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INDUCED SEISMICITY FROM ENERGY TECHNOLOGIES

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED TWELFTH CONGRESS

SECOND SESSION

TO

RECEIVE TESTIMONY ON THE POTENTIAL FOR INDUCED SEISMICITY FROM ENERGY TECHNOLOIGES, INCLUDING CARBON CAPTURE AND STORAGE, ENHANCED GEOTHERMAL SYSTEMS, PRODUCTION FROM GAS SHALES, AND ENHANCED OIL RECOVERY

JUNE 19, 2012

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INDUCED SEISMICITY FROM ENERGY TECHNOLOGIES

TUESDAY, JUNE 19, 2012

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 10:03 a.m. in room SD–366, Dirksen Senate Office Building, Hon. Jeff Bingaman, chairman, presiding.

OPENING STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

The CHAIRMAN. OK. Why don't we get started? Senator Murkowski is delayed a very few minutes here, but asked us to go ahead and proceed.

Welcome everyone to the hearing. This is on the potential for inducing manmade earthquakes from energy technologies. Many of the current and next generation energy technologies that are vital to our country's future require the injection of fluids like water and carbon dioxide or other mixtures deep into the Earth's subsurface.

Geothermal energy extraction, geological carbon sequestration, the injection of waste water from hydraulic fracturing and enhanced oil recovery all require the injection and movement of fluids deep underground. Scientists have known for many decades that one potential side effect of pumping fluids in or out of the Earth is the creation of small to medium sized earthquakes. Though only a small number of recent seismic events here and abroad have been definitely linked to energy development, public concern has been raised about the potential for manmade earthquakes after seismic events that were felt in Arkansas and Oklahoma and Ohio and other places in the country. Those events in some cases were located near energy development and waste disposal sites.

In 2010 I asked Secretary Chu to initiate a comprehensive and independent study by the National Academy of Sciences and the National Academy of Engineering to examine the possible scale, scope and consequences of seismicity induced by energy technologies. In particular, I asked them to focus on the potential for induced seismicity from enhanced geothermal systems, production from gas shales, enhanced oil recovery and carbon capture and storage.

The Academy released their report this past Friday. The results provide a timely assessment of the potential hazards and risks of induced seismicity potential posed by these energy technologies. I want to thank the members of the Study Committee, the staff of the National Academies and all of those associated with putting together this important report for their very hard work.

The National Academy of Science's Committee found that of all the energy related injection and extraction activities conducted in the United States only a small percentage have created earthquakes at levels noticeable to humans. None have caused significant damage to life or property.

The committee also determined that because hydraulic fracturing for natural gas development typically involves the injection of relatively small amounts of fluid into localized areas. Hydraulic fracturing, itself, rarely triggers earthquakes large enough to be felt. Activities that inject greater amounts of fluid over longer periods of time, however, such as the injection of drilling waste water, pose a greater risk for causing noticeable earthquakes.

Recent data from USGS suggests that the rate of earthquakes in the U.S. mid-continent has increased significantly in the past decade. The locations of these earthquakes are near many oil and gas extraction operations. As a result have raised public concern that they are the result of underground injection of drilling waste water.

The study also indicates that injection and storing—injecting and storing vast amounts of carbon dioxide in the subsurface may pose a risk for seismicity that needs to be better understood and quantified through research.

The discussion we're having today is an important and timely one. As the National Academy's report indicates risk from manmade earthquakes associated with energy technologies has been minimal and provided appropriate proactive measures are taken, may be effectively managed for the future. I look forward to hearing more about the topic from our panel of expert witnesses here.

Let me defer to Senator Murkowski for any comments she has before I introduce the witnesses.

STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

Senator MURKOWSKI. Thank you, Mr. Chairman and good morning to all of our witnesses today. I do look forward to your testimony also.

Over the past year or so I think we've all seen some of the trade press articles about issues of induced seismicity. While some of the headlines might look a bit sensational, it did seem that the true risk in reality is actually quite remote. But as such it's good to get a reality check from the experts. That's why you have been invited here today.

The headline on this study from the NAS reads, "Federal Research concludes quake risk from drilling low, avoidable." This covers geothermal wells, oil and gas wells and waste water wells. Really the unfortunate thing here is that the headline associates this report with drilling when drilling is perhaps not the issue so much as the actual permanent injection of waste water or carbon into an area where the pressures have become destabilized and some vibration then occurs.

I think it's good news that most of the seismic activity under discussion here, even with the hundreds of thousands of areas energy projects at play, have been quite small and often barely noticeable to humans. None of this is to say that anyone should be dismissive of this discussion. I think we all know that energy development of all sources and in all places does have attendant risks and impacts. It's not surprising to me to see that injecting and removing large volumes of fluids and gases underground might, under some conditions, cause vibrations to be felt above the ground. The question is whether that sort of seismicity is avoidable and manageable.

The study that we're looking at seems to indicate the answer is yes, which is also not surprising. But I'm interested to hear our other witnesses? views on the study. Since the study was only released on Friday, I realize that you may have more to say once you've had more time to actually study it carefully. But I do look forward to your initial impressions today.

With that, I thank the Chairman.

The CHAIRMAN. Thank you very much.

Let me introduce our witnesses.

First will be Dr. Murray Hitzman, who is a Professor with Colorado School of Mines. He's also Chairman of the National Academy's Committee that has prepared this report. So we thank you again for that heroic effort.

Dr. William Leith is the Senior Science Advisor for Earthquake and Geologic Hazards with the Geological Survey.

Ms. Susan Petty is President and Chief Technology Officer with Altarock Energy. Thank you very much for being here.

Dr. Mark Zoback is a Professor at Stanford. He's testified here before and we welcome him back.

Dr. Hitzman, why don't you go right ahead?

If each of you could take 5 or 6 minutes and tell us the main points you think we need to try to understand. Then we will undoubtedly have questions.

STATEMENT OF MURRAY W. HITZMAN, CHARLES FOGARTY PROFESSOR OF ECONOMIC GEOLOGY, DEPARTMENT OF GEOLOGY AND GEOLOGICAL ENGINEERING, COLORADO SCHOOL OF MINES, GOLDEN, CO

Mr. HITZMAN. Thank you very much.

Chairman Bingaman, Ranking Member Murkowski and members of the committee, thank you for the invitation to address you.

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. Since the 1920s we have recognized that pumping fluids into or out of the Earth has the potential to cause seismic imbalance that can be felt. Only a very small fraction of injection and extraction activities at hundreds of thousands of energy development sites in the U.S. have induced seismicity at levels that are noticeable to the public.

However, seismic events caused by or likely related to energy developments have been measured and felt in a number of States. Although none of these events has resulted in loss of life or significant structural damage, their effects were felt by local residents, some of whom also experienced minor property damage. Anticipating public concern about the potential for induced seismicity related to energy development, Chairman, Senator Bingaman, did request from DOE that they conduct a study of this issue through the National Research Council.

The committee that wrote the NRC report released last Friday consisted of 11 experts in various aspects of seismicity and energy technologies from both academia and industry.

The committee found that induced seismicity associated with fluid injection or withdrawal associated with energy development is caused, in most cases, by a change in pore 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 or put more simply, the total balance of fluid either introduced or taken out from the subsurface. Additional factors may also influence the way fluids affect the subsurface.

The committee concluded that 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 a comprehensive data on complex natural rocks or systems in the subsurface and the lack of validated predictive models.

The committee found for the largest induced seismic events associated with energy projects were those that did not balance the large volumes of fluids injected into or extracted from the Earth. We emphasize this is a statistical observation. It suggests, however, that the net volume of fluid that is injected and/or extracted may serve as a proxy for the changes in subsurface stress conditions in pore pressure.

I'm going to briefly discuss the induced seismicity potential now for each of the energy technologies that was asked for in the report.

Although it felt induced seismicity has been documented with the development of geothermal resources, such 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 aids in reducing the potential for induced seismicity.

Oil and gas extraction 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 decrease in pore pressure as fluid has been drawn.

Secondary recovery and enhanced oil recoveries or EOR for oil and gas production both involve injection of fluids into the subsurface to push more of the hydrocarbons out of the pore spaces and to maintain reservoir pressure. Approximately 151,000 injection wells are currently permitted in the U.S.

For a combination of secondary recovery EOR and waste water disposal with only a very few documented incidents where the injection caused or is likely related to felt seismic events.

Among the tens of thousands of wells used for enhanced oil recovery in the U.S. the committee did not find any documentation in the published literature of felt induced seismicity.

Shale formations also contain hydrocarbons. The extremely low permeability of these rocks has trapped the hydrocarbons and prevented them from migrating from the rock. The low permeability also prevents the hydrocarbons from easily flowing into a well bore without production stimulation.

These types of unconventional reservoirs are developed by drilling rails horizontally through the reservoir rock and using hydraulic fracturing techniques to create new fractures in the reservoir to allow us to get the hydrocarbons out. About 35,000 hydraulically fractured shale wells exist in the U.S. Only one case of felt seismicity in the United States has been described in which hydraulic fracturing for shale gas development is suspected but not confirmed. Globally, one case of felt induced seismicity in Blackpool, England has been confirmed as being caused by hydraulic fracturing for shale gas development.

The very low number of felt events relative to the large number of hydraulically fractured wells for shale gas is likely due to the short duration of injection of fluids and the limited fluid volumes used.

In addition to the fluid injection directly related to energy development, injection wells drilled to dispose of waste water generated during oil and gas production are very common in the United States. Tens of thousands of waste water disposal wells are currently active. Although only a few induced seismic events have been linked to these disposal wells, the occurrence of these events has generated considerable public concern.

Examination of these cases suggest casual links between the injection zones and previously unrecognized faults in the subsurface. Injection wells are used only for the purpose of waste water 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 the possible nearby faults is often not a standard part of citing and drilling these disposal wells. In addition, the presence of a fault does not necessarily imply an increased potential for induced seismicity.

The majority of hazardous and non-hazardous waste water disposal wells do not pose a hazard for induced seismicity. However, the long term affects of any significant increases in the number of waste water disposal wells in a particular area on induced seismicity are unknown.

Carbon capture and sequestration or CCS is also a means of disposing of fluids in the subsurface. The committee found that 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 demonstration projects underway in the U.S., there are few data available to evaluate the induced seismicity potential of this technology.

The existing projects have involved relatively small injection volumes. CCS differs from the other energy technologies in that it involves continuous injection of carbon dioxide fluid at high rates, under pressure, for long periods of time. It is purposely intended for permanent storage. There's no fluid withdrawal.

Given that the potential magnitude from induced seismic event correlates strongly with a fault rupture area. Which in turn relates to the magnitude of pore pressure change and the rock volume which exists, the committee determined that large scale CCS may have the potential for causing significant induced seismicity.

The committee also investigated governmental responses to induced seismic events. Responses have been undertaken by a number of Federal and State agencies in a variety of ways. To date, Federal and State agencies have dealt with induced seismic events with different and localized actions.

These actions have been successful, but they've been ad hoc in nature. With the potential for increased numbers of induced seismic events due to expanding energy development governmental agencies and research institutions may not have sufficient resources to address unexpected events. The committee concluded that forward looking, interagency cooperation to address potential induced seismicity is warranted.

Methodologies can be developed for quantitative probabilistic hazard assessments of induced seismicity risk. The committee determined that 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 events. The committee suggested that practices that consider induced seismicity both before and during the actual operations of an energy project should be employed to develop best practices protocols specific to each of the energy technologies and to site location.

Although induced seismic events have not resulted in loss of life or major damage to the U.S., 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.

I'd like to thank the committee for its time and its interest in this subject. I request the balance of my written testimony be placed in the record. I certainly look forward to your questions.

[The prepared statement of Mr. Hitzman follows:]

PREPARED STATEMENT OF MURRAY W. HITZMAN, CHARLES FOGARTY PROFESSOR OF ECONOMIC GEOLOGY, DEPARTMENT OF GEOLOGY AND GEOLOGICAL ENGINEERING, COLORADO SCHOOL OF MINES, GOLDEN, CO

Chairman Bingaman, Ranking Member Murkowski, and members of the committee, I would like to thank you for the invitation to address you on the subject of induced seismicity potential in energy technologies. My name is Murray Hitzman. I am a professor of geology at the Colorado School of Mines in Golden, Colorado and served as the chair of the National Research Council Committee on Induced Seismicity Potential in Energy Technologies. The Research Council is the operating arm of the National Academy of Sciences, National Academy of Engineering, and the Institute of Medicine of the National Academies, chartered by Congress in 1863 to advise the government on matters of science and technology. I would like to thank the committee for the invitation to address it on the subject of induced seismicity potential in energy technologies.

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 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. Energy technologies that involve injection or withdrawal of fluids from the subsurface can also create induced seismic events that can be measured and felt.

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. 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. However, 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. 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 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.

Anticipating public concern about the potential for induced seismicity related to energy development, the Chairman of this Committee, Senator Bingaman, requested that the Department of Energy conduct a study of this issue through the National Research Council. The Chairman requested that this study examine the scale, scope, and consequences of seismicity induced during the injection of fluids related to energy production. The energy technologies to be considered included geothermal energy development, oil and gas production, including enhanced oil recovery and shale gas, and carbon capture and storage or CCS. The study was also 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 National Research Council (NRC) released the report Induced Seismicity Potential in Energy Technologies on June 15.

The committee that wrote this NRC report consisted of eleven experts in various aspects of seismicity and energy technologies from academia and industry. 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. We heard from government and industry representatives. We also talked with members of the public familiar with the world's largest geothermal operation at The Geysers at a public meeting in Berkeley, California. We also spoke to people familiar with shale gas development, enhanced oil recovery, waste water disposal from energy development, and CCS at meetings in Dallas, Texas and Irvine, California. Meetings were also held in Washington, D.C. and Denver, Colorado to explore induced seismicity in theory and in practice.

This study took place during a period in which a number of small, felt seismic events occurred that 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 information to add to better understanding of induced seismicity.

The committee found that induced seismicity associated with fluid injection or withdrawal associated with energy development 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 or put more simply, the total balance of fluid introduced into or removed from the subsurface. Additional factors may also influence the way fluids affect the subsurface. The committee concluded that 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.

The committee found that the largest induced seismic events associated with energy projects 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. We emphasize that this is a statistical observation. It suggests, however, that 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. The committee recognizes that coupled thermo-mechanical and chemo-mechanical effects may also play a role in changing subsurface stress conditions.

I will briefly discuss the potential for induced seismicity with each of the energy technologies that the committee considered, beginning with geothermal energy.

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, 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, pre-production value-and aids 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 vapor or steam dominated geothermal system at The Geysers 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. This has resulted 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 Oil & Gas

Oil and gas extraction 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 decrease in pore pressure as fluid is withdrawn.

Oil or gas reservoirs often reach a point when insufficient pressure exists to allow sufficient hydrocarbon recovery. Various technologies, including secondary recovery and tertiary recovery—also called enhanced oil recovery or EOR—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. Approximately 151,000 injection wells are currently permitted in the United States for a combination secondary recovery, EOR, and waste water disposal with only very few documented incidents where the injection caused or was likely related to felt seismic events. Secondary recovery-through waterflooding-has been associated with very few felt induced seismic events. 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.

Shale Gas

Shale formations can also contain hydrocarbons-gas and/or oil. The extremely low permeability of these rocks has trapped the hydrocarbons and largely prevented them from migrating out of the rock. 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. This process is now commonly referred to as "fracking." About 35,000 hydraulically fractured shale gas wells exist in the United States. Only one case of felt seismicity in the United States has been described in which hydraulic fracturing for shale gas development is suspected, but not confirmed. Globally only one case of felt induced seismicity at Blackpool, England has been confirmed as being caused by hydraulic fracturing for shale gas development. The very low number of felt events relative to the large number of 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.

Waste Water Disposal

In addition to fluid injection directly related to energy development, injection wells drilled to dispose of waste water generated during oil and gas production, including during hydraulic fracturing, are very common in the United States. Tens of thousands of waste water disposal wells are currently active throughout the country. Although only a few induced seismic events have been linked to these disposal wells, the occurrence of these events has generated considerable public concern. Examination of these cases suggests 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 waste water 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. This creates challenges for the evaluation of potential sites for disposal injection wells that will minimize the possibility for induced seismic activity.

Most waste water 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. Of the well-documented cases of induced seismicity related to waste water fluid injection, many are associated with operations involving large amounts of fluid injection over significant periods of time. Thus, although a few occurrences of induced seismic activity associated with waste water injection have been documented, the majority of the hazardous and nonhazardous waste water disposal wells do not pose a hazard for induced seismicity. However, the long-term effects of any significant increases in the number of waste water disposal wells in particular areas on induced seismicity are unknown.

Carbon capture and sequestration

Carbon capture and sequestration—or CCS—is also a means of disposing of fluid in the subsurface. The committee found that 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 underway in the United States, there are few data available to evaluate the induced seismicity potential of this technology. The existing projects have involved very small injection volumes. CCS differs from other energy technologies in that it involves continuous injection of carbon dioxide fluid at high rates under pressure for long periods of time. It is purposely intended for permanent storage—meaning that there is 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, the committee determined that large-scale CCS may have the potential for causing significant induced seismicity.

The committee's findings suggest that energy projects with large net volumes of injected or extracted fluids over long periods of time, such as long-term waste water disposal wells and CCS, appear to have a higher potential for larger induced seismic events. The magnitude and intensity of possible induced events would be dependent upon the physical conditions in the subsurface-state of stress in the rocks, presence of existing faults, fault properties, and pore pressure.

