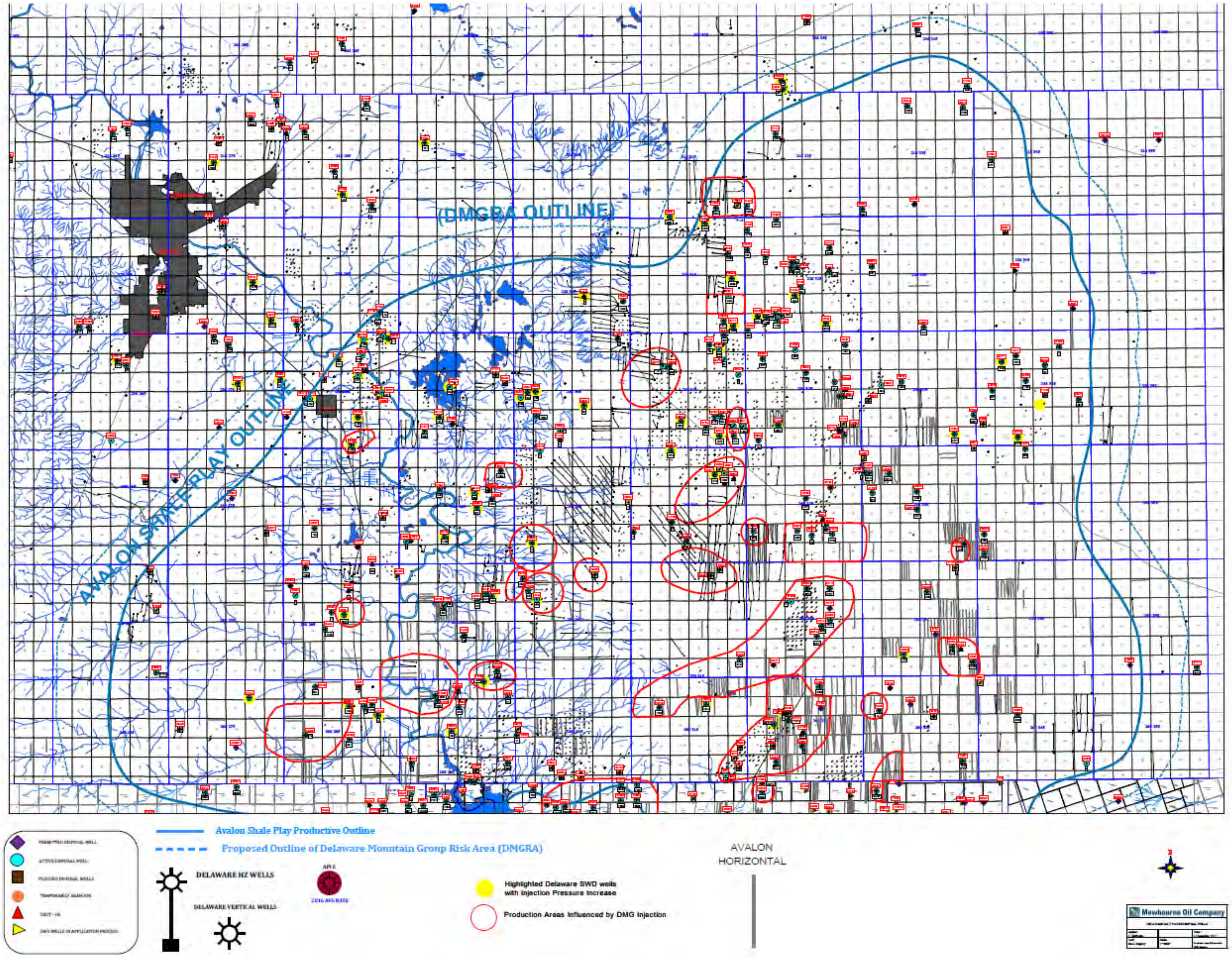
NEW MEXICO UIC TECHNICAL WORK GROUP

2/26/18

UIC TECHNICAL WORK GROUP – DELAWARE ISSUES

- **First UIC Technical Work Group meeting held 8/23/17**
  - **Top topic under subjects requiring immediate attention was "Injection into Delaware Mountain Group".**
  - **ACTION ITEM: OCD requested a map that highlighted where communication had occurred and / or has the potential to occur**

DELAWARE MOUNTAIN GROUP INJECTION RISK AREA



UIC TECHNICAL WORK GROUP – DELAWARE ISSUES

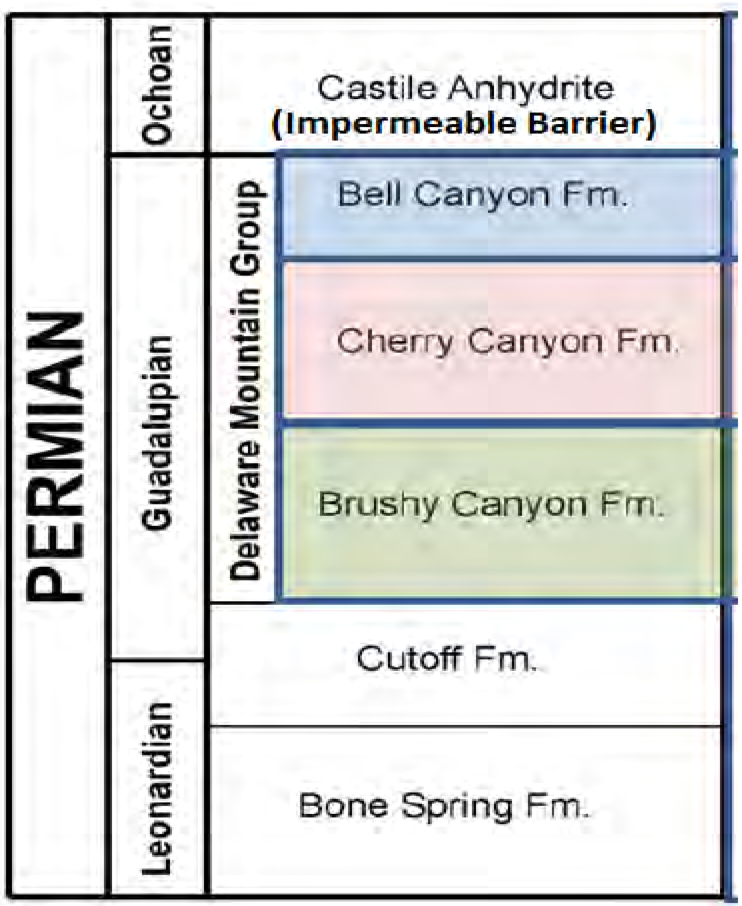
- **Proposed outline of Delaware Mountain Group Risk Area (DMGRA)**
  - **Areas where waste has been created, leading to potential reduction in reserves, are outlined in red**
    - **Complete watering out of producers**
    - **Well performance reduction**
    - **Increase in operating expenses associated with higher water cuts**
  - **All of estimated Avalon Shale productive (blue) area is included within the DMGRA**
  - **Proposed DMGRA outline (dashed blue) includes a two mile buffer envelope**

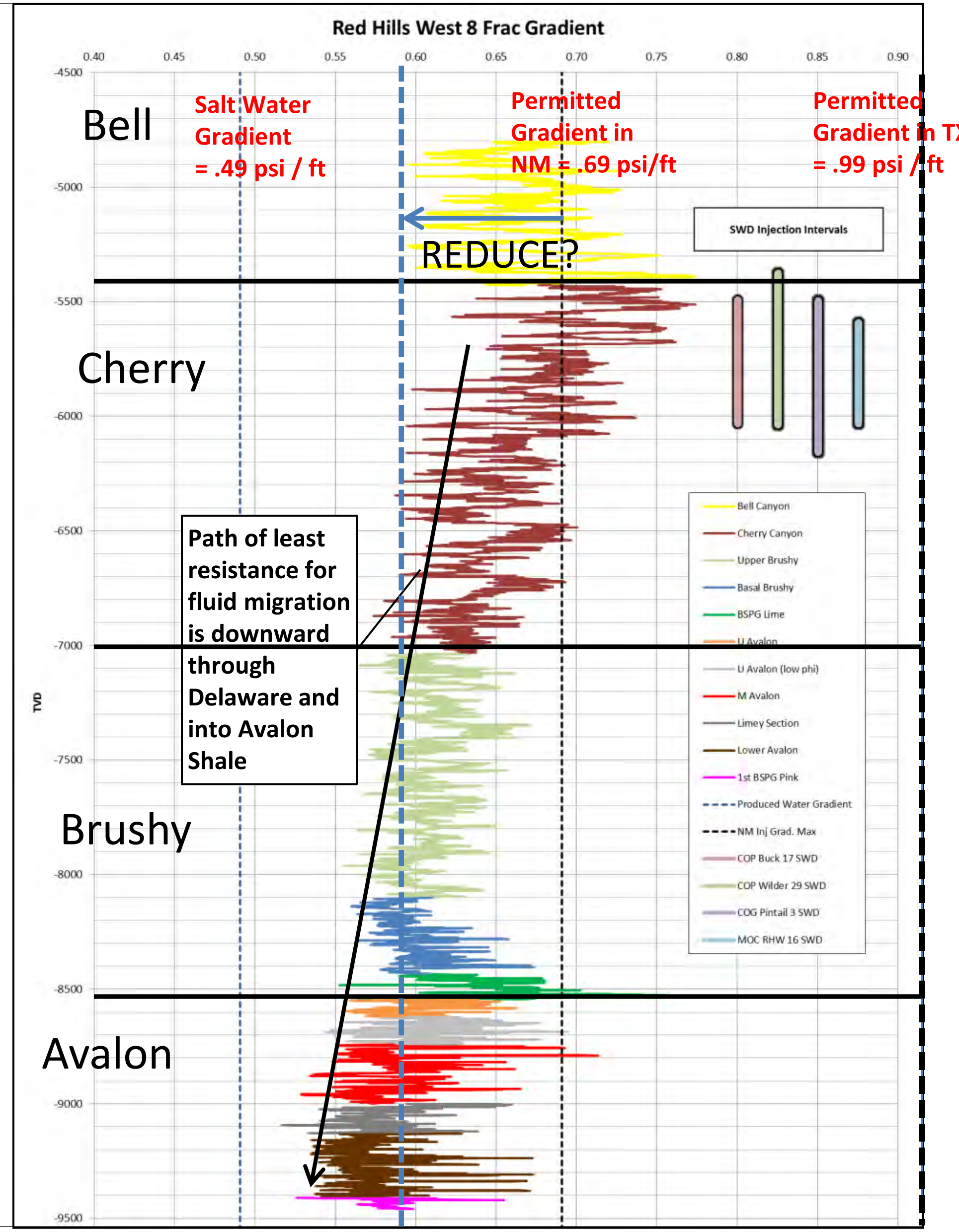
UIC TECHNICAL WORK GROUP – DELAWARE ISSUES

- **Where we are now**
  - **OCD has distributed the DMGRA map for comment**
  - **NMOGA Delaware SWD Team creating a Delaware completion frac gradient database**
  - **OCD has distributed an Injection Pressure Increase guidance document**

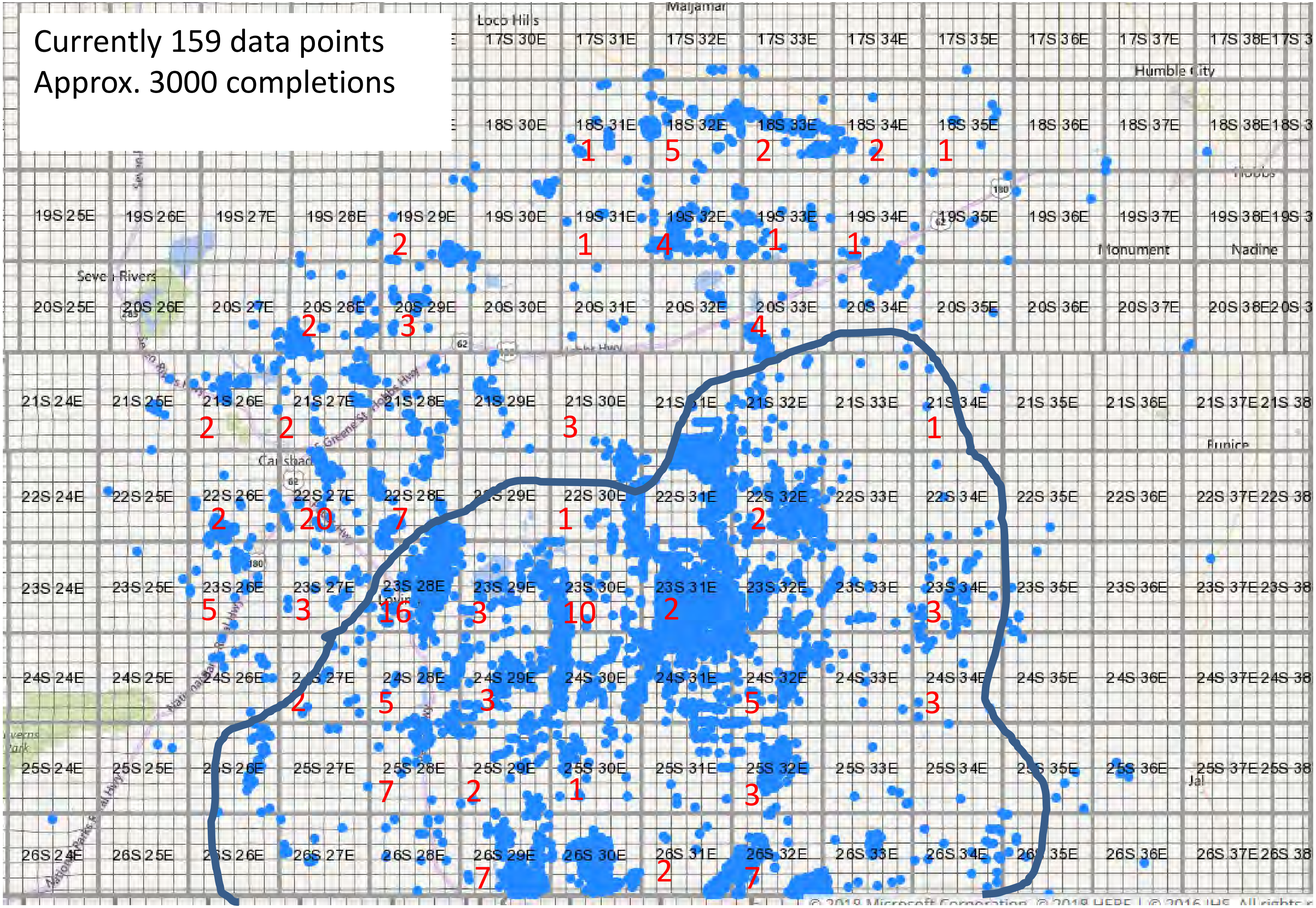
Frac Gradient Data
Pilot Hole Drilled in:
Unit P Section 8 T26S R32E

Stratigraphic Section

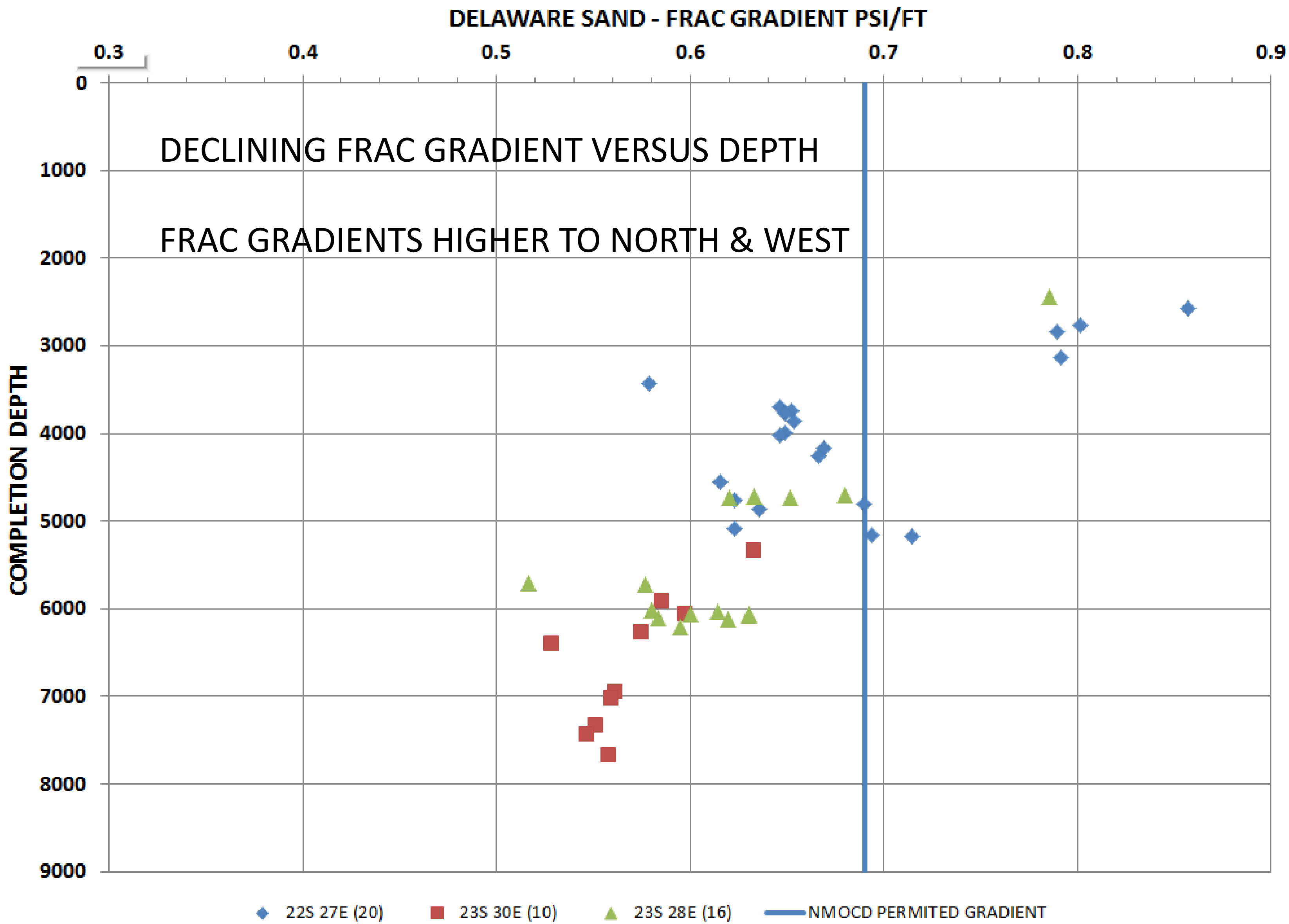




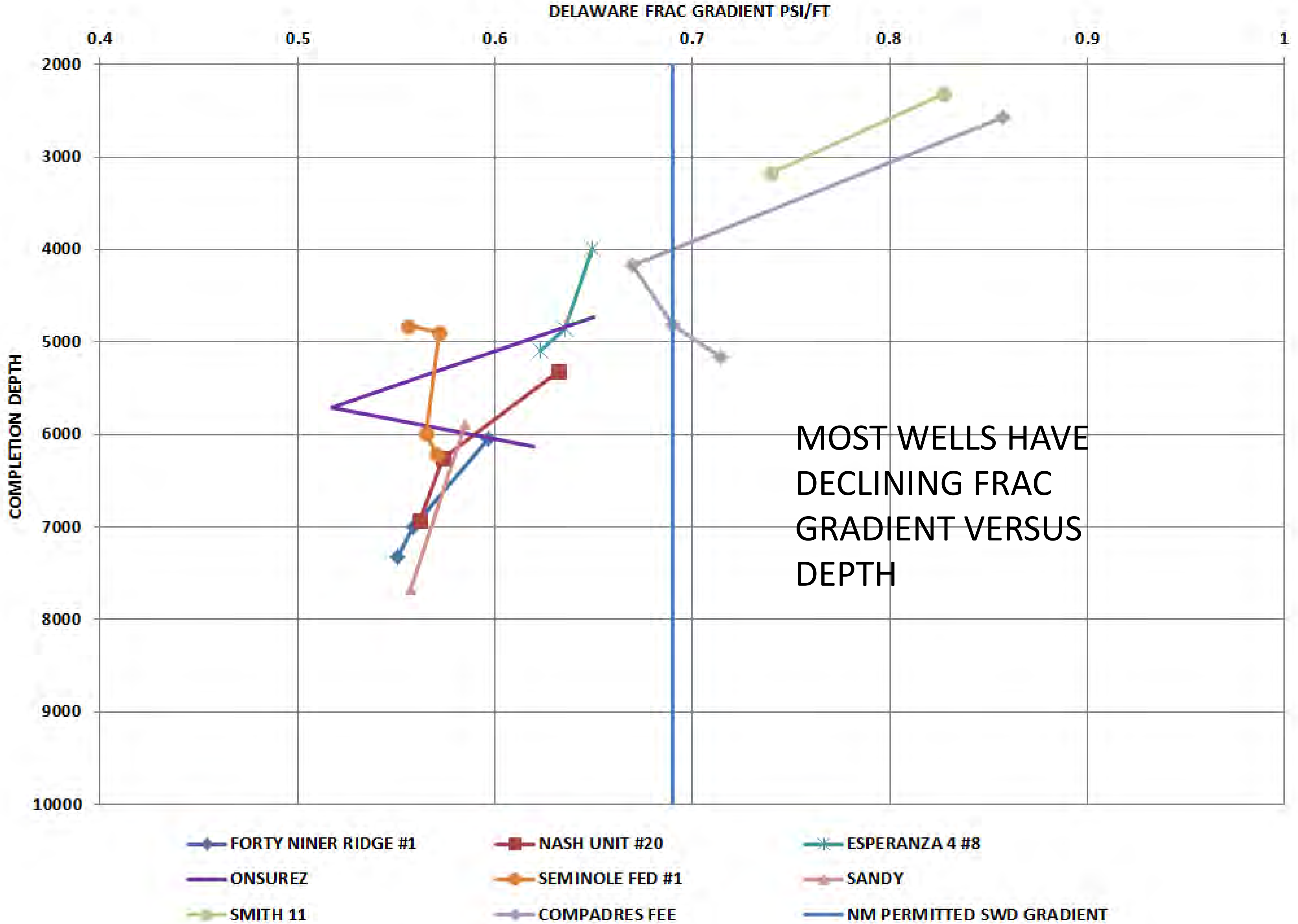
DELAWARE PRODUCER MAP

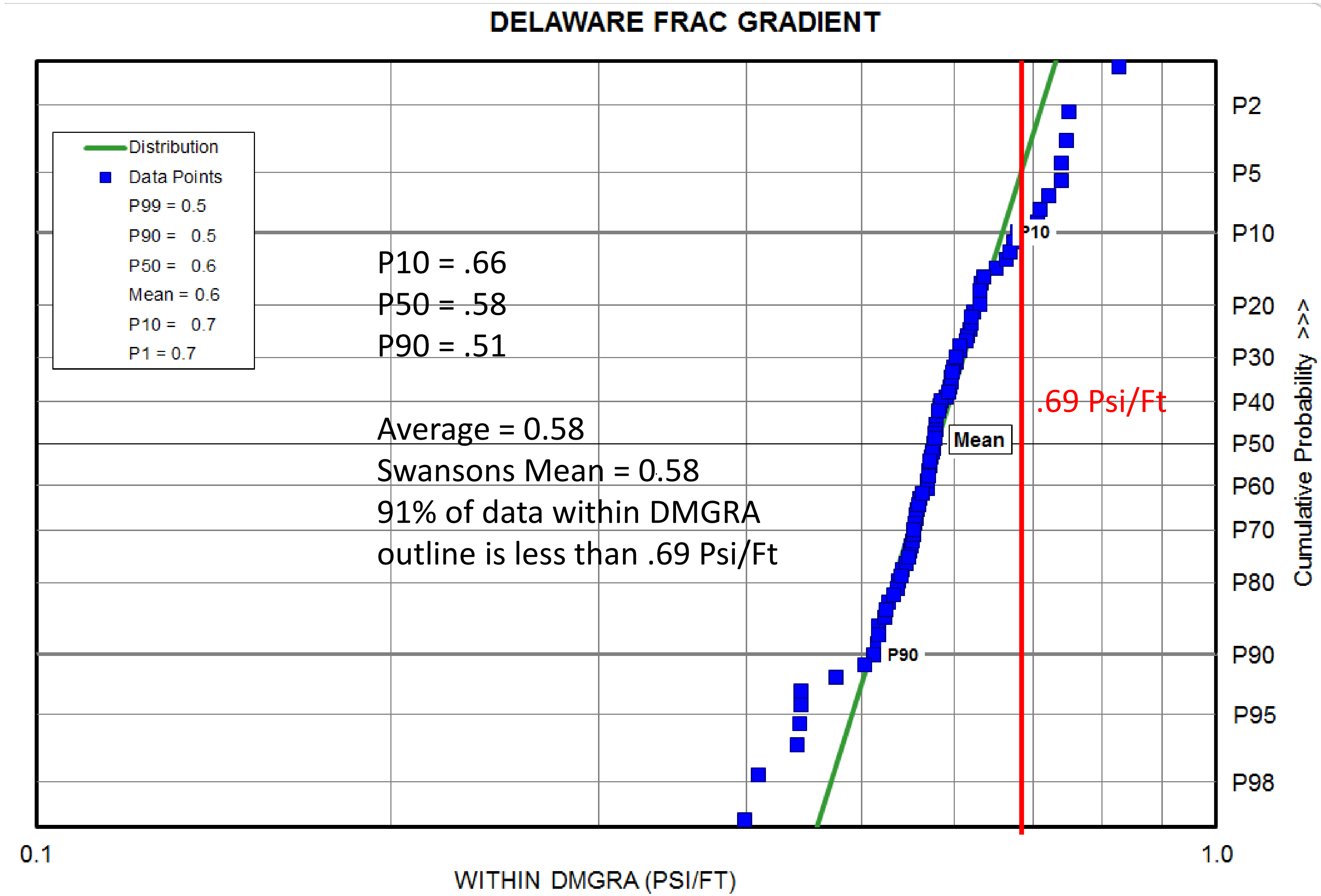


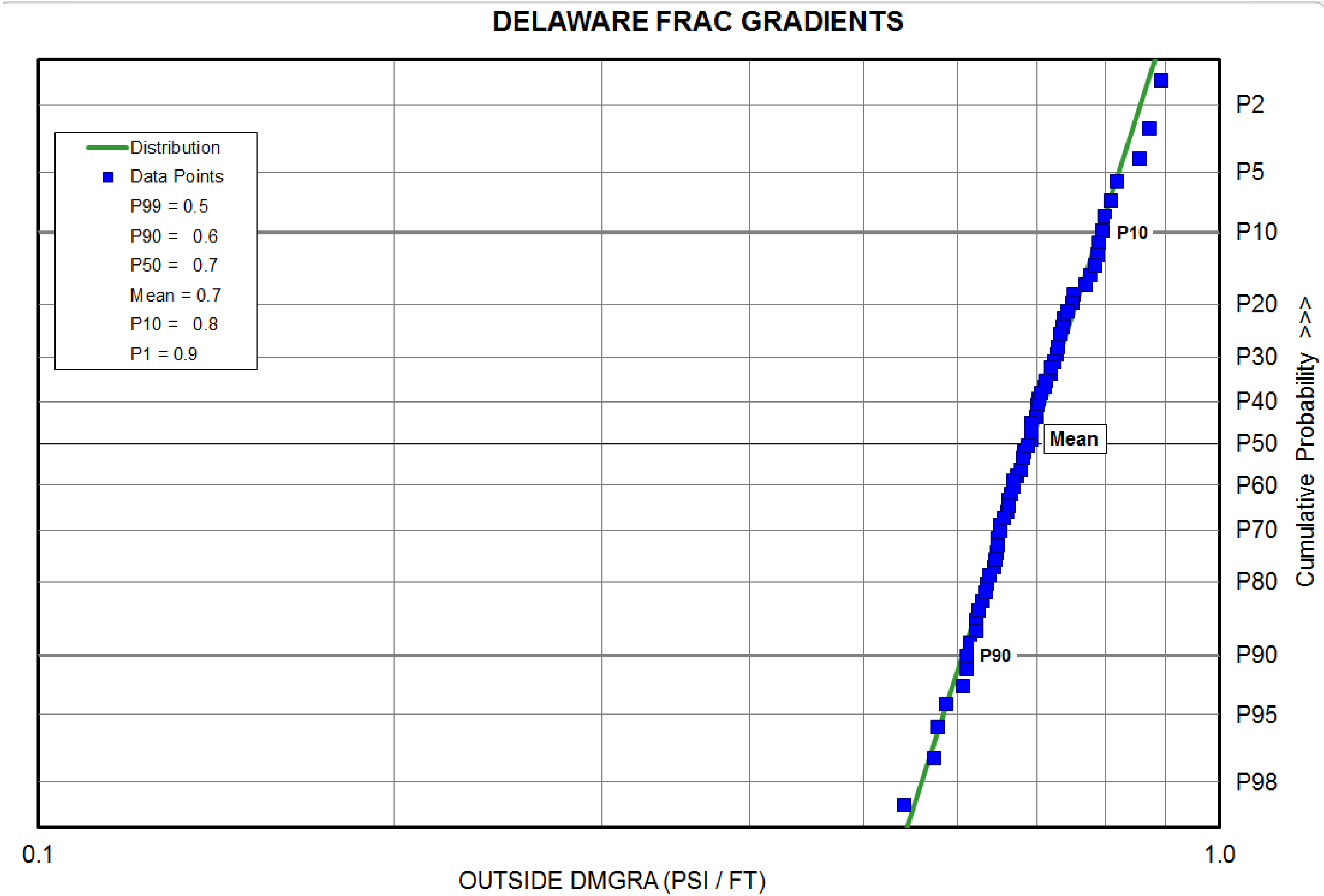
DMGRA OUTLINE X FRAC GRADIENT DATA COUNT WITHIN TOWNSHIP


DELAWARE SAND - FRAC GRADIENT PSI/FT
0.3
0.4
0.5
0.6
0.7
0.8
0.9
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
COMPLETION DEPTH
DECLINING FRAC GRADIENT VERSUS DEPTH
FRAC GRADIENTS HIGHER TO NORTH & WEST
22S 27E (20)
23S 30E (10)
23S 28E (16)
NMOCD PERMITED GRADIENT

CALCULATED FRAC GRADIENTS VERSUS DEPTH – SAME WELL




DELAWARE FRAC GRADIENT
Distribution
Data Points
P99 = 0.5
P90 = 0.5
P50 = 0.6
Mean = 0.6
P10 = 0.7
P1 = 0.7
P10 = .66
P50 = .58
P90 = .51
Average = 0.58
Swansons Mean = 0.58
91% of data within DMGRA
outline is less than .69 Psi/Ft
.69 Psi/Ft
Mean
P10
P90
P2
P5
P10
P20
P30
P40
P50
P60
P70
P80
P90
P95
P98
Cumulative Probability >>>
0.1
1.0
WITHIN DMGRA (PSI/FT)



DELAWARE FRAC GRADIENTS
Distribution
Data Points
P99 = 0.5
P90 = 0.6
P50 = 0.7
Mean = 0.7
P10 = 0.8
P1 = 0.9
P10
Mean
P90
P2
P5
P10
P20
P30
P40
P50
P60
P70
P80
P90
P95
P98
Cumulative Probability >>>
0.1
1.0
OUTSIDE DMGRA (PSI / FT)

NEW MEXICO OIL CONVERVATION DIVISION

UIC PROGRAM GUIDANCE

APPLICATION PROCESS FOR INJECTION PRESSURE INCREASES

Where the injection well is located on federal surface, the Sundry Notice of Intent describing the proposed SRT operation will be submitted and approved by the BLM Field Office. The operator will supply a copy of the same sundry to the OCD District Office. The BLM may require supplementary testing not related to the SRT and may not require the pre-SRT testing requested by OCD. OCD has the authority for approval of any injection pressure increase for wells operated with orders (permits) issued under Division rule 19.15.26 NMAC.

Guidance for Conducting a Step-Rate Test

1. The operator must submit Division Form C-103 to the OCD District office with the description of the procedure for the SRT. The procedure will include the following information:
   - ☐ A description of the equipment for measurement and data recording (manufacturer and model) Note: the pressure gauge and recorder must have an appropriate range for use during the test.
   - ☐ Summary of injection volumes for last five years with average injection pressure.
   - ☐ Summary of well treatments and pressures especially any historical Instantaneous Shut-in Pressure (ISIP).

2. Once the operator has an approved Sundry Notice, the operator shall notify the appropriate OCD District office at least 72 hours prior to the scheduled SRT so that OCD personnel may be present to witness the test.

3. A bradenhead test (if required by the District) and mechanical integrity test (MIT) will be performed before the SRT. If the subject well fails either test, then the SRT will be suspended until the mechanical integrity issue(s) has been remediated. The mechanical integrity testing may be modified at the discretion of the District Supervisor.

4. The casing and bradenhead pressures will be monitored during the test. All wellhead equipment must be rated for the anticipated pressures.

5. Bottomhole pressure measurements will be required for wells deeper than 1000 feet (ft) and injection rates greater than one (1) barrel per minute (BPM).

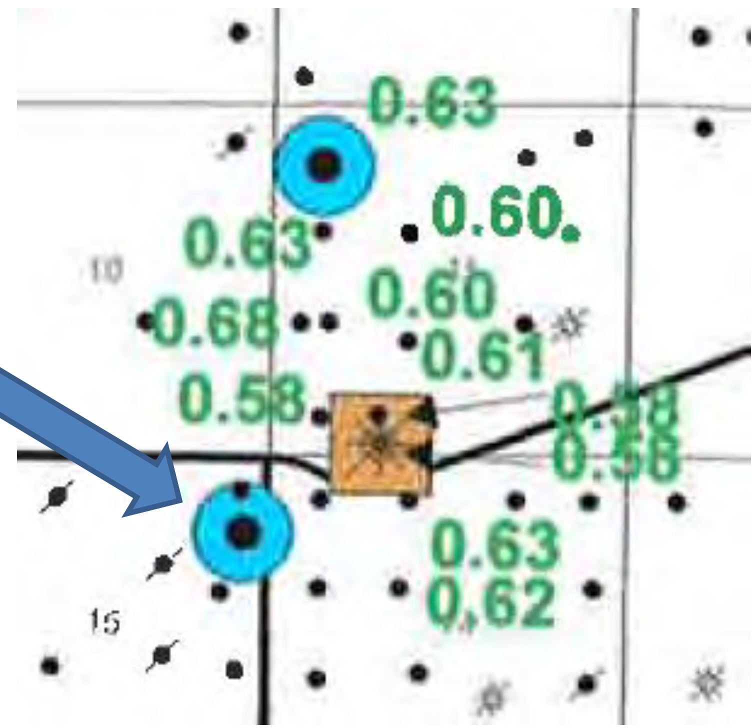
6. Wells currently injecting must be shut-in at least 48 hours before the test unless the shut-in pressures indicate that the well has not adequately stabilized and a longer time is required for the permitted interval to approximate pre-injection conditions.

SRT performed in 2007 to obtain a higher permitted wellhead injection pressure.

The initial SRT test point:

839 Psig Surface
3046 Psig BH
Equivalent to .70 Psi / ft gradient

Approved IPI @ 0.82 Psi / Ft



Average Frac Gradient of vertical producers = .61 psi / ft

7. Selection of rates for the SRT will be developed by the operator based on the proposed operation and the historical information of the well. Suggested rates for the test are 5%, 10%, 20%, 40%, 60%, 80% and 100% of the proposed maximum daily injection rate at the corresponding pressure. The intent is to complete a SRT with at least three (3) steps below the 0.5 psi/ft gradient and three (3) steps above the fracture parting pressure (breakdown pressure). Starting pump rates and pressures must be lower than the current rates and pressures if the well is currently injecting. It may be necessary to backflow the well to reduce initial SRT pressures.

8. Each step shall be at least 30 minutes in duration unless otherwise determined by the OCD. Longer step intervals of 60 minutes shall be required for low permeability injection intervals (less than 0.5 millidarcies) and for open-hole intervals greater than 500 feet in length. The operator may request, in the submission of the Sundry Notice of

Intent, a modification of the time length for the step intervals with an explanation for the modification. The goal is for increments with equal time and rate and allow for downhole stabilization of pressure for each step.

9. <u>The duration of the step intervals for the SRT must not change during the test or the test results will not be deemed adequate for determining an accurate fracture parting pressure.</u>

10. Pumping equipment must be able to pump at the rates and pressures needed for the test. Rate changes will be 0.5 BPM or smaller unless the OCD witness determines that bigger rate changes are necessary due to small incremental increases in pressure.

11. The operator shall ensure that there is enough water to conduct the entire test.

12. The completed SRT results are to be submitted to the Engineering Bureau in Santa Fe and should include the following information:
    - ☐ Administrative application checklist (available on OCD website under Unnumbered Forms on Form webpage).
    - ☐ Cover letter with contact information, general description of test and pressure increase being proposed.
    - ☐ Complete data summary including injection rates, duration of each step, pressure measurements (surface and bottom hole) and the ISIP.
    - ☐ SRT-specific information: location of pressure gauges (depth); initial bottomhole pressure; injection fluid type and specific gravity.
    - ☐ Graph summary of pressure versus injection rate with interpretation.
    - ☐ Current well completion diagram.
    - ☐ Copy of the order authorizing the injection into the well.

13. If a pressure increase is granted, it shall be limited for use in the well with the same tubing, size, length, and type of interior coating as present for the SRT. If these components are changed, the operator must ask the Engineering Bureau to re-calculate the surface pressure limit, which may require another SRT.

COMMENTS RECEIVED TO DATE

- **Should offset operators within ½ mile radius be notified prior to running SRT?**
- **Should there be the requirement to send offset operators, within ½ mile radius, a copy of the SRT application packet?**
- **Item 13: should a new fracture stimulation on a SWD well be considered a "change component" that may require another SRT?**

<u>DEADLINE FOR COMMENTS 5/01/18</u>

NEW MEXICO

emnrd

Energy, Minerals and Natural Resources Department

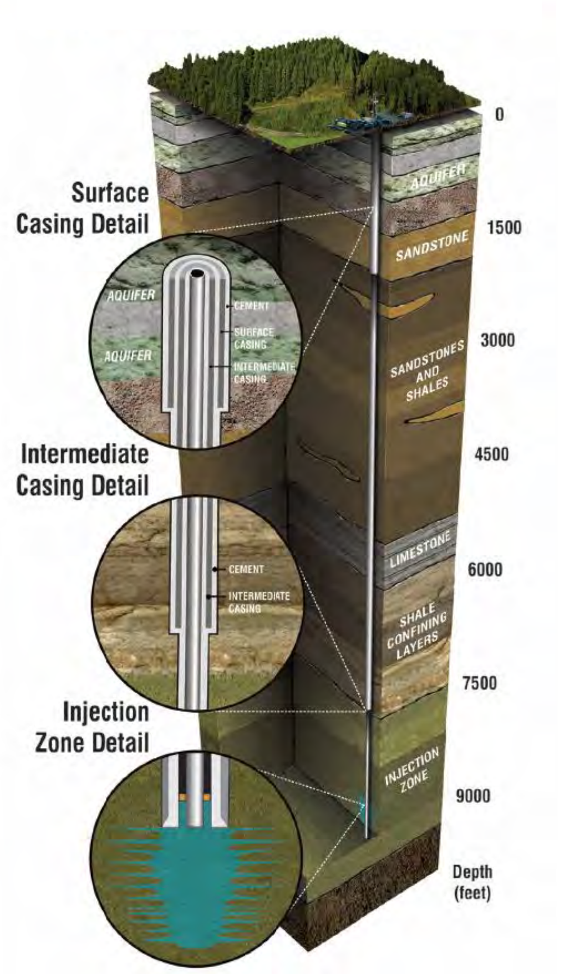
CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 7-C

Current Status of the New Mexico Underground Injection Control (UIC) Class II Program

Phillip Goetze, Engineering Bureau
New Mexico Oil Conservation Division

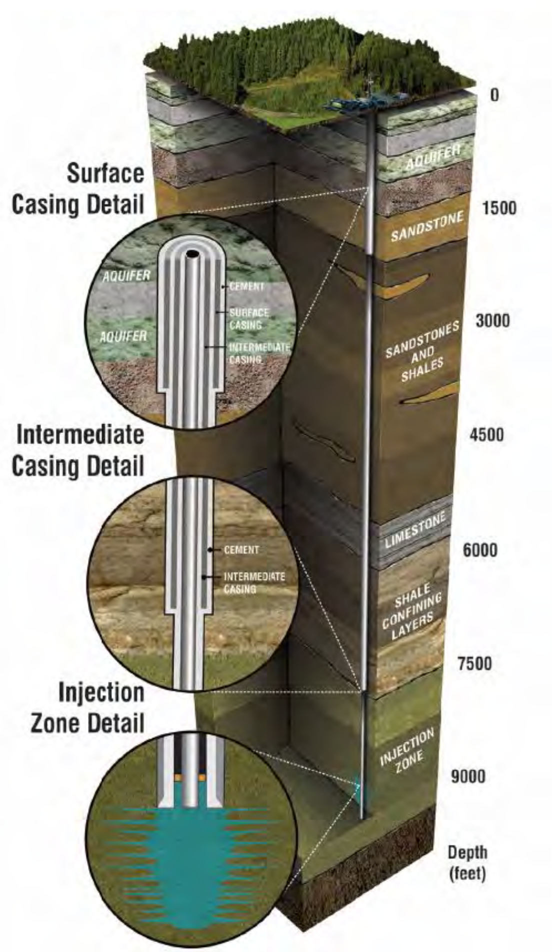
State Primacy Under the Safe Drinking Water Act (SDWA)

- In 1981, the Oil Conservation Division provided the EPA with a Program Demonstration, called the *New Mexico State Demonstration for Class II Wells,* as required under Part C, Section 1425 of the SDWA (Public Law 93-523 as amended).
- Following the review by EPA, the Program Demonstration was accepted and the state was approved for primacy effective March 7, 1982.
- This primacy allowed the Division to issue permits, referred to as "orders", and regulate operations for Underground Injection Control (UIC) Class II wells.
- This primacy agreement resulted in rulemaking which is found in the New Mexico Administrative Code (NMAC) under Title 19, Chapter 15, Part 26 Injection.



State Primacy Under the Safe Drinking Water Act (SDWA)

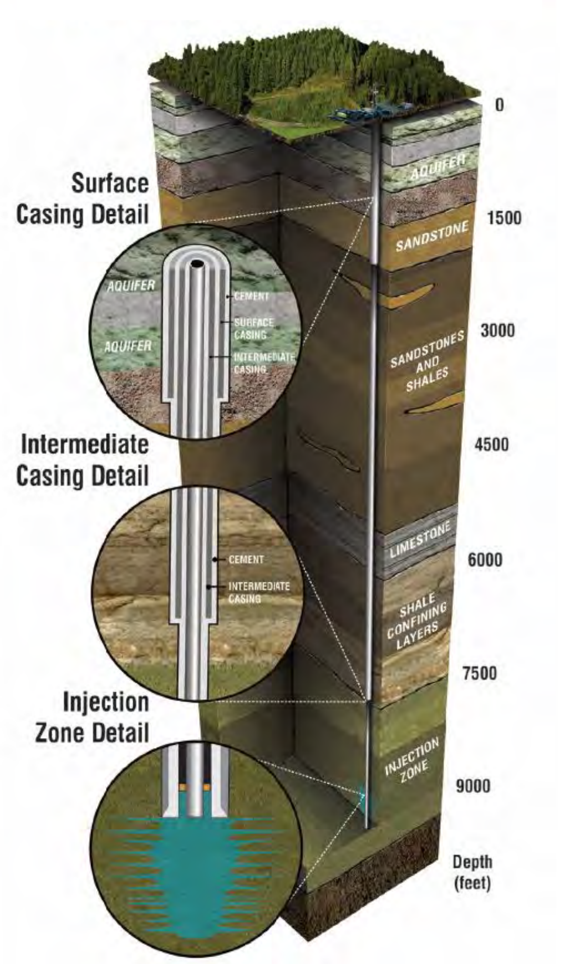
- The current method of application for an order approving injection begins with the submission of Form C-108 that contains the information such as the proposed injection interval and the underground sources of drinking water (USDWs) in the area, suitable drilling, casing, and cementing programs that protect USDWs, an evaluation of penetrating wells within the Area of Review, description of the sources of fluids to be disposed and notification.
- The applicant must be an operator in the state of New Mexico and must be in compliance with Division rules on financial assurance and inactive wells.
- If the application is protested, then the application cannot be considered for administrative approval and must be considered in a hearing before an examiner or the Oil Conservation Commission.



State Primacy Under the Safe Drinking Water Act (SDWA)

- Three groups of injection activities are approved under 19.15.26 NMAC:
  1. Enhanced recovery (ER) wells: primarily waterfloods, water-alternating gas (WAG) flooding operations, and pressure maintenance projects
  2. Hydrocarbon storage wells: injection wells for the underground storage of liquified hydrocarbons
  3. Disposal wells: produced water disposal wells and acid-gas injection wells. Disposal wells for produced water are referred to as both UIC Class II wells or salt water disposal (SWD) wells
- Exempted E&P Waste

  UIC Class II or SWD wells are permitted to accept waste resulting from oil and gas exploration and production (E&P). These wastes commonly include produced water associated with production from a well, well completion and stimulation operations (including flowback), drilling fluids and workover wastes



Additional Requirements for Review of Injection Applications

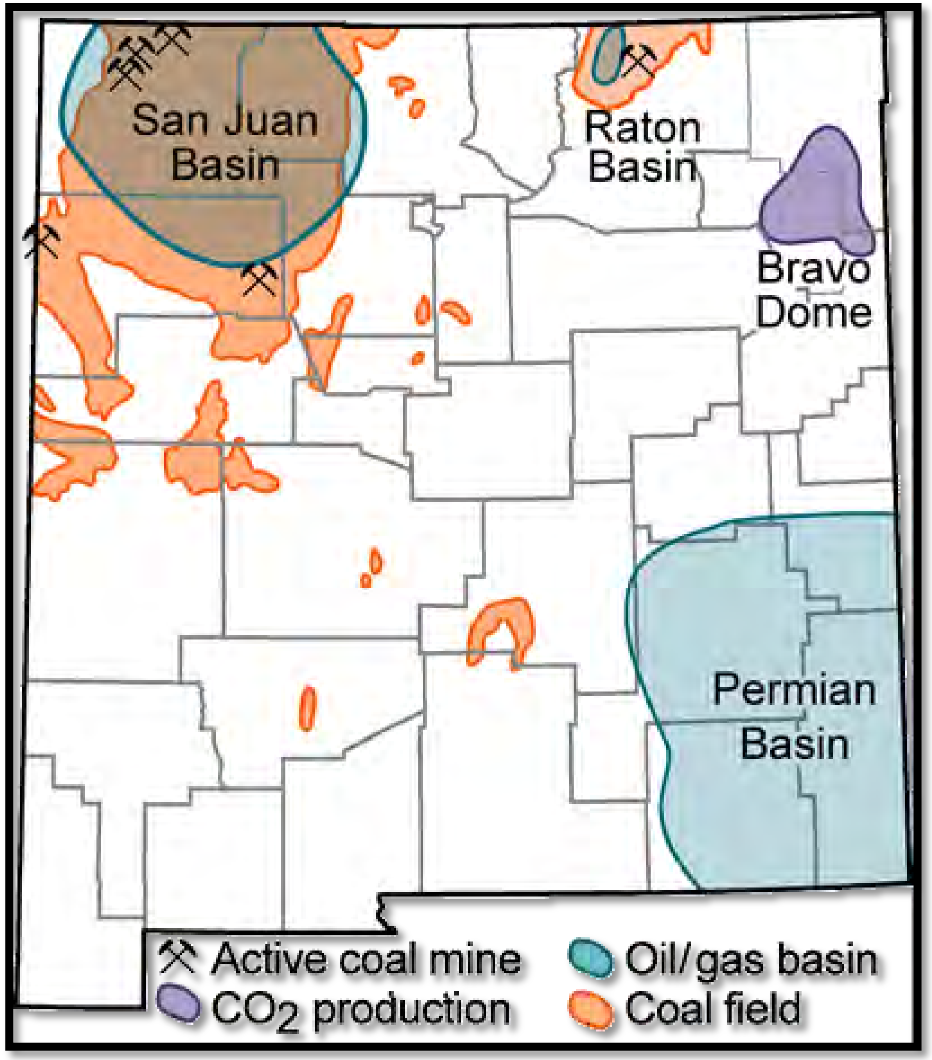
- Along with authority granted to the state under the SDWA, the New Mexico Oil and Gas Act of 1978 (NMSA) delegated additional responsibilities when considering an application, the Division is authorized to make rules, regulations and orders:

70-2-12. Enumeration of powers.

B. (4) to prevent the drowning by water of any stratum or part thereof capable of producing oil or gas or both oil and gas in paying quantities and to prevent the premature and irregular encroachment of water or any other kind of water encroachment that reduces or tends to reduce the total ultimate recovery of crude petroleum oil or gas or both oil and gas from any pool;

- The Bureau of Land Management also participates in the Division’s UIC Program through the assessment of applications in the Secretary’s potash area, the assessment of impacts to hydrocarbon potential in proposed disposal intervals that include federal mineral estate, and with approvals of Applications for Permits to Drill for disposal wells on federal lands.

