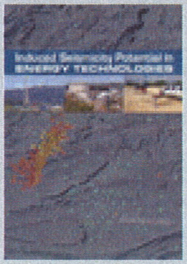

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Preface

Since the 1920s we have recognized that pumping fluids into or out of the Earth has the potential to cause seismic events that can be felt. Seismic events in Basel, Switzerland, between 2006 and 2008 were felt by local residents and were related to geothermal energy development. Strings of small seismic events in Arkansas, Ohio, Oklahoma, and Texas in the past several years have been related to wastewater disposal associated with oil and gas production. These seismic events have brought the issue of induced (human-caused) seismicity firmly into public view.

Ensuring a reliable twenty-first-century energy supply for the United States presents seminal economic, environmental, and social challenges. A variety of conventional and unconventional energy technologies are being developed to meet these challenges, including new technologies associated with shale gas production and geothermal energy. Energy technologies may also produce wastes. "Wastewater" is often produced during oil and gas drilling and is generally managed either by disposal through pumping the fluids back into the subsurface or by storage, treatment, or reuse. Carbon dioxide may also be generated as a by-product of energy production and may be captured and similarly pumped into the ground for storage.

Anticipating public concern about the potential for induced seismicity related to energy development, Senator Bingaman requested that the Department of Energy conduct a study of this issue through the National Research Council. The study was designed to examine the scale, scope, and consequences of seismicity induced during the injection of fluids related to energy production; to identify gaps in knowledge and research needed to advance the understanding of induced seismicity; to identify gaps in induced seismic hazard assessment methodologies and the research needed to close those gaps; and to assess options for interim steps toward best practices with regard to energy development and induced seismicity potential.

The committee (Appendix A) investigated the history and potential for induced seismicity associated with geothermal energy development; with oil and gas production, including enhanced oil recovery and shale gas; and with carbon capture and storage (CCS). The committee examined peer-reviewed literature, documents produced by federal and state agencies, online databases and resources, and information requested from and submitted by external sources. The committee heard from government and industry representatives; from members of the public familiar with the world's largest geothermal operation at The Geysers, California, at a public meeting in Berkeley, California; and from people familiar with shale gas development, enhanced oil recovery, wastewater disposal, and CCS at meetings in

Dallas, Texas, and Irvine, California (Appendix B). Meetings were also held in Washington, D.C., and Denver, Colorado, to explore induced seismicity in theory and in practice.

During the meeting in Northern California, the committee was able to talk with individuals from Anderson Springs and Cobb, California, who live with induced seismicity continuously generated by geothermal energy production. Understanding their concerns and the history of how they have worked with individuals from both industry and local government, together with technical experts from the federal government, to deal with their very tangible issue of induced seismicity brought immediacy to the committee's deliberations. This knowledge was invaluable as the committee explored the concept of a protocol system for responding to induced seismicity with some of the individuals who helped devise the proposed protocol system for induced seismicity caused by or likely related to enhanced geothermal energy development.

This study took place during a period in which a number of small, felt seismic events occurred that had been caused by or were likely related to fluid injection for energy development. Because of their recent occurrence, peer-reviewed publications about most of these events were generally not available. However, knowing that these events and information about them would be anticipated in this report, the committee attempted to identify and seek information from as many sources as possible to gain a sense of the common factual points involved in each instance, as well as the remaining, unanswered questions about these cases. Through this process, the committee has engaged scientists and engineers from academia, industry, and government because each has credible and viable information to add to better understanding of induced seismicity.

This report describes what we know about the potential for induced seismicity related to energy development. It highlights areas where our knowledge is weak and discusses inherent difficulties in dealing with an issue that does not have a well-defined regulatory "home." The committee hopes this report will inform both the public and the decision-making process with respect to an important issue that will undoubtedly become more widely recognized as additional induced seismic events occur.

As chair, I would like to thank the committee members for their dedication and hard work. The committee commends Dr. Elizabeth Eide, the project study director, for helping to make this an exciting learning experience for us all. The committee also benefited from the dedication and excellence of research associate Jason Ortego and program associate Courtney Gibbs.

Murray W. Hitzman, *Chair*
June 2012

Acknowledgments

In addition to its own expertise, the study committee relied on input from numerous external professionals and members of the public with extensive experience in addressing the range of issues related to induced seismicity. These individuals were very generous in sharing their research knowledge from the laboratory and the field, their direct experiences from industry settings and with energy development in the private sector and in government, and their personal experiences in dealing with induced seismic events. We gratefully acknowledge their contributions to help us with this work. In particular, the committee would like to thank the following people: Scott Ausbrooks, Joe Beall, Lisa Block, Jay Braitsch, Mike Bruno, Linda Christian, David Coleman, Tim Conant, Kevin Cunningham, Mark Dellinger, Philip Dellinger, Nancy Dorsey, Ola Eiken, Leo Eisner, Bill Ellsworth, Cheryl Engels, Rob Finley, Cliff Frohlich, Julio Garcia, Domenico Giardini, Jeffrey Gospe, George Guthrie, Craig Hartline, Werner Heigl, Hamilton Hess, Austin Holland, Steve Horton, Ernst Huenges, John Jeffers, Doug Johnson, Don Juckett, Bill Leith, Ernie Majer, Shawn Maxwell, Steve Melzer, Meriel Medrano, Alexander Nagelhout, Jay Nathwani, David Oppenheimer, Susan Petty, Bruce Presgrave, Philip Ringrose, Jim Rutledge, Jean Savy, Alexander Schriener, Serge Shapiro, Karl Urbank, Mark Walters, Charlene Wardlow, Norm Warpinski, Stefan Wiemer, Colin Williams, Melinda Wright, Bob Young, and Mark Zoback.

The helpful assistance we received with regard to planning and executing the field trip and workshop for the committee's meeting in Northern California was also very important. We recognize the contributions from Calpine, the Northern California Power Agency, the Lawrence Berkeley National Laboratory, and the communities of Anderson Springs and Cobb, California, for their excellent cooperation and efforts to provide us with access to necessary information and localities that greatly informed the committee's work.

The committee gratefully acknowledges the support of three standing committees under the Board on Earth Sciences and Resources for their guidance and oversight during the study process: the Committee on Earth Resources, the Committee on Geological and Geotechnical Engineering, and the Committee on Seismology and Geodynamics (Appendix M). This report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise, in accordance with procedures approved by the National Research Council's (NRC's) Report Review Committee. The purpose of this independent review is to provide candid and critical comments that will assist the institution in making its published report as sound as possible and to ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The

review comments and draft manuscript remain confidential to protect the integrity of the deliberative process. We wish to thank the following individuals for their participation in the review of this report:

Jon Ake, Nuclear Regulatory Commission, Rockville, Maryland
Dan Arthur, ALL Consulting, Tulsa, Oklahoma
John Bredehoeft, The Hydrodynamics Group, Sausalito, California
Brian Clark, Schlumberger Companies, Sugar Land, Texas
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Shawn Maxwell, Schlumberger Canada, Calgary
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Ed Przybylowicz, Eastman Kodak Company (retired), Webster, New York
Carlos Santamarina, Georgia Institute of Technology, Atlanta, Georgia
Mark Zoback, Stanford University, Stanford, California

Although the reviewers listed above provided many constructive comments and suggestions, they were not asked to endorse the conclusions or recommendations nor did they see the final draft of the report before its release. The review of this report was overseen by William L. Fisher, The University of Texas at Austin, and R. Stephen Berry, the University of Chicago, Illinois. Appointed by the NRC, they were responsible for making certain that an independent examination of this report was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of this report rests entirely with the authoring committee and the institution.

Contents

APPENDIXES

Executive Summary

Earthquakes attributable to human activities are called induced seismic events or induced earthquakes. In the past several years induced seismic events related to energy development projects have drawn heightened public attention. Although only a very small fraction of injection and extraction activities at hundreds of thousands of energy development sites in the United States have induced seismicity at levels that are noticeable to the public, seismic events caused by or likely related to energy development have been measured and felt in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas.

Anticipating public concern about the potential for energy development projects to induce seismicity, the U.S. Congress directed the U.S. Department of Energy to request that the National Research Council examine the scale, scope, and consequences of seismicity induced during fluid injection and withdrawal activities related to geothermal energy development, oil and gas development including shale gas recovery, and carbon capture and storage (CCS). The study was also to identify gaps in knowledge and research needed to advance the understanding of induced seismicity; identify gaps in induced seismic hazard assessment methodologies and the research to close those gaps; and assess options for steps toward best practices with regard to energy development and induced seismicity potential.

Three major findings emerged from the study:

1. The process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events.
2. Injection for disposal of wastewater derived from energy technologies into the subsurface does pose some risk for induced seismicity, but very few events have been documented over the past several decades relative to the large number of disposal wells in operation.
3. CCS, due to the large net volumes of injected fluids, may have potential for inducing larger seismic events.

Induced seismicity associated with fluid injection or withdrawal is caused in most cases by change in pore fluid pressure and/or change in stress in the subsurface in the presence of faults with specific properties and orientations and a critical state of stress in the rocks. The factor that appears to have the most direct consequence in regard to induced seismicity is the net fluid balance (total balance of fluid introduced into or removed from the subsurface), although additional factors may influence the way fluids affect the subsurface. While the general mechanisms that create induced seismic events are well understood, we are currently unable to accurately predict the magnitude or occurrence of such events due to the lack of comprehensive data on complex natural rock systems and the lack of validated predictive models.

Energy technology projects that are designed to maintain a balance between the amount of fluid being injected and withdrawn, such as most oil and gas development projects, appear to produce fewer seismic events than projects that do not maintain fluid balance. Hydraulic fracturing in a well for shale gas development, which involves injection of fluids to fracture the shale and release the gas up the well, has been confirmed as the cause for small felt seismic events at one location in the world.

Wastewater disposal from oil and gas production, including shale gas recovery, typically involves injection at relatively low pressures into large porous aquifers that are specifically targeted to accommodate large volumes of fluid. The majority of wastewater disposal wells do not pose a hazard for induced seismicity, though there have been induced seismic events with a very limited number of wells. The long-term effects of a significant increase in the number of wastewater disposal wells for induced seismicity are unknown.

Projects that inject or extract large net volumes of fluids over long periods of time such as CCS may have potential for larger induced seismic events, though insufficient information exists to understand this potential because no large-scale CCS projects are yet in operation. Continued research is needed on the potential for induced seismicity in large-scale CCS projects.

Induced seismicity in geothermal projects appears to be related to both net fluid balance considerations and temperature changes produced in the subsurface. Different forms of geothermal resource development appear to have differing potential for producing felt seismic events. High-pressure hydraulic fracturing undertaken in some geothermal projects has caused seismic events that are large enough to be felt. Temperature changes associated with geothermal development of hydrothermal resources have also induced felt seismicity.

Governmental response to induced seismic events has been undertaken by a number of federal and state agencies in a variety of ways. However, with the potential for increased numbers of induced seismic events due to expanding energy development, government agencies and research institutions may not have sufficient resources to address unexpected events. Forward-looking interagency cooperation to address potential induced seismicity is warranted.

Methodologies can be developed for quantitative, probabilistic hazard assessments of induced seismicity risk. Such assessments should be undertaken before operations begin in areas with a known history of felt seismicity and updated in response to observed, potentially induced seismicity. Practices that consider induced seismicity both before and during the actual operation of an energy project can be employed in the development of a "best practices" protocol specific to each energy technology and site location.

Although induced seismic events have not resulted in loss of life or major damage in the United States, their effects have been felt locally, and they raise some concern about additional seismic activity and its consequences in areas where energy development is ongoing or planned. Further research is required to better understand and address the potential risks associated with induced seismicity.

Summary

Although the vast majority of earthquakes that occur in the world each year have natural causes, some of these earthquakes and a number of lesser-magnitude seismic events are related to human activities and are called induced seismic events or induced earthquakes. Induced seismic activity has been documented since at least the 1920s and has been attributed to a range of human activities, including the impoundment of large reservoirs behind dams, controlled explosions related to mining or construction, and underground nuclear tests. In addition, energy technologies that involve injection or withdrawal of fluids from the subsurface can also create induced seismic events that can be measured and felt. Historically known induced seismicity has generally been small in both magnitude and intensity of ground shaking.

Recently, several induced seismic events related to energy technology development projects in the United States have drawn heightened public attention. Although none of these events resulted in loss of life or significant structural damage, their effects were felt by local residents, some of whom also experienced minor property damage. Particularly in areas where tectonic (natural) seismic activity is uncommon and energy development is ongoing, these induced seismic events, though small in scale, can be disturbing to the public and raise concern about increased seismic activity and its potential consequences.

This report addresses induced seismicity that may be related to four energy development technologies that involve fluid injection or withdrawal: geothermal energy, conventional oil and gas development including enhanced oil recovery (EOR), shale gas recovery, and carbon capture and storage (CCS). These broad categories of energy technologies, including underground wastewater disposal, are discussed in detail as they relate to induced seismic events. The study arose through a request by Senator Bingaman of New Mexico to Department of Energy (DOE) Secretary Stephen Chu. The DOE was asked to engage the National Research Council to examine the scale, scope, and consequences of seismicity induced during the injection of fluids related to energy production; to identify gaps in knowledge and research needed to advance the understanding of induced seismicity; to identify gaps in induced seismic hazard assessment methodologies and the research needed to close those gaps; and to assess options for interim steps toward best practices with regard to energy development and induced seismicity potential. The report responds to this charge and aims to provide an understanding of the nature and scale of induced seismicity caused by or likely related to energy development and guidance as to how best to proceed with safe development of these technologies while minimizing their potential to induce earthquakes that can be felt by the public.

INDUCED SEISMICITY RELATED TO FLUID INJECTION OR WITHDRAWAL AND CAUSAL MECHANISMS

Seismic events have been measured and felt at a limited number of energy development sites in the United States. Seismic events caused by or likely related to energy development have been documented in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas (Figure S.1). Proving that a particular seismic event was caused by human activity is often difficult because conclusions about the causal relationship rely on local data, prior seismicity, and the preponderance of scientific studies. In this report we give examples of seismic events that

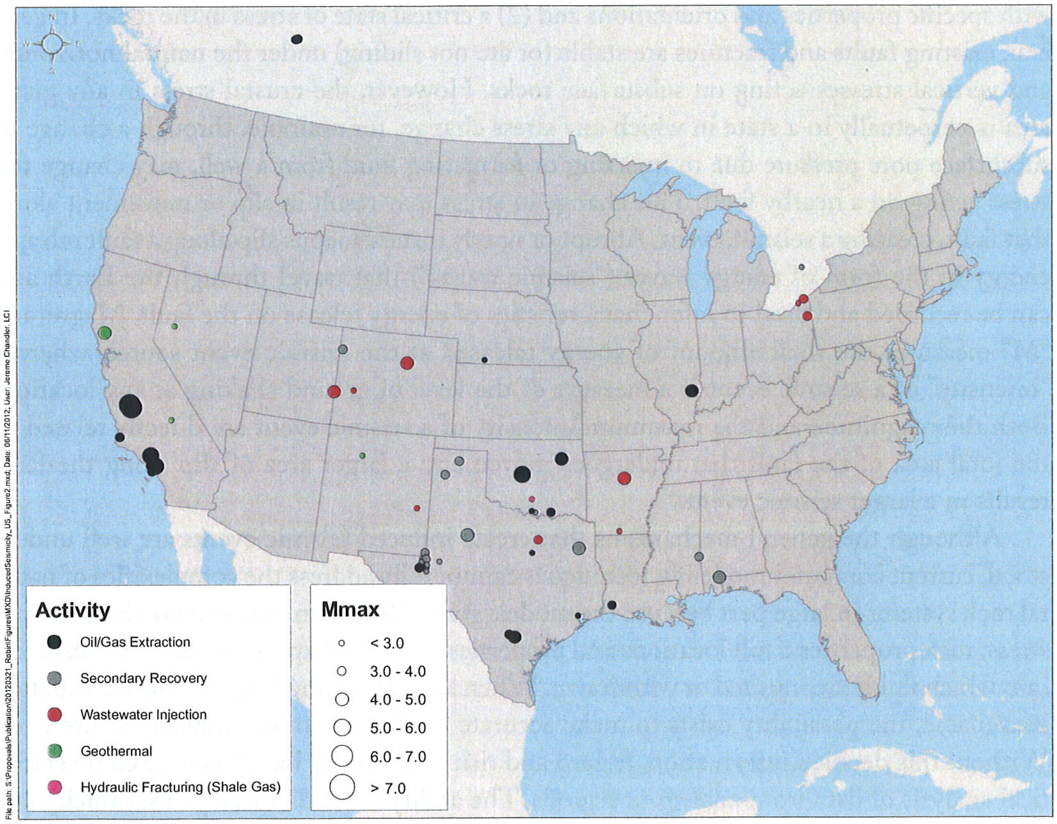

FIGURE S.1 Sites in the United States and Canada with documented reports of seismicity caused by or likely related to energy development from various energy technologies. The reporting of the occurrence of small induced seismic events is limited by the detection and location thresholds of local surface-based seismic monitoring networks.

are universally believed to have been caused by human activities, as well as seismic events for which the evidence for causality is credible but less solid.

Research conducted on some of these incidents has led to better understanding of the probable physical mechanisms of inducing seismic events and allowed for the identification of criteria that could be used to predict whether future induced seismic events might occur. The most important criteria include the amplitude and direction of the state of stress in the Earth's crust in the vicinity of the fluid injection or withdrawal area; the presence, orientation, and physical properties of nearby faults; pore fluid pressure (pressure of fluids in the pores of the rocks at depth, hereafter simply called pore pressure); pore pressure change; the rates and volumes of fluid being injected or withdrawn; and the rock properties in the subsurface.