The committee also investigated governmental responses to induced seismic events. Responses have been undertaken by a number of federal and state agencies in a variety of ways. Four federal agencies-the Environmental Protection Agency (EPA) the Bureau of Land Management (BLM), the U.S. Department of Agriculture Forest Service (USFS), 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. Currently EPA has primary regulatory responsibility for fluid injection under the Safe Drinking Water Act. It is important to note that the Safe Drinking Water Act does not explicitly address induced seismicity.

To date, federal and state agencies have dealt with induced seismic events with different and localized actions. These actions have been successful but have been ad hoc in nature. 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. The committee concluded that forward-looking interagency cooperation to address potential induced seismicity is warranted.

Methodologies can be developed for quantitative, probabilistic hazard assessments of induced seismicity risk. The committee determined that 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. The committee suggested that practices that consider induced seismicity both before and during the actual operation of an energy project should be employed to develop a "best practices" protocol specific to each energy technology and site location. The committee's meetings with individuals from Anderson Springs and Cobb, California, who live with induced seismicity continuously generated by geothermal energy production at The Geysers were invaluable in understanding how such a best practices protocol works.

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.

I would like to thank the committee for its time and interest in this subject and I look forward to questions.

The CHAIRMAN. Thank you very much.

Dr. Leith, go right ahead.

STATEMENT OF WILLIAM LEITH, SENIOR SCIENCE ADVISOR FOR EARTHQUAKE AND GEOLOGIC HAZARDS, U.S. GEOLOGICAL SURVEY, DEPARTMENT OF THE INTERIOR

Mr. LEITH. Mr. Chairman, members of the committee, thank you for inviting the USGS to testify at this hearing.

The United States is expanding its use of technologies that involve the injection and production of fluid at depth. As detailed in the report released last week by the National Research Council, the practices employed in these technologies have the potential to induce earthquakes. I commend this committee for requesting that such a study be undertaken and the Department of Energy for commissioning and funding the study. The NRC panel has done an outstanding job and made a significant contribution on this important issue.

Since 2011 the central and eastern portions of the U.S. have experienced a number of moderately strong earthquakes in areas of historically low seismicity. Of these, only the earthquake that occurred last August in Central Virginia is unequivocally a natural tectonic earthquake. In all of the other cases there arises the possibility that the earthquakes were induced by waste water disposal.

The disposal of fluids by deep injection is occurring more frequently in recent years. The occurrence of induced seismicity associated with fluid disposal from natural gas production in particular has increased significantly since the expanded use of hydraulic fracturing. Although there appears to be very little hazard associated with hydraulic fracturing itself, the disposal of the waters that are produced with the gas does appear to be linked to increased earthquake activity. As evidence, Mr. Chairman, you mentioned recent research by USGS seismologist Bill Ellsworth and colleagues which has documented that magnitude 3 and larger earthquakes have significantly increased in the U.S. midcontinent since the year 2000. Most of this increase in seismicity has occurred in areas of enhanced hydrocarbon production and hence, increased disposal of production related fluids.

To understand this phenomena the key research questions are:

One, what factors distinguish those injection activities that induced earthquakes from those that do not?

Two, to what extent can the occurrence of earthquakes triggered by deep fluid injection be influenced by altering the operational procedures?

Three, can small induced earthquakes trigger much larger tectonic earthquakes?

Four, what will be the magnitude of the largest induced earthquake from a specific injection operation?

Five, what is the probability of ground motion from induced earthquakes reaching a damaging level at a particular injectionsite?

We're already working collaboratively with the Department of Energy and EPA on some of these issues in response to the President's establishment of the Interagency Hydraulic Fracturing Working Group. The involvement of industry is welcomed here and may be essential to make progress on some of these questions. Also any Federal research dollars spent to minimize the risk of induced seismicity will serve multiple goals since not only is this research relevant to natural gas development, geothermal development and carbon sequestration, but it also addresses several important gaps in our understanding of the natural earthquake process and fault behavior.

Currently the precise data on injection volumes, rates and pressures needed to address these research questions are simply lacking for many sites of induced seismicity. Data collection required by underground injection control permits may not be sufficient to make confident, cause and effect statements about injection induced earthquakes after the fact. Without more precise and complete data it will be very difficult to assess the earthquake hazard potential from the tens of thousands of UIC wells that are currently in operation.

Looking forward, the Administration has proposed to significantly increase our efforts on induced seismicity in the coming Fiscal year as part of a comprehensive initiative to address potential environmental health and safety issues associated with hydraulic fracturing. We hope that the Congress will support that initiative.

Thank you again for the opportunity to testify. I'd be happy to answer any questions you may have.

[The prepared statement of Mr. Leith follows:]

PREPARED STATEMENT OF WILLIAM LEITH, SENIOR SCIENCE ADVISOR FOR EARTHQUAKE AND GEOLOGIC HAZARDS, U.S. GEOLOGICAL SURVEY, DEPARTMENT OF THE INTERIOR

Chairman Bingaman, Ranking Member Murkowski, members of the committee, thank you for inviting the U.S. Geological Survey (USGS) to testify at this hearing on induced seismicity. My name is Bill Leith. I am the Senior Science Advisor for Earthquake and Geologic Hazards at the U.S. Geological Survey (USGS). The USGS is the science agency for the Department of the Interior (DOI).

As part of its strategy to meet future energy needs, limit emissions of greenhouse gases, and safely dispose of wastewater, the United States is expanding the use of technologies that involve the injection, and in some cases the associated production, of fluid at depth. As detailed in the report released last week by the National Research Council (NRC), Induced Seismicity Potential in Energy Technologies (hereafter, NRC report), the injection and production practices employed in these technologies have, to varying degrees, the potential to introduce earthquake hazards. I would like to commend this committee for requesting that such a study be undertaken and the Department of Energy (DOE) for funding the study. The members of the National Research Council panel who wrote the report have done an outstanding job and have made a significant and lasting contribution to the public discourse on this important issue.

The USGS is well positioned to provide solutions for challenging problems associated with meeting the Nation's future energy needs. Various new approaches to produce oil and gas and alternative energy entail deep injection of fluid that can induce earthquakes. The cause and effect of induced earthquakes pose a number of risks that must be understood. USGS scientists, along with scientists from the National Labs and Universities funded by DOE, are already involved in studying a number of these injection projects, and we possess substantial expertise in the associated science and technology of mitigating the effects of induced earthquakes.

I summarize here the research topics that the USGS can address in order to assist the Nation in meeting its future energy needs through an improved understanding of induced seismicity that leads to mitigation of the associated risks.

To put this hazard in perspective, since the beginning of 2011 the central and eastern portions of the United States have experienced a number of moderately strong earthquakes in areas of historically low earthquake hazard. These include earthquakes of magnitude (M) 4.7 in central Arkansas on February 27, 2011; M5.3 near Trinidad, Colorado on August 23, 2011; M5.8 in central Virginia also on August 23, 2011; M4.8 in southeastern Texas on October 20, 2011; M5.6 in central Oklahoma on November 6, 2011; M4.0 in Youngstown, Ohio, on December 31, 2011; and M4.8 in east Texas on May 17, 2012. Of these, only the central Virginia earthquake is unequivocally a natural tectonic earthquake. In all of the other cases, there is scientific evidence to at least raise the possibility that the earthquakes were induced by wastewater disposal or other oil-and gas-related activities. Research completed to date strongly supports the conclusion that the earthquakes in Arkansas, Colorado and Ohio were induced by wastewater injection. Investigations into the nature of the Oklahoma and Texas earthquakes are in progress.

The disposal of wastewater from oil and gas production by injection into deep geologic formations is a process that is being used more frequently in recent years. The occurrence of induced seismicity associated with wastewater disposal from natural gas production, in particular, has increased significantly since the development of technologies to facilitate production of gas from shale and tight sand formations. While there appears to be little seismic hazard associated with the hydraulic fracturing process that prepares the shale for production (hydrofracturing), the disposal of waters produced with the gas does appear to be linked to increased seismicity, as was made evident by the earthquake sequence near the Dallas-Fort Worth airport in 2008 and 2009. In addition, recent research by USGS seismologist Bill Ellsworth and colleagues has documented that M3 and larger earthquakes have significantly increased in the U.S. mid-continent since 2000, from a long-term average of 21 such earthquakes per year between 1970 and 2000, to 31 per year during 2000-2008, to 151 per year since 2008. Most of this increase in seismicity has occurred in areas of enhanced hydrocarbon production and, hence, increased disposal of production-related fluids.

Industry has been working to expand the development of unconventional geothermal resources known as Enhanced Geothermal Systems (EGS), because of their significant potential to contribute to the U.S. domestic energy mix. These geothermal resources are widespread throughout the United States and are areas of high heat flow but low permeability. To make EGS projects viable, the permeability of geologic formations must be enhanced by injecting fluid at high pressure into the low-permeability formations and inducing shear slip on pre-existing fractures. This process of permeability enhancement generally induces a large number of very small earthquakes with magnitudes less than 2 (microearthquakes). The microearthquakes provide critical information on the spatial extent and effectiveness of reservoir creation. Depending on the circumstances, however, the resulting seismicity can have serious, unintended consequences, such as project termination, if any of the induced events are sufficiently large (greater than magnitude 4) to result in surface damage or disturbance to nearby residents. As a means to address these issues, the DOE published an induced seismicity protocol in 2012, which is cited in the NRC study as "a reasonable initial model for dealing with induced seismicity that can serve as a template for other energy technologies."

As emphasized in the NRC report, there is a potential seismic hazard associated with geologic carbon sequestration projects that involve the injection of very large quantities of CO_2 into sedimentary basins, some of which are located in or near major urban centers of the eastern and central United States. Because carbon dioxide storage requires a high porosity formation of high permeability that is capped by an impermeable seal (e.g., shale), there are two important sources of seismic risk. The first type of risk is due to the possibility of a large magnitude earthquake that causes damage to structures in the environs of the project. More importantly, there is the possibility that an induced earthquake rupture would breach the cap rock allowing the CO_2 to escape.

Historically, the USGS has contributed significantly toward understanding seismicity induced by liquid injection, starting with the Rocky Mountain Arsenal in the

1960's, where it was first discovered that liquid waste disposal operations can cause earthquakes. Between 1969 and 1973, the USGS conducted a unique experiment in earthquake control at the Rangely oil field in western Colorado. This experiment confirmed the predicted effect of fluid pressure on earthquake activity and demonstrated how earthquakes can be controlled by regulating the fluid pressure in a fault zone. The state of the science on the earthquake hazard related to deep well injection was summarized by the USGS in 1990, in a review that proposed criteria to assist in regulating well operations so as to minimize the hazard. This study was part of a co-operative agreement with EPA and was used to inform site selection and operating criteria during the development of underground injection control regulations for Class I Hazardous wells. This 1990 study is the most recent review of this topic but is likely to be superseded by the new NRC report. With support from our partners, USGS scientists are currently investigating induced seismicity associated with brine disposal operations in the Paradox Basin of Colorado and the Raton Basin coal bed methane field along the Colorado-New Mexico border. We and our partners, including the DOE, are also investigating the state of stress, heat flow, and microseismicity within geothermal reservoirs to evaluate the effectiveness of hydraulic stimulation for EGS. The combination within USGS of expertise in both energy science and earthquake science has proven particularly effective in addressing current issues.

Some of the key questions that arise in connection with fluid injection and production projects are:

- What factors distinguish injection activities that induce earthquakes from those that do not?
- To what extent can the occurrence of earthquakes induced by deep liquid-injection and production operations be influenced by altering operational procedures in ways that do not compromise project objectives?
- Can deep liquid-injection operations interact with regional tectonics to influence the occurrence of natural earthquakes by, for example, causing them to occur earlier than they might have otherwise? Similarly, can induced earthquakes trigger much larger tectonic earthquakes?
- What distribution of earthquakes (frequency of occurrence as a function of magnitude) is likely to result from a specified injection operation?
- What is likely to be the magnitude of the largest induced earthquake from a specific injection operation?
- What is the probability of ground motion from induced earthquakes reaching a damaging level at a particular site, and what would be the consequences (e.g., injury and/or structural damage)?

In the recent NRC report and in workshops sponsored by the DOE, , a common need has been identified for research to address the science questions posed above. The USGS, as an independent and unbiased science organization, can play a major role in studying, assessing, and providing solutions to these problems. We are already working collaboratively with DOE and U.S. Environmental Protection Agency on some of these issues, in response to the President's establishment of the interagency hydraulic fracturing working group, as well as with the States.

Although our primary research is directed at natural earthquakes and hydrogeology, we have in the past assessed the hazards associated with induced earthquakes due to mining operations, reservoir impoundment, oil and gas production and fluid injection. Thus, for many of these items, the research would mostly involve modifying existing approaches to the specialized requirements of fluid injection-and production-induced earthquakes.

Addressing these science problems will require a multidisciplinary approach that includes research in seismology, hydrology, crustal deformation, laboratory rock mechanics, in situ stress and fracture permeability, heat transport, fluid flow and other areas of study. The research activities might potentially include field-scale experiments, laboratory rock mechanics experiments, and the development and application of numerical models that simulate the effects of fluid injection operations on fracturing, fault reactivation and stress transfer, especially in low-permeability formations. Careful analyses of published case histories involving seismicity caused by fluid injection and production operations would be an important component of a comprehensive research program.

The involvement of industry is welcomed and may be essential to make progress on many of the key science questions. We see value in establishing an experimental site, or sites, in cooperation with industry and other agencies that could further the early work on induced earthquake triggering that was conducted so long ago at the Rangely field in Colorado. We note that DOE has in fact proposed a government-managed test site for EGS in its FY13 budget proposal, at which such R&D could be conducted in a carefully controlled and instrumented environment.

While a comprehensive effort is needed, and is called for in the NRC's recent report, any federal research dollars spent to minimize the risks of induced seismicity will serve multiple goals. Not only is this research relevant to shale gas development, geothermal development and carbon sequestration, but it also addresses several important gaps in our knowledge of the natural earthquake process and fault behavior.

I wish to expand on two of the findings and recommendations in the NRC report:

The first of these is what I will call the "data gap", for which the report recommends, "Data related to fluid injection... should be collected by state and federal regulatory authorities in a common format and made publicly available (through a coordinating body such as the USGS)." Currently, the data on injection volumes, rates and pressures needed to address many of the research questions above are simply lacking for many sites of induced seismicity. Permitting requirements for Underground Injection Control (UIC) wells are defined under Safe Drinking Water Act regulations, administered by the EPA and the states. Unless the potential for induced seismicity has been identified as a local risk prior to issuing a UIC permit, data collection required under these permits may not be sufficient to make confident cause-and-effect statements about injection-induced earthquakes after the fact, making it difficult to provide useful information to the regulating authorities about whether a particular disposal operation has or will have increased local earthquake risk.

Without more precise and complete data, it will be very difficult to assess the hazard potential from the tens of thousands of UIC wells that are currently in operation and for which their earthquake potential is unknown. An equal challenge is posed by UIC wells that may be permitted and become active injectors in the future, particularly if the permitting agency for the well is not cognizant of the associated earthquake hazard, or not in communication with parties that would be sensitive to a change in earthquake risk. For example, how close to an existing nuclear power plant or a dam is "too close" to site a disposal well permitted for a specified volume and pressure? Whose responsibility is it to evaluate the risk? Who is responsible for notifying the parties at risk? Who carries the liability should a damaging earthquake occur? Getting answers to these questions requires accurately assessing the induced-earthquake hazard, but at present the needed statistics are lacking because of the data gap. The NRC report provides some helpful guidance on how to develop "best practice" protocols that could help to close the data gap if implemented The report cites the recently published DOE IS protocol as an important step towards establishing a best practices effort.

The NRC report also found: "To date, the 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." Above in this testimony, I detailed the large number of induced or potentially induced earthquakes that have occurred in 2011 and 2012. Further, USGS scientists have also documented a seven-fold increase since 2008 in the seismicity of the central U.S., an increase that is largely associated with areas of wastewater disposal from oil, gas and coal-bed methane production. Scientifically, USGS has a depth of expertise relevant to understanding induced seismicity and the increasing demand for better monitoring, analysis, assessment, and public information. We have also worked closely with colleagues in academia and the State Geological Surveys, which have also seen increasing demands.

To meet these increasing demands, we have increased research efforts within our current budget. Looking forward, the Administration has proposed to significantly increase our efforts on induced seismicity in the coming fiscal year, as part of a comprehensive initiative to address potential environmental, health, and safety issues associated with hydraulic fracturing, and we hope that the Congress will support that initiative.

Thank you again for the opportunity to testify and for your attention to this important matter. I would be happy to answer any questions you may have.

The CHAIRMAN. Thank you very much.

Ms. Petty.

STATEMENT OF SUSAN PETTY, PRESIDENT AND CHIEF TECHNOLOGY OFFICER, ALTAROCK ENERGY, INC, SEATTLE, WA

Ms. PETTY. Thank you, Mr. Chairman and members of the committee. Good morning.

I really appreciate this opportunity to talk to you about our experiences with the mitigation of induced seismicity in the geothermal industry. Over the past few years injection induced seismicity has become an increasingly important issue that Earth scientists working in the geothermal, mining, petroleum and other industries must address. At Altarock Energy we're in the trenches focused on developing advanced technology to reduce the cost of enhanced geothermal systems to extend the ability to use this base load renewable energy source across the United States.