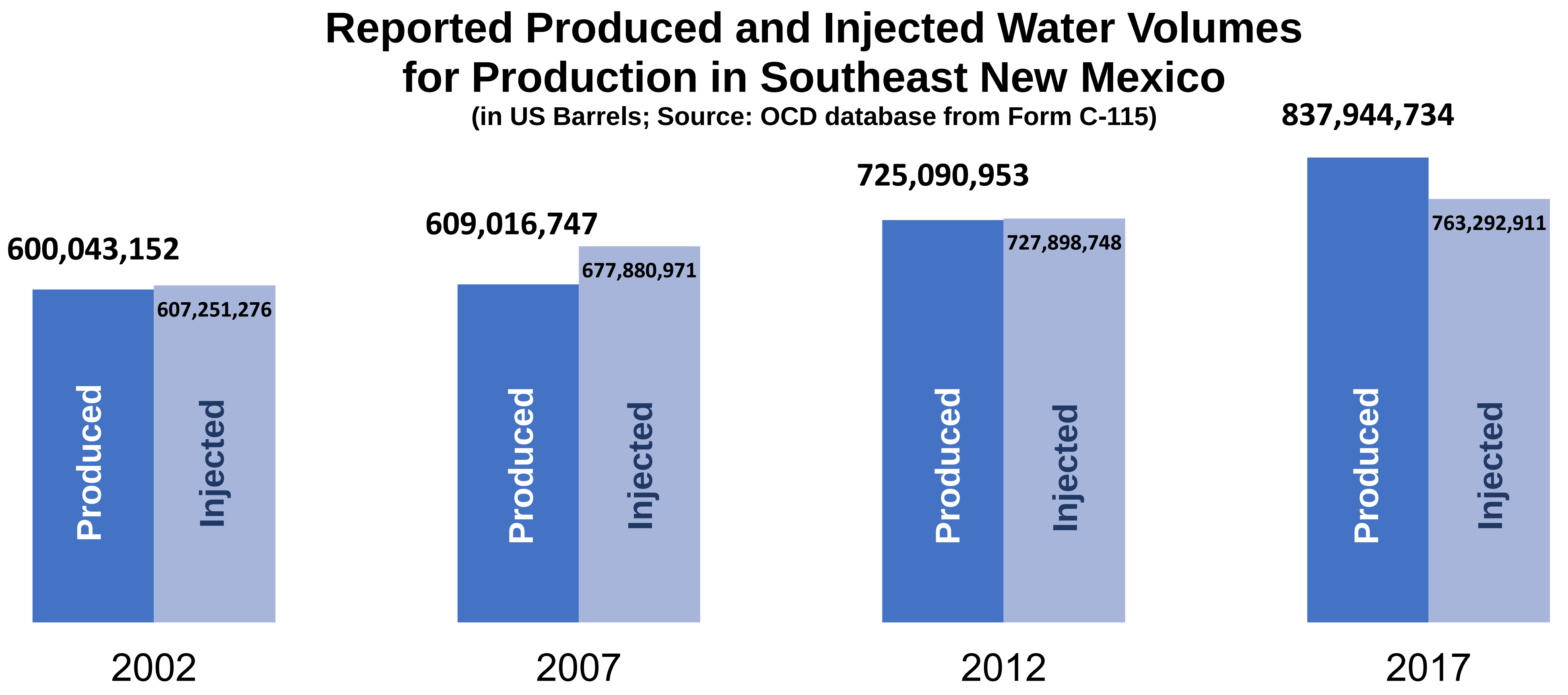
Summary of Disposal Activities in New Mexico By The Numbers



- Since 2004, horizontal drilling has grown to become the primary method of completion for oil and gas wells in New Mexico.
- With the expansion of horizonal completions, the greatest demand for proper disposal has occurred in the Permian Basin.
- Produced water disposal in the San Juan and Raton Basins, with coal-bed methane wells as the primary source of produced water, has not significantly increased as compared to the Permian Basin.

Summary of Disposal Activities in New Mexico By The Numbers

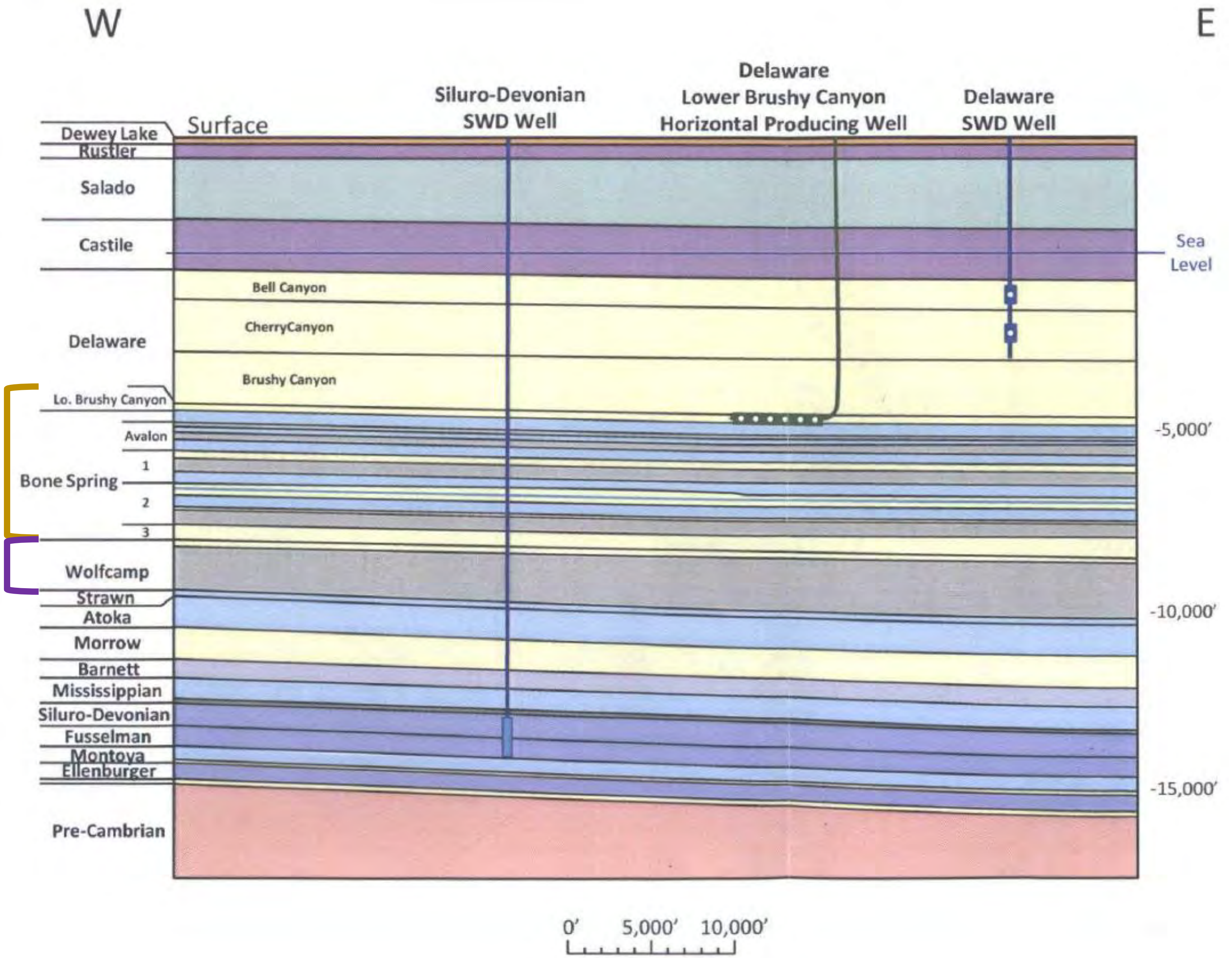
- The Division's November database shows there are 832 active SWD wells statewide with 729 wells (88%) located in the New Mexico portion of the Permian Basin.
- Of the approved 116 SWD orders yet to be drilled or are drilling, 113 are located in the Permian Basin.



Recent Developments in Disposal Activities in Southeast New Mexico

Expansion in Exploration and Development of Permian Targets

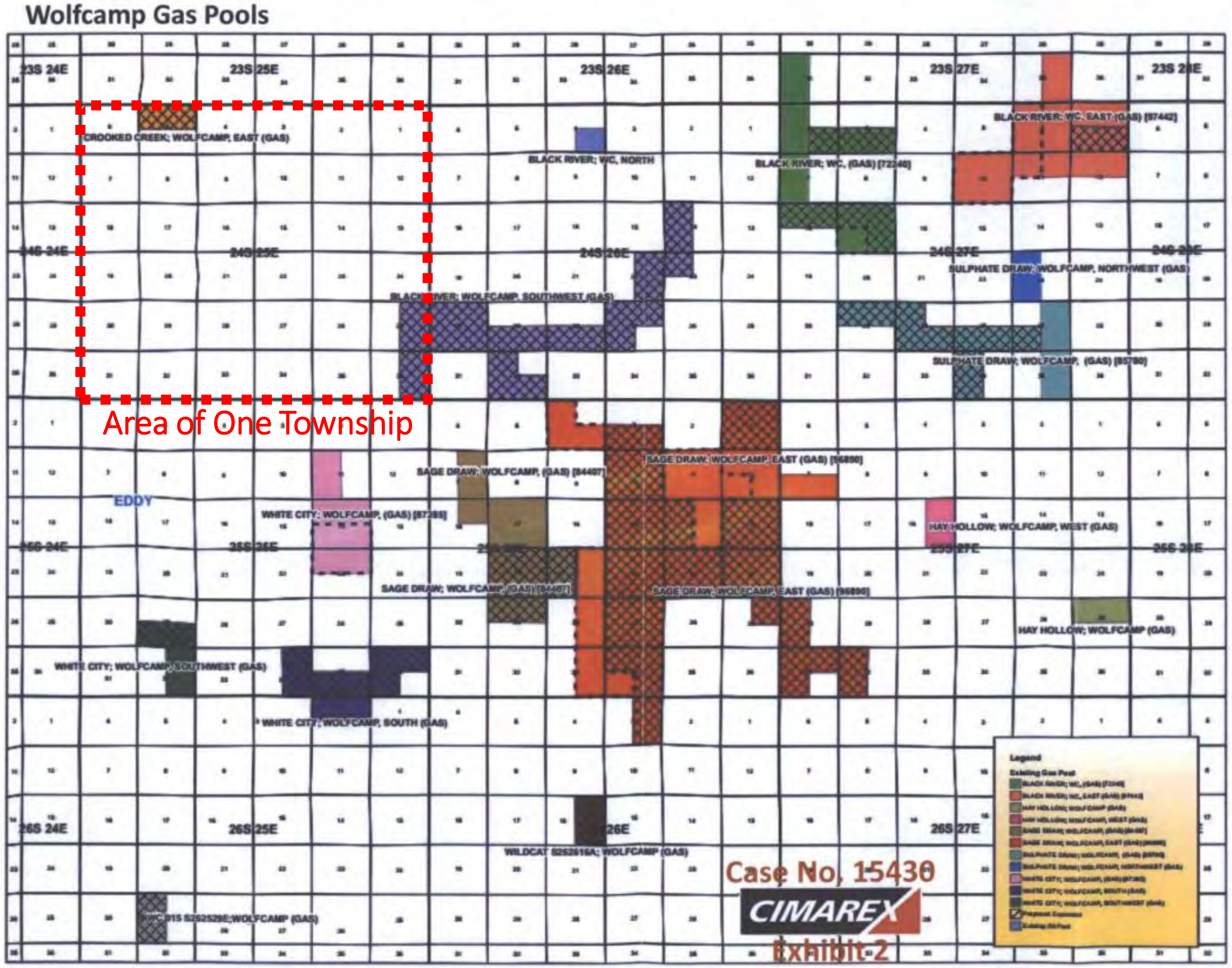
- The primary targets for earlier horizontal wells have been intervals in the upper Permian including:
  - ❑the Bone Spring Formation,
  - ❑the Avalon Shale which occurs at the top of the Bone Spring Formation, and
  - ❑the lower Brushy Canyon Formation at the base of the Delaware Mountain Group.
- During the last two years, there has been a significant shift in new horizontal well completions to include the lower Permian Wolfcamp Formation.



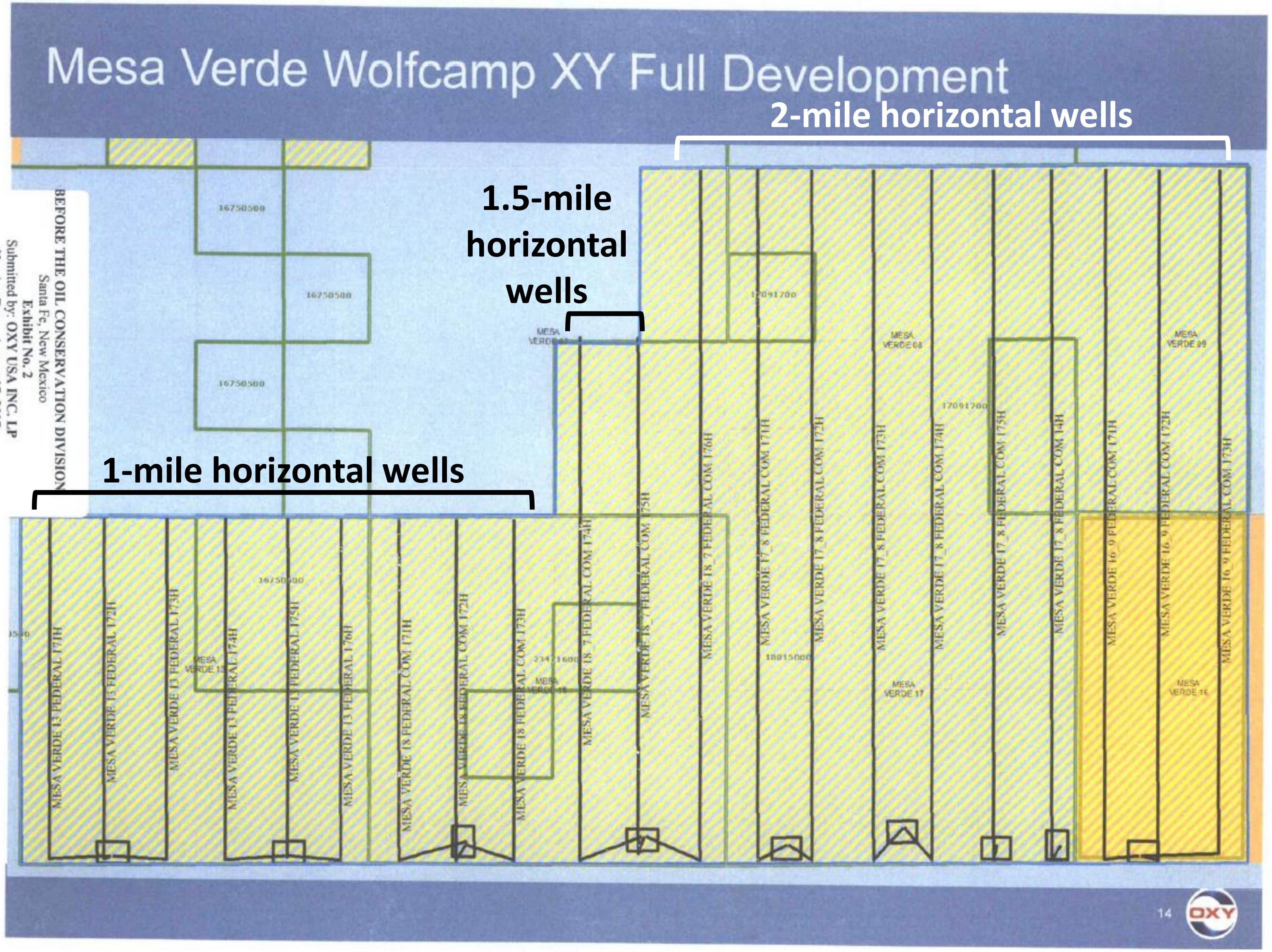
Recent Developments in Disposal Activities in Southeast New Mexico

Expansion in Exploration and Development of Permian Targets

- The recent establishment of the Purple Sage (Wolfcamp) pool by combining several smaller pools into a single pool covering 30 townships reflects the significant increase in drilling activity, especially in the area south of Loving extending to the New Mexico – Texas state line.
- Other Wolfcamp plays are being identified to the east of this pool and are being consolidated for drilling programs.



Recent Developments in Disposal Activities in Southeast New Mexico



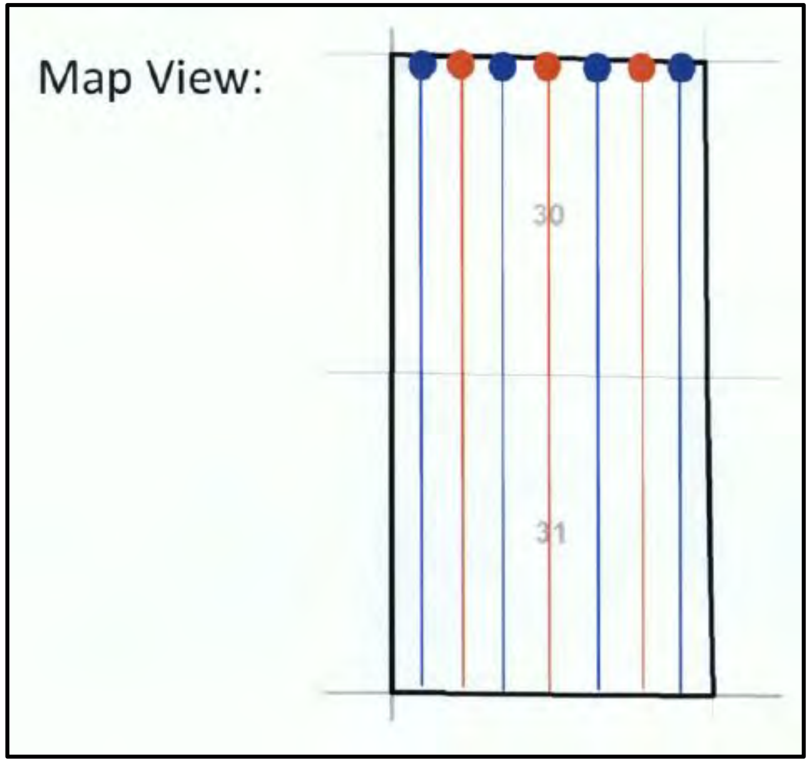
Expansion in Exploration and Development of Permian Targets

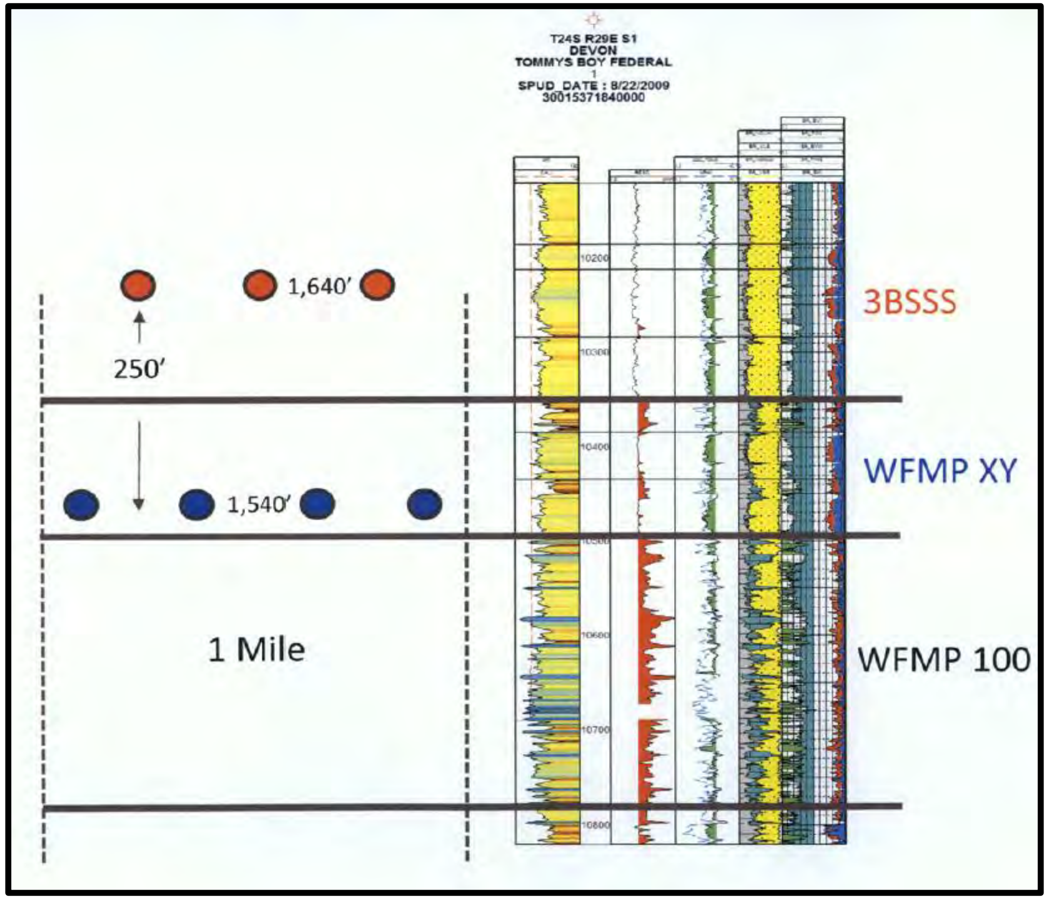
- In addition to an increase in a variety of target intervals, operators have adopted their drilling and completion programs to optimize well production.
- Operators now identify "batch drilling" along with "zipper fracking" of individual wells as preferred practices to increase well performance, reduce completion costs, and improve the ultimate recovery of lease tract.

Recent Developments in Disposal Activities in Southeast New Mexico

Expansion in Exploration and Development of Permian Targets

- Other new completion techniques include staggered placement of horizontal wells in two formations with close proximity. This example shows targets in the base of the Bone Spring Formation and the top of the Wolfcamp Formation.

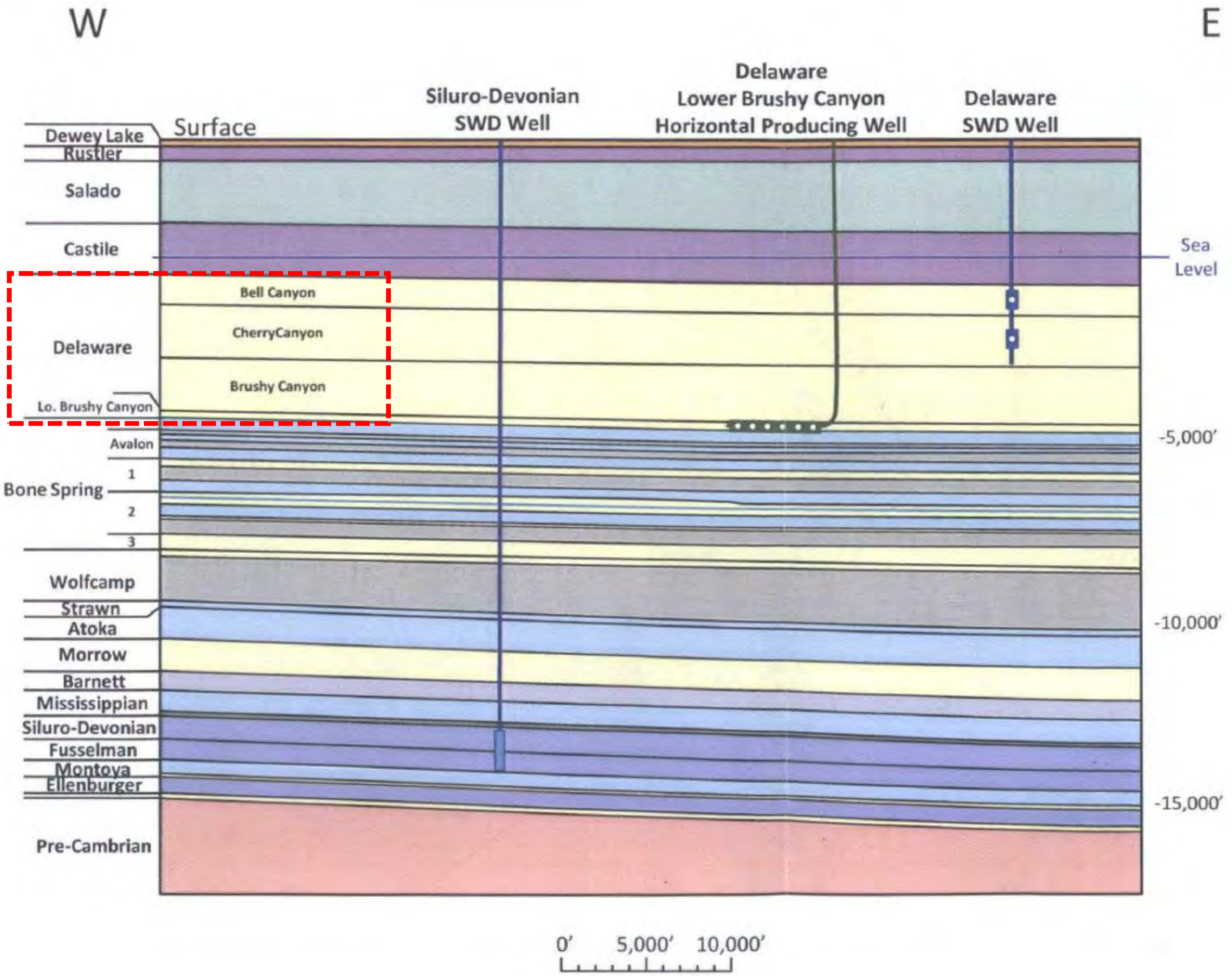




Recent Developments in Disposal Activities in Southeast New Mexico

Delaware Mountain Group

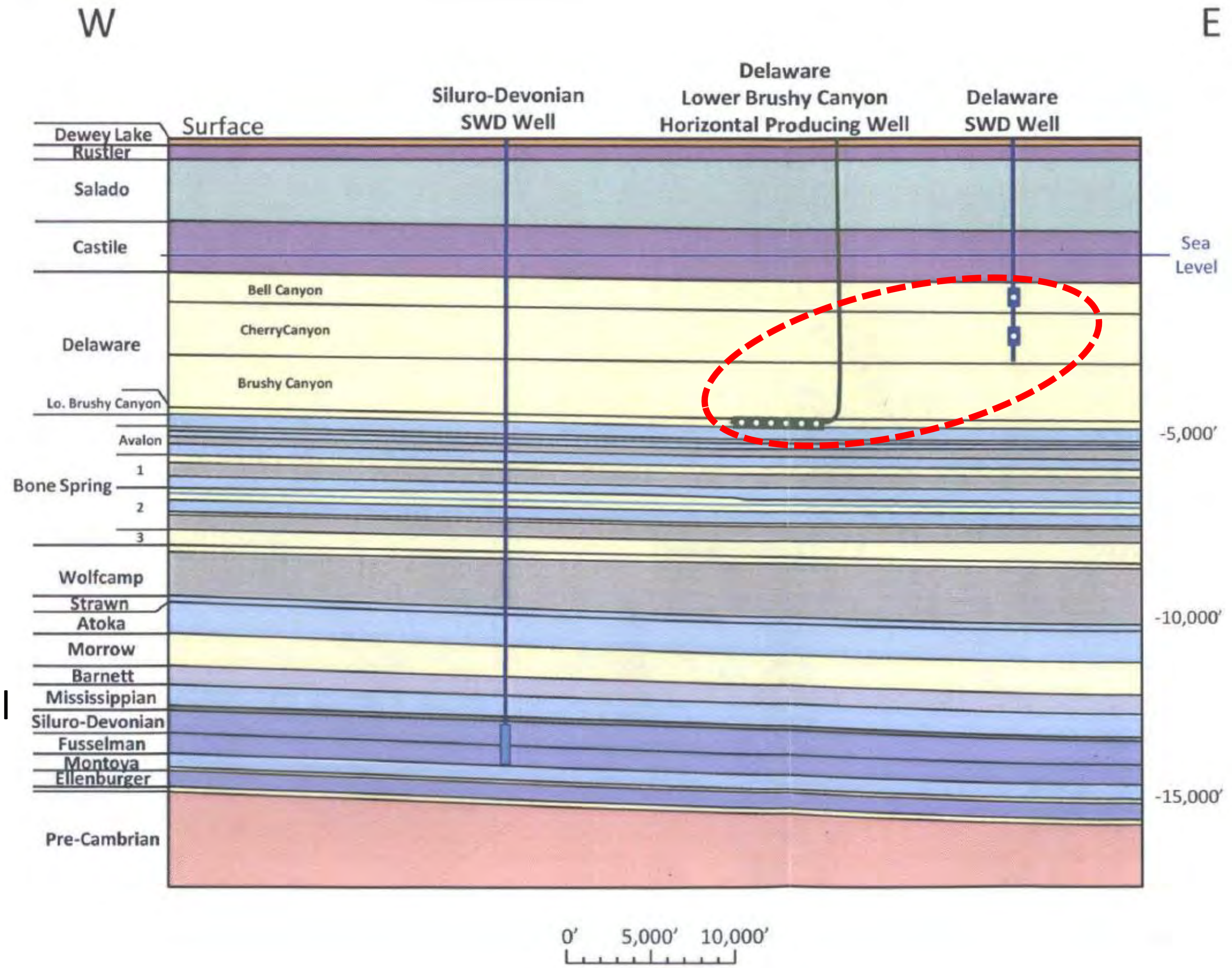
- Consists of the Bell Canyon, Cherry Canyon and Brushy Canyon Formations.
- Prior to the widespread use of horizontal wells and fracking techniques, the Delaware Mountain Group (DMG) was the favored strata for disposal of produced water.
- As the majority of wells were being drilled and completed as horizontal wells, oil and gas production increased and, correspondingly, the need for disposal of additional E&P wastes.



Recent Developments in Disposal Activities in Southeast New Mexico

Delaware Mountain Group

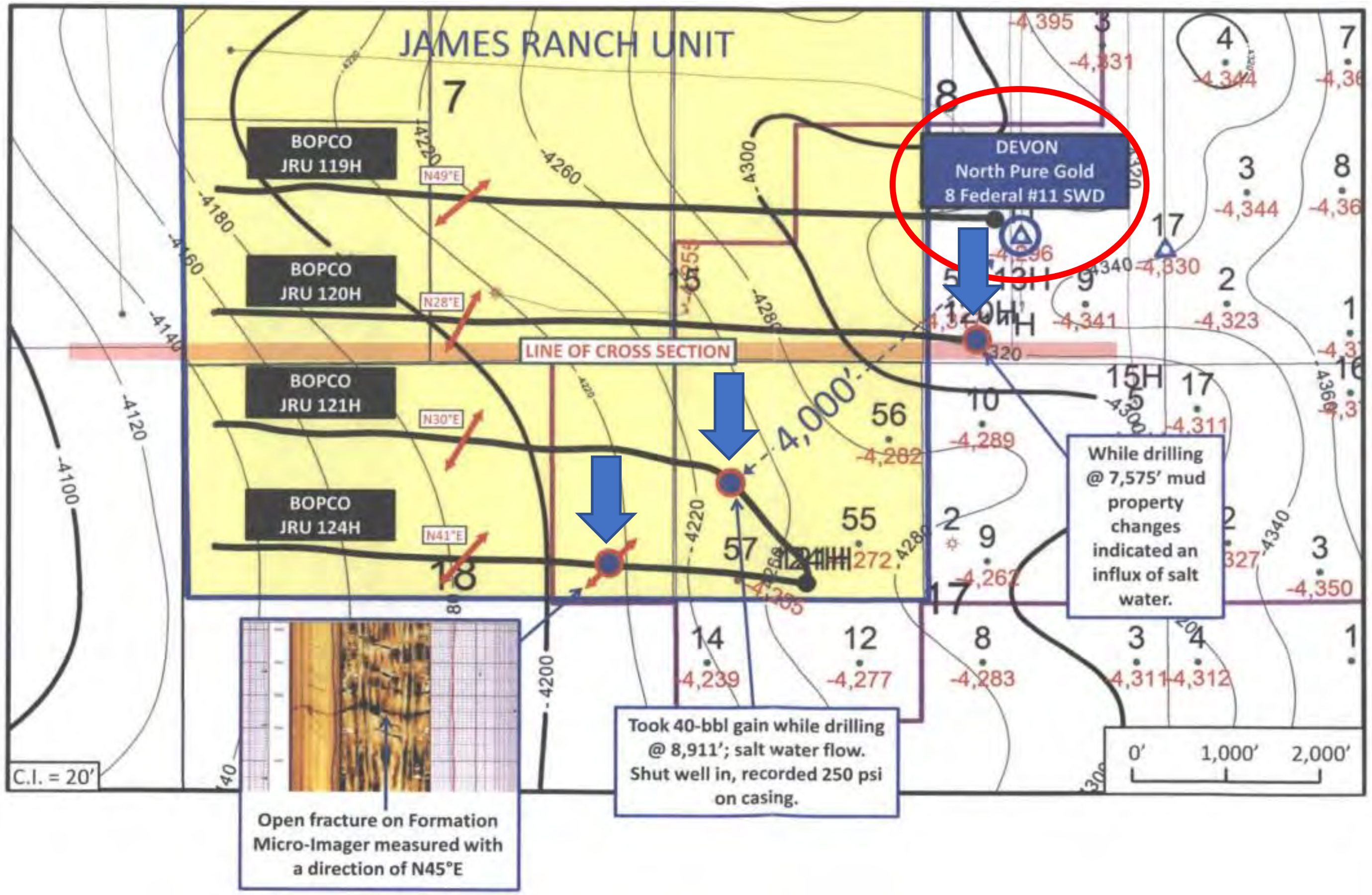
- With the expanded use of the DMG for produced water disposal, there was an increase in reports of local waterflows and abnormally high reservoir pressures in these formations.
- By 2014, the Division became involved in several hearings where operators had identified adjacent disposal injection as the source of increased water cuts in their producing horizontal wells completed in the lower Brushy Canyon Formation.



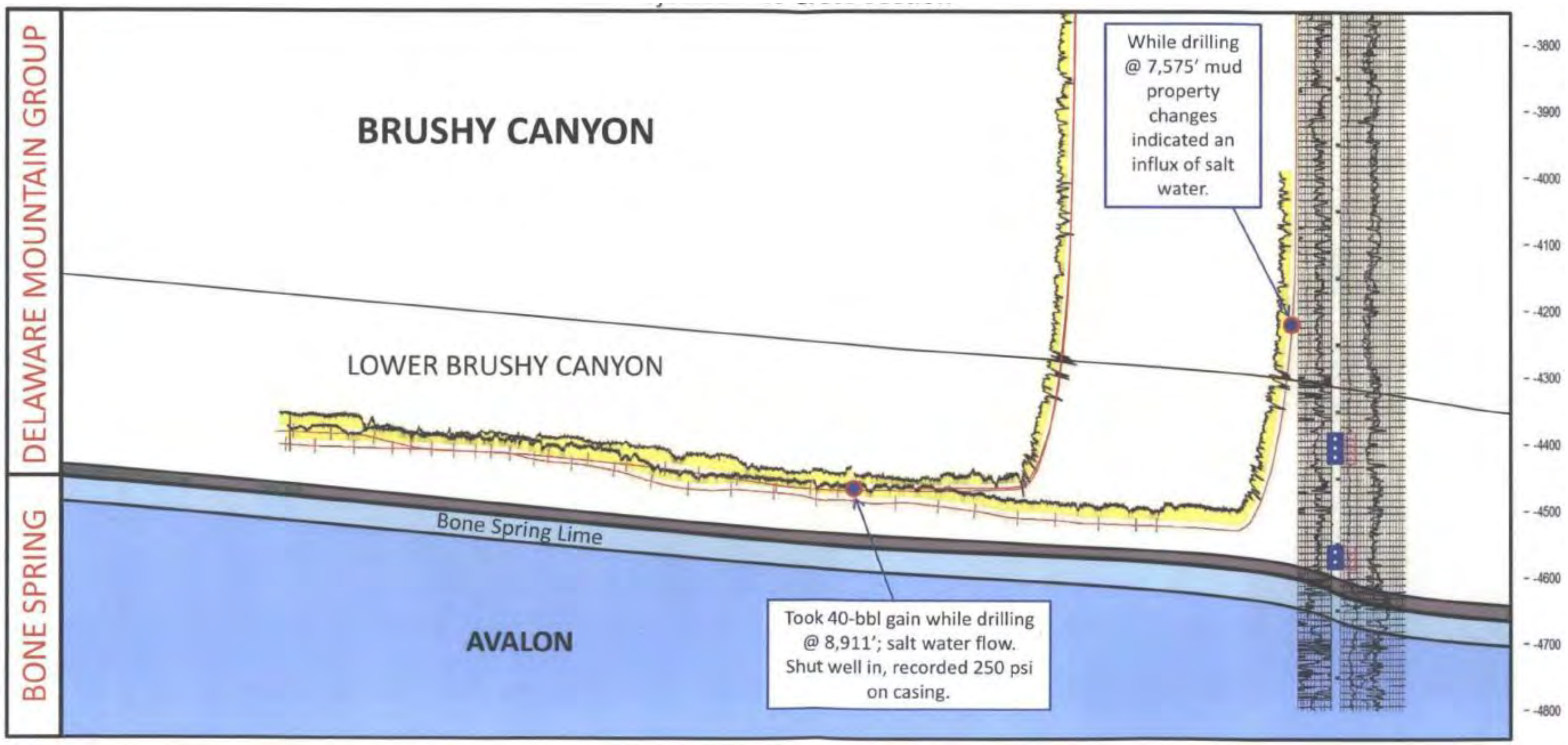
Recent Developments in Disposal Activities in Southeast New Mexico

Delaware Mountain Group

- In this case, horizontal production wells being drilled through the DMG observed pressure increase linked to a Delaware SWD disposal well injecting in close proximity.



Recent Developments in Disposal Activities in Southeast New Mexico



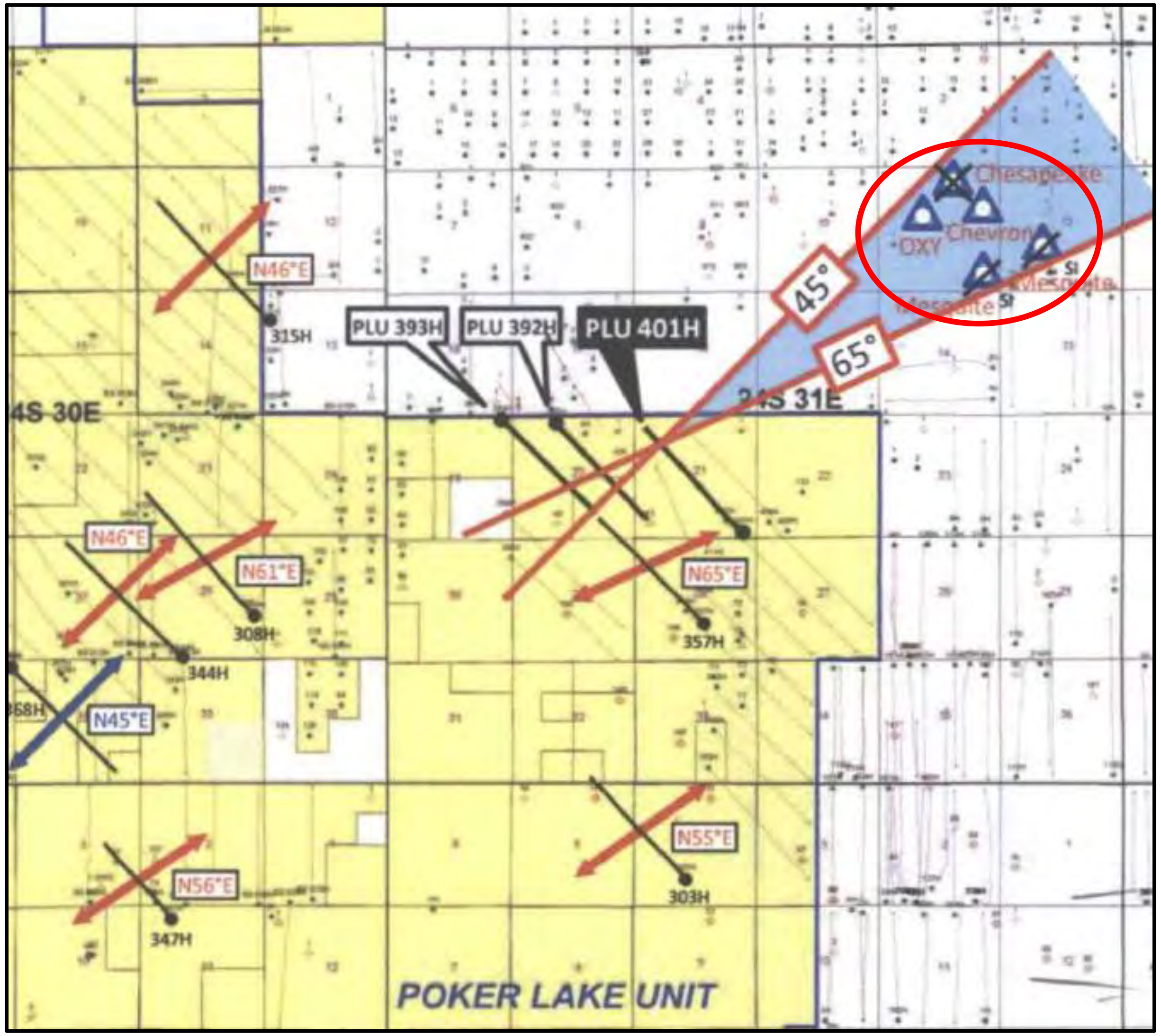
Delaware Mountain Group

- The Division approved disposal in the DMG interval in 2004 following an assessment using vertical well costs that classified the well as "uneconomical" for the Brushy Canyon Formation. With the changes in horizontal well completion, the new well was drilled in 2010 and encountered problems.

Recent Developments in Disposal Activities in Southeast New Mexico

Delaware Mountain Group

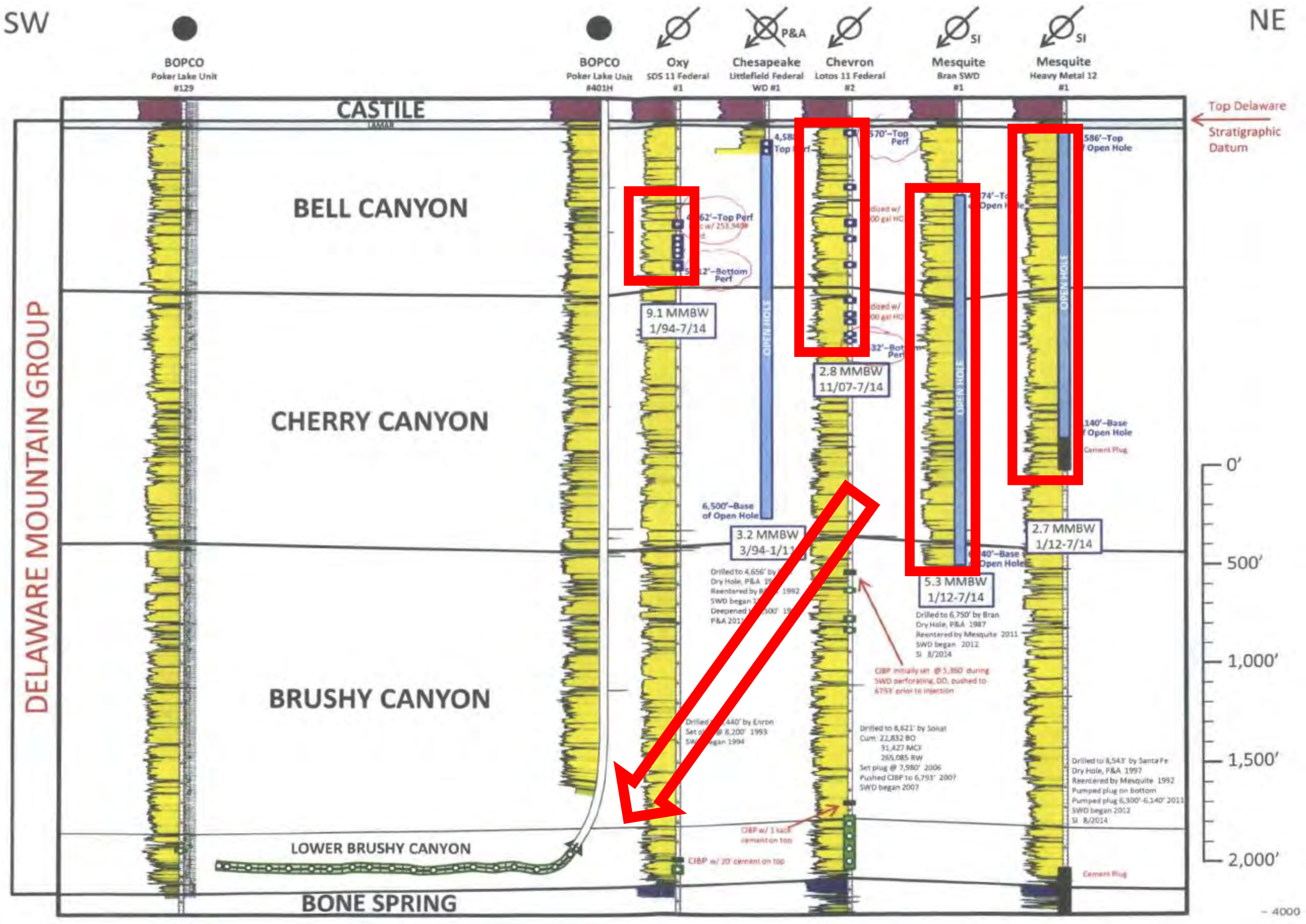
- Another case identified the impacts of multiple disposal wells injecting into the upper formations of the DMG
- The operator demonstrated that the horizontal production wells in the deeper Brushy Canyon Formation were being washed out at a distance of 1.5 miles from the cluster of disposal wells.



Recent Developments in Disposal Activities in Southeast New Mexico

Delaware Mountain Group

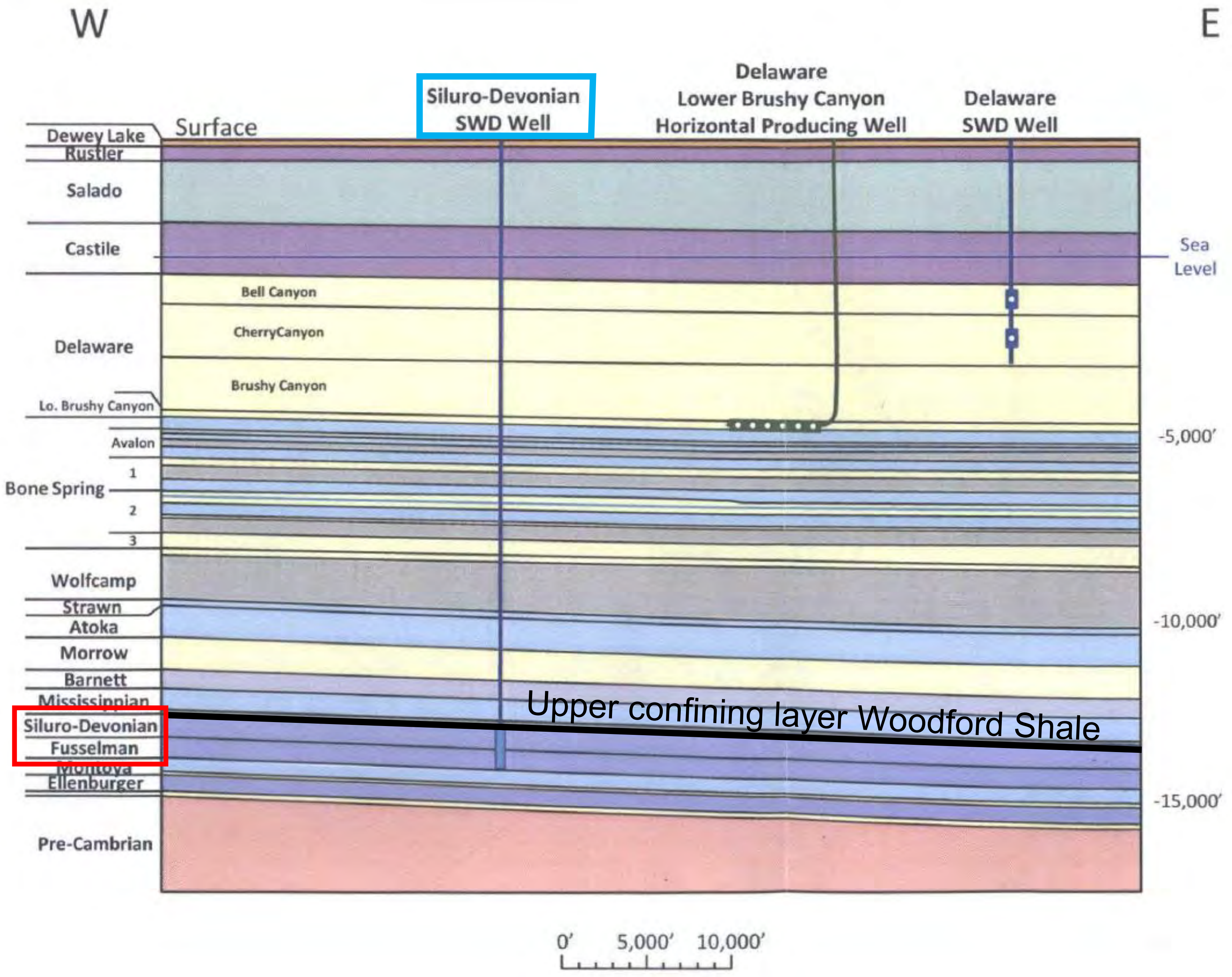
- The DMG disposal wells involved in this specific case showed a cumulative effect from injection with different rates and pressures gradients.
- This case also identified issues about the use of the DMG for disposal:
  - ❑ the lack of continuous confining layers to prevent vertical migration of injection fluids; and
  - ❑ the low formation parting pressures observed in the DMG.