Seismicity induced by human activity related to energy technologies is caused by change in pore pressure and/or change in stress taking place in the presence of (1) faults with specific properties and orientations and (2) a critical state of stress in the rocks. In general, existing faults and fractures are stable (or are not sliding) under the natural horizontal and vertical stresses acting on subsurface rocks. However, the crustal stress in any given area is perpetually in a state in which any stress change, for example, through a change in subsurface pore pressure due to injecting or extracting fluid from a well, may change the stress acting on a nearby fault. This change in stress may result in slip or movement along that fault, creating a seismic event. Abrupt or nearly instantaneous slip along a fault releases energy in the form of energy waves ("seismic waves") that travel through the Earth and can be recorded and used to infer characteristics of energy release on the fault. Magnitude "**M**" measures the total amount of energy released at the seismic event source, whereas "intensity" of a seismic event is a measure of the level of ground shaking at any location. Both the magnitude and the maximum intensity of a seismic event are directly related to the total area of the fault that undergoes movement: a larger area of slip along the fault results in a larger seismic event.

Although the general mechanisms that create induced seismic events are well understood, current computer modeling techniques cannot fully address the complexities of natural rock systems in large part because the models generally lack information on local crustal stress, rock properties, fault locations and properties, and the shape and size of the reservoir into which fluids are injected or withdrawn. When adequate knowledge of this information is available, the possibility exists to make accurate predictions of earthquake occurrences. Without this detailed information, hazard and risk assessments have to be based on statistical analysis of data from analogous regions. The ability to predict induced seismicity at a particular energy development site will continue to rely on both theoretical modeling and available data including field measurements, and on statistical methods.

ENERGY TECHNOLOGIES AND THEIR INDUCED SEISMICITY POTENTIAL

Geothermal energy, oil and gas production (including hydraulic fracturing for shale gas production), and CCS technologies each involve fluid injection and/or withdrawal. Therefore, each technology has the potential to induce seismic events that can be felt. Seismic events with **M** greater than 2.0 have the possibility of being felt, particularly if they occur at shallow depths, but smaller seismic events (**M** < 2.0) generally are not felt. The injection rate and pressure, fluid volumes, and injection duration vary with the technology as do the potential sizes of the seismic events and the possible risk and hazards of the induced events (Table S.1).

Geothermal Energy

The three different types of geothermal energy resources are (1) "vapor dominated," where primarily steam is contained in the pores or fractures of hot rock; (2) "liquid dominated," where primarily hot water is contained in the rock; and (3) "enhanced geothermal systems" (EGS), where the resource is hot, dry rock that requires engineered stimulation to allow fluid movement for commercial development. Although felt induced seismicity has been documented with all three types of geothermal resources (Table S.1), geothermal development usually attempts to keep a mass balance between fluid volumes produced and fluids replaced by injection to extend the longevity of the energy resource. This fluid balance helps to maintain fairly constant reservoir pressure—close to the initial, preproduction value—and can aid in reducing the potential for induced seismicity. Seismic monitoring at liquid-dominated geothermal fields in the western United States has demonstrated relatively few occurrences of felt induced seismicity. However, in The Geysers geothermal steam field in Northern California, the large temperature difference between the injected fluid and the geothermal reservoir results in significant cooling of the hot subsurface reservoir rocks, causing the rocks to contract, reducing confining pressures, and allowing the release of local stresses that results in a significant amount of observed induced seismicity. EGS technology is in the early stages of development; many countries, including the United States, have pilot projects to test the potential for commercial production. In each case of active EGS development, at least some, generally minor, levels of felt induced seismicity have been recorded.

Conventional and Unconventional Oil and Gas Development, Including EOR and Shale Gas

In a conventional oil or gas reservoir the hydrocarbon fluids and associated aqueous fluids in the pore spaces of the rock are usually under significant natural pressure. Fluids in the oil or gas reservoir flow to the surface when penetrated by a well bore, generally aided by pumping. Oil or gas reservoirs often reach a point when insufficient pressure, even in the presence of pumping, exists to allow sufficient hydrocarbon recovery. Various technologies, including secondary recovery and tertiary recovery (the latter is often referred to as enhanced oil recovery [EOR], which is the term used hereafter), can be used to extract some of the remaining oil and gas. Secondary recovery and EOR technologies both involve injection of fluids into the subsurface to push more of the trapped hydrocarbons out of the pore spaces in the reservoir and to maintain reservoir pore pressure. Secondary recovery often uses water injection or "waterflooding," and EOR technologies often inject carbon dioxide (CO_2). Approximately 151,000 injection wells are currently permitted in the United States for a combination of secondary recovery, EOR, and wastewater disposal, with only very few documented incidents where the injection caused or was likely related to felt seismic events (Table S.1). Secondary recovery—through waterflooding—has been associated with very few felt induced seismic events (Table S.1). Among the tens of thousands of wells used for EOR in the United States, the committee did not find any documentation in the published literature of felt induced seismicity, nor were any instances raised by experts in the field with whom the committee communicated during the study. Oil and gas extraction (fluid withdrawal) from a reservoir may cause induced seismic events. These events are rare relative to the large number of oil and gas fields around the world and appear to be related to a decrease in pore pressure as fluid is withdrawn (Table S.1).

Similar to geothermal systems, conventional oil and gas projects are designed to maintain the pore pressure within a field at its preproduction level by maintaining a balance between fluids being removed from one part of the reservoir and fluids injected in another part of the reservoir. The proportionally very small number of induced seismic events generated by these technologies relative to the large number of wells is in part due to this effort to maintain the original pore pressure of the reservoir.

Shale formations can also contain hydrocarbons—gas and/or oil. The extremely low permeability of these rocks has trapped the hydrocarbons as they developed in the rock and largely prevented them from migrating out of the rock over geologic time. The low permeability also prevents the hydrocarbons from easily flowing into a well bore without production stimulation by the operator. These types of "unconventional" reservoirs are developed by drilling wells horizontally through the reservoir rock and using hydraulic fracturing techniques to create new fractures in the reservoir to allow the hydrocarbons to migrate up the well bore. About 35,000 hydraulically fractured shale gas wells exist in the United States (Table S.1); only one case of felt seismicity (**M** ~ 2.8) in the United States has been described in which hydraulic fracturing for shale gas development is suspected, but not confirmed, as the cause (Table S.1). Globally only one case of felt induced seismicity in England (**M** 2.3) has been confirmed to have been caused by hydraulic fracturing for shale gas development. The very low number of felt events relative to the large number of

TABLE S.1 Summary Information about Historical Felt Seismic Events Caused by or Likely Related to Energy Technology Development in the United States[a]

Energy Technology	Number of Projects	Number of Felt Induced Events	Maximum Magnitude of Felt Events	Number of Events $M \geq 4.0$[b]	Net Reservoir Pressure Change	Mechanism for Induced Seismicity	Location of $M \geq 2.0$ Events
Vapor-dominated geothermal	1	300-400 per year since 2005	4.6	1-3 per year	Attempt to maintain balance	Temperature change between injectate and reservoir	CA (The Geysers)
Liquid-dominated geothermal	23	10-40 per year	4.1[c]	Possibly one	Attempt to maintain balance	Pore pressure increase	CA
Enhanced geothermal systems	~8 pilot projects	2-5 per year[d]	2.6	0	Attempt to maintain balance	Pore pressure increase and cooling	CA, NV
Secondary oil and gas recovery (waterflooding)	~108,000 (wells)	One or more events at 18 sites across the country	4.9	3	Attempt to maintain balance	Pore pressure increase	AL, CA, CO, MS, OK, TX
Tertiary oil and gas recovery (EOR)	~13,000 (wells)	None known	None known	0	Attempt to maintain balance	Pore pressure increase (likely mechanism)	None known
Hydraulic fracturing for shale gas production	35,000 (wells)	1	2.8	0	Initial positive; then withdraw	Pore pressure increase	OK

Hydrocarbon withdrawal	~6,000 fields	20 sites	6.5	5	Withdrawal	Pore pressure decrease	CA, IL, NB, OK, TX
Wastewater disposal wells	~30,000	9	4.8[e]	7	Addition	Pore pressure increase	AR, CO, OH
Carbon capture and storage, small scale	2[f]	None known	None known	0	Addition	Pore pressure increase	IL, MS
Carbon capture and storage, large scale	0	None	None	0	Addition	Pore pressure increase	None yet in operation

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

[b] Although seismic events **M** > 2.0 can be felt by some people in the vicinity of the event, events **M** ≥ 4.0 can be felt by most people and may be accompanied by more significant ground shaking, potentially causing greater public concern.

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

[d] Estimate based on the fact that there have been events reported in the mid **M** 2 range at previously active sites and currently active sites but without a large number of total projects (sites) from which to acquire information over time.

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

[f] Noncommercial, pilot projects with active injection supported by the Department of Energy.

hydraulically fractured wells for shale gas is likely due to the short duration of injection of fluids and the limited fluid volumes used in a small spatial area.

Wastewater Disposal Wells Associated with Energy Extraction

In addition to fluid injection directly related to energy development, injection wells drilled to dispose of wastewater generated during oil and gas production are very common in the United States. Tens of thousands of wastewater disposal wells are currently active throughout the country. Although only a few induced seismic events have been linked to these disposal wells (Table S.1), the occurrence of these events has generated considerable public concern. Examination of these cases has suggested causal links between the injection zones and previously unrecognized faults in the subsurface.

In contrast to wells for EOR, which are sited and drilled for precise injection into well-characterized oil and gas reservoirs, injection wells used only for the purpose of wastewater disposal normally do not have a detailed geologic review performed prior to injection, and the data are often not available to make such a detailed review. Thus, the location of possible nearby faults is often not a standard part of siting and drilling these disposal wells. In addition, the presence of a fault does not necessarily imply an increased potential for induced seismicity, creating challenges for the evaluation of potential sites for disposal injection wells that will minimize the possibility for induced seismic activity.

Carbon Capture and Storage

For several years researchers have explored various methods for reducing carbon emissions to the atmosphere, such as by capturing CO_2 and developing means for storing (or sequestering) it permanently underground. If technically successful and economical, CCS could become an important technology for reducing CO_2 emissions to the atmosphere. The risk of induced seismicity from CCS is currently difficult to accurately assess. With only a few small-scale commercial projects overseas and several small-scale demonstration projects under way in the United States, few data are available to evaluate the induced seismicity potential of this technology (Table S.1); these projects so far have involved very small injection volumes. CCS differs from other energy technologies in that it involves continuous CO_2 injection at high rates under pressure for long periods of time, and it is purposely intended for permanent storage (no fluid withdrawal). Given that the potential magnitude of an induced seismic event correlates strongly with the fault rupture area, which in turn relates to the magnitude of pore pressure change and the rock volume in which it exists, large-scale CCS may have the potential for causing significant induced seismicity. CCS projects that do not cause a significant increase in pore pressure above its original value will likely minimize the potential for inducing seismic events.

Energy Technology Summary

The balance of injection and withdrawal of fluids is critical to understanding the potential for induced seismicity with respect to energy technology development projects. The factors important for understanding the potential to generate felt seismic events are complex and interrelated and include the rate of injection or extraction, the volume and temperature of injected or extracted fluids, the pore pressure, the permeability of the relevant geologic layers, faults and fault properties, crustal stress conditions, the distance from the injection point, and the length of time over which injection and/or withdrawal takes place. However, the net fluid balance (total balance of fluid introduced and removed) appears to have the most direct consequence on changing pore pressure in the subsurface over time. Energy technology projects that are designed to maintain a balance between the amount of fluid being injected and the amount of fluid being withdrawn, such as geothermal and most oil and gas development, may produce fewer induced seismic events than technologies that do not maintain fluid balance.

Of the well-documented cases of induced seismicity related to fluid injection, many are associated with operations involving large amounts of fluid injection over significant periods of time. Most wastewater disposal wells typically involve injection at relatively low pressures into large porous aquifers that have high natural permeability and are specifically targeted to accommodate large volumes of fluid. Thus, although a few occurrences of induced seismic activity have been documented, the majority of the hazardous and nonhazardous wastewater disposal wells do not pose a hazard for induced seismicity. However, the long-term effects of any significant increases in the number of wastewater disposal wells on induced seismicity are unknown.

The largest induced seismic events reported in the technical literature are associated with projects that did not balance the large volumes of fluids injected into, or extracted from, the Earth within the reservoir. This is a statistical observation; the net volume of fluid that is injected and/or extracted may serve as a proxy for changes in subsurface stress conditions and pore pressure, injection and extraction rates, and other factors. Coupled thermomechanical and chemomechanical effects may also play a role in changing subsurface stress conditions. Projects with large net volumes of injected or extracted fluids over long periods of time such as long-term wastewater disposal wells and CCS would appear to have a higher potential for larger induced events. The magnitude and intensity of possible induced events would be dependent upon the physical conditions in the subsurface—the state of stress in the rocks, presence of existing faults, fault properties, and pore pressure. The relationship between induced seismicity and projects with large-volume, long-term injection, such as in large-scale CCS projects, is untested because no large-scale projects are yet in existence.

UNDERSTANDING AND MANAGING HAZARDS AND RISKS ASSOCIATED WITH INDUCED SEISMICITY FROM ENERGY DEVELOPMENT

The *hazard of induced seismicity* is the description and possible quantification of what physical effects will be generated by human activities associated with subsurface energy production or CCS. The *risk of induced seismicity* is the description and possible quantification of how induced seismic events might cause losses, including damage to structures, and effects on humans, including injuries and deaths. If seismic events occur in an area with no structures or humans present, there is no risk. The concept of risk can also be extended to include frequent occurrence of ground shaking that is a nuisance to humans.

Several questions can be addressed to understand and possibly quantify the hazard and risk associated with induced seismicity associated with energy technologies. Questions associated with understanding the hazard include whether an energy technology generates apparent seismic events, whether such events are of $\mathbf{M} > 2.0$, whether the events generate ground shaking (shallower earthquakes have greater likelihood of causing felt ground shaking than deep earthquakes), and the effects of the shaking. Risk to structures occurs only if the shaking is minor, moderate, or larger; risk to structures does not occur if the shaking is felt by humans but is not strong enough to damage the structures.

The quantification of hazard and risk requires probability assessments, which may be either statistical (based on data) or analytical (based on scientific and engineering models). These assessments can then be used to establish "best practices" or specific protocols for energy project development. A risk analysis of an entire industry project would include the extent of the spatial distribution of the operation and the multiple structures in the area that an induced seismic event might affect. While the risk of minor, moderate, or heavy damage from induced event shaking may be small from an individual well, a large number of spatially distributed wells may lead to a higher probability of such damage; a risk analysis of an industry operation thus includes the entire spatial distribution of the operation and the structures an earthquake might affect.

Although historical data indicate that induced seismic events have not generally been very large nor have they resulted in significant structural damage, induced seismic events are of concern to affected communities. Practices that consider induced seismicity both before and during the actual operation of an energy project can be employed in the development of a "best practices" protocol specific to each energy technology. The aim of such protocols is to diminish the possibility of a felt seismic event occurring and to mitigate the effects of an event if one should occur. A "traffic light" control system within a protocol can be established to respond to an instance of induced seismicity, allowing for low levels of seismicity, but adding monitoring and mitigation requirements, including the requirement to modify or even cease operations if seismic events are of sufficient intensity to result in a significant concern to public health and safety. The ultimate success of such a protocol is fundamentally tied to the strength of the collaborative relationships and dialogue among operators, regulators, the research community, and the public.

GOVERNMENT ROLES AND RESPONSIBILITIES

Four federal agencies—the Environmental Protection Agency (EPA), the Bureau of Land Management, the U.S. Forest Service, and the U.S. Geological Survey (USGS)—and different state agencies have regulatory oversight, research roles, and/or responsibilities related to different aspects of the underground injection activities that are associated with energy technologies. To date, these various agencies have dealt with induced seismic events with different and localized actions. These efforts to respond to potential induced seismic events have been successful but have been ad hoc in nature. Many events that scientists suspect may be induced are not labeled as such, due to lack of confirmation or evidence that those events were in fact induced by human activity. In areas of low historical seismicity, the national seismic network coverage tends to be sparser than that in more seismically active areas, making it difficult to detect small events and to identify their locations accurately.

ADDRESSING INDUCED SEISMICITY

The primary findings, gaps in knowledge or information, proposed actions, and research recommendations to address induced seismicity potential in energy technologies are presented below. Details specific to each energy technology are elaborated in Chapter 7.

Overarching Issues

FINDINGS

1. The basic mechanisms that can induce seismic events related to energy-related injection and extraction activities are not mysterious and are presently well understood.
2. Only a very small fraction of injection and extraction activities among the hundreds of thousands of energy development wells in the United States have induced seismicity at levels that are noticeable to the public.
3. Models to predict the size and location of earthquakes in response to net fluid injection or withdrawal require calibration from field data. The success of these models is compromised in large part due to the lack of basic data on the interactions among rock, faults, and fluid as a complex system; these data are difficult and expensive to obtain.

4. Increase of pore pressure above ambient value due to injection of fluids and decrease in pore pressure below ambient value due to extraction of fluids have the potential to produce seismic events. For such activities to cause these events, a certain combination of conditions has to exist simultaneously:
    a. Significant change in net pore pressure in a reservoir
    b. A preexisting near-critical state of stress along a fracture or fault that is determined by crustal stresses and the fracture or fault orientation
    c. Fault rock properties supportive of a brittle failure
5. Independent capability exists for geomechanical modeling of pore pressure, temperature, and rock stress changes induced by injection and extraction and for modeling of earthquake sequences given knowledge of stress changes, pore pressure changes, and fault characteristics.
6. The range of scales over which significant responses arise in the Earth with respect to induced seismic events is very wide and challenges the ability of models to simulate and eventually predict observations from the field.