This resource is so large that recovering even a small fraction of it could provide electric power and heat sufficient to supply 10 percent or more of the Nation's need for thousands of years to come. The MIT study of the future of geothermal energy in 2007 projected that there is the potential to generate over 2 million megawatts across the U.S. if only 2 percent of this resource can be recovered. The USGS found that there is the potential for more than 500,000 megawatts in the Western United States alone.

In order to develop this vast resource we need a way to recover the heat by injecting water into a well, have it move through the hot rock and pick up heat and then be produced through production wells. To do this, we create a network of fine fractures that access a large volume of hot rock. Doing this requires pumping cold water into the ground at relatively modest pressures and then using the temperature contrast combined with the pressure to extend existing fractures and planes of weakness outward from the well.

While this is not new technology, it is technology that is still in development. Advances are needed to both reduce the risks associated with the development and to improve economics. One of the areas of risk is the possibility that seismicity of concern to people will be induced during the process of creating the reservoir or operating the EGS project long term. By looking at our past experiences with injection and induced seismicity, we can gain a better understanding of how to select project sites with—and operate the reservoir, so that we can reduce the risk of problematic induced seismicity. Our experience with the Newberry EGS Demonstration Projects, I feel, can help us grasp the issues and the potential solutions to these issues that will affect any future projects that use EGS technology.

Injection induced seismicity occurs when the fluid pressure in a fault or fracture reaches a critical value above which the friction preventing slip is overcome.

This concept was proposed in 1959.

Inadvertently demonstrated at the Rocky Mountain Arsenal in 1962.

Further tested at the Rangely Oil Field in 1969.

Has been incorporated into continuous injection operations at Paradox Valley since 1996.

EGS reservoir creation relies upon controlled induced seismicity to create the high surface area fracture paths needed for sustainable and economic heat extraction. The lessons learned from past EGS projects, in particular to projects along the Rhine Garben in Europe, are being used to refine the plans for future projects.

It's important to understand that creation of the EGS reservoir necessarily causes tiny seismic events when the small fractures slip and slide against one another. We use these tiny seismic events, as does the oil and gas industry, to map the fractures as we form them. What we don't want is larger faults to slip during this process and release enough energy for people to feel.

The energy released measured by the moment magnitude, commonly thought of as the Richter scale, is only one aspect of whether the seismicity will be felt by people or not. The rocks that the energy passes through and the types of soils near the surface as well as the structures that sit on those soils all contribute to whether seismicity is problematic or not.

One of the things we need to do to better communicate about injection induced seismicity is understand that that relationship between the magnitude of the event at depth and what people might potentially feel on the surface, the ground shaking. It would be better to talk about the risk of ground shaking than to talk about the risk around a particular magnitude of event occurring. I might add that the mining industry has long had regulations regarding ground shaking that we can maybe look to, to get this kind of experience.

For the Newberry EGS demonstration project we have gone through a process of both developing an induced seismicity mitigation protocol for the project activities and also communicating with the public about the project and the issues associated with induced seismicity. Three Federal agencies were involved with the permitting process, the Department of Energy, the Bureau of Land Management and the Forest Service. Only the DOE had staff with expertise in induced seismicity to help us through the process. We had, therefore, to inform and educate other regulators about the methods used to assess the potential risks related to induced seismicity and the possibilities for mitigating those risks.

The most difficult part of the induced seismicity hazards assessment was commuting the information it contains to the public. The ability of scientists to explain risk to the general public is limited by the public's familiarity with that risk. Using maps and graphics help, but the language we have for discussing seismicity is difficult for the best of us to relate to our everyday lives.

One of the interesting aspects of our public outreach effort is that in this region of tectonic activity with volcanoes and subduction zones as well as offshore large faults and fractures, people are much more concerned with potential for ground water contamination or water use impacts than they are with induced seismicity. While the Newberry area itself is very seismically quiet and quite remote from people, Oregonians are regularly rattled by temblors mostly on offshore faults. So they are familiar with small, natural seismic events.

On the other hand this is arid area with little water and little rainfall. Water is of key importance. It's in scarce supply. The focus by the regulators on induced seismicity took attention away from the key issue for the public which is water.

The result of a public outreach on our communication with regulators, as well as the expert input of the DOE, was a mitigation protocol that should enable us to both conduct our project and reduce the risk of felt seismicity. Our effort at Newberry is far more extensive and in depth. What is required of operators of waste water disposal wells with the risk, based on past experience, is far higher than what we have at Newberry.

What can we take away from our experience with the Newberry project and with other EGS projects?

Project citing can help us to reduce the risk and also the concerns of the public about that risk. We need to site projects away from large populations and dense populations until we better understand the risks surrounding this technology.

We need to avoid areas with large faults. How far away do we need to be from those faults? We don't yet know. That's something that needs further research.

Existing background data on seismicity is crucial for site selection and for gathering the information needed for permitting and operation of these sites.

Public outreach is very important. But communication with regulators is equally so. Risk assessment results are difficult to explain to both the public and to regulators. So we need to select experts to write up and communicate these results, who have excellent communication skills.

Graphics are needed. But they need to be easy to explain and understand.

We also need to work with the press to get the message across. We have to provide data and graphics to reporters to help them understand the project. I have to say that this has been one area that has really been very difficult. I think has resulted in a lot of misunderstanding about what's going on in this technology.

We also need to identify key local issues. We don't want to let induced seismicity dominate the discussion if it isn't the key issue.

Induced seismicity mitigation protocol for all injection related projects in the energy interest—industry that's consistent across the technologies would be a useful tool for both project developers and regulators.

Thank you.

[The prepared statement of Ms. Petty follows:]

PREPARED STATEMENT OF SUSAN PETTY, PRESIDENT AND CHIEF TECHNOLOGY OFFICER, ALTATROCK ENERGY, INC. SEATTLE, WA

Summary

Over the past few years injection-induced seismicity (*IIS*) has become an increasingly important issue that Earth scientists working in the geothermal, mining, petroleum and other industries must address. At AltaRock Energy we are focused on developing advanced technology to reduce the cost of Enhanced Geothermal Systems to extend the ability to use this baseload renewable energy source across the US. This resource is so large that recovering even a small fraction of it could provide electric power and heat sufficient to supply 10% or more of the nation's need for thousands of years to come. The MIT study of "The Future of Geothermal Energy", 2007, projected that there is the potential to generate over 2,000,000 MW across the US if only 2% of this resource can be recovered. The USGS found that there is the potential for 500,000 MW in the Western US alone.

In order to develop this vast resource, we need a way to recover the heat by injecting water into a well, have it move through the hot rock and pick up heat and then be produced through production wells drilled into the fractures. To do this we create a network of fine fractures that access a large volume of hot rock. Doing this requires pumping cold water into the ground at relatively modest pressures and then using the temperature contrast combined with the pressure to extend existing fractures and planes of weakness outward from the well.

While this is not new technology, it is technology that is still in development. Advances are needed to both reduce the risks associated with the development and to improve economics. One of the areas of risk is the possibility that seismicity of concern to people will be induced during the process of creating the reservoir or during operation of the EGS project long term. By looking at our past experiences with injection and induced seismicity we can gain a better understanding of how to select project sites that will have a low risk of problematic induced seismicity and also operate the project from stimulation through development to long term operation with a reduced risk that seismicity will be felt by people. I would like to provide a brief review of the history of *IIS*, the importance of *IIS* to the growth of the geothermal energy industry, and suggest possible paths forward to managing the risks associated with *IIS*. Our experience with the Newberry EGS Demonstration Project I feel can help us grasp the issues and the potential solutions to these issues that will affect any future projects that use EGS technology.

IIS occurs when the fluid pressure in a fault or fracture reaches a critical value above which the friction preventing fault slip is overcome. This concept was proposed in 1959, inadvertently demonstrated at the Rocky Mountain Arsenal in 1962, further tested at Rangely Oil field in 1969, and has been incorporated into continuous injection operations at Paradox Valley since 1996. EGS reservoir creation relies upon controlled *IIS* to create the high surface-area fracture paths necessary for sustainable

and economic heat extraction. The lessons learned from past EGS projects, in particular at two projects along the Rhine Graben in Europe, are being used to refine the plans for future projects.

It's important to understand that creation of the EGS reservoir necessarily causes tiny seismic events when the small fractures slip and open up. We use these tiny seismic events, as does the oil and gas industry, to map the fractures as we form them. What we don't want is larger faults to slip during this process and release enough energy for people on the surface to feel. The energy released, measured by the moment magnitude, commonly thought of as the Richter scale, is only one aspect of whether seismicity will be felt by people or not. The rocks that the energy passes through and the types of soils near the surface as well as the structures that sit on those soils all contribute to whether seismicity is problematic or not. One of the things we need to do to better communicate about injection induced seismicity is that the magnitude of seismic events does not necessarily directly translate to the amount of ground shaking that can be expected. It would be better to talk about the risk of ground shaking than to talk about the risk around a particular magnitude of event occurring.

For the Newberry EGS Demonstration Project we have gone through a process of both developing an induced seismicity mitigation protocol for the project activities and also communicating with the public about the project and the issues associated with induced seismicity. One of the interesting aspects of our public outreach effort is that in this region of tectonic activity with volcanos and subduction zones as well as offshore large faults and fractures, people are much more concerned with the potential for groundwater contamination or water use impacts than they are with induced seismicity. While the Newberry area itself is very seismically quiet, Oregonians are regularly rattled by temblors, mostly on offshore faults. This is an arid area with little rainfall and water is of key importance and in very scarce supply.

For the project we developed our mitigation plan using the guidelines provided by the US DOE for projects of our type. We have had two separate induced seismicity hazards assessments done by reputable independent contractors using separate methodologies. Background seismicity was recorded using a temporary seismic network installed in 2010. This data, although sparse, combined with data from the USGS regional seismic network was used for the probabilistic seismic hazards assessment to predict the natural hazard. The potential for seismicity that people could feel was then predicted and compared to the natural hazard. At our site, with no observable large faults and no history of large earthquakes, the natural hazard far exceeds the potential for induced seismicity from our project.

The most difficult part of the induced seismicity hazards assessment was communicating the information it contains to the public. The ability of scientists to explain risk to the general public is limited by the public's familiarity with that risk. Using maps and graphics helped, but the language we have for discussing seismicity is difficult for the best of us to relate to our everyday lives.

However, the result of the public outreach and our communication with regulators was a mitigation protocol that should enable us to both conduct our project and reduce the risk of felt seismicity.

History of Injection Induced Seismicity

The industrial activities associated with *IIS*, withdrawal or injection of fluids, have occurred worldwide for decades, and scientific understanding of *IIS* and our ability to minimize the risk has increased in concert. Starting in the 1940's, oil and gas wells were hydraulically fractured with injected fluid to increase near-well permeability, and *IIS* was not considered to be a significant issue. Below, we review some salient points of four injection projects with well-studied *IIS*. For more details, the reader is referred to the excellent papers reviewed below. See Table 1 for a summary of the relevant quantitative parameters for each project.

Rocky Mountain Arsenal – 1962-1966

In 1961, less than 10 miles from downtown Denver, a 3671 m deep well was drilled for the purpose of disposal of contaminated waste water. The well was cased through the sedimentary rocks of the Denver Basin and the bottom 21 m was left open in highly fractured Precambrian gneiss. Shortly after the injection program began in 1962, minor earthquakes were detected on a single local seismograph station. By 1967, over 1500 earthquakes had been detected within 8 km of the well, prompting the end of the waste disposal program in 1966 (Figure 1). *IIS* continued until 1972, six years after injection stopped including three earthquakes with magnitude greater than 5 in 1967 (Hsieh and Bredehoeft, 1981). Between 1966 and 1968, temporary seismic arrays were installed and the shape of the *IIS* zone was determined to be a 10x3 km ellipse with a major axis of N60°W. This zone can be interpreted as a subvertical NW trending, pre-existing fault or fracture zone (Healy et al., 1966; Hsieh and Bredehoeft, 1981).

Figure 1: Comparison of fluid injected and the frequency of earthquakes at the Rocky Mountain Arsenal. Upper graph shows monthly volume of fluid waste injected in the disposal well. Lower graph shows number of earthquakes per month. After Hsieh and Bredehoeft (1981) and Evans (1966).

Reservoir analysis of this early example of *IIS* confirmed the theory of Rubey and Hubbert (1959) on the fault-weakening effect of high fluid pressures and set the foundation for further studies of IIS (Healy et al., 1968; Hsieh and Bredehoeft, 1981; Zoback and Healy, 1984). The critical fluid pressure change, ΔP_c, was determined to be just 3.2 MPa or 325 m of hydraulic head. This was based on the observation that it took 6 years for the reservoir pressure to diffuse, drop below P_c and *IIS* to cease. Eventually the water table in the cased well settled at 923 m below the surface, indicating an underpressured aquifer in the fractured basement.

During the injection program, downhole pressures sometimes reached as high as 43 MPa (ΔP_{max}= 16). Examination of pressure records at the start of shut-in periods during the injection program indicated that above a downhole pressure of ~38 MPa hydraulic fracturing had occurred.

Table 1: Summary of parameters for injection projects discussed in text.

Project	Injection rates	Time Span	Est. press-ures	Depth (km)	Deformation Modes on fractures	Rate of Detected Events*	Max M_L

			(MPa)				
RMA (1962-1967)	>6.3 L/s	4 years	$P_o = 26.9$ $\Delta P_c = 3.2$ $\Delta P_{max} \approx 16$	3.7	Shear, Opening	1 / day	5.3
Rangely (1969-1970)	Unk.	1 year	$P_o = 17$, $P_c = 25.7$ $P_{max} = 29.0$	~2	Shear	0.7 / day	3.1
Paradox Valley (7 tests) 1991-1994	9 – 25 L/s	438 days	Po = 43.6 ΔP_c=17 P_f=70	4.5	Shear, Opening, Acid dissolution, Tensile failure	Av. 1.5 / day Max 4 /day	--
Paradox Valley (Phase 1-2) 1996-2000	21.5 L/s	4 yrs at high rate	P_{wh}=34.5 P_{max}=82	4.5	Shear, Opening, Tensile failure, Thermal?	2.1 / day	4.3
Paradox Valley (3-4) 2000-2003	14.5 L/s	3 yrs at low rate	P_{wh}=30.3	4.5		0.3 / day	2.8
Geysers (2003-2010) in ~40 wells	~2000 L/s	7 yrs w/ current supply	$P_c << P_h$	2-3	Shear, Thermal	3/day M_L> 1.5	4.6
Soultz: GPK2	50 L/s	5.9 d	P_{wp} = 14.5	5	Shear	122/day M_L> 1.0	2.5
Soultz: GPK3	50 L/s briefly 90L/s	10.6 d	P_{wp} = 16	5	Shear	23/day M_L> 1.0	2.9
Soultz: GPK4	45 L/s	7.4 d	P_{wp} = 17,14	5	Shear	17/day M_L> 1.0	2.7
Basel	55 L/s	6 d	P_{wp} = 29.6 $\Delta P_c < 11$ ΔP_{max} = 17	5	Shear, on conjugate sets in cataclastic zone	400/day M_L> -1.0	3.4
Newberry (planned)	<50 L/s	Max 21 d	$\Delta P_{max} <$ 15	3	Shear		

* <1% of detected events are typically felt. In addition, comparing event rates should be done with great caution due to network sensitivities, reporting thresholds, and the different volumes over which the seismicity is occurring.

According to Hsieh and Bredehoeft (1981) most seismologists of the day agreed that the earthquakes were of tectonic origin – they resulted from the sudden release of tectonic strain energy stored in the gneiss. The release of the stored energy was triggered by the increase in fluid pressure from the injection program resulting in a ten year earthquake swarm. Since then it has become clearer that seismically quiet intraplate crust may often been under a compressive stress state and have stored strain energy that can be released by fluid injection, but would otherwise remain stored (i.e. Zoback and Zoback, 1980; Zoback et al., 1989).

Rangely –1967-1974

The RMA discovery led to speculation that the natural earthquake cycle might be controllable by *IIS*. This hypothesis was tested at the Rangely Oil Field near Vernal, Utah, which had been on waterflood for secondary oil recovery since 1957. The experiment is described thoroughly by Raleigh et al. (1976). To begin, a seismic network of 14 stations was installed and a calibration shot detonated in an injection well to determine seismic velocities and station corrections. From October 1969 to November 1970 bottom-hole pressures in four wells open in the Weber Sandstone at a depth of two kilometers were raised from 23.5 to 27.5 MPa. During that time period, 367 seismic events occurred within 1 km of the wells; the largest of which had a magnitude of 3.1 (Figure 2). Analysis of the event focal mechanisms and locations suggested that the *IIS* was occurring as right-lateral slip in a 1 km wide zone near the tip of a modest (~6 km long), vertical fault; consistent with the known tectonic stress field in the region. A critical pressure, P_c, of 25.7 MPa was determined, compared to a virgin reservoir pressure, P_o, of 17 MPa. After the wells were shut-in and back-flowed, the seismic activity near the wells dropped to 1 event/month.

The success of the experiment led the authors to propose a scheme in which the fluid pressures in wells along the San Andreas Fault could be alternately increased and decreased in order to relieve the shear stress along the fault and prevent great earthquakes (Raleigh et al., 1976).