Recent Developments in Disposal Activities in Southeast New Mexico

Devonian and Silurian Interval

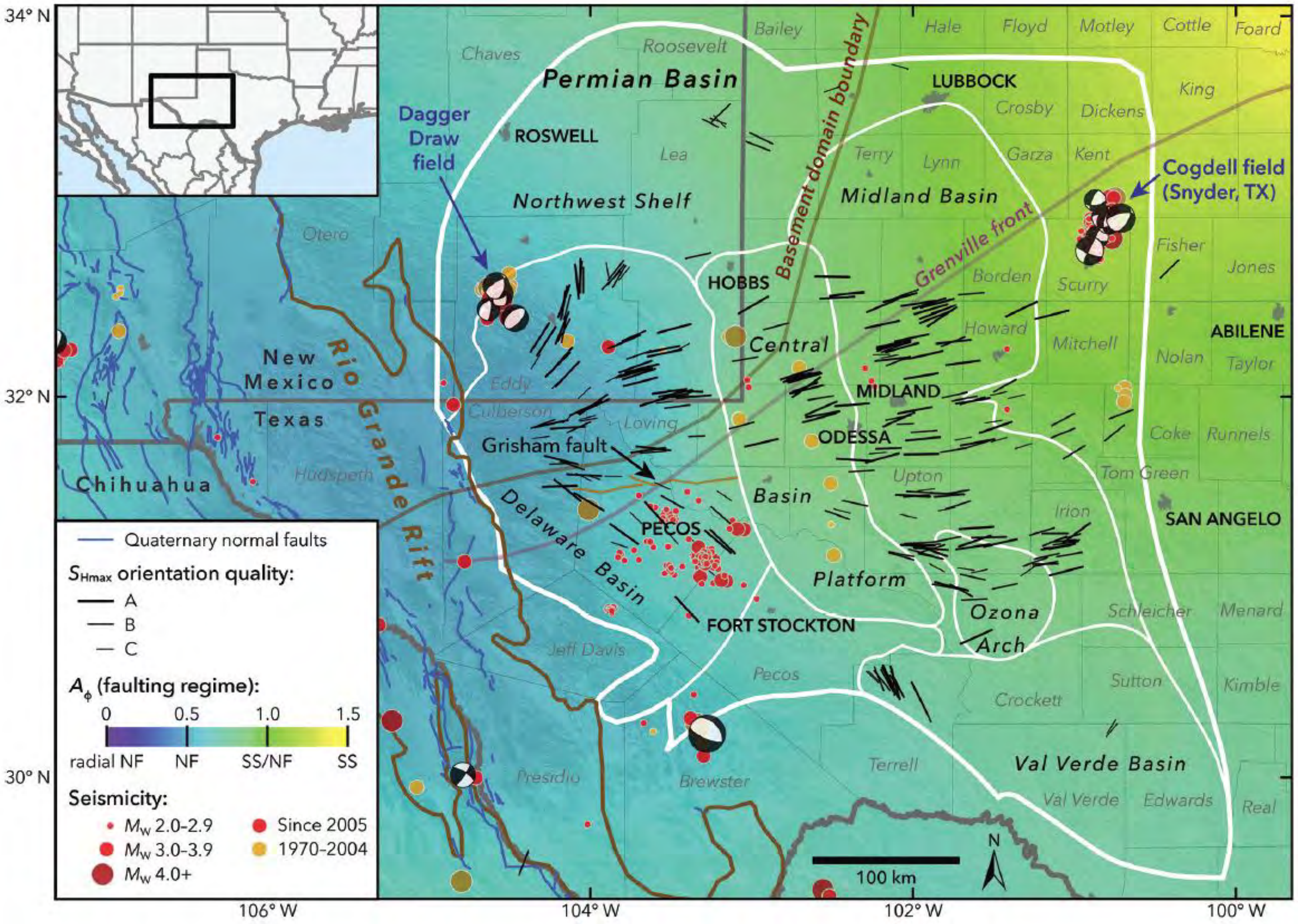
- With the growing necessity for capacity to receive produced water, the Division reviewed options for alternatives to the DMG and other injection intervals available within the center portion of the basin.
- The Primacy Demonstration identified Devonian strata as a possible alternative to shallower injection but deemed this as impractical due to cost and the available technology.
- With operators prepared to drill to the deeper strata, the ability to increase tubing sizes to increase the disposal volumes for these wells was necessary resulting in what the Division has categorized as "high-volume, Devonian disposal wells".



Recent Developments in Disposal Activities in Southeast New Mexico

Devonian and Silurian Interval

- In 2015, the EPA UIC Technical Workgroup release its final work product on induced seismicity and Class II wells.
- In response, the Division is requiring a supplemental assessment with applications that would consider the overall risk for seismic potential for the life of these deeper SWD wells.
- Another recommendation was to minimize the potential impacts of injection-induced seismicity by limiting activation of stresses of the pre-Cambrian basement by injection fluids.

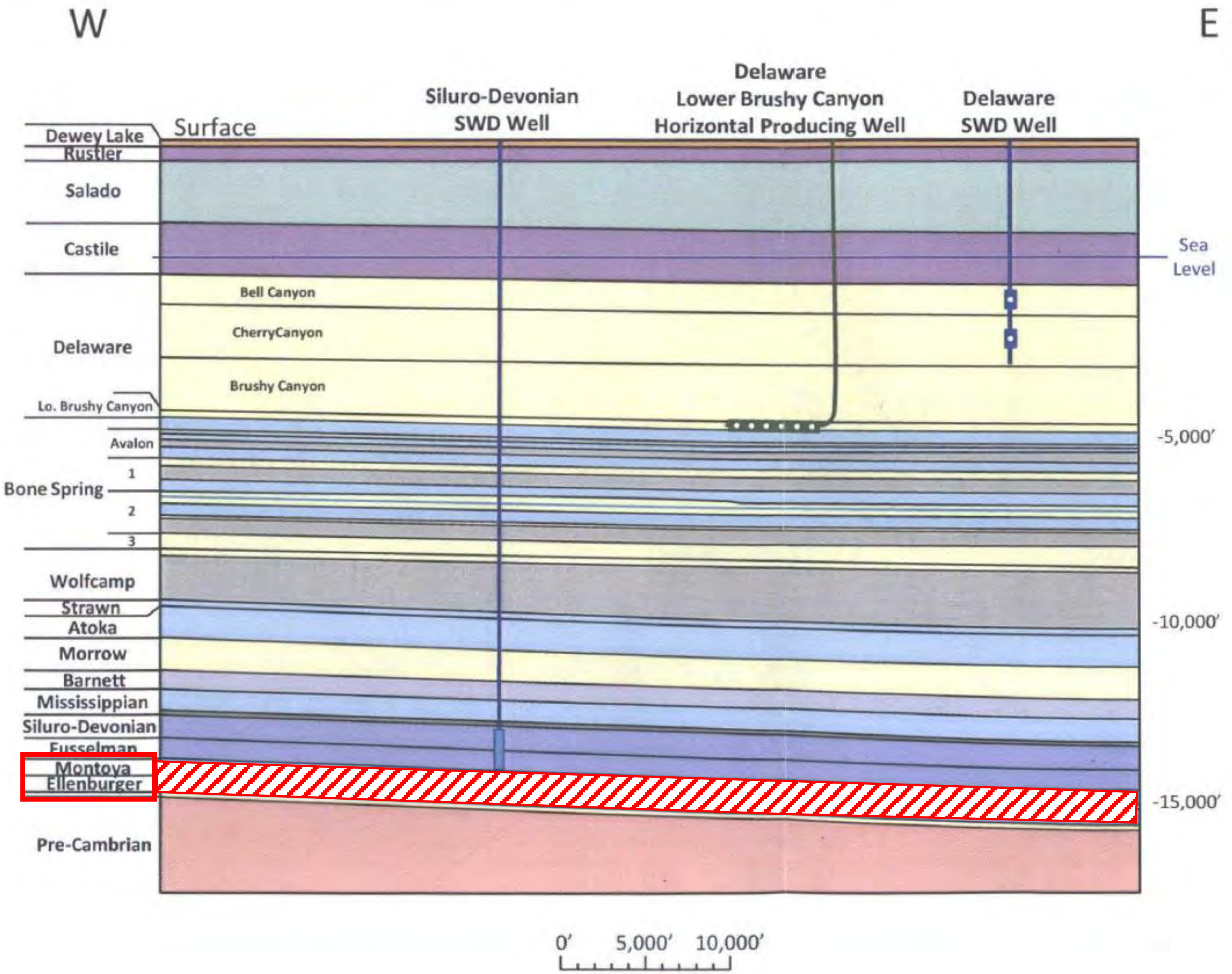


[**Source:** Lund Snee and Zobach; 2018; *State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity*]

Recent Developments in Disposal Activities in Southeast New Mexico

Devonian and Silurian Interval

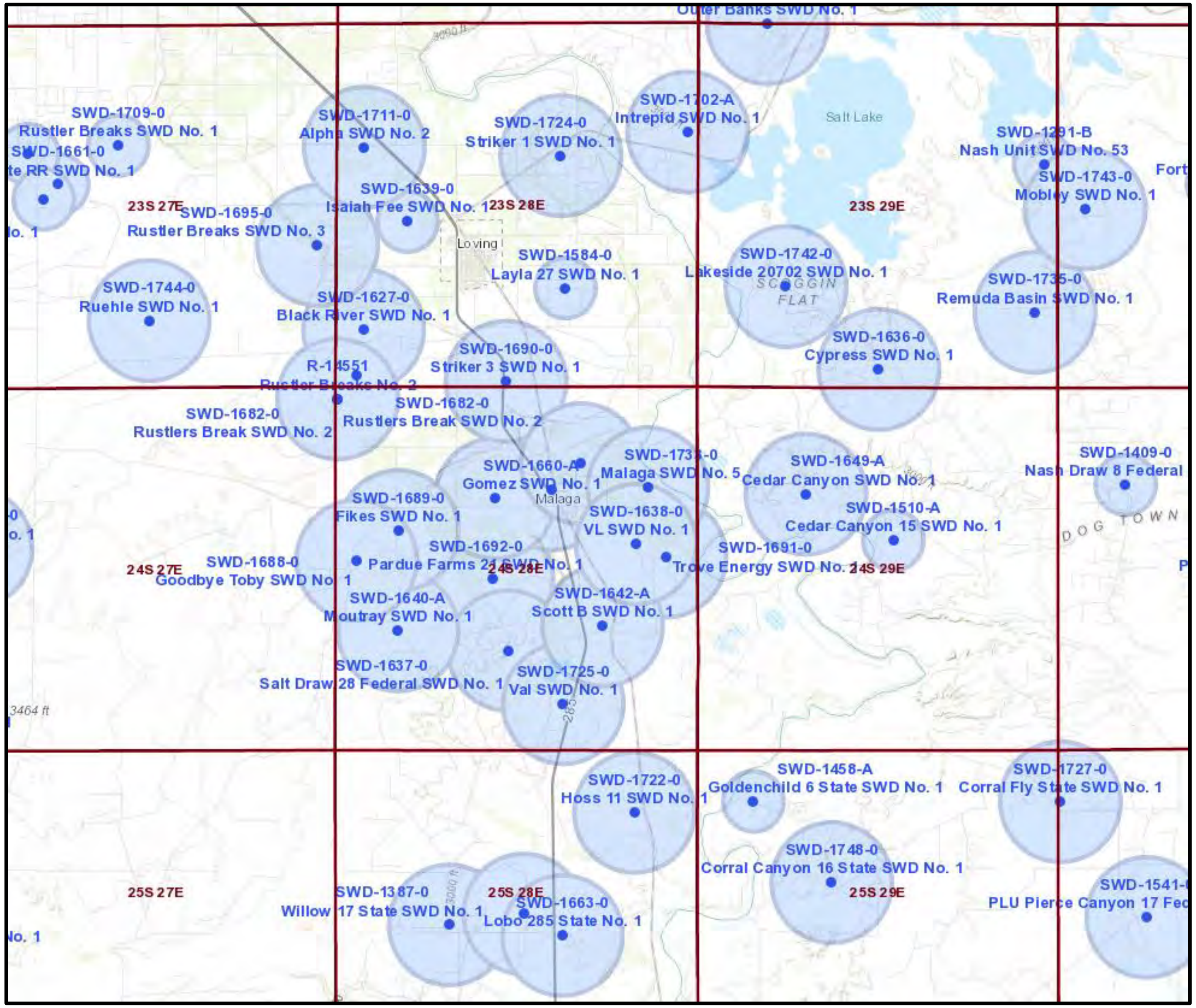
- With this guidance on sources of induced seismicity, the Division enacted a moratorium on any new injection into the Ordovician strata.
- This is an effort to isolate any injection effects of the SWD wells from migrating deeper by using the Ordovician formations, including the Ellenburger Formation, as a lower confining zone or “buffer”.



Recent Developments in Disposal Activities in Southeast New Mexico

Devonian and Silurian Disposal Wells

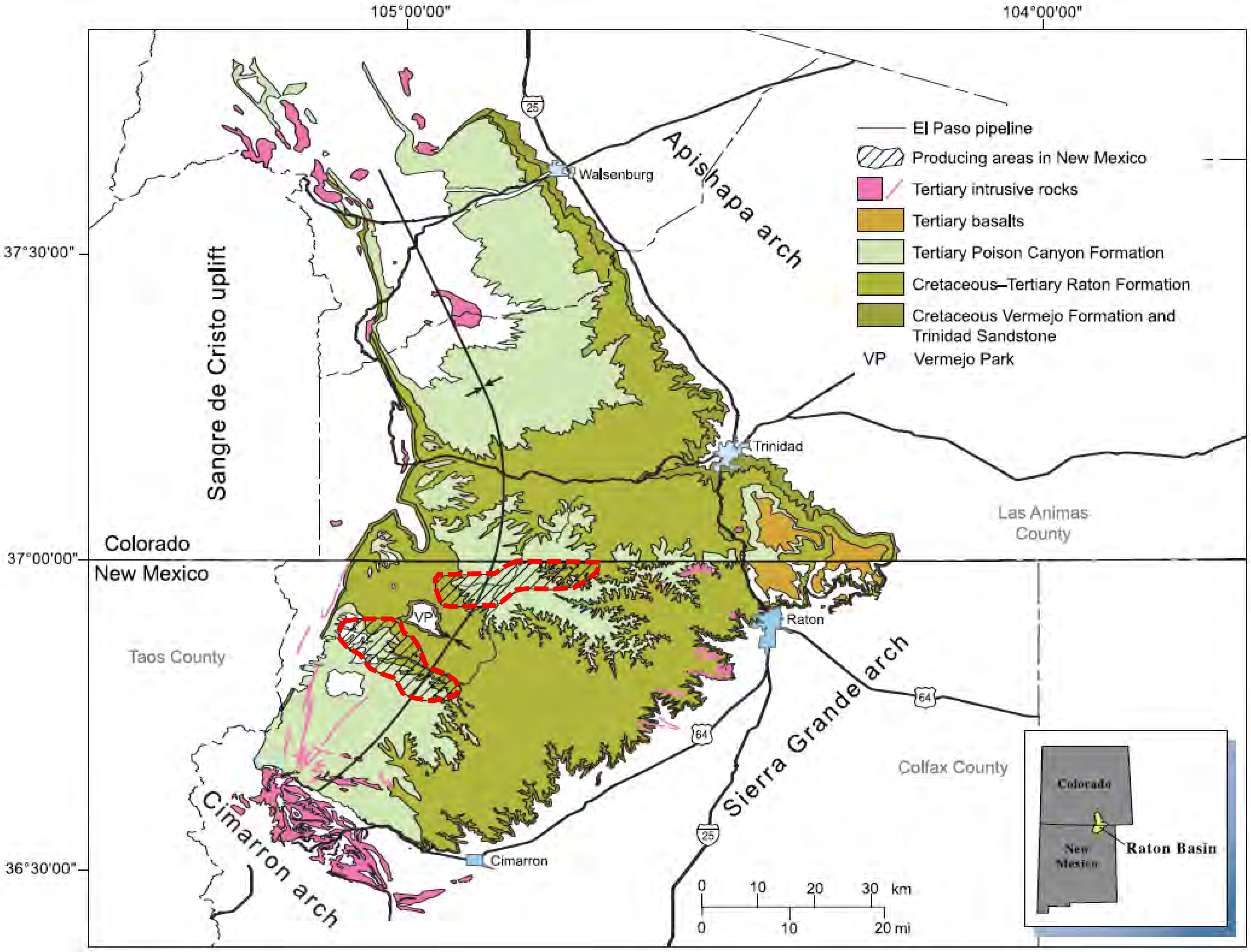
- The attempt to utilize deeper Siluro-Devonian SWD wells has resulted in concentration of approved orders for injection in the vicinity of the Purple Sage (Wolfcamp) pool especially between Loving and Malaga.
- The Division is proceeding with approval of SWD orders with the intent to "space" disposal wells as to limit impacts to the Siluro-Devonian strata and extend the operational life of these wells.



Disposal Activities in Other Basins of New Mexico

Raton and San Juan Basins

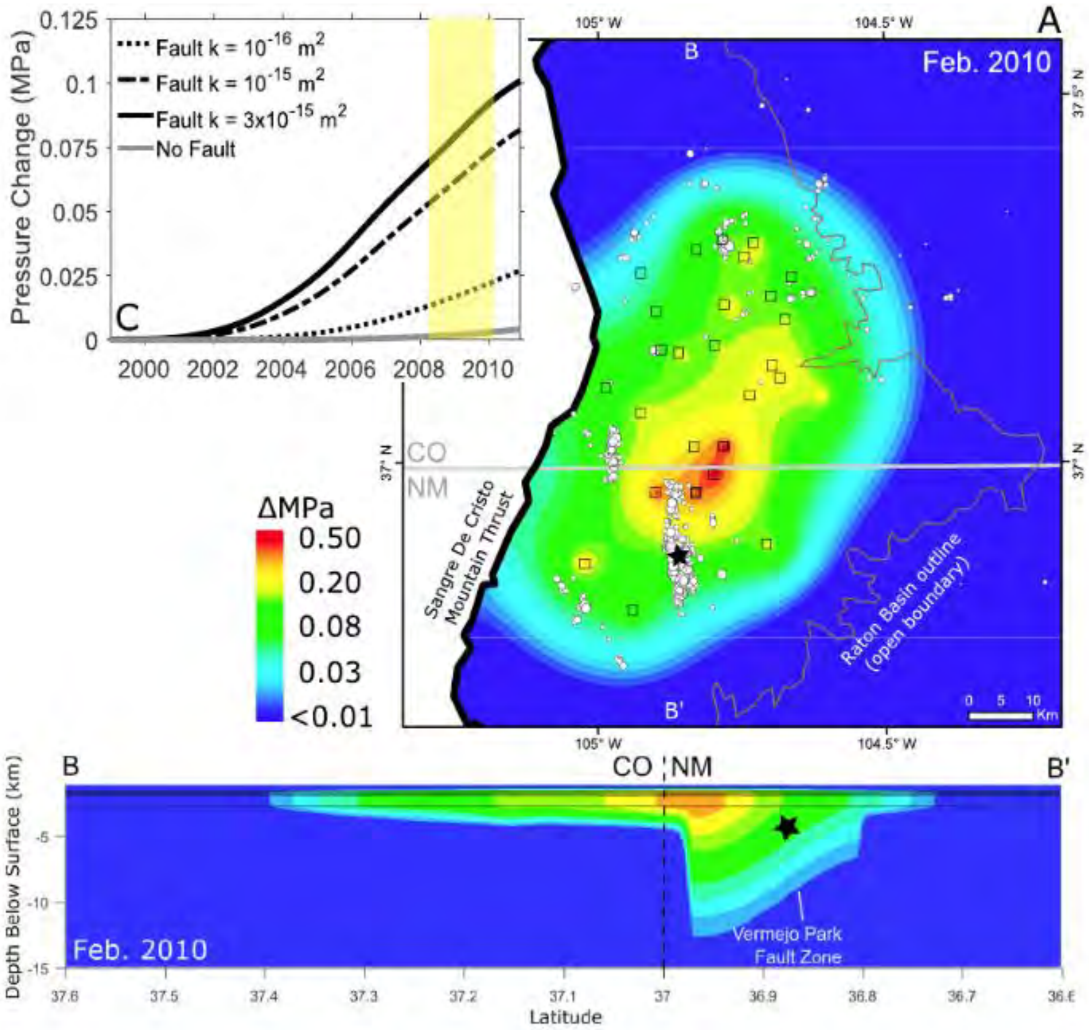
- Production by coal-bed methane (CBM) wells in the Raton and San Juan Basins continues to provide a steady source of produced water but on a much smaller scale than the Permian Basin activities.
- The New Mexico portion of the Raton Basin currently has 847 active CBM wells and seven active SWD wells.
- The daily rates of injection of these SWD wells range from 1,394 barrels of produced water to 5,428 barrels.



Disposal Activities in Other Basins of New Mexico

Raton and San Juan Basins

- Recent research and publications have indicated a correlation between CBM produced water disposal in the Raton Basin and the current catalog of seismic activity.
- The Division is monitoring and reviewing these disposal operations within this basin while waiting for the conclusion of several investigations before making any recommendations regarding injection activities.



Future Plans Regarding Produced Water Disposal Activities in New Mexico

- Continue Efforts to Address Current Practices for Disposal of Produced Water
    - The Division is cooperating with NMOGA and other stakeholders to maintain the preferred use of the Devonian and Silurian strata for addressing current and future produced water injection.
    - This includes actively compiling and reviewing information to revaluate conditions of approval for SWD orders relating monitoring, reporting, and limitations (such as well “spacing”, injection pressures, injection rates, well design, etc.).
    - The Division modifies the administrative application process for high-volume, Devonian SWD wells in an effort to maximize these type of wells while reducing the potential for future issues such as induced seismicity or impacts to correlative rights.
- Support Efforts to Increase Alternatives to Disposal of Produced Water
    - Recycling by operators
    - Treatment and reuse

Future Plans Regarding Produced Water Disposal Activities in New Mexico

- Final Thought – The Division is pursuing this course for its permitting process of SWD orders to address the current demands, but it does not necessarily provide the long-term solution. The growing competition for disposal will eventually necessitate increased costs, increased hearing of protested disposal cases before Division and Commission, and possibly rulemaking as the final resolution.
- And with this situation, there has been ample occasion for increased discussion…………

MR. GOETZE.
Please report
to the Director's
office!

Current Status of the New Mexico Underground Injection Control (UIC) Class II Program

Thank you for your attention

State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity

Jens-Erik Lund Snee[1] and Mark D. Zoback[1]

Abstract

Since the 1960s, the Permian Basin of west Texas and southeast New Mexico has experienced earthquakes that were possibly triggered by oil and gas activities. In recent years, seismicity has been concentrated near Pecos, Texas; around the Dagger Draw Field, New Mexico; and near the Cogdell Field, Snyder, Texas. We have collected hundreds of measurements of stress orientation and relative magnitude to identify potentially active normal, normal/strike-slip, or strike-slip faults that might be susceptible to earthquake triggering in this region. In the Midland Basin and Central Basin Platform, the faulting regime is consistently normal/strike slip, and the direction of the maximum horizontal compressive stress (S_{Hmax}) is approximately east–west, although modest rotations of the S_{Hmax} direction are seen in some areas. Within the Delaware Basin, however, a large-magnitude clockwise rotation (~150°) of S_{Hmax} occurs progressively from being nearly north–south in the north to east-southeast–west-northwest in the south, including the western Val Verde Basin. A normal faulting stress field is observed throughout the Delaware Basin. We use these stress data to estimate the potential for slip on mapped faults across the Permian Basin in response to injection-related pressure changes at depth that might be associated with future oil and gas development activities in the region.

Introduction

The Permian Basin of west Texas and southeast New Mexico is one of the most important petroleum-producing regions in the United States, containing numerous vertically stacked producing intervals (Dutton et al., 2005). The basin is subdivided into several structural regions (Figure 1), including the prolific Midland and Delaware basins, which are separated by the Central Basin Platform, a crystalline-basement-involved structural high overlain by carbonate reef deposits and clastic rocks (Cartwright, 1930; Galley, 1958; Matchus and Jones, 1984).

Fluid injection and hydrocarbon production have been suspected as the triggering mechanisms for numerous earthquakes that have occurred in the Permian Basin since the 1960s (Rogers and Malkiel, 1979; Keller et al., 1981; Orr, 1984; Keller et al., 1987). The area is also naturally seismically active (Doser et al., 1991, 1992). Seismicity in the Permian Basin has historically occurred in several localized areas (Figure 1), including parts of the Central Basin Platform and around the Dagger Draw and Cogdell fields (Sanford et al., 2006; Gan and Frohlich, 2013; Pursley et al., 2013; Herzog, 2014; Frohlich et al., 2016). Since about 2009, seismicity has occurred in the southern Delaware Basin (Jing et al., 2017), an area where the USGS National Earthquake Information Center and Keller et al. (1987) report very little previous seismicity. Since the TexNet Seismological Network (Savvaidis et al., 2017) began recording earthquakes across Texas in January 2017, at least three groups of earthquakes, surrounded by more diffusely located events, have occurred in the southern Delaware Basin, near Pecos, Texas. A fourth group of events occurred mostly in mid-November 2017 farther to the west in northeastern Jeff Davis County. In addition, a group of mostly small (M_L < 2) earthquakes occurred between Midland and Odessa, in the Midland Basin.

As illustrated through recent studies of induced seismicity in Oklahoma (Walsh and Zoback, 2016), knowledge of the current state of stress is an essential component in estimating the pore-pressure perturbation needed to trigger an earthquake on a given fault. Such analyses enable both retrospective analyses of potential triggering conditions of past earthquakes as well as estimates of the likelihood of future slip on mapped faults due to fluid injection or extraction. As part of our work to map the state of stress in Texas, we (Lund Snee and Zoback, 2016) recently contributed more than 100 new, reliable (A–C-quality) maximum horizontal compressive stress (S_{Hmax}) orientations specifically within the Permian Basin, together with an interpolated map of the relative principal stresses expressed using the A_ϕ parameter (Simpson, 1997). In anticipation of fluid-injection activities associated with the thousands of wells to be drilled in the Permian Basin in the next few years, we report more than 100 additional S_{Hmax} orientations and a refined map of the relative stress magnitudes (Figure 1) to provide a comprehensive view of the state of stress in the Permian Basin and its relation to potential earthquake triggering on faults in the region.

In this paper, we first summarize the compilation of new stress measurements and provide an overview of relative stress magnitudes. We then discuss the stress field (especially in areas where it varies considerably, such as the Delaware Basin) and apply the new stress data to estimate the fault slip potential that would be expected due to fluid-pressure increases that might be associated with fluid injection at depth. This analysis will utilize FSP v.1.07, a freely available software tool developed by the Stanford Center for Induced and Triggered Seismicity in collaboration with ExxonMobil (Walsh et al., 2017). We use only publicly available information about faults in the region.

Methods

In the earth, a combination of tectonic driving forces and local factors such as density heterogeneities give rise to anisotropic principal stresses with consistent orientations and relative magnitudes throughout the brittle upper crust (Zoback and Zoback, 1980; Zoback, 1992). These principal stresses, which are continually replenished by tectonic activity, are modulated by the finite strength of the crust, which dissipates accumulated stresses through seismic and aseismic slip on faults. Consequently, most of the brittle crust is thought to be critically stressed, meaning

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https://doi.org/10.1190/tle37020127.1.

that it is in a state of frictional equilibrium in which the faults best oriented for slip with respect to the principal stress directions are usually within one earthquake cycle of failure (Zoback et al., 2002). Thus, knowing the orientations of the principal stresses reveals the faults that are most likely to slip. Conveniently, one principal stress is usually vertical and the other two horizontal (Zoback and Zoback, 1980) because the earth's surface is an interface between a fluid (air or water) and rock, across which no shear tractions are transmitted. Knowing both the orientation of S_{Hmax} and the relative magnitudes of the principal stresses is therefore sufficient to predict the orientations (strike and dip) and type (normal, strike slip, and/or reverse) of faults most likely to slip.

Measuring the orientation and relative magnitudes of the principal stresses. (*Editor's note: Figures A1 and A2 and Tables A1–A5 are included as supplemental material to this paper in SEG's Digital Library at https://library.seg.org/doi/suppl/10.1190/tle37020127.1.*) The S_{Hmax} orientations shown in Figure 1 and reported in supplemental Tables A1 and A2 were mostly measured using well-established techniques. The vast majority of these orientations represent means of the azimuths of drilling-induced tensile fractures (DITF) or wellbore breakouts observed using image logs such as the fullbore formation microimager (FMI) and ultrasonic borehole imager. As reported in the supplemental material that accompanies this article, the quality of each measurement was assessed using Fisher et al. (1987) statistics where possible. Quality ratings were assigned to each measurement using criteria provided in Table A3, which now include criteria for aligned microseismic events that define the orientations of hydraulic fractures. Our criteria are based on those presented by Zoback and Zoback (1989), Zoback (2010), and Alt and Zoback (2017), who specify that only A–C-quality data are sufficiently robust to justify plotting on a map (D-quality measurements are reported in Tables A1 and A2 but are not mapped). These quality criteria were developed to ensure that each mapped S_{Hmax} orientation is well constrained and is based on a sufficient number and depth range of measured stress indicators.

Six orientations, previously reported by Lund Snee and Zoback (2016) and included in Figure 1, were measured by averaging the

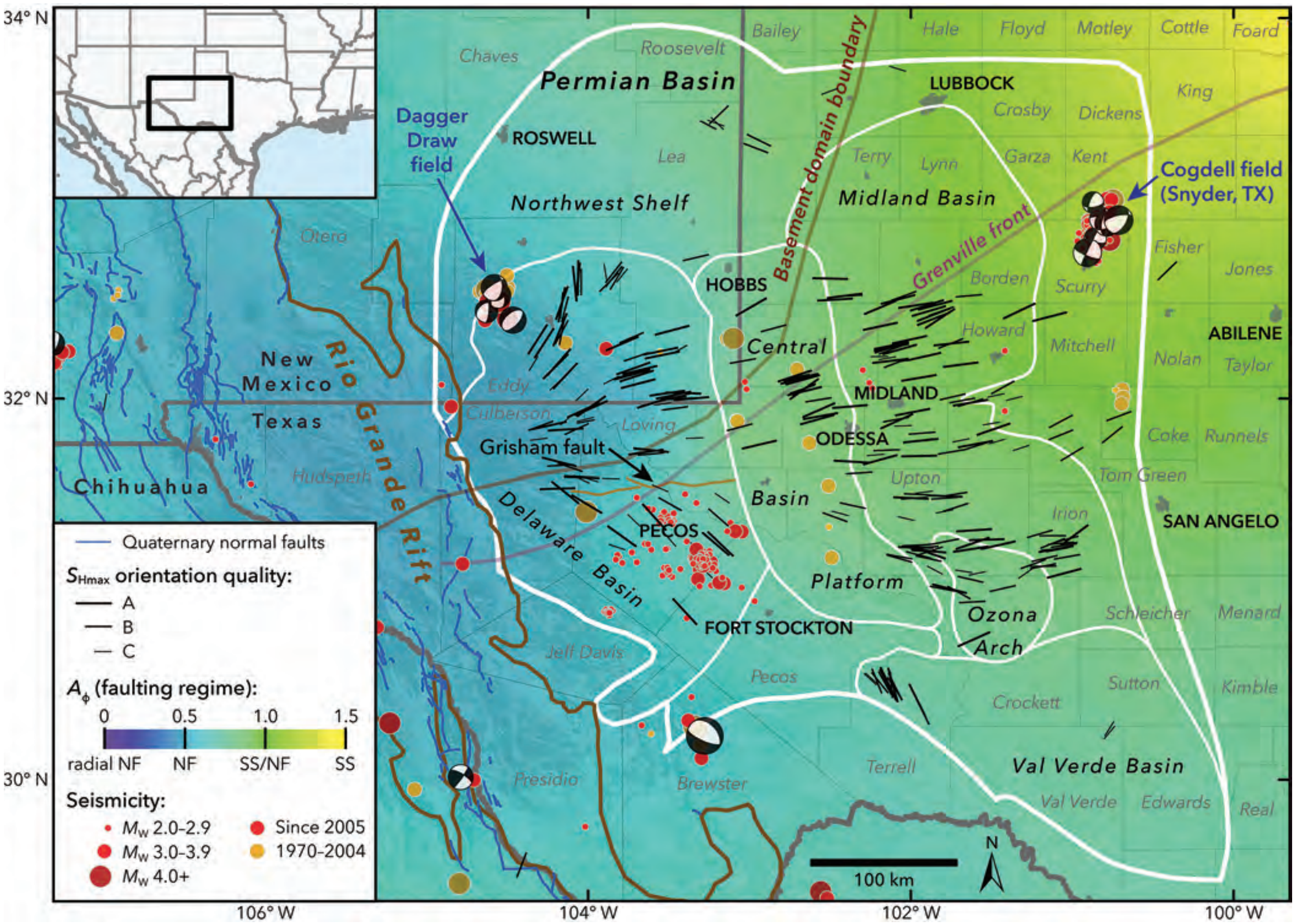

Figure 1. State of stress in the Permian Basin, Texas and New Mexico. Black lines are the measured orientations of S_{Hmax}, with line length scaled by data quality. The colored background is an interpolation of measured relative principal stress magnitudes (faulting regime) expressed using the A_ϕ parameter (see text for details) of Simpson (1997). Blue lines are fault traces known to have experienced normal-sense offset within the past 1.6 Ma, from the USGS Quaternary Faults and Folds Database (Crone and Wheeler, 2000). The boundary between the Shawnee and Mazatzal basement domains is from Lund et al. (2015), and the Precambrian Grenville Front is from Thomas (2006). The Permian Basin boundary is from the U.S. Energy Information Administration, and the subbasin boundaries are from the Texas Bureau of Economic Geology Permian Basin Geological Synthesis Project. Earthquakes are from the USGS National Earthquake Information Center, the TexNet Seismic Monitoring Program, and Gan and Frohlich (2013). Focal mechanisms are from Saint Louis University (Herrmann et al., 2011).

horizontal azimuth of the fastest shear-wave propagation in subvertical wells using measurements from crossed-dipole sonic logs. We also include several new S_{Hmax} orientations that were obtained from formal inversions of focal mechanisms from microseismic events detected during hydraulic fracturing operations. Several other S_{Hmax} orientations were obtained by measuring the orientations of aligned microseismic events thought to represent propagating hydraulic fractures. When collecting stress measurements from microseismic data, we do not account for the possibility of localized changes of stress orientations that might develop as a result of fracturing and proppant emplacement. It is unlikely that stimulation-induced changes in stress orientation would occur except in areas of very low stress anisotropy (which we demonstrate are rare). In such areas, there would not be consistent microseismic alignments orthogonal to the least principal stress that would satisfy the quality-control criterion for reliable stress orientations that we have developed (Table A3).

In addition to our new data, Figure 1 also includes previously published S_{Hmax} orientations from the Permian Basin area that we consider reliable. The 2016 release of the World Stress Map (Heidbach et al., 2016) included only a handful of S_{Hmax} orientations in the Permian Basin. We have downgraded the quality ratings for two older measurements that we suspect were made on the basis of mistaken interpretations. A large collection of S_{Hmax} orientations published by Tingay et al. (2006) and included in the World Stress Map Database were given D-quality ratings due to the lack of sufficient quality information (e.g., depth ranges, number of fractures, or standard deviations of fracture orientations), although many are in agreement with high-quality nearby measurements we utilize. Previously unpublished information contributed by R. Cornell (personal communication) is reported in Table A1, but there is not sufficient quality information to upgrade any of his measurements to C quality and be included in Figure 1. We also include S_{Hmax} orientations recently published by Forand et al. (2017), who report S_{Hmax} patterns consistent with the variations shown by Lund Snee and Zoback (2016). Although Forand et al. (2017) do not list the number and depth intervals for the stress indicators that they present, this information is included in their map because the distributions of fracture orientations shown in their rose diagrams allow us to interpret means, standard deviations, and the minimum number of fractures.

We interpolate the relative principal stress magnitudes across this area (colored background in Figure 1) using measurements reported in Table A4. We choose to represent the relative magnitudes of the three principal stresses (S_V, S_{Hmax}, and S_{hmin}) using the A_ϕ parameter (Simpson, 1997). The A_ϕ parameter (explained graphically in Figure A1) conveniently describes the ratio between the principal stress magnitudes using a single, readily interpolated value that ranges smoothly from 0 (the most extensional possible condition of radial normal faulting) to 3 (the most compressive possible condition of radial reverse faulting). The parameter is defined mathematically by

$$A_\phi = (n + 0.5) + (-1)^n (\phi - 0.5), \tag{1}$$

where

$$\phi = \frac{S_2 - S_3}{S_1 - S_3}. \tag{2}$$

S_1, S_2, and S_3 are the magnitudes of the maximum, intermediate, and minimum principal stresses, respectively, and n is 0 for normal faulting, 1 for strike-slip faulting, and 2 for reverse faulting.

Probabilistic analysis of fault slip potential. As mentioned earlier, we utilize FSP v.1.07 (Walsh et al., 2017) to estimate the slip potential on faults throughout the Permian Basin. The FSP tool allows operators to estimate the potential that planar fault segments will be critically stressed within a local stress field. Critically stressed conditions occur when the ratio of resolved shear stress to normal stress reaches a failure criterion, in this case the linearized Mohr-Coulomb failure envelope. The FSP program allows for either deterministic or probabilistic geomechanical analysis of the fault slip potential, the former of which treats each input as a discrete value with no uncertainty range. The probabilistic geomechanics function estimates the FSP on each fault segment using Monte Carlo-type analysis to randomly sample specified, uniform uncertainty distributions for input parameters including the fault strike and dip, ambient stress field, rock properties, and initial fluid pressure.

We conducted our analysis on fault traces compiled from Ewing et al. (1990), Green and Jones (1997), Ruppel et al. (2005), and the USGS Quaternary Faults and Folds Database (Crone and Wheeler, 2000). Most of these databases do not specify fault dips, so we make the conservative assumption that, within the generally normal and normal/strike-slip faulting environment of the Permian Basin, all potentially active faults dip in the range of 50° to 90°. This assumption implies that all fault segments could be ideally oriented for slip in either normal or strike-slip faulting environments at reasonable coefficients of friction, depending on the alignment of their strike with respect to S_{Hmax} (Figure A1).

Here we apply the probabilistic geomechanics function of the FSP tool. We apply reasonable stress values and uncertainty ranges based on the variability of the stress field we observe within 16 study areas (listed in Table A5). The study areas were selected to represent fairly uniform A_ϕ values and S_{Hmax} orientations (Figure 2) to minimize spatial variations of stress field in any given study area. As an example, Figure A2 shows input parameter distributions sampled during FSP analysis for a random fault within Area 10.

For the purposes of this demonstration, we do not hydrologically model the pressure changes associated with any known injection scenario; we instead estimate the fault slip potential in response to an increase in the fluid-pressure gradient corresponding to a 4% increase relative to hydrostatic (0.4 MPa/km or 0.018 psi/ft) to evaluate the potential for relatively modest pressure changes in crystalline basement (2 MPa [300 psi] at 5 km [16,400 ft]) associated with produced water disposal. This is the same gradient of pore-pressure perturbation applied by Walsh and Zoback (2016) for FSP analysis in north-central Oklahoma. The eventual pore-pressure increase that will occur in the uppermost parts of the crystalline basement due to injection in this area is of course unknown, and it is important to note that *relative* differences in slip potential between differently oriented faults will remain the same regardless of the magnitude of uniform pressure increase (although the absolute fault slip potential will vary). Operators interested in screening potential sites for wastewater injection wells, for example, might alternatively use the software to test specific scenarios of pore-pressure evolution with time due to injection from wells in a localized area. Although large portions of the Permian Basin are known to be overpressured and underpressured at certain stratigraphic intervals (e.g., Orr, 1984; Doser et al., 1992; Rittenhouse et al., 2016), for the sake of simplicity in this whole-basin demonstration, we initially assume hydrostatic conditions (P_P = 9.8 MPa/km ≈ 0.43 psi/ft). In general, hypocentral depths for potentially damaging injection-triggered earthquakes are within the upper crystalline basement (e.g., Zhang et al., 2013; Walsh and Zoback, 2015), for which little pore-pressure information is available but for which hydrostatic values are reasonable (Townend and Zoback, 2000).

State of stress in the Permian Basin

Figure 1 shows all reliable S_{Hmax} orientations and an interpolated view of the A_ϕ parameter across the Permian Basin. Throughout the Midland Basin, the eastern part of the Permian Basin, the stress field is remarkably consistent, with S_{Hmax} oriented ~east–west (with modest rotations of S_{Hmax} in some areas) and $A_\phi \approx 1.0$ (indicative of normal/strike-slip faulting). The stress field is more extensional in the Val Verde Basin to the south, with $A_\phi \approx 0.7$. Few S_{Hmax} orientations are presently available in that subbasin, but S_{Hmax} is northwest–southest in the western part of the basin and appears to be ~northeast–southwest in the central part of the basin. This is similar to the stress state seen farther to the southeast, where S_{Hmax} follows the trend of the growth faults that strike subparallel to the Gulf of Mexico coastline (Lund Snee and Zoback, 2016). Along the Central Basin Platform, S_{Hmax} is generally ~east–west but rotates slightly clockwise from east to west, with A_ϕ ~ 0.8–1.0. In the Delaware Basin, the stress field is locally coherent but rotates dramatically by ~150° clockwise from north to south across the basin. In the western part of Eddy County, New Mexico, S_{Hmax} is ~north–south (consistent with the state of stress in the Rio Grande Rift; Zoback and Zoback, 1980) but rotates to ~east-northeast–west-southwest in southern Lea County, New Mexico, and the northernmost parts of Culberson and Reeves counties, Texas. It should be noted that where rapid stress rotations are observed in the Delaware Basin are areas with low values of A_ϕ (indicative of relatively small differences between the horizontal stresses) and elevated pore pressure (Rittenhouse et al., 2016), making it possible for relatively minor stress perturbations to cause significant changes in stress orientation (e.g., Moos and Zoback, 1993).

S_{Hmax} continues to rotate clockwise southward in the Delaware Basin to become ~N155°E in western Pecos County, westernmost Val Verde Basin, and northern Mexico (Suter, 1991; Lund Snee and Zoback, 2016). On the Northwest Shelf, A_ϕ varies from ~0.5 (normal faulting) in north Eddy County to ~0.9 (normal and strike-slip faulting) further east. S_{Hmax} rotates significantly across the Northwest Shelf as well, from ~north–south in northwest Eddy County to ~east-southeast–west-northwest in northern Lea and Yoakum counties.

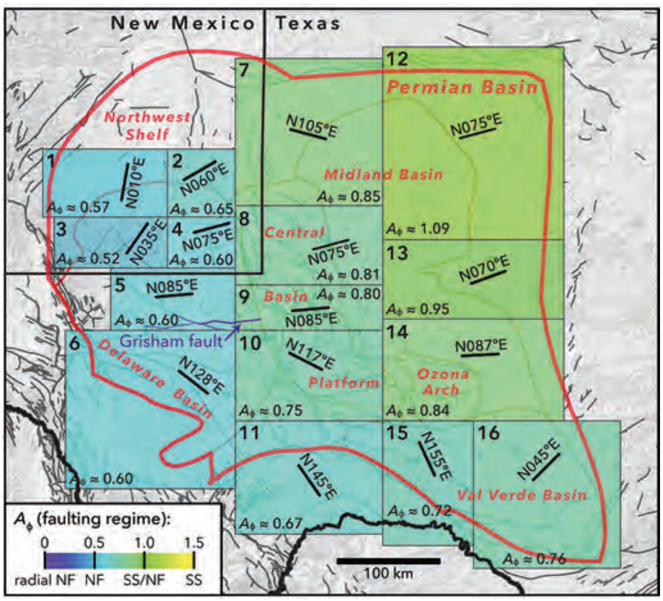

Figure 2. Map of study areas chosen for FSP analysis on the basis of broadly similar stress conditions. Text annotations indicate representative S_{Hmax} orientation and relative principal stress magnitudes (A_ϕ parameter) for each study area based on the data presented in Figure 1. Gray lines in the background indicate fault traces compiled from Ewing et al. (1990), Green and Jones (1997), Ruppel et al. (2005), and the USGS Quaternary Faults and Folds Database (Crone and Wheeler, 2000), to which we apply FSP analysis.

Slip potential on mapped faults

Figure 3 shows the results of our fault slip potential analysis for all study areas across the Permian Basin. We selected a color scale in which dark green lines represent faults with ≤5% probability of being critically stressed at the specified pore-pressure increase; dark red indicates faults with ≥45% fault slip potential; and yellow, orange, and light red represent intermediate values. The results shown in Figure 3 indicate that high fault slip potential is expected for dramatically different fault orientations across the basin, reflecting the varying stress field. In the northern Delaware Basin and much of the Central Basin Platform, for example, faults striking ~east–west are the most likely to slip in response to a fluid-pressure increase. However, farther south in the southern Delaware Basin, faults striking northwest–southeast are the most likely to slip, and ~east–west-striking faults have relatively low slip potential. Notably, we find high slip potential for large fault traces mapped across the southern Delaware Basin and Central Basin Platform, and along the Matador Arch. Figure 3 also indicates the faults that are *unlikely* to slip in response to a modest fluid-pressure increase. We find that large groups of mostly north–south-striking faults, predominantly located along the Central Basin Platform, the western Delaware Basin, and large parts of the Northwest Shelf have low fault slip potential at the modeled fluid-pressure perturbation. Knowing the orientations of faults that are unlikely to slip at a given fluid-pressure perturbation can be of great value because it provides operators with practical options for injection sites. Probabilistic geomechanical analysis of the type enabled by the FSP software is especially useful in areas with complex fault patterns. Figure 4 shows a larger-scale view of Area 10, an area of particularly dense faults. In Figure 4, it is clear that even seemingly minor variations in fault strike can significantly change the fault slip potential.

Figures 3 and 4 illustrate the locations of earthquakes that have been recorded since 1970 in relation to the mapped faults. It is noteworthy that many earthquakes have occurred away from faults mapped at this regional scale, with the most obvious examples being groups of events described earlier, near the Dagger Draw Field (southeast New Mexico); the Cogdell Field (near Snyder, Texas); a group around the town of Pecos, Texas; and a recent group of mostly M < 2 events between the towns of Midland and Odessa, Texas. As the earthquakes undoubtedly occurred on faults, this observation underscores the necessity of developing improved subsurface fault maps, particularly for use in areas that might experience injection-related pore-pressure increases. Nevertheless, Figures 3 and 4 also show a number of earthquakes that may have occurred on mapped faults for which we estimate elevated fault slip potential. Of particular note are the recent (2009–2017) earthquakes in southeastern Reeves and northwestern Pecos counties, Texas, of which an appreciable number occurred on or near yellow or orange faults. Potentially active faults are identified near some towns in the Permian Basin, including Odessa (Figure 3) and Fort Stockton, Texas (Figure 4). In some areas, such as northern Brewster County, Texas, and parts of the northern Central Basin Platform, earthquakes occurred on or near orange or red faults that have relatively short along-strike lengths, making the faults appear fairly insignificant at this scale. In the area of active seismicity in Pecos and Reeves counties, we estimate relatively high slip potential for several significantly larger faults (>20 km along-strike length) on which few or no earthquakes have been recorded thus far (Figures 3 and 4). Larger faults are of particular concern for seismic hazard because they are more likely to extend into basement and, therefore, to potentially be associated with larger magnitude earthquakes.

As labeled in Figure 3, a number of regional-scale faults are known to exist in this area (Walper, 1977; Shumaker, 1992; Yang and Dorobek, 1995). The Permian Basin overlies a major boundary separating Precambrian-age lithospheric basement domains (Lund et al., 2015), and its crystalline "basement" hosts numerous major

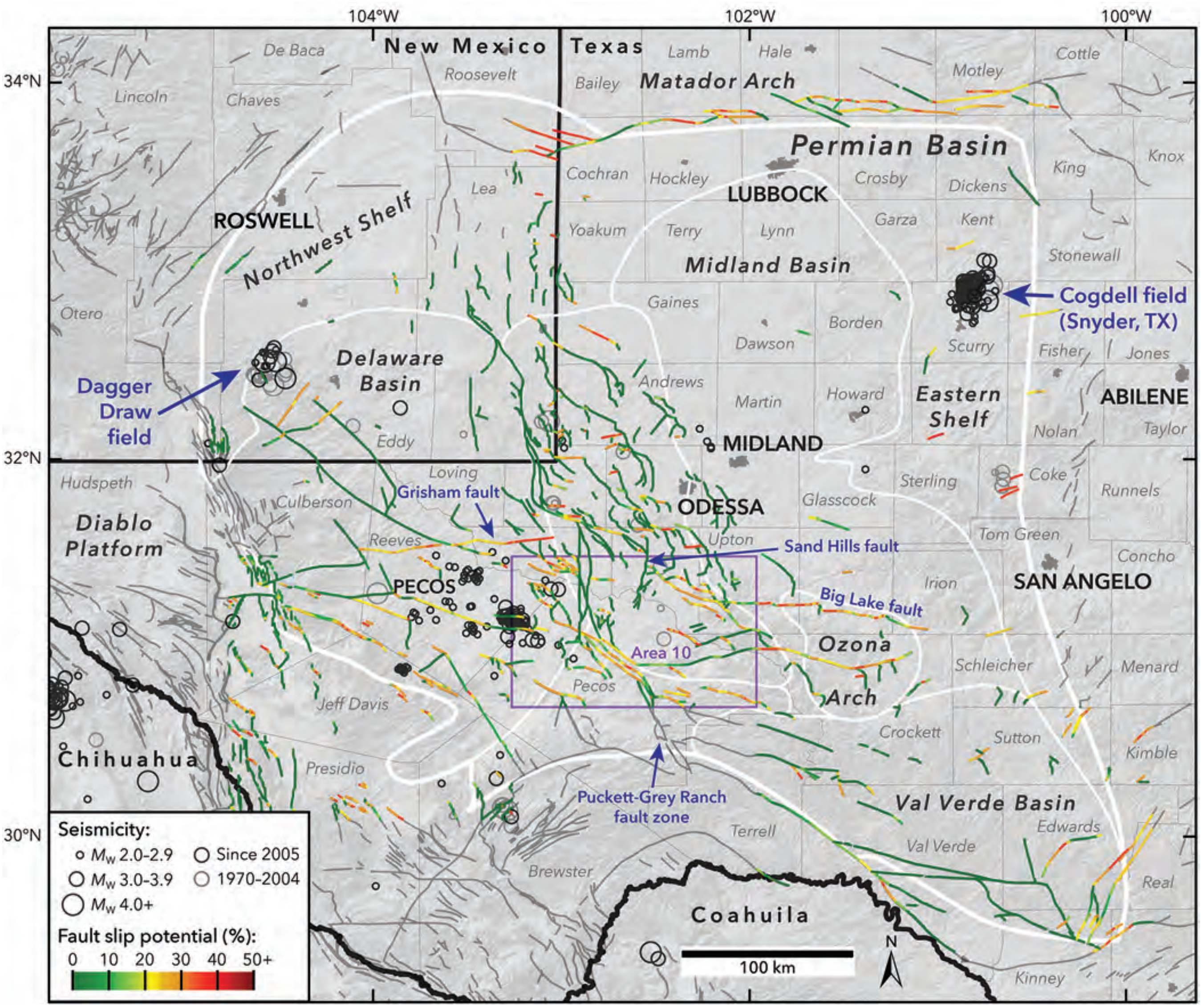

Figure 3. Results of our probabilistic FSP analysis across the Permian Basin. Data sources are as in Figures 1 and 2.

structures that have been repeatedly activated during subsequent plate collisions and rifting events (Kluth and Coney, 1981; Thomas, 2006). One notable example is the east–west-striking Grisham Fault (also referred to as the Mid-Basin Fault), which is between the rift margin of the Rodinia supercontinent and the boundary between the Shawnee and Mazatzal basement domains. The Grisham Fault is of particular importance for understanding the potential for induced seismicity in the Permian Basin because it is laterally extensive, offsets basement, and may have high slip potential. The upper part of Figure 5 (and Figure 3) shows a scenario in which the stresses resolved on the Grisham Fault are representative of Area 5, with S_{Hmax} oriented N085°E. However, the measured stress field changes dramatically from north to south across the Grisham Fault (Figures 1 and 2), presenting uncertainty about the stresses resolved upon the fault, reflected by its close proximity to Area 6, with a generalized S_{Hmax} orientation of N128°E. The lower part of Figure 5 shows the Grisham Fault in detail if the stress field shown in Area 6, just to the south, was appropriate. Needless to say, in the stress field represented by Area 5, fault segments oriented east–west are expected to have high probability of being critically stressed in response to a pore-pressure increase, but nearby west-northwest–east-southeast-striking faults have relatively low fault slip potential. In contrast, inclusion within the Area 6 stress field would result in low expected fault slip potential on the east–west segments but high values on the west-northwest–east-southeast-striking segments.