BOX S.1
Research Recommendations

Data Collection—Field and Laboratory

1. Collect, categorize, and evaluate data on potential induced seismic events in the field. High-quality seismic data are central to this effort. Research should identify the key types of data to be collected and the data collection protocol.
2. Conduct research to establish the means of making in situ stress measurements nondestructively.
3. Conduct additional field research on microseisms[a] in natural fracture systems including field-scale observations of the very small events and their native fractures.
4. Conduct focused research on the effect of temperature variations on stressed jointed rock systems. Although of immediate relevance to geothermal energy projects, the results would benefit understanding of induced seismicity in other energy technologies.
5. Conduct research that might clarify the in situ links among injection rate, pressure, and event size.

Instrumentation

1. Conduct research to address the gaps in current knowledge and availability of instrumentation: Such research would allow the geothermal industry, for example, to develop this domestic renewable source more effectively for electricity generation.

Hazard and Risk Assessment

1. Direct research to develop steps for hazard and risk assessment for single energy development projects (as described in Chapter 5, Table 5.2).

GAPS

1. The basic data on fault locations and properties, in situ stresses, fluid pressures, and rock properties are insufficient to implement existing models with accuracy on a site-specific basis.
2. Current predictive models cannot properly quantify or estimate the seismic efficiency and mode of failure; geomechanical deformation can be modeled, but a challenge exists to relate this to number and size of seismic events.

PROPOSED ACTIONS

The actions proposed to advance understanding of the types and causes of induced seismicity involve research recommendations outlined in Box S.1. These recommendations also have relevance for specific energy technologies and address gaps in present understanding of induced seismicity.

Modeling

1. Identify ways simulation models can be scaled appropriately to make the required predictions of the field observations reported.
2. Conduct focused research to advance development of linked geomechanical and earthquake simulation models that could be utilized to better understand potential induced seismicity and relate this to number and size of seismic events.
3. Use currently available and new geomechanical and earthquake simulation models to identify the most critical geological characteristics, fluid injection or withdrawal parameters, and rock and fault properties controlling induced seismicity.
4. Develop simulation capabilities that integrate existing reservoir modeling capabilities with earthquake simulation modeling for hazard and risk assessment. These models can be refined on a probabilistic basis as more data and observations are gathered and analyzed.
5. Continue to develop capabilities with coupled reservoir fluid flow and geomechanical simulation codes to understand the processes underlying the occurrence of seismicity after geothermal wells have been shut in; the results may also contribute to understanding post-shut-in seismicity in relation to other energy technologies.

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[a] Microseisms designate seismic events that are not generally felt by humans, and in this report are **M** < 2.

Energy Technologies

FINDINGS

1. Injection pressures and net fluid volumes in energy technologies, such as geothermal energy and oil and gas production, are generally controlled to avoid increasing pore pressure in the reservoir above the initial reservoir pore pressure. These technologies thus appear less problematic in terms of inducing felt seismic events than technologies that result in a significant increase or decrease in net fluid volume.
2. The induced seismic responses to injection or extraction differ in cause and magnitude among each of the three different forms of geothermal resources. Decrease of the temperature of the subsurface rocks caused by injection of cold water in a geothermal field has the potential to produce seismic events.
3. The potential for felt induced seismicity due to secondary recovery and EOR is low.
4. The process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events.
5. The United States currently has approximately 30,000 Class II[1] wastewater disposal wells among a total of 151,000 Class II injection wells (which includes injection wells for both secondary recovery and EOR). Very few felt seismic events have been reported as either caused by or temporally associated with wastewater disposal wells; these events have produced felt earthquakes generally less than **M** 4.0. Reducing injection volumes, rates, and pressures has been successful in decreasing rates of seismicity associated with wastewater injection.
6. The proposed injection volumes of liquid CO_2 in large-scale sequestration projects are much larger than those associated with other energy technologies. There is no experience with fluid injection at these large scales and little data on seismicity associated with CO_2 pilot projects. If the reservoirs behave in a similar manner to oil and gas fields, these large net volumes may have the potential to impact the pore pressure over vast areas. Relative to other energy technologies, such large spatial areas may have potential to increase both the number and the magnitude of seismic events.

PROPOSED ACTION

Because of the lack of experience with large-scale fluid injection for CCS, continued research supported by the federal government is needed on the potential for induced seismicity in large-scale CCS projects (see Box S.1). As part of a continued research effort,

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[1] Class II wells are specifically those that address injection of brines and other fluids associated with oil and gas production and hydrocarbons for storage.

collaboration between federal agencies and foreign operators of CCS sites is important to understand induced seismic events and their effects on the CCS operations.

Hazards and Risk Assessment

FINDING

Risk assessments depend on methods that implement assessments of hazards, but those methods currently do not exist. The types of information and data required to provide a robust hazard assessment would include

- net pore pressures, in situ stresses, and information on faults;
- background seismicity; and
- gross statistics of induced seismicity and fluid injection or extraction.

PROPOSED ACTIONS

1. A detailed methodology should be developed for quantitative, probabilistic hazard assessments of induced seismicity risk. The goal in developing this methodology would be to

    - make assessments before operations begin in areas with a known history of felt seismicity and
    - update assessments in response to observed induced seismicity.

2. Data related to fluid injection (well location coordinates, injection depths, injection volumes and pressures, time frames) should be collected by state and federal regulatory authorities in a common format and made publicly accessible (through a coordinating body such as the USGS).
3. In areas of high density of structures and population, regulatory agencies should consider requiring that data to facilitate fault identification for hazard and risk analysis be collected and analyzed before energy operations are initiated.

Best Practices

FINDING

The DOE Protocol for EGS is a reasonable model for addressing induced seismicity that can serve as a template for protocol development for other energy technologies.

GAP

No best practice protocol for addressing induced seismicity is generally in place for each energy technology. The committee suggests that best practice protocols be adapted and tailored to each technology to allow continued energy technology development.

PROPOSED ACTIONS

Protocols for best practice should be developed for each of the energy technologies (secondary recovery and EOR for conventional oil and gas production, shale gas production, CCS) by experts in each field, in coordination with permitting agencies, potentially following the model of the DOE EGS protocol. For all the technologies a "traffic light" system should be employed for future operations. The protocols should be applied to

- the permitting of operations where state agencies have identified areas of high potential for induced seismicity or
- an existing operation that is suspected to have caused an induced seismic event of significant concern to public health and safety.

Simultaneous development of public awareness programs by federal or state agencies in cooperation with industry and the research community could aid the public and local officials in understanding and addressing the risks associated with small-magnitude induced seismic events.

Government Roles and Responsibilities

FINDINGS

1. Induced seismicity may be produced by a number of different energy technologies and may involve either injection or extraction of fluid. However, responsibility for oversight of induced seismicity is dispersed among a number of federal and state agencies.
2. Responses to energy development-related seismic events have been addressed in a variety of manners involving local, state, and federal agencies, and research institutions. These agencies and research institutions may not have resources to address unexpected events, and more events could stress this ad hoc system.
3. Currently EPA has primary regulatory responsibility for fluid injection under the Safe Drinking Water Act, which does not explicitly address induced seismicity.

EPA is addressing the issue of induced seismicity through its current study in consultation with other federal and state agencies.

4. The USGS has the capability and expertise to address monitoring and research associated with induced seismic events. However, the scope of its mission within the seismic hazard assessment program is focused on large-impact, natural earthquakes. Significant new resources would be required if the USGS mission were expanded to include comprehensive monitoring and research on induced seismicity.

GAP

No mechanisms are currently in place for efficient coordination of governmental agency response to seismic events that may have been induced.

PROPOSED ACTIONS

1. Relevant agencies, including EPA, USGS, and land management agencies, and possibly DOE, and state agencies with authority and relevant expertise (e.g., oil and gas commissions, state geological surveys, state environmental agencies) should develop coordination mechanisms to address induced seismic events.
2. Appropriating authorities for agencies with potential responsibility for induced seismicity should consider resource allocations for responding to induced seismic events in the future.

CHAPTER ONE

Induced Seismicity and Energy Technologies

INTRODUCTION TO INDUCED SEISMICITY AND STUDY BACKGROUND

An earthquake is a shaking of the ground caused by a sudden release of energy within the Earth. Most earthquakes occur because of a natural and rapid shift (or slip) of rocks along geologic faults that release energy built up by relatively slow movements of parts of the Earth's crust. The numerous, sometimes large earthquakes felt historically in California and the earthquake that was felt along much of the East Coast in August 2011 are examples of naturally occurring earthquakes related to Earth's movements along regional faults (see also the section Earthquakes and Their Measurement, this chapter). An average of ~14,450 earthquakes with magnitudes above 4.0 ($\mathbf{M} > 4.0$)[1] are measured globally every year. This number increases dramatically—to more than 1.4 million earthquakes annually—when small earthquakes (those with greater than **M** 2.0) are included.[2]

Although the vast majority of earthquakes have natural causes, some earthquakes may also be related to human activities and are called induced seismic events.[3] Induced seismic events are usually small in both magnitude and intensity of shaking (see the section on Earthquakes and Their Measurement later in this chapter). For example, underground nuclear tests, controlled explosions in connection with mining or construction, and the impoundment of large reservoirs behind dams can each result in induced seismicity (Box 1.1). Energy technologies that involve injection or withdrawal of fluids from the subsurface also have the potential to induce seismic events that can be measured and felt (see Kerr, 2012).

The earliest and probably most familiar documented example of an induced seismic event related to fluid injection is the activity that occurred in the Denver, Colorado, area in the 1960s in connection with liquid waste disposal at the Rocky Mountain Arsenal. An injection well at the Arsenal pumping into relatively impermeable crystalline basement

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[1] **M** represents magnitude on the moment-magnitude scale, which is described in the section Earthquakes and Their Measurement, this chapter.

[2] See earthquake.usgs.gov/learn/faq/?faqID=69.

[3] Some researchers (e.g., McGarr et al., 2002) draw a distinction between "induced" seismicity and "triggered" seismicity. Under this distinction, induced seismicity results from human-caused stress changes in the Earth's crust that are on the same order as the ambient stress on a fault that causes slip. Triggered seismicity results from stress changes that are a small fraction of the ambient stress on a fault that causes slip. Anthropogenic processes cannot "induce" large and potentially damaging earthquakes, but anthropogenic processes could potentially "trigger" such events. In this report we do not distinguish between the two and use the term "induced seismicity" to cover both categories.

BOX 1.1
Observations of Induced Seismicity

Seismicity induced by human activity has been observed and documented since at least the 1920s (Pratt and Johnson, 1926). The number of sites where seismic events of **M** > 0 have occurred that are caused by or likely related to energy development are listed below by technology. (References for these sites with location and magnitude information are in Appendix C; note that in several cases the causal relationship between the technology and the event was suspected but never confirmed.) The numbers of sites globally are listed first in the column; the world map (Figure 1) shows these sites by technology and magnitude. The numbers in parentheses are the numbers of sites, as a subset of the global totals, in which seismic events in the United States have been caused by or likely related to energy development. In addition to energy technologies that are the topic of this report, the list also shows induced seismicity due to surface water reservoirs (dams) and other activities related to mining.[a] Event locations are plotted on global and U.S. maps in Figures 1 and 2.

	Global (United States only)
Wastewater injection	11 (9)
Oil and gas extraction (withdrawal)	38 (20)
Secondary recovery (water flooding)	27 (18)
Geothermal energy	26 (4)
Hydraulic fracturing (shale gas)	2 (1)
Surface water reservoirs	44 (6)
Other (e.g., coal and solution mining)	8 (3)
Total	156

Note that the figures include locations where a spatial association between seismicity and human activity has suggested a causal relationship, but where a causal relationship has not been positively established. Indeed, establishing such a causal relationship often requires a significant amount of scientific effort and fieldwork in the form of temporary seismometer arrays, particularly for the remote locations at which underground activities are conducted.

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[a] Mining operations can cause seismic events, in addition to the explosions that are used to fracture rock for excavation. These seismic events may occur at shallow depths as a result of changes in crustal stress, both by removal of mining ore and by redistribution of crustal stress from fracturing sound rock. Such events are not considered further in this report.

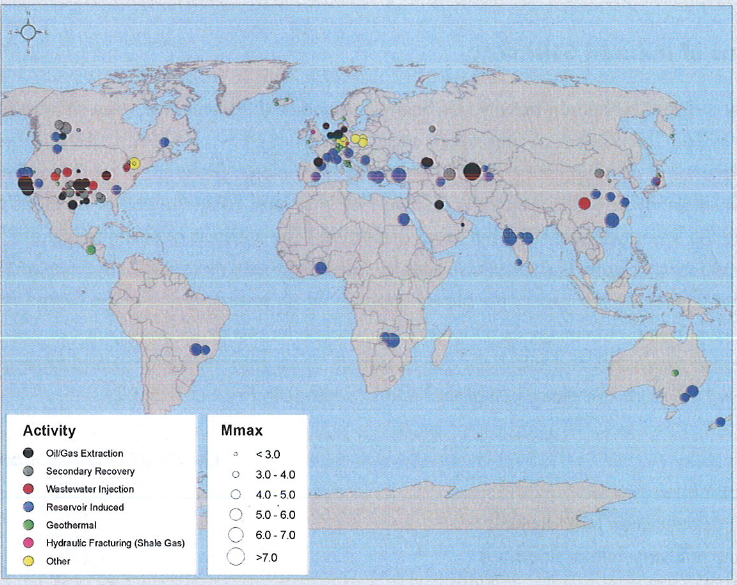

Figure 1 Worldwide locations of seismicity reported in the technical literature caused by or likely related to human activities, with the maximum magnitude reported to be induced at each site.

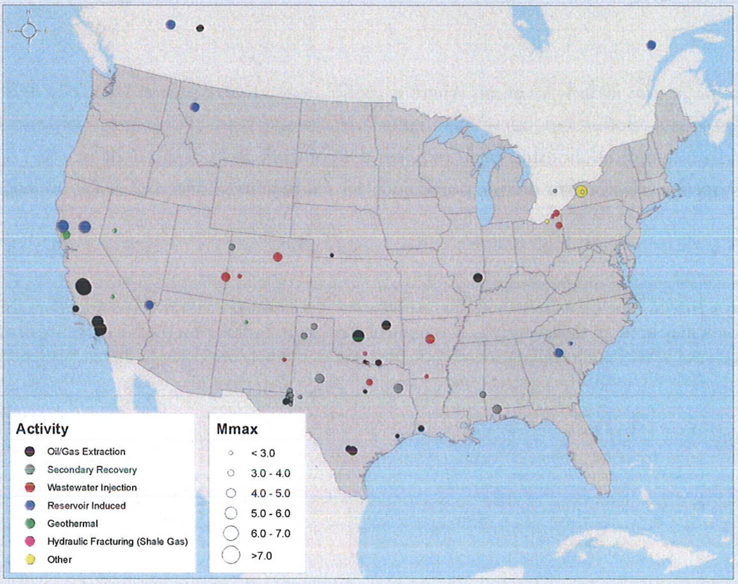

Figure 2 Locations of seismic events caused by or likely related to human activities within the coterminous United States and portions of Canada as documented in the technical literature.

rock caused induced earthquakes (three **M** 5.0 to **M** 5.5 earthquakes[4]), the largest of which caused an estimated $500,000 in damages in 1967 (Nicholson and Wesson, 1990) (Box 1.2).

More recent public attention to the potential correlation between seismic events and energy technology development began with several felt seismic events: in Basel, Switzerland, in 2006; at The Geysers, California, in 2008; and near the Dallas-Fort Worth airport in 2008. During the course of this study, several additional seismic events with potential correlation to energy development have occurred in different parts of the United States and in several other nations (see later in this chapter and in Chapters 2 and 3 for details of some of these events). The potential for induced seismic events has also been highlighted in the context of ongoing public discussion of shale gas development through hydraulic fracturing operations. Although none of these recent events resulted in loss of life or significant structural damage, their effects were felt by local residents, some of whom also experienced minor property damage. Particularly in areas where tectonic (natural) seismic activity is uncommon or historically nonexistent and energy development is ongoing, these seismic events, though small in scale, can be disturbing for the public and can raise concern about further seismic activity and its consequences.

This report addresses induced seismicity that may be related specifically to certain kinds of energy development that involve fluid injection or withdrawal. The study arose through a request made in 2010 by Senator Bingaman of New Mexico, chair of the Senate Energy and Natural Resources Committee, to Department of Energy Secretary Stephen Chu (Appendix D). The senator asked the secretary to engage the National Research Council to examine the scale, scope, and consequences of seismicity induced by energy technologies and specifically associated with four energy technologies: geothermal energy, shale gas,[5] enhanced oil recovery (EOR), and carbon capture and storage (CCS). The study's statement of task is presented in Box 1.3.

The aim of this report is to provide an understanding of the nature and scale of induced seismicity related to energy technologies and to suggest guidance as to how best to proceed with safe development of these technologies in terms of any potential induced seismicity risks. The report begins with an examination of the types and potential causes or mechanisms for induced seismicity (Chapter 2), reviews the four energy technologies that are the subject of the study and the ways they may induce seismic activity (Chapter 3), and discusses government roles and responsibilities related to underground injection and induced seismicity (Chapter 4). Chapter 5 considers the hazard and risk for induced seismicity and identifies some paths for understanding and managing induced seismicity, with steps toward

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[4] The initial reports of the magnitudes of the events at the Rocky Mountain Arsenal did not have details about the magnitude scale being used. Subsequent detailed analysis of seismograms (Herrmann et al., 1981) indicated that the magnitudes of the largest earthquakes were actually **M** 4.5 to **M** 4.8, slightly smaller than the initially reported magnitudes. See Box 1.2 for details.

[5] When the committee uses the term "shale gas," it is referring to dry gas, gas, and some liquids.

best practices for mitigating induced seismicity risk in Chapter 6. Chapter 7 contains the report's findings, conclusions, proposed actions, and research recommendations, including identification of information and knowledge gaps and research and monitoring needs. The remainder of this chapter briefly reviews earthquakes and their measurement, introduces the four energy technologies that are the subject of this report, and presents several historical examples of induced seismic activity related to energy development.