Paradox Valley - 1991-2004

The Paradox Valley unit (PVU) is a U.S. Bureau of Reclamation facility that extracts aquifer brine from shallow wells and re-injects the brine at high pressure into a single deep well. The purpose of the PVU is to reduce salt water seeps into the Dolores River and thus improve the quality of the Colorado River into which it runs. The PVU has been operating continuously since 1996.

Figure 2: Frequency of earthquakes at Rangely. Stippled barbs indicate earthquakes within 1 km of experimental wells. The clear areas indicate all others. Pressure history in well Fee 69 is shown by the heavy line; predicted critical pressure is shown by the dashed line (after Raleigh et al., 1976).

Ake et al. (2005) describe the facilities of the PVU and analyze 15 years of *IIS*. The Paradox Valley Seismic Network (PVSN) was installed in 1985. It consists of 15 surface stations in two roughly concentric rings around the injection well. The PVSN can detect events down to M_L = -0.5 and reliably locate events down to M_L = 0.5. The 4900 m deep injection well targets the Leadville Limestone, which is a highly-fractured, very-tight dolomitic limestone. The well was sited to optimize fluid migration into and along inactive northeast dipping, Laramide-age faults of the Wray Mesa.

In six years of pre-test seismic monitoring no events were detected within 10+ km of the proposed injection site. The first injection test in 1991 was 14 days long at an average rate of 9 L/s. The downhole pressure reached ~64 MPa on the third day, and the first seismic event was recorded on the fifth day. The authors used this observation to estimate that ΔP_c=17 MPa. In all, 20 events were detected in Test 1 (3.3/day). Following an acid job in 1993, a 41-day injection test reached 25 liters per second (L/s), and the seismicity rate peaked at 4 events/day.

Continuous injection began in 1996 at 21.5 L/s and reservoir volume growth stabilized by mid 1999 at 20-30 km^3. After three felt events (M_L 3.5, 3.6 and 4.3) in 1999 and 2000, changes were made to the injectate makeup, and the injection rate was eventually reduced to 14.25 L/s with a corresponding drop in average wellhead pressure, P_{wp}, from 33.8 to 30.3 MPa. The reduced injection rate had the desired effect on *IIS*, and the detected event rate dropped from ~2.7 events/day down to ~0.3 events/day (Figure 3) and resulted in no additional events with M_L>3.0 from 2000 to 2003. From 1996 to 2003, 99.9% of the 4000 surface recorded events had M_L<2.0 and only 15 events were felt.

Figure 3: Four phases of continuous pumping (1996-2003) superimposed on monthly injected volumes and induced seismic events per month versus time. PVB designates Paradox Valley Brine, the extract fluid from the local aquifer (from Ake et al., 2005).

Our own analysis of the data from after the second injection test through both phases of continuous injection (Ake et al., 2005) shows a remarkable linear relationship with R^2 =96% of

$$S_R = 0.27\, I_R - 3.1 \qquad (6)$$

where I_R is the injection rate in L/s, and S_R is the seismicity rate in events/day. This fit has a zero seismic event intercept of 11.3 L/s, indicating that it might be possible, as occurred in Test 4 at 10.3 L/s, to inject with no *IIS* (but other PVU brine disposal requirements would then be unmet).

The average downhole pressure in 2003 at the lower injection rate, 79.3 MPa, is sufficient to open pre-existing fractures (σ_h=69.6 MPa) and cause tensile failure (P_f=70 MPa). However, this tensile failure occurs at the well bore. Due to the high frictional losses in flowing fractures, the pressure dissipates rapidly away from the well. Thus while, in the region near the well, fractures may be held open by the fluid pressure,in the regions experiencing *IIS*, the pressure would likely be less that 70 MPa.

Finally, Ake et al. (2005) note that seismically illuminated faults and fractures can accommodate only a few percent of injectate. Therefore, numerous small fractures must open to provide the remaining ~97% additional storage. This ratio may also be relevant to Engineered Geothermal Systems that are discussed in the next section.

The Geysers - 1960-2010

The Geysers Geothermal Field (GGF) is one of the most seismically active producing geothermal fields in the world. The GGF is large, geologically and operationally diverse, has been actively produced for 50 years, and is in an active tectonic region. Thus, it is likely that seismicity at the GGF has many contributing causes in addition to changes in fluid pressure, including stress changes due to tectonic, thermal and poro-elastic forces. Scientific studies have shown a correlation between , the field-wide annual fluid injection volume and *ISS* rate at The Geysers (Smith et al., 2000; Stark et al. 2005; Greensfelder et al., 2008). This relationship is shown in Figure 4; compare the number of events with M_L>1.5 (blue curve) and the injection volume (green curve). The M_L>1.5 *IIS* rate tracks the increases in injection volume due to new supply pipelines finished in 1998 and 2003. In fact, similar to the Paradox Valley relation shown in equation (7), Greensfelder et al. (2008) suggested a simple linear relation between the injection rate in multiple wells on the NCPA lease in the southeast Geysers, I_R and the seismicity rate, S_R with R^2 =65% of

$$S_R = 0.0007\, I_R - 0.035 \qquad (7)$$

However, the relationship between injection and *ISS* rates does not extend to M_L>3.0 events. Since 1985, 13 to 32 of these events occur per year with no upward trend despite the doubling of injected fluid (Figure 4). Currently about 1000 events with M_L>1.5 and approximately 20 events with M_L>3.0 occur in the GGF every year. During 50 years of production and 40 years of injection, there have been 22 events with M_L between 4.0 and 4.6, the largest occurring in 1982 when injection was more modest than today. If there is any water table at the GGF, it lies below the steam reservoir (2-3 km); therefore, the reservoir itself is severely underpressured ($P_o \ll P_h$) and pre-existing fractures fail in shear before well bores are filled with water. Assuming that most GGF seismicity is *IIS* implies that the reservoir pressure currently exceeds the critical value, P_c.

Figure 4. The steam reservoir at The Geysers has no natural recharge and production has been declining since 1987. Water injection has slowed the decline considerably; microseismicity (M<3.0) has increased. (Stark et al., 2005).

EGS and IIS

Engineered Geothermal Systems (EGS) have the potential to expand the availability of clean renewable, baseload energy beyond conventional geothermal areas. An EGS reservoir is created by injecting large volumes of cold water into hot, low-permeability rock to induce seismic slip and enhance the permeability of pre-existing fractures. Compared to the examples discussed above, *IIS* needs to be much more carefully controlled in order to achieve the goal of creating an economic EGS reservoir. The flowing fractures in an EGS reservoir form a heat exchanger at depth and, like a radiator, should contain many, high-surface-area channels and no paths that short circuit the heat exchange surfaces. Thus, the fluid pressures during EGS reservoir creation must be greater than the critical pressure to create hydroshearing (P_c) but less than the breakdown pressure associated with typical hydraulic fracturing (P_f). It also means that large faults and open fracture zones should be avoided, as they will also create short circuits. Most EGS-related *IIS* will be detected only by sensitive, local seismometers designed to monitor reservoir growth; however, some of the seismic events may reach magnitudes of 2-3.

EGS projects have been carried out at Fenton Hill in New Mexico, Ogachi and Hijiori in Japan, Landau, Soultz, and Basel in Europe's Rhine Graben, and Cooper Basin in South Australia. Majer et al (2007) provides a more complete review of *IIS* associated with EGS projects. Below we briefly discuss the results at two of these sites.

Soultz- 1987-2010

Over two decades of research and development in EGS has been carried out at Soultz-sous-Forêts, France, resulting in a pilot program that currently includes a 200° C EGS reservoir, an injector, two producers, two downhole pumps and a 1.5 MWe binary power plant (Genter et al., 2009). A great deal has been written on the Soultz EGS project; here we summarize the relationship between the hydraulic stimulation (hydroshearing) and *IIS* from an extensive body of literature (Baria et al, 2005; Baria et al, 2006; Dorbath et al., 2009; Genter et al., 2009 and many others).

The EGS project at Soultz started at GPK1, a shallower, cooler well and has progressed to three deep wells with BHT of 200°C: an injector, GPK3, and two producers, GPK2 and GPK4. The wells are drilled from the same pad, and penetrate approximately 1400 m of sediments before reaching fractured Paleozoic granites. The wells deviate from vertical at ~2500 m, such that the wells align with the maximum horizontal stress direction (N170°E). At depth, GPK3 is between the other two with ~700 m well spacing (Genter et al, 2009). The wells are cased between the surface and 4500 m with approximately 500 m of open-hole at the bottom. The seismic network at Soultz consists of two arrays. The first is a surface array of 9 permanent stations plus up to 14 temporary stations. The second is an array of four (4) accelerometers at depths greater than 1500 m, so that they are deployed in the granite itself. The down hole array, which is only operated during stimulation or circulation, returned locatable events at about 2-3x the rate as the surface array in the GPK2 and GPK3 stimulations and 24x in the GPK4 stimulation (Dorbath et al., 2009).

Each of the wells was hydraulically stimulated after drilling. Although the stimulation designs for each well were similar, the results of each stimulation and the characteristics of the associated *IIS* were quite different.

Well GPK2 was stimulated in 2000 for six days with a maximum flow rate of 50 L/s and a well head pressure of 14 MPa. Figure 5 is a synoptic figure of this stimulation; it shows flow rate, well head pressure, and rate of seismicity. Dorbath et al (2009) present this informationrich figure for the stimulation of each well. A huge amount of microseismic events were generated when GPK2 was stimulated; 14000 events were located by the downhole array and 7215 events by the surface array of which 718 events had M_L>1. The largest event was a M_L 2.5. The b-value, a measure of the size distribution of the seismicity, was 1.23, which is slightly higher than for most tectonic regions and indicates relatively few large events and numerous small events. The relatively high b-value and character of the *IIS* cloud indicate that a dense network of medium sized fractures were stimulated. The injectivity of GPK2 increased 20-fold from a low initial value of 0.2 to 4.4 L s^{-1} MPa^{-1} (Dorbath et al, 2009).

Figure 5: The 2000 stimulation of GPK2 hydraulic parameters; pressure (red) and flow rate (blue). Cumulative seismic moment: all earthquakes (black), and M<2 earthquakes (violet) from Dorbath et al. (2009).

Well GPK 3 was stimulated in 2003 for 10.6 days at a standard flow rate of 50 L/s (with pulses of a few hours up to 90 L/s) and a well head pressure of 16 MPa (with 19 MPa spikes at the high rate). Despite 1.5x the volume and ~2x the duration, fewer microseismic events were generated than at GPK2; 8345 events were located by the downhole array and 3253 events by the surface array of which 240 events had M_L>1. The largest event, a M_L=2.9, was the largest at Soultz to date, which occurred three days after the stimulation. The b-value for the GPK3 *IIS* was 0.94, which is closer to a tectonic value and indicates relatively more large events. The low b-value and character of the *IIS* cloud, indicates hydroshearing occurred along one large structure (Dorbath et al, 2009). This conclusion was confirmed by borehole image and flow logs which show a large scale fault at a depth of 4770 m, which took 70% of flow in GPK3 (Baria et al, 2005; Genter et al, 2009). The injectivity of GPK3 was relatively high after drilling, 3.5L s^{-1} MPa^{-1}, and did not significantly improve after stimulation (Tischner and Teza 2005).

GPK4 was stimulated in 2004 and 2005. In the first stage, a continuous flow rate of only 30 L/s was achieved at a well head pressure of 17 MPa. After 3.5 days of stimulation, a PTF sonde in GPK4 quit working, and the casing was found to have collapsed above the tool (Baria et al 2006). GPK4 hydraulic stimulation resumed for an additional four days in 2005 at flow rates of 30 and 45 l/s and well head pressures from 14 to 18 MPa. GPK4 stimulation produced a large amount of locatable events on the downhole array (32,288) but the fewest locatable events on the surface array; 1341 located, 128 M_L>1. The largest event was a M_L=2.7, which started the activity in the second stage after a full day of stimulation with no events. The character of the *IIS* indicates that the stimulated zone in GPK4 is a single zone like that in GPK2. After the hydraulic stimulation, an acid stimulation was also performed; 6000 m^3 of water with 30 m^3 of 30% HCl was injected (Portier et al., 2009). The injectivity of GPK4, which started very low at <0.15 L s^{-1} MPa^{-1}, had improved to 2.5 L s^{-1} MPa^{-1} after the acid job (Baria et al 2006).

The stimulation results at the three Soultz wells demonstrate that *IIS* characteristics (maximum magnitude, b-Value, and event rate) and stimulation efficacy (improvement of injectivity and reservoir volume) seem to be a function of the characteristics of the preexisting natural fractures and faults in the well bore. To maximize the effectiveness of hydroshearing, stimulation plans need to account for the features encountered by the well.

Basel – 2008

In 2006, a deep well was drilled for the purpose of creating an EGS reservoir as part of the Deep Heat Mining (DHM) project at Basel, Switzerland. The well passes into crystalline basement at 2507 m, reaches TD of 5000m and a BHT of 190°C, a well geology similar to the Soultz project. The 371 m open-hole section at the bottom has a fracture spacing of 3-5 m and contains two major clay-rich cataclastic fracture zones, indicating that significant fault slip had occurred at this location in the past (Haring et al, 2008). A normal fault in the hills just south of Basel is thought to be responsible for an earthquake that destroyed much of Basel in 1356 (Meghraoui et al., 2009).

A seismic network consisting of six down-hole three-component geophones was installed to monitor the *IIS*. Since the project was located in a major city, a seismic response procedure, adapted from the "Traffic Light System" proposed by Bommer et al. (2006), was developed to monitor and control *IIS*. Three independent parameters were chosen; public response (phone calls), local magnitudes (M_L), and peak ground velocity (PGV). Thresholds were set for each parameter, with an appropriate response at the well site predetermined for each threshold (Dyer et al, 2008; Haring et al, 2008).

The well Basel-1 was hydraulically stimulated in December 2006 starting with a flow rate of 1.7 L/s, enough to increase the well head pressure (W_{wp}) to 11 MPa and initiate *IIS*. Over six days the flow rate was increased to a maximum flow rate of 55 L/s and a well head pressure of 29.6 MPa or a downhole pressure of 74 MPa (Figure 6). No hydrofracturing tests were performed in Basel-1 prior to stimulation; however, since there was no hydraulic evidence of tensile fracturing at the shoe during the massive stimulation, it is assumed that $\sigma_h > 74$ MPa (Figure 7).

During the six days of stimulation 11,200 events were detected and 2400 located. At 3:06 am December 8th, a $M_L = 2.6$ event occurred, so the rate was reduced to 30 L/s, a response more precautionary than required by the safeguard procedure (which would have allowed continued pumping at 55 L/s). Later that morning additional $M_L>2$ events occurred and the injection was stopped completely and the well shut-in. However, the same afternoon 2.7 M_L and 3.4 M_L events required that the well be bled off. *IIS* continued after bleed off, including three $M_L > 3.0$ events in the following two months (Haring et al, 2008).

The felt intensity of the M_L 3.4 event appears to have been very strong compared to other induced and natural events of this low magnitude (Baisch et al, 2009). The peak ground velocity was 0.9 cm/s and the Modified Mercali Intensity reported by the public was IV or V (light or moderate shaking perceived). Despite the exceptional human alarm, Haring et al (2007) reports that "[t]he still ongoing investigations have found only minor damages so far. The great majority of reported damages are small cracks in plasterwork , often of disputable age. There are no claims of injury and no structural damage has been detected."

Figure 6: Data on the hydraulic stimulation of well Basel-1. History of (a) injection rates, (b) wellhead pressures, (c) trigger event rates and (d) Basel earthquake magnitude as determined by Swiss Seismological Survey (SED). From Haring et al., (2008)

Figure 7: Mohr diagram illustrating the effect of increasing pore pressure in weak rock. Circle 1 is total stress, Circle 2 is effective stress at hydrostatic conditions, and Circle 3 is effective stress at maximum overpressure conditions during hydraulic stimulation stimulation (Haring et al., 2008).

A report on the long-term seismic risk of the DHM project commissioned by the Canton government (Baisch et al., 2009) concluded that "from a seismic risk perspective, the location of Basel is unfavourable for the exploitation of a deep geothermal reservoir in the crystalline basement. Other locations in Switzerland may offer a significantly lower risk."

Theory and Models

In concert with the field experiences of *IIS* such as those described above, theory and models of *IIS* have significantly progressed. For example, Shapiro et al. (2007) and Shapiro and Dinske (2009) provide a theoretical basis for *IIS* rates, size distributions and volume growth. The theory begins with the simple relation between the IIS triggering front as a function of time, r(t), and a hydraulic diffusivity, D:

$$r(t) = \sqrt{4\pi Dt} \qquad (8)$$

Figure 8 shows the fit of equation (8) for *r-t* data for Basel. From the starting point of equation (8), additional factors such as non-linear diffusion effects, pumping rates, critical pressure, tectonic b-values, and tectonic potential are included. The final equations are tested against data from EGS projects (Ogachi, Cooper Basin, and Basel) and hydraulic fracturing injection into tight gas reservoirs (Cotton Valley sandstones and Barnett Shale). The data for these five projects can be well-explained by the theory.

Figure 8: Injection pressure, flow rate and an r-t plot of the corresponding fluid injection microseismicity at a geothermal borehole in Basel region of Switzerland. The data are courtesy of U. Schanz and M.O Haring. Curve is equation (7) with D= 0.06 m^2/s. From Shapiro et al., (2009).