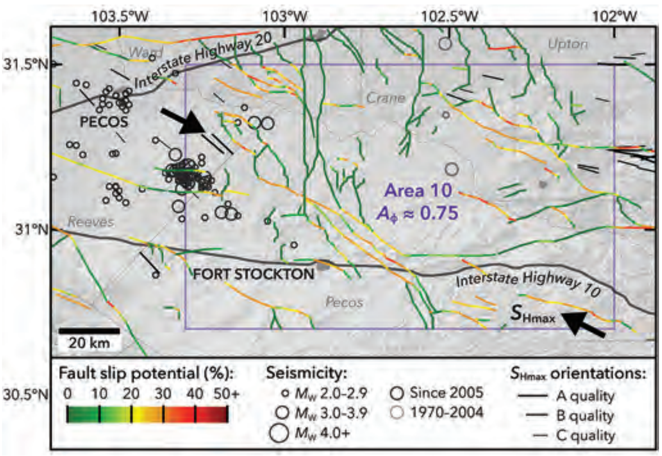

Figure 4. Large-scale view of the results of FSP analysis in Area 10 (location shown in Figures 2 and 3). Data sources are as in Figures 1 and 3.

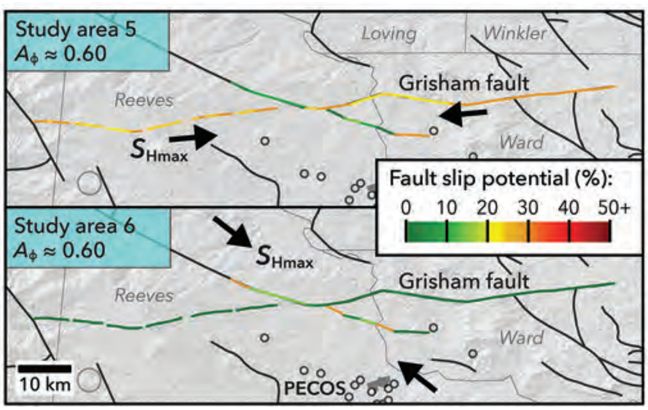

Figure 5. Map comparing the results of fault slip potential analysis on the Grisham (Mid-Basin) fault and selected nearby structures (locations shown in Figure 3) for stress conditions of Area 5 (S_{Hmax} N085°E ± 8°; top panel) and Area 6 (S_{Hmax} N128°E ± 15°; bottom panel). Symbols as in Figures 3 and 4.

The results shown in Figures 3–5 are not intended to provide a definitive view of the fault slip potential across this complex basin, nor do they constitute a seismic hazard map. While the stress field is complicated in this area, the changes in the stress field are coherent and mappable. We consider the greatest uncertainties in the map to be the lack of knowledge of subsurface faults and the magnitude and extent of potential pore-pressure changes in areas where increased wastewater injection may occur in the future, especially wastewater injection that might change pore pressure on basement faults. Operators wishing to use the FSP tool to screen sites for fluid injection should use detailed fault maps that are specific to the injection interval, the underlying basement, and any intervening units, which take into account geometric uncertainties.

Conclusions

As part of our stress mapping across the U.S. midcontinent, we have collected hundreds of S_{Hmax} orientations within the Permian Basin, and we also map the faulting regime across the region. Our new data reveal dramatic rotations of S_{Hmax} within the Delaware Basin and Northwest Shelf but relatively consistent stress orientations elsewhere. The rapid stress rotations in the Delaware Basin are observed in areas with relatively small differences between the horizontal stresses and with elevated pore pressure, making it easier for stress perturbations to cause significant changes in the stress field.

We show how the FSP software package can be used as a quantitative screening tool to estimate the fault slip potential in a region with large variations of the stress field, and accounting for uncertainties in stress measurements, rock properties, fault orientations, and fluid pressure. Although many historical earthquakes have occurred away from mapped faults in this area, we find that a number of earthquakes have occurred on or near faults for which there is high fault slip potential under the modeled conditions. TLE

Acknowledgments

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Oil Conservation Division
Energy, Minerals and Natural Resources Department
State of New Mexico

CASES NO. 20313, 20314, 20472, 20463 and 20465
Index of Division Exhibit No. 8

Exhibit No.	Exhibit Name
8-A	Order No. R-14392-A; Case No. 15654 – Application of Mesquite SWD Inc. to Amend Approvals for Salt Water Disposal Wells in Lea and Eddy Counties.
8-B	Order No. R-14392-A; Case No. 15654 – Application of Mesquite SWD Inc. to Amend Approvals for Salt Water Disposal Wells in Lea and Eddy Counties; Testimony of Scott Wilson.
8-C	Order No. R-14551; Case No. 15854 – Application of Black River Management Company, LLC for a Salt Water Disposal Well, Lea County, New Mexico.
8-D	Order No. R-14716; Case No. 15972 – Application of Chevron U.S.A., Inc. to Amend Administration Order SWD-1682 of a Saltwater Disposal Well Located in Eddy County, New Mexico.
8-E	Order No. R-20322; Case No. 16439 – Amended Application of NGL Water Solutions Permian, LLC for Approval of a Salt Water Disposal Well in Lea County, New Mexico.
8-F	Order No. R-20323; Case No. 16441 – Amended Application of NGL Water Solutions Permian, LLC for Approval of a Salt Water Disposal Well in Lea County, New Mexico.
8-G	Case No. 20235 –Application of NGL Water Solutions Permian, LLC to Approve Salt Water Disposal Well in Lea County, New Mexico; Affidavit of Scott Wilson.
8-H	Case No. 20235 –Application of NGL Water Solutions Permian, LLC to Approve Salt Water Disposal Well in Lea County, New Mexico; Exhibit of Todd Reynolds.

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 8-A

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

APPLICATION OF MESQUITE SWD, INC. TO AMEND APPROVALS FOR SALT WATER DISPOSAL WELLS IN LEA AND EDDY COUNTIES.

CASE NO. 15654
ORDER NO. R-14392-A

ORDER OF THE COMMISSION

This matter came before the Oil Conservation Commission ("Commission") for a *de novo* hearing on November 9, 2017.

The Commission, having conducted a public hearing and having considered the testimony, the record in this case, the arguments of the applicant, and being otherwise fully advised, enters the following findings, conclusions, and order:

THE COMMISSION FINDS THAT:

1. Notice has been given of this *de novo* hearing and the Commission has jurisdiction over the parties and the subject matter herein;

2. In Case No. 15654 the applicant, Mesquite SWD, Inc. ("Mesquite") (OGRID 161968), seeks an order amending administrative orders SWD-1667 approving the Sand Dunes SWD Well No. 2 (API 30-015-44131), SWD-1642 and SWD-1642-A approving the Scott B SWD Well No. 1 (API 30-015-44061), SWD-1638 approving the VL SWD Well No. 1 (API 30-015-pending), SWD-1558 approving the Station SWD Well No. 1 (API 30-025-43473), SWD-1636 approving the Cypress SWD Well No. 1 (API 30-015-43867), SWD-1610 approving the Gnome East SWD Well No. 1 (API 30-015-43801)[1], SWD-1602 approving the Uber East SWD Well No. 1 (API 30-015-43806), and SWD-1600 approving the Uber North SWD Well No. 1 (API 30-015-43805) (collectively referred to as the "wells"), in order to allow an increase in the size of disposal tubing from 4 ½ inches to 5 ½ inches for each well.

3. The Sand Dunes SWD Well No. 2 is located 2600 feet from the South line and 2500 from the West line, Unit K of Section 8, Township 24 South, Range 31 East, NMPM, Eddy County, for disposal of oil field produced water (UIC Class II only) through an open hole interval consisting of the Devonian and Silurian formations from 16620 feet to approximately 18010 feet.

[1] Mesquite and the Commission have agreed to remove this well from the proceeding.

4. The Scott B SWD Well No. 1 is located 274 feet from the South line and 2165 feet from the West line, Unit N of Section 23, Township 24 South, Range 28 East, NMPM, Eddy County, for disposal of oil field produced water (UIC Class II only) through an open-hole interval within the Devonian and Silurian formations from 14152 feet to 15212 feet.

5. The VL SWD Well No. 1 is or will be located 2142 feet from the South line and 249 feet from the East line, Unit I of Section 14, Township 24 South, Range 28 East, NMPM, Eddy County, for disposal of oil field produced water (UIC Class II only) through an open-hole interval within the Devonian and Silurian formations from 15100 feet to 16300 feet.

6. The Station SWD Well No. 1 is located 2625 feet from the North line and 2315 feet from the West line, Unit letter F of Section 7, Township 24 South, Range 32 East, NMPM, Lea County, for disposal of oil field produced water (UIC Class II only) through an open-hole interval within the Devonian and Silurian formations from 16470 feet to 17975 feet.

7. The Cypress SWD Well No. 1 is located 1590 feet from the South line and 165 feet from the West line, Unit L of Section 34, Township 23 South, Range 29 East, NMPM, Eddy County, for disposal of oil field produced water (UIC Class II only) through an open-hole interval within the Devonian formation from 14780 feet to 15780 feet.

8. The Gnome East SWD Well No. 1 is located 220 feet from the North line and 305 feet from the West line, Unit D of Section 35, Township 23 South, Range 30 East, NMPM, Eddy County, for commercial disposal of oil field produced water (UIC Class II only) in the Devonian formation, through an open-hole interval from 15550 feet to 16550 feet.[2]

9. The Uber East SWD Well No. 1 is located 2345 feet from the South line and 660 feet from the East line, Unit I of Section 24, Township 23 South, Range 31 East, NMPM, Eddy County, for commercial disposal of oil field produced water (UIC Class II only) in the Devonian formation, through an open-hole interval from 16390 feet to 17500 feet.

10. The Uber North SWD Well No. 1 is located 516 feet from the North line and 2355 feet from the East line, Unit B of Section 15, Township 23 South, Range 31 East, NMPM, Eddy County, for commercial disposal of oil field produced water (UIC Class II only) in the Devonian formation, through an open-hole interval from 16500 feet to 17500 feet.

11. Each of the administrative orders listed in paragraph 2 requires that injection occur through a 4 ½ inch or smaller tubing, and establishes a maximum wellhead injection pressure for each well. (Mesquite Ex. 2).

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[2] Mesquite and the Commission have agreed to remove this well from the proceeding

12. Mesquite submitted a written request to the Oil Conservation Division ("Division") to increase the tubing size for each of the wells from a maximum of 4 ½ inches to 5 ½ inches. The Division did not approve the request and asked that Mesquite file an application to set the matter for hearing. (Ex. 1). Mesquite presented Case No. 15654 to the Division Hearing Examiners on March 30, 2017, and Order No. R-14392 was issued by the Division on July 21, 2017. Order No. R-14392 denied Mesquite's requests to upsize disposal tubing, indicating that further study was needed.

13. On August 18, 2017, Mesquite submitted an application for a *de novo* hearing before the Commission pursuant to NMSA 1978, §70-2-13.

14. On November 9, 2017, a Commission hearing was held and Mesquite appeared at the hearing through counsel and presented 5 witnesses: Riley Neatherlin, Kate Zeigler, Scott Wilson, Dr. Susan Bilek and Stephen Nave. Mesquite offered evidence demonstrating the following:

a. Notice of the application was provided to all affected parties. (Ex. 5).

b. The wells, which are the subject matter of this application, are spaced out and not located closer than 5 miles from one other. There are no other active injection wells that Mesquite is aware of which are located within a one-mile radius of each of the wells.

c. The injection zone for each of the wells is located below the Woodford Shale. The Woodford Shale is an Upper Devonian unit which has low porosity and permeability and consists predominantly of mudstone with some carbonate bed. The Woodford Shale acts as a permeability boundary to prevent fluids from moving upward out of the underlying formations. The Woodford Shale formation in the areas where the wells are located is between 80 feet to 140 feet thick. (Ex. 6)

d. Below the injection zone for the wells is the Simpson Group which contains sequences of shale that make up approximately 55% of the total thickness of the formation in any given place and can likewise act as a permeability boundary which prevents fluids from migrating downwards into deeper formations and the basement rock. In the areas where the wells are located, the Simpson Group is between 200 and 800 feet thick and, as a result, there is a significant thickness in this lower shale. Below the Simpson Group is the Ellenburger Formation, which is up to 1,000 feet thick. (Ex. 9).

e. The wells will primarily be injecting fluids into the Wristen Group and Fusselman formations, with some fluids potentially being injected into the Upper Montoya Group. Each of these sub-formations or zones are located within what is commonly referred to by operators and the Division as the "Devonian" and "Devonian Silurian" formations. These zones consist of a very thick sequence of limestone and dolostone which has significant primary and secondary porosity and permeability that is collectively between 1,500 to 3,000 feet thick. (Ex. 7).

f. There is no risk to freshwater resources for injection within the Wristen Group, Fusselman, and Upper Montoya Group because of the depth of these sub-formations and the shale permeability boundary.

g. There are no currently recognized production shales within the Wristen Group, Fusselman, and Upper Montoya Group. While there may be some isolated traps located within these sub-formations, it takes significant ability with imaging to be able to locate these deposits in order to properly target them; and no operators appeared at the hearing indicating that correlative rights would be impacted by the wells. (Ex. 8).

h. Mesquite showed through expert testimony that a large percentage of surface pressure it was encountering using 4 ½ inch tubing was a result of friction pressure. In Case No. 15720 evidence had been presented to the Division showing that up to 85% of this surface pressure was due to friction. Increasing the tubing size from 4 ½ inches to 5 ½ inches would reduce friction and would conserve forced power.

i. Mesquite further showed that increasing the tubing size to 5 ½ inches would not significantly increase reservoir pressures over a twenty-year time period. The injection zone is located within a reservoir with significant thickness which consists of high permeability rocks, which results in only very small pressure increases even when injection is increased to a rate of 40,000 barrels per day over a 20-year period. (Ex. 18-22).

j. Mesquite's expert witness testified that wellhead pressures are set at a maximum that is below the formation fracture pressure and, as a result, it is impossible to get above the formation fracture pressure. Consequently, Mesquite showed that it is highly unlikely that increasing the tubing size in the wells would result in fractures to the formation.

k. The closest known fault line is located approximately 16 miles away from where the wells are located. (Ex. 10, 11).

l. New Mexico Tech has gathered seismic monitoring data in areas near where the wells are located for several decades. This seismic data, along with data compiled from other sources, shows there has not been significant seismic activity within the areas where the wells are located.

m. Mesquite's expert seismology witness ran several different fault slip probability analyses, using a tool created by Stanford University. These fault slip potential models showed low probability of slip or earthquakes to known mapped faults. (Ex. 23-29).

n. Finally, Mesquite presented expert witness testimony on the feasibility of performing fishing operations when 5 ½ inch tubing is utilized. Mesquite's fishing expert has been performing fishing operations on wells since 1980 and testified that the use of 5 ½ inch tubing provides more flexibility when fishing operations are required to be performed. 5 ½ inch tubing is a standard tubing size used for producing wells, so there are more tools available to conduct fishing operations. Mesquite's expert concluded that the use of 5 ½ inch tubing inside of 7 5/8 inch casing would not negatively impact fishing operations on the wells. (Ex. 30-33).

15. Black River Water Management Company, LLC appeared through counsel at the hearing and took no position as to Mesquite's application. No other party appeared at the hearing, or otherwise opposed the granting of the application.

<u>THE COMMISSION CONCLUDES THAT:</u>

16. The Commission has jurisdiction over the parties and the subject matter of this case.

17. Proper notice of Mesquite's application has been given.

18. Mesquite's request to increase the approved tubing size from 4 ½ inches to 5 ½ inches in the Sand Dunes SWD Well No. 2 (API 30-015-44131), Scott B SWD Well No. 1 (API 30-015-44061), VL SWD Well No. 1 (API 30-015-pending), Station SWD Well No. 1 (API 30-025-43473), Cypress SWD Well No. 1 (API 30-015-43867), Uber East SWD Well No. 1 (API 30-015-43806), and Uber North SWD Well No. 1 (API 30-015-43805) will reduce tubing friction but will not result in significant increases to reservoir pressures.

19. The evidence presented in this particular case indicates that an increase in tubing diameter, as proposed, will result in higher disposal rates without exceeding allowable surface or bottom hole pressures.

20. The evidence presented indicates that the approved injection zones for each of the wells at issue are located below the base of the Woodford Shale formation and above the Simpson Group formation, which consists of significant shale deposits. Evidence indicates that shale formations located above and below the approved injection zones will likely restrict fluids from migrating beyond the approved injection zones for the wells.

21. Mesquite also presented sufficient evidence and testimony in this particular case which indicates that the increased injection rates, achieved through the use of 5 ½ inch tubing, is unlikely to create fault slippage or induced seismicity. This is, in

part, due to the distance between the wells at issue in Mesquite's application and the distance from the wells to known fault lines.

22. The evidence presented further indicated that fishing operations could successfully be performed on the wells when 5 ½" tubing is utilized within 7 5/8" casing.

IT IS THEREFORE ORDERED THAT:

1. The application of Mesquite SWD, Inc. to amend administrative orders SWD-1667 approving the Sand Dunes SWD Well No. 2 (API 30-015-44131), SWD-1642 and SWD-1642-A approving the Scott B SWD Well No. 1 (API 30-015-44061), SWD-1638 approving the VL SWD Well No. 1 (API 30-015-pending), SWD-1558 approving the Station SWD Well No. 1 (API 30-025-43473), SWD-1636 approving the Cypress SWD Well No. 1 (API 30-015-43867), SWD-1602 approving the Uber East SWD Well No. 1 (API 30-015-43806), SWD-1600 approving the Uber North SWD Well No. 1 (API 30-015-43805) to allow an increase in the size of the tubing in the injection interval from a maximum of 4 ½ inches to a maximum of 5 ½ inches for each well is hereby granted.

2. All other provisions of Administrative Orders SWD-1667, SWD-1642, SWD-1642-A, SWD-1638, SWD-1558, SWD-1636, SWD-1602, and SWD-1600 remain in full force and effect.

3. The Commission directs the Division to continue conducting a work group on UIC Class II wells in order to develop best management practices and advise the Commission concerning the need to develop new regulations related to disposal wells.

4. Jurisdiction is hereby retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico on the 7th day of December, 2017.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

ROBERT BALCH, Member

EDWARD MARTIN, Member

DAVID R. CATANACH, Chair

SEAL

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 8-B

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

APPLICATION OF MESQUITE SWD, INC. TO AMEND APPROVALS FOR SALT WATER DISPOSAL WELLS IN LEA AND EDDY COUNTIES.

CASE NO. 15654
ORDER NO. R-14392

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSIONER HEARING

November 9, 2017

Santa Fe, New Mexico

BEFORE: DAVID R. CATANACH, CHAIRPERSON
ED MARTIN, COMMISSIONER
DR. ROBERT S. BALCH, COMMISSIONER
BILL BRANCARD, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Thursday, November 9, 2017, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

REPORTED BY: Mary C. Hankins, CCR, RPR
New Mexico CCR #20
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EXHIBITS OFFERED AND ADMITTED

any location, because what will ultimately happen is if you build up pressure next to your wellbore, your injectivity will drop, and you just won't have enough pressure to push more fluid in the well. So it's kind of self-correcting. If the well's capable of injecting 40,000 barrels a day at original reservoir pressure and then you increase the reservoir pressure due to offset injection, the injectivity of that well will decline. So, in general, you just -- it corrects itself. You just can't get above those pressures.

Q. And how do these factors impact when you're looking at the radial influence of fluids within the formation?

A. I'm sorry. Can you rephrase the question?

Q. Yeah. Did these factors or your analysis have any -- do they give you any understanding of how fluids migrate within the Devonian --

A. Yes. The simulation work, since it's all -- since it's all one phase, water, it's difficult to track any individual molecule of water as it's moving from the injector away from the injector. In a normal reservoir simulation where you have a water flood or gas flood, you can actually watch the flood front move forward. Here it's more difficult because you don't get -- the new water doesn't look any different than the old water.

You just see a pressure response. And that pressure response is very contiguous and continuous because the permeability is so high. It's a very smooth and discreet pressure response.

Q. So in your -- and in your opinion, is it more important to look at the pressure responses here? Does that give you some indication about what's going on in the formation?

A. Absolutely. That's your only way of tracking where the fluids have gone because the pressure will respond. There are fluids that have gone a certain direction.

Q. And based on your study, is it your opinion that a half-mile notification requirement is sufficient for Mesquite's application?

A. Yes. The half-mile captures the lion's share of the pressure change near these injectors.

Q. And all wells within the formation are -- within these formations based on your -- are typically cemented?

A. Oh, absolutely.

Q. And wells drilled within a half mile are more likely to be impacted by the pressure; is that correct?

A. Yes, because they're closer to these wells.

Q. Is there any incentive for operators to want to

locate their wells further than half a mile apart or a mile apart?

A. From a technical standpoint, if someone was injecting at a location, I would try to site the next injector as far away from that location as possible because that would give me a longer period of time before I ever recognize that other injection was happening. So from a purely technical standpoint, people would distribute their injectors evenly and widely dispersed.

Q. And based on your study of the formation and the modeling that you've performed for this application, what are your conclusions concerning Mesquite's request on the overall -- overall formation in the area?

A. Concerning the 5-1/2-inch tubing?

Q. Yeah.

A. The loss of frictional pressure, the number of increased wells needed to put away the same amount of injection all drive a person to think the best opportunity is to use larger tubing because there is less waste of horsepower and potentially fewer wells needed to accomplish the same injection.

Q. And there'll be relatively minor impacts on the formation pressure, correct?

A. Correct.

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 8-C

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 15854
ORDER NO. R-14551

APPLICATION OF BLACK RIVER WATER MANAGEMENT COMPANY, LLC TO AMEND ADMINSTRATIVE ORDER SWD-1682 FOR A SALT WATER DISPOSAL WELL LOCATED IN EDDY COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This case came on for hearing at 8:15 a.m. on October 12, 2017, at Santa Fe, New Mexico, before Examiner Phillip R. Goetze.

NOW, on this 22nd day of January, 2018, the Division Director, having considered the testimony, the record and the recommendations of the Examiner,

FINDS THAT:

(1) Due public notice has been given, and the Division has jurisdiction of this case and of the subject matter.

(2) Black River Water Management Company, LLC (the "Applicant") seeks an order approving the modification of the tubing size for an Underground Injection Control (UIC) Class II well with an approved administrative order granting authority to inject. The UIC Class II well (the "Subject Well") is the Rustler Breaks SWD Well No. 2 (API No. 30-015-44240) authorized to inject under administrative order SWD-1682, issued July 7, 2017, with a surface location 1064 feet from the North line and 230 feet from the West line (Lot 4) in Section 6, Township 24 South, Range 28 East, NMPM, Eddy County, New Mexico.

(3) Applicant seeks a modification of the tubing size for the Subject Well by amending the administrative order to approve the use of 5½-inch tubing in the existing well. The Applicant stated the modification of the tubing size would result in a significant decrease of tubing friction while increasing the disposal capacity of the Subject Well.

(4) On November 3, 2017, the Applicant met with the Division and provided additional geologic and engineering data requested by the Examiner at the October

hearing. This presentation for the Examiner involved interpretations based on proprietary data. The Applicant summarized the presentations without the inclusion of the proprietary data and submitted affidavits of the interpretations for inclusion into the case file.

(5) Applicant appeared at the hearing through counsel and presented engineering evidence to the effect that:

(a) the Applicant is an operator of multiple disposal wells in New Mexico in support of the oil and gas operations of MRC Energy Company;

(b) the Subject Well has been completed as proposed in the application for administrative order SWD-1682;

(c) based on Applicant's Form C-105 for the subject well, the final depths of the permitted open-hole injection interval extends from 13,680 feet to 14,716 feet below surface;

(d) there is only one disposal well that penetrates the Devonian formation within a one-mile radius of the Subject Well, the Cigarillo SWD No. 1 (API No. 30-015-21643) which is approximately 0.9 mile northwest of the Subject Well;

(e) the use of a larger 5½-inch tubing with BTC couplings will decrease friction loss by as much as 85 percent and provide for increased capacity for disposal of UIC Class II fluids into the deeper Devonian formation;

(f) this additional capacity would increase disposal efficiency offsetting the need for new deep disposal wells to be completed in the same Devonian interval;

(g) the Applicant performed numerous nodal analysis evaluations using a variety of injection rates and multiple tubing configurations which verified the selection of the 5½-inch tubing size;

(h) the 5½-inch tubing size would allow an injection rate to increase from approximately 21,700 barrels of water per day (BWPD) to 38,000 BWPD with a relatively small increase in in the reservoir pressure of less than two percent over the projected lifespan of disposal activity;

(i) this small increase in the reservoir pressure with the proposed injection rate of 38,000 BWPD should not impact the reservoir pressures for similar disposal operations in the same formation located within two kilometers (1.24 miles) of the Subject Well;

(j) the installation of 5½-inch, 20 pounds per foot (lb/ft) tubing (with 6.05-inch outside diameter (OD) couplings) inside of 7⅝-inch

(OD), 33.7 lb/ft casing (with an interior diameter of 6.765 inches) provides a difference in diameter of approximately 0.715-inch annular clearance at tubing couples and approximately 1.265 inches between the interior of the 7⅝-inch (OD) casing wall and the exterior wall of the 5½-inch tubing body;

(k) the deviation log for the Subject Well showed a vertically straight completion with no abnormal departures (such as "doglegs") in the wellbore;

(l) the proper well completion and the available annular space of the 5½-inch tubing inside 7⅝-inch production casing would be sufficient to allow the extraction of any lost tubing with standard fishing tools including overshot tools;

(m) the Applicant provided additional reduction in the risk associated with unrecoverable tubing by extending the 7⅝-inch production casing to surface, thereby protecting tubing from external wellbore and formation fluids and eliminating potential interference from liner hangers; and

(n) the Applicant provided notice of this application to "*affected persons*" by certified mail, return receipt requested and with publication in a newspaper of general circulation in the county. The list of affected persons was compiled from the parties notified in the Form C-108 application for administrative order SWD-1682.

(6) At the meeting on November 3, 2017, the Applicant provided supplemental evidence to the effect:

(a) that based on the application of an industry-recognized, risk assessment model (the *Fault Slip Potential* software tool; Stanford Center for Induced and Trigger Seismicity; 2017) with Applicant's proprietary 3-D seismic data, there was an extremely low probability of any induced-seismic event occurring during the operational lifespan of injection activity for the Subject Well;

(b) that the estimated radius of maximum injection fluid migration following 20 years of disposal operation would be greater than 0.5 mile but less than one mile; and

(c) that as a result of the increased radius of fluid migration, the Applicant provided evidence of notification of this application to all "*affected persons*" within a one-mile radius of the Subject Well.

(7) No other party appeared at the hearing, or otherwise opposed the granting of this application.

The Division concludes as follows:

(8) The Division is responsible for the orderly development and production of hydrocarbon resources including the authority to regulate the disposition of produced water as described in NMSA 1978, Section 70-2-12(B)(15). It is obligated to prevent waste, to protect correlative rights, and to protect human health and the environment.

(9) The Division supports the use of Devonian and Silurian formations as suitable disposal intervals to lessen the potential impact upon production of hydrocarbon resources and associated correlative rights that occur in shallower Permian formations. The Division recognizes the necessity to increase the efficiency of these deeper disposal wells with their increased cost associated with the deeper disposal interval.

(10) Under Division Order No. R-14392 (Case No. 15654), the Division determined that the increase in tubing size and the corresponding increase in injection rates required additional information not previously incorporated into an administrative application for tubing modifications. This included, but was not limited to, the following specific subjects:

(a) the potential cumulative impacts to a common injection interval utilized by multiple disposal wells in close proximity;

(b) the consideration that the area of review for penetrating wells based on a one-half mile radius from the disposal well's surface location was adequate;

(c) the consideration that the notification of affected persons based on a one-half mile radius from the disposal well's surface location was protective of correlative rights;

(d) addressing the induced-seismicity issue, especially with regards to the potential impacts of increased injection volumes into reservoirs with faulting and the determination of a lower confining layer to ensure injection fluids do not migrate out the permitted interval; and

(e) the use of the larger diameter tubing in UIC Class II wells and the development of "best management practices" for all future applications with similar requests.

(11) The Applicant offered evidence or testimony to sufficiently respond to the items of concerns brought forth by the Division in its findings in Division Order No. R-14392. This included expanding the area of reviews for penetration wells and notification and conducting a risk assessment for the potential of induced seismicity related to the Subject Well's operation with a larger disposal rate.

(12) The Division noted at hearing that these responses for this application are specific to a unique disposal well and, under current procedures, each similar application would be considered based on its own merits.

(13) To avoid the drilling of additional wells, protect correlative rights, and prevent waste while affording the Applicant the opportunity to fully utilize the disposal potential of the Subject Well in a manner that safeguards the public health and the environment, this application should be approved.

IT IS THEREFORE ORDERED THAT:

(1) The application by Black River Water Management Company, LLC (the "Operator") seeking the use of internally-coated, 5½-inch OD tubing in the Rustler Breaks SWD Well No. 2 (API No. 30-015-44240, the "Subject Well") with a surface location 1064 feet from the North line and 230 feet from the West line (Lot 4) in Section 6, Township 24 South, Range 28 East, NMPM, Eddy County, New Mexico, is hereby approved.

(2) The Division further stipulates the following "best management practices" shall be included as conditions of the approved application:

(a) The Operator shall complete a step-rate test prior to commencing injection with the new tubing in place and after completing a successful mechanical integrity test.

(b) The Subject Well shall be included in a Supervisory Control and Data Acquisition (SCADA) system for operation as an injection well.

(c) The Operator shall first contact the Division's District II supervisor for approval of proposed remedial actions prior to initiating any recovery attempts should a failure of tubing occur with a loss of a tubing section within the Subject Well.

(d) The Operator shall review the well performance every fifth calendar year (five-year cycle initiated with the commencement of injection with the new tubing size). This evaluation shall consider, at a minimum, any pressure increases in the reservoir, a review of the accuracy of induced-seismicity risk assessment model using data obtained during the operation of the Subject Well, and a brief summary of any issues that required modification of the well's operation.

(e) The Operator shall submit all well tests and performance reports to Division's District II attached to a Form C-103 and made part of the well file for future availability.

(3) All provisions of this order shall be transferable and shall remain in full force and effect with any assignment of the Subject Well to a new operator.

(4) All other provisions of administrative order SWD-1682 remain in full force and effect.

(5) Based on the current casing design, the Division shall not consider any future application for an increase in the tubing size greater than 5½-inch OD for the Rustler Breaks SWD Well No. 2.

(6) Jurisdiction of this case is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

HEATHER RILEY
Director

SEAL

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 8-D

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 15972
ORDER NO. R-14716

APPLICATION OF CHEVRON U.S.A., INC. FOR APPROVAL OF A SALTWATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This case came on for hearing at 8:15 a.m. on February 8, 2018, at Santa Fe, New Mexico, before Examiner Phillip R. Goetze.

NOW, on this 7th day of June, 2018, the Division Director, having considered the testimony, the record and the recommendations of the Examiner,

FINDS THAT:

(1) Due public notice has been given, and the Division has jurisdiction of this case and of the subject matter.

(2) Chevron U.S.A., Inc. (the "Applicant" or "Chevron") seeks an order granting authority to utilize its Maelstrom SWD Well No. 1 (API No. 30-025-Pending; the "Subject Well") with a surface location 2050 feet from the South line and 1793 feet from the East line (Unit J) in Section 15, Township 26 South, Range 32 East, NMPM, Lea County, as an Underground Injection Control (UIC) Class II well for disposal of produced water into the Silurian formations through an open-hole interval from approximately 17,400 feet to approximately 19,100 feet below surface.

(3) On December 5, 2017, Chevron submitted an administrative application (Application No. pMAM1733947142) to the Division for approval of the Subject well for disposal of produced water from its operating wells. Following the submittal and review of the application, the Division requested that Chevron seek approval of the application through hearing before an examiner due to the following concerns:

(a) that notification using current Division Rule 19.15.26.8(B) NMAC for a radius of one-half mile from the surface location would not be sufficient to protect correlative rights;

(b) that the current Area of Review for wells penetrating the disposal interval for a radius of one-half mile from the surface location of the proposed well was not sufficient to protect underground sources of drinking water (USDWs); and

(c) that the proposed disposal activities for the predicted service life of the subject well did not consider the potential for induced-seismic events.

(4) Subsequently on December 20, 2017, the Applicant met with the Division and pro4ided additional geologic and engineering data regarding the potential for induced seismic events to occur as a result of the disposal well activities. This presentation for the Division involved interpretations based on proprietary data. The Applicant later summarized these presentations without the inclusion of the proprietary data as evidence at hearing.

(5) Applicant appeared at the hearing through counsel and presented geologic and engineering evidence to the effect that:

(a) the Applicant seeks to drill the Subject Well to an approximate total depth of 19,100 feet below surface. The injection will occur through an open borehole from approximately 17,400 feet to approximately 19,100 feet below surface;

(b) the Subject Well will be constructed with the following four casing strings and liner system: 20-inch surface casing set at 800 feet; 16-inch intermediate casing set at 4540 feet; 13⅜-inch intermediate casing set at 12000 feet; 9⅝-inch intermediate casing set at 17410 feet; and a 7-inch liner set at a total depth of 17950 feet;

(c) all four casings will have cement circulated to the surface while the liner will have cement circulated to the top of the liner;

(d) the Subject well will inject fluids through a tapered tubing set consisting of plastic-lined, 4½-inch tubing within the liner and plastic-lined, 7-inch tubing above the liner. The tubing is attached to a packer set no shallower than 100 feet above the top of the open-hole interval;

(e) the primary sources for disposal in the Subject Well will be produced water from Applicant's production wells within a four-mile radius of the Subject Well;

(f) the analyses of produced water samples provided by Applicant showed the compatibility of the injection fluids with formation fluids in the proposed disposal interval;

(g) the Applicant proposes a closed system operation with an average injection rate of 50,000 barrels of water per day (BWPD) using a maximum surface pressure of 3480 pounds per square inch (psi);

(h) there are no disposal wells or production wells within a one-mile radius of the Subject Well that penetrate either the Devonian or Silurian formations;

(i) the Applicant states that approximately 160 feet of Woodford Shale provides an upper confining layer for the proposed disposal interval while approximately 400 feet of Montoya formation along with remainder of the Simpson group provide a lower confining layer;

(j) the proposed construction of the Subject Well will isolate and protect the two USDWs identified in the area, the Rustler formation and the Dockum group, from any disposal activities by the Subject Well;

(k) based on the records of the New Mexico Office of the State Engineer, there are no fresh water wells within one mile of the Subject Well;

(l) the use of a tapered tubing configuration will decrease friction loss and provide increased disposal efficiency, thereby offsetting the need for new deep disposal wells to be completed in the same Silurian interval;

(m) the proposed well completion with the tapered tubing set with the available annular space of the 4½-inch tubing inside 7⅝-inch liner and with the annular space of the 7-inch tubing inside 9⅝-inch intermediate casing would be sufficient to allow the extraction of any lost tubing with standard fishing tools including overshot tools;

(n) the estimated small increase in the reservoir pressure with the proposed injection rate of 50,000 BWPD should not impact the reservoir pressures for similar disposal operations in the same formation located within a mile of the Subject Well;

(o) based on the application of an industry-recognized, risk assessment model (the *Fault Slip Potential* software tool; Stanford Center for Induced and Trigger Seismicity; 2017), additional analysis by Applicant's seismic group and the use of Applicant's proprietary 3-D seismic data, there was an extremely low or "*de minimis*" probability of any induced-seismic event occurring during the operational lifespan of injection activity for the Subject Well;

(p) the estimated radius of maximum injection fluid migration following 30 years of disposal operation would be greater than 0.5 mile but less than one mile; and

(q) as a result of the increased radius of fluid migration, the Applicant provided evidence of notification of this application to all "*affected persons*" within a one-mile radius of the Subject Well and with publication in a newspaper of general circulation in the county.

(6) No other party appeared at the hearing, or otherwise opposed the granting of this application.

The Division concludes as follows:

(7) The application has been duly filed under the provisions of Division Rule 19.15.26.8 NMAC.

(8) Applicant has presented satisfactory evidence that all requirements prescribed in Division Rule 19.15.26.8 NMAC have been met.

(9) There are no wells within the one-mile AOR for the Subject Well that penetrate the proposed injection interval.

(10) Division records indicate Chevron U.S.A., Inc. (OGRID 4323) as of the date of this order is in compliance with Division Rule 19.15.5.9 NMAC.

(11) The Division is responsible for the orderly development and production of hydrocarbon resources including the authority to regulate the disposition of produced water as described in NMSA 1978, Section 70-2-12(B)(15). It is obligated to prevent waste, to protect correlative rights, and to protect human health and the environment.

(12) The Division supports the use of Devonian and Silurian formations as suitable disposal intervals to lessen the potential impact upon production of hydrocarbon resources and associated correlative rights that occur in shallower Permian formations. The Division recognizes the necessity to increase the efficiency of these deeper disposal wells with their increased cost associated with the deeper disposal interval.

(13) Under Division Order No. R-14392 (Case No. 15654), the Division

determined that the increase in tubing size and the corresponding increase in injection rates necessitated additional information not previously incorporated into an administrative application for disposal wells with injection capacities greater than 25,000 BWPD. This included, but was not limited to, the following specific subjects:

(a) the potential cumulative impacts to a common injection interval utilized by multiple disposal wells in close proximity;

(b) the consideration that the area of review for penetrating wells based on a one-half mile radius from the disposal well's surface location was adequate;

(c) the consideration that the notification of affected persons based on a one-half mile radius from the disposal well's surface location was protective of correlative rights;

(d) addressing the induced-seismicity issue, especially with regards to the potential impacts of increased injection volumes into reservoirs with faulting and the determination of a lower confining layer to ensure injection fluids do not migrate out the permitted interval; and

(e) the use of the larger diameter tubing in UIC Class II wells and the development of "best management practices" for all future applications with similar requests.

(14) The Applicant offered evidence or testimony to sufficiently respond to the items of concerns brought forth by the Division in its findings in Division Order No. R-14392. This included expanding the area of reviews for penetration wells and notification and conducting a risk assessment for the potential of induced seismicity related to the Subject Well's operation with a larger disposal rate.

(15) To avoid the drilling of additional disposal wells, protect correlative rights, and prevent waste while affording the Applicant the opportunity to fully utilize the disposal potential of the Subject Well in a manner that safeguards the public health and the environment, this application should be approved.

IT IS THEREFORE ORDERED THAT:

(1) Chevron U.S.A., Inc. (the "Operator" or "Chevron") is hereby authorized to utilize its Maelstrom SWD Well No. 1 (API No. 30-025-Pending; the "Subject well"), to be located 2050 feet from the South line and 1793 feet from the East line (Unit J) in Section 15, Township 26 South, Range 32 East, NMPM, Lea County, New Mexico, as a disposal well for UIC Class II fluids.

(2) Disposal shall be through open hole in the Silurian formation (or

equivalent of the Wristen Group) from approximately 17,400 feet to approximately 19,100 feet below surface. Injection is to be through a plastic-lined, tapered tubing set and a packer placed within 100 feet above the top of the permitted interval. This order shall approve the use of a tapered tubing set consisting of 4½-inch (OD) or smaller tubing placed within the 7-inch liner and 7-inch (OD) or smaller tubing placed in the 9⅝-inch intermediate casing above the 7-inch liner.

(3) The Operator shall take all steps necessary to ensure that the disposed water enters only the permitted disposal interval and is not permitted to escape to other formations or onto the surface. This order does not allow disposal into formations below the Silurian formations including the Montoya formation and the Ellenburger formation (lower Ordovician) or lost circulation intervals directly on top and obviously connected to these formations.

(4) The Operator shall complete a mudlog over the permitted disposal interval sufficient to demonstrate the hydrocarbon potential. The Operator shall notify the Division's District I office and the Bureau of Land Management of significant hydrocarbon shows that are observed during drilling. The Operator shall provide the District office and the Bureau of Land Management with copies of the log.

(5) Prior to commencing disposal, the operator shall submit mudlog and geophysical logs information to the Division's District geologist and Santa Fe bureau engineering office, showing evidence agreeable that only the permitted formation is open for disposal including a summary of depths (picks) for contacts of the formations which the Division shall use to amend this Order for a final description of the depth for the injection interval.

(6) As provided in testimony, the Operator shall circulate to surface the cement for all casings and to the top of liner for the 7-inch liner. The tie-in of the 7-inch liner with the 9⅝-inch casing shall be no less than 200 feet. The Operator shall run a cement bond log ("CBL" or equivalent) across the 7-inch liner from 500 feet above the liner to the bottom of the liner to demonstrate placement cement across the length of the liner and the cement bond with the tie-in with the 9⅝-inch casing. Copies of the CBL shall be provided to the Division's District I office and the Bureau of Land Management.

(7) After installation of tubing, the casing-tubing annulus shall be loaded with an inert fluid and equipped with a pressure gauge or an approved leak detection device in order to determine leakage in the casing, tubing, or packer. The casing shall be pressure tested from the surface to the packer setting depth to assure casing integrity.

(8) The well shall pass an initial mechanical integrity test ("MIT") prior to commencement of disposal and prior to resumption of disposal each time the disposal packer is unseated. All MIT procedures and schedules shall follow the requirements in Division Rule 19.15.26.11(A) NMAC.

(9) The wellhead injection pressure shall be limited to **no more than 3480**

psi. In addition, the Subject Well shall be equipped with a pressure limiting device in workable condition which shall, at all times, limit surface tubing pressure to the maximum allowable pressure for this well.

(10) The Director of the Division may authorize an increase in tubing pressure upon a proper showing by the Operator of said well that such higher pressure will not result in migration of the disposed fluid from the approved injection interval. Such proper showing shall be demonstrated by sufficient evidence including but not limited to an acceptable Step-Rate Test.

(11) The Operator shall notify the supervisor of the Division's District I office of the date and time of the installation of disposal equipment and of any MIT test so that the same may be inspected and witnessed. The Operator shall provide written notice of the date of commencement of disposal to the Division's District I office. The Operator shall submit monthly reports of the disposal operations on Division Form C-115, in accordance with Division Rules 19.15.26.13 NMAC and 19.15.7.24 NMAC.

(12) Without limitation on the duties of the Operator as provided in Division Rules 19.15.29 NMAC and 19.15.30 NMAC, or otherwise, the Operator shall immediately notify the Division's District office of any failure of the tubing, casing or packer in the well, or of any leakage or release of water, oil or gas from around any produced or plugged and abandoned well in the area, and shall take such measures as may be timely and necessary to correct such failure or leakage.

(13) If the Subject Well fails a MIT or if there is evidence that the mechanical integrity of said well is impacting correlative rights, the public health, any underground sources of fresh water, or the environment, the Division Director shall require the well to be shut-in within 24 hours of discovery and the operator shall redirect all disposal waters to another facility. The operator shall take the necessary actions to address the impacts resulting from the mechanical integrity issues in accordance with Division Rule 19.15.26.10 NMAC, and the well shall be tested pursuant to Rule 19.15.26.11 NMAC prior to returning to injection.

(14) The Division further stipulates the following "best management practices" shall be included as conditions of the approved application:

(a) The Subject Well shall be included in a Supervisory Control and Data Acquisition (SCADA) system for operation as an injection well.

(b) The Operator shall first contact the Division's District I supervisor for approval of proposed remedial actions <u>prior to initiating any recovery attempts</u> should a failure of tubing occur with a loss of a tubing section within the Subject Well.

(c) The Operator shall submit all well tests and performance reports to Division's District I (attached to a Form C-103) and made part of the well file for future availability.

(15) The injection authority granted under this order is not transferable except upon Division approval. The Division may require the Operator to demonstrate mechanical integrity of any injection well that will be transferred prior to approving transfer of authority to inject.

(16) The Division may revoke this injection permit after notice and hearing if the Operator is in violation of Division Rule 19.15.5.9 NMAC.

(17) The disposal authority granted herein shall terminate two years after the effective date of this order if the Operator has not commenced injection operations into the proposed well, provided however, the Division, upon written request, mailed by the Operator prior to the termination date, may grant an extension thereof for good cause.

(18) One year after disposal into the Subject Well has ceased, said well will be considered abandoned and the authority to dispose will terminate *ipso facto*.

(19) Compliance with this order does not relieve the Operator of the obligation to comply with other applicable federal, state or local laws or rules, or to exercise due care for the protection of fresh water, public health and safety and the environment.

(20) Jurisdiction is retained by the Division for the entry of such further orders as may be necessary for the prevention of waste and/or protection of correlative rights or upon failure of the Operator to conduct operations (1) to protect fresh or protectable waters or (2) consistent with the requirements in this order, whereupon the Division may, after notice and hearing, or prior to notice and hearing in event of an emergency, terminate the disposal authority granted herein.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

HEATHER RILEY
Director

SEAL

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 8-E

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 16439
ORDER NO. R-20322

AMENDED APPLICATION OF NGL WATER SOLUTIONS PERMIAN, LLC FOR APPROVAL OF A SALT WATER DISPOSAL WELL IN LEA COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This case came on for hearing at 8:15 a.m. on October 4, 2018, at Santa Fe, New Mexico, before Examiners Michael A. McMillan and Phillip R. Goetze, and on October 18, 2018, before Phillip R. Goetze.

NOW, on this 23rd day of January, 2019, the Division Director, having considered the testimony, the record and the recommendations of Examiner Goetze,

FINDS THAT:

(1) Due public notice has been given, and the Division has jurisdiction of this case and of the subject matter.

(2) Cases No. 16439, No. 16441, and No. 16442 were consolidated at the hearing for testimony; however, a separate order is being issued for each case.

(3) In Case No. 16439, NGL Water Solutions Permian, LLC (the "Applicant" or "NGL") seeks an order granting authority to utilize its McCloy Central SWD Well No. 1 (API No. 30-025-Pending; the "Subject Well") with a surface location 762 feet from the North line and 383 feet from the East line (Unit A) and a bottom-hole location 762 feet from the North line and 256 feet from the East line (Unit A), both in Section 24, Township 24 South, Range 32 East, NMPM, Lea County, as an Underground Injection Control (UIC) Class II well for commercial disposal of produced water into the Devonian

and Silurian formations through an open-hole interval from approximately 17424 feet to approximately 18533 feet below surface.

(4) On September 26, 2018, the Applicant met with the Division in a pre-hearing conference and provided preliminary geologic and engineering data proposed for presentation as evidence at hearing. This data included proposed well completion, risk assessment for induced seismicity, detailed presentation of geology and stratigraphy, and an evaluation for recovery of failed tubing.

(5) At the September conference, the Division also reviewed the proposed surface location with respect to other Devonian disposal wells with similar injection capacities. The Division concluded that the proposed location would not overlap the ¾-mile radius buffers for adjacent Devonian disposal wells.

(6) Subsequently on August 27, 2018, NGL submitted a hearing application to the Division for approval of the Subject Well for authority to inject produced water.

(7) Applicant appeared at the hearing through counsel and presented geologic and engineering evidence to the effect that:

(a) The Applicant seeks to drill the Subject Well to an approximate total depth of 18533 feet below surface. The injection will occur through an open borehole from approximately 17424 feet to approximately 18533 feet below surface.

(b) The Subject Well will be constructed with the following four casing strings and liner system: 20-inch surface casing set at 1250 feet; 13⅜-inch intermediate casing set at 4950 feet; 9⅝-inch intermediate casing set at 12300 feet; and a 7⅝-inch liner (with a weight of 39 pounds per foot) set from 11800 feet to a total depth of 17424 feet.

(c) All three casings will have cement circulated to the surface while the liner will have cement circulated to the top of the liner.

(d) The Subject Well will inject fluids through a tapered tubing set consisting of plastic-lined, 5½-inch outside diameter (OD) tubing within the liner and plastic-lined, 7-inch OD tubing above the liner. The tubing is attached to a packer set no shallower than 100 feet above the top of the open-hole interval.

(e) The primary sources of produced water will be wells with production from the Bone Spring and the Wolfcamp formations.

(f) The analyses of produced water samples provided by Applicant showed the compatibility of the injection fluids with formation fluids in the proposed disposal interval.

(g) The Applicant proposes a commercial operation with a maximum average injection rate of 50000 barrels of water per day (BWPD) using a maximum surface injection pressure of 3484 pounds per square inch (psi).

(h) There are no production or disposal wells that penetrate the Devonian formation within the one-mile Area of Review (AOR) of the surface location and the bottom-hole location for the Subject Well.

(i) The Applicant states that approximately 150 feet of Woodford Shale provides an upper confining layer for the proposed disposal interval while approximately 500 feet of the remainder of the Simpson group (excluding the Ellenburger formation) provide a lower confining layer.

(j) The proposed construction of the Subject Well will isolate and protect the two underground sources of drinking water (USDWs) identified in the area, the Rustler formation and the Dockum group (Santa Rosa sandstone), from any disposal activities by the Subject Well.