The significance of understanding and mitigating the effects of induced seismicity related to energy technologies has been recognized by other groups as well, both internationally and domestically. The International Partnership for Geothermal Technology Working Group on Induced Seismicity[6] under the auspices of the International Energy Agency, for example, has been addressing the issue as it relates specifically to geothermal energy development. International professional societies such as the Society of Petroleum Engineers and the Society of Exploration Geophysicists are coordinating a public technical workshop on the topic.[7] Within the United States, government agencies such as the Department of Energy and U.S. Geological Survey have also been engaged in explicit efforts to understand and address induced seismicity in technology development. The Environmental Protection Agency has been facilitating a National Technical Working Group on Injection Induced Seismicity[8] since mid-2011 and anticipates releasing a report that will contain technical recommendations directed toward minimizing or managing injection-induced seismicity.

EARTHQUAKES AND THEIR MEASUREMENT

The process of earthquake generation is analogous to a rubber band stretched to the breaking point that suddenly snaps and releases the energy stored in the elastic band. Earthquakes result from slip along faults that release tectonic stresses that have grown high enough to exceed a fault's breaking strength. Strain energy is released by the Earth's crust during an earthquake in the form of seismic waves, friction on the causative fault, and, for some earthquakes, crustal elevation changes. Seismic waves can travel great distances; for large earthquakes they can travel around the globe. Ground motions observed at any location are a manifestation of these seismic waves. Seismic waves can be measured in different ways: earthquake **magnitude** is a measure of the size of an earthquake or the amount of energy released at the earthquake source, while earthquake **intensity** is a measure of the level of ground shaking at a specific location. The distinction between earthquake magnitude and intensity is important because intensity of ground shaking determines what

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[6] See http://internationalgeothermal.org/; http://www.iea-gia.org/documents/Switzerland_Inducedseismicity_IPGT_IEA_201105031.pdf

[7] See http://www.spe.org/events/12aden/documents/12ADEN_Brochure.pdf

[8] See http://www.gwpc.org/meetings/uic/2012/proceedings/09McKenzie_Susie.pdf; P. Dellinger, presentation to the committee, September 2011.

BOX 1.2
The Rocky Mountain Arsenal Earthquakes

During the spring of 1962 seismological stations in Colorado began recording a number of small earthquakes near Denver. Although Denver had previously been considered to be in an area of low seismicity, between April 1962 and August 1967 over 1,500 earthquakes were recorded at the seismograph station at Bergen Park, Colorado. Some of the earthquakes were noticeable to local residents and exceeded **M** 3 and **M** 4. The earthquakes were eventually attributed to the underground injection of fluid using a deep well drilled on land known as the Rocky Mountain Arsenal approximately 6 miles northeast of downtown Denver.

The Rocky Mountain Arsenal was used by the U.S. Army from 1942 through 1985 for both the manufacture and the disposal of chemical weapons. In 1961 the army drilled a well on the arsenal grounds for the disposal of chemical fluid wastes by underground injection. The well was drilled to a depth of 12,045 feet into Precambrian crystalline rocks (rocks greater than about 700 million years old) beneath the sedimentary rocks of the Denver basin. Fluid injection began in March 1962, and from that time through September 1963, fluid was injected at an average rate of 181,000 gallons per day (gal/day). Injection was stopped in October 1963, but commenced again from August 1964 through April 1965. During this second injection cycle the fluid was not injected under pressure but was fed to the well under gravity flow at a rate of 65,800 gal/day. In April 1965 pressure injection resumed at a rate of 148,000 gal/day. The maximum injection pressure at any time was 72 bars (1,044 pounds per square inch [psi]).[a]

In April and May 1962, two seismological observatories in the Denver area began recording a series of small earthquakes.

> *In June of 1962 several earthquakes occurred which were large enough to be felt by residents and caused considerable concern. By November of 1965 over 700 shocks had been recorded and, although 75 of these had been felt, no damage was reported...."* (McClain, 1970)

Research conducted in the mid-1960s on the deep injection well located on the Arsenal grounds detailed the correlation between the amount of fluid injected into the Arsenal well and the number of Denver earthquakes (Evans, 1966). This research indicated a strong relationship between injection volumes and earthquake frequency (see Figure). More detailed investigation by several local universities and the U.S. Geological Survey (USGS) gave further support to this conclusion. The research showed the majority of the earthquakes had epicenters within 5 miles of the Arsenal's injection well. The depths of the earthquakes varied from 12,140 to 23,000 feet (3,700 to 7,000 meters) below the surface, which is the depth of Precambrian rocks in the area. Research also showed that the epicenters for the earthquakes aligned in a generally northwest-to-southeast direction, similar to the orientation of a system of natural vertical fractures found in the Precambrian rocks in the area.

Although injection into the Arsenal well ceased in February 1966, earthquake activity continued for several more years. The strongest earthquakes actually occurred after injection into the well was discontinued. A detailed analysis of seismograms (Herrmann et al., 1981) indicated seismic moments of the largest earthquakes that can be converted to **M** 4.5 (April 1967), **M** 4.8 (August 1967), and **M** 4.5 (November 1967). These magnitudes are more accurately determined and somewhat smaller than the magnitudes reported in earlier papers on the

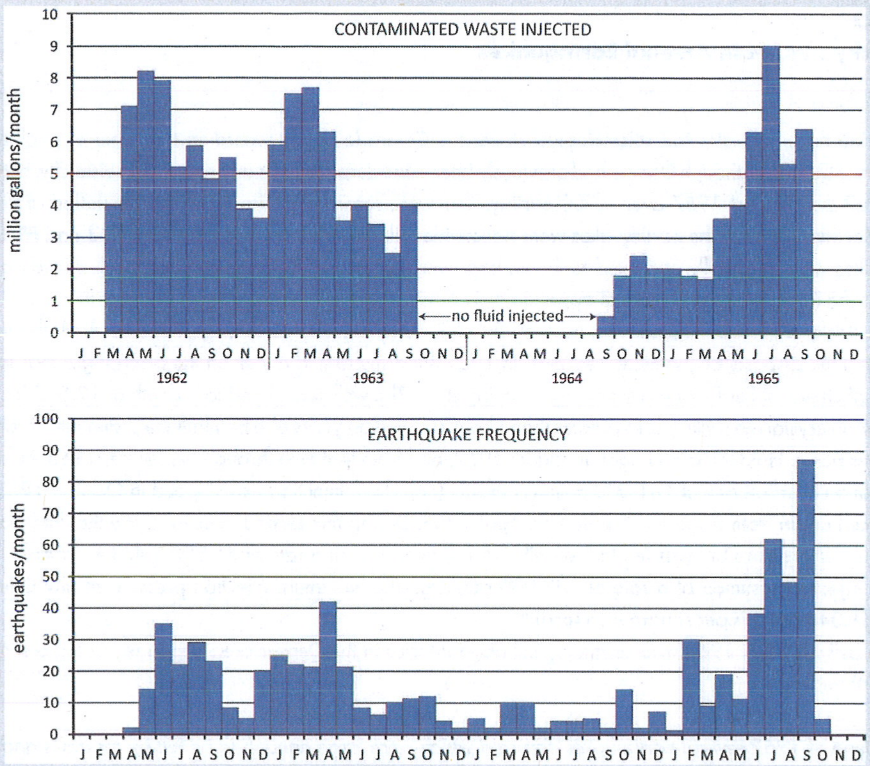

Figure Histograms showing relation between volume of waste injected into the Rocky Mountain Arsenal well and earthquake frequency. SOURCES: Adapted from Evans (1966); Healy et al. (1968); McClain (1970); Hsieh and Bredehoeft (1981).

Rocky Mountain Arsenal earthquakes, which did not have details about the magnitude scale being used. After November 1967 earthquake activity steadily declined and virtually ceased by the late 1980s.

Initial theories postulated that the Denver earthquakes were caused by fluids being pumped into the ground by pressure injection in the disposal well; the fluids were suggested to have acted as a lubricant, allowing large blocks of rock in the subsurface to shift more easily. However, further analysis showed earthquakes triggered by fluid injection are not caused by lubrication of a fracture system but suggested instead that the earthquakes were caused by increasing the pressure of the existing fluid in the formation through high-pressure injection, which lowered the frictional resistance between rocks along an existing fault system; lowering the frictional resistance allowed the rocks to slide relative to each other.

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[a] Note: Throughout the report we cite the units presented in the original reference followed by a conversion in parentheses to U.S. measures, metric, or units that might be more familiar to the general reader.

BOX 1.3
Statement of Task

The study will focus on areas of interest related to CCS, enhanced geothermal systems, production from shale gas, and EOR, and will

1. summarize the current state-of-the-art knowledge on the possible scale, scope, and consequences of seismicity induced during the injection of fluids related to energy production, including lessons learned from other causes of induced seismicity;
2. identify gaps in knowledge and the research needed to advance the understanding of induced seismicity, its causes, effects, and associated risks;
3. identify gaps and deficiencies in current hazard assessment methodologies for induced seismicity and research needed to close those gaps; and
4. identify and assess options for interim steps toward best practices, pending resolution of key outstanding research questions.

we, as humans, perceive or feel and the extent of damage to structures and facilities. The intensity of an earthquake depends on factors such as distance from the earthquake source and local geologic conditions, as well as earthquake magnitude. Throughout this work we refer to earthquake magnitudes using the moment-magnitude scale (Hanks and Kanamori, 1979), which is a scale preferred by seismologists because it is theoretically related to the amount of energy released by the Earth's crust. The common symbol used to indicate moment magnitude is **M**.[9]

The earthquake magnitude scale spans a truly immense range of energy releases. For example, an earthquake of **M** 8 does not represent energy release that is four times greater than an earthquake of **M** 2; rather, an **M** 8 releases 792 million times greater energy than an **M** 2. For tectonic ("natural") earthquakes, magnitude is also closely tied to the earthquake rupture area, which is defined as the surface area of the fault affected by sudden slip during an earthquake. A great earthquake of **M** 8 typically has a fault-surface rupture area of 5,000 to 10,000 km^2 (equivalent to ~1,931 to 3,861 square miles or about the size of Delaware,

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[9] The moment magnitude scale, designated **M**, is the conventional scale now in use worldwide because it is related to the energy or "work" done by the Earth's crust in creating the earthquake. An earthquake magnitude scale was first published by Richter (1936) and was based on the amplitudes of ground motions recorded on standard seismometers in Southern California. The desire was to assign a numerical magnitude value to earthquakes that was logarithmically proportional to the amount of energy released in the Earth's crust, although it was recognized by Richter that the available data were inadequate for developing a direct correlation with energy. The original scale for Southern California achieved widespread use, was designated "Richter" or local magnitude, and was adapted for other areas with modifications to account for regional differences in earthquake wave attenuation. The moment magnitude has the ability to represent the energy released by very large earthquakes. Moment magnitude, where available, has been used throughout the report.

which is 2,489 square miles). In contrast, **M** 3 earthquakes typically have rupture areas of roughly 0.060 km^2 (about 0.023 square miles or about 15 acres, equivalent to about 15 football fields). "Felt earthquakes" are generally those with **M** between 3 and 5, and "damaging earthquakes" are those with **M** > 5. The maximum velocity of ground shaking is a measure of how damaging the ground motion will be near the fault causing the earthquake. The intensity of shaking at any location is usually expressed using the Modified Mercalli scale and varies from III[10] (felt by few people and would cause hanging objects to sway) for **M** 3, to X (when severe damage would occur). A large earthquake located onshore will generate intensity X near the fault rupture, intensity III at far distances, and all intensities between at intermediate distances.

Most earthquakes, whether natural or induced, that are recorded by seismometers are too small to be noticed by people. These small earthquakes are often referred to as **microearthquakes** or **microseisms.** This report adopts the latter term for all seismic events with magnitude **M** < 2.0. Microseisms as small as **M** –2 (see Appendix E for an explanation of negative magnitudes) are routinely recorded by local **seismometer arrays** during hydraulic fracturing operations used to stimulate oil and gas recovery. At **M** –2 the rupture areas are on the order of 1 m^2 (a little less than 11 square feet).

Most naturally occurring earthquakes occur near the boundaries of the world's tectonic plates where faults are historically active. However, low levels of seismicity also occur *within* the tectonic plates. This fact, together with widespread field measurements of stress and widespread instances of induced seismicity, indicate that the Earth's crust, even in what we may consider geologically or historically stable regions, is commonly stressed near to the critical limit for fault slip (Zoback and Zoback, 1980, 1981, 1989). Because of this natural state of the Earth's crust, *no region can be assumed to be fully immune to the occurrence of earthquakes.*

Induced seismicity may occur whenever conditions in the subsurface are altered in such a way that stresses acting on a preexisting fault reach the breaking point for slip. If stresses in a rock formation are near the critical stress for fault rupture, theory predicts and experience demonstrates that relatively modest changes of pore fluid pressures can induce seismicity. Generally, induced earthquakes are not damaging, but if preexisting stress conditions or the elevated pore fluid pressures are sufficiently high over a large fault area, then earthquakes with enough magnitude or intensity to cause damage can potentially occur.

Identifying whether a particular earthquake or microseism was caused by human activity or occurred naturally is commonly very difficult; often, inferences are made based on spatial and temporal proximity of the earthquake and human activity, on seismic history in the region, and on whether general models of induced seismicity would support a connection. For example, a small amount of fluid injected into the crust at shallow depths (e.g., during

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[10] The Mercalli scale uses Roman numerals.

a hydraulic fracturing operation) would not be considered the cause of a **M** 7 earthquake that was initiated at 10 km depth, even if the hydraulic fracturing and earthquake were close in space and time.

The earthquake history of a region also plays a role in inferring whether a particular earthquake was induced. If a certain earthquake appears to be related to human activity, but similar earthquakes have occurred in the past in that region, the connection with human activity is more tenuous than if the correlation between earthquake and human activity occurred in a previously aseismic region. In the latter case, an important indicator might be the *rate* of occurrence of multiple earthquakes, compared to the historical rate (Ellsworth et al., 2012). The important point is that there often is no definitive proof that a particular earthquake was induced; conclusions are usually based on inference.

ENERGY TECHNOLOGIES AND INDUCED SEISMICITY

Geothermal Energy

Geothermal energy production captures the natural heat of the Earth to generate steam that can drive a turbine to produce electricity. Geothermal systems fall into one of three different categories: (1) **vapor-dominated** systems, (2) **liquid-dominated** systems, and (3) **enhanced geothermal systems** (EGS). Vapor-dominated systems are relatively rare. A major example is The Geysers geothermal field in Northern California. Liquid-dominated systems are used for geothermal energy in Alaska, California, Hawaii, Idaho, Nevada, and Utah. In both of these types of hydrothermal resource systems, either steam or hot water is extracted from naturally occurring fractures within the rock in the subsurface and cold fluid is injected into the ground to replenish the fluid supply. EGS are a potentially new source of geothermal power in which the subsurface rocks are naturally hot and fairly impermeable, and contain relatively little fluid. Wells are used to pump cold fluid into the hot rock to gather heat, which is then extracted by pumping the fluid to the surface. In some cases a potential EGS reservoir may lack sufficient connectivity via fractures to allow fluid movement through rock. In this case the reservoir may be fractured using high-pressure fluid injection in order to increase permeability. Permeability is a measure of the ease with which a fluid flows through a rock formation. (See Chapter 2 for detailed discussion of permeability and its relevance to fracture development and fluid flow.) In each of these geothermal systems, the injection or extraction of fluid has the potential to induce seismic activity. Further description of these technologies and examples of induced seismic activity are provided in Chapter 3.

Oil and Gas Production

Oil and gas production involves pumping hydrocarbon liquids (petroleum and natural gas), often together with large amounts of aqueous fluids (groundwater) that commonly contain high amounts of dissolved solids and salts ("brine"), from the subsurface. In the United States, oil and gas operators are required to manage these aqueous fluids through some combination of treatment, storage, disposal, and/or use, subject to government regulations. Commonly, these fluids, if not reused in the extraction process (see also Carbon Capture and Storage, below), are disposed of by injection into the deep subsurface in wells that may be located at some distance from the site of the oil or gas extraction (see also Chapters 3 and 4).

Fluids may also be produced from a well during "flow-back operations" after a well has been hydraulically fractured. Hydraulic fracturing is a method of stimulating an oil- or gas-producing geologic formation by injecting fluid underground to initiate fractures in the rock to aid oil or gas production from the well. A portion of the fluid is later recovered from the well and may be reinjected for additional hydraulic fracture treatments or managed through storage, permanent disposal in an injection well, or treatment for disposal or beneficial use similar to aqueous fluids that are normally produced directly from an oil or gas reservoir. Injection of fluids related to hydraulic fracturing and injection of waste fluids into the subsurface for permanent disposal are two different processes described in detail in Chapter 3.

Oil and gas production (withdrawal) often includes fluid reinjection. The reinjected fluid may be natural gas, aqueous fluids, or carbon dioxide (CO_2) used to help push more oil and gas out from the rocks and to the surface; such reinjection is termed secondary recovery. Enhanced oil recovery, also known as tertiary recovery, uses technologies that also aid in increasing the recovery of hydrocarbons from a reservoir by changing the properties of the oil (primarily aiming to lower the viscosity of the oil so that it flows more easily). The most common EOR techniques involve injecting CO_2 or hydrocarbons, or heating the oil through steam injection or combustion. The injection of fluid to facilitate oil and gas production, similar to fluid injection for geothermal systems, has the potential to generate induced seismic activity. To date, EOR has not been associated with induced seismicity, although felt seismic events have been documented in connection with waterflooding for secondary recovery. The withdrawal of oil and gas has also been associated with induced seismic activity. All of these technologies and examples of induced seismic activity are described further in Chapter 3.

