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NEW DEVELOPMENTS IN UPSTREAM OIL AND GAS TECHNOLOGIES

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED TWELFTH CONGRESS

FIRST SESSION

TO

RECEIVE TESTIMONY ON NEW DEVELOPMENTS IN UPSTREAM OIL AND GAS TECHNOLOGIES

MAY 10, 2011

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NEW DEVELOPMENTS IN UPSTREAM OIL AND GAS TECHNOLOGIES

TUESDAY, MAY 10, 2011

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

The committee met, pursuant to notice, at 10:02 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 on the hearing? This morning's hearing focuses on new developments in technologies for the exploration and production of oil and natural gas. It's a continuation of a series of hearings the Committee has held on oil and gas this Congress beginning with our first hearing on overall trends in oil and gas markets including our hearing with the leaders of the National Commission on the BP Deep Water Horizon oil spill.

Senator Murkowski suggested we have a technology focused hearing to understand better the new exploration and production activities that the industry is undertaking. I appreciate her suggestion. I think it is timely. Given the broader interest in these activities, particularly, so we have invited a group of highly qualified technical experts to come and give us testimony on this subject today.

This hearing will help inform our coming deliberations on legislation related to oil and natural gas. Yesterday I introduced 2 bills related to these topics. The Oil and Gas Facilitation Act of 2011 and the Outer Continental Shelf Reform Act of 2011.

Both bills are comprised of provisions that were introduced and passed out of our Committee in the last Congress with strong bipartisan support. Along with this hearing these bills are a good starting point for what I hope will be a constructive bipartisan dialog on the topic as the rest of this month unfolds. We hope to have a hearing on the bills and related legislation next week. I hope we can mark up legislation related to oil and natural gas as part of our overall Committee agenda during this work period.

Today we will be hearing from experts on the topic of recent events as in seismic data acquisition, processing and its new applications, advanced drilling technologies. How enhanced oil recovery is allowing operators to get more production in their fields without drilling additional wells.

Before we start hearing from our witnesses let me defer to Senator Murkowski for her opening comments.

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

Senator MURKOWSKI. Thank you, Mr. Chairman. I appreciate the hearing this morning. To the witnesses, thank you all for being here.

I think we all recognize that it's worth our time to learn more about technological advances in the production of oil and gas as we endeavor to legislate on the subject. Whether we're debating access or safety or simply trying to understand how our energy needs will be met in the years ahead it helps if we know what truly is and is not possible with technology. Many examples throughout history of technology changing our nation's behavior, our energy portfolio and really the overall economy.

A century and a half ago the steam engine brought America to the West. A half century ago, nuclear power began to revolutionize the way that we generate electricity and even power our submarines and our aircraft carriers. Then just more recently in the past few years, we've seen natural gas evolve from a dangerously scarce commodity to a secure, long term source of energy.

These are all American success stories. I hope that we hear this morning perhaps some more success stories. Recognizing, of course, that with new territory comes the need to understand new risks and the impacts.

As this hearing's joint background memo indicates we've got incredible advances in seismic technology that have substantially reduced the cost of exploration, the risks associated with exploration and the environmental impacts associated with drilling.

Directional drilling has enabled operators to shrink their environmental footprint, maximize efficiency and lower costs. Advances in directional drilling can now facilitate access to 20 or more deposits and reach as far as seven or eight miles away from a rig. This translates to less surface area being occupied, fewer emissions and a lesser impact on humans as well as the flora and the fauna.

Enhanced oil recovery also provides many of those same effects. Its increased production from existing wells and helps ensure that American taxpayers receive the fullest return possible on resource development.

New technologies present new opportunities for the responsible development of our nation's tremendous energy resources. That's true whether the operation is out of Bakersfield or whether it's out of Barrow. I would suggest that it's through a combination of economics, geology and policy that these technologies have come about.

But because this committee can really only control and influence the third factor which is the policy, I hope that we can work to reward and encourage developments like those that we're hearing about today. On balance these demonstrate significant benefits for the environment, for energy security and for the American people.

Again, Mr. Chairman, I'm pleased that you have worked with us to schedule a hearing this morning. I look forward to the comments from the witnesses.

The CHAIRMAN. Thank you very much.

Let me introduce our witnesses.

Professor Thomas L. Davis, who is Director of the Reservoir Characterization Project at the Colorado School of Mines in Golden, Colorado. Thank you for being here.

Mr. Andy Hendricks, who is President of Drilling and Measurements with Schlumberger in Sugarland, Texas. Thank you for being here.

Mr. Steve Melzer, who is Engineer and Founder of Melzer Consulting in Midland, Texas. Thank you for being here.

Mr. Kevin Banks, who is Director of the Division of Oil and Gas in the Alaska Department of Natural Resources in Anchorage. Thank you for being here.

Ms. Lois Epstein, who is the Director of the Arctic Program for the Wilderness Society. Thank you for coming.

Why don't we just take you in that order? If you'll just give us about 5 minutes to make the main points that you think we need to try to understand. We will include your entire statement in the record as if read.

Dr. Davis.

STATEMENT OF THOMAS DAVIS, DIRECTOR, RESERVOIR CHARACTERIZATION PROJECT, COLORADO SCHOOL OF MINES, GOLDEN, CO

Mr. DAVIS. Good morning. Thank you very much, Chairman Bingaman and Ranking Member Murkowski. I'm here to talk to you about seismic technologies. The technologies I'm going to focus on are related to data acquisition systems.

These—before I jump into that framework of acquisition systems let me just tell you a little bit about seismic data itself. How it's acquired. What it is.