(k) Based on the records of the New Mexico Office of the State Engineer, there are no fresh water wells within one mile of the surface location of the Subject Well.

(l) The use of a tapered tubing configuration will decrease friction loss and provide increased disposal efficiency, thereby offsetting the need for new deep disposal wells to be completed in the same Devonian and Silurian interval.

(m) The proposed well completion with the tapered tubing set with the available annular space of the 5½-inch OD tubing inside 7⅝-inch liner and with the annular space of the 7-inch OD tubing inside 9⅝-inch intermediate casing would be sufficient to allow the extraction of any lost tubing with standard fishing tools including overshot tools.

(n) The estimated small increase in the reservoir pressure with the proposed injection rate of 50000 BWPD should not impact the reservoir pressures for similar disposal operations in the same injection interval located within 1.5 miles of the Subject Well.

(o) Based on the application of a risk assessment model (the *Fault Slip Potential* software tool; Stanford Center for Induced and Trigger Seismicity; 2017) with publicly-available data, there was an extremely low probability of any induced-seismic event occurring during the operational lifespan of injection activity for the Subject Well.

(p) The estimated radius of maximum injection fluid migration following 20 years of disposal operation would be greater than 0.5 mile but less than one mile.

(q) The Applicant provided evidence of notification of this application to all *"affected persons"* within a one-mile radius of both the surface and bottom-hole locations of the Subject Well and with publication in a newspaper of general circulation in the county.

(8) Devon Energy Production Company, LLC and Fulfer Oil & Cattle LLC appeared through counsel at hearing and did not oppose the granting of this application. No other party appeared at the hearing, or otherwise opposed the granting of this application.

The Division concludes as follows:

(9) The application has been duly filed under the provisions of Division Rule 19.15.26.8 NMAC.

(10) Applicant has presented satisfactory evidence that all requirements prescribed in Division Rule 19.15.26.8 NMAC have been met.

(11) The proposed well construction provided in the application is protective of USDWs.

(12) There are no wells that penetrate the proposed injection interval within the one-mile AOR for the Subject Well.

(13) Division records indicate NGL Water Solutions Permian, LLC (OGRID 372338) as of the date of this order is in compliance with Division Rule 19.15.5.9 NMAC.

(14) The Division is responsible for the orderly development and production of hydrocarbon resources including the authority to regulate the disposition of produced water as described in NMSA 1978, Section 70-2-12(B)(15). It is obligated to prevent waste, to protect correlative rights, and to protect human health and the environment.

(15) The Division supports the use of Devonian and Silurian formations as suitable disposal intervals to lessen the potential impact upon production of hydrocarbon

resources and associated correlative rights that occur in shallower Permian formations. The Division recognizes the necessity to increase the efficiency of these deeper disposal wells with their increased cost associated with the deeper disposal interval.

(16) Under Division Order No. R-14392 (Case No. 15654), the Division determined that the increase in tubing size and the corresponding increase in injection rates necessitated additional information not previously incorporated into an administrative application for disposal wells with injection capacities greater than 20000 BWPD. This included, but was not limited to, the following specific subjects:

(a) the potential cumulative impacts to a common injection interval utilized by multiple disposal wells in close proximity;

(b) the consideration that the area of review for penetrating wells based on a one-mile radius from the disposal well's surface location was adequate;

(c) the consideration that the notification of affected persons based on a one-half mile radius from the disposal well's surface location was protective of correlative rights; and

(d) addressing the induced-seismicity issue, especially with regards to the potential impacts of increased injection volumes into reservoirs with faulting and the determination of a lower confining layer to ensure injection fluids do not migrate out the permitted disposal interval.

(17) The Applicant offered evidence and testimony to sufficiently respond to the items of concerns brought forth by the Division in the findings of Division Order No. R-14392 as listed previously and later addressed in Commission Order No. R-14392-A (*de novo*).

(18) To avoid the drilling of additional disposal wells, protect correlative rights, and prevent waste while affording the Applicant the opportunity to fully utilize the disposal potential of the Subject Well in a manner that safeguards the public health and the environment, this application should be approved.

IT IS THEREFORE ORDERED THAT:

(1) NGL Water Solutions Permian, LLC (the "Operator" or "NGL") is hereby authorized to utilize its McCloy Central SWD Well No. 1 (API No. 30-025-Pending; the "Subject Well") with a surface location 762 feet from the North line and 383 feet from the East line (Unit A) and a bottom-hole location 762 feet from the North line and 256 feet from the East line (Unit A), both in Section 24, Township 24 South, Range 32 East, NMPM, Lea County, New Mexico, as a commercial disposal well for UIC Class II fluids.

(2) Disposal shall be through open hole in the Devonian and Silurian formations (below the lower contact of the Woodford Shale) from approximately 17424 feet to approximately 18533 feet below surface (the "permitted disposal interval"). Injection is to be through a plastic-lined, tapered tubing set and a packer placed within 100 feet above the top of the permitted interval. This order shall approve the use of a tapered tubing set consisting of 5½-inch (OD) or smaller tubing placed within the 7⅝-inch liner (with a weight of 39 pounds per foot) and 7-inch (OD) or smaller tubing placed in the 9⅝-inch intermediate casing above the 7⅝-inch liner.

(3) The Operator shall take all steps necessary to ensure that the disposed water enters only the permitted disposal interval and is not permitted to escape to other formations or onto the surface. This order does not allow disposal into formations below the Silurian formations including the Montoya formation and the Ellenburger formation (lower Ordovician) or lost circulation intervals directly on top and obviously connected to these formations.

(4) The Operator shall provide to the Division's District a Notice of Intent on Division Form C-103 with the anticipated date and time for the well to be spud. This initial Notice shall be filed with the District at least 72 hours prior to commencing drilling.

(5) The Operator shall complete a mudlog over the permitted disposal interval sufficient to demonstrate the hydrocarbon potential. The Operator shall notify the Division's District I office and the Santa Fe engineering bureau office of significant hydrocarbon shows that are observed during drilling of the permitted disposal interval. The Operator shall provide the District office with copies of the log.

(6) Prior to commencing disposal, the Operator shall submit mudlog and geophysical logs information, to the Division's District geologist and Santa Fe engineering bureau office, showing evidence agreeable that only the permitted formation is open for disposal including a summary of depths (picks) for contacts of the formations which the Division shall use to amend this order for a final description of the depth for the injection interval.

(7) Prior to commencing disposal, the Operator shall obtain a **bottom-hole pressure measurement** representative of the injection interval and submit this data with the information required in Ordering Paragraph (15).

(8) As provided in testimony, the Operator shall circulate to surface the cement for all casings and to the top of liner for the 7⅝-inch liner. The tie-in of the 7⅝-inch liner with the 9⅝-inch casing shall be equal to or greater than 200 feet. The Operator shall run a cement bond log ("CBL" or equivalent) across the 7⅝-inch liner from 500 feet above the liner to the bottom of the liner to demonstrate placement cement across the length of the liner and the cement bond with the tie-in with the 9⅝-inch casing. Copies of the CBL shall be provided to the Division's District I office.

(9) After installation of tubing, the casing-tubing annulus shall be loaded with an inert fluid and equipped with a pressure gauge or an approved leak detection device in order to determine leakage in the casing, tubing, or packer. The casing shall be pressure tested from the surface to the packer setting depth to assure casing integrity.

(10) The well shall pass an initial mechanical integrity test ("MIT") prior to commencement of disposal and prior to resumption of disposal each time the disposal packer is unseated. All MIT procedures and schedules shall follow the requirements in Division Rule 19.15.26.11(A) NMAC.

(11) The wellhead injection pressure shall be limited to **no more than 3485 psi**. In addition, the Subject Well shall be equipped with a pressure limiting device in workable condition which shall, at all times, limit surface tubing pressure to the maximum allowable pressure for this well.

(12) The Director of the Division may authorize an increase in tubing pressure upon a proper showing by the Operator of said well that such higher pressure will not result in migration of the disposed fluid from the approved injection interval. Such proper showing shall be demonstrated by sufficient evidence including but not limited to an acceptable Step-Rate Test.

(13) Further, the Subject Well shall be limited to a maximum injection rate of **no more than 50000 barrels of water per day.**

(14) The Director of the Division may authorize an increase in the injection rate upon a proper showing by the Operator of said well that such increase in injection rate will not result in migration of the disposed fluid from the approved injection interval. Such proper showing shall be demonstrated by sufficient evidence including but not limited to an amended assessment of induced-seismicity risks and calculation of a radius of influence representative of the proposed injection rate.

(15) The Operator shall notify the supervisor of the Division's District I office of the date and time of the installation of disposal equipment and of any MIT test so that the same may be inspected and witnessed. The Operator shall provide written notice of the date of commencement of disposal to the Division's District I office. The Operator shall submit monthly reports of the disposal operations (maximum surface injection pressure, injection volume and days of operation) using the online version of Division Form C-115, in accordance with Division Rules 19.15.26.13 and 19.15.7.24 NMAC.

(16) Without limitation on the duties of the Operator as provided in Division Rules 19.15.29 and 19.15.30 NMAC, or otherwise, the Operator shall immediately notify the Division's District office of any failure of the tubing, casing or packer in the well, or of any leakage or release of water, oil or gas from or around any produced or plugged and abandoned well in the area, and shall take such measures as may be timely and necessary to correct such failure or leakage.

(17) If the Subject Well fails a MIT or if there is evidence that the mechanical integrity of said well is impacting correlative rights, the public health, any underground sources of fresh water, or the environment, the Division Director shall require the well to be shut-in within 24 hours of discovery and the operator shall redirect all disposal waters to another facility. The operator shall take the necessary actions to address the impacts resulting from the mechanical integrity issues in accordance with Division Rule 19.15.26.10 NMAC, and the well shall be tested pursuant to Rule 19.15.26.11 NMAC prior to returning to injection.

(18) The Division further stipulates the following "best management practices" shall be included as conditions of the approved application:

(a) The Subject Well shall be included in a Supervisory Control and Data Acquisition (SCADA) system for operation as an injection well.

(b) The Operator shall first contact the Division's District I supervisor for approval of proposed remedial actions <u>prior to initiating any recovery attempts</u> should a failure of tubing occur with a loss of a tubing section within the Subject Well.

(c) The Operator shall submit all well tests and performance reports to Division's District I (attached to a Form C-103) and made part of the well file for future availability.

(19) The injection authority granted under this order is not transferable except upon Division approval. The Division may require the Operator to demonstrate mechanical integrity of any injection well that will be transferred prior to approving transfer of authority to inject.

(20) The Division may revoke this injection permit after notice and hearing if the Operator is in violation of Division Rule 19.15.5.9 NMAC.

(21) The disposal authority granted herein shall terminate one year after the effective date of this order if the Operator has not commenced injection operations into the proposed well, provided however, the Division, upon written request, mailed by the Operator prior to the termination date, may grant an extension thereof for good cause.

(22) One year after disposal into the Subject Well has ceased, said well will be considered abandoned and the authority to dispose will terminate *ipso facto*.

(23) Compliance with this order does not relieve the Operator of the obligation to comply with other applicable federal, state or local laws or rules, or to exercise due care for the protection of fresh water, public health and safety, and the environment.

(24) Jurisdiction is retained by the Division for the entry of such further orders as may be necessary for the prevention of waste and/or protection of correlative rights or

upon failure of the Operator to conduct operations (1) to protect fresh or protectable waters or (2) consistent with the requirements in this order, whereupon the Division may, after notice and hearing, or prior to notice and hearing in event of an emergency, terminate the disposal authority granted herein.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

GABRIEL WADE
Acting Director

SEAL

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 16441
ORDER NO. R-20323

AMENDED APPLICATION OF NGL WATER SOLUTIONS PERMIAN, LLC FOR APPROVAL OF A SALT WATER DISPOSAL WELL IN LEA COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This case came on for hearing at 8:15 a.m. on October 4, 2018, at Santa Fe, New Mexico, before Examiners Michael A. McMillan and Phillip R. Goetze, and on October 18, 2018, before Phillip R. Goetze.

NOW, on this 23rd day of January, 2019, the Division Director, having considered the testimony, the record and the recommendations of Examiner Goetze,

FINDS THAT:

(1) Due public notice has been given, and the Division has jurisdiction of this case and of the subject matter.

(2) Cases No. 16439, No. 16441, and No. 16442 were consolidated at the hearing for testimony; however, a separate order is being issued for each case.

(3) In Case No. 16441, NGL Water Solutions Permian, LLC (the "Applicant" or "NGL") seeks an order granting authority to utilize its Minuteman SWD Well No. 1 (API No. 30-025-Pending; the "Subject Well") with a surface location 659 feet from the South line and 449 feet from the West line (Unit M) in Section 14, Township 24 South, Range 33 East, NMPM, Lea County, as an Underground Injection Control (UIC) Class II well for commercial disposal of produced water into the Devonian and Silurian formations through an open-hole interval from approximately 16691 feet to approximately 18326 feet below surface.

(4) On September 26, 2018, the Applicant met with the Division in a pre-hearing conference and provided preliminary geologic and engineering data proposed for presentation as evidence at hearing. This data included proposed well completion, risk assessment for induced seismicity, detailed presentation of geology and stratigraphy, and an evaluation for recovery of failed tubing.

(5) At the September conference, the Division also reviewed the proposed surface location with respect to other Devonian disposal wells with similar injection capacities. The Division concluded that the proposed location would not overlap the ¾-mile radius buffers for adjacent Devonian disposal wells.

(6) Subsequently on August 27, 2018, NGL submitted a hearing application to the Division for approval of the Subject Well for authority to inject produced water.

(7) Applicant appeared at the hearing through counsel and presented geologic and engineering evidence to the effect that:

(a) The Applicant seeks to drill the Subject Well to an approximate total depth of 18326 feet below surface. The injection will occur through an open borehole from approximately 16691 feet to approximately 18326 feet below surface.

(b) The Subject Well will be constructed with the following four casing strings and liner system: 20-inch surface casing set at 1400 feet; 13⅜-inch intermediate casing set at 5200 feet; 9⅝-inch intermediate casing set at 12300 feet; and a 7⅝-inch liner (with a weight of 39 pounds per foot) set from 11800 feet to a total depth of 16691 feet.

(c) All three casings will have cement circulated to the surface while the liner will have cement circulated to the top of the liner.

(d) The Subject Well will inject fluids through a tapered tubing set consisting of plastic-lined, 5½-inch outside diameter (OD) tubing within the liner and plastic-lined, 7-inch OD tubing above the liner. The tubing is attached to a packer set no shallower than 100 feet above the top of the open-hole interval.

(e) The primary sources of produced water will be wells with production from the Bone Spring and the Wolfcamp formations.

(f) The analyses of produced water samples provided by Applicant showed the compatibility of the injection fluids with formation fluids in the proposed disposal interval.

(g) The Applicant proposes a commercial operation with a maximum average injection rate of 50000 barrels of water per day (BWPD) using a maximum surface injection pressure of 3338 pounds per square inch (psi).

(h) There are no production or disposal wells that penetrate the Devonian formation within the one-mile Area of Review of the surface location and the bottom-hole location for the Subject Well.

(i) The Applicant states that approximately 150 feet of Woodford Shale provides an upper confining layer for the proposed disposal interval while approximately 500 feet of the remainder of the Simpson group (excluding the Ellenburger formation) provide a lower confining layer.

(j) The proposed construction of the Subject Well will isolate and protect the two underground sources of drinking water (USDWs) identified in the area, the Rustler formation and the Dockum group (Santa Rosa sandstone), from any disposal activities by the Subject Well.

(k) Based on the records of the New Mexico Office of the State Engineer, there are nine fresh water wells within one mile of the surface location of the Subject Well. The Applicant stated that inspections by a consultant to obtain water samples found each well plugged and abandoned.

(l) The use of a tapered tubing configuration will decrease friction loss and provide increased disposal efficiency, thereby offsetting the need for new deep disposal wells to be completed in the same Devonian and Silurian interval.

(m) The proposed well completion with the tapered tubing set with the available annular space of the 5½-inch OD tubing inside 7⅝-inch liner and with the annular space of the 7-inch OD tubing inside 9⅝-inch intermediate casing would be sufficient to allow the extraction of any lost tubing with standard fishing tools including overshot tools.

(n) The estimated small increase in the reservoir pressure with the proposed injection rate of 50000 BWPD should not impact the reservoir pressures for similar disposal operations in the same injection interval located within 1.5 miles of the Subject Well.

(o) Based on the application of a risk assessment model (the *Fault Slip Potential* software tool; Stanford Center for Induced and Trigger

Seismicity; 2017) with publicly-available data, there was an extremely low probability of any induced-seismic event occurring during the operational lifespan of injection activity for the Subject Well.

(p) The estimated radius of maximum injection fluid migration following 20 years of disposal operation would be greater than 0.5 mile but less than one mile.

(q) The Applicant provided evidence of notification of this application to all *"affected persons"* within a one-mile radius of both the surface and bottom-hole locations of the Subject Well and with publication in a newspaper of general circulation in the county.

(8) Devon Energy Production Company, LLC and Fulfer Oil & Cattle LLC appeared through counsel at hearing and did not oppose the granting of this application. No other party appeared at the hearing, or otherwise opposed the granting of this application.

(9) Following the hearing on October 18, 2018, Invenergy Solar Development LLC ("Invenergy") submitted a written objection, dated November 20, 2018, opposing the approval of this application for authority to inject. Invenergy stated that it was a surface lessee for Section 14 with "exclusive right to use the surface of the Property for solar development." The objection stated "NGL is the owner of the surface estate of the Property, and NGL acquired the surface with full knowledge that the Lease was in effect." Invenergy based their objection on improper notice to Invenergy by NGL for this application and the opportunity to appear at hearing in opposition.

The Division concludes as follows:

(10) The application has been duly filed under the provisions of Division Rule 19.15.26.8 NMAC.

(11) Applicant has presented satisfactory evidence that all requirements prescribed in Division Rule 19.15.26.8 NMAC have been met.

(12) The Division reviewed the protest submitted by Invenergy for this application and determined that the claim of improper notice lacked standing. Pursuant to Rule 19.15.26.8(B)(2) NMAC, *"The applicant shall furnish, by certified or registered mail, a copy of the application to each owner of the land surface on which each injection or disposal well is to be located.*" As noted by Invenergy in its protest, NGL is both the applicant and the surface owner and, therefore, the minimum notice requirement for the owner of the land surface under rule was satisfied. Any disputes of agreements or contracts regarding surface use for the location of the Subject Well are not within the authority of the Division or the UIC permit process.

(13) The proposed well construction provided in the application is protective of USDWs.

(14) There are no wells that penetrate the proposed injection interval within the one-mile AOR for the Subject Well.

(15) Division records indicate NGL Water Solutions Permian, LLC (OGRID 372338) as of the date of this order is in compliance with Division Rule 19.15.5.9 NMAC.

(16) The Division is responsible for the orderly development and production of hydrocarbon resources including the authority to regulate the disposition of produced water as described in NMSA 1978, Section 70-2-12(B)(15). It is obligated to prevent waste, to protect correlative rights, and to protect human health and the environment.

(17) The Division supports the use of Devonian and Silurian formations as suitable disposal intervals to lessen the potential impact upon production of hydrocarbon resources and associated correlative rights that occur in shallower Permian formations. The Division recognizes the necessity to increase the efficiency of these deeper disposal wells with their increased cost associated with the deeper disposal interval.

(18) Under Division Order No. R-14392 (Case No. 15654), the Division determined that the increase in tubing size and the corresponding increase in injection rates necessitated additional information not previously incorporated into an administrative application for disposal wells with injection capacities greater than 20000 BWPD. This included, but was not limited to, the following specific subjects:

(a) the potential cumulative impacts to a common injection interval utilized by multiple disposal wells in close proximity;

(b) the consideration that the area of review for penetrating wells based on a one-mile radius from the disposal well's surface location was adequate;

(c) the consideration that the notification of affected persons based on a one-half mile radius from the disposal well's surface location was protective of correlative rights; and

(d) addressing the induced-seismicity issue, especially with regards to the potential impacts of increased injection volumes into reservoirs with faulting and the determination of a lower confining layer to ensure injection fluids do not migrate out the permitted disposal interval.

(19) The Applicant offered evidence and testimony to sufficiently respond to the items of concerns brought forth by the Division in the findings of Division Order No.

R-14392 as listed previously and later addressed in Commission Order No. R-14392-A (*de novo*).

(20) To avoid the drilling of additional disposal wells, protect correlative rights, and prevent waste while affording the Applicant the opportunity to fully utilize the disposal potential of the Subject Well in a manner that safeguards the public health and the environment, this application should be approved.

IT IS THEREFORE ORDERED THAT:

(1) NGL Water Solutions Permian, LLC (the "Operator" or "NGL") is hereby authorized to utilize its Minuteman SWD Well No. 1 (API No. 30-025-Pending; the "Subject Well") with a surface location 659 feet from the South line and 449 feet from the West line (Unit M) in Section 14, Township 24 South, Range 33 East, NMPM, Lea County, New Mexico, as a commercial disposal well for UIC Class II fluids.

(2) Disposal shall be through open hole in the Devonian and Silurian formations (below the lower contact of the Woodford Shale) from approximately 16691 feet to approximately 18326 feet below surface (the "permitted disposal interval"). Injection is to be through a plastic-lined, tapered tubing set and a packer placed within 100 feet above the top of the permitted interval. This order shall approve the use of a tapered tubing set consisting of 5½-inch (OD) or smaller tubing placed within the 7⅝-inch liner (with a weight of 39 pounds per foot) and 7-inch (OD) or smaller tubing placed in the 9⅝-inch intermediate casing above the 7⅝-inch liner.

(3) The Operator shall take all steps necessary to ensure that the disposed water enters only the permitted disposal interval and is not permitted to escape to other formations or onto the surface. This order does not allow disposal into formations below the Silurian formations including the Montoya formation and the Ellenburger formation (lower Ordovician) or lost circulation intervals directly on top and obviously connected to these formations.

(4) The Operator shall provide to the Division's District a Notice of Intent on Division Form C-103 with the anticipated date and time for the well to be spud. This initial Notice shall be filed with the District at least 72 hours prior to commencing drilling.

(5) The Operator shall complete a mudlog over the permitted disposal interval sufficient to demonstrate the hydrocarbon potential. The Operator shall notify the Division's District I office and the Santa Fe engineering bureau office of significant hydrocarbon shows that are observed during drilling of the permitted disposal interval. The operator shall provide the District office with copies of the log.

(6) Prior to commencing disposal, the Operator shall submit mudlog and geophysical logs information, to the Division's District geologist and Santa Fe engineering bureau office, showing evidence agreeable that only the permitted formation

is open for disposal including a summary of depths (picks) for contacts of the formations which the Division shall use to amend this order for a final description of the depth for the injection interval.

(7) Prior to commencing disposal, the Operator shall obtain a **bottom-hole pressure measurement** representative of the injection interval and submit this data with the information required in Ordering Paragraph (15).

(8) As provided in testimony, the Operator shall circulate to surface the cement for all casings and to the top of liner for the 7⅝-inch liner. The tie-in of the 7⅝-inch liner with the 9⅝-inch casing shall be equal to or greater than 200 feet. The Operator shall run a cement bond log ("CBL" or equivalent) across the 7⅝-inch liner from 500 feet above the liner to the bottom of the liner to demonstrate placement cement across the length of the liner and the cement bond with the tie-in with the 9⅝-inch casing. Copies of the CBL shall be provided to the Division's District I office.

(9) After installation of tubing, the casing-tubing annulus shall be loaded with an inert fluid and equipped with a pressure gauge or an approved leak detection device in order to determine leakage in the casing, tubing, or packer. The casing shall be pressure tested from the surface to the packer setting depth to assure casing integrity.

(10) The well shall pass an initial mechanical integrity test ("MIT") prior to commencement of disposal and prior to resumption of disposal each time the disposal packer is unseated. All MIT procedures and schedules shall follow the requirements in Division Rule 19.15.26.11(A) NMAC.

(11) The wellhead injection pressure shall be limited to **no more than 3338 psi**. In addition, the Subject Well shall be equipped with a pressure limiting device in workable condition which shall, at all times, limit surface tubing pressure to the maximum allowable pressure for this well.

(12) The Director of the Division may authorize an increase in tubing pressure upon a proper showing by the Operator of said well that such higher pressure will not result in migration of the disposed fluid from the approved injection interval. Such proper showing shall be demonstrated by sufficient evidence including but not limited to an acceptable Step-Rate Test.

(13) Further, the Subject Well shall be limited to a maximum injection rate of **no more than 50000 barrels of water per day.**

(14) The Director of the Division may authorize an increase in the injection rate upon a proper showing by the Operator of said well that such increase in injection rate will not result in migration of the disposed fluid from the approved injection interval. Such proper showing shall be demonstrated by sufficient evidence including but not limited to an amended assessment of induced-seismicity risks and calculation of a radius of influence representative of the proposed injection rate.

(15) The Operator shall notify the supervisor of the Division's District I office of the date and time of the installation of disposal equipment and of any MIT test so that the same may be inspected and witnessed. The Operator shall provide written notice of the date of commencement of disposal to the Division's District I office. The Operator shall submit monthly reports of the disposal operations (maximum surface injection pressure, injection volume and days of operation) using the online version of Division Form C-115, in accordance with Division Rules 19.15.26.13 and 19.15.7.24 NMAC.

(16) Without limitation on the duties of the Operator as provided in Division Rules 19.15.29 and 19.15.30 NMAC, or otherwise, the Operator shall immediately notify the Division's District office of any failure of the tubing, casing or packer in the well, or of any leakage or release of water, oil or gas from or around any produced or plugged and abandoned well in the area, and shall take such measures as may be timely and necessary to correct such failure or leakage.

(17) If the Subject Well fails a MIT or if there is evidence that the mechanical integrity of said well is impacting correlative rights, the public health, any underground sources of fresh water, or the environment, the Division Director shall require the well to be shut-in within 24 hours of discovery and the operator shall redirect all disposal waters to another facility. The Operator shall take the necessary actions to address the impacts resulting from the mechanical integrity issues in accordance with Division Rule 19.15.26.10 NMAC, and the well shall be tested pursuant to Rule 19.15.26.11 NMAC prior to returning to injection.

(18) The Division further stipulates the following "best management practices" shall be included as conditions of the approved application:

(a) The Subject Well shall be included in a Supervisory Control and Data Acquisition (SCADA) system for operation as an injection well.

(b) The Operator shall first contact the Division's District I supervisor for approval of proposed remedial actions <u>prior to initiating any recovery attempts</u> should a failure of tubing occur with a loss of a tubing section within the Subject Well.

(c) The Operator shall submit all well tests and performance reports to Division's District I (attached to a Form C-103) and made part of the well file for future availability.

(19) The injection authority granted under this order is not transferable except upon Division approval. The Division may require the operator to demonstrate mechanical integrity of any injection well that will be transferred prior to approving transfer of authority to inject.

(20) The Division may revoke this injection permit after notice and hearing if the operator is in violation of Division Rule 19.15.5.9 NMAC.

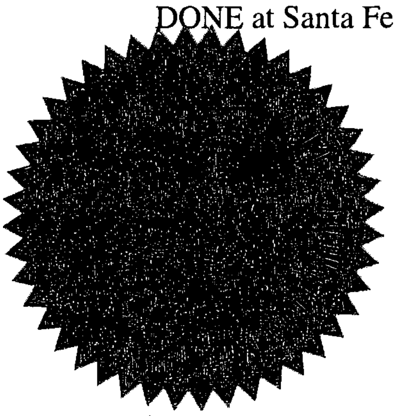
(21) The disposal authority granted herein shall terminate one year after the effective date of this order if the Operator has not commenced injection operations into the proposed well, provided however, the Division, upon written request, mailed by the operator prior to the termination date, may grant an extension thereof for good cause.

(22) One year after disposal into the Subject Well has ceased, said well will be considered abandoned and the authority to dispose will terminate *ipso facto.*

(23) Compliance with this order does not relieve the Operator of the obligation to comply with other applicable federal, state or local laws or rules, or to exercise due care for the protection of fresh water, public health and safety, and the environment.

(24) Jurisdiction is retained by the Division for the entry of such further orders as may be necessary for the prevention of waste and/or protection of correlative rights or upon failure of the Operator to conduct operations (1) to protect fresh or protectable waters or (2) consistent with the requirements in this order, whereupon the Division may, after notice and hearing, or prior to notice and hearing in event of an emergency, terminate the disposal authority granted herein.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.



SEAL

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

GABRIEL WADE
Acting Director

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 8-G

Exhibits of Scott Wilson
On Behalf of NGL Water Solutions Permian, LLC

STATE OF NEW MEXICO
DEPARTMENT OF ENERGY, MINERALS AND NATURAL RESOURCES
OIL CONSERVATION DIVISION

APPLICATION OF NGL WATER SOLUTIONS PERMIAN, LLC FOR APPROVAL OF SALT WATER DISPOSAL WELL IN LEA COUNTY, NEW MEXICO

CASE NO. 20235

AFFIDAVIT OF SCOTT J. WILSON

STATE OF COLORADO)
) ss.
COUNTY OF DENVER)

I, Scott J. Wilson, make the following affidavit based upon my own personal knowledge.

1. I am over eighteen (18) years of age and am otherwise competent to make the statements contained herein.

2. I am the Senior Vice President for Ryder Scott Company in Denver, Colorado. My responsibilities at Ryder Scott Company include the performance of reserve appraisals, technical evaluations, and reservoir analysis.

3. I have obtained a bachelor's degree in petroleum engineering from the Colorado School of Mines, and a master's degree business from the University of Colorado. I have worked as a petroleum engineer since 1983.

4. I am familiar with the application that NGL Water Solutions Permian, LLC ("NGL") has filed in this matter, and I have conducted a nodal analysis and reservoir study related

to the area which is the subject matter of the application. A copy of my study is attached hereto as Exhibit A.

5. The applicant, NGL (OGRID No. 372338), seeks an order approving the Javelin SWD #1 well (Case No. 20235) which is a salt water disposal well.

6. The well will be spaced out and will not be located closer than approximately 1.5 miles from other disposal wells, approved for injection into the Devonian and Silurian formations.

7. The approved injection zone for the wells is located below the base of the Woodford Shale formation and above the Ordovician formation, which consists of significant shale deposits.

8. The wells will primarily be injecting fluids into the Wristen Group and Fusselman formations, with some fluids potentially being injected into the Upper Montoya Group. Each of these sub-formations or zones are located within what is commonly referred to by operators and the Division as the "Devonian Silurian" formations. These zones consist of a very thick sequence of limestone and dolostone which has significant primary and secondary porosity and permeability that is collectively between 800 to 1,800 feet thick.

9. I have reviewed step rate tests for similar disposal wells drilled within the area and conducted a nodal analysis. It is my opinion that a large percentage of surface pressure it was encountering using smaller diameter tubing was a result of friction pressure. In Case No. 15720 evidence had been presented to the Division showing that up to 85% of this surface pressure was due to friction. Increasing the tubing size would reduce friction and would conserve pump horsepower, fuel, and reduce emissions.

10. My nodal analysis indicates that increasing the tubing size to 7" by 5 ½" would not significantly increase reservoir pressures over a twenty-year time period. The injection zone is located within a reservoir with significant thickness which consists of high permeability rocks,

which results in only very small pressure increases even when injection is increased to a rate of 40,000 barrels per day over a 20 year period.

11. It is my opinion that increasing the tubing size will not cause fractures in the formation. Wellhead pressures are set at a maximum that is below the formation fracture pressure and, as a result, it is impossible to get above the formation fracture pressure while honoring wellhead pressure constraints. Consequently, it is highly unlikely that increasing the tubing size in the wells would result in fractures to the formation.

12. I have also studied the potential impact on pore pressures and put together a simulation of the radial influence that the wells would have if larger tubing is used for a period of time. A copy of this study is included within Exhibit A to this affidavit. This study shows that it is anticipated that there will be a minimal impact on reservoir pressures and that the majority of fluids will not travel greater than 1 mile in 20 years.

13. My studies further indicate that additional injection wells located one mile away from the well will not create any materially adverse pressures in the formation.

14. I attest that the information provided herein is correct and complete to the best of my knowledge and belief.

15. The granting of these applications is in the interests of conservation and the prevention of waste.

[Signature page follows]

Scott J. Wilson

SUBSCRIBED AND SWORN to before me this 6 th day of February, 2019 by Scott J. Wilson.

Notary Public

My commission expires: 8/23/21

DARSHAE E RODRIGUEZ
Notary Public - State of Colorado
Notary ID 20134006986
My Commission Expires Aug 23, 2021

COLORADO REGISTERED PROFESSIONAL ENGINEER
SCOTT JAMES WILSON
36112
2/6/2019

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 8-H

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Texas Registered Engineering Firm No F – 16381

February 6, 2019

RE: FSP Analysis Multiple NGL SWD well locations
Lea Counties, New Mexico

FSP Analysis

The FSP software used for this analysis was jointly developed by Stanford University, Exxon Mobil and XTO Energy as a tool for estimating fault slip potential resulting from fluid injection.

I have reviewed the geology, seismic activity, injection history and future proposed injection in the Subject Area and I would conclude that the Proposed SWD wells do not pose a risk of increasing seismicity in the area. The primary risk reduction factor is that the faults are not optimally oriented to slip, and significant pressure increases would be necessary to initiate slip on the faults analyzed.

Fault slip potential (FSP) was analyzed in the area of review shown on **Exhibit No. 1.** The analysis integrates all of the proposed well locations as well as any existing injection wells in order to fully assess the pressure implications of injection in the area and the potential for slip along existing faults. Historical USGS earthquake events are denoted by the "blue" bulls-eye symbols.

Exhibit No. 2 shows the FSP input parameters for the local stress, average reservoir depth, pressure gradients and reservoir characteristics. Depths and reservoir characteristics were derived from nearby well logs and stress values were derived from the Lund Snee and Zoback (2018) paper related to Stress in the Permian Basin.

Exhibit No. 3 shows the location of existing wells and locations of the Proposed SWD wells relative to the faults documented in this area. The faults are sourced from the Texas Bureau of Economic Geology and these are also the fault traces shown in the referenced Snee/Zoback paper (Figure 3 in the paper) and shown as **Exhibit No. 4** in my report. The Snee/Zoback paper only considers fault

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EXHIBIT
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tabbies

orientation relative to the stress orientation in determination of fault slip potential. Based on their limited analysis of the area they concluded the faults have low slip potential based on orientation/azimuth. My analysis further incorporates the injection history and future injection projections and the injection reservoir characteristics to fully assess the potential for slip along these faults. Existing wells were incorporated into the analysis using their injection volume histories and holding them constant into the future at their last reported monthly injection volume. The highlighted Subject wells were modelled at 40,000 bbls/day and held constant for the life of the analysis (+25 years). Additionally, proposed wells FA, TL and AS were modelled at 40,000 bbls/day. The remaining proposed wells were all modelled at 30,000 bbls/day and held constant for the life of the analysis (+25 years).

The proposed wells are denoted in the model as follows: **(Exhibit No. 3)**

AR – Asroc SWD
AS – Aspen SWD
FA – Falcon SWD
HP – Harpoon SWD
JV – Javelin SWD
MC – McCloy Central SWD
MM – Minuteman SWD
MV – Maverick SWD
MW – McCloy West SWD
Mo – Moab SWD
PT - Patriot SWD
SR - Sparrow SWD
SW - Sidewinder SWD
TL – Telluride SWD
TB – Thunderbolt SWD
TD -Trident SWD
TH - Tomahawk SWD
VP - Viper SWD

Also included in the model are existing SWD injection wells as follows: **(Exhibit No. 3)**

MD - Madera SWD
S6 – Striker Six SWD
VD – Vaca Draw SWD

Exhibit No. 5 illustrates the geomechanical properties of the fault segments in the area of review. It should be noted that the FSP software only calculates a single pressure change along a fault (at the fault mid-point) so it is critical that faults are broken into multiple segments to get a true evaluation of the pressure increases associated with injection. **Exhibit No. 5 also** shows the **direction** of max hor. stress as denoted by the grey arrows outside the circle on the stereonet in the lower right portion of this exhibit. Faults that align parallel or closer to this orientation will have the highest potential for slip or lowest ΔP to slip. Faults 15-17 have the highest potential for slip and Faults 1-14 have very low potential for slip.

Exhibit No. 6 shows that the input stress and fault values were varied by +/-10% to allow for uncertainty in the input parameters. Even considering the variability of the inputs the model results show low probability for slip on the faults in the area of review. An increase of 750 psi at Fault 15 still only results in a 10% probability of fault slip.

Exhibit No. 7 takes a closer look at fault 15. The sensitivity analysis is highlighted in the lower right portion of this exhibit and shows that without any variability of inputs the ΔP needed to slip is 1,150 psi along this fault. A 10% decrease in the friction coefficient of the fault could lower ΔP needed to slip to 750 psi.

Exhibit No. 8 takes a closer look at fault 16. The sensitivity analysis is highlighted in the lower right portion of this exhibit and shows that without any variability of inputs the ΔP needed to slip is 1,530 psi along this fault. A 10% decrease in the friction coefficient of the fault could lower ΔP needed to slip to 1,100 psi. Fault 17 shows similar FSP values as fault 16.

Exhibit No. 9 takes a closer look at fault 14. The sensitivity analysis is highlighted in the lower right portion of this exhibit and shows that without any variability of inputs the ΔP needed to slip is +3,500 psi along this fault. A 10% change in the fault strike or SHmax azimuth could lower ΔP needed to slip to 1,850 psi.

Exhibit No. 10 takes a closer look at fault 1. The sensitivity analysis is highlighted in the lower right portion of this exhibit and shows that without any variability of inputs the ΔP needed to slip is +5,600 psi along this fault. A 10% change in the fault strike or SHmax azimuth could lower ΔP needed to slip to 3,050 psi. Faults 2-13 all exhibit similar high ΔP pressure values needed to initiate slip and thus fault slip potential is very low along all of the N-S trending faults.

In general, only Fault segment 15 shows any concern for fault slip potential. The following exhibits will track the pressure changes at the faults moving forward in time based upon the anticipated injection in the future from these proposed wells and the existing wells in the Subject Area.

Exhibit No. 11 illustrates the ΔP pressure in a "heat map" and shows ΔP pressure increases at the faults as of 1/1/2020. This map indicates ΔP pressure increases of 7 psi at F15 and 53 psi at F17.

Exhibit No. 12 illustrates the ΔP pressure in a "heat map" and shows ΔP pressure increases at the faults as of 1/1/2025. This map indicates ΔP pressure increases of 51 psi at F15 and 109 psi at F17.

Exhibit No. 13 illustrates the ΔP pressure in a "heat map" and shows ΔP pressure increases at the faults as of 1/1/2030. This map indicates ΔP pressure increases of 141 psi at F15 and 180 psi at F17. Note that these pressures are still well below the pressures that could initiate fault slip. F9 shows a ΔP pressure increase of 1,160 psi however this fault requires extremely high pressures (+4,400 psi) to initiate fault slip.

Exhibit No. 14 illustrates the ΔP pressure in a "heat map" and shows ΔP pressure increases at the faults as of 1/1/2035. This map indicates ΔP pressure increases of 260 psi at F15 and 271 psi at F17. Note that these pressures are still well below the pressures that could initiate fault slip. F9 shows a ΔP pressure increase of 1,521 psi however this fault requires extremely high pressures (+4,400 psi) to initiate fault slip.

Exhibit No. 15 illustrates the ΔP pressure in a "heat map" and shows ΔP pressure increases at the faults as of 1/1/2040. This map indicates ΔP pressure increases of 387 psi at F15 and 373 psi at F17. Note that these pressures are still well below the pressures that could initiate fault slip. F9 shows a ΔP pressure increase of 1,821 psi however this fault requires extremely high pressures (+4,400 psi) to initiate fault slip.

Exhibit No. 16 illustrates the ΔP pressure in a "heat map" and shows ΔP pressure increases at the faults as of 1/1/2045. This map indicates ΔP pressure increases of 514 psi at F15 and 478 psi at F17. Note that these pressures are still well below the pressures that could initiate fault slip. F9 shows a ΔP pressure increase of 2,078 psi however this fault requires extremely high pressures (+4,400 psi) to initiate fault slip.

The pressure analysis over time shows that pressure is expected to increase along the faults however pressures remain below critical levels. The table below shows the ΔP pressure increases needed to imitate fault slip along each fault segment and the corresponding ΔP pressure increases as of 2045:

Fault Segment	ΔP to slip (fixed inputs)	ΔP to slip (10% varied inputs)	ΔP at 2045
F1	5,600	3,050	45
F2	6,300	3,850	338
F3	7,000	4,750	905
F4	7,000	4,750	1,345
F5	6,850	4,400	1,559
F6	6,850	4,400	1,730
F7	6,850	4,400	1,979
F8	6,850	4,400	2,024
F9	6,850	4,400	2,078
F10	6,850	4,400	1,944
F11	6,850	4,400	1,881
F12	6,850	4,400	1,120
F13	6,990	4,750	268
F14	3,500	1,800	224
F15	1,150	750	514
F16	1,530	1,100	490
F17	1,530	1,100	478

This analysis demonstrates that there is a low likelihood of injection induced seismicity in the Subject Area.

Conclusion

The faults and fault trends in this area of review are not optimally oriented to slip. The orientation of the faults requires significant pressure changes (ΔP +1,000 psi) based on the fixed input parameters and the ΔP increase at the most vulnerable fault only reaches 512 psi by 2045. This model assumes constant injection rates over the next +25 years which is not a typical scenario as SWD wells tend to decrease injection volumes over time as the well ages and disposal demand decreases in the area. If injection volumes are lower over time than the model represents, then the risk for fault slip is lowered also.

In the event seismicity should occur in the future, the wells closest to the faults (proposed and existing) should be the wells considered for modification or reduction of injection rates. At this time there is no evidence to support rate reduction for any of the existing or proposed wells.

Should you have any questions, please do not hesitate to call me at (512) 327-6930 or email me at todd.reynolds@ftiplattsparks.com.

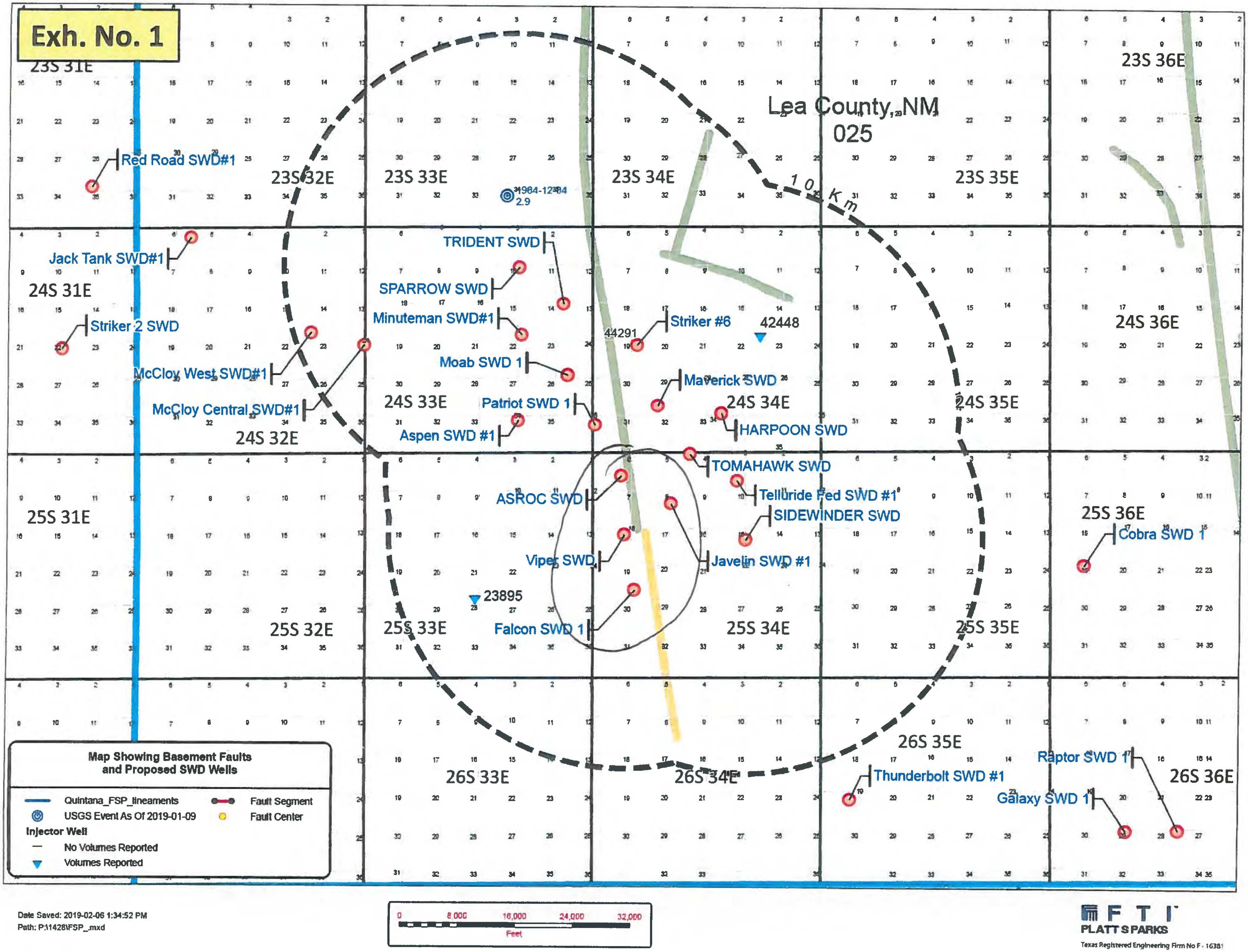
Regards,

Todd W. Reynolds – Geologist/Geophysicist
Managing Director, Economics/FTI Platt Sparks

Todd W. Reynolds

FTI Platt Sparks
512.327.6930 office

FTI PLATT SPARKS



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FTI PLATT SPARKS

Texas Registered Engineering Firm No F - 16381

Exh. No. 2

FSP INPUT PARAMETERS

Stress Data

Vertical Stress Gradient [psi/ft]	1.1
Max Hor Stress Direction [deg N CW]	75
Reference Depth for Calculations [ft]	16900
Initial Res. Pressure Gradient [psi/ft]	0.46
Min Horiz. Stress Gradient [psi/ft]	0.66517
Max Horiz. Stress Gradient [psi/ft]	0.92607
A Phi Parameter	0.6
Reference Friction Coefficient mu	0.6

OK

Hydrology Data

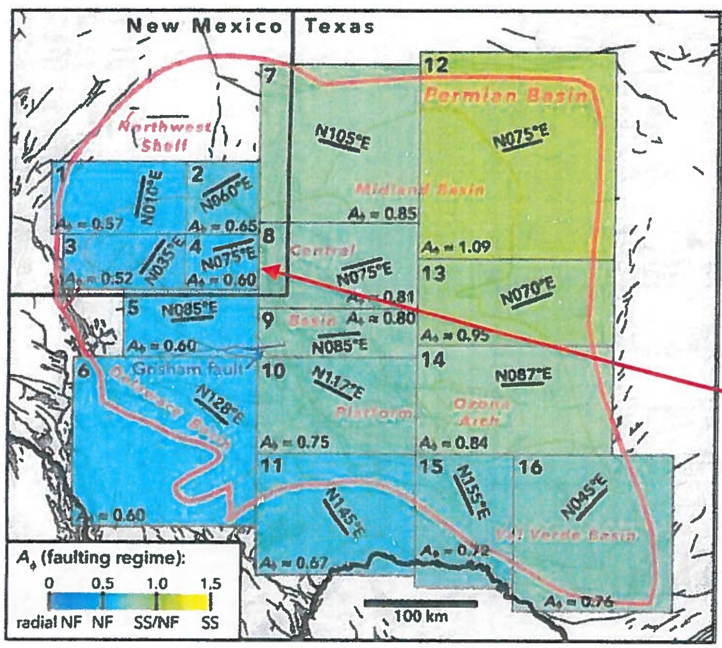
Enter Hydrologic Parameters

Load External Hydrologic Model

Aquifer Thickness [ft]	900
Porosity [%]	4
Permeability [mD]	20

Fault dips assumed – 80 deg

OK



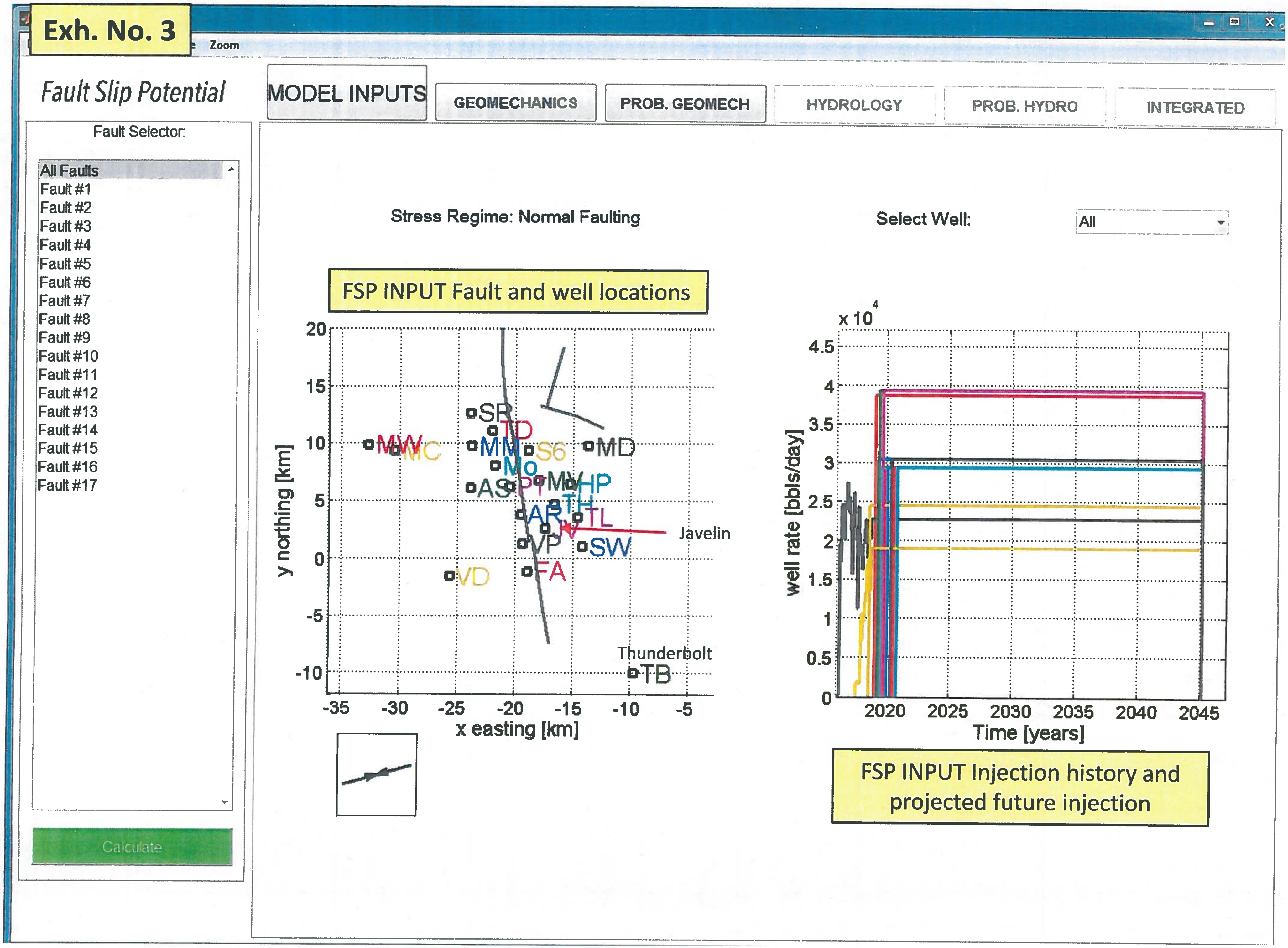
Input Parameter Comments

Hydrologic Parameters – Derived from Striker 6 SWD #2 logs

Stress Gradients – Derived from A Phi parameter from Snee/Zoback paper (.60)