Carbon Capture and Storage

Carbon capture and geologic storage is the separation and capture of CO_2 from emissions of industrial processes, including energy production, and the transport and permanent storage of the CO_2 in deep underground formations. Currently five different types of underground formations are being investigated for permanent CO_2 storage: (1) oil and gas reservoirs, (2) saline formations, (3) unmineable coal seams, (4) organic-rich shales, and (5) basalt formations.[11] Carbon dioxide has been injected into oil and gas reservoirs for several decades to enhance oil recovery. Current large-scale CCS projects in the United States are focused on injection of carbon dioxide into saline brines in regional aquifers. Carbon dioxide must be in the supercritical (liquid) phase to minimize the required underground storage volume; this requires a fluid pressure of greater than 6.9 MPa (about 68 atm[12]) and temperature greater than 31.1°C, which can be achieved at depths greater than about 2,600 feet (~800 meters) (Sminchak et al., 2001). Because no large-scale CCS projects have been completed in the United States, no data or reports on induced seismic activity are available. Chapter 3 reviews in more detail the CCS research and development projects ongoing in the United States, as well as three small, commercial CCS projects overseas.

HISTORICAL INDUCED SEISMICITY RELATED TO ENERGY ACTIVITIES

In the United States, seismicity caused by or likely related to energy development activities involving fluid injection or withdrawal has been documented in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas (see Chapters 2 and 3 for details). Appendix C lists documented and suspected cases globally and in the United States of induced seismicity, including, for example, seismic events caused by waste injection at the Rocky Mountain Arsenal (Healy et al., 1968; Hsieh and Bredehoeft, 1981; Box 1.1) and in the Paradox Basin of western Colorado (see Appendix K); secondary recovery of oil in Colorado (Raleigh et al., 1972), southern Nebraska (Rothe and Lui, 1983), western Texas (Davis, 1985; Davis and Pennington, 1989), and western Alberta (Milne, 1970) and southwestern Ontario, Canada (Mereu et al., 1986); and fluid stimulation to enhance geothermal energy extraction in New Mexico (Pearson, 1981), at The Geysers, California (see Box 3.1), and in Basel, Switzerland (see Box 3.3). Suckale (2010) provides a thorough overview of seismicity induced by hydrocarbon production. Investigations of some of these cases have led to better understanding of the probable physical mechanisms of inducing seismic events and have allowed for the establishment of some of the most important criteria that may induce a felt seismic event, including the state of stress in the Earth's crust in the vicinity of the fluid injection or withdrawal; the presence, orientation, and physical properties of nearby faults; pore fluid pressure (pressure of fluids in the pores of the rocks at depth, hereafter referred to as pore pressure); the volumes, rates, and temperature of fluid being injected or withdrawn; the pressure at which the fluid is being injected; and the length of time over which the fluid is

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[11] See, for example, http://www.netl.doe.gov/technologies/carbon_seq/FAQs/carbonstorage2.html.

[12] One unit of atmospheric pressure or 1 atm is equivalent to the pressure exerted by the Earth's atmosphere on a point at sea level.

injected or withdrawn (e.g., Nicholson and Wesson, 1990). Controlled experiments both at Rangely, Colorado (Raleigh et al., 1976; see also Chapter 2), and in Matsushiro, Japan (Ohtake, 1974), were undertaken to directly control the behavior of large numbers of small seismic events by manipulation of fluid injection pressure.

Fluid withdrawal has also been observed to cause seismic events. McGarr (1991) identified three earthquakes in California caused by or likely related to extraction of oil: (1) Coalinga, in May 1983, **M** 6.5; (2) Kettleman North Dome, in August 1985, **M** 6.1; and (3) Whittier Narrows, in October 1987, **M** 5.9. All three events occurred in a crustal anticline close to active oil fields and on or near seismically active faults. Although seismic deformation (uplift) observed during each earthquake has been suggested to have a correlation to removal of hydrocarbon mass (McGarr, 1991), well-documented and ongoing uplift and seismicity over the entire region, related to natural adjustments of the Earth's crust, make it difficult to determine unequivocally if these were induced seismic events. In the mid-1970s and 1980s three large earthquakes (measuring **M** ~ 7) were recorded near the Gazli gas field in Uzbekistan in an area that had largely been aseismic. Although precise locations and magnitudes of the earthquakes were not possible to determine, a potential relation to gas extraction was suggested based on available data and modeling (Adushkin et al., 2000; Grasso, 1992; Simpson and Leith, 1985).

Some surface effects associated with energy technologies may occur (without associated shaking at the surface) that result from surface subsidence or "creep" rather than from slip along a fault. Examples include the Baldwin Hills dam failure in California (Appendix F).

CONCLUDING REMARKS

Human activity, including injection and extraction of fluids from the Earth, can induce seismic events. While the vast majority of these events have intensities below that which can be felt by people living directly at the site of fluid injection or extraction, potential exists to produce significant seismic events that can be felt and cause damage and public concern. Examination of known examples of induced seismicity can aid in determining what the risks are for energy technologies. These examples also provide data on the types of research required to better constrain induced seismicity risks and to develop options for best practices to define and alleviate risks from energy-related induced seismicity. These issues are explored in the remaining chapters of this report.

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CHAPTER TWO

Types and Causes of Induced Seismicity

INTRODUCTION

Energy technology activities known to have produced induced seismicity, whether significant enough to be felt by humans or so small as to be detected only with sensitive monitoring equipment, are fluid injection and withdrawal as well as purposeful fracturing of rocks. For each of these activities the critical components required to produce induced seismicity are the presence and orientation of existing faults, the state of stress of the Earth's crust, the rates and volumes of fluid injection or withdrawal, and time. Understanding these components gives some confidence in being able to draw conclusions about what seismicity might be induced in the future, and under what conditions. The physical mechanisms[1] responsible for inducing seismic events are discussed here with reference to specific energy technologies; detailed explanations of these technologies and their relationship to induced seismic events are presented in Chapter 3.

FACTORS AFFECTING INITIATION AND MAGNITUDE OF A SEISMIC EVENT

Shallow earthquakes result from slip (movement) along a preexisting fault. Two critical questions concerning such earthquakes are (1) which factors are responsible for the initiation of a seismic event and (2) which factors control the magnitude of the event.

Initiation of a Seismic Event

The Earth's crust is crossed by a network of preexisting fractures and faults of various sizes. Any of these faults could, in principle, be activated if the shear stress (τ) acting on the fault overcomes its resistance to slip or movement of the adjacent rock blocks (called "shear resistance"). In most cases, the shear resistance (or shear strength) is due to friction. In other words, the shear strength is proportional to the difference between the normal stress (σ) acting on the fault and the pressure (ρ) of the fluid permeating the fault and the surrounding rock. The fault remains stable (does not slip) as long as the magnitude of

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[1] Although hydromechanical coupling is the dominant mechanism responsible for inducing seismic events, other coupling mechanisms (e.g., thermomechanical and chemomechanical) could also play a role.

the shear stress (τ) is smaller than the frictional strength, which can be represented by this expression: $\mu(\sigma - \rho)$. The term $(\sigma - \rho)$ is called the effective stress. The symbol μ represents the friction coefficient, a parameter that varies only in a narrow range, typically between 0.6 and 0.8 for most rock types. This condition for triggering slip, known as the Coulomb criterion, is discussed in more detail in Box 2.1 and Appendix G (see also Jaeger et al., 2007; Scholz, 2002).

The key parameters controlling the initiation of slip are therefore the normal and shear stresses acting on the fault as well as the pore fluid pressure (hereafter simply referred to as "pore pressure"). The normal and shear stresses on the fault depend on the orientation of the fault and on the state of stress in the rock. Due to the weight of the overlying rock and other processes in the Earth's crust, rocks are usually under compression. The compressive normal stress acting on a rock at depth varies with direction; this variation of the normal stress with direction is linked to the shear stresses that are responsible for slip along a fault if the frictional resistance of the fault is overcome. In contrast, for a fluid at rest, the state of stress is hydrostatic: the normal stress is the same in all directions, and it cannot transmit any shear stresses.

The state of effective stress at a point in the Earth involves both the stress tensor and the pore pressure. The stress tensor is described by the vertical stress (σ_v) and the minimum and maximum horizontal stresses (σ_h and σ_H) that act in two orthogonal directions. The direction of σ_H, as well as the relative values of σ_v, σ_h, and σ_H, control the orientation of the fault most likely to slip; three different fault regimes are defined depending on the relative magnitude of σ_v, σ_h, and σ_H (Box 2.2). Once the most critical fault orientation has been identified, the normal and shear stresses acting on the fault can in principle be computed from the state of effective stress.

Determination of the in situ state of stresses in the subsurface is complex and often expensive. Consequently, the information on the in situ stress in the Earth is usually too fragmentary to allow confident estimates of the actual stresses acting on a fault. In most cases the only reliable information available is the magnitude of the vertical stress, as it can simply be estimated from the average density of the overlying rock and the depth. Estimating the general fault types and configurations as well as the broad orientation of the maximum and minimum horizontal stresses at a scale of tens or hundreds of kilometers is also sometimes possible, based on a variety of stress indicators (see also Figure 4 in Box 2.2).

In contrast to the difficulty of determining the maximum and minimum horizontal stresses and their orientations, the undisturbed initial pressure of the fluid permeating the rock and the fractures or faults can usually be reliably estimated from the depth of the rocks, under normally pressurized conditions. Techniques also exist for direct measurement of the pore pressure from a well.

Although the conditions for initiating slip on a preexisting fault are well understood, the difficulty remains to make reliable estimates of the various quantities in the Coulomb criterion. Lacking these estimates, predicting how close or how far the fault system is from instability remains difficult, even if the orientation of the fault is known. This implies that the magnitude of the increase in pore pressure that will cause a known fault to slip cannot generally be calculated. Nonetheless, understanding how different factors contribute to slip initiation is valuable because it provides insight about whether fluid injection or withdrawal may be a stabilizing or a destabilizing factor for a fault (in other words, whether fluid injection or withdrawal causes the difference between the driving shear stress and the shear strength to increase or decrease). Any perturbation in the stress or pore pressure that is associated with an increase of the shear stress magnitude and/or a decrease of the normal stress and/or an increase of the pore pressure could be destabilizing; such a perturbation brings the system closer to critical conditions for failure. A large body of evidence suggests that the state of stress and pore pressure are often not far from the critical conditions where a small destabilizing perturbation of the stress and/or of the pore pressure could cause a critically oriented fault to slip (Zoback and Zoback, 1980, 1989).

Magnitude of a Seismic Event

The moment magnitude scale, designated **M**, is directly related to the amount of crustal energy released during a seismic event (Hanks and Kanamori, 1979). This energy can be thought of as the total force released during the earthquake times the average fault displacement over the fault rupture area (see also the section Earthquakes and Their Measurement in Chapter 1).

Earthquake magnitude is correlated to the area of the rupture surface. Earthquakes with large magnitudes always involve large parts of the Earth's crust, because the large energies being released can only be stored in large volumes of rock, and large rupture areas are necessary to produce large fault displacements. Correlations between **M** and rupture area from observations of historical earthquakes indicate that an increase of 1 magnitude unit implies, on average, an increase by a factor of about 8 in fault rupture area, and a concurrent increase by a factor of about 4½ in rupture displacement (Wells and Coppersmith, 1994). The following examples are typical fault rupture areas and rupture displacements associated with earthquakes of **M** 4 and **M** 5:

	M 4	**M 5**
Fault rupture area:	1.4 km^2 (~0.5 mi^2)	11 km^2 (~4.2 mi^2)
Fault displacement:	1 cm (~0.4 in)	4.5 cm (~1.8 in)

A larger-magnitude earthquake implies both a larger area over which crustal stress is released and a larger displacement on the fault. From the definition of **M**, we can expect that a 1-unit increase in magnitude will be associated with a factor of about 32 larger release

BOX 2.1
Conditions Leading to Seismic Slip on a Fault

Shallow earthquakes result from slip along a preexisting fault. The slip is triggered when the stress acting along the fault exceeds the frictional resistance to sliding. The critical conditions are quantified by the Coulomb criterion, which embodies two fundamental concepts, friction and effective stress. These two concepts can be illustrated by considering the shearing of a split block (Figure 1). The block is subjected to a normal force F_n and a shear force F_s, which can be translated into a normal stress $\sigma = F_n/A$ and the shear stress $\tau = F_s/A$ acting across the joint, with A designating the interface area of the joint. The joint (and possibly also the block if it is porous) is infiltrated by fluid at pressure ρ.

According to the Coulomb criterion, there is no relative movement across the joint, as long as the shear stress (τ) is less than the frictional strength $\mu(\sigma - \rho)$, where μ is the coefficient of friction. The conditions for slip are thus met when $\tau = \mu(\sigma - \rho)$. The term $(\sigma - \rho)$ is called the effective stress; the presence of effective stress in the Coulomb criterion shows that the fluid pressure (ρ) counterbalances the stabilizing effect of the normal stress (σ). The Coulomb criterion indicates that slip can be triggered by a decrease of the normal stress, an increase of the pore pressure, and/or an increase of the shear stress (Figure 1b).

Note that the common concept that "injected fluids cause earthquakes by lubricating underground faults" is not accurate because fluids do not decrease the coefficient of friction, μ. Rather, injected fluids (or extracted fluids) cause earthquakes by changing the stress conditions around faults, bringing these stresses into a condition where driving stresses equal or exceed resistive stresses, thereby promoting slip on the fault.

Within the context of slip on a fault, the normal and shear stresses acting across the fault, σ and τ, can be directly expressed in terms of the vertical stress (σ_v), the horizontal stress (σ_h), and the fault inclination (β) (Figure 2). Prior to injection or extraction of fluid, the initial state is stable because the shear stress (τ_o) is less than the frictional strength $\mu(\sigma_o - \rho_o)$, although the condition could be close to critical. Injection or extraction of fluid could cause changes in the stress and pore pressure such that the critical condition expressed as $\tau = \mu(\sigma - \rho)$ is met (Figure 2b is a graphical representation).

This box describes the simple case of a frictional fault. The more general case of a fault with cohesive-frictional strength is treated in Appendix H.

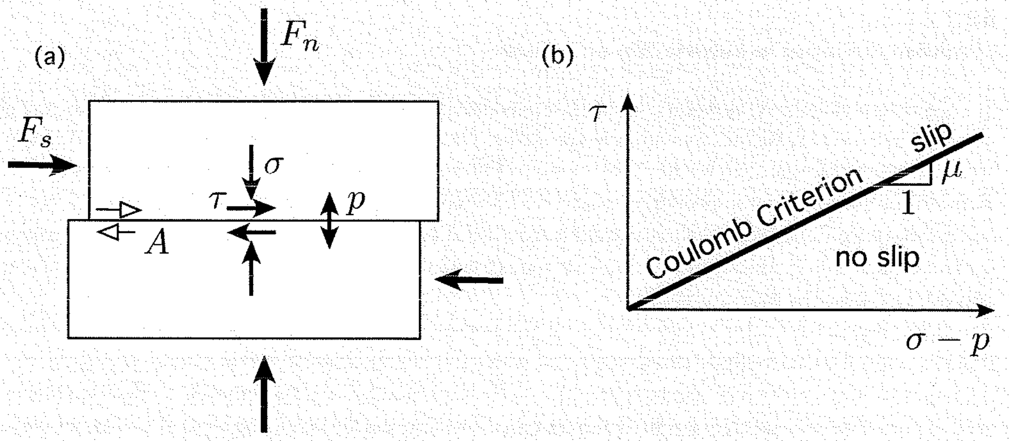

Figure 1 (a) Shearing of a jointed block subjected to normal force F_n and shear force F_s, with fluid inside the joint at pressure ρ. Slip along the joint is triggered when the shear stress τ is equal to the frictional strength $\mu(\sigma - \rho)$, where $(\sigma - \rho)$ is the effective stress and μ is the coefficient of friction. (b) Graphical representation of the Coulomb criterion: there is no slip if the "point" $(\sigma - \rho, \tau)$ is below the critical line defined by slope μ.

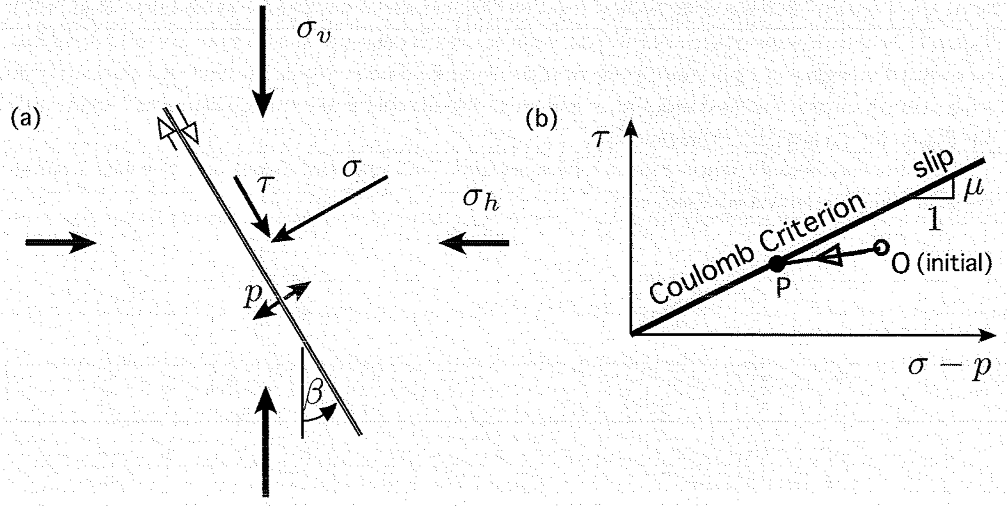

Figure 2 (a) The normal and shear stresses (σ and τ) acting across the fault depend on the vertical and horizontal stress (σ_v and σ_h) and the fault inclination (β). (b) Fluid injection or extraction could induce changes in the stress and the pore pressure; for example, fluid injection could move the initially stable "point" "O" in Figure 2b to a new position "P" that is on the critical Coulomb line, thus triggering slip on the fault. The inclination of the segment OP is a function of the poroelastic coupling described in Box 2.3.