There have also been recent advances on stochastic fracture models (e.g. Willis-Richards et al.,1996; Jing et al., 2000). Computer models based on this work will allow hydroshearing plans to be simulated on a modeled volume populated with geologically realistic fractures. Based on reasonable assumptions about the rock mass, hydroshearing scenarios can be tested to predict which fractures will shear, and help predict the size and shape of the EGS reservoir likely to be created.

Southeast Geysers EGS Demo Project

In early 2009, AltaRock planned and commenced a DOE-funded project in the southeast Geysers, California, with the objective of creating an EGS reservoir in intrusive rock below the currently producing steam reservoir (Cladouhos et al., 1999).

The AltaRock project began without DOE funding in August of 2008. After an initial meeting with the BLM and state and county regulators, AltaRock staff and contracted expert seismologists assessed the risk of hazardous *IIS*. After receiving an award from the DOE in October, 2008, DOE agreed to follow the requirements of the BLM in their efforts to comply with NEPA for the grant. The induced seismicity hazards study, completed in November of 2008, which was incorporated into the Environmental Assessment (EA) for the project, concluded that the EGS project would not significantly impact the already high rate of seismicity or cause events as large or larger than those already occurring. To monitor seismicity around the project, AltaRock installed a network of eight state-of-the-art, three-component borehole accelerometers to monitor the stimulation. Additionally, a strong ground motion seismometer was installed in the nearby community of Anderson Springs. The BLM issued a Finding of No Significant Impact (FONSI) for The Geysers EGS project in June of 2009 with protocols for monitoring and mitigating *IIS* during the project. The DOE requires that any EGS projects with federal funding comply with protocols established by the International Energy Agency (IEA) that include a maximum threshold for shaking recorded on a strong motion seismometer in the nearest community.

Adverse publicity linking the Geysers project to the DHM project in Basel resulted in separation of the DOE NEPA compliance from the BLM effort. The DOE asked for further review of the seismicity anticipated from the stimulation. Drilling difficulties in the soft, wet serpentinite caprock at the project site resulted in suspension of the workover effort and eventual release of the rig. At the end of 2009, AltaRock ceased all work on the project. To date, no direct EGS-related activities have occurred in the southeast Geysers. Despite this setback, the DOE went on to fund three new EGS projects in the fall of 2009.

Conclusion and Plans for Future EGS Projects

The successes and lessons learned from past injection and EGS projects suggest the following principles for a successful EGS project:

Cultural Setting

The RMA disposal well and the DHM injection well were too close to major cities for the public's comfort. The risk of damage to buildings and infrastructure was deemed too great. For now, EGS will be best performed away from urban areas. Even in more sparsely populated areas, the local population and media must be well-educated about the project, so that there are no surprises if an event large enough to be felt does occur.

Geological and Tectonic Setting

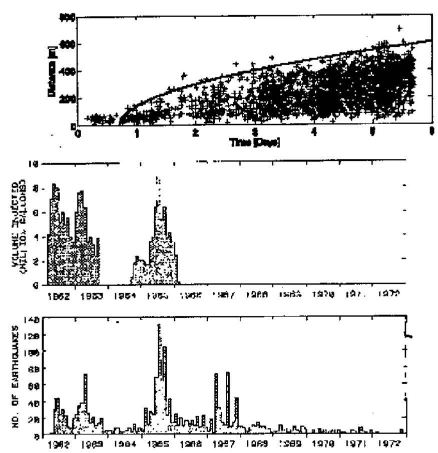
The disposal well at the RMA, Soultz GPK3, and Basel-1, all injected fluid directly into large faults zone or weak zones. These zones seem to be more susceptible to larger seismic events, and it is difficult to significantly improve the already high levels of productivity/injectivity of these zones (i.e. GPK3). Thus, when possible, known structures in the well bore should be avoided and the injection focused to a different depth in the injection well.

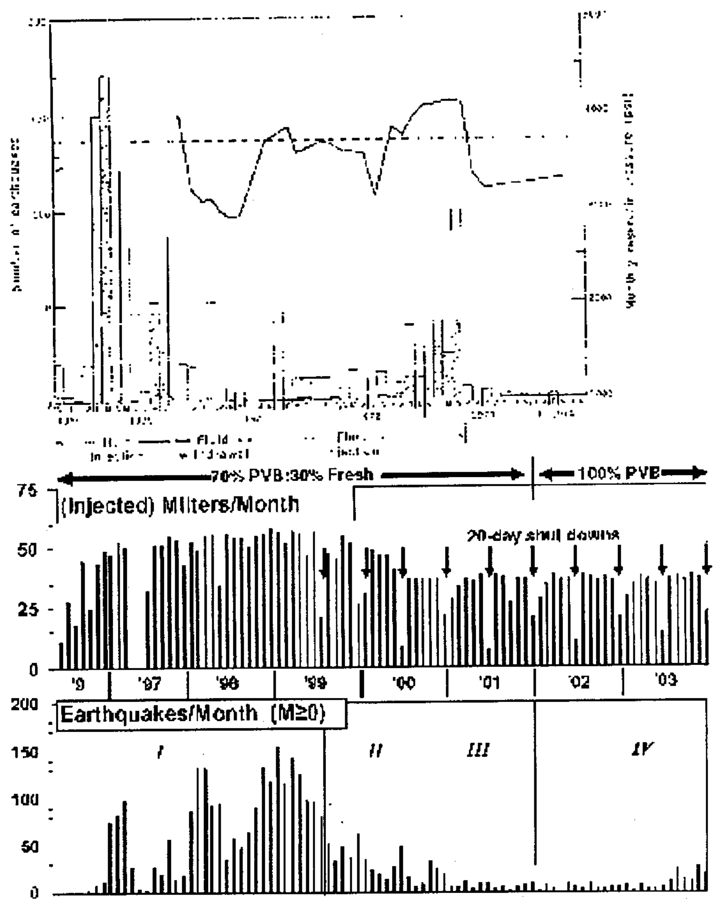
The existing seismic hazards and background seismicity need to be studied at the project onset. If faults capable of damaging earthquakes are found in the region, appropriate buffers and exclusions zones to prevent interaction with these faults should be defined.

Seismic Network and Monitoring

Initially, the *IIS* Rocky Mountain Arsenal near Denver was recorded on a single seismometer. Projects since have confirmed the importance of a microseismic array (MSA) in order to collect data on the background seismicity and monitor the growth and size distribution of project *IIS*. The MSA is also key to determining the onset of microseismicity and providing feedback to operators on the effect of flow rates and well head pressures on *IIS* (e.g. Figures 3, 4, 5, and 6).

In order to monitor the impact of IIS on the local community, a strong motion seismometer (SMS) should be installed in the nearest local community. The potential for heightened human perception of EGS *IIS* also needs to be part of any public outreach plans. Despite the overall disappointment at the DHM project, the modified "Traffic Light System" employed was successful at preventing *IIS* magnitudes from reaching damaging magnitudes.




70% PVB:30% Fresh
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Earthquakes/Month (M≥0)
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I
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Geysers Annual Steam Production, Water Injection and Seismicity, 1960 - 2006

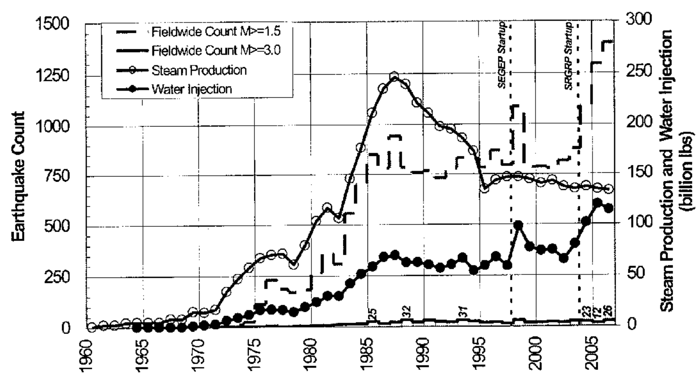
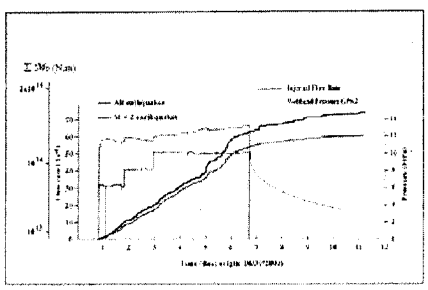
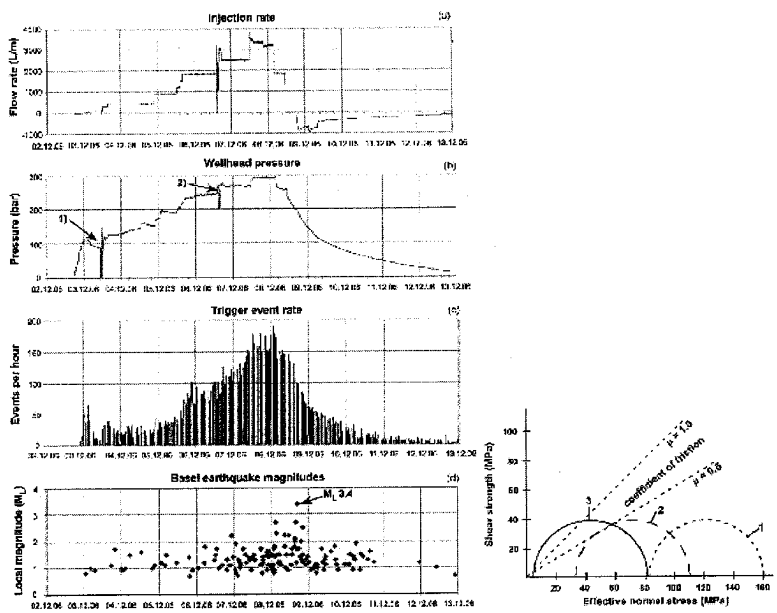


Figure 3.





The CHAIRMAN. Thank you very much.
Dr. Zoback.

STATEMENT OF MARK D. ZOBACK, BENJAMIN M. PAGE PROFESSOR OF EARTH SCIENCES, DEPARTMENT OF GEOPHYSICS, STANFORD UNIVERSITY, STANFORD, CA

Mr. ZOBACK. Chairman Bingaman, Senator Murkowski and committee members, thank you for asking me to testify today.

My name is Mark Zoback. I'm a Professor of Geophysics at Stanford University. My field of expertise is in quantifying the geologic processes in the Earth that control earthquakes and hydraulic fracture propagation. I've been doing this research for over 30 years.

While I was not a member of the NRC Committee chaired by Professor Hitzman, I did have the opportunity to speak to them about the issues I'll talk to you about today. Let me say at the outset, that I'm in full agreement with the principle findings of their report.

I want to limit my comments today to discussing earthquakes and energy technologies in 2 specific contexts.

First will be the earthquakes triggered by injection of waste water. Of course of particular interest has been the injection of the flow back water coming out from shale gas wells following hydraulic fracturing.

Second, I want to comment briefly about the potential for triggered seismicity associated with the large scale carbon capture and storage or CCS, as it is widely known.

As Dr. Leith pointed out, in 2011 the relatively stable interior of the U.S. was struck by a surprising number of small to moderate size, but still widely felt earthquakes. Most of these events, as he indicated, were the kinds of natural events that occur from time to time in intra-plate regions. But a number of the small to moderate earthquakes that did occur in 2011 appeared to be associated with the disposal of waste water, at least in part related to shale gas production. Seismic events associated with waste water in 2011 include the earthquakes near Guy, Arkansas and those near Youngstown, Ohio.

It is understandable that the occurrence of injection related earthquakes is of concern to the public, the government and industry alike. I think it is clear that with proper planning, monitoring and response, the occurrence of small to moderate earthquakes associated with waste injection can be reduced and the risks associated with these events effectively managed.

Five straight forward steps can be taken to reduce the probability of triggering seismicity whenever we inject fluid into the subsurface.

First, and as Susan Petty just pointed out, we need to avoid injection into faults in brittle rock. While this may seem like a no-brainer, there's not always a sufficient site characterization prior to approval of an injectionsite. In fact EPA guidelines does not include the consideration of triggered seismicity among its requirements.

Second, formations need to be selected that minimize the pore pressure changes. It is the increase of pore pressure that is the problem. We can minimize that increase in pore pressure by careful selection of formations used for injection.

Third, local seismic monitoring arrays should be installed when there is a potential for triggered seismicity.

Fourth, protocols should be established in advance to define how operations would be modified if seismicity were to be triggered.

These kinds of proactive steps, I think, will go a long way toward making the rare occurrence of these events even more rare and assure the public that their safety is being protected.

I'd now like to comment briefly about the potential for triggered seismicity associated with large scale carbon capture and storage. My colleague, Steve Gorelick and I, have recently pointed out that not only would large scale CCS be an extremely costly endeavor, there is a high probability that earthquakes will be triggered by injection of the enormous volumes of CO_2 associated with large scale CCS in many regions currently being considered.

There are 2 issues I want to emphasize in particular.

First, our principle concern is not the probability of triggering large earthquakes. Large faults are required to produce large earthquakes. We assume that such faults would be detected and thus avoided by careful site characterization studies.

Our concern is that even small to moderate size earthquakes would threaten the seal integrity of the formations being used to store the CO_2. Studies by other scientists have shown that a leak rate from an underground CO_2 storage reservoir of less than 1 percent per thousand years is required for CCS to achieve the same climate benefits as switching to renewable energy sources.

Second, it's important to emphasize that we recognize that CCS can be a valuable and useful tool for reducing greenhouse gas emissions in specific situations. Our concern is whether CCS can be a viable strategy for achieving global greenhouse gas reductions and appropriate positive effects on climate change. From a global perspective, if large scale CCS is to significantly contribute to reducing the accumulation of greenhouse gases, it must operate at a massive scale on the order of the volume injected has to be on the order of the 27 billion barrels of oil that are produced each year around the world. So it's a truly massive undertaking.

Now multiple lines of evidence indicate that pre-existing faults found in brittle rocks almost everywhere in the Earth's crust are close to frictional failure. In fact, over time periods of just a few decades, modern seismic networks have shown us that earthquakes occur nearly everywhere in continental interiors.

So in the light of the risk posed to a CO_2 repository by even small to moderate sized earthquakes, formations for suitable large scale injection of CO_2 must be well sealed by impermeable overlying strata.

They must be weakly cemented so as to not fail through brittle faulting.

They must be porous, permeable and laterally extensive to accommodate large volumes of CO_2 with minimal pressure increases.

Thus the issue is not whether CO_2 can be safely stored at a given site. The issue is whether the capacity exists for sufficient volumes of CO_2 to be stored in geologic formations for it to have a beneficial effect on climate change. In this contest—in this context, it must be recognized that large scale CCS will be an extremely expensive and risky strategy for achieving significant reductions in greenhouse gas emissions.

Mr. Chairman, Senator Murkowski, members of the committee, thank you for the opportunity to speak to you today.

[The prepared statement of Mr. Zoback follows:]

PREPARED STATEMENT OF MARK D. ZOBACK, BENJAMIN M. PAGE PROFESSOR OF EARCH SCIENCES, DEPARTMENT OF GEOPHYSICS, STANFORD UNIVERSITY, STANFORD, CA

Chairman Bingaman, Senator Murkowski and members of the committee, thank you for asking me to testify today. My name is Mark Zoback, I am a Professor of Geophysics at Stanford University. For your general information, I last spoke to this committee in October as a member of the Secretary of Energy's Advisory Board Shale Gas Subcommittee. I also served on the National Academy of Engineering committee that investigated the Deepwater Horizon accident. My field of expertise is in quantifying geologic processes in the earth that control earthquakes and hydraulic fracture propagation. I have been doing research in these fields for over 30 years ago. My PhD students and I have been carrying out a number of collaborative research projects seeking to better understand these processes in the context of carbon capture and storage and production from shale gas reservoirs.

While I was not a member of the NRC committee chaired by Professor Hitzman, I did have the opportunity to speak with the committee about the issues I'll comment upon today. Let me say at the outset that I am in full agreement with the principal findings their report.

Today, I will limit my comments to discussing earthquakes and energy technologies in two specific contexts. First, will be earthquakes triggered by injection of wastewater. While wastewater can come from many sources, of particular interest in the past few years has been the injection of the flow-back water coming out of shale gas wells following hydraulic fracturing. Second, I want to comment briefly about the potential for triggered seismicity associated large-scale carbon capture and storage, or CCS, as it is widely known.

In most cases, if earthquakes are triggered by fluid injection it is because injecting fluid increases the pore pressure at depth. The increase in pore pressure reduces the frictional resistance to slip on pre-existing faults, allowing elastic energy already stored in the rock to be released in earthquakes. For the cases I will speak about today, the earthquakes in question would have occurred someday as a natural geologic process—injection could simply advance their time of occurrence.

I have provided the committee staff with recently published papers I've written on these topics to provide more details.

Earthquakes associated with wastewater injection

In 2011 the relatively stable interior of the U.S. was struck by a surprising number of small-to-moderate, but widely felt earthquakes. Most of these were natural events, the types of earthquakes that occur from time to time in all intraplate regions. The magnitude 5.8 that occurred in northern Virginia on Aug. 23, 2011 that was felt throughout the northeast and damaged the Washington Monument was one of these natural events. While the magnitude of this event was unusual for this part of the world, the Aug. 23rd earthquake occurred in the Central Virginia seismic zone, an area known for many decades to produce relatively frequent small earthquakes.