Max Hor. Stress Direction - Derived from Snee/Zoback paper (N75E)

Exh. No. 3


Zoom
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOMECH
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1
Fault #2
Fault #3
Fault #4
Fault #5
Fault #6
Fault #7
Fault #8
Fault #9
Fault #10
Fault #11
Fault #12
Fault #13
Fault #14
Fault #15
Fault #16
Fault #17
Calculate
Stress Regime: Normal Faulting
Select Well:
All
FSP INPUT Fault and well locations
y northing [km]
x easting [km]
SR
TD
MW
MC
MM
S6
MD
Mo
AS
PT
MV
HP
AR
TH
TL
Javelin
VP
SW
VD
FA
Thunderbolt
TB
x 10^4
well rate [bbls/day]
Time [years]
FSP INPUT Injection history and projected future injection

Exh. No. 4

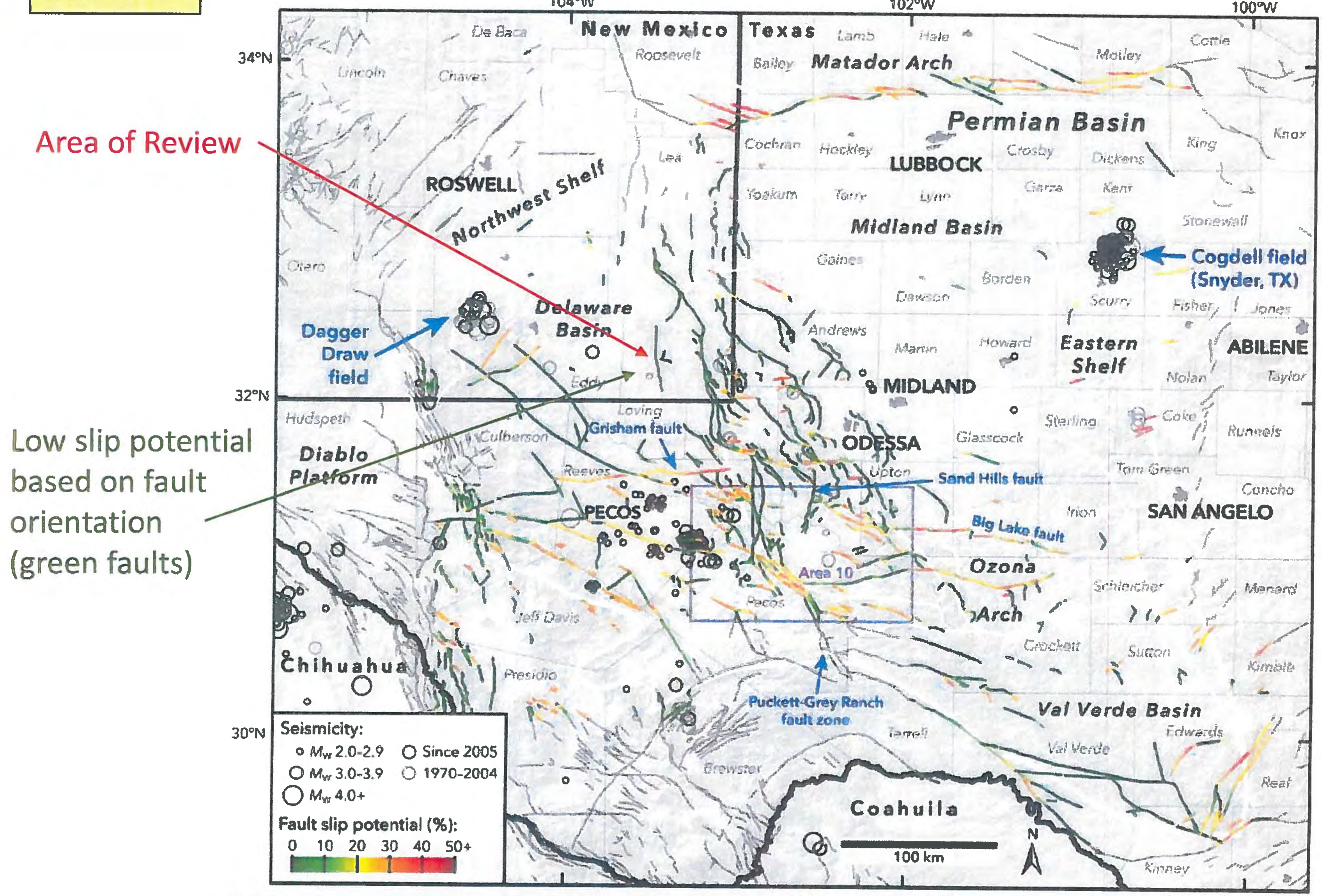
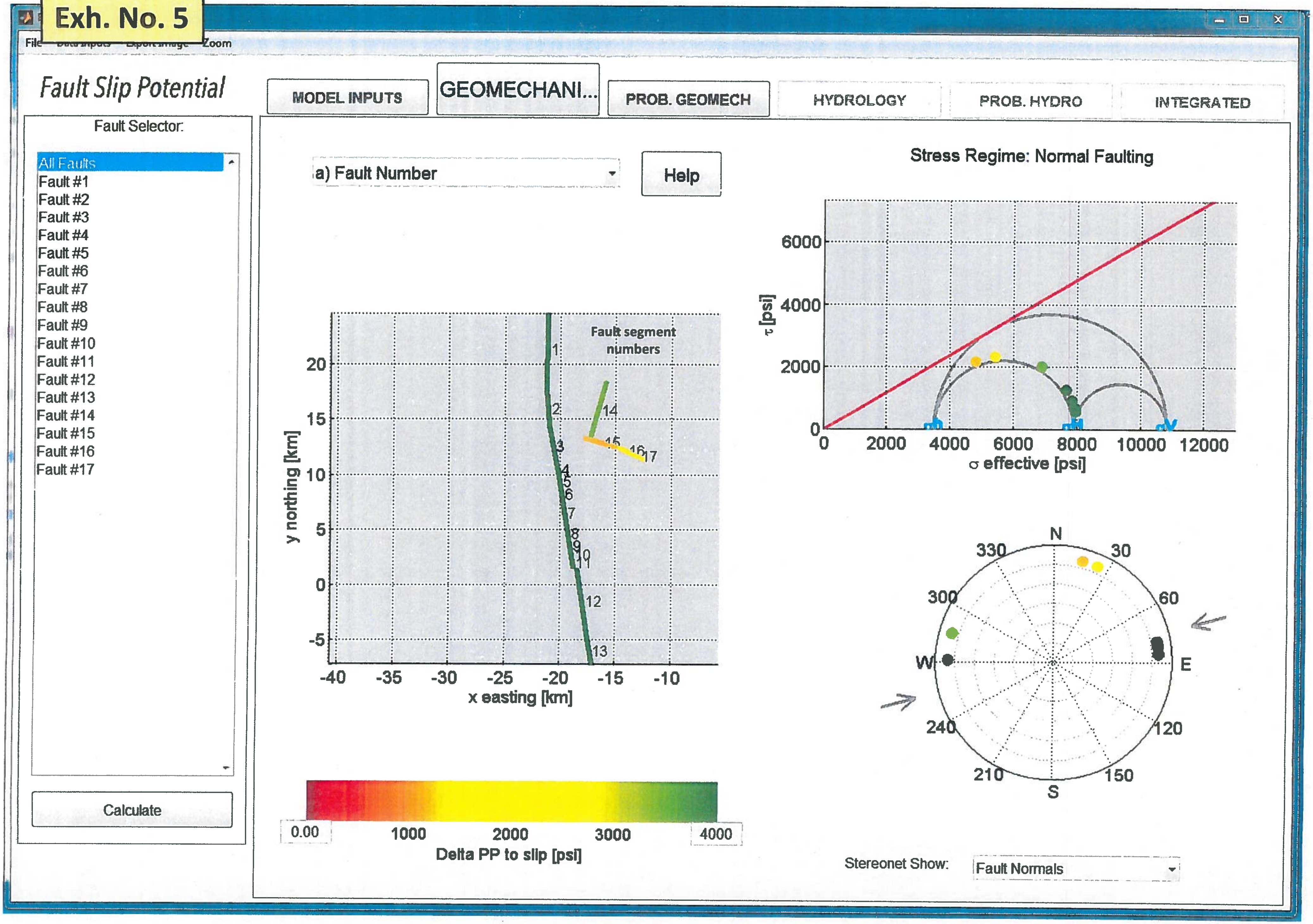


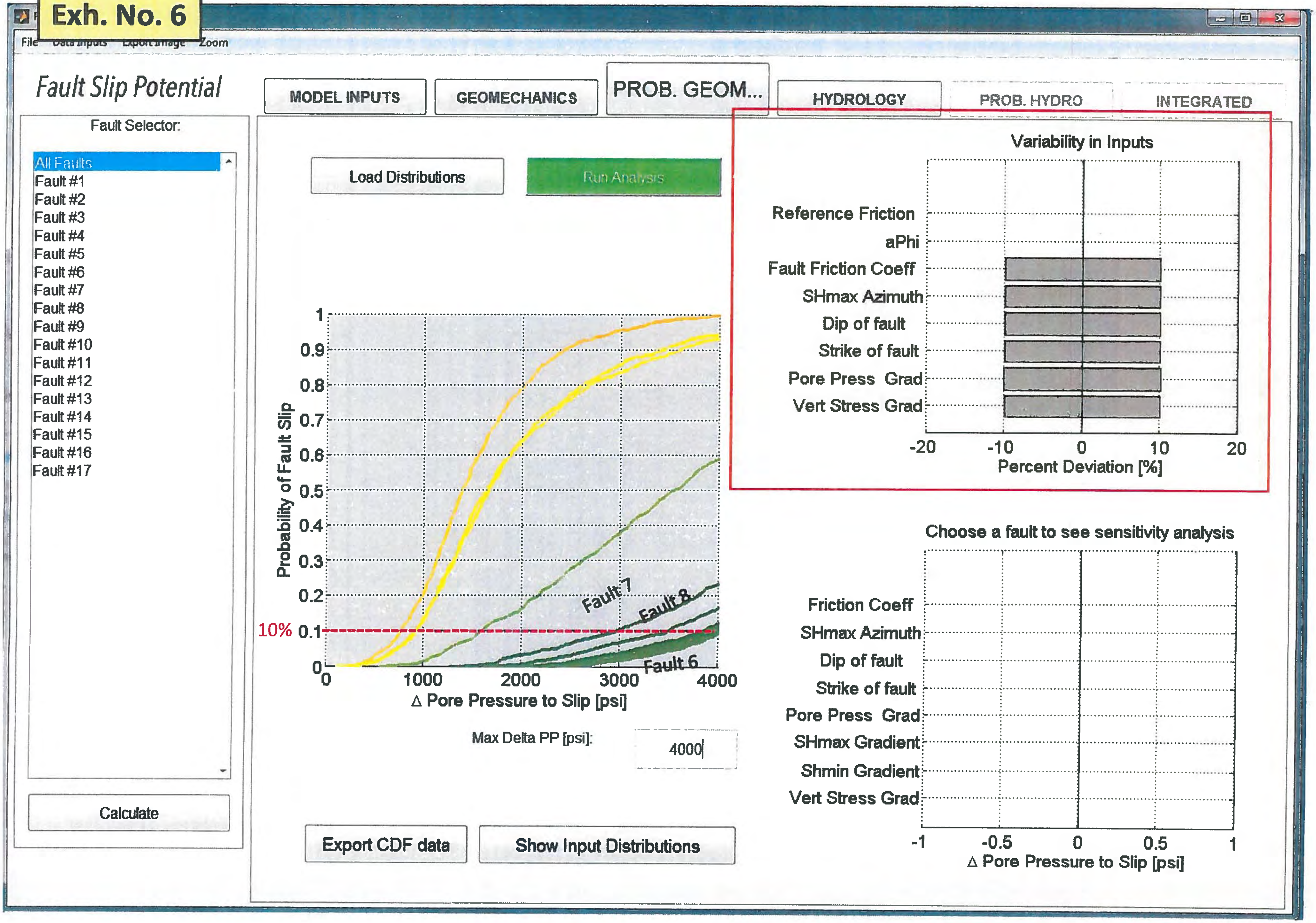
Figure 3. Results of our probabilistic FSP analysis across the Permian Basin. Data sources are as in Figures 1 and 2.

From Lund Snee and Zoback (2018)

Exh. No. 5

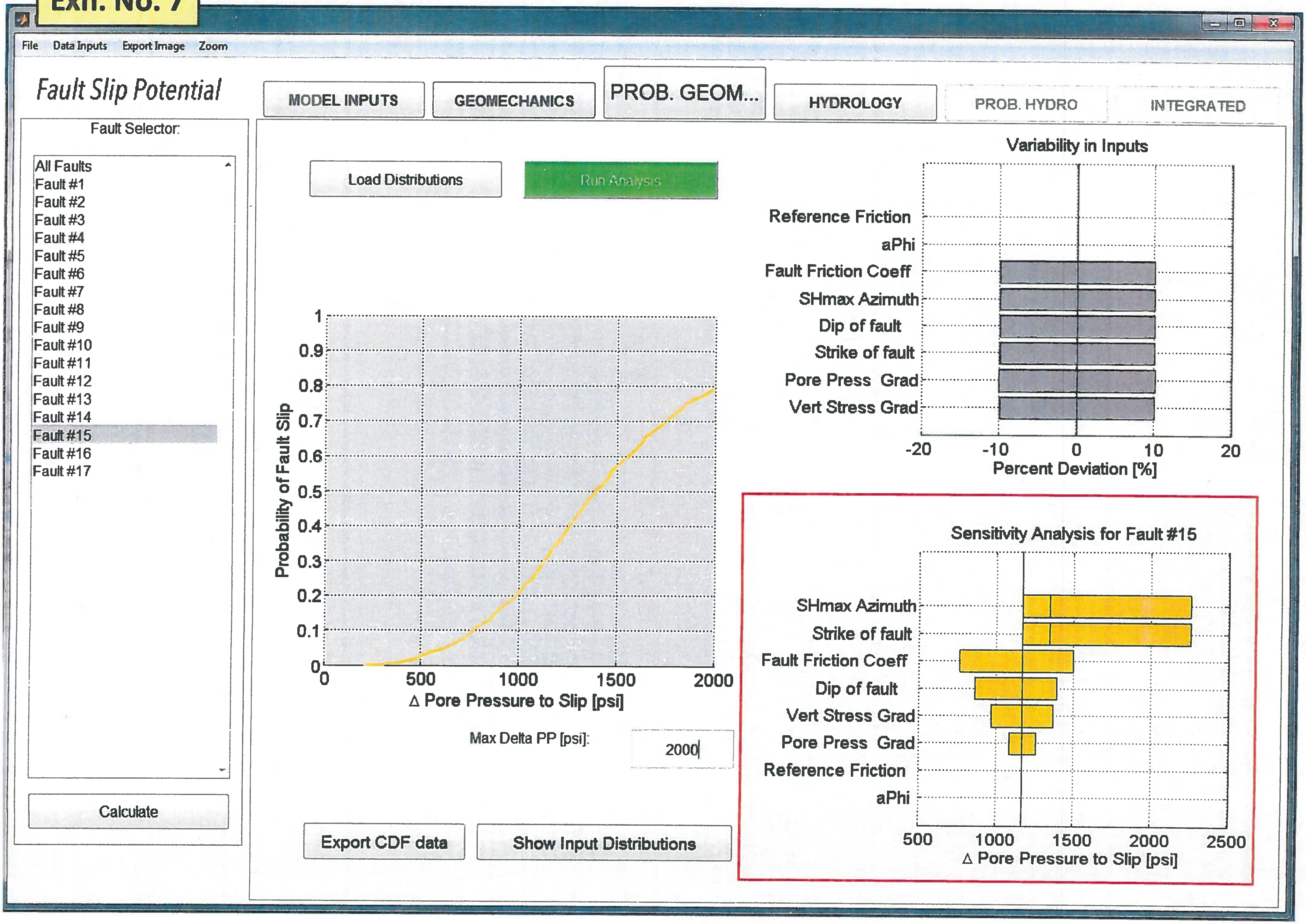

File
Zoom
Fault Slip Potential
MODEL INPUTS
GEOMECHANI...
PROB. GEOMECH
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1
Fault #2
Fault #3
Fault #4
Fault #5
Fault #6
Fault #7
Fault #8
Fault #9
Fault #10
Fault #11
Fault #12
Fault #13
Fault #14
Fault #15
Fault #16
Fault #17
Calculate
a) Fault Number
Help
Fault segment numbers
y northing [km]
x easting [km]
Delta PP to slip [psi]
0.00
1000
2000
3000
4000
Stress Regime: Normal Faulting
τ [psi]
σ effective [psi]
N
S
E
W
Stereonet Show:
Fault Normals

Exh. No. 6



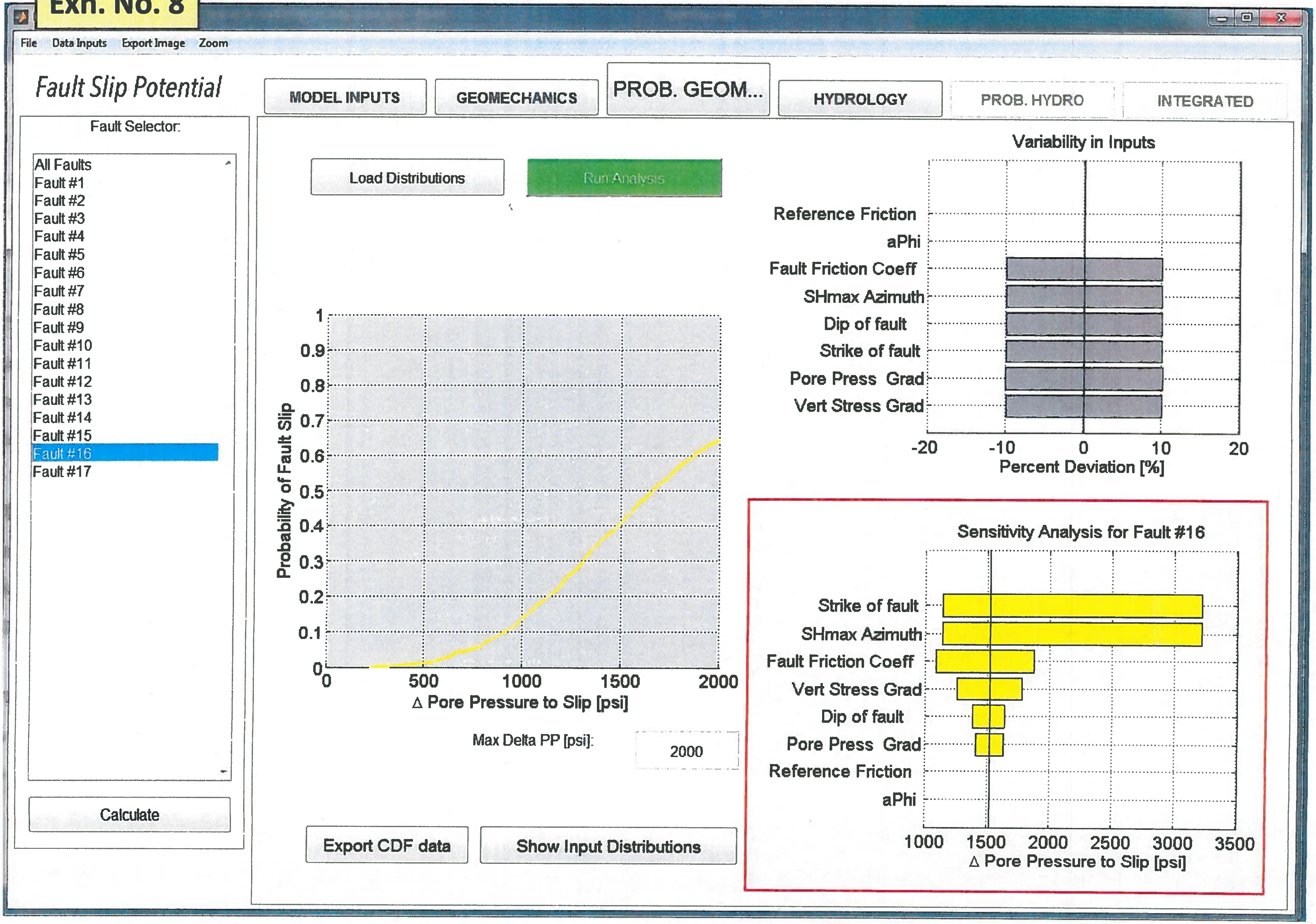
File
Data Inputs
Export Image
Zoom
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOM...
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1
Fault #2
Fault #3
Fault #4
Fault #5
Fault #6
Fault #7
Fault #8
Fault #9
Fault #10
Fault #11
Fault #12
Fault #13
Fault #14
Fault #15
Fault #16
Fault #17
Calculate
Load Distributions
Run Analysis
Probability of Fault Slip
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
10% 0.1
0
Fault 7
Fault 8
Fault 6
0
1000
2000
3000
4000
Δ Pore Pressure to Slip [psi]
Max Delta PP [psi]:
4000
Export CDF data
Show Input Distributions
Variability in Inputs
Reference Friction
aPhi
Fault Friction Coeff
SHmax Azimuth
Dip of fault
Strike of fault
Pore Press Grad
Vert Stress Grad
-20
-10
0
10
20
Percent Deviation [%]
Choose a fault to see sensitivity analysis
Friction Coeff
SHmax Azimuth
Dip of fault
Strike of fault
Pore Press Grad
SHmax Gradient
Shmin Gradient
Vert Stress Grad
-1
-0.5
0
0.5
1
Δ Pore Pressure to Slip [psi]

Exh. No. 7

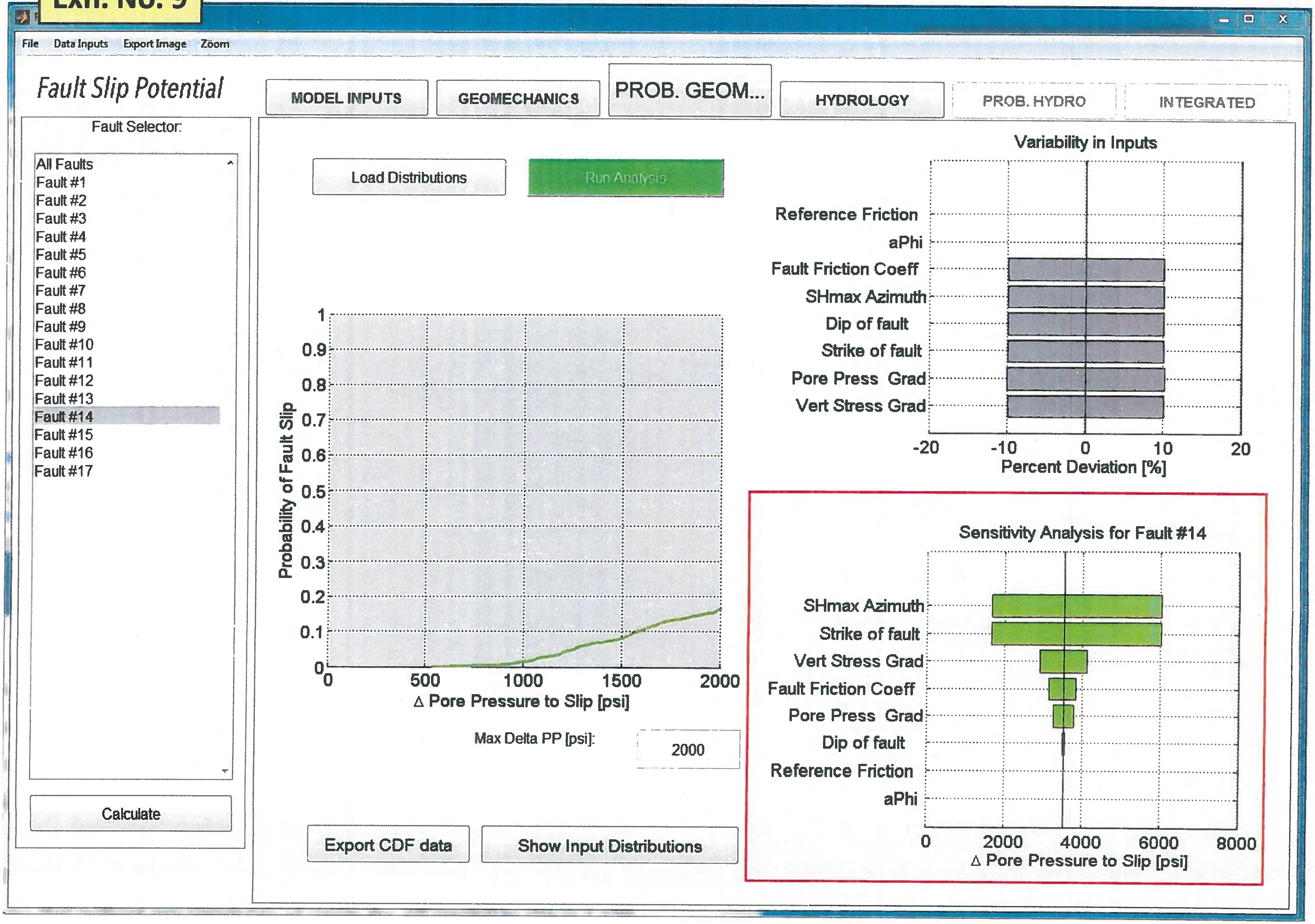


File
Data Inputs
Export Image
Zoom
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOM...
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1
Fault #2
Fault #3
Fault #4
Fault #5
Fault #6
Fault #7
Fault #8
Fault #9
Fault #10
Fault #11
Fault #12
Fault #13
Fault #14
Fault #15
Fault #16
Fault #17
Calculate
Load Distributions
Run Analysis
Probability of Fault Slip
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
0
500
1000
1500
2000
Δ Pore Pressure to Slip [psi]
Max Delta PP [psi]:
2000
Export CDF data
Show Input Distributions
Variability in Inputs
Reference Friction
aPhi
Fault Friction Coeff
SHmax Azimuth
Dip of fault
Strike of fault
Pore Press Grad
Vert Stress Grad
-20
-10
0
10
20
Percent Deviation [%]
Sensitivity Analysis for Fault #15
SHmax Azimuth
Strike of fault
Fault Friction Coeff
Dip of fault
Vert Stress Grad
Pore Press Grad
Reference Friction
aPhi
500
1000
1500
2000
2500
Δ Pore Pressure to Slip [psi]

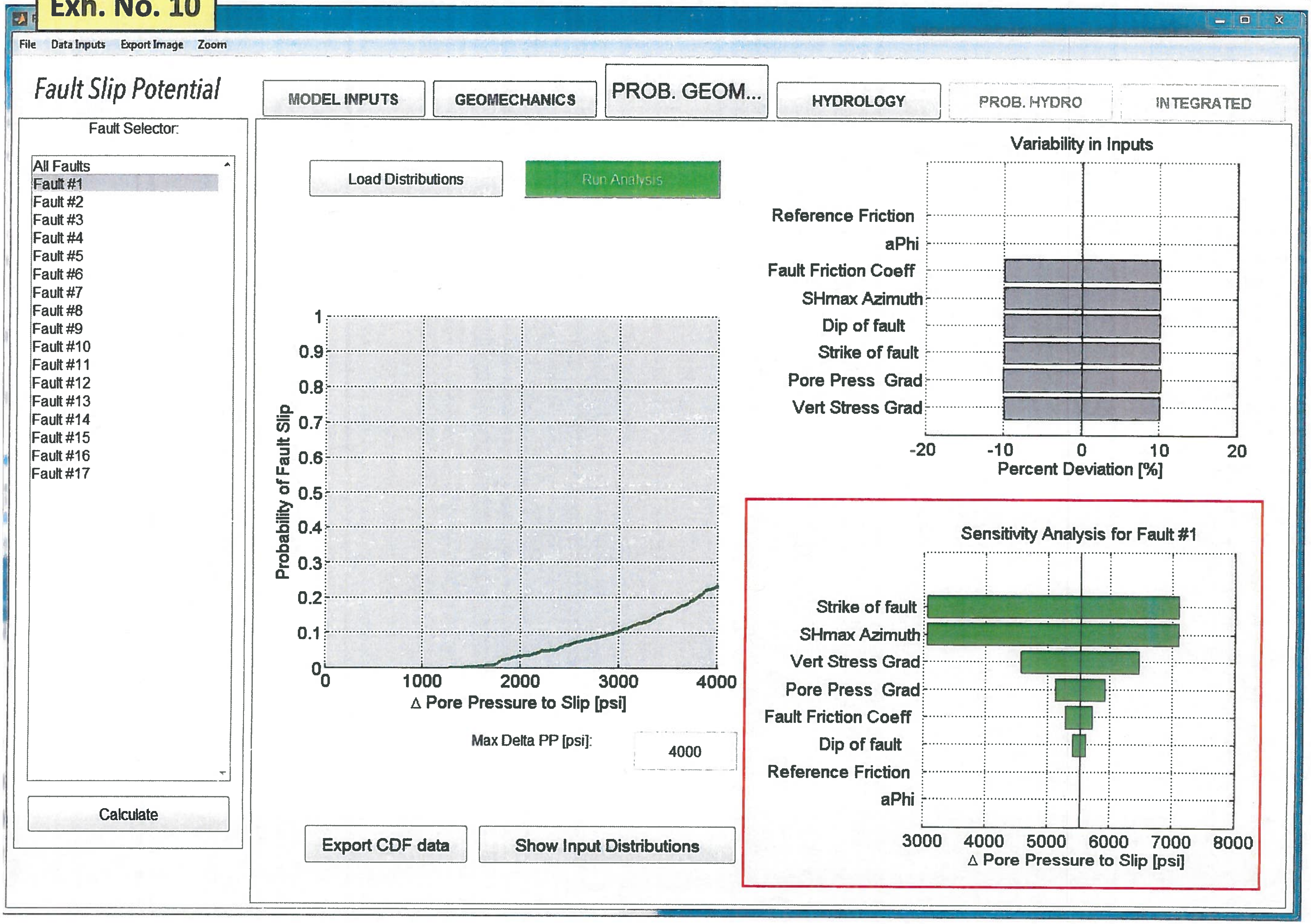
Exh. No. 8


File
Data Inputs
Export Image
Zoom
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOM...
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1
Fault #2
Fault #3
Fault #4
Fault #5
Fault #6
Fault #7
Fault #8
Fault #9
Fault #10
Fault #11
Fault #12
Fault #13
Fault #14
Fault #15
Fault #16
Fault #17
Calculate
Load Distributions
Run Analysis
Probability of Fault Slip
Δ Pore Pressure to Slip [psi]
Max Delta PP [psi]:
2000
Export CDF data
Show Input Distributions
Variability in Inputs
Reference Friction
aPhi
Fault Friction Coeff
SHmax Azimuth
Dip of fault
Strike of fault
Pore Press Grad
Vert Stress Grad
Percent Deviation [%]
Sensitivity Analysis for Fault #16
Strike of fault
SHmax Azimuth
Fault Friction Coeff
Vert Stress Grad
Dip of fault
Pore Press Grad
Reference Friction
aPhi
Δ Pore Pressure to Slip [psi]

Exh. No. 9

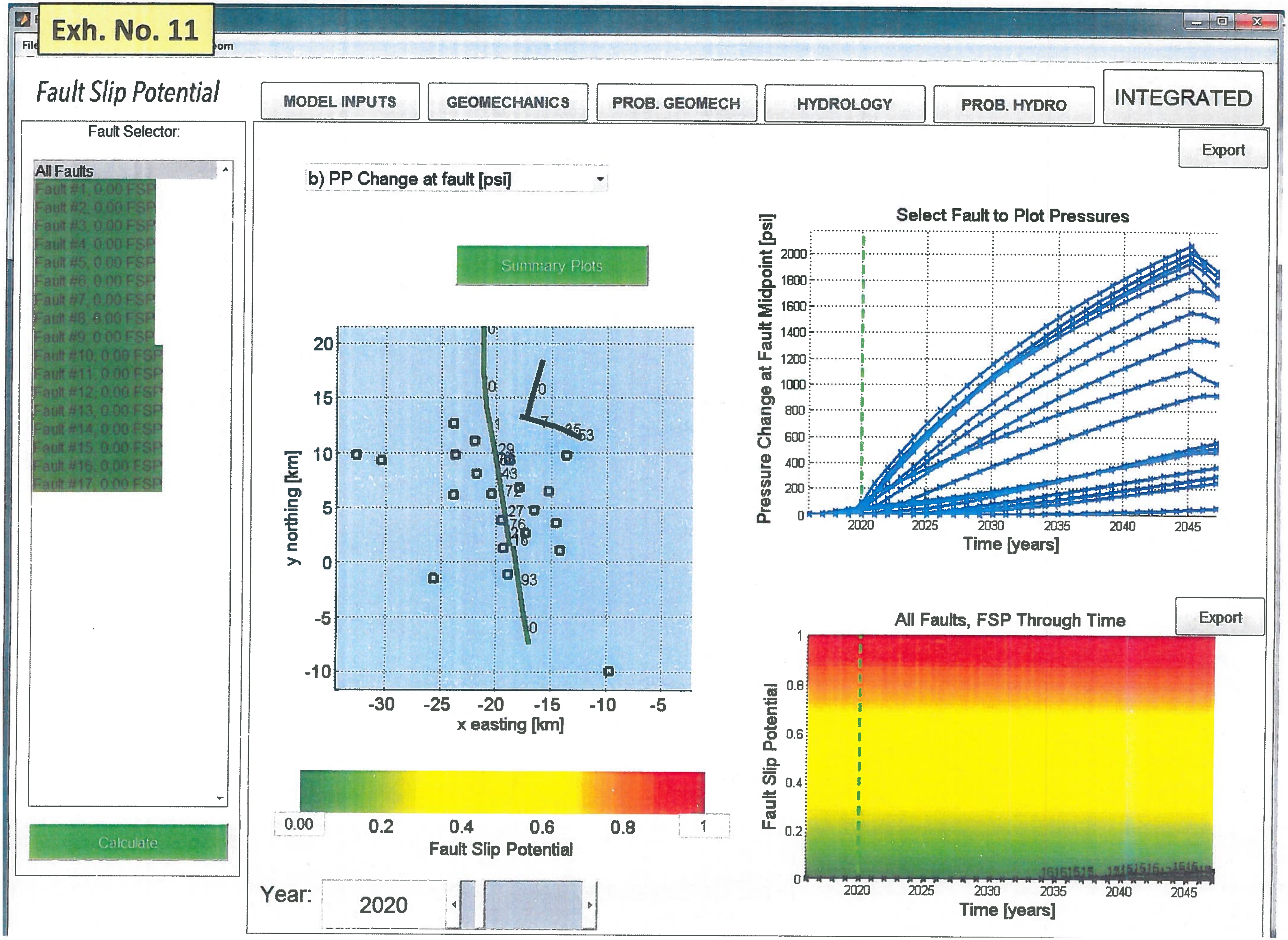

File
Data Inputs
Export Image
Zoom
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOM...
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1
Fault #2
Fault #3
Fault #4
Fault #5
Fault #6
Fault #7
Fault #8
Fault #9
Fault #10
Fault #11
Fault #12
Fault #13
Fault #14
Fault #15
Fault #16
Fault #17
Calculate
Load Distributions
Run Analysis
Probability of Fault Slip
Δ Pore Pressure to Slip [psi]
Max Delta PP [psi]:
2000
Export CDF data
Show Input Distributions
Variability in Inputs
Reference Friction
aPhi
Fault Friction Coeff
SHmax Azimuth
Dip of fault
Strike of fault
Pore Press Grad
Vert Stress Grad
Percent Deviation [%]
Sensitivity Analysis for Fault #14
SHmax Azimuth
Strike of fault
Vert Stress Grad
Fault Friction Coeff
Pore Press Grad
Dip of fault
Reference Friction
aPhi
Δ Pore Pressure to Slip [psi]

Exh. No. 10



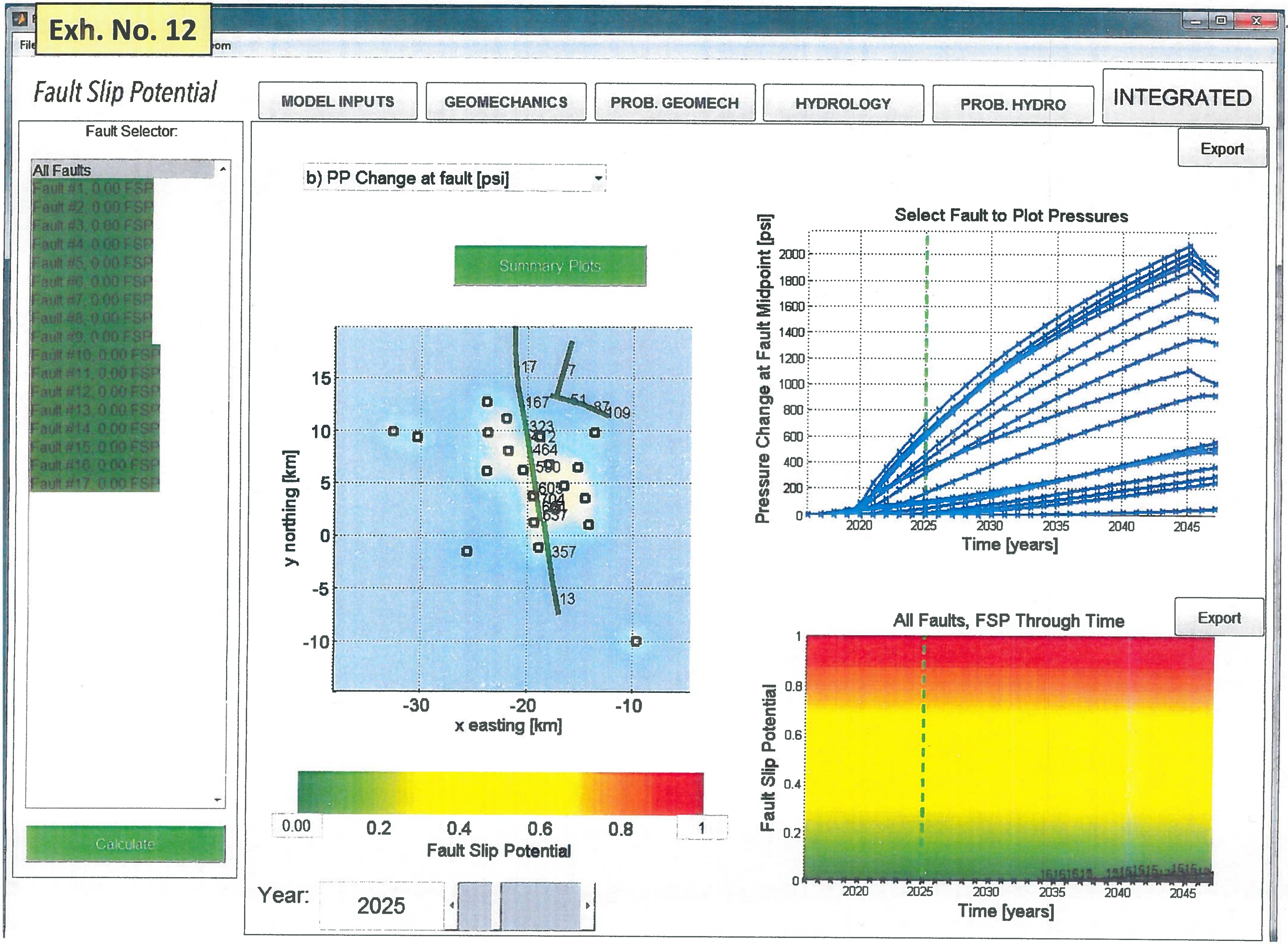
File
Data Inputs
Export Image
Zoom
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOM...
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1
Fault #2
Fault #3
Fault #4
Fault #5
Fault #6
Fault #7
Fault #8
Fault #9
Fault #10
Fault #11
Fault #12
Fault #13
Fault #14
Fault #15
Fault #16
Fault #17
Calculate
Load Distributions
Run Analysis
Probability of Fault Slip
Δ Pore Pressure to Slip [psi]
Max Delta PP [psi]:
4000
Export CDF data
Show Input Distributions
Variability in Inputs
Reference Friction
aPhi
Fault Friction Coeff
SHmax Azimuth
Dip of fault
Strike of fault
Pore Press Grad
Vert Stress Grad
Percent Deviation [%]
Sensitivity Analysis for Fault #1
Strike of fault
SHmax Azimuth
Vert Stress Grad
Pore Press Grad
Fault Friction Coeff
Dip of fault
Reference Friction
aPhi
Δ Pore Pressure to Slip [psi]

Exh. No. 11



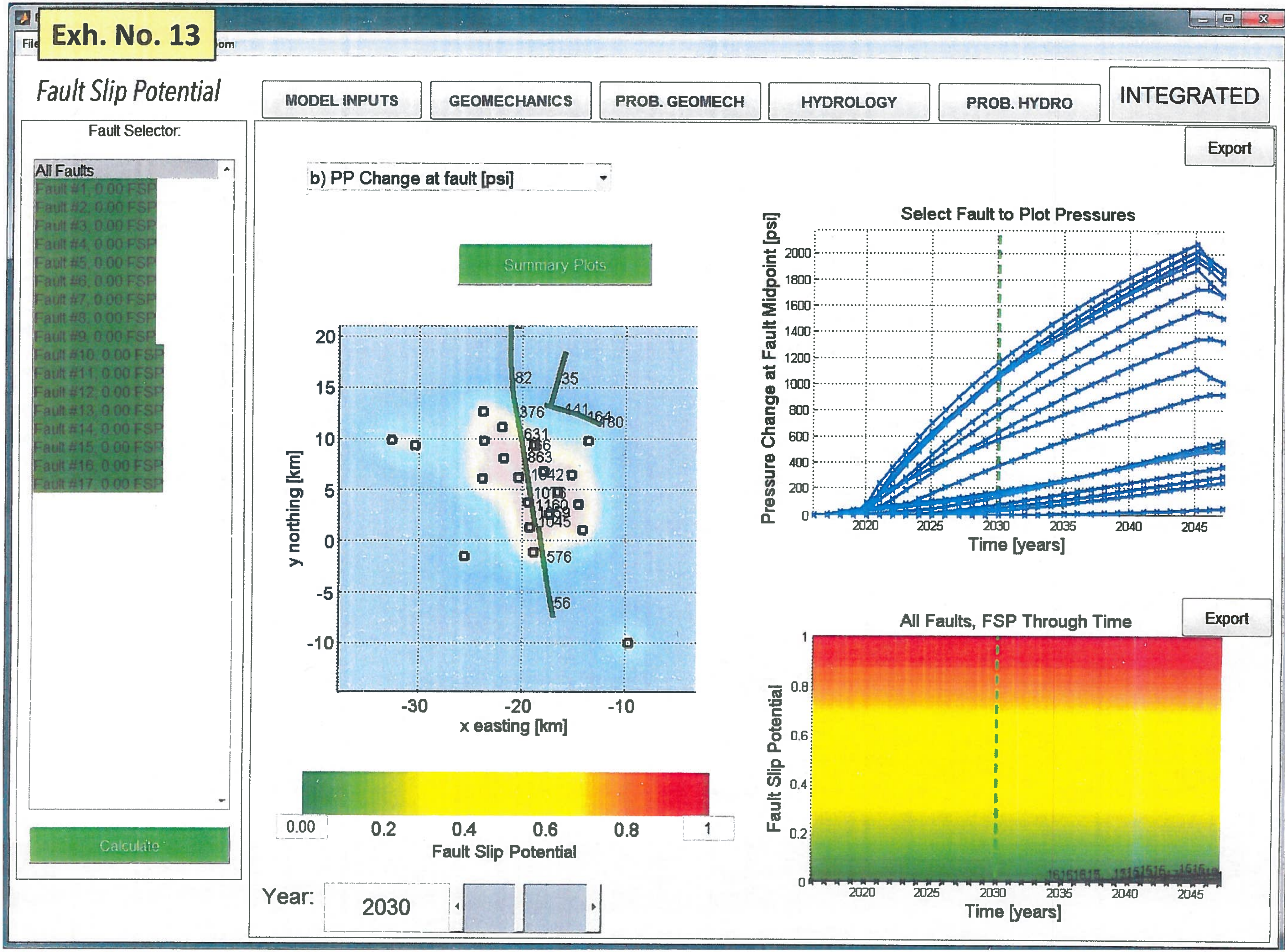
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOMECH
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1, 0.00 FSP
Fault #2, 0.00 FSP
Fault #3, 0.00 FSP
Fault #4, 0.00 FSP
Fault #5, 0.00 FSP
Fault #6, 0.00 FSP
Fault #7, 0.00 FSP
Fault #8, 0.00 FSP
Fault #9, 0.00 FSP
Fault #10, 0.00 FSP
Fault #11, 0.00 FSP
Fault #12, 0.00 FSP
Fault #13, 0.00 FSP
Fault #14, 0.00 FSP
Fault #15, 0.00 FSP
Fault #16, 0.00 FSP
Fault #17, 0.00 FSP
Calculate
b) PP Change at fault [psi]
Summary Plots
y northing [km]
x easting [km]
Fault Slip Potential
Year:
2020
Export
Select Fault to Plot Pressures
Pressure Change at Fault Midpoint [psi]
Time [years]
All Faults, FSP Through Time
Fault Slip Potential
Time [years]

Exh. No. 12



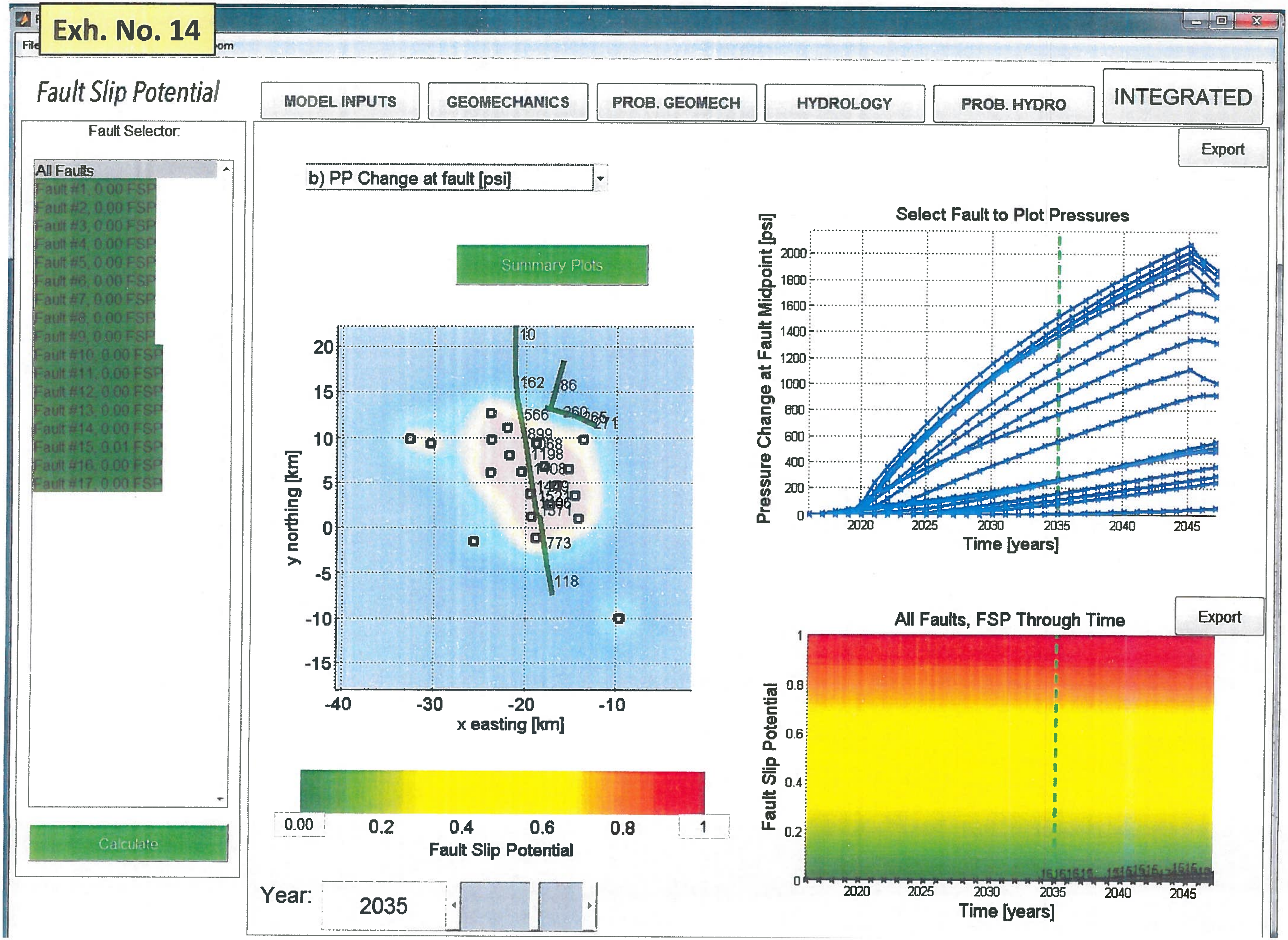
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOMECH
HYDROLOGY
PROB. HYDRO
INTEGRATED
Export
Fault Selector:
All Faults
Fault #1, 0.00 FSP
Fault #2, 0.00 FSP
Fault #3, 0.00 FSP
Fault #4, 0.00 FSP
Fault #5, 0.00 FSP
Fault #6, 0.00 FSP
Fault #7, 0.00 FSP
Fault #8, 0.00 FSP
Fault #9, 0.00 FSP
Fault #10, 0.00 FSP
Fault #11, 0.00 FSP
Fault #12, 0.00 FSP
Fault #13, 0.00 FSP
Fault #14, 0.00 FSP
Fault #15, 0.00 FSP
Fault #16, 0.00 FSP
Fault #17, 0.00 FSP
Calculate
b) PP Change at fault [psi]
Summary Plots
y northing [km]
x easting [km]
Fault Slip Potential
Year:
2025
Select Fault to Plot Pressures
Pressure Change at Fault Midpoint [psi]
Time [years]
All Faults, FSP Through Time
Fault Slip Potential
Time [years]