BOX 2.2
In Situ Stress State

The full characterization of the state of stress at a point of the subsurface requires in principle six independent quantities, illustrated through the following example.

Imagine that a small cube of rock centered on the point of interest is cut from its surrounding. To leave the material inside the cube undisturbed by the cutting, forces have to be applied on each face of the cube to mimic the action of the surrounding medium onto the cut material, noting also that forces acting on opposed faces are equal and opposite in direction. However, in considering in situ stress state, using the term "stress," which is equivalent to the force exerted over a defined area, is more appropriate than discussing "force" alone; in this way, stress is not dependent on the size of the cube.

If the cube is rotated in space, the stresses acting on its faces change in magnitude and direction. However, a certain orientation of the cube exists for which each face is only loaded by a stress normal to the face (Figure 1). The three independent normal stresses are referred to as principal stresses, and their corresponding orientations in space as principal directions. On two faces of the cube oriented according to the principal directions, the normal stress is maximum and minimum and for any other orientation of the cube, the normal stress on any face is in between these two limiting values. The principal stress acting on the face parallel to the minimum and maximum principal stresses is called intermediate.

A set of six quantities, the three principal stresses and their directions, thus represents the state of stress. Fortunately, vertical can often be considered as one of the principal directions, with the consequence that the vertical stress σ_v at depth h is then simply given by the weight of the overlying rock (i.e., $\sigma_v = pgh$, where p is the average density of the overlying rock and g is gravity). Determination of the state of stress is then reduced to identifying three quantities, the minimum and maximum horizontal stresses, respectively σ_h and σ_H, and the azimuth of σ_H (or equivalently of σ_h).

Stress data compiled by Brown and Hoek (1978) confirm that, despite some scattering, the vertical stress is proportional to depth in a manner consistent with an average rock density $p = 2{,}700$ kg/m^3 (~170 lb/ft^3) (Fig-

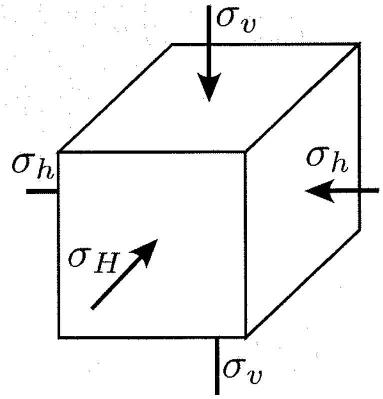

Figure 1 State of stress in the subsurface, with one of the principal stress directions being vertical. By convention, $\sigma_H > \sigma_h$.

ure 2a). The ratio of the mean horizontal stress to the vertical stress (Figure 2b) appears to vary over a narrower range with increasing depth, the ratio being generally less than 1 at depths larger than 2 km (~1.2 miles).

The relative magnitude of the three principal stresses, σ_h, σ_H, and σ_v, establishes the conditions for the orientation of the faults. Three regimes of stress, each associated with different fault orientations, are commonly defined (Figure 3): (a) thrust fault regime with σ_v equal to the minimum principal stress, (b) normal fault regime

continued

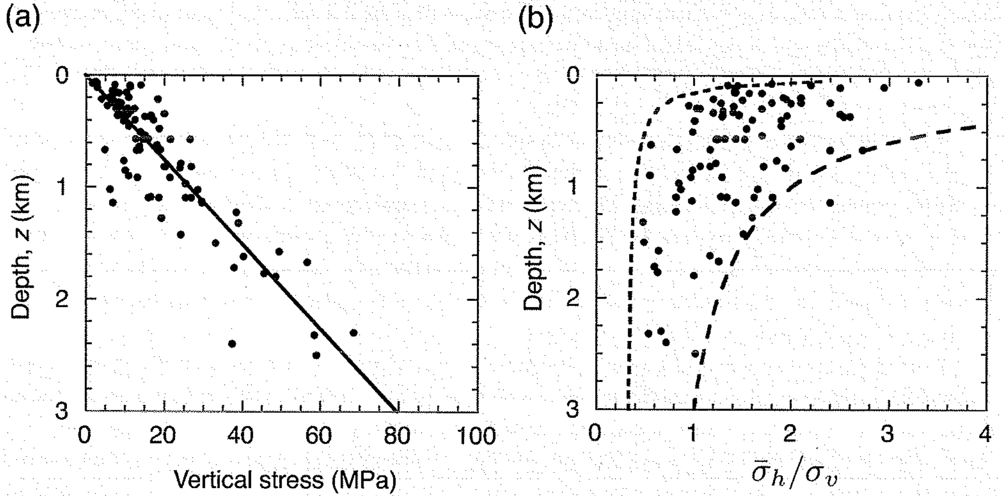

Figure 2 (a) Vertical stress variation with depth; the linear trend corresponds to a mean density of 2,700 kg/m^3. (b) Variation of the ratio of the mean horizontal stress $(\sigma_H + \sigma_h)/2$ over the vertical stress σ_v with depth. SOURCES: Figure modified from Jaeger et al. (2007), which was itself redrawn from the original figure of Brown and Hoek (1978).

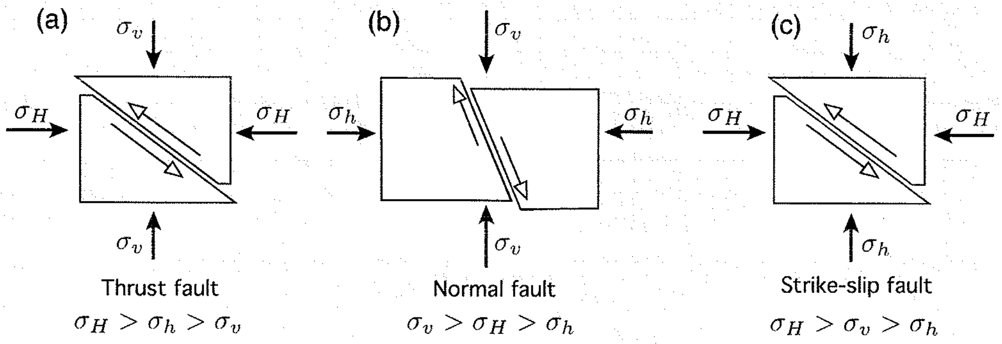

Figure 3 (a) Thrust fault, (b) normal fault, and (c) strike-slip fault. (Cross sections shown are in vertical plane for (a) and (b) and horizontal plane for (c).)

BOX 2.2 Continued

with σ_v equal to the maximum stress, and (c) strike-slip fault regime corresponding to the vertical stress being equal to the intermediate principal stress.

Determination of three unknown quantities (σ_h , σ_H , and their orientation) remains a formidable problem. Most of the time, the only information available is the stress regime and the broad orientation of σ_H , which can be inferred using a variety of stress indicators such as earthquake focal mechanisms, wellbore breakouts, drilling-induced fractures, and other data (Zoback and Zoback, 1980, 1989).

Furthermore, the stress varies from point to point within the Earth, subject to the constraint of having to satisfy the equilibrium equations, a consequence of Newton's second law. Spatial variation of the state of stress exists at various scales, as the stress is affected by the structure of the subsurface, the geometry and mechanical properties of different lithologies, preexisting faults and other discontinuities in the crust, and other characteristics. Yet, when viewed at the scale of hundreds of kilometers, patterns emerge that can be seen on the stress map for North America (Figure 4). This stress map, a compilation of all available stress information, shows the orientation of σ_H and the stress regime superimposed on a topographical map of North America (Heidbach et al., 2008).

The example above refers to the initial state of stress (i.e., to the stress prior to injection or extraction of fluid). Large variation of the pore pressure and/or temperature could also induce significant stress changes that have to be accounted for when assessing the potential for induced seismicity.

in crustal energy (a factor often cited in news reports following large earthquakes), and the estimates cited in the examples from empirical observations are in general agreement with that definition.

Most existing fractures in the Earth's crust are small and capable of generating only

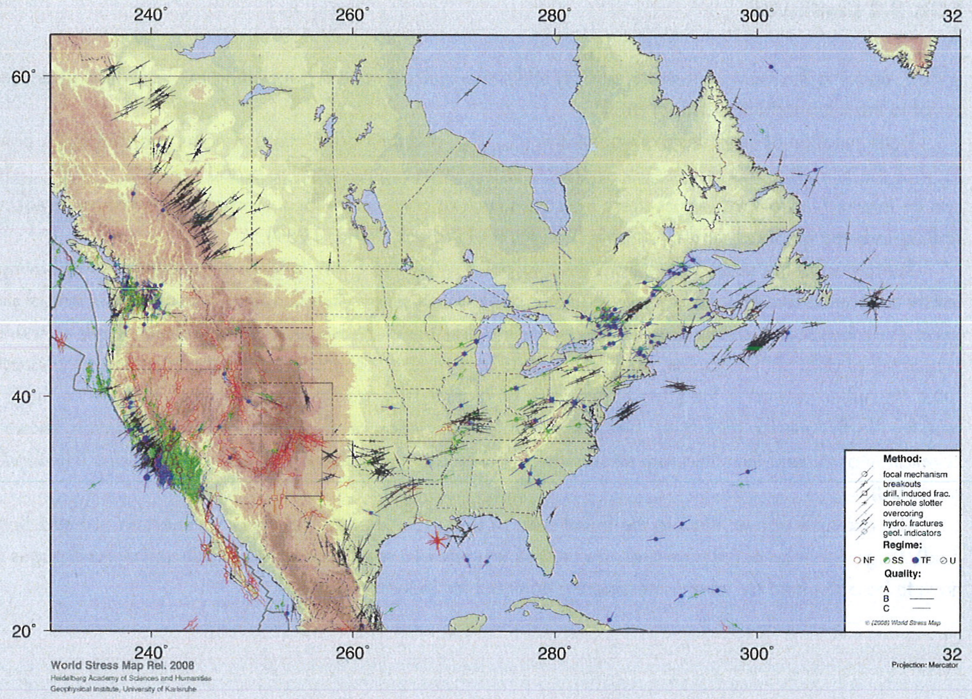

Figure 4 North America stress map. The stress map displays the orientations of the maximum horizontal compressive stress (σ_H). The length of the stress symbols represents the data quality, with A being the best quality. Quality A data are assumed to record the orientation of σ_H to within 10°-15°, quality B data to within 15°-20°, and quality C data to within 25°. As can be seen from this global dataset, stress measurements are absent in many parts of North America and the offshore regions. Because stress measurements are important in the consideration of induced seismicity, their measurement, particularly in areas where data are sparse, could usefully contribute to understanding the potential for induced seismicity related to energy development. The tectonic regimes are NF for normal faulting, SS for strike-slip faulting, TF for thrust faulting, and U for an unknown regime. Topographic relief is indicated by green (lower elevations) to brown (higher elevations) shading. SOURCE: Data used to plot this map were accessed from www.world-stress-map.org/ (see Heidbach et al., 2008).

small earthquakes. Thus, for fluid injection to trigger a significant earthquake, a fault or faults of substantial size must be present that are properly oriented relative to the existing state of crustal stress, and these faults must be sufficiently close to points of fluid injection to have the rocks surrounding them experience a net pore pressure increase.

SEISMICITY INDUCED BY FLUID INJECTION

Injection of fluid in rocks causes an increase of the pore pressure and also modifies the state of the stress (Hsieh, 1996; NRC, 1990). The stress change is associated with a volume expansion of the rock due to the increase of the pore pressure, similar to the familiar thermal expansion experienced by materials (Box 2.3). However, the pore pressure perturbation

BOX 2.3
Stress Induced by Fluid Injection or Withdrawal

Injection or extraction of fluid into or from a permeable rock induces not only a pore pressure change in the reservoir but also a perturbation in the stress field in the reservoir and in the surrounding rock. The physical mechanism responsible for this hydraulically induced stress perturbation can be illustrated by considering the injection of a finite volume of fluid inside a porous elastic sphere surrounded by a large impermeable elastic body (see Figure). The magnitude of the induced pore pressure (Δp), once equilibrated, is proportional to the volume of fluid injected.

Assuming that the sphere is removed from the surrounding body, the pore pressure increase (Δp) induces a free expansion of the sphere (ΔV_*), similar in principle to the familiar thermal expansion experienced by a solid subject in response to a temperature increase. To force the expanded sphere back to its earlier size requires the application of an external confining stress ($\Delta \sigma_*$), which is then relaxed. The final state corresponds to a constrained expansion of the sphere (ΔV), which is less than the free expansion; this state can be associated with a stress perturbation ($\Delta \sigma$) that is isotropic and uniform inside the sphere, but nonisotropic and nonuniform outside the sphere. The magnitude of the stress perturbation decays away from the sphere, becoming negligible at a distance about twice the sphere radius. The stress induced inside the sphere is compressive when the pore pressure increases (fluid injection) but tensile if the pore pressure decreases from its ambient value (fluid withdrawal).

This example illustrates the fundamental mechanism by which the stress field in the rock is modified by injection or withdrawal of fluid. The complexities associated with geological settings—in particular, the actual shape of the reservoir, its size, as well as the nonuniformity of the pore pressure field—affect the nature of the stress perturbation. The horizontal and vertical stress variations within most geological reservoirs are rarely identical; inside a tabular reservoir of large lateral extent compared to its thickness, only the horizontal stress is affected by the pore pressure change.

In the case of fluid injection in a fractured impermeable basement rock, such as that which may be a target for development of enhanced geothermal systems (EGS; see also Chapter 3), the perturbation is only of a hydraulic nature and the stress change can generally be ignored.

An analysis of the pore pressure and stress perturbation indicates that, in general, fluid injection increases the risk of slip along a fault located in the region where the pore pressure has increased. In the case of fluid withdrawal, the region at risk is generally outside the reservoir (see also Nicholson and Wesson, 1990).

dominates over the stress variation and, when the consequence of fluid injection with regard to the induced seismicity is considered, the stress perturbations can often be ignored. Disregarding the stress change in the rock caused by injection is a conservative approach because these kinds of perturbations are usually of a stabilizing nature (see Appendix G for a detailed explanation).

Pore pressure increases in the joints and faults are potentially destabilizing, since they

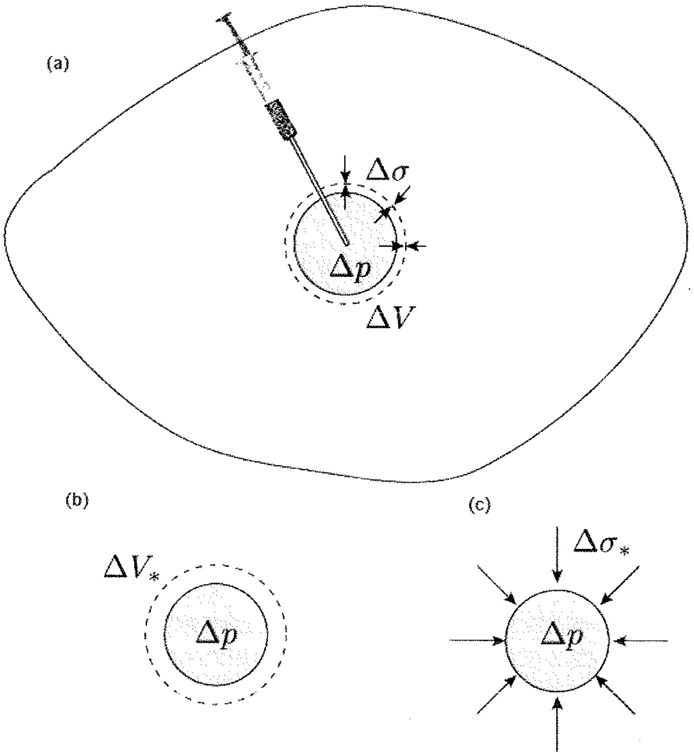

Figure (a) Injection of a finite volume of fluid inside the porous elastic sphere embedded in a large impermeable elastic body induces a pore pressure increase Δp inside the sphere as well as a stress perturbation $\Delta\sigma$ inside and outside the sphere, caused by the expansion ΔV of the sphere. (b) If the sphere is freed from its elastic surrounding, it will expand by the amount ΔV_* due to the pore pressure increase Δp. (c) A confining stress $\Delta\sigma_*$ needs to be applied on the free sphere to prevent the expansion ΔV_* caused by Δp. If the material in the surrounding medium is much softer than the material in the sphere, then $\Delta V \simeq \Delta V_*$ and $\Delta\sigma \simeq 0$; if the medium is much stiffer, then $\Delta V \simeq 0$ and $\Delta\sigma \simeq \Delta\sigma_*$. $\Delta\sigma$ refers only to the radial stress in the exterior region. Note: Syringe based on a concept from H.F. Wang (Wang, 2000).

cause a reduction of the slip resistance of a fault located in the region of pore pressure increase. In assessing the potential for induced seismicity, two basic questions arise: (1) What is the magnitude of the pore pressure change? and (2) What is the extent of the volume of rock where the pore pressure is modified in any significant manner? The magnitude of the induced pore pressure increase and the extent of the region of pore pressure change depend on the rate of fluid injection and total volume injected, as well as on two hydraulic properties of the rock, its intrinsic permeability (k) and its storage coefficient (S), and on the fluid viscosity (μ).

The permeability (k) is a quantitative measure of the ease of fluid flow through a rock; it depends strongly on the porosity of the rock (the volume percentage of voids in the rock volume) but also on the connectivity between pores. The storage coefficient (S) is a measure of the relative volume of fluid that needs to be injected in a porous rock in order to increase the pore pressure by a certain amount; the storage coefficient depends on the rock porosity in addition to the fluid and rock compressibility. The permeability (k) can vary by many orders of magnitude among rocks; for example, the permeability of a basement rock such as granite could be up to a billion times smaller than the permeability of oil reservoir sandstone (Figure 2.1).