This said, a number of the small-to-moderate earthquakes that occurred in the interior of the U.S. in 2011 appear to be associated with the disposal of wastewater, at least in part related to shale gas production.

Following hydraulic fracturing of shale gas wells, the water that was injected during hydraulic fracturing is flowed back out of the well. The amount of water that flows back after fracturing varies from region to region. It's typical for 25-50% of injected water to flow back. While the chemicals that comprise the fracturing fluid are relatively benign, the flow-back water can be contaminated with brine, metals and potentially dangerous chemicals picked up from the shale and must be disposed of properly.

Seismic events associated with injection of wastewater in 2011 include the earthquakes near Guy, Ark., where the largest earthquake was a magnitude-4.7 event on Feb. 27th and the earthquakes that occurred on Christmas Eve and New Year's Eve near Youngstown, Ohio. The largest Youngstown event was magnitude 4.0. It is understandable that the occurrence of injection-related earthquakes is of concern to the public, government officials and industry alike.

I believe that with proper planning, monitoring and response, the occurrence of small-to-moderate earthquakes associated with fluid injection can be reduced and the risks associated with such events effectively managed. No earthquake triggered by fluid injection has ever caused serious injury or significant damage. Moreover, approximately 140,000 Class II wastewater disposal wells have been operating safely and without incident in the U.S. for many decades.

Five straightforward steps can be taken to reduce the probability of triggering seismicity whenever we inject fluid into the subsurface. First, it is important to avoid injection into faults in brittle rock. While this may seem a "no-brainer", there is not always sufficient site characterization prior to approval of a injection site. Second, formations should be selected for injection (and injection rates limited) so as to minimize pore pressure changes. Third, local seismic monitoring arrays should be installed when there is a potential for injection to trigger seismicity. Fourth, protocols should be established in advance to define how operations would be modified if seismicity were to be triggered. And fifth, operators need to be prepared to reduce injection rates or abandon injection wells if triggered seismicity poses any hazard. These five steps provide regulators and operating companies with a framework for reducing the risk associated with triggered earthquakes.

In addition, the re-cycling of flow-back water (for use in subsequent hydraulic fracturing operations) is becoming increasingly common (especially in the northeastern U.S.). This is a very welcome development. Re-use of flow-back water avoids potential problems associated with transport and injection flow-back water or the expense and difficulty of extensive water treatment operations.

It is important to note that the extremely small microseismic events occur during hydraulic fracturing operations. These microseismic events affect a very small volume of rock and release, on average, about the same amount of energy as a gallon of milk falling off a kitchen counter. The reason these events are so small is that pressurization during hydraulic fracturing affects only limited volumes of rock (typically several hundred meters in extent) and pressurization typically lasts only a few hours. A few very small earthquakes have occurred during hydraulic fracturing (such as a magnitude-2.3 earthquake near Blackpool, England, in April 2011), but such events are extremely rare.

It is important for the public to recognize that the risks posed by injection of wastewater are extremely low. In addition, the risks can be minimized further through proper study and planning prior to injection, careful monitoring in areas where there is a possibility that seismicity might be triggered, and operators and regulators taking a proactive response if triggered seismicity was to occur.

Earthquake potential and large-scale carbon storage

I would now like to comment briefly about the potential for triggered seismicity associated large-scale carbon capture and storage. My colleague Steve Gorelick and I have recently pointed out that not only would large-scale CCS be an extremely costly endeavor, there is a high probability that earthquakes will be triggered by injection of the enormous volumes CO_2 associated with large-scale CCS.

There are two issues I wish to emphasize in particular this morning. First, our principal concern is not the probability of triggering large earthquakes. Large faults are required to produce large earthquakes. We assume that such faults would be detected, and thus avoided, by careful site characterization studies. Our concern is that even small-to-moderate size earthquakes would threaten the seal integrity of the formations being used to store CO_2 for long periods without leakage. Studies by other scientists have shown that a leak rate from underground CO_2 storage reservoirs of less than 1% per thousand years is required for CCS to achieve the same climate benefits as switching to renewable energy sources.

Second, it is important to emphasize that we recognize that CCS can be a valuable and useful tool for reducing greenhouse gas emissions in specific situations. Our concern is whether CCS can be a viable strategy for achieving appreciable global greenhouse gas reductions. From a global perspective, if large-scale CCS is to significantly contribute to reducing the accumulation of greenhouse gases, it must operate at a massive scale, on the order of 3.5 billion tonnes of CO_2 per year. This corresponds to a volume roughly equivalent to the 627 billion barrels of oil currently produced annually around the world.

Multiple lines of evidence indicate that pre-existing faults found in brittle rocks almost everywhere in the earth's crust are close to frictional failure, often in response to small increases in pore pressure. In fact, over time-periods of just a few decades, modern seismic networks have shown that earthquakes occur nearly everywhere in continental interiors. In light of the risk posed to a CO_2 repository by even small-to-moderate size earthquakes, formations suitable for large-scale injection of CO_2 must be well-sealed by impermeable overlaying strata, weakly cemented (so as not to fail through brittle faulting) and porous, permeable, and laterally extensive to accommodate large volumes of $CO_2$with minimal pressure increases.

Thus, the issue is not whether CO_2 can be safely stored at a given site, the issue is whether the capacity exists for sufficient volumes of CO_2 to be stored in geologic formations for it to have a beneficial affect on climate change. In this context, it must be recognized that large scale CCS will be an extremely expensive and risky strategy for achieving significant reductions in greenhouse gas emissions.

Mr. Chairman, Senator Murkowski and members of the committee, thank you for the opportunity to speak to you today.

The CHAIRMAN. Thank you all very much for the excellent testimony. Let me start with a few questions.

Dr. Hitzman, I'm trying to get clearly in mind the main thrust of your conclusions. From what I believe I heard you say and have read in your report here, the 2 biggest potential causes of this seismic activity, human causes, would be injection of waste water which is a significant issue because there's a lot of it injected.

Second, if in fact we were to pursue carbon capture and storage at a large scale that also would be significant.

That those 2 types of injection pose a much greater threat and are a much greater issue, in your mind, then the injection that is generally referred to as fracking and geothermal activity as well as I understand it. Is that a reasonable summary of your——

Mr. HITZMAN. That's a very fair statement of what the report says. Yes.

The CHAIRMAN. So you're not as worried about fracking. You're not as worried about geothermal energy production activities.

But you are worried about waste water and you are worried about CCS if it goes to a large scale?

Mr. HITZMAN. Correct. It really is volume dependent.

So in geothermal we're trying to balance a reservoir.

In fracking there's very small volume.

But in waste water, most of the waste water disposal wells are fine. But with vast numbers of them and putting lots and lots of these wells in, some of them with fairly large volumes, occasionally there will be an event.

CCS, because it has such very large volumes, as pointed out by Dr. Zoback, are sort of in a different league. So that clearly is of concern.

The CHAIRMAN. Now as far as I understand, to deal with the—or to reduce the likelihood that you're going to have human felt induced seismic activity from waste water injection. I think your suggestion is that there are some best practices that can be followed. I guess my question there is, is it clear that who would have the responsibility or authority to define those best practices and try to implement them or is this such—you've got so many agencies and so many different levels of government involved here that the whole thing is a hodgepodge?

Mr. HITZMAN. The committee actually didn't try to specify who should do it because, as you say, there are a number of agencies and different groups involved. But clearly, sort of as happened with the DOE protocol for EGS. What took place there was a cooperative venture between several levels of government with academia, with industry, with local communities try and come up with best practices.

The committee felt that that was the sort of way moving forward with the other energy technologies as well.

The CHAIRMAN. So the Department of Energy or EPA or somebody at the Federal level could convene a group of all the various players in this field and try to come up with some kind of guidelines. Say this is what we need to be doing in order to reduce the likelihood of this seismic activity resulting from waste water injection.

Mr. HITZMAN. Yes, absolutely.

The CHAIRMAN. Yes.

Now what's your reaction to Dr. Zoback's comment?

He's made a very interesting point here which is basically that he thinks that, as I understand it, and Dr. Zoback correct me if I misstate your view here. But your basic view is that in order for carbon capture and storage to be pursued on the large scale that it would have to be pursued in order to achieve significant climate change benefits or, you know, we have real problems in pursuing it at that scale considering the likelihood of leakage out of these underground storage facilities.

Is that a fair summary of—maybe you can state it much better than that.

Mr. ZOBACK. I'll try.

When we look at the global greenhouse gas problem, you know, the real problem is that by mid-century the—if we do nothing emissions will be twice as much as they are today. So we'll be adding, you know, something like 15 billion tons of carbon to the atmosphere per year in 2050. You know, we're currently at the 7 or 8 billion ton level.

So we have a problem that's on the scale of needing to reduce emissions by 7 or 8 billion tons of carbon. Now if CCS is going to be part of that solution at that scale it has been proposed that it should deal with say, one seventh or one eighth of the problem.

Can it go along with, you know, enhanced use of renewables?

Can it go along with energy efficiency programs?

Can it go along with fuel switching from coal to natural gas?

All of which will reduce emissions.

If it's going to be a player at the billion ton level then we get into a situation where we need 3,500 projects of the scale of the single operable project that's going on now in the North Sea. So it's really not the fact that we can't find good places to put CCS. But for CCS to be part of a global strategy for stabilizing emissions it's got to operate at this billion ton of carbon scale which is 3,500 times what we're doing today at a single site.

The CHAIRMAN. OK.

Why don't I defer to Senator Murkowski for her questions and then Senator Landrieu?

Senator MURKOWSKI. Thank you, Mr. Chairman.

I appreciate the testimony from all the witnesses this morning. Very interesting. I think that the focus here on CCS and waste water injection is an interesting one. Perhaps the results of this study were different than what some imagined before you began this.

But let me ask the question again, sticking with the CCS. I mean we've got new EPA rules that essentially ban construction of new coal fired power plants unless CCS is out there. So a lot of interest in whether or not we can do this right and/or if at all.

More specific perhaps to this committee is the work that we've done to draft the liability protections for CCS operators. So I guess the question to you, Dr. Hitzman, is with this information that we know have do you think that it is perhaps premature or even unwise to provide liability protection for CCS operators? I mean, can we even do this or do we need to know more?

Mr. HITZMAN. That certainly is outside the scope of what our committee looked at. We did not look at insurance whatsoever. So where we can down to is that there is significant concerns. We thought that DOE should address those concerns to look at how this technology may play out in the large scales that Dr. Zoback has talked about.

Senator MURKOWSKI. You—we're talking now about the increased risk, comparative, when we're talking about geothermal or fracking as it relates to waste water injection and CCS. But is it—it's not fair to describe that the risk or the consequences between waste water injection and CCS are comparable. Is that correct?

I mean, you've got a higher risk with CCS?

Mr. HITZMAN. It depends on the volumes. So it's volume related. If we were injecting billions of tons, as Dr. Zoback discussed, then the risks are probably much greater because certainly none of our waste water wells are injecting anywhere near that.

So really it's—think about volume. The more volume probably the more risk.

Senator MURKOWSKI. You made a statement that, let's see, no geologic review before injection. This is with the disposal of the waste water. Is that, perhaps, part of the reason that we see higher rates of seismic activity is because you don't have that same geologic study that you have, say for instance, when you're doing a geothermal well or even fracking?

You've got some pretty serious studies that proceed before you move forward. Is that perhaps accounting for some of the difference?

Mr. HITZMAN. That's part of it, yes. With any of the CCS projects going on, with certainly with geothermal, we have a lot of geologic data before those happen.

For many waste water wells they're relatively low cost operations. They don't have a lot of citing—site characterizations done ahead of time.

But it also is important to note that the vast majority of waste water wells do not have an issue. So we're not, in the report, we certainly do not suggest requiring that that occur for all waste water wells.

Senator MURKOWSKI. OK.

Dr. Leith, let me ask you about monitoring. Both the report and your testimony indicate that we need greater monitoring activity. In terms of scale do we need to double the monitoring that we're doing?

What would you suggest in terms of stepped up monitoring activities here?

Mr. LEITH. The USGS, the National Seismic Network, is capable of routinely locating earthquakes that are around magnitude 3 and in many areas lower than that. But with that network we certainly cannot detect the onset of low magnitude induced earthquakes from an injection operation in most of the country.

So what we rely upon is learning early about the occurrence of earthquakes. That typically doesn't happen until they're felt. It's just going to be above magnitude two somewhere.

Then deploying portable seismometers to go in and assess what's going on. This is what we did in Arkansas and in Oklahoma and——

Senator MURKOWSKI. Do you do that just in a few specific areas or is—are you doing this monitoring across the country?

Mr. LEITH. We do not have enough portable systems to deploy to all of the interesting cases of induced seismicity.

Senator MURKOWSKI. If you have enough portable systems in these interesting areas, as you put it, what would that require?

Mr. LEITH. We have been so busy with natural earthquakes for the last few years. Then this increased occurrence of induced earthquakes has piled onto that demand.

We would need, I would estimate, some hundreds of portable systems to respond to just the earthquakes that are in the magnitude 4 and above range. That, of course, doesn't include the scientist's time, the analyst to evaluate the data and the researchers to then correlate what's recorded by the seismometer to determine its relation to the injection activity, the fluid volumes injected, the pressures and those sort of things.

Senator MURKOWSKI. Thank you, Mr. Chairman.

The CHAIRMAN. Senator Landrieu.

Senator LANDRIEU. Thank you very much. I have a short statement for the record.

Senator LANDRIEU. I want to say I really appreciate the hearing the chairman and the ranking member have put together. This is very, very interesting, particularly about the volume necessary, the 3,500 sites, to take care of the billion tons of carbon sequestration.

Let me ask you, if you could, Dr. Zoback, to describe these locations to the best of your ability to those of us that are trying to get our heads around what such a location might look like. You said there would need to be 3,500 sites. So we could pick 100 countries, put 35 in each one.

How—what would a site look like? Describe the one that exists now so we can get a little better understanding of that.

Mr. ZOBACK. The project that exists now is a gas field. It's operating in the North Sea. When they produce the gas it has a large fraction of CO_2 mixed with the methane. So they have to deal with the CO_2.

They separate it from the natural gas. Put the natural gas into a pipeline. Then they have an injection well in which they inject the CO_2 into a geologic formation, basically above the gas reservoir. This geologic formation has, what I consider to be, you know, ideal characteristics.

First, it's very laterally extensive. It's big. So you're putting the CO_2 into a large volume.

Senator LANDRIEU. It's right near the site itself.

Mr. ZOBACK. That's exactly right. It's—the well has been drilled off the same platform that the gas wells were drilled from.

So the geologic formation, it's called the Utsira formation. It's a very—it's laterally extensive. It's very porous and permeable so it's easy for them to get the CO_2 into it. It has this added characteristic that it's very weak and friable.

It's easy to imagine that if you had a very weak sandstone and you squeezed on it, well it would just kind of deform slowly in your hands and, you know, there's no problem. Whereas a very strong rock, as you squeeze on it, it holds the force much better. But when it does fail it will fail brittle-ly. You know, it's like a very small earthquake.

So the Utsira formation is porous, permeable, laterally extensive and very weak and located where you want it to be. It's absolutely ideal.

Senator LANDRIEU. Let me follow that up. Because I was thinking that it would have to be on countries, on land. But this could be 3,500 sites in the world in the oceans, on land, etcetera, etcetera.

So while it sounds like a lot of sites, you know, it's a big planet. So I think we have to get the scale of this to understand. But I think it's a very important point that you raised.

But it's also, I would say in response, while it seems overwhelming when you first say it. Until you've had a little bit more information about how many other potentially, really enormous and very good sites there might be. Before we completely rule this out we need to have a little bit more, a lot more, data about that.

Let me ask my other question.

I'm very pleased to hear that fracking is not the problem. We've heard a lot of problems about fracking. Since my State is doing a lot of it and think we're contributing to the natural gas production which is helping clean our atmosphere and provide the energy that our Nation and the world needs to move forward. But it's the waste water injections.

So I want to ask a couple of questions.

Is the oil and gas industry, primarily in the United States, responsible for the majority of waste water wells? Are there other industries that are injecting waste water? Could somebody give us some data, if you have it, about that?

Is it primarily the oil and gas industry or is it primarily other mining or is it petrochemical or agriculture, etcetera, etcetera?

Mr. HITZMAN. There's some data in the NRC report. I don't have at the top of my head the percentage. But there are a number of producers of waste water that are disposed in the subsurface. Oil and gas is one of the major ones in the country.

Senator LANDRIEU. But there are other major ones?

Mr. HITZMAN. There are other major ones.

Senator LANDRIEU. Are there any industries that are more than the oil and gas industry? Does anybody know? You think there would be——

Mr. HITZMAN. I think it probably is the single largest. But it's probably not super high above.

Senator LANDRIEU. Above the others.

Mr. HITZMAN. Some of the others, yes.

Senator LANDRIEU. OK.

Those are my questions. Thank you. I'm going to submit the rest for the record.

The CHAIRMAN. Thank you very much.

Let me just try to put a little finer point on Dr. Zoback's testimony and as least as I understand it just to be clear. As I understand, your basic point is that you doubt that CCS, carbon capture and storage, can be a successful strategy for dealing with the long term effects of climate change. A main reason you doubt that is because of these small to moderate sized earthquakes that, not only do you have to have 3,500 of these projects like the one you've just described to us.