Exh. No. 13



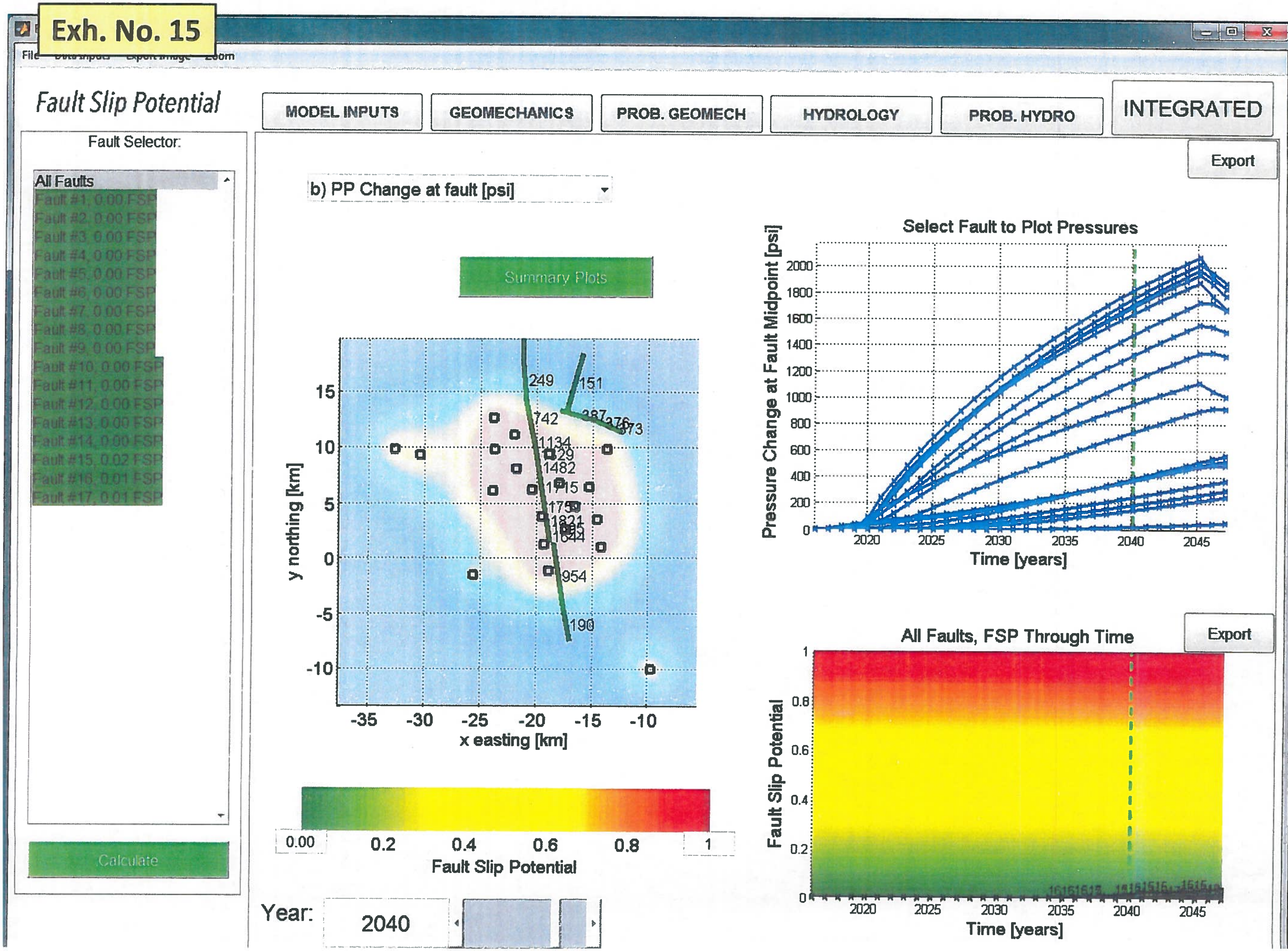
File
om
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOMECH
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1, 0.00 FSP
Fault #2, 0.00 FSP
Fault #3, 0.00 FSP
Fault #4, 0.00 FSP
Fault #5, 0.00 FSP
Fault #6, 0.00 FSP
Fault #7, 0.00 FSP
Fault #8, 0.00 FSP
Fault #9, 0.00 FSP
Fault #10, 0.00 FSP
Fault #11, 0.00 FSP
Fault #12, 0.00 FSP
Fault #13, 0.00 FSP
Fault #14, 0.00 FSP
Fault #15, 0.00 FSP
Fault #16, 0.00 FSP
Fault #17, 0.00 FSP
Calculate
b) PP Change at fault [psi]
Summary Plots
y northing [km]
x easting [km]
0.00
0.2
0.4
0.6
0.8
1
Fault Slip Potential
Year:
2030
Export
Select Fault to Plot Pressures
Pressure Change at Fault Midpoint [psi]
Time [years]
Export
All Faults, FSP Through Time
Fault Slip Potential
Time [years]

Exh. No. 14



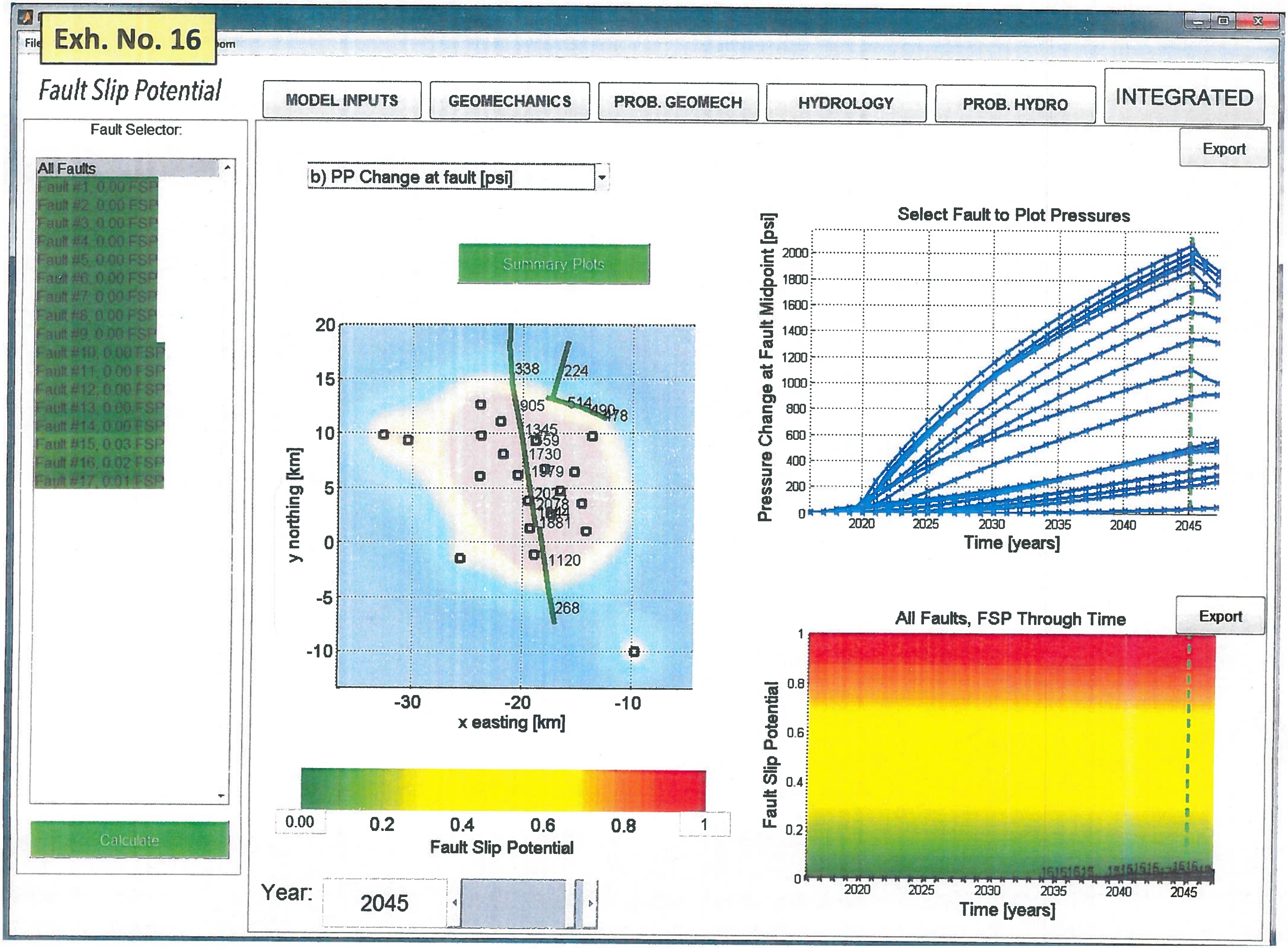
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOMECH
HYDROLOGY
PROB. HYDRO
INTEGRATED
Export
Fault Selector:
All Faults
Fault #1, 0.00 FSP
Fault #2, 0.00 FSP
Fault #3, 0.00 FSP
Fault #4, 0.00 FSP
Fault #5, 0.00 FSP
Fault #6, 0.00 FSP
Fault #7, 0.00 FSP
Fault #8, 0.00 FSP
Fault #9, 0.00 FSP
Fault #10, 0.00 FSP
Fault #11, 0.00 FSP
Fault #12, 0.00 FSP
Fault #13, 0.00 FSP
Fault #14, 0.00 FSP
Fault #15, 0.01 FSP
Fault #16, 0.00 FSP
Fault #17, 0.00 FSP
Calculate
b) PP Change at fault [psi]
Summary Plots
y northing [km]
x easting [km]
Fault Slip Potential
0.00
1
Year:
2035
Select Fault to Plot Pressures
Pressure Change at Fault Midpoint [psi]
Time [years]
All Faults, FSP Through Time
Export
Fault Slip Potential
Time [years]

Exh. No. 15



Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOMECH
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1, 0.00 FSP
Fault #2, 0.00 FSP
Fault #3, 0.00 FSP
Fault #4, 0.00 FSP
Fault #5, 0.00 FSP
Fault #6, 0.00 FSP
Fault #7, 0.00 FSP
Fault #8, 0.00 FSP
Fault #9, 0.00 FSP
Fault #10, 0.00 FSP
Fault #11, 0.00 FSP
Fault #12, 0.00 FSP
Fault #13, 0.00 FSP
Fault #14, 0.00 FSP
Fault #15, 0.02 FSP
Fault #16, 0.01 FSP
Fault #17, 0.01 FSP
Calculate
b) PP Change at fault [psi]
Summary Plots
249
151
742
954
190
y northing [km]
x easting [km]
Fault Slip Potential
0.00
1
Year:
2040
Export
Select Fault to Plot Pressures
Pressure Change at Fault Midpoint [psi]
Time [years]
Export
All Faults, FSP Through Time
Fault Slip Potential
Time [years]

Exh. No. 16


File
Fault Slip Potential
MODEL INPUTS
GEOMECHANICS
PROB. GEOMECH
HYDROLOGY
PROB. HYDRO
INTEGRATED
Fault Selector:
All Faults
Fault #1, 0.00 FSP
Fault #2, 0.00 FSP
Fault #3, 0.00 FSP
Fault #4, 0.00 FSP
Fault #5, 0.00 FSP
Fault #6, 0.00 FSP
Fault #7, 0.00 FSP
Fault #8, 0.00 FSP
Fault #9, 0.00 FSP
Fault #10, 0.00 FSP
Fault #11, 0.00 FSP
Fault #12, 0.00 FSP
Fault #13, 0.00 FSP
Fault #14, 0.00 FSP
Fault #15, 0.03 FSP
Fault #16, 0.02 FSP
Fault #17, 0.01 FSP
Calculate
b) PP Change at fault [psi]
Summary Plots
y northing [km]
x easting [km]
338
224
905
514
490
478
1345
1730
1120
268
Fault Slip Potential
0.00
0.2
0.4
0.6
0.8
1
Year:
2045
Export
Select Fault to Plot Pressures
Pressure Change at Fault Midpoint [psi]
Time [years]
Export
All Faults, FSP Through Time
Fault Slip Potential
Time [years]

CASES NO. 20313, 20314, 20472, 20463 and 20465
Index of Division Exhibit No. 9

Exhibit No.	Exhibit Name
9-A	New Mexico Statutes Annotated (NMSA 1978); Section 70-2-3
9-B	Oil Conservation Division, 2016, *Current status of induced seismicity policy for New Mexico*; Division Memorandum dated January 28, 2016, to the Director.
9-C	Summary of Oil Conservation Division UIC Technical Work Group on Part 26 Injection NMAC and Salt Water Disposal Activities.
9-D	Recommendations [November 2018] of the New Mexico Oil and Gas Association to the Oil Conservation Division in response to the UIC Technical Work Group.
9-E	Example of changes in language to UIC permit (SWD order) as approved by the Secretary in 2018.
9-F	Scanlon, B., Weingarten, M., Murray, K. and Reedy, R., 2019, Managing basin-scale fluid budgets to reduce injection-induced seismicity from the recent U.S. shale oil revolution; Seismological Research Letters; v. 90, no. 1, January/February 2019; p. 171-182.

CASES NO. 20313, 20314, 20472, 20460, 20463 and 20465
Division Exhibit No. 9-A

NEW MEXICO STATUTES ANNOTATED (1978)
CHAPTER 70 OIL AND GAS
ARTICLE 2 Oil Conservation Commission; Division; Regulation of Wells
SECTION 70-2-3 Waste; definitions.

As used in this act the term "waste," in addition to its ordinary meaning, shall include:

A. "underground waste" as those words are generally understood in the oil and gas business, and in any event to embrace the inefficient, excessive or improper, use or dissipation of the reservoir energy, including gas energy and water drive, of any pool, and the locating, spacing, drilling, equipping, operating or producing, of any well or wells in a manner to reduce or tend to reduce the total quantity of crude petroleum oil or natural gas ultimately recovered from any pool, and the use of inefficient underground storage of natural gas;

B. "surface waste" as those words are generally understood in the oil and gas business, and in any event to embrace the unnecessary or excessive surface loss or destruction without beneficial use, however caused, of natural gas of any type or in any form or crude petroleum oil, or any product thereof, but including the loss or destruction, without beneficial use, resulting from evaporation, seepage, leakage or fire, especially such loss or destruction incident to or resulting from the manner of spacing, equipping, operating or producing, well or wells, or incident to or resulting from the use of inefficient storage or from the production of crude petroleum oil or natural gas in excess of the reasonable market demand;

C. the production of crude petroleum oil in this state in excess of the reasonable market demand for such crude petroleum oil. Such excess production causes or results in waste which is prohibited by this act. The words "reasonable market demand," as used herein with respect to crude petroleum oil, shall be construed to mean the demand for such crude petroleum oil for reasonable current requirements for current consumption and use within or outside the state, together with the demand for such amounts as are reasonably necessary for building up or maintaining reasonable storage reserves of crude petroleum oil or the products thereof, or both such crude petroleum oil and products;

D. the nonratable purchase or taking of crude petroleum oil in this state. Such nonratable taking and purchasing causes or results in waste, as defined in the Subsections A, B, C of this section and causes waste by violating Section 12(a) [70-2-16A NMSA 1978] of this act;

E. the production in this state of natural gas from any gas well or wells, or from any gas pool, in excess of the reasonable market demand from such source for natural gas of the type produced or in excess of the capacity of gas transportation facilities for such type of natural gas. The words "reasonable market demand," as used herein with respect to natural gas, shall be construed to mean the demand for natural gas for reasonable current requirements, for current consumption and for use within or outside the state, together with the demand for such amounts as are necessary for building up or maintaining reasonable storage reserves of natural gas or products thereof, or both such natural gas and products;

F. drilling or producing operations for oil or gas within any area containing commercial deposits of potash where such operations would have the effect unduly to reduce the total quantity of such commercial deposits of potash which may reasonably be recovered in commercial quantities or where such operations would interfere unduly with the orderly commercial development of such potash deposits.

History: Laws 1935, ch. 72, § 2; 1941, ch. 166, § 1; 1941 Comp., § 69-203; Laws 1949, ch. 168, § 2; 1953 Comp., § 65-3-3; Laws 1965, ch. 58, § 1.

State of New Mexico
Energy, Minerals and Natural Resources Department

Susana Martinez
Governor

David Martin
Cabinet Secretary

Tony Delfin
Deputy Cabinet Secretary

David R. Catanach, Division Director
Oil Conservation Division

MEMORANDUM

Date: January 28, 2016

To: David Catanach, Director, OCD

From: Phillip Goetze, Engineering and Geological Services Bureau, OCD

RE: CURRENT STATUS OF INDUCED SEISMICITY POLICY FOR NEW MEXICO

The Bureau staff is currently developing an induced seismicity policy regarding oil and gas operations in New Mexico. This policy will include injection operations related to disposal wells and enhanced oil recovery wells, both Class II wells authorized under the Underground Injection Control Program of the Safe Drinking Water Act. The staff is reviewing the existing information developed by academic, regulatory and industry sources, and includes interviews with technical representatives of the New Mexico Bureau of Geology and Mineral Resources (NMBGMR) and the IRIS PASSCAL facility. The policy will follow the Injection-Induced Seismicity Decision Model proposed by the United States Environmental Protection Agency in its final report titled *Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches* issued February 5, 2015.

Recent events in Arkansas, Ohio, Oklahoma, and Texas have identified injection operations from disposal wells as the primary source of induced seismic activity detected in each state. The principle components behind injection-induced seismicity are (1) sufficient pressure buildup from disposal activities, (2) a fault system or individual fault in the vicinity of the disposal well, and (3) a pathway allowing the increased pressure to communicate from the disposal well to the fault.

New Mexico has two identified seismic active areas with disposal wells in the same location. One area is located in southeast New Mexico in the proximity of the Dagger Draw oil field and the second region is the Raton Basin in northern New Mexico where there are large coal-bed methane production operations. The Dagger Draw field is located between Artesia and Carlsbad along the west slope of the Delaware Basin. The catalog of seismic occurrences in the Dagger Draw area has dropped significantly due to the economic decline of this older field. The seismic occurrences in the Raton Basin (in Colorado and New Mexico) are currently being investigated by federal and private entities.

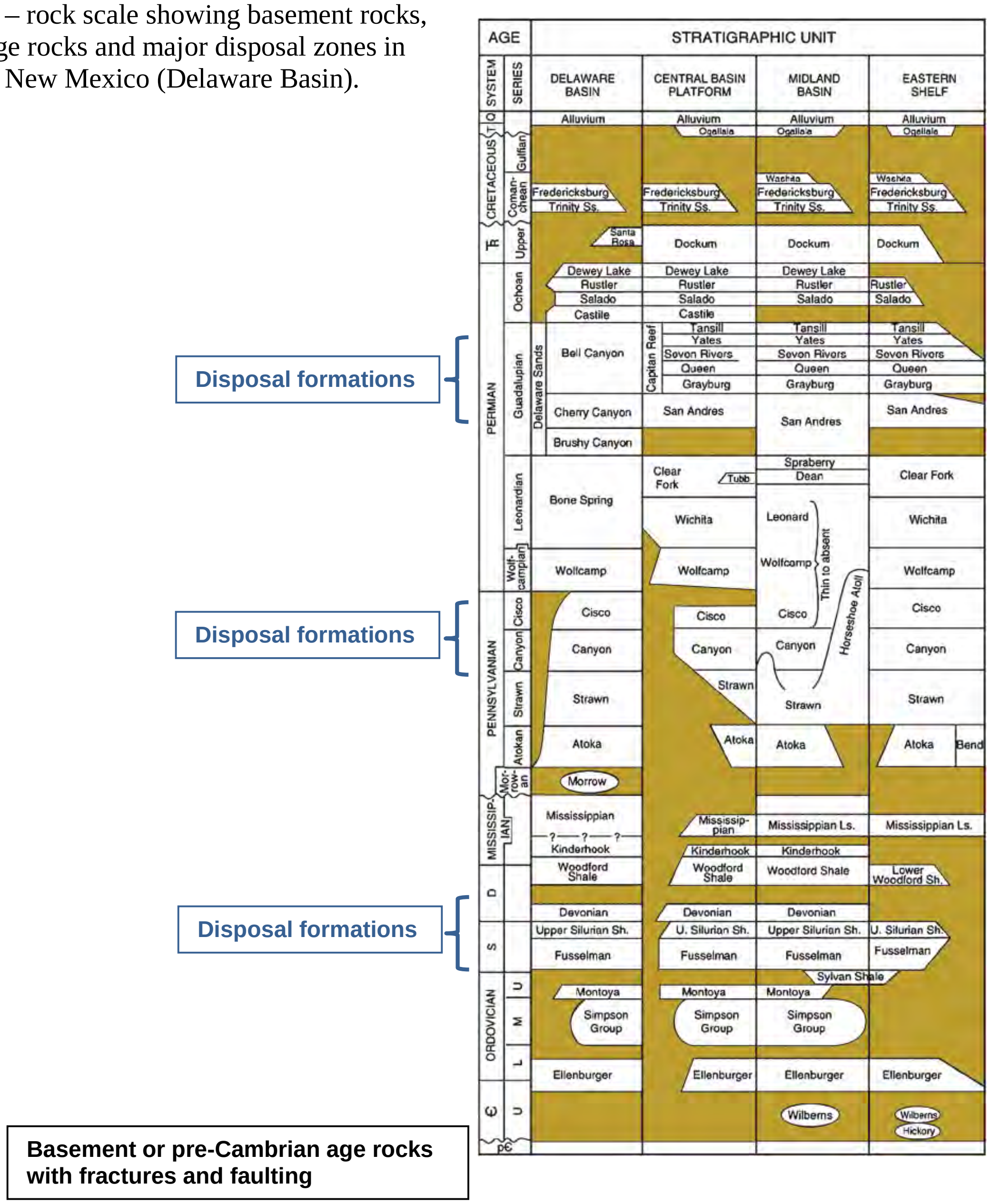
At this time, OCD is using an interim policy that restricts disposal into formations older than the upper Ordovician age with potential pathways to the pre-Cambrian contact where the “basement rock” contains fault systems (see Figure 1). Experiences in other states has indicated that injection to deeper zones near the pre-Cambrian contact has induced seismic events as the energy (pressure and volume of fluid) provided by the injection fluids active existing faults within the basement rock.

Additionally, OCD includes three items in its reviews of new applications to inject to evaluate the potential for injection-induced seismicity. These items include the following:

1. Review of injection pressures and volumes in these historical areas to assess if there is a correlation with any newly reported seismic events and the proposed injection activity;
2. Review of the geology and reservoir information to determine if the proposed injection interval are associated with potential pathways that may communicate with a known fault or fault system; and
3. Review of United State Geological Survey seismic data (including the National Earthquake Information Center) as well the catalogs maintained with by the NMBGMR.

A relevant papers with more specific information is a presentation by Ron Broadhead of the NMBGMR that can be made available as a PDF [Broadhead, R., 2014; *Oil & Gas Production and Seismicity in New Mexico*, presented at the New Mexico Tech Induced Seismicity Workshop, August 21, 2014].

Figure 1. Time – rock scale showing basement rocks, Ordovician-age rocks and major disposal zones in southeast New Mexico (Delaware Basin).



Oil Conservation Division
Energy, Minerals and Natural Resources Department
State of New Mexico

CASES NO. 20313, 20314, 20472, 20460, 20463 and 20465
Division Exhibit No. 9-C

UIC Technical Work Group (July and August 2018)

At the request of the Secretary, the Division was requested to review the current Title 19, Chapter 15, Part 26: Injection, New Mexico Administrative Code (NMAC) for possible rulemaking and the preparation of guidance in light of the recent expansion of the Permian development within the Delaware Basin.

Participants included:

1. Energy, Minerals and Natural Resources Department (EMNRD) Secretary Ken McQueen
2. EMNRD Deputy Secretary Matthias Sayer
3. Oil Conservation Division (OCD) Director Heather Riley
4. EMNRD General Counsel Bill Brancard
5. William Jones, OCD, Engineering Bureau chief
6. Phillip Goetze, OCD, Engineering Bureau
7. Kevin Burns, 3Bear Field Services
8. Neel Duncan, IPT for NGL
9. Tim Harrington, Mewbourne and New Mexico Oil and Gas Association (NMOGA)
10. Tim Tyrrell, XTO and NMOGA
11. Patrick Padilla, NMOGA
12. Anchor Holms, State Land Office
13. Lisa Winn, XTO

Meeting Date Record:

1. Meeting No. 1: July 12, 2018
2. Meeting No. 2: July 18, 2018
3. Meeting No. 3: July 24, 2018
4. Meeting No. 4: August 1, 2018 and August 2, 2018

- All meetings were held at the Office of the Secretary conference room.

General Discussion Subjects:

1. Current trends towards deeper injection with consideration to future expansion of disposal requirements, the protection of correlative rights, the prevention of waste resulting from Devonian disposal activities, and the expansion of midstream corporations as operators of disposal facilities.
2. Induced-seismicity and Devonian disposal – rulemaking, policy, guidance.
3. Shallow injection and impacts on current drilling – the Delaware Mountain Group (DMG) as a current disposal interval and future potential.
4. Review of the current administrative process for issuance of UIC permits (SWD orders) with recommendations for increased efficiency and accountability.

5. Assessment of current rule language for conformity with the USEPA definitions and recent changes in Division rule (specifically "affected person" as defined in the Horizontal Rule amendments).
6. Practicality of rulemaking within the scope of recommendations and available resources.

Recommendations:

1. For large volume, Devonian wells applications and resulting SWD order:
    a. Continue with the application of physical separation ("physical") between Devonian wells (decreased from one mile to 3/4-mile radius) noting that this is not a final solution to outstanding concerns and permitting process;
    b. Continue with one-mile radius notice with the inclusion of operators of SWD orders as part of the notice;
    c. Apply a minimum risk assessment criterion using current available information and modelling with the intention of expanding the assessment with a more reliable risk model;
    d. Obtain initial bottom-hole pressure measurements for future use;
    e. Pursue alternative parameters for assessing the injection interval other than a step-rate test; and
    f. Continue to investigate the potential for additional permit requirements for Devonian wells with issues such as improved fishing techniques and increased plugging bonds.
2. For SWD well applications requesting an injection interval in the Delaware Mountain Group (DMG):
    a. Limit approval of new applications for "commercial" operations within the DMG where production is present or probable considering current horizontal well technology;
    b. Allow "lease only" or "operator only" disposal in the DMG for either operators with limited access to disposal wells or operators with small volume disposal specific to a lease area;
    c. Review current DMG disposal wells for compliance with SWD order and Part 26 NMAC requirements.
3. Counsel recommended initial rulemaking would be limited to amending Part 26 NMAC to be consistent with EPA definitions and address new definition of "affected person".

[Phillip Goetze, December 2018]

CASES NO. 20313, 20313, 20472, 20463 and 20465
Division Exhibit No. 9-D

NMOCD Permit Guidelines for Delaware Basin Deep Saltwater Disposal Wells

The Guidelines below apply to all Delaware Basin salt water disposal (SWD) well applications seeking to inject below the base of the Woodford Shale into Silurian-Devonian reservoirs. Applicants choosing to complete notifications and analyses in accordance with this technical guidance may be subject to administrative approval of the application.

1. **19.15.26.8.**
   - B.2: Notification requirement increased from 'one-half mile of the well' to 'one mile of the well'.
   - Notification to include current SWD well permit holders/operators

2. **UIC Manual – Permitting Class II Wells**
   - 5. Area of Review: 'within one-half mile of each proposed injection well' increased to 'within one mile of each proposed injection well'.

3. **New Item – Seismicity Risk Assessment**
   - Suggest current wording requiring statement from 'knowledgeable person' be removed.
   - Seismicity Risk Assessment should include:
     - *A.* Assessment of historical seismicity within 6 miles of the proposed location utilizing USGS and/or other resources that may become publically available (example: WIPP data). *This loosely leverages the Texas Railroad Commission requirement*
     - B. Characterization of subsurface stress conditions
       - Stress regime (normal, strike-slip, reverse)
       - Orientation of maximum horizontal stress (Hmax)
     - C. Characterization of basement involved faults in the area of the proposed SWD well
       - Fault strike orientation and fault dip
     - D. Characterization of potential pore pressure increases due to the proposed SWD well
     - E. Integration of items A through D into a consolidated risk assessment

4. **New Item - Initial Static Reservoir Pressure Measurement**
   - The operator shall determine the static reservoir pressure prior to initiating disposal operations.
   - The pressure information shall be submitted to the NMOCD utilizing Form C103

5. **New Item – SWD Well Spacing**
   - Spacing for new SWD wells should be at least 1.5 miles from existing or permitted Deep SWD wells.

6. **New Item – Casing / Tubing**
   - *NMOCD's primary concern is the ability to plug the well should downhole configuration not allow for effective fishing operations*
   - Casing / Tubing relative dimensions:
     A. The tubing OD must have adequate clearance with the casing ID. The tubing size selected should permit washover and fishing operations in case the tubing becomes stuck and requires recovery. A wash pipe must be available that has an outside coupling dimension less than the casing drift diameter and an internal drift diameter that is greater than the tubing coupling OD. Also, the tubing OD should permit use of an overshot inside the casing that will go over the body of the pipe. (It is assumed for the purposes of this policy that tubing collars may be milled.)

     B. Special circumstances requiring small clearances (0.5" or less difference between the tubing pipe body OD and casing drift ID) shall be risk assessed by the operator and the risk assessment attached to the well application or sundry notice. The operator shall describe in the risk assessment how plugging will be accomplished through stuck tubing should fishing not be successful.

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 9-E

State of New Mexico
Energy, Minerals and Natural Resources Department

Susana Martinez
Governor

Ken McQueen
Cabinet Secretary

Matthias Sayer
Deputy Cabinet Secretary

Heather Riley, Division Director
Oil Conservation Division

Administrative Order SWD-17XX
March XX, 2018

ADMINISTRATIVE ORDER
OF THE OIL CONSERVATION DIVISION

Pursuant to the provisions of Division Rule 19.15.26.8(B) NMAC, Mewbourne Oil Company (the "operator") seeks an administrative order for its proposed Hoss 11 SWD Well No. 1 (the "proposed well") with a location of 200 feet from the North line and 215 feet from the East line, Unit letter A of Section 11, Township 25 South, Range 28 East, NMPM, Eddy County, New Mexico, for the purpose of produced water disposal.

THE DIVISION DIRECTOR FINDS THAT:

The application has been duly filed under the provisions of Division Rule 19.15.26.8(B) NMAC and satisfactory information has been provided that affected parties have been notified and no objections have been received within the prescribed waiting period. The applicant has presented satisfactory evidence that all requirements prescribed in Division Rule 19.15.26.8 NMAC have been met and the operator is in compliance with Division Rule 19.15.5.9 NMAC.

Application for Disposal in Devonian and Silurian Formations: Due to the potential for the projected injection volume of the proposed well to impact an area greater than the one-half mile radius applied in Division Form C-108 and Division rule, the applicant has provided the following supplementary information:

1. Notification following Division Rule 19.15.26.8(B) NMAC for a radius of one mile from the surface location of the proposed well;
2. An expanded Area of Review for wells penetrating the disposal interval for a radius of one mile from the surface location of the proposed well; and
3. A statement by a qualified person assessing the potential of induced-seismic events associated with the disposal activities for the predicted service life of the proposed well.

IT IS THEREFORE ORDERED THAT:

The applicant, Mewbourne Oil Company (OGRID 14744), is hereby authorized to utilize its Hoss 11 SWD Well No. 1 (API 30-015-44666) with a location of 200 feet from the North line and 215 feet from the East line, Unit letter A of Section 11, Township 25 South, Range 28 East, NMPM, Eddy County, for disposal of oil field produced water (UIC Class II only) through open-hole completion into an interval consisting of the Devonian formations from approximately 14450 feet to approximately 15650 feet. Injection will occur through internally-coated, 5-inch or smaller

CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 9-F

Ⓔ

Managing Basin-Scale Fluid Budgets to Reduce Injection-Induced Seismicity from the Recent U.S. Shale Oil Revolution

by Bridget R. Scanlon, Matthew B. Weingarten, Kyle E. Murray, and Robert C. Reedy

ABSTRACT

With the U.S. unconventional oil revolution, adverse impacts from subsurface disposal of coproduced water, such as induced seismicity, have markedly increased, particularly in Oklahoma. Here, we adopt a new, more holistic analysis by linking produced water (PW) volumes, disposal, and seismicity in all major U.S. unconventional oil plays (Bakken, Eagle Ford, and Permian plays, and Oklahoma) and provide guidance for long-term management. Results show that monthly PW injection volumes doubled across the plays since 2009. We show that the shift in PW disposal to nonproducing geologic zones related to low-permeability unconventional reservoirs is a fundamental driver of induced seismicity. We statistically associate seismicity in Oklahoma to (1) PW injection rates, (2) cumulative PW volumes, and (3) proximity to basement with updated data through 2017. The major difference between intensive seismicity in Oklahoma versus low seismicity levels in the Bakken, Eagle Ford, and Permian Basin plays is attributed to proximity to basement with deep injection near basement in Oklahoma relative to shallower injection distant from basement in other plays. Directives to mitigate Oklahoma seismicity are consistent with our findings: reducing (1) PW injection rates and (2) regional injection volumes by 40% relative to the 2014 total in wells near the basement, which resulted in a 70% reduction in the number of $M \geq 3.0$ earthquakes in 2017 relative to the 2015 peak seismicity. Understanding linkages between PW management and seismicity allows us to develop a portfolio of strategies to reduce future adverse impacts of PW management, including reuse of PW for hydraulic fracturing in the oil and gas sector.

Electronic Supplement: Additional information on methods; a more detailed bubble plot containing water and energy information; maps of oil- and gas-producing wells and saltwater disposal and enhanced oil-recovery wells; a geologic cross section of the Permian Basin; boxplots showing the statistical data evaluating relationships between produced water management and seismicity; tables listing the number of earthquakes in each of the plays, oil, gas, produced-water volumes, and management of produced water using saltwater disposal and enhanced oil recovery.

INTRODUCTION

The United States has been the global leader in oil production since 2013, exceeding production in Saudi Arabia (U.S. Energy Information Administration [EIA], 2018a). The marked increase in U.S. oil production is attributed to technology advances, primarily hydraulic fracturing (HF) and horizontal drilling of wells up to 2–3 miles long (~3–5 km). These advances allow oil to be extracted from low-permeability source rocks (e.g., shales, tight sands, or carbonates) or through dewatering of oil reservoirs, as in Oklahoma (Murray, 2013; Scanlon *et al.*, 2016, 2017). Oil production from shales and tight rocks accounted for about half of the U.S. production in 2017, greatly enhancing U.S. energy security (U.S. EIA, 2018a). Shales and tight rocks are generally referred to as unconventional or continuous (areally extensive) reservoirs that require HF and horizontal wells to extract oil (Schenk and Pollastro, 2002). These unconventional reservoirs contrast with traditional higher permeability conventional reservoirs that can be developed with vertical wells and without large-water-volume HF.

Oil wells also produce large volumes of water, averaging ~10 barrels (bbl) of water per barrel of oil in the United States in 2012 (Veil, 2015). Water coproduced with oil has been referred to as produced water (PW), wastewater, or saltwater. We have been generating large volumes of PW with oil production in the United States for decades (U.S. EIA, 2018b), but widespread induced seismicity (earthquakes caused by human activity) in some regions has been relatively recent, raising the question about what has changed. Are we generating more PW with oil production or are we managing PW differently? At the scale of the United States, we did not produce more water with oil and gas in 2012 relative to 2007 (< 1% change in PW

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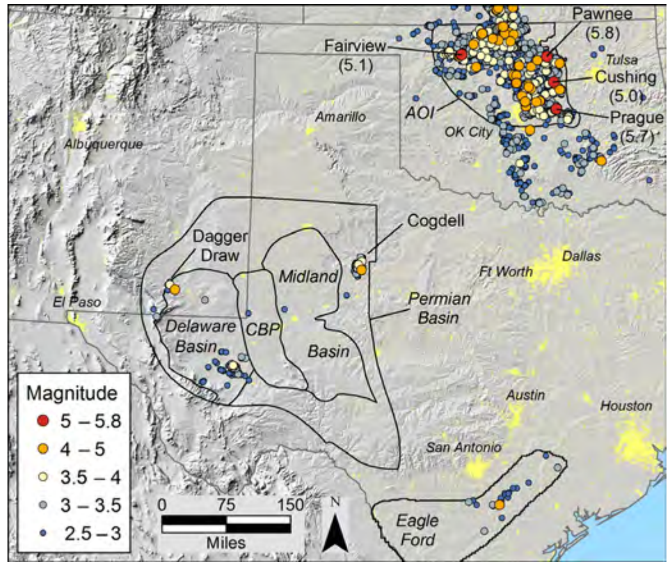
relative to 30% increase in oil production; Clark and Veil, 2009; Veil, 2015). However, we are managing PW differently. PW from moderate-to-high-permeability conventional reservoirs is mostly injected back into the reservoir for pressure maintenance or for enhanced oil recovery injection (EORI) using water flooding, whereas PW from unconventional reservoirs cannot be reinjected into the producing reservoir because of the low permeability of the shales and tight rocks.

A National Research Council (NRC) report on induced seismicity emphasizes the impact of the net fluid balance (fluid injection minus extraction [or production]) in controlling subsurface pressure changes and induced seismicity (NRC, 2013). Because injection and extraction are generally balanced in *conventional* reservoirs, net pore-fluid pressure changes should be minimal, reducing the risk of seismicity. However, seismicity related to water flooding has been recorded in some regions (e.g., the Cogdell field in the Permian Basin; Frohlich *et al.*, 2016). In contrast, PW from *unconventional* reservoirs is generally injected into non-oil-producing geologic intervals, resulting in net fluid volume and related pressure increases. Some producing reservoirs in Oklahoma (e.g., Mississippi Lime and Hunton Lime) do not fit neatly into conventional or unconventional reservoir categories but have been referred to as "where unconventional meets conventional" because HF and horizontal drilling stimulation techniques are applied to these higher-permeability reservoirs (Drillinginfo, 2012). Because these Oklahoma reservoirs are being dewatered, PW is not reinjected back into the producing reservoir. Typical ratios of PW to oil in these dewatering reservoirs are up to ~120 bbl water/bbl oil initially (Oklahoma Corporation Commission [OCC], 2017).

PW management in unconventional or dewatering reservoirs is similar to other energy technologies that inject or extract large fluid volumes over long periods of time (e.g., carbon capture and storage, some geothermal systems) and have a much higher potential of modifying pressures and inducing seismicity (Rubinstein and Mahani, 2015). Increasing pore-fluid pressure (ρ) reduces effective stress on faults (normal stress [σ] − pore-fluid pressure [ρ]) making fault slip more likely (NRC, 2013). Critical factors to consider for induced seismicity include (Ground Water Protection Council [GWPC], 2017):

1. sufficient pore pressure buildup from injection,
2. presence of an optimally oriented fault for movement located in a critically stressed region (fault of concern), and
3. a pathway connecting the pressure increase with the fault.

The pressure buildup is attributed to PW injection that is not offset by production, resulting in an increasing pressure footprint (U.S. EIA, 2014). The time period of injection is also important (U.S. EIA, 2014). Although seismicity has been linked to water injection during HF stimulation (the Horn River, Canada; Lancashire, United Kingdom; Oklahoma), time periods for HF are short (days) and any impacts from HF are generally mitigated within a short period (Davies *et al.*, 2013; OCC, 2017).



▲ **Figure 1.** Seismic events with magnitude (M) ≥ 2.5 that occurred from January 2009 through December 2017 in the Oklahoma, southern Kansas, Permian Basin, and Eagle Ford play study areas. There were 8532 events in the Oklahoma/southern Kansas cluster, including four $M \geq 5.0$ events (labeled). By comparison, there were 122 events in the Permian Basin and 19 events in the Eagle Ford. However, 66 of the Permian Basin events are associated with CO_2 injection in the Cogdell field (including an M 4.3 event) and 6 with enhanced oil-recovery injection (EORI) in the Dagger Draw field (including an M 4.1 event). The largest event in the Eagle Ford was an M 4.8 event. The number of earthquakes with $M \geq 3.0$ is provided in Ⓔ Table S1 (available in the electronic supplement to this article). Subregions outlined in the Permian Basin include the Delaware Basin, Midland Basin, and the Central Basin Platform (CBP). Data source: U.S. Geological Survey (USGS) Advanced National Seismic System Comprehensive Catalog (see Data and Resources). The color version of this figure is available only in the electronic edition.

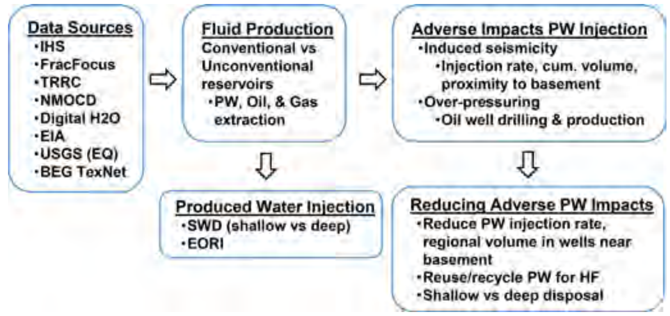
Previous studies examined linkages between PW injection and induced seismicity. Understanding these linkages has important implications for PW management. Many studies have focused on Oklahoma where several large earthquakes occurred, including the M 5.7 earthquake near Prague in November 2011, the M 5.1 Fairview earthquake in February 2016, the M 5.8 Pawnee earthquake in September 2016, and the M 5.0 Cushing earthquake in November 2016 (Fig. 1; Kroll *et al.*, 2017). A previous study found that PW injection rate was the most critical control on induced seismicity based on linkages between seismicity and high-rate injection wells (≥ 300,000 bbl/month) in the U.S. Midcontinent (Weingarten *et al.*, 2015). The study of seismicity in the U.S. Midcontinent indicated that cumulative PW injection volume or proximity of injection to the crystalline basement (consisting mostly of igneous or metamorphic rocks at the base of sedimentary units) was not statistically linked to seismicity. The implications of this study suggest that reducing injection rate could be used to minimize induced seismicity. A recent study related the occurrence of seismicity to proximity to basement, noting the absence of seismicity in the Bakken and Marcellus plays with shallow or little or no disposal, respectively (Skoumal *et al.*, 2018). Another study underscored well depth related to proximity to basement in Oklahoma as the primary factor controlling seismicity (Hincks *et al.*, 2018). Large faults are expected to be more prevalent at greater depth, particularly in old, brittle basement rocks that have been subjected to different stresses over long times. The study by Hincks *et al.* (2018) implies that disposing of PW in shallow zones away from the basement should minimize induced seismicity. In another study, monthly regional injection rates at depth near the basement (Arbuckle Group) were correlated to monthly earthquake counts in central and western Oklahoma (Langenbruch and Zoback, 2016). Additional factors considered important relative to seismicity include time-variable injection that was linked to large-magnitude earthquakes in Oklahoma, considering poroelastic effects (Barbour *et al.*, 2017; Goebel *et al.*, 2017). Chang *et al.* (2016) also linked injection-induced seismicity to basement faults, including poroelastic stressing. A much broader scale study relating induced seismicity to hydrocarbon production, used as a proxy for HF and PW volumes, in the United States and Canada emphasizes the importance of tectonic factors, for example, critically stressed, favorably oriented faults (van der Baan and Calixto, 2017). In contrast, another study assumes that seismogenic faults are pervasive in basement rocks in Oklahoma (Norbeck and Rubinstein, 2018). Understanding the controlling mechanisms for seismicity and the role of PW injection is critical for developing PW management strategies to mitigate or minimize seismicity.

Few studies address management strategies to reduce seismicity. Some studies focus on developing a detailed seismic network to monitor induced seismicity (Norbeck and Rubinstein, 2018). A primer on technical and regulatory considerations related to risk management and mitigation strategies includes detailed recommendations on PW injection rates, volumes, and proximity to basement, among many other factors (GWPC, 2017). The EPA developed a decision model to manage and minimize injection-induced seismicity by considering critical factors, including pressure buildup, fault of concern, and interconnectivity and provides a number of recommendations (U.S. EIA, 2014).

The objectives of this study were to:

1. determine controls on linkages between PW management and induced seismicity, and
2. assess approaches to improve PW management to minimize future seismicity.

This study differs from previous studies in that (1) it considers all of the major tight-oil plays in the United States, not just Oklahoma; (2) it links PW injection to specific geologic zones, calculating net fluid balances of such zones; (3) it reevaluates the approach of assessing injection rates, cumulative injection volumes, and proximity to basement, previously applied to the



▲ **Figure 2.** Flow chart showing data sources, fluid balance (production vs. injection), adverse impacts, and approaches to reducing these impacts. TRRC, Texas Railroad Commission; NMOCD, New Mexico Oil Conservation District; OCC, Oklahoma Corporation Commission; EIA, Energy Information Administration; USGS (EQ), U.S. Geological Survey earthquake data; BEG TexNet, Bureau of Economic Geology Texas Network; PW, produced water; SWD, saltwater disposal wells; cum. volume, cumulative injection volume; HF, hydraulic fracturing; WW, wastewater. The color version of this figure is available only in the electronic edition.

U.S. Midcontinent (Weingarten *et al.*, 2015), by including an additional 3.5 yrs of data; and (4) it evaluates strategies for managing PW to minimize future seismicity, particularly through PW reuse and/or recycling. Although the U.S. Geological Survey currently develops hazard forecasts for induced seismicity (Petersen *et al.*, 2017) that do not consider PW injection data, results of this study relating PW management to induced seismicity should be valuable in future hazard forecasts that incorporate PW data. The insights from PW injection related to oil and gas production in this study may be considered an analog for CO_2 sequestration, injection of other industrial wastewaters, or fluid injection for geothermal energy projects.

MATERIALS AND METHODS

A flow chart describing the methodology is shown in Figure 2. Additional details related to methods applied in this study are provided in the Ⓔ Materials and Methods section, available in the electronic supplement to this article. Fluid (oil, gas, and water) production for the Bakken, Eagle Ford, and Permian Basin plays and in Oklahoma was quantified based on data primarily from the IHS database (2009–2016). Monthly data on PW volumes or PW injection into saltwater disposal (SWD) and EORI wells were also obtained from IHS or state regulatory agencies. Analysis of the net fluid balance consisted of quantifying oil, gas, and water extraction (production) and water injection (SWD or EORI) relative to oil-producing and non-oil-producing geologic intervals in the major tight-oil plays. The previous assessment of linkages between PW injection and earthquakes in Oklahoma (Weingarten *et al.*, 2015) was updated with an additional 3.5 yrs of data, evaluating injection rates, cumulative injection volumes, and proximity to basement.

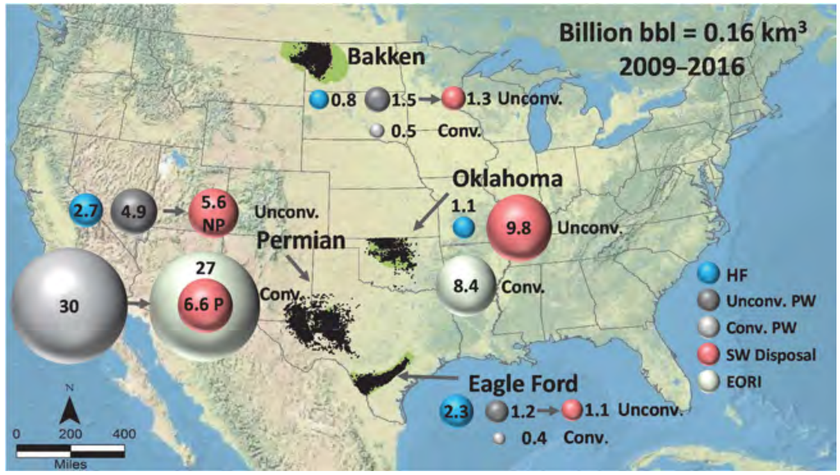
Earthquakes within 15 km of an active SWD well were assumed to be associated with that SWD well. New basement depth maps were used for Oklahoma, with much more detailed information (Crain and Chang, 2018). Similar analysis was applied to the other major U.S. tight-oil plays (Bakken, Eagle Ford, and Permian Basin). A first-order spatiotemporal filter was applied to identify earthquakes potentially associated with injection wells. Confidence limits on these associated earthquakes were determined using a bootstrap resampling method. Results from other plays were compared with those from Oklahoma to determine linkages between PW management and lower seismicity rates in other plays. We examined current approaches to mitigating seismicity in Oklahoma and preventing potential seismicity in the other tight-oil plays. Various approaches to PW management were considered, including reducing regional-scale and local-scale injection rates and volumes, shallow versus deep injection, and reuse and/or recycling of PW for HF.