However, the storage coefficient increases only by about one order of magnitude between a tight basement rock and high-porosity sandstone. The ratio $k:\mu S$ is the hydraulic diffusivity coefficient (c), which provides a measure of how fast a perturbation in the pore

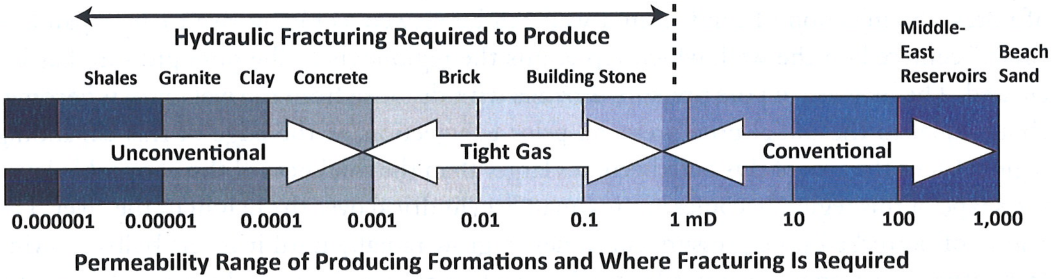

FIGURE 2.1 Comparison of permeability in oil and gas reservoirs utilizing permeability values for typical rock types and common building materials. The higher the connectivity between the pore spaces, the higher the permeability; for oil and gas reservoirs, higher permeability generally indicates greater ease with which the hydrocarbons will flow out of the reservoir and into a production well. Permeability is most commonly measured using a unit called a millidarcy (mD), and permeabilities can range between 1,000 mD (high permeability, comparable to beach sand) to very low permeability (0.000001 mD, which would describe the least permeable rocks such as shales). Other common materials (such as granite or brick) are noted on the upper part of the scale in this figure to give a sense of the range of permeabilities on the millidarcy scale. Although hydraulic fracturing has been used for decades to stimulate some conventional reservoirs, hydraulic fracturing is required to produce from low-permeability reservoirs such as tight sands and shales (left-hand side of the diagram). SOURCE: Adapted from King (2012).

pressure propagates in a saturated rock; like the permeability (*k*), the diffusivity (*c*) can vary over many orders of magnitude for different rocks. These parameters can be determined either from laboratory tests on drill core samples from wells or from pumping or injection tests, which have the advantage of providing estimates that are averaged over a scale relevant for reservoir calculations.

The intrinsic permeability of basement rocks is so low that the transport of fluid in these rocks can be thought of as taking place almost exclusively in the network of fractures that is pervading the crust. In other words, the rock itself can be viewed as being impermeable. Concepts of permeability and storage coefficient can be extended to fractures, where they transform into a transmissivity and storativity, with their ratio also having the meaning of diffusivity (see, e.g., Nicholson and Wesson, 1990; NRC, 1996).

The important point is that faults and fractures in basement rocks offer relatively little resistance to flow, and thus the equivalent permeability and diffusivity of these fractured rocks (with fractures and rocks viewed as a whole) can be very high. For example, the hydraulic diffusivity deduced from the time evolution of spatial spread of microseismic events measured during injection of water into a crystalline rock at Fenton Hill, an EGS site (Fehler et al., 1998), is about 0.17 m^2/s (Shapiro et al., 2003), a value in the range of those for very permeable sandstones. The combination of high transmissivity, small storativity, and the planar nature of fractures implies that significant pore pressure changes can be transmitted over considerable distances (several kilometers [miles]) through a fracture network from an injection well.

In permeable rocks, where the fluid is dominantly transported by a connected network of pores, the injection of fluid from a well can be viewed as giving rise to an expanding "bulb," centered on the well, which represents the region where the pore pressure has increased. The increase in pore pressure *decreases* with distance from the well until it becomes about equal to the initial pore pressure, prior to injection, at the edge of this expanding region. Once the size of this bulb becomes larger than the thickness of the permeable layer, the shape of this region becomes approximately cylindrical over the height of the layer. The region of perturbed pore pressure continues to grow radially until it meets bulbs growing from other injection wells or until it reaches the lateral boundaries of the reservoir (see also Nicholson and Wesson, 1990).

The dependence of the magnitude of induced pore pressure and of the size of the perturbed pore pressure region on the injection rate, the volume of fluid injected, and the rock hydraulic properties (permeability and storage coefficient) is complex. Numerical simulations are generally needed to establish these relationships, which depend on the geometry of the permeable rock. However, some general rules apply either at the early stage of injection when the bulb of increased pore pressure grows unimpeded by the interaction with the lateral boundaries of the reservoir or with other bulbs, or at a late stage of injection when the increase of the pore pressure is nearly uniform in the reservoir, which is here assumed to be of finite extent (see Appendix H for the calculation of the pore pressure induced by injection into a disc-shaped reservoir).

At the early stage of injection, the size of the bulb will essentially depend on the diffusivity of the rock and on the duration of injection (equal to the ratio of injected volume over the injection rate). The maximum induced pore pressure is equal to the ratio of the injection rate over the permeability times a function of the duration of injection. This means that the bulb size increases but the maximum pore pressure decreases with increasing rock permeability, everything else being equal. In other words, the induced pore pressure dissipates faster with increasing permeability. At the late stage of injection, the induced pore pressure does not depend on the injection rate and on the permeability, because it becomes proportional to the ratio of the volume of fluid injected over the storage coefficient.

The extent of the induced pore pressure field and the magnitude of the induced pressure are both relevant when assessing the risk of induced seismicity. A larger pore pressure increase brings the system closer to the conditions for initiating slip on a suitably oriented fault, if such a fault exists; a larger region of disturbed pore pressure will increase the risk of intersecting and activating a fault.

Inducing a significant seismic event requires an increase of the pore pressure above levels that have existed prior to fluid injection and over a region large enough to encompass a fault area consistent with the magnitude of the earthquake. For example, an earthquake of magnitude **M** 3 results from a rupture area of about 0.060 km^2 (corresponding to 15 acres). Such a situation was encountered at the Rangely, Colorado, oilfield starting in 1957, when sustained waterflooding operations (secondary recovery to improve petroleum production) over a period of several years caused the pore pressure to increase (Box 2.4). Eventually, pore pressure reached a level about 17 MPa (170 bars)[2] above the preproduction pore pressure, a threshold at which a series of seismic events began to occur; the largest of these events was **M** 3.4. However, waterflooding would not be expected to cause any significant seismic activity if the pore pressure did not exceed the initial pore pressure in a reservoir. Operators generally do not exceed preproduction pore pressure during waterflooding projects because they tend to maintain relative balance between the volumes of fluid injected and extracted. Exceptions to this generally balanced condition for waterflooding and resulting induced seismicity are cited in Appendix C.

Observations and monitoring of hydraulic fracturing treatments indicate that generally only microseismic events (microseisms, **M** < 2.0; see Chapter 1) are produced because the volume of fluid injected is relatively small (see also Chapter 3 for further details). Despite the fact that hydraulic fracturing does increase pore pressure above the minimum in situ stress (typically σ_h), the area affected by the increase in pore pressure is generally small, remaining in the near vicinity of the created fracture.

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[2] MPa = megapascal; 1 MPa is equivalent to 10 bars or about 10 atmospheres of pressure.

SEISMICITY INDUCED BY FLUID WITHDRAWAL

Fluid extraction from a reservoir can cause declines in the pore pressure that can reach hundreds of bars. The declining pore pressure causes large contraction of the reservoir, which itself induces stress changes in the surrounding rock (Segall, 1989), in particular increasing horizontal stresses above and below the reservoir that could lead to reverse faulting (Figure 2.2). Grasso (1992) estimates that volume contraction of reservoirs from fluid withdrawal can cause earthquakes up to **M** 5.0.

Several examples of induced seismicity associated with fluid withdrawal and associated pore pressure decrease have been reported, notably at the Lacq gas field in France (Box 2.5). A study of induced seismicity associated with natural gas extraction in the Netherlands (Van Eijs et al., 2006) indicates that the three most important factors in producing seismicity are the pore pressure drop from pumping, the density of existing faults overlying the gas field, and the contrast in crustal stiffness between the reservoir rock and the surrounding rock.

Another proposed mechanism for initiating slip on preexisting faults is linked to the reduction of the vertical stress on the layers underlying the reservoir from which a large mass of hydrocarbons has been extracted (McGarr, 1991). In this mechanism, the buoyancy force of the Earth's lithosphere will cause an upward movement in the part of the crust that has been unloaded, thereby inducing slip on preexisting faults at depth.

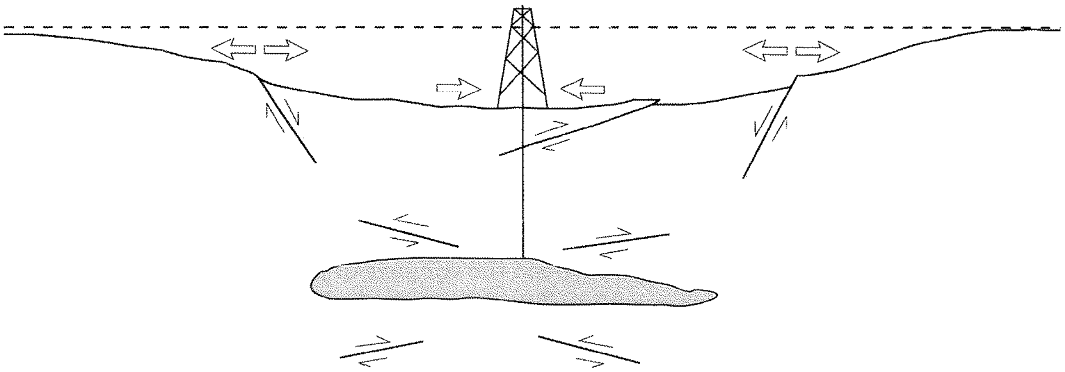

FIGURE 2.2 Observed faulting suggested to be associated with fluid withdrawal. Open arrows denote horizontal strain. In this interpretation, normal faults develop on the flanks of a field when the oil reservoir is located in a region of crustal extension. Reverse faults may develop above and below the reservoir if the reservoir is located in a region undergoing compression. Adapted after Segall (1989).

BOX 2.4
Induced Seismicity at the Rangely, Colorado, Oilfield

The Rangely, Colorado, induced seismicity experiment is an important milestone in the study of induced seismicity that firmly established the effective stress mechanism for induced seismicity. Water injection at the Rangely oilfield began in 1957 in response to declining petroleum production and decreased reservoir pressures. As a result of the waterflooding (secondary recovery) operations, reservoir pore pressures increased throughout the field, and by 1962 pore pressure in parts of the field substantially exceeded the original preproduction pressure of about 170 bars (17 MPa). In the same year the Uinta Basin Seismological Observatory, located about 65 km (~39 miles) from Rangely, began operation and detected numerous small seismic events **M** ≥ 0.5 in the vicinity of Rangely. With sustained fluid injection and elevated pore pressures the seismic events continued and the largest, **M** 3.4, occurred on August 5, 1964. Detailed monitoring with a local U.S. Geological Survey (USGS) seismic network installed in 1969 showed that the seismic events were occurring along a subsurface fault within the oilfield (Figure 1).

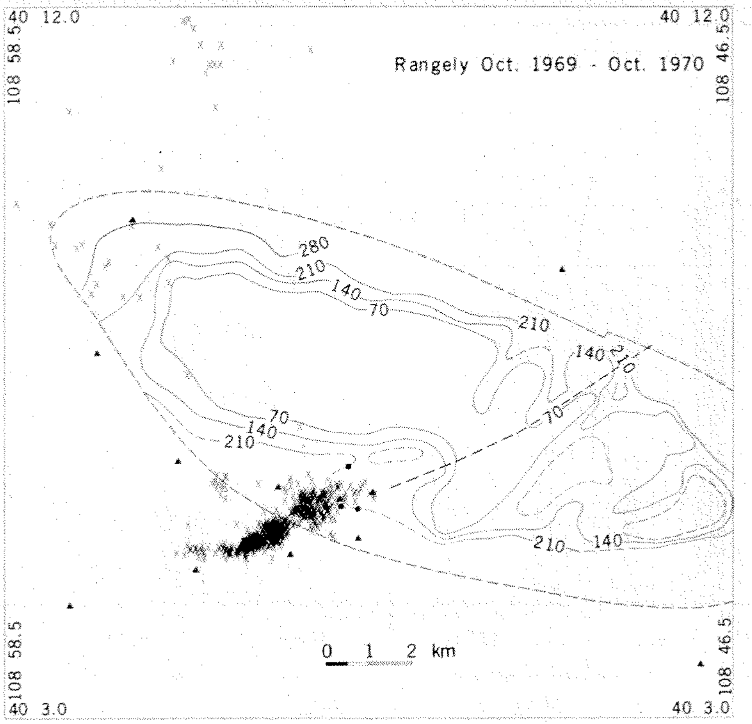

Figure 1 Earthquakes (x) located at Rangely between October 1969 and November 1970. The contours are bottom-hole 3-day shut-in pressures as of September 1969; the interval is 70 bars (7 MPa). Seismic stations are represented by triangles; experimental wells are represented by dots. The heavy, dashed line indicates the fault mapped in the subsurface. SOURCE: Raleigh et al. (1976).

With the cooperation of the Chevron Oil Company, which operated the field, USGS researchers carried out a controlled induced seismicity experiment beginning in November 1970 and continuing to May 1974 (Raleigh et al., 1976). One goal of the experiment was to quantitatively test the effective stress theory for activation of slip on preexisting faults by pore pressure increases (Box 2.1). This portion of the experiment entailed a program of careful measurements of the parameters involved in the Coulomb criterion (Box 2.1), including in situ stress measurements, monitoring and modeling of changes of reservoir pore pressures, laboratory measurement of the sliding resistance between rock surfaces in the reservoir formation where seismic events were occurring, and detailed seismic monitoring to precisely locate the events and determine the fault orientation with respect to the stress field. Together these measurements, when used with the Coulomb criterion expressed in terms of the effective stress, predicted that a critical reservoir pressure of 257 bars was required to induce earthquakes at an injection site within the cluster of earthquakes—a result that agreed with the observed and modeled pore pressures. The second phase of the experiment turned seismic events "on" and "off" by cycling the pore pressures above and below the critical reservoir pore pressure of 257 bars (25.7 MPa) (Figure 2). This experiment proved that induced seismic events could be controlled by regulating the pore pressures.

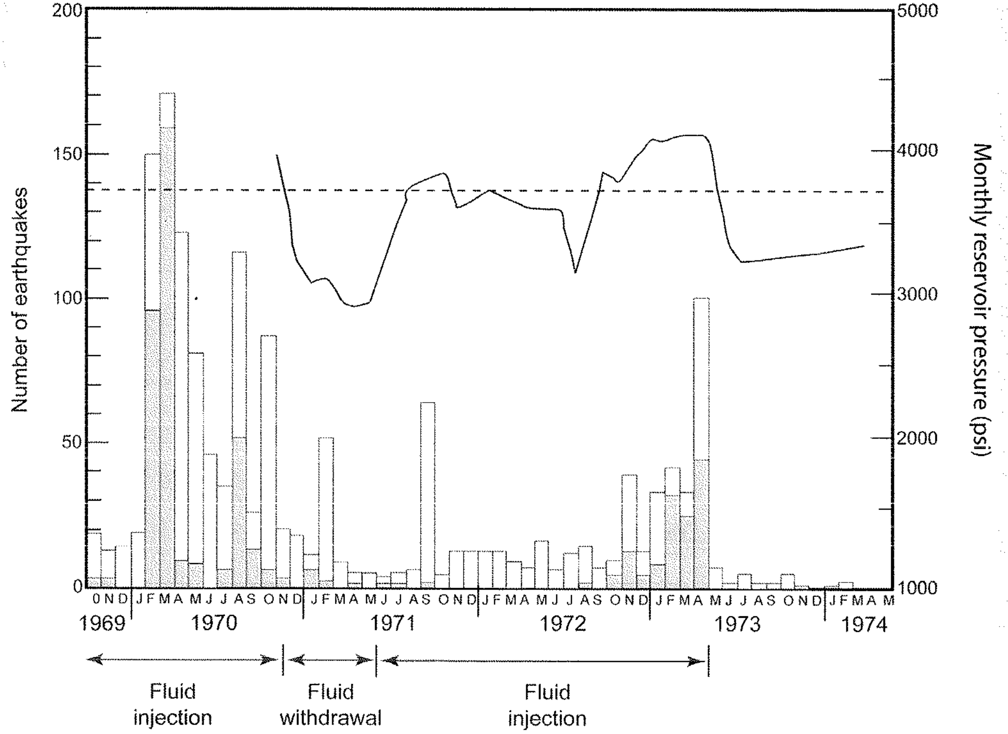

Figure 2 Frequency of seismic events at Rangely. Stippled bars are seismic events within 1 km of the experimental wells. The clear bars represent all other events. Pressure history in well Fee 69 is shown by the heavy line and predicted critical pressure is designated by the dashed line. SOURCE: Raleigh et al. (1976).

BOX 2.5
Induced Seismicity at the Lacq Gas Field (France)

The Lacq gas field in southwestern France offers one of the best-documented cases of seismicity induced by extraction of pore fluids (Grasso and Wittlinger, 1990; Segall et al., 1994). The gas reservoir is a 500-m-thick (~1,640-feet-thick) sequence of limestone that forms a dome-shaped structure at depths of 3.2 to 5.5 km (~2.0 to 3.4 miles) (Figure 1). The reservoir was highly overpressured when production started in 1957, with a pressure of about 66 MPa (660 bars) at a depth of 3.7 km (~2.3 miles) below sea level. The first felt earthquake took place in 1969, at a time when the pore pressure had decreased by about 30 MPa (300 bars). By 1983, the pressure had dropped by 500 bars, and 800 seismic events with magnitude up to **M** 4.2 had been recorded

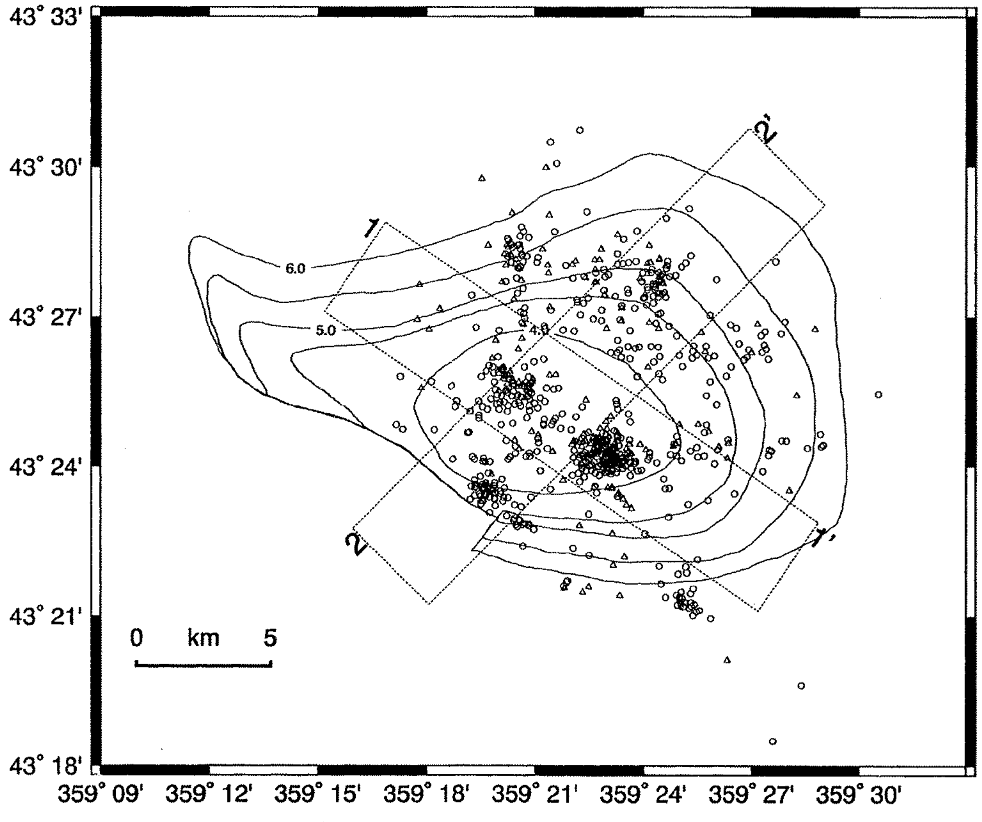

Figure 1 Location of seismic events compared to the size of the gas field (contours indicate depth to the top of the gas reservoir). Locations were determined from a local network and were based on an assumed velocity model. Triangles on the map are epicenters for events between 1976 and 1979; circles represent epicenters for events from 1982 to 1992. The rectangular areas (1-1′ and 2-2′) refer to other parts of the analysis conducted by Segall et al. (1994) and are not discussed further. SOURCE: After Segall et al. (1994).

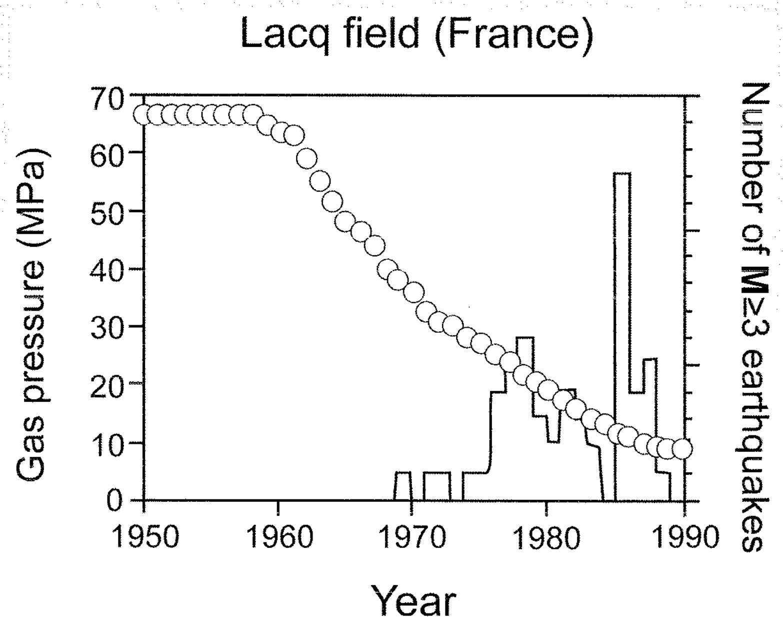

Figure 2 Decline of the pore pressure due to production at the Lacq gas reservoir and number of recorded earthquakes with magnitude **M** ≥ 3, with time, gas pressure (in MPa; 1 MPa is equal to 10 bars) (circles, left scale), and number of **M** > 3 earthquakes per year (solid line, right scale). The number of earthquakes increased with decreasing pressure. SOURCE: Segall (1989).

(Figure 2). The epicenters of 95 percent of the well-located events and all of the **M** > 3 events were within the boundaries of the gas field (Grasso and Wittlinger, 1990).

An analysis of the stress changes above and below the reservoir indicates that the induced seismicity is consistent with a thrust fault regime where the least compressive stress is vertical. Furthermore, the maximum shear stress change is calculated to be about 0.1 MPa (1 bar) for a pressure drop of 30 MPa (300 bars), suggesting that the in situ stress prior to production was close to causing frictional failure of the rock.

SOURCES: Segall (1989); Segall et al. (1994); Segall and Fitzgerald (1998); Grasso and Wittlinger (1990); Grasso (1992).

SUMMARY

Both the conditions that lead to the initiation of a seismic event and the factors that affect the magnitude of the resulting event are well understood. The conditions of initiation are embodied in the Coulomb criterion (involving a comparison of the shear stress on the fault to the fault frictional strength), while the magnitude of the seismic event is related to the area of the fault undergoing slip. Inducing a seismic event requires a triggering event that will either increase the shear stress or reduce the normal effective stress on the fault and/or reduce the fault frictional resistance, for example, an increase of the pore pressure that reduces the frictional strength to a level at which it is overcome by the driving shear stress. However, to cause a significant event requires activating slip over a large enough area; for example, a seismic event of **M** 4 involves a fault area of about 1.4 km^2 (~0.5 square miles) and a slip of about 1 m (~39 inches).

Unfortunately, despite our understanding of the factors affecting the initiation and the magnitude of a seismic event, the values of the process parameters (such as the injection rate or the volume of fluids injected) that will trigger the seismic event and what magnitude the event will be are generally not possible to quantify. The inability to make these kinds of predictions is due to several factors: (1) fragmentary knowledge of the state of stress in the Earth; (2) lack of knowledge about the faults themselves, including their existence (if they have not yet been mapped) and their orientations and physical properties; and (3) difficulty in collecting the basic data (hydraulic and mechanical parameters, geometry of the geological structure, such as the reservoir) that are required to calculate the pore pressure and stress change induced by the fluid injection or withdrawal.

Nonetheless, the insights into the mechanisms causing seismic events allow us to make some broad conclusions. In processes involving fluid injection, the pore pressure increase is the dominant factor to be considered, as stress change can often be ignored. Any increase of the pore pressure above historical undisturbed values may bring the system closer to critical conditions. The probability of triggering a significant seismic event increases with the volume of fluid injected: the larger the volume injected, the more likely a larger fault will be intersected. However, injection of fluid in depleted reservoirs (such as in secondary recovery stimulation—waterflooding) is unlikely to create an earthquake, irrespective of the volume of fluid injected, if the pore pressure remains below preproduction values.

The transient region of high pore pressure that surrounds a newly created hydraulic fracture is not expected to be large enough for a significant seismic event to be triggered, except in rare cases where the new hydraulic fracture intersects or is very near an existing fault. Even in such cases, the magnitude of the event is expected to be small because a large fault area will not be affected.

The fluid injected in crystalline basement rocks is essentially transmitted by a network of interconnected fractures and joints. Because of the high transmissivity and low storativity of these kinds of rocks, the potential exists to induce pore pressure increase at considerable distances from the injection well and thus trigger slip on faults that are located kilometers away from the injection source.

Seismicity induced by fluid withdrawal cannot be explained without taking into account the accompanying stress changes, which are associated with the large-scale contraction of the reservoir caused by pore pressure reduction or uplift caused by removal of a significant mass of hydrocarbons. The magnitude of the events can be potentially large, because the stress change takes place over areas that are similar in size to the reservoir. However, to trigger an earthquake requires the initial state of stress to be very close to critical, because the perturbation of the stress is minute compared to the magnitude of the pore pressure reduction. For example, in the well-documented Lacq gas field (France) the increase of the maximum shear stress was estimated to be about 0.1 MPa (1 bar) in regions surrounding the reservoir for a pressure drop of 30 MPa (300 bar) in the reservoir.

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CHAPTER THREE

Energy Technologies: How They Work and Their Induced Seismicity Potential

Much of the energy used in the United States comes from fluids pumped out of the ground. Oil and gas have been major energy sources in the country for over 100 years, and new developments in the production of natural gas indicate that it may provide a significant source of energy for the nation during the twenty-first century. Geothermal power has been used to supply energy in the United States for almost as long as oil, although major electricity generation from geothermal energy sources began only in the 1960s at The Geysers in Northern California. A 2006 report on the potential of geothermal energy (MIT, 2006) suggested it could be a major contributor to the nation's energy supply in the coming decades. Efforts to reduce concentrations of carbon dioxide (CO_2) in the atmosphere have spurred development of technologies to capture and store (sequester) CO_2. Projects to accomplish carbon capture and storage (CCS) from industrial facilities are currently being piloted in the United States and elsewhere in the world. Underground injection of CO_2 has also been commonly used to enhance oil and gas recovery.

This chapter reviews the potential for induced seismicity related to geothermal energy production, conventional oil and gas development (including enhanced oil recovery [EOR]), shale gas development, injection wells related to disposal of wastewater associated with energy extraction, and CCS.

GEOTHERMAL ENERGY

Geothermal energy exists because of the substantial heat in the Earth and the temperature increase with depths below the Earth's surface. Depending upon the regional geology—including the composition of the rocks in the subsurface and any of the fluids contained in the rocks—the temperature increase with depth (the thermal gradient) may be fairly steep and represent the source of sufficient geothermal energy to allow commercial development for electricity generation. The largest actively producing geothermal field in the United States at The Geysers in Northern California generates approximately 725 megawatts of electricity per year ("megawatts electrical" or MWe). This is enough to power 725,000 homes or a city the size of San Francisco. Currently this geothermal field supplies nearly 60 percent of the average electricity demand of the northern coastal region of California.

The most likely regions for commercial development of geothermal power are generally the same regions that have experienced recent volcanism (Figure 3.1). Such areas are concentrated in the western portion of the country. The U.S. Geological Survey (USGS) estimates that the total power output from the hydrothermal (vapor- and liquid-dominated) geothermal resources in the United States can probably be increased to 3,700 MWe per year, and a 50 percent probability exists that it can be increased to about 9,000 MWe per year (Williams et al., 2008). Two recent studies have produced nationwide estimates of the electric power potential that might be achieved by a successful implementation of enhanced geothermal systems (EGS) technology, perhaps contributing 100,000 MWe of electrical power per year (MIT, 2006). More recently the USGS (Williams et al., 2008) has published a mean estimate for potential EGS development on private and accessible public land at

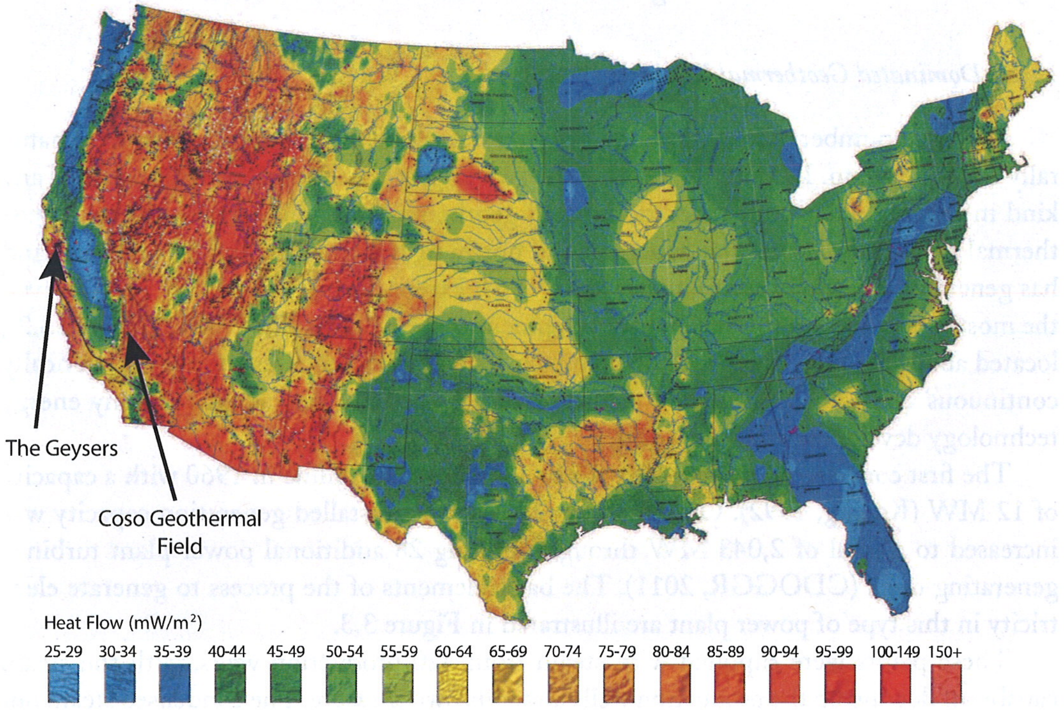

FIGURE 3.1 The location of the geothermal provinces in the United States. Within the United States the regions of relatively high thermal gradients, shown in red, exist only in the West. The typical local geologic setting for these high-geothermal-gradient areas is within sedimentary basins located near or intruded by recent volcanics, or within (as part of) the buried volcanic rocks themselves. Only one vapor-dominated reservoir has been developed in the United States (The Geysers); the remainder of the areas in red and orange may host viable liquid-dominated or enhanced geothermal system reservoirs. SOURCE: SMU Geothermal Lab; Blackwell and Richards (2004).

517,800 MWe. This is approximately half of the current installed electric power generating capacity in the United States.[1]

The three different forms of geothermal resources are recognized: (1) "vapor-dominated," where primarily steam is contained in the pores or fractures of hot rock; (2) "liquid-dominated," where primarily hot water is contained in the rock; and (3) "hot dry rock," where the resource is simply hot and currently dry rock that requires an EGS to facilitate development (see Figure 2.1). Vapor- and liquid-dominated systems are collectively termed hydrothermal resources. The vast majority of known hydrothermal resources are liquid dominated.

The different forms of geothermal resources result in significant differences in the manner in which they are developed and particularly in the manner that liquids are injected to help stimulate energy development. Different injection practices can cause induced seismicity through different processes. The nature of and differences among the induced seismicity that may result from each of the three geothermal resources are summarized here.

Vapor-Dominated Geothermal Resources

A limited number of localities in the world exist where the geothermal resources naturally occur as steam. Despite their rarity, the two largest geothermal developments of any kind in the world are both vapor-dominated geothermal reservoirs. The Larderello geothermal field in the Apennine Mountains of northern Italy became the first of these and has generated electricity continuously since 1904, except during World War II. However, the most productive geothermal field development in the world is The Geysers (Figure 3.2), located about 75 miles north of San Francisco. The Geysers also has the most historically continuous and well-documented record of seismic activity associated with any energy technology development in the world.

The first commercial power plant at The Geysers came online in 1960 with a capacity of 12 MW (Koenig, 1992). Over the next 29 years the installed generation capacity was increased to a total of 2,043 MW through building 28 additional power plant turbine-generating units (CDOGGR, 2011). The basic elements of the process to generate electricity in this type of power plant are illustrated in Figure 3.3.

These plants were supplied with steam from 420 production wells, with the steam capable of flowing up the production wells under its own pressure. The condensed steam not evaporated at the power plant cooling towers was being reinjected into the steam reservoir by using 20 injection wells drilled to similar depths. The area of development had been expanded from the original 3 square miles to about 30 square miles. Because the generation of energy from the field consumes natural steam originally in the reservoir, by 1988

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[1] See http://www.eia.gov/electricity/capacity.

FIGURE 3.2 Ridgeline Unit 7 and 8 Power Plant (rated at 69 MW) in the left foreground at The Geysers in California. The turbine building, housing the two turbine-generator sets, the operator's control room, and various plant auxiliaries are on the left. The evaporative cooling tower with steam emanating from the top is on the right of the main complex. The beige pipelines along the roads (with square expansion loops) are the steam pipelines that gather the steam from the production pads and bring it to the plant. A high-voltage transmission line (denoted by lattice towers) is in the middle foreground of the picture. SOURCE: Calpine.

the production of steam had started to decline; this decline was marked by a significant decrease in reservoir pressure from an original pressure of about 500 pounds per square inch (psi)[2] to levels as low as 175 psi (Barker et al., 1992). For years the annual injection volumes returned to the geothermal reservoir were less than a third of the amount of steam being produced, so the reservoir was drying up. New sources of water were established by constructing two pipelines that currently deliver about 25 million gallons of treated wastewater a day for injection, increasing the current annual mass replacement to 86 percent compared to 26 percent back in 1988 (CDOGGR, 2011).

Early reports of induced seismicity at The Geysers, begun by USGS researchers (Hamilton and Muffler, 1972), described microseismicity that was observed close to where

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[2] A car tire for a standard, midsized automobile is usually inflated to a pressure of about 30-35 psi for comparison.