But there are small to moderate size earthquakes that occur naturally, as I understand it, that will, as you put it, threaten the seal integrity of the formations that might be used for the CCS. Is that accurate?

Mr. ZOBACK. That's exactly our point, Senator.

The CHAIRMAN. Yes. Alright.

Is this something you and fellow researcher expert that you mentioned have concluded on your own? Is this anything that the—any other group has looked at? Has the National Academy reviewed that set of recommendations or conclusions?

Mr. ZOBACK. Basically the conclusions we've recently written about are essentially identical to the conclusions that the committee, chaired by Professor Hitzman, came to. So we're in complete concordance. They basically said——

The CHAIRMAN. But their report, the one that we have before us today doesn't go as far as you're going with your conclusions about the problems with planning on CCS as a strategy for long term climate change mitigation.

Mr. ZOBACK. That's true. They did not go that far. But in some ways they went further by pointing out the potential for large earthquakes because of the extremely large volumes to be injected.

The question there is how good site characterization studies will be. We took what we thought was an approach by saying the site characterization will be so comprehensive that, you know, there will be no big faults. There will be no probability for a bigger earthquake. But it's the small faults that you can miss.

So therefore, our statement would have been due to the large scale, large volumes, there's a high probability of something happening, probably something small to moderate in size. Their statement was a bit stronger on the hazard part of it. They said that in fact there was the potential, perhaps, of missing some of the bigger faults and a potential for a larger earthquake occurring.

So philosophically I think we're 100 percent in agreement. It's a slight change in interpretation about what the hazard might be.

The CHAIRMAN. Dr. Hitzman, let me just ask you.

Did you—does your report deal with the issue of whether or not small earthquakes or small instances of induced seismicity might result in natural earthquakes being substantially more likely in certain areas? For example if you go to a place where there's a natural known fault and there's a real risk of an earthquake at some point, could you hasten the time of that earthquake or increase the likelihood of that natural major earthquake by doing the type of small injection activity that we're talking about here?

Mr. HITZMAN. That is addressed in the report. The basic answer is yes that many faults are near a critical state. So if we perturb them, manmade, we can trigger events. So the answer is yes.

Is that something we routinely do? No. I mean site characterization, especially around areas of known faults we do today.

So I don't see that as a particular large issue.

The CHAIRMAN. So as long as we stay away from the known faults that are naturally there, we pretty much deal with that problem.

Mr. HITZMAN. Right. But what happens is there are faults we don't know about. That's where, certainly in the waste water injection, that's where we've had the problems. We found faults we didn't know existed.

The CHAIRMAN. Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman.

I want to follow up to the questioning that Senator Landrieu had about the various types of waste water injection. It's my understanding that there are 6 different classes of injection wells.

One is municipal and industrial waste. We've got mineral solution, mining. We've got other things.

So the question would be whether or not we think that any of these other well classifications. Whether or not they've been associated with any additional seismic activity, whether we've looked at that. Whether it's possible that they could.

Then as a follow on as we see communities expanding and population going into certain areas, is it possible that we could see enhanced seismic activity just due to what we're contributing from the municipal and industrial waste? I don't know whether it's a significant enough volume or quantity to make a difference. Have you looked at that?

Mr. HITZMAN. Our committee specifically looked at Class Two wells with energy injection.

Senator MURKOWSKI. OK.

Mr. HITZMAN. So we didn't consider the others.

But what I would say is it really makes no difference whether the fluid is produced by an energy or by another industry or just simply waste water. It's water being injected down.

Senator MURKOWSKI. It's the volumes that are the critical piece.

Mr. HITZMAN. Right. Right.

So as we inject more and more volume into the subsurface, we probably will have more and more potential for seismic events.

Senator MURKOWSKI. OK. Alright.

Ms. Petty, we've been quiet regarding geothermal here. I am a huge advocate of geothermal power and the resource itself. We've got, I think, some considerable opportunities in my State. We've also got some pretty impressive fault lines that run up there have had a history of earthquake activity.

We've apparently managed to avoid any major issues. I think that that's great. But in listening to your testimony you seem to indicate that the risks associated with geothermal are perhaps more minimal.

I guess a very generic question is whether or not you think the benefits then of geothermal outweigh any potential risk associated.

Ms. PETTY. I think that the main aspect of this, as Dr. Hitzman said, is that in geothermal we want to balance the injection and production so that we don't have a disproportionate amount of either. That way the pore pressure doesn't change. There have been some cases in geothermal fields where we didn't do that, where we took out more than we put back in.

In those cases, especially when we started to put more in we've had increased amounts of seismicity. I think it's that balancing of injection and production that's kind of inherent to doing a good job of managing geothermal that makes me feel that we have less of an issue for potential large scale, induced seismicity, felt induced seismicity in geothermal.

The cases where we are near large faults, I mean, in fact there are a number of geothermal fields that are near or actively injecting into faults. But because they add balance to the injection and production there hasn't been an issue.

For EGS where we are creating a reservoir, we—a necessity when we start out, we inject more than we produce because we don't produce anything until we make the reservoir. That's when the risk is more clear to us. In that's where we need to have some kind of mitigation protocol. We have to have good site characterization, so that we can get that big resource.

Senator MURKOWSKI. It sounds like so much of this is, is we are learning. That's an important piece to recognize in all of this as well.

Dr. Zoback, you mention that there are ways that we can manage the risk. You cited 4 different points.

I mean, one, which is pretty obvious, is avoid the faults. So we need to know where we are and we need to better understand our geology. Pay attention to that I would think.

But appreciating that we can manage risk is one thing. Is there any way to avoid it to the extent that you can tell people don't worry? We know and we understand what it is that we have to do to balance this. There should be no cause for concern.

Are we to that point?

Mr. ZOBACK. In some cases. For example thorough site characterization is a basis for assuring the public that you've done due diligence before you start.

Monitoring with enhanced seismic networks if you think you're in an area where something might happen. You know, you're on top of it. That's another issue that should assure the public.

But something else is happening that should be pointed out with respect to the shale gas development and waste water injection problem. That is in the Northeastern U.S. which is, you know, an area of active development with the Marcellus shale is being exploited. There are really no good places to inject the waste water.

So what's happening is that industry has largely started to recycle the waste water. So the water that comes back from hydraulic fracturing is now being reused in subsequent hydraulic fracturing operations. That's beneficial for everyone.

You use less water. So the water resources are protected. You basically put the contaminated water, which was contaminated by its interaction with the shale to begin with. You put it back into the shale.

So the more you can recycle these flow back waters, the smaller you make the problem. In the Northeastern U.S. this is now standard practice. In other areas, if there's difficulty finding, you know, safe injectionsites, that practice can be extended to other parts of the country.

Senator MURKOWSKI. We were in West Virginia this weekend looking at—we were at the Marcellus. They were speaking exactly to that process of the recycling and how that all plays into it. Again a recognition that we're learning a little bit more.

Did you learn anything from this report that you found surprising?

Mr. ZOBACK. It was really nice to see that the information compiled, as it was. I was aware of the general issues, but they did a terrific job of pulling together information on a global basis and of course, with the United States getting particular emphasis.

The other thing I really appreciated out of the report was that it points to the need for data. So often we're asked, well, was that earthquake triggered or not. You don't have a baseline to make an answer to that question.

Whether it's a seismic baseline and you're not aware of what the seismicity was prior to a larger event occurring or the pore pressure or the stress or the pre-existing faults. In both the Youngstown and Guy, Arkansas cases scientists have come forward after the fact and said, oh yeah, there was an active fault right there that was being injected into. Had that data been available prior to the injection neither incident would have occurred.

So, you know, in some ways, as the report illustrates in case after case we have a good conceptual understanding of what the issues are but we rarely have the data in order to use that conceptual understanding to be definitive about, you know, what's happened and how to prevent things from happening in the future. So it's a data issue as much as anything else.

Senator MURKOWSKI. Thank you all. I appreciate your testimony this morning.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you.

Let me ask about a bill. Senator Murkowski referred to one of the bills that's been reported out of our committee, S. 699, that provides—it proposes to provide some liability protection for CCS projects. The idea of that or the general thrust of it is to say that for the first ten large demonstrations of CCS there would be some liability protection provided if DOE could determine that there's adequate measuring and monitoring and testing to verify that the carbon dioxide that is injected into the injection zone is not escaping or migrating and is not endangering underground drinking water sources.

The idea of the legislation and then of course the bill tries to provide a long term stewardship for these demonstration projects, these first 10. I guess that I'd ask Dr. Hitzman. Is there anything in your report or in the work that your committee did that would tell us whether it makes sense to proceed with these kinds of large demonstration projects or to have encouragement to industry to proceed with these or not?

I mean, is this something that is a waste of effort or is it something that would make some sense to help us understand whether or not this is an avenue that's going to be beneficial?

Mr. HITZMAN. I think what the report says is that we also see the potential benefits of doing CCS. But that we really need to understand it better at the scales that are being projected. So I'm not sure exactly how large, how many—what the volume is in these ten demonstration projects over the long term.

But we recommend that the DOE continue with its research, probably use some of the research it's doing now and focus it a little more on this particular issue so it can be better understood. That right now, we need the data. We can't answer your question directly.

The CHAIRMAN. OK.

Dr. Zoback, did you have thoughts as to whether it makes sense for the Department of Energy and the Federal Government to be encouraging some of these large scale demonstration projects through this kind of legislation or do you think it's such a nonstarter as that we really should look elsewhere to solve the long term climate change issue.

Mr. ZOBACK. The paper that we, my colleague and I, just published on this topic is published as a perspective piece. It really is our perspective that because of these potential problems one has to consider this, the strategy of large scale CCS with these issues in mind. So what we're trying to do—and by the way, the paper was published yesterday. So there's going to be a lot of reaction to it without question.

What we're trying to do is just change the dialog and ask people to consider this question not just in the context of the scale and the cost which have been raised by many people in the past. They are very real issues. But also in the context if 10 or 20 years from now one of these moderate sized earthquakes occur in one of the repositories what is that going to mean for this strategy that we've, you know, we've embarked on.

So this has to be thought through very carefully. I'm not familiar with the legislation you referred to. So I'd rather not comment on it.

But we're just trying to change the dialog and broaden people's perspective just as the case that triggered seismicity is not considered in the licensing requirements for a Type Two waste water injection well. Perhaps it should be, at least in certain parts of the country. Triggered seismicity should certainly be a strong consideration as we look at CCS in a research mode in the future.

The CHAIRMAN. But your concern is triggered seismicity. But you're also—your concern is natural seismicity. You're basically saying there are natural, small and medium sized earthquakes that may thwart our ability to use CCS at large scale to solve climate change problems long term.

Mr. ZOBACK. That's true, Senator. We're—but by raising the pore pressure, you know, the probability of something happening goes up because you are basically advancing the time at which a natural event would have occurred anyway. So in a given area natural earthquakes occur but they might be so infrequent that you would assume that during the lifetime of the repository there's no possibility of an event occurring.

But by injecting fluid we sort of bring the faults closer to failure and therefore enhance that probability.

The CHAIRMAN. Senator Murkowski, did you have additional questions?

Thank you all very much. I think this has been very useful.

Again, Dr. Hitzman, thank you for all the work you did on this report and your entire committee.

That will conclude our hearing.

[Whereupon, at 11:18 a.m. the hearing was adjourned.]

APPENDIX

RESPONSES TO ADDITIONAL QUESTIONS

RESPONSES OF MURRAY W. HITZMAN TO QUESTIONS FROM SENATOR BINGAMAN

Question 1. Dr. Zoback has testified that the risk of venting stored carbon dioxide from small, induced seismic events is a primary concern and obstacle to the scaling up of CCS technologies to play a significant role in mitigating global greenhouse gas emissions to the atmosphere. Do you agree with this assessment?

Answer. The statement of task for the study did not examine include consideration of the escape of carbon dioxide from CCS projects, thus we are not in a position to comment on this aspect of induced seismicity.

Question 2. The NAS study we just heard about indicates that there have been relatively few induced seismic events that are directly attributable to the energy technologies considered here. At the same time, Dr. Leith's testimony shows a sharp increase in the number of mid-continent earthquakes that USGS has measured over the past decade.

Question 2a. Is there something else going on that could be causing this trend in earthquakes?

Answer. The data Dr. Leith referred to in his testimony became available at the end of the NRC study and was not available in a peer-reviewed form. Hence, we were unable to examine it in detail. There could be a number of reasons for the seismicity to have apparently increased. Deep well disposal of waste water associated with energy development is one possibility. Another is a natural increase in seismicity. Finally, the apparent increase in number of events could be due to changes in the monitoring technologies employed over the past several years.

Question 2b. Is this a measurement issue, or is it just that more work needs to be done to figure out what caused these earthquakes?

Answer. As noted above, it could be a measurement issue. Certainly more work is required to better understand these seismic events.

RESPONSES OF MURRAY W. HITZMAN TO QUESTIONS FROM SENATOR MURKOWSKI

Question 1. To the extent that wastewater injection wells are geologically unavailable in certain Eastern US areas, might those areas bear a correspondingly remote risk of induced seismicity from natural gas development?

Answer. If the question is if waste water injection wells are not utilized will the seismic risks be decreased the answer is yes. However, fluids from energy development will need to be managed in some manner.

Question 2. The NRC report indicates that the Federal and State Underground Injection Control (UIC) Programs "do[es] not address the issue of seismicity induced by underground injection." At the same time, the current UIC program does require the injection well operator to perform a site characterization, including identifying the risks associated with nearby faults if any are located. Furthermore, several states (including Arkansas, Colorado, Ohio, and West Virginia,) are currently modifying their UIC Programs to specifically address seismicity. To this extent, might those state regimes reflect any of the proposed actions as noted in the report?

Answer. The NRC report states "the Safe Drinking Water Act . . . does not specifically address the issue of seismicity induced by underground injection. (page 106)" However, individual states have the authority to promulgate rules above and beyond the requirements of the SDWA including requirements such as providing additional information concerning induced seismicity as part of the permitting process. Our report (page 119) specifically notes the states of Colorado and Arkansas have adopted additional permitting regulations concerning induced seismicity in addition to the regulatory framework put forth in the SDWA. The additional information required by the state of Colorado closely parallels portions of the "Hazard Assessment" protocol recommended in our report on page 146. Our report also notes on page 106

"UIC regulations requiring information on locating and describing faults in the area of a proposed disposal well are concerned with containment of the injected fluid, not the possibility of induced seismicity."

Question 3. The report establishes the "felt at surface" threshold as a magnitude 2.0 seismic event. However, USGS documents state that a magnitude 2.0 to 2.9 is generally not felt, but might be recorded, while for the general population a magnitude 3.0 to 3.9 is more likely to be "felt." As also noted, a seismic event typically does not cause damage until its magnitude falls in the range of 4.0 to 4.9, and the report indicates that the purpose of implementing a risk management protocol is to prevent the occurrence of damaging events. Are the report's proposed actions targeted at such a risk management protocol or do they go further to seek to address any induced seismicity which might be recorded?

Answer. While seismic events in the 2.0 range are commonly not felt, particularly if they occur deep within the Earth's crust, the NRC committee met with residents living in the area of The Geysers where events in this range are shallow and are routinely felt. Damage from a seismic event depends on the location of the event relative to the structures being considered, the construction of such structures, and their contents. The NRC committee identified magnitude 2.0 since this is the smallest seismic event that can usually be felt by humans, even for shallow events caused by humans. The committee certainly is suggesting a risk protocol that is practical and widely applicable, not one for events that pose no risk. We would note that we are not disagreeing with the USGS documents, but feel the difference in wording has to do with the preciseness of the threshold of what may be felt.

Question 4. Of the corresponding wells drilled for each of the following energy technologies in the U.S., please provide what percentage have been proven to induce seismicity:

A) Enhanced oil recovery
B) Wastewater injection wells
C) Geothermal
D) Hydraulic fracturing

Answer. The committee could not find reliable statistics on the percentage of wells that have, or might have, induced felt seismicity (greater than M 2.0) for various energy technologies. Developing a reliable database of the numbers and characteristics of wells, and of the incidences of induced seismicity, as recommended in our report, will help with the understanding of the percentages associated with induced seismicity.

However, based upon the available data from peer-reviewed resources the committee identified and examined, neither enhanced oil recovery nor hydraulic fracturing have to date have been proven to have induced felt seismic events in the United States.

Regarding geothermal energy, although some of the events in our report's database were clearly caused by injection to generate geothermal energy (for example at the Geysers and in the Coso geothermal field), geothermal wells tend to be drilled in areas that are often seismically active, making 'proof' of the tie to fluid injection difficult.

Our report suggests that felt earthquakes at about 8 locations in the US over a period of about 40 years have been reasonably proven to be linked to wastewater injection. We know only the approximate number of wells today (~30,000); some of the older wells that caused felt events are no longer in operation. An approximate estimate of the fraction of wastewater wells that have induced felt earthquakes is therefore 8/30,000, which is about 3/100 of 1%.

Question 5. At the hearing, it was not clear how many of the various UIC wells of various classes were associated with oil and gas development (as opposed to municipal waste, etc.). Can you provide the committee with the breakdown of the various UIC well types and percentages relative to the total number of wells?