RESULTS

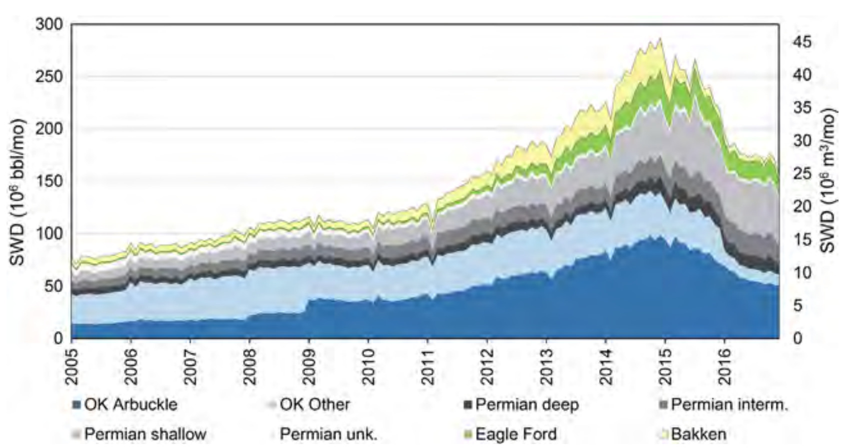
Net Fluid Balance of Major Tight-Oil Plays

Water is a major component of the net fluid balance in the Permian, Bakken, and Eagle Ford plays and in Oklahoma (Fig. 3 and Ⓔ Fig. S1). Traditionally, PW is managed primarily via reinjection back into the producing horizon, often aimed at maintaining pressure or for enhanced oil recovery (EOR). The recent U.S. unconventional oil revolution, however, not only increased PW volumes but also created a marked shift in the net fluid balance of the major plays. The recent increase in PW has been managed primarily by PW disposal into nonproducing horizons, mostly using SWD wells (Fig. 4), because unconventional production primarily focuses on low-permeability reservoirs or dewatering reservoirs, not suitable for PW reinjection. This shift, increased disposal into nonproducing horizons, coupled with increased PW volumes, has likely yielded larger net positive reservoir pressure changes at the regional scale. Here, we quantify PW volumes in the Permian, Bakken, and Eagle Ford plays and in Oklahoma, with an emphasis on the breakdown of PW injection into oil-producing or nonproducing geologic intervals and disposal type (EORI or SWD).

Although PW volumes from conventional reservoirs are high, this PW is mostly recycled for EOR. PW volumes are the highest from



▲ **Figure 3.** Total volumes of HF water use, of PW from unconventional and conventional wells, and PW management through SWD wells and EORI in the Bakken play, Eagle Ford play, Permian Basin, and the state of Oklahoma for the period 2009–2016. Bubble areas represent fluid volumes and are proportionally consistent across all regions. PW management through EORI and SWD cannot be linked directly to PW generation. Data on PW are not available for Oklahoma. PW volumes are provided in Ⓔ Tables S2–S5. Additional information on SWD volumes is provided in Ⓔ Table S6. The color version of this figure is available only in the electronic edition.



▲ **Figure 4.** Comparison of annual total SWD volumes in the Permian Basin, Oklahoma, Eagle Ford play, and Bakken play. SWD in the Permian is based on injection into nonproducing intervals and is subdivided relatively into deep (lower Paleozoic), intermediate (Pennsylvanian, Wolfcampian, and Leonardian), and shallow (Guadalupian) depth formations. SWD in Oklahoma is subdivided into Arbuckle Group wells and all other wells. Other wells in Oklahoma include Devonian to Middle Ordovician age rocks (Wilcox and Simpson Groups, ~7% of SWD), Mississippian to Pennsylvanian age rocks (~11%), Permian age rocks (~5%), and wells completed in multiple zones (~11%). SWD in the Eagle Ford is also subdivided into shallow units above the Eagle Ford Shale. SWD in the Bakken play is primarily (93%) in the Dakota Formation above the Bakken/Three Forks producing units. Annual data are provided in Ⓔ Tables S7–S10. The color version of this figure is available only in the electronic edition.

the Permian Basin conventional reservoirs, totaling 30 billion bbl (Bbbl, 4.8 km^3, 2009–2016), with an average of 14 barrels of water produced for every barrel of oil (Fig. 3 and Ⓔ Fig. S1). For context, this cumulative water volume (30 Bbbl, 1260 billion gallons, Bgal) is ~4.5 times the daily freshwater use in the United States in 2015 (281 Bgal; Dieter *et al.*, 2018). Conventional reservoirs are found mostly along the margins of the Permian Basin and in the Central Basin Platform between the two mostly unconventional reservoirs in the Delaware and Midland Basins (Ⓔ Fig. S2a). Most PW from Permian conventional plays is injected back into the producing reservoir for EOR (27 Bbbl; Fig. 3). There is no direct linkage between PW volume reporting and SWD volume reporting. SWD wells in Texas are classified as disposing into producing (SWD-P) or nonproducing (SWD-NP) intervals based on the presence or absence, respectively, of any current or historical hydrocarbon production within a 2-mile radius of the SWD well. Some of the PW from the conventional reservoirs is assumed to be disposed into producing intervals (SWD-P: < 6.6 Bbbl). Imbalances in PW and SWD volumes are likely related to uncertainties in reporting, particularly in the PW volumes. Water production or extraction from conventional plays is generally balanced with water injection, and regional-scale pore-fluid pressure changes should be minimal. Water essentially moves in a large recycle loop in these conventional reservoirs (Ⓔ Fig. S3b). PW is not reported in Oklahoma; however, conventional reservoirs likely operate in a similar way to those in the Permian Basin, and the large volume of EORI (8.4 Bbbl) should represent PW from conventional reservoirs (Fig. 3).

PW from unconventional reservoirs in the Permian, Bakken, and Eagle Ford plays, as well as from Oklahoma reservoirs that are being dewatered, is managed in a markedly different fashion from that in conventional reservoirs. PW is not injected back into the oil-producing intervals but instead is injected into non-oil-producing intervals using SWD wells, resulting in a net pressure increase. Cumulative PW injection into non-oil-producing intervals is the highest in Oklahoma (9.8 Bbbl), followed by the Permian Basin (5.6 Bbbl), but is much lower in the Bakken (1.3 Bbbl) and Eagle Ford (1.1 Bbbl) plays (2009–2016; Fig. 3). Monthly total SWD volumes into non-oil-producing intervals more than doubled from a monthly mean of 0.11 Bbbl in 2009 to a monthly peak of 0.29 Bbbl in 2014 (Fig. 4).

How much water is produced relative to oil in the various reservoirs? The PW intensity relative to oil production (PW to oil ratio, PWOR) is the highest in Oklahoma, ranging from 21 bbl PW/bbl of oil (water cut [WC = PW/[PW + oil] = PW/[PW + 1], e.g., 21/22 = 95%) for conventional wells to 25 for unconventional wells (2009–2016; Ⓔ Fig. S1). These PW intensities in Oklahoma assume that EORI and SWD serve as proxies for PW from conventional and unconventional reservoirs, respectively. In the Permian Basin, the PWOR for conventional wells (PWOR: 14; WC, 93%) is much higher than that for unconventional wells (PWOR: ~2.6; WC, ~70%). PWORs are much lower in the Bakken (5 for conventional wells [WC, 83%] and 0.7 for unconventional wells [WC, ~40%]) and in the Eagle Ford (~4 for conventional wells [WC: ~80%] and 0.6 for unconventional wells [WC: ~40%]).

What Controls Linkages between Produced Water Management and Seismicity?

Oklahoma

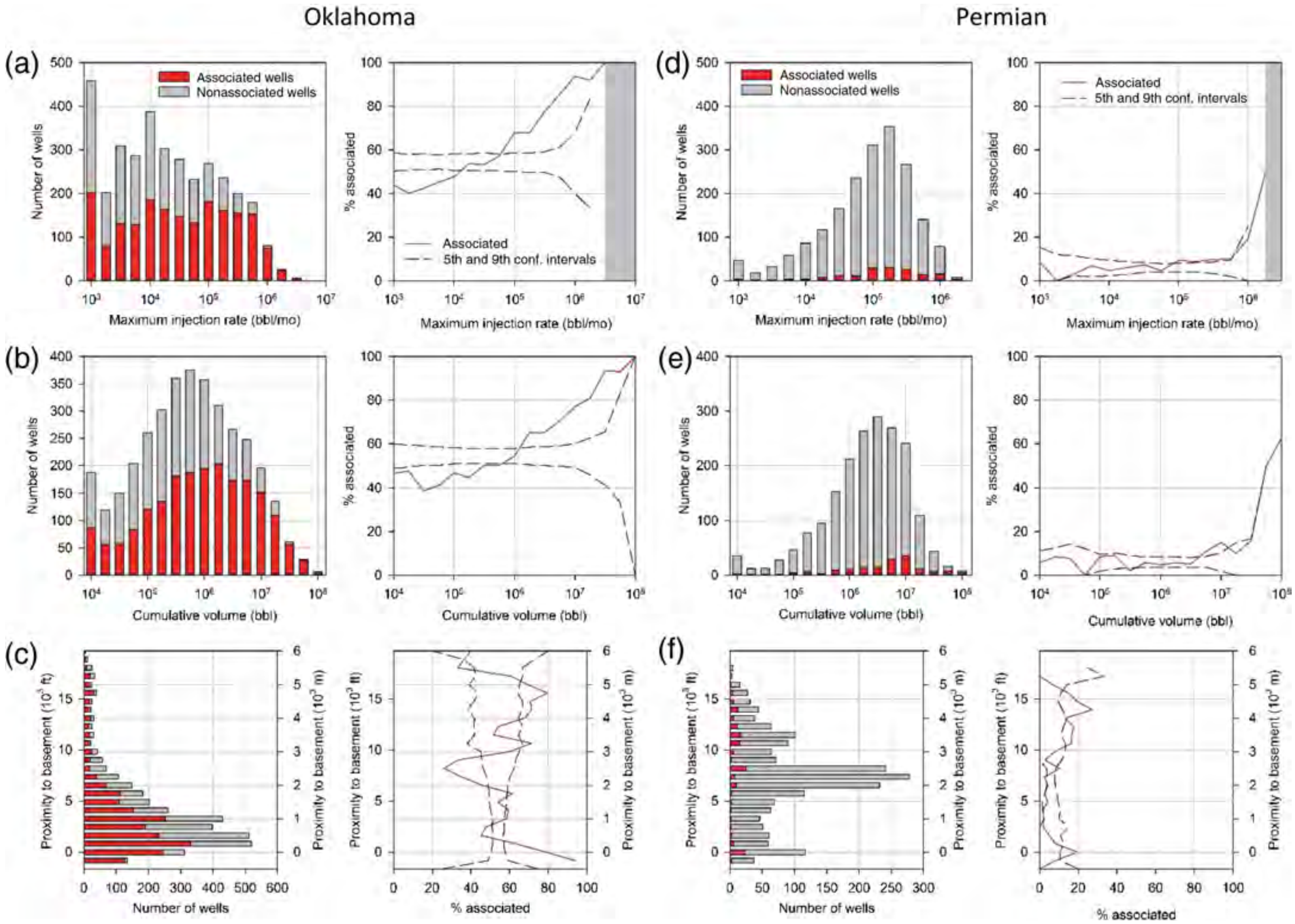
Potential controls on PW management and seismicity include:

1. PW injection rate at the well level,
2. regional cumulative injection volume, and
3. proximity of injection to basement.

In (1), using a first-order spatiotemporal filter, about 55% of SWD wells (~1900 out of ~3500 SWD wells) are potentially associated with earthquakes ($M \geq 3.0$) within a 15 km radius in the area of interest (AOI) in central and north-central Oklahoma (OK) (2009–2017; Figs. 1 and 5a). Individual injection rates for wells associated with earthquakes vary by a few orders of magnitude (~10,000 to 4 million bbl/month [mo]) with a median of ~16,000 bbl/mo. PW injection rate in SWD wells plays an important role in induced seismicity because the likelihood of association between SWD wells and earthquakes increases with increasing injection rate: specifically, from ~50% of wells at injection rates ≤ 30,000 bbl/mo (1000 bbl/day) to 85%–100% at rates ≥ 300,000 bbl/mo (10,000 bbl/day) (Fig. 5a). The increasing percentage of higher-injection-rate wells associated with earthquakes exceeds the 5%–95% confidence bounds, based on a bootstrapped resampling method (see the Ⓔ Estimating Confidence Intervals Based on Bootstrapped Resampling section). These results are consistent with earlier findings from the U.S. Midcontinent that linked injection rate with seismicity (Oklahoma, Colorado, New Mexico, and Arkansas), based on data through 2013 (Weingarten *et al.*, 2015).

In (2), we find the cumulative injection volume for SWD wells in Oklahoma from 2009 to 2017 to be statistically associated with earthquakes (Fig. 5b). The percentage of SWD wells associated with earthquakes increases with increasing cumulative injection volumes. Cumulative injection volumes range from ~10,000 bbl/well (5th percentile) to almost 84 million bbl/well (one well had 139 million bbl). Wells with cumulative injection volumes ≤ ~1 million bbl exhibit statistically random association with earthquakes. The percentage association generally increases from ~60% at cumulative volumes of ~1 million bbl to ~90%–100% at ≥ 30 million bbl. This increase is statistically significant, based on the bootstrap resampling method. A prior study did not find a statistically significant relationship based on data from the U.S. Midcontinent through 2013 (Weingarten *et al.*, 2015). With 3.5 yrs of additional injection data, a given well's cumulative injection volume is now correlated with its maximum monthly injection rate (coefficient of determination, $r^2 = 0.83$; Ⓔ Fig. S4a). Therefore, cumulative injection volume is now expected to also be statistically associated with earthquakes.

In (3), using a newly developed basement map (Crain and Chang, 2018) and PW injection database for the state of Oklahoma (Murray, 2015), the proximity of the injection interval of the SWD wells to the crystalline basement is found to be



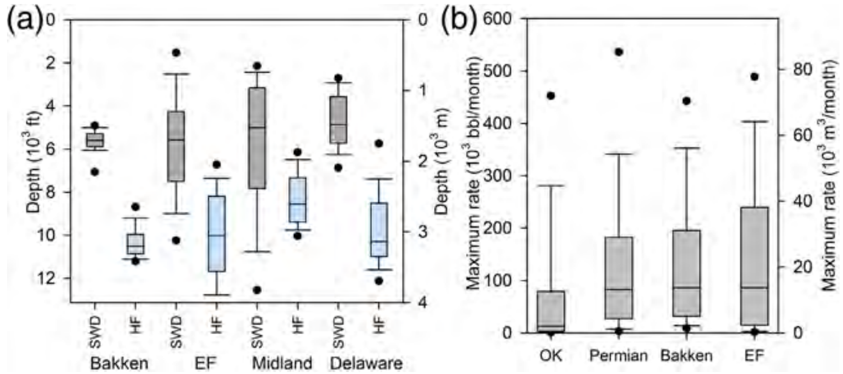
▲ **Figure 5.** Assessment of linkages between SWD and seismicity in Oklahoma and Permian Basin. Output includes histogram of (a,d) maximum monthly injection rate in SWD wells in Oklahoma and the Permian Basin. The bars show the number of wells operating at a given maximum monthly injection rate for all SWD wells and SWD wells spatiotemporally associated with an earthquake. (b,e) Histogram showing cumulative injected volume at all wells in the same states as those in (a). The percentage of all wells that are associated with an earthquake in each histogram bin is plotted as a function of (a,d) maximum monthly injection rate and (b,e) cumulative injected volume. Dashed lines represent the 5% and 95% confidence bounds in each bin from 10,000 bootstrap resamples assuming rates of association are random. The color version of this figure is available only in the electronic edition.

related to earthquake association (Fig. 5c). The median injection depth for Oklahoma SWD wells is 3400 ft (~1 km) (range: 1000–8000 ft [0.3–2.4 km], 5th–95th percentile). Between ~60% and 90% of SWD wells with injection intervals within 800 ft (~240 m) of the basement are associated with earthquakes, which is statistically significant (Fig. 5c). This result also contrasts with the previous findings at the U.S. Midcontinent scale that did not find a statistically significant relationship between proximity of SWD injection interval to basement and seismicity (Weingarten *et al.*, 2015). The previous analysis utilized a basement map that contained much larger uncertainties in basement depth (±15% in depth to basement) than the present study; thus no statistically significant relationship was found when taking this uncertainty into account (Mooney and Kaban, 2010).

Bakken, Eagle Ford, and Permian Basin Plays

The number of earthquakes $M \geq 3.0$ in the Bakken (2), Eagle Ford (12), and Permian Basin (53) is much less than that in the Oklahoma AOI (2642) (2009–2017; Fig. 1; Ⓔ Table S1). The percentage of SWD wells potentially associated with earthquakes is also much lower in those plays (5% in the Bakken; 9%, Permian; 20%, Eagle Ford) relative to Oklahoma (56%) (Fig. 5a,d and Ⓔ Fig. S5a,d). There is no regional-scale, statistically significant linkage between seismicity and PW injection rates, cumulative injection volumes, or proximity to basement in these plays because all of the data plot within the confidence bounds of random association (Fig. 5d–f and Ⓔ Fig. S5).

The biggest difference between PW management in the other plays relative to Oklahoma is proximity to basement, with much shallower injection in the Bakken, Eagle Ford,



▲ **Figure 6.** (a) Depths of PW injection using SWD wells in the Bakken and Eagle Ford plays and in the Midland and Delaware Basins within the Permian Basin relative to the oil-producing zones. (b) Comparison of maximum monthly injection rate distributions for SWD wells completed in the different plays. Median (solid) and mean (dashed line) are shown along with 25th and 75th percentiles (box), 10th and 90th percentiles (whiskers), and 5th and 95th percentiles (points). (a) Injection of PW in Bakken SWD wells is in the Dakota Formation (median depth 5600 ft) relative to oil production from the Bakken Petroleum System (Bakken and underlying Three Forks, median depth of HF wells, 10,500 ft). Wastewater injection in Eagle Ford SWD wells is primarily in multiple shallower formations (median depth, 5600 ft) relative to oil production from the Eagle Ford (median depth of HF wells, 10,000 ft). Injection of PW in Midland Basin SWD wells is primarily in the San Andres Formation (median depth, 5000 ft) relative to oil production from the Wolfcamp, as reflected in HF well depths (median depth of HF wells, 8600 ft). Injection of PW in Delaware Basin SWD wells is primarily in the Delaware Mountain Group (median depth, 4900 ft) relative to oil production from the Wolfcamp (median depth of HF wells, 10,300 ft). The appearance of overlap between Eagle Ford SWD and HF distributions results from the dip and increased formation depths toward the southeast of the Eagle Ford play geology. The data are provided in Ⓔ Table S11. The color version of this figure is available only in the electronic edition.

and Permian Basin SWD wells relative to crystalline basement depths than the predominantly deep disposal in Oklahoma (Fig. 5c,f, and Ⓔ Fig. S5c; Table 1). In the Permian Basin, most of the increase in SWD between 2009 and 2016 occurred in the shallow zone above oil-producing intervals (factor of 4.3 increase in volume) relative to the deep zone below oil-producing intervals (factor of 2.0 increase) (Fig. 4). PW injection in the Midland and Delaware Basins within the Permian Basin is mostly shallower than the oil-producing intervals, as shown by the contrast in SWD well depths (median ~5000 ft [1.5 km] for both basins) relative to HF well depths (corresponding to the oil reservoir, 8600–10,300 ft [2.6–3.1 km]; Fig. 6a). The percentage of SWD wells associated with earthquakes in the Permian Basin is slightly elevated in the shallow zone (~15,000 ft [4.6 km] from basement; Fig. 5f), consistent with the large increase in injection through SWD wells into this zone. Disposal of PW in the Bakken and Eagle Ford plays is also much shallower than the oil-producing intervals (median SWD well depths ~5600 ft [1.7 km] for both plays relative to HF well depths, oil reservoir, ~10,000 ft [3 km] in both plays) (Table 1; Fig. 6a). These reservoirs are also much shallower than the crystalline basement (Ⓔ Fig. S5).

Maximum monthly injection rates alone cannot explain the differences in seismicity among the plays (Fig. 6b). Although Oklahoma has similar numbers of wells injecting at high rates to the other plays (Oklahoma = 85%–100% at 95th percentile), the state has many more wells injecting at lower rates, as evidenced by the median maximum monthly injection rate being ~15% of the median maximum rates in the other plays. Lower seismicity in the other plays relative to Oklahoma may be partially attributed to the lower regional-scale cumulative PW injection volumes in the Permian and much lower volumes in the Bakken and Eagle Ford plays relative to volumes in Oklahoma (2009–2016, Fig. 3).

In summary, the much lower levels of seismicity in the other plays relative to Oklahoma may be related to shallower disposal far from basement and to lower regional-scale cumulative injection volumes.

Table 1
Comparison between Horizontal Hydraulic Fracturing (HF) Well Depths, Saltwater Disposal (SWD) Well Depths, and Crystalline Basement Rock Depths at the SWD Well Locations in the Different Plays

				Permian		
Value (ft)	**Statistic**	**Bakken**	**Eagle Ford**	**Delaware**	**Midland**	**Oklahoma**
HF well depth	Range	8,500–11,500	6,500–13,000	6,000–12,000	6,000–10,000	4,000–8,000
	Median	10,500	10,000	10,000	8,500	5,400
SWD well depth	Range	5,000–7,000	1,500–10,000	2,500–8,500	2,000–13,000	1,500–9,000
	Median	5,600	5,600	5,300	4,600	6,400
Basement depth	Range	12,400–15,200		14,000–21000	8,200–13,600	4,000–9,800
	Median	14,300		20,000	11,300	6,000

Managing Produced Water to Reduce Induced Seismicity

Large volumes of PW in many plays indicate that managing PW is a critical issue. We can learn from the experiences in Oklahoma related to mitigating seismicity, and we can explore various options for reducing future seismicity in different plays.

Mitigating Induced Seismicity in Oklahoma

The OCC, the regulatory body responsible for permitting disposal wells, took direct action to mitigate induced seismicity in Oklahoma in early 2016. The OCC issued the following directives related to PW management to reduce seismicity in the AOI where intense earthquakes were recorded in central/north-central Oklahoma (see Data and Resources):

1. reduction in maximum PW injection (SWD disposal) rate at the well level to ≤ 10,000–15,000 bbl/day per well;
2. reduction in regional-scale injection by 40% from the 2014 total injection; and
3. application of directives to wells completed in the Arbuckle Group adjacent to the basement, impacting ~700 Arbuckle wells.

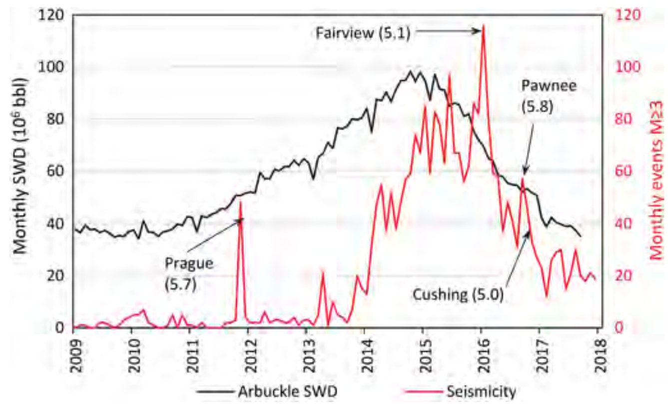
In addition, the OCC (2014–present) requested that operators plug back SWD wells completed in the basement. These directives are consistent with the findings from this analysis related to the importance of PW injection rate with large increases in seismicity rates at injection rates ≥ 10,000 bbl/day (300,000 bbl/mo; Fig. 5a), cumulative injection volume (Fig. 5b), and proximity to basement (Fig. 5c). These directives consider both local (well level) and regional (AOI) impacts of injection on seismicity. Changes in SWD disposal were phased in over several months to avoid rapid pressure changes and potential additional earthquakes (Segall and Lu, 2015).

Seismicity has markedly decreased in response to the reduction in PW injection in SWD wells. The annual number of earthquakes $M \geq 3.0$ decreased by 67% from the peak in 2015 (901 earthquakes) to 2017 (298 earthquakes) in the AOI (Fig. 7; Ⓔ Table S1). The peak month was in January 2016 with 116 earthquakes $M \geq 3.0$. The marked decline in seismicity is consistent with the forecasted seismicity rate from decreased stresses computed using a rate-and-state modeling approach that was originally developed for natural seismicity (Norbeck and Rubinstein, 2018).

Reducing Potential Future Induced Seismicity

A variety of approaches can be used to reduce potential induced seismicity associated with PW in the future. Historical data from plays in the United States suggest that shallow disposal may help reduce seismicity; however, the trade-offs between shallow versus deep disposal should be considered. Reducing subsurface disposal by managing PW in different ways should also reduce potential induced seismicity.

Shallow versus Deep Disposal. The strong linkage between induced seismicity and PW injection into the Arbuckle Group adjacent to the basement in Oklahoma suggests that injecting into shallower zones that are hydraulically isolated from the crystalline basement faults should reduce the likelihood of seismicity. About 60% of PW in Oklahoma is injected into the Arbuckle Group, with the remaining ~40% into shallower intervals. However, the Arbuckle Group is up to 2000 ft (600 m) thick, subdivided into three main zones: high-permeability upper Arbuckle (27% of thickness), low-permeability middle Arbuckle (41% of thickness), and high-permeability lower Arbuckle (32% of thickness) (Carrell, 2014; Morgan and Murray, 2015). We cannot dispose into low-permeability zones because of low injectivity; however, disposing into shallower intervals in the Arbuckle Group might reduce seismicity if they are hydraulically disconnected from the basement.



▲ **Figure 7.** Comparison between monthly SWD rates and the monthly number of seismic events with $M \geq 3.0$ in the Oklahoma area of interest. The timings of seismic events with $M \geq 5.0$ are indicated. The color version of this figure is available only in the electronic edition.

PW injection in the Bakken, Eagle Ford, and Permian Basin has been primarily into zones stratigraphically far from basement, mostly above the oil-producing intervals (Figs. 4 and 5f, Ⓔ Fig. S5c; Table 1). While stratigraphically far from basement, earthquakes can occur in shallow intervals because hypocenters for some earthquakes in the Permian Basin are located in the sediments rather than in the basement, even considering the general ±2 km uncertainty in hypocentral depths in this region (see Data and Resources; A. Savaidis, personal comm., 2018).

The trade-offs between shallow versus deep PW injection need to be considered (Table 2). Shallow disposal wells have been favored in many plays because of low cost, whereas deep disposal wells, extending below oil reservoirs, may cost 2–3 times more. Disposal of PW into shallow intervals has a higher likelihood of impacting overlying aquifers. Overpressuring caused by disposal can result in upward migration of PW through faults or fractures or through abandoned oil wells that have not been properly plugged. There were over half a million oil wells drilled in the Permian Basin within the past century, with many abandoned or orphaned wells that could provide pathways for overpressured fluids, that is, pressures exceeding hydrostatic pressure. Airborne electromagnetic surveys have

Table 2
Trade-Offs between Shallow versus Deep SWD

Shallow Disposal	Deep Disposal
Low cost	High cost
Could impact overlying aquifer	Little or no impact on aquifers
Impact oil well drilling (overpressuring, extra casing)	Little or no direct impact on oil well drilling
Can impact oil production	Little direct impact on oil production
Less seismicity	More seismicity
	Underpressured, high injectivity
Inexpensive, drill many wells	Expensive, few wells, high rates

been used to link salinity to leaking wells in west Texas (Paine *et al.*, 1999). Potential contamination is exacerbated in the Permian Basin because of thick halite and anhydrite deposits (up to 4000 ft [1200 m] thick; Castile, Salado, and Rustler formations) that can result in highly saline fluids corroding well casings. Surface subsidence can also result from dissolution of these salts (Paine *et al.*, 2012). Aquifer impacts from PW injection in the Bakken play are likely lower because the primary disposal reservoir, the Dakota formation (~5600 ft [1.7 km] deep), is much deeper than the Fox Creek confined aquifer or the shallow alluvial aquifers in this region (Scanlon *et al.*, 2016; Table 1). Rising interest in deep, brackish, groundwater resources in Texas increases concerns about shallow SWD, with zones containing SWD wells excluded from consideration (Young *et al.*, 2016).

Shallow disposal of PW can also affect oil production because wells have to penetrate disposal intervals. Shallow disposal in the Permian Basin created health and safety concerns related to drilling through overpressured zones, requiring additional casing in some regions (see the Ⓔ Shallow versus Deep Disposal section).

Although disposal into deep intervals adjacent to basement has been linked to seismicity in Oklahoma, there are some advantages to disposing into these deep units (Table 2). Deep disposal should not impact oil production directly because the units are generally below the oil-producing intervals. Potential impacts on overlying aquifers should be greatly reduced because of the depth of these units. The Arbuckle in Oklahoma and corresponding Ellenburger in the Permian Basin are both underpressured, that is, having pressures less than hydrostatic pressure (Nelson *et al.*, 2015). Therefore, injection into these units can largely be conducted under gravity without pumping water into the subsurface. Both units are potentially karstified, as seen in surface exposures of the Arbuckle Group in the Arbuckle Mountains of south-central Oklahoma; however, the extent of fracturing, secondary porosity, and karstification is unknown because of the depths of the rock below the land surface and limited geologic characterization of the disposal zone.

Reusing Produced Water for Hydraulic Fracturing. An alternative approach to managing the net fluid balance is to reuse PW to hydraulically fracture new producing wells. PW reuse would accomplish a number of goals, including reducing PW disposal and also reducing water demand for HF from other water sources. The potential for this approach to work depends in part on the ability to match PW supplies with HF water demand both spatially and temporally. Comparison of cumulative water volumes (2009–2016) indicates that PW supplies, estimated from SWD volumes, are about nine times HF water demand in Oklahoma (Fig. 3); therefore, even if all of the HF water were sourced with PW reuse, 90% of the PW would still need to be managed. There is also a spatial disconnect because PW supplies in north-central Oklahoma (e.g., Woods and Alfalfa counties) are not collocated with the large HF water demands in central Oklahoma (e.g., Blaine County in the Sooner Trend Anadarko Canadian Kingfisher [STACK] play). Despite these issues, a current study is investigating the potential for developing a pipeline system to transfer minimally treated PW, referred to as a clean brine (~220,000 mg/L total dissolved solids [TDS]), from Alfalfa County in the north to the HF demand center in Blaine County, ~35 miles (56 km) to the south (Dunkel, 2017). Too little PW relative to HF water demand can also be an issue. For example, historical PW in the Eagle Ford represents ~50% of HF water demand (Figs. 1 and 3). Previous efforts to reuse PW in this play encountered logistical issues with trying to capture sufficient PW to support HF. PW supply versus HF water demand issues would need to be resolved at a much more granular spatial and temporal scale than at the play level to assess feasibility of reuse.

Cumulative PW volumes match HF water demands better in the Bakken and Permian Basin plays (Fig. 3). Although the quality of some of the PW in the Bakken is extremely saline, greater than 10 times that of seawater, studies suggest that advances in HF fluid chemistry can accommodate such saline water with minimal treatment (McMahon *et al.*, 2015). The ratio of cumulative PW from unconventional wells to HF water demand in the Permian is ~2.0 (2009–2016; Fig. 3). PW (12-month cumulative) to HF ratios are ~3 times higher in the Delaware Basin than in the Midland Basin (2015; Scanlon *et al.*, 2017). Therefore, even if all the HF water were sourced from PW in the Delaware Basin, there would still be a large excess of PW to manage. Additional approaches will need to be considered to manage this PW, such as treatment for use in other sectors (e.g., irrigation or municipal use) or evaporation ponds.

DISCUSSION

This study focuses on quantifying the net fluid balance in the major tight-oil plays and dewatering reservoirs in the United States because of the impacts on subsurface pressures and potential induced seismicity. The data from conventional reservoirs provide context for more recent unconventional reservoir development. The emphasis on conventional oil development and subsequent reinjection of PW into producing intervals throughout the latter half of the twentieth century can explain the relatively low levels of seismicity associated with this development. This net fluid balance is achieved by matching oil and PW extraction with injection using EORI and SWD wells into oil-producing intervals. Pressure maintenance and EOR are key goals for conventional reservoir operations.

The updated analysis of linkages between PW injection and induced seismicity for Oklahoma shows that not only PW injection rate but also cumulative injection volume and proximity to crystalline basement all contribute to induced seismicity in this region. Statistically significant associations between active Oklahoma SWD wells and nearby earthquakes (within 15 km) were found for maximum injection rates exceeding ~300,000 bbl/mo, cumulative disposal volumes $\sim \geq 1$ million bbl/well, and in wells operating within ~1000 ft [300 m] of crystalline basement. Seismicity in the Bakken, Eagle Ford, and Permian Basin plays is much less than that in Oklahoma but has been increasing in the Delaware Basin within the Permian Basin. At present, relationships between SWD well operations and seismicity in the Bakken, Eagle Ford, and Permian Basin plays fell within the bounds for statistically random association. However, these relationships can change through time. Much lower seismicity in the other plays may be attributed to much shallower injection stratigraphically far from the basement and lower cumulative PW injection volumes through SWD wells (10%–60% of volumes in Oklahoma, 2009–2016; Figs. 1 and 3; Table 1).

Our original goal was to determine what lessons we could learn from injection and seismicity in Oklahoma and how we might apply those lessons to the other plays to reduce the potential for induced seismicity. The obvious lesson from the Oklahoma data is that induced seismicity can be mitigated by reducing injection rates and regional injection volumes in wells operating near the basement. Injection into shallow zones far from the basement is a potential mitigation strategy. However, this has been occurring in the other plays with some drawbacks. Some of the negative factors include impacts on oil-well drilling and production complications from shallow zone overpressuring and the potential to affect overlying aquifers. Reducing injection rates has had a positive effect on managing induced seismicity in Oklahoma, but it is important to note that there is a time lag in seismicity response to reductions in injection, with some of the largest-magnitude earthquakes occurring in 2016 after the reduction in PW injection (Fig. 7).

Maintaining a balance between extraction and injection in unconventional reservoirs can be partially achieved by reusing PW for HF in these reservoirs. This approach may be most effective where the PW volumes generally match HF water demands. The large mismatch in Oklahoma, with a factor of 9:1 ratio between SWD and HF, limits the value of PW reuse in this region (Fig. 3). However, the volumes are more closely matched in the Bakken play and the Midland Basin within the Permian Basin, suggesting greater potential in these regions. However, the trade-offs associated with potentially increased risks of contamination during storage and transport of PW (e.g., TDS in the 100,000–200,000 mg/L range in the Permian Basin and 250,000–500,000 range in the Bakken play; Scanlon *et al.*, 2016) need to be considered.

Implications for Regulators and Policy Makers

Although the EPA has authority over the Underground Injection Control (UIC) program (SWD and EORI wells) under the Safe Drinking Water Act, the authority has been delegated to the states in most cases. The state agencies grant permits for SWD and EORI wells. A number of reports have been developed to provide guidance to UIC regulators for evaluating, managing, and minimizing injection-induced seismicity (U.S. EIA, 2014; GWPC, 2017).

The directives issued by the OCC in early 2016 are consistent with the findings from this analysis in terms of injection rates, regional cumulative injection volumes, and proximity to basement. Although permits are generally granted for individual SWD wells, the importance of net fluid budgets at local to regional scales suggests that the regulators should consider individual well permits within a larger context of the net fluid balance, as is done in Oklahoma. No new SWD permits are being granted in Oklahoma for wells in the Arbuckle Group adjacent to the basement. In addition, permits for shallow (Delaware Mountain Group) or deep (Ellenburger Group) disposal in New Mexico are restricted to individual operators, rather than for commercial wells, to reduce potential seismicity. Although EORI wells in conventional reservoirs are managed as a system, groups of SWD wells in unconventional reservoirs may benefit from larger-scale management, similar to current practices in Oklahoma.

CONCLUSIONS

The rapid increase in unconventional oil production is associated with an increase in coproduced water that cannot be reinjected into the low-permeability tight-oil reservoirs. This PW is managed primarily by subsurface injection into nonproducing geologic intervals through SWD wells. Reanalysis of Oklahoma data with an additional 3.5 yrs of data and a newly developed basement map (Crain *et al.*, 2018) reveals that induced seismicity is not only linked to PW injection rates but is also related to cumulative injection volume and proximity to basement. Quantifying the water budgets of the main tight-oil plays in the United States indicates that the major difference between Oklahoma, with intensive induced seismicity, and the other plays (Bakken, Eagle Ford, and Permian Basin) is disposal depths, with shallow disposal above oil-producing reservoirs in most plays relative to deep disposal near the basement in Oklahoma. There are problems with shallow disposal also, including overpressuring affecting oil well drilling and potential contamination of overlying aquifers, particularly in the Permian Basin. A variety of management strategies will need to be considered, including reuse of PW, to support increasing demand for HF as an alternative approach to subsurface disposal. This analysis provides a comprehensive assessment of PW issues related to tight-oil production that can be used to guide future seismic monitoring and feed into regulatory and decision-making processes.

DATA AND RESOURCES

Data on oil, gas, and water production were compiled from the IHS Enerdeq database for the Bakken, Eagle Ford, Permian Basin, and Oklahoma. The IHS data are ultimately derived from data reported by operators to the various states and can be accessed from the state websites on a well-by-well basis. Water volumes used for hydraulic fracturing (HF) were also obtained from the IHS Enerdeq database, as were well-completion data, including well depth and the length of horizontals. IHS increasingly obtains data on HF water volumes from the publicly accessible FracFocus database (https://fracfocus.org, last accessed July 2018) operated by the Groundwater Protection Council. Data on produced water (PW) management, including saltwater disposal (SWD) and enhanced oil recovery injection (EORI) volumes, were compiled from the IHS database. Well types (SWD vs. EORI) were determined from the Texas Railroad Commission Underground Injection Control (UIC) database, the New Mexico Oil Conservation Division, the North Dakota Industrial Commission, and the Montana UIC database. Data on earthquakes were obtained from the U.S. Geological Survey (USGS) Advanced National Seismic System (ANSS) Comprehensive Catalog (ComCat, https://earthquake.usgs.gov/earthquakes/search/, last accessed February 2018). The stratigraphy in the Permian Basin is based on analysis of formation tops derived from Geologic Data Systems (GDS) logs by the Bureau of Economic Geology. The depth to basement surface map was estimated from the same source based on 3075 data points using ordinary Kriging methods in ArcGIS. The depth to basement in Oklahoma is based on the map provided in Crain and Chang (2018). Data on depth to basement in the North Dakota area of the Bakken play was provided by the North Dakota Industrial Commission (NDIC) for about 70 wells. In the Montana area of the Bakken play, basement depth was estimated using a contour map published by the Montana Bureau of Mines and Geology (Bergantino and Clark, 1985). There are no data on basement depths in the Eagle Ford play; however, basement is extremely deep in this region. The other relevant data can be found at www.occeweb.com (last accessed July 2018, Hot Topics) and http://www.beg.utexas.edu/texnet (last accessed July 2018).

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CASES NO. 20313, 20314, 20472, 20463 and 20465
Division Exhibit No. 10

PHILLIP R. GOETZE

Oil Conservation Division
Energy, Minerals and Natural Resources Department, State of New Mexico

Over 40 years of experience developing and implementing a variety of projects with environmental, hydrologic, or regulatory applications.

PROFESSIONAL EXPERIENCES:
February 2013 to Present: Senior Petroleum Geologist / Hearing Examiner / Geohydrologist
Engineering Bureau, Oil Conservation Division, Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive, Santa Fe, NM 87505

Administrative permitting for development and management of oil and gas resources under the state Oil and Gas Act. These projects include technical review of administrative applications and preparation of orders for non-standard locations, pool delineations, and non-standard proration units. Lead technical reviewer of applications for Class II wells (including salt water disposal wells and enhanced oil recovery (EOR) projects) under the New Mexico primacy agreement with the United States Environmental Protection Agency (USEPA) for its Underground Injection Control (UIC) Program under the Safe Drinking Water Act. Hearing examiner for Division hearings for cases regarding both protested and unprotested applications for approval of non-standard oil and gas circumstances that cannot be administratively permitted. Additional assignments related to the position:

- Provide technical assistance to District personnel and General Counsel staff regarding compliance issues for disposal and EOR wells.
- Development of protocols and recommended guidance for UIC related subjects such as induced seismicity, exempted aquifers and Class II disposal impacts on producing intervals.
- Prepare quarterly reports for review by the UIC coordinator for submission to the USEPA.
- Recommend changes in policy reflecting application of new technology or processes (e.g. injection rules per 19.15.26 NMAC).
- Provided expert testimony before the Oil Conservation Commission for applications and in support of rulemaking (e.g. acid gas injection well applications, casing requirements in the Roswell Artesian Basin, and reporting requirements for fracturing fluids).
- Provided expert testimony before the New Mexico Water Quality Control Commission (NMWQCC) in support of rulemaking (e.g. expanded authority for UIC Class I hazardous disposal wells).

Appointed as hearing examiner by the Division Director under 19.15.4.18 NMAC. Assist Santa Fe and District personnel with the Division's Loss Control Program.

March 2007 to February 2013: Hydrogeologist / Environmental Scientist / Project Manager
Gloreita Geoscience, Incorporated
1723 Second Street, Santa Fe, NM 87505

Multiple projects for environmental, hydrologic, and natural resource assessments including:

- Los Alamos National Laboratory (LANL): contract team leader for ground-water sampling (including springs, shallow wells, monitoring wells with Baski and Westbay systems) in support of the Ground Water Stewardship Program; four years of sediment mapping and soil sampling for contaminants as part of the LANL assessment of geomorphic influences following the Cerro Grande and Las Conchas fires; geodetic surveying (with Trimble RTK GPS and Geodimeter total station units) and waste characterization sampling following LANL and New Mexico Environment Department (NMED) protocols.
- Oversight of drilling, logging, and construction of deep exploration wells as part of Rio Rancho's City Water Program and the NM Office of the State Engineer (Ft. Sumner project).

- Hydrologic modeling and ground-water abatement plan development for multiple dairy facilities in southern and eastern New Mexico.
- Numerous Phase I Environmental Site Assessments (ESAs) for commercial, industrial, and undeveloped properties in northern New Mexico, Nevada, and Texas.
- Establish protocols, sampling requirements, and compile data for annual reporting for clients with Closure and Post Closure plans for landfills.
- Oversight of petroleum storage tank removals, closures, and Minimum Site Investigations following closure.
- Preparation and annual reporting of NPDES permits for commercial clients in New Mexico.
- Preparation and implementation of Stage I Abatement Plans for dairies in violation of the NMWQCC ground-water standards.
- Quality assurance for ground-water modeling and various sampling programs including mandatory monitoring and special client-specific events.

April 2006 to January 2007: Hydrogeologist / Project Manager
Tetra Tech EM Incorporated
6121 Indian School Road NE, Suite 205, Albuquerque, NM 87110

This position included responsibility for redevelopment of previous client relationships while maintaining obligations to state, Federal and private projects. Most significant projects include the following:

- Supervising geologist for drilling, construction, and development of deep monitoring wells at Kirtland Air Force Base for Long-Term Monitoring Program.
- Preparation of sampling and analysis plans for Texas Department of Criminal Justice landfills.

September 1999 to March 2006: Hydrogeologist / Project Manager
ASCG Incorporated *of New Mexico* (now the WH Pacific Corporation)
6501 Americas Parkway NE, Suite 400, Albuquerque, NM 87110

Responsible for a variety of environmental services for site assessment and remediation of contaminated sites associated with Federal, state, and private clients in New Mexico, Arizona, and the Navajo Nation. Significant projects entail the following:

- Field Technical Leader (as subcontractor) for drilling, construction, and development of deep and shallow monitoring wells at LANL for 2005.
- Developed and supervised assessment drilling programs for Risk-Based Corrective Action assessments of petroleum-contaminated NMED and Bureau of Indian Affairs (BIA) sites in New Mexico and Arizona.
- Responsible for project development and management of soil and ground-water remediation of hydrocarbon and solvent-contaminated sites including quarterly water sampling events and air monitoring for compliance.
- Supervised and participated in resolution of correction actions identified under USEPA CA/CO 1998-02 at approximately 35 Bureau of Indian Affairs federal facilities including review of asbestos programs, PCB investigations and remediations, Phase I ESAs for property transfer, AST/UST removals, hazardous waste disposal activities, environmental audits, and validation sampling of previous remedial activities.
- Completed development and oversight of voluntary corrective actions of hazardous wastes cited in notice of violations at the Southwestern Polytechnic Indian Institute.
- Provided sampling program for the AMAFCA Storm Water Study for assistance in compliance of the MS4 for the City of Albuquerque.
- Completed assessment for hydrocarbon contamination and prepared plans for remedial actions for five locations at BIA facilities during the last quarter of 2004.

Phillip R. Goetze

July 1996 to August 1999: Geologist / Environmental Scientist; General Contractor
Phillip R. Goetze, Consulting Geologist, Edgewood, New Mexico

Subcontractor for environmental firms providing on-site technical support and report preparation. Primary contractors included the following:

Billings and Associates, Inc., Albuquerque, New Mexico
Responsible for acquisition of both soil and water data for assessment and for installation of remediation systems for hydrocarbon-contaminated sites.

Roy F. Weston Inc., Albuquerque, New Mexico
Temporary position with responsibilities for on-site supervisor for data acquisition (three drilling rigs), for health and safety monitoring, and for quality assurance of installation of multiple ground-water wells at a Department of Energy tailings remediation (UMTRA) site near Tuba City, Arizona.

January 1993 to July 1996: Project Geologist / Project Manager
Billings and Associates, Inc.
6808 Academy Pkwy, E-NE, Suite A-4, Albuquerque, NM 87109

Responsible for acquisition of air, soil, and water data for site assessments related to leaking underground storage tanks throughout New Mexico. Participated and supervised installation, operation, and maintenance of biosparging/SVE remediation systems at five New Mexico locations. Site assessment activities included preparation of health and safety plans, drilling supervision, water and soil sampling preparation, chain-of-custody maintenance, analytical data review and compilation, and report preparation.

June 1985 to December 1992: Independent Geologist and Environmental Scientist
Phillip R. Goetze, Consulting Geologist, Albuquerque, New Mexico

Subcontracting services for data acquisition in geophysics and mineral exploration. Primary contractors included:

Charles B. Reynolds and Associates, Albuquerque, New Mexico
Performed functions of seismologist and crew chief for consulting group specializing in shallow seismic geophysics for environmental and engineering applications. Projects included USGS hydrologic assessment of Mesilla Bolson; plume and paleosurface mapping at Johnson Space Center facility north of Las Cruces; plume and paleosurface mapping in Mortandad Canyon and TA-22 site, LANL; plume and paleosurface mapping at Western Pipeline facility at Thoreau, NM; plume and paleosurface mapping at UNC Partners mill and tailings site north of Milan; engineering assessment of collapsible soils at Tanoan residential development and along the east edge of Albuquerque.

Glorieta Geoscience, Inc., Santa Fe, New Mexico
Initiated and conducted sampling program for assessing economic potential of low-grade gold occurrence in southwest New Mexico.

November 1983 to September 1984: Fluid Minerals Geologist
Bureau of Land Management, Department of Interior, Cheyenne, Wyoming

Temporary detail to Casper office to alleviate backlog of assessments of federal oil and gas leases in Wyoming and Nebraska. Assessments required geologic evaluation of oil and gas potential for lands in Powder River, Wind River, Big Horn and Denver-Julesburg Basins. Determination of “known geologic structures (KGSs)” per Secretarial Order for categorizing of federal oil and gas minerals into competitive and non-competitive status. Deposed as expert witness and provide expert summaries and affidavits for cases before the Interior Board of Land Appeals (example: Case No. IBLA 84-798 for protest of KGS delineation).

June 1982 to September 1983: Field Geologist
United States Bureau of Mines, Department of Interior, Lakewood, Colorado

Assisted primary authors with field inventory and evaluation of mineral occurrences in 15 wilderness areas in Colorado (Central Mineralized Region), southern Wyoming, and eastern Utah. Field work included field mapping and sampling of abandoned mines and mineral occurrences within these areas and adjacent areas with potential impacts on wilderness designation.

July 1979 to January 1982: Geologist
United States Geological Survey, Department of Interior, Casper, Wyoming and Lakewood, Colorado

First two years exclusively mapping, drilling, and classifying coal resources in south central Wyoming. Detailed for two years to special team for preparation of impact statement: one of four principle authors for the Cache Creek-Bear Thrust Environmental Impact Statement which documented effects of two proposed oil and gas wells in designated wilderness area near Jackson, Wyoming. Deposed as expert witness in federal court. Final year primarily responsible for assessments of federal oil and gas leases for lands in Wyoming and Nebraska.

July 1977 to July 1979: District Geologist
Bureau of Land Management, Department of Interior, Socorro District Office, Socorro, New Mexico

Responsible for District minerals program for federal lands in west central portion of state. Assisted in environmental reports for land exchanges, classification of saleable mineral sites, mining claim validity determinations, inspection of surface reclamation for mineral extractions, inspection of oil exploration and geothermal gradient wells, and assessments for location of water wells in support of grazing projects.

EDUCATION:
New Mexico Institute of Mining and Technology, Socorro, New Mexico
Bachelor of Science in Geology, 1977

Additional Courses: EPA course requirements for Asbestos Inspector (10 years as active inspector); completion of state program for Licensed Contractor (NM; GS-29); EPA course requirements for Lead-Based Paint Risk Assessor (EPA Regions VI and IX; two years as active inspector); GSI Course *Application of Ground Penetrating Radar*; NGWA Course *Monitoring Natural Attenuation of Contaminants*.

PROFESSIONAL MEMBERSHIPS, LICENSES, OR CERTIFICATIONS:
American Association of Petroleum Geologists, Member No. 51,310
American Institute of Professional Geologist, Certified Professional Geologist No. 6,657
Alliance of Hazardous Materials Professionals, CHMM No. 11,401
ASTM International, Member No. 1,314,118 (Voting Member); Committees D18 (Soil and Rock) and E50 (Environmental Assessment, Risk Management and Corrective Action)
OSHA 40HR and 8HR Refresher Hazardous Waste Operations and Emergency Response (Current)
OSHA Hazardous Waste Operations and Emergency Response Manager/Supervisor (Current)
State of Alaska, Licensed Professional Geologist No. 514
State of Arizona, Registered Professional Geologist No. 40,812
State of Nevada, Certified Environmental Manager No. 2,218
State of Texas, Licensed Professional Geologist No. 2,278