In this particular regard, the fact that I'm talking to you in here relates to seismic waves. These are acoustic waves that we transmit. So our ears are sensors. In the same vein in the framework of the seismic industry we developed sensors that record ground motion. So the ground motion allows us to hear and see into the subsurface.

Now the kinds of sensors that we use today have transformed or changed. We have different mechanical sensors, acoustic sensors. We put sensors in the water which we call hydrophones. So there's a whole variety of sensors. They record different types of waves.

So as I've indicated there's acoustic waves. But there are also other types of waves we call elastic waves. Now with these multiple sensors and the ability to be able to look at recording all these different forms, we can better characterize the subsurface. This gives us a huge uplift in terms of our ability to see the unseen, what's underneath us.

In this regard then the kinds of sensors that we've been going toward now have been matched up with new recording systems. The kinds of recording systems that we're now looking at you can hold in your hand, much like a cell phone. In this regard then they're easy to put out, to place in different places. They're also environmentally friendly in the sense that we can walk in and place them in different places.

We're not locked in grid lock anymore. The grid lock used to be the framework of cables. Like a land phone lines these cables would go for miles and miles and were really hampering a lot of our ability to record with very sensitive measurements in the subsurface. So in this regard then the fact that we're now using cable less or wireless systems helps us tremendously.

So we can place these on the surface of the Earth in different locations, many, many of these sensors, up to hundreds of thousands actually now. We can leave them there and let them record. So in that regard we can use natural seismicity of the Earth to be able to sense what's underneath. We can also use active recording where we vibrate the Earth itself in low vibration intensity levels and record.

So in that regard we develop better images. The better images right now are akin to your high definition television. Not only is it high definition but it's also 3D. So that's where the television industry has been going. Hollywood is into 3D. We've been there for many years now.

Moreover, it's not just 3D. We operate in what we call 4D. This is a framework of looking at monitoring and sensing changes in the subsurface.

The changes could be induced by some operational change, some drilling change, some completion change, the introduction of fluids into the reservoir. We can know sense that and see that. We call this 4D. Others would call it time lapse.

So we do time lapse imaging much like a medical doctor will do in recording different images. In that sense then it gives us the huge benefit of being able to see where the fluids are going. Even to characterize those fluids over time and their time changes.

Reservoirs change. So in this regard better reservoir characterization helps us increase the recovery efficiency, the recovery factor, in a lot of our reservoirs. Conventional reservoirs, unconventional reservoirs, you name it.

In that regard, the technology here has been developing over the last several decades here to allow us to do this. It's very exciting technology. It's also going to cause a greater alignment with the environmental framework. That is, the environmental areas that were off limits before we can now go into. Look at very, very, I guess we'll just say, with new technology we can then advance into those areas, other areas that we haven't been into for a long, long time.

Thank you.

[The prepared statement of Mr. Davis follows:]

PREPARED STATEMENT OF THOMAS DAVIS, DIRECTOR, RESERVOIR CHARACTERIZATION PROJECT, COLORADO SCHOOL OF MINES, GOLDEN CO

Seismic Technology—A Transformation

Good Morning and Thank you Chairman Bingaman and Ranking Member Murkowski for this opportunity to come and speak to you today in this hearing about recent advances to upstream oilfield technologies. I will be speaking to you today about new developments in the area of seismic technologies and its importance to finding, developing, and eventually producing oil and gas.

Let me begin with a brief explanation of what seismic data is. Seismic data are acquired by "listening" to motion related to seismic waves. Seismic waves are vibrations within the Earth induced naturally or artificially. The devices used to listen are seismic sensors that transform Earth motion into impulses that are recorded by seismic recording systems. After the data is recorded, the data is processed and used to get a better understanding, or a "picture", in two or three dimensions of what the rock below the Earth's surface looks like, as well as any potential oil and gas that might be contained within those rocks.

There are exciting new developments in seismic technology that will create greater efficiency in oil and gas exploration with an increased emphasis on the environment with a greater transparency in the upstream petroleum industry going forward. The main development has been in new seismic acquisition systems creating higher definition and greater productivity. The transformation involves new wireless recording systems. The systems can record actively as well as passively, meaning that they can record with an active source or they can "listen" to the natural seismicity of the Earth. It is equivalent to putting "cell phones" as monitoring stations on the ground.

These devices can record various kinds of seismic waves. The most widely used waves are acoustic waves, or sound waves, but other waves propagate within the Earth. Detecting different types of waves gives us additional information about the subsurface including: the strength or integrity of the substrate, stresses within the subsurface, fluid pressures and even the fluids themselves. Combined recording of different seismic waves enables us to characterize the subsurface to optimally target wells, provide guidance on well drilling, and to monitor well completions and to monitor well and completion integrity. As a result, the petroleum industry is being transformed and the seismic industry is leading the transformation of the upstream oil and gas sector as we know it.

New seismic recording systems are being used to conduct monitoring of enhanced oil recovery projects in the US and Canada including carbon dioxide flooding and sequestration. The results have enabled scientists and regulators to work together to assess environmental safety associated with these projects. They have been used recently in resource plays in the US and Canada to determine "sweet spots" that are more economical to develop through horizontal drilling and hydraulic fracturing. The combined use of new seismic, drilling and completions technology is changing the landscape of the petroleum industry to lessen the environmental footprint and to create greater transparency.

Seismic technology is traditionally used for oil and gas exploration, but is capable of being used for much more. Recent uses include advanced reservoir characterization to increase the recovery factor of oil and gas reservoirs. Reservoir characterization is basically the methodology to