Answer. The committee examined in detail only Class II wells, with some mention of Class V and Class VI (CCS) wells. The only Class VI wells currently in operation are those associated with two carbon sequestration test sites supported by the Department of Energy. Class II wells, of which there are approximately 151,000 currently permitted in the United States, are all used for the injection of fluids associated with oil and gas operations. Of that total of 151,000, approximately 30,000 (~20%) are for waste water disposal (from oil and gas development), approximately 108,000 (~71%) are for secondary oil and gas recovery (waterflooding), and approximately 13,000 (~9%) are for tertiary recovery (enhanced oil recovery). Class V wells are the most numerous, accounting for almost 79 percent of the total number of UIC wells; wells used for fluid injection related to geothermal energy fall within this well class. However, only 239 wells in the United States among approximately 400,000-

650,000 Class V wells permitted in the country are for geothermal energy. The committee did not examine the other kinds of wells (which include storm water drainage wells, septic system leach fields, etc.) in this study so cannot provide a breakdown of the numbers of these kinds of wells.

RESPONSE OF MARK D. ZOBACK TO QUESTION FROM SENATOR BINGAMAN

Question 1. Your testimony noted that offshore formations similar to the one utilized by the Sleipner project in Norway and also depleted oil and gas reservoirs could potentially be suitable for long-term storage of high volumes of carbon dioxide. The Department of Energy indicates there may be as much as 7.5 trillion tons of CO_2 storage capacity in offshore formations in the Gulf Coast that are similar to the Sleipner project in Norway. The most recent estimates from the National Energy Technology Laboratory indicate that there may be as much as 20 billion tons of CO_2 storage capacity in depleted oil and gas reservoirs.

Question 1a. Could you please comment on these assessments of storage capacity and their suitability for the long-term storage of high volumes of carbon dioxide?

Question 1b. Could you provide an estimate of how much storage is available in the types of formations that you described as having suitable characteristics for such long-term storage?

Answer. As we noted in our PNAS paper on the potential of triggered seismicity associated with CO_2 storage, there are a large number of formations in the Gulf Coast that have appropriate characteristics for long term CO_2 storage. In other words, they are porous, permeable, weakly-cemented, laterally extensive, have adequate cap rocks and seals, etc. I am not familiar with the screening criterion used by the Dept. of Energy in their assessment of 7.5 trillion tons of CO_2 storage capacity in these formations. If their criterion considered all of the characteristics enumerated above, it should be straightforward to calculate the rates at which CO_2 could be injected without generating excess pore pressure could accommodate the enormous volumes of CO_2 generated in the U.S. each year. Obviously, transport of large quantities of £ from thousands of point sources throughout the U.S. to the Gulf Coast would be a formidable operational challenge. Nonetheless, utilizing appropriate geologic formations in the Gulf Coast is a far more attractive strategy than utilization of non-ideal formations (from the perspective of possible earthquake triggering) that are located more closely to CO_2 sources.

With respect to the National Energy Technology Laboratory's estimate that 20 billion tons of CO_2 could be stored in depleted oil and gas reservoirs, it is important to recognize that this does not represent very much capacity. Coal burning power plants in the U.S. alone generate about 2 billion tons of CO_2 each year so that depleted oil and gas reservoirs could accommodate emissions from coal burning plants for only 10 years. Another consideration is that successful long-term storage of CO_2 in depleted reservoirs could be compromised by leakage through the cemented annulus of wells or via damaged well casings. Both are common occurrences in old wells. In addition, it is important to assure that oil field operations did not affect the natural geologic seals of the hydrocarbon reservoir. There are a variety of mechanisms could compromise the reservoir's seal such as depletion-induced faulting or hydraulic fracturing, either when the well was first drilled or during subsequent water flooding operations.

I have not carried out an assessment of the CO_2 storage capacity of the geologic formations I would classify as being ideal for sequestration. Thus, I cannot respond to question 1b.

RESPONSES OF MARK D. ZOBACK TO QUESTIONS FROM SENATOR MURKOWSKI

Question 1. To the extent that wastewater injection wells are geologically unavailable in certain Eastern US areas, might those areas bear a correspondingly remote risk of induced seismicity from natural gas development?

Answer. It is true that there is a remote risk of triggering seismicity associated with multistage hydraulic fracturing in horizontal wells, the typical technique used to produce natural gas from shale formations. Any given hydraulic fracturing operation involves pressurization of small volumes of rock (typically a few hundred feet along the length of the wellbore) for short periods of time (typically about two hours). Hence, the probability of the pressurization affecting faults that might induce earthquakes large enough to be felt at the surface is extremely low. I fully agree with the conclusion of the NRC report that this is the principal reason why hundreds of thousands of hydraulic fracturing operations to develop gas from shale in the U.S. have not produced any confirmed cases of triggered seismicity. Globally, there has only been one confirmed case in which hydraulic fracturing associated with shale gas development has triggered one very small earthquakes big enough to be felt at the surface. Considering the extremely small number of triggered earthquakes with hundreds of thousands of hydraulic fracturing operations clearly demonstrates that the risk associated with shale gas development is extremely low.

Question 2. The NRC report indicates that the Federal and State Underground Injection Control (UIC) Programs "do[es] not address the issue of seismicity induced by underground injection." At the same time, the current UIC program does require the injection well operator to perform a site characterization, including identifying the risks associated with nearby faults if any are located. Furthermore, several states (including Arkansas, Colorado, Ohio, and West Virginia,) are currently modifying their UIC Programs to specifically address seismicity. To this extent, might those state regimes reflect any of the proposed actions as noted in the report?

Answer. It is good to learn that several states are modifying their UIC Programs to address the potential for triggered seismicity. If this has been in response to the NRC report, this is indeed a welcome development.

Responses of William Leith to Questions From Senator Bingaman

Question 1. Dr. Zoback has testified that the risk of venting stored carbon dioxide from small, induced seismic events is a primary concern and obstacle to the scaling up of CCS technologies to play a significant role in mitigating global greenhouse gas emissions to the atmosphere. Do you agree with this assessment?

Answer. Dr. Zoback's study identified the need to carefully study any prospective CCS projects and to evaluate potential risks associated with particular projects. We agree that induced earthquakes could be a significant risk to the efficacy of large-scale CCS and that this hazard needs to be carefully studied and better understood. Although injection of CO_2 into depleted oil and gas reservoirs (for example, as used in secondary oil recovery) may pose a low risk for induced seismicity, such is not the case during injection of CO_2 into normally pressurized, undepleted aquifers. For injection in undepleted reservoirs, the geologic sequestration of CO_2 is probably not significantly different from other large-volume liquid-injection projects, such as wastewater disposal at depth, for which there are numerous case histories involving earthquakes large enough to be of concern to the public. One of the early case histories concerned the injection of 625,000 cubic meters of wastewater at the Rocky Mountain Arsenal (RMA) well in the mid-1960s, which induced earthquakes of about magnitude 5 and caused damage to structures in the Denver, CO, area.

Over the next three years, a DOE-sponsored demonstration project in Decatur, IL, will inject 1 million tons-about 1.4 million cubic meters of CO_2- into an undepleted brine aquifer within the Mt. Simon sandstone at a depth of about 2 km. Injection at the Decatur well began in November 2011. Although the induced earthquakes at this site have been tiny as of July 2012, it is much too early to know what the seismic response will be as the injection grows; the total planned volume of injected CO_2 at Decatur is more than double what was injected at the RMA. If the induced earthquake pattern at Decatur turns out to be similar to that at RMA, then some of the larger induced earthquakes that would occur at the site could indeed pose threats to the integrity of the capping seals. It is also possible that high pressures generated within the Mt. Simon sandstone could be communicated to "hidden" faults within the underlying granite basement. Although such faults have not been seen in the seismic data collected at Decatur so far, it is notoriously difficult to image faults in deep granitic rocks. Thus, a prudent approach would be to assume that there could be an earthquake risk to nearby communities during this project.

To assess these seismic hazards, it is necessary to monitor induced earthquakes at each CCS pilot project with a seismic network designed to locate events precisely in three dimensions and thereby determine the exact nature of the seismic source. Microearthquake locations enabled by such a network would allow us to identify previously unknown faults within the underlying basement, as well as determine the maximum likely fault slip associated with these and other faults, including those located near the sealing formations. Other types of field and laboratory research will be needed to achieve a comprehensive understanding of the risk to reservoir seals from earthquake slip in various geological settings.

Question 2. As USGS considers the amount of available storage for CCS, is the possibility of leakage from small seismic events something that is factored in?

Answer. The 2007 Energy Independence and Security Act (Public Law 110-140, section 711) authorized the USGS to conduct a national assessment of geologic storage resources for carbon dioxide (CO_2). The methodology that was developed for the national assessment (Brennan and others, 2010, http://pubs.usgs.gov/of/2010/1127/) addresses the geographical extent, the capacity, injectivity (permeability), and the risk associated with potential storage formations. We evaluate the risk of a potential formation by providing maps of existing well penetrations which, in some cases, may be potential CO_2 leakage pathways (for example well penetration maps see Covault and others, 2012, http://pubs.usgs.gov/of/2012/1024/a/). The USGS methodology also incorporates the Environmental Protection Agency (EPA) guidelines to prevent CO_2 leakage to the surface and CO_2 contamination of underground sources of drinking water (USDW) and overlying aquifers. EPA's guidelines are: (1) a regional, well defined sealing unit to be present above each storage assessment unit, and (2) only assessing storage assessment units that have formation waters that are greater than 10,000 parts per million total dissolved solids. The risk of induced seismicity associated with a particular CO_2 storage project depends on local storage reservoir fluid pressure management and CO_2 injection rates and volumes, and is, therefore, an engineering problem that is not specifically evaluated in the current USGS CO_2 storage assessment efforts. We do, however, note that a potential storage formation may be located in a region of the country where natural seismic risks are more likely. We are incorporating a discussion of the proximity of a potential storage formation to seismically active areas in the geologic framework reports for each assessed area that will be published during the coming year.

Question 3. Dr. Zoback's testimony noted that offshore formations similar to the one utilized by the Sleipner project in Norway and also depleted oil and gas reservoirs could potentially be suitable for long-term storage of high volumes of carbon dioxide. The Department of Energy indicates there may be as much as 7.5 trillion tons of CO_2 storage capacity in offshore formations in the Gulf Coast that are similar to the Sleipner project in Norway. The most recent estimates from the National Energy Technology Laboratory indicate that there may be as much as 20 billion tons of CO_2 storage capacity in depleted oil and gas reservoirs.

Question 3a. Could you please comment on these assessments of storage capacity and their suitability for the long-term storage of high volumes of carbon dioxide?

Question 3b. Could you provide an estimate of how much storage is available in the types of formations that Dr. Zoback has described as having suitable characteristics for such long-term storage?

Answer a. The North American Carbon Storage Atlas (2012, available at: http://www.netl.doe.gov/technologies/carbon__seq/global/nacap.html), published jointly by the Department of Energy and representative agencies from the governments of Canada and Mexico, indicates that within the Atlantic, Gulf of Mexico, and Pacific offshore regions of the United States, there is an estimated range of 467 billion to 6.4 trillion metric tons of potential CO_2 storage capacity in saline formations. The North American Storage Atlas also reports that oil and gas reservoir CO_2 storage resources for the United States (onshore and offshore) are approximately 124 billion metric tons. In addition, a report by Kuuskraa and others (2011, http://www.netl.doe.gov/energy-analyses/pubs/storing percent20co2 percent20w percent20eor__final.pdf), that was prepared for the National Energy Technology Laboratory, indicates that nearly 20 billion metric tons of CO_2 may be needed to economically produce oil using "Next Generation" enhanced-oil-recovery techniques utilizing a mixture of naturally occurring CO_2 produced from CO_2-rich underground reservoirs and CO_2 from anthropogenic sources. The resource numbers reported by the North American Carbon Storage Atlas (2012), the Carbon Sequestration Atlas of the United States and Canada (NETL, 2010, http://www.netl.doe.gov/technologies/carbon__seq/natcarb/index.html), and Kuuskraa and others (2011) are general estimates of potential geologic CO_2 storage resources in various regions of North America and the United States.

The USGS is currently working on a comprehensive assessment of onshore areas and State waters that will identify and evaluate the Nation's potential CO_2 storage resources. Data used in the previous DOE assessments and data provided by State geological surveys are being integrated with USGS data to conduct these assessments. The USGS typically does not assess Federal offshore U.S. resources and refers to or works with the Bureau of Ocean Energy Management (BOEM) when evaluating offshore resources. By 2013, the USGS Geologic CO_2 Sequestration Assessment Project will have geologically characterized and assessed more than 200 potential storage formations in 37 basins across the United States. This assessment will be the most comprehensive accounting of the Nation's CO_2 storage potential ever completed, and provide quantitative, probabilistic estimates of resource storage potential. A summary report is in preparation that will provide the storage assessment results for the Nation. In addition, the Geologic CO_2 Sequestration Project is building an assessment methodology and associated engineering database that can be used for a detailed national assessment of recoverable hydrocarbon resources associated with CO_2 injection and sequestration. USGS assessments are impartial, robust, statistically sound, and widely cited in the scientific literature and public media.

Answer b. The USGS assessment of CO_2 storage capacities of onshore areas and State waters of the United States is scheduled to be completed in 2013. We do not have resource estimates available at this time. As mentioned in the answer for question 2 above, the risk of induced seismicity associated with a particular CO_2 storage project depends on local storage reservoir fluid pressure management and CO_2 injection rates and volumes, and is, therefore, a scientific and engineering problem that is not specifically evaluated in the current USGS CO_2 storage assessment. The scope of research needed to better predict seismic risk in particular geologic settings is discussed further in the answer to question 1. In order to provide resource estimates for formations that are not likely to be prone to induced seismicity, an additional set of screening geologic and engineering criteria will need to be developed and applied to the assessment results generated by the current USGS Geologic CO_2 Sequestration Assessment Project.

Question 4. Is USGS doing, or planning to do work to better understand the risks of induced seismicity due to large-scale CCS as indicated in the report? Are there efforts at other agencies or national labs?

Answer. The USGS is currently proposing to monitor induced seismicity at one or more DOE-funded CCS pilot projects, and we have been in contact with the operators of two such projects: one at Decatur, Illinois, and the other at Kevin Dome, northern Montana. Although no agreements have been reached so far, the USGS, as an objective science agency, is in a unique position to provide scientific knowledge needed to better understand and mitigate the potential seismic risk associated with CCS. In so doing, it is critical that these data and analyses be maintained in the public domain, to be amenable to full scientific peer review and to maintain public trust.

The USGS recently purchased seismic recording equipment sufficient for a ten-station monitoring network that includes three seismometers that will record down boreholes about 500 feet deep. In the lower-noise environment at the bottom of these boreholes, we anticipate that the magnitude threshold for earthquake detection will be reduced considerably.

The DOE-funded National Laboratories have conducted earthquake monitoring at CCS sites in Algeria and Australia, and perhaps other sites. In addition, the National Laboratories maintain an active and highly visible program in monitoring induced seismicity associated with Enhanced Geothermal Systems demonstration projects at several locations in the United States.

The President's budget request for fiscal year 2013 includes, as part of the hydraulic fracturing initiative, a proposed $1.1 million increase to the Earthquake Hazards Program for work assessing the factors controlling the triggering of earthquakes due to fluid injection activities, developing a method to forecast the magnitude-frequency distributions of induced earthquakes including the maximum-magnitude earthquakes resulting from a specified fluid injection operation, and accounting in National Seismic Hazard Maps for the additional hazards due to fluid disposal-induced earthquakes.

Question 5. The NAS study we heard about indicates that there have been relatively few induced seismic events that are directly attributable to the energy technologies considered here. At the same time, your testimony shows a sharp increase in the number of mid-continent earthquakes that USGS has measured over the past decade.

Question 5a. Is there something else going on that could be causing this trend in earthquakes?

Question 5b. Is this a measurement issue, or is it just that more work needs to be done to figure out what caused these earthquakes?

Answer a. USGS believes that the increase in the number of magnitude 3 and larger earthquakes in the U.S. midcontinent is most probably caused by increased wastewater injection activities. The increase is most pronounced in Arkansas, along the Colorado-New Mexico border, and in Oklahoma. Earthquakes have also been noted in Texas, Ohio, and West Virginia, where they are otherwise uncommon. Research published since the NAS report was written demonstrates that the increase in earthquake activity in Arkansas is due to injection of wastewater related to shale gas development and production: http://srl.geoscienceworld.org/content/83/2/250. Studies recently completed by the USGS show that the earthquakes along the Colorado-New Mexico border are due to wastewater injection from coal-bed methane production in the Raton Basin. Studies to identify the underlying cause or causes of the increase in seismicity in Oklahoma are underway.

Answer b. USGS is certain that the rate change discovered is not a measurement issue. Three lines of evidence support this conclusion. First, earthquakes with magnitudes of 3 and above (those used to detect the rate change) have been uniformly detected through the midcontinent since the 1970s by the USGS. Second, while improvements in seismic instrumentation and installation of additional seismic stations have improved earthquake location accuracy, the algorithms for computing magnitude have remained unchanged. Third, both the USGS catalog and the catalog of the Oklahoma Geological Survey independently document the increase in activity that began in that state in 2009.

To understand the factors that have led to the increased rate of induced earthquakes in the central and eastern United States, more work is clearly needed. Site-specific investigations will be required to identify the underlying causes and improve our understanding so that the risk of induced earthquakes can be managed in the future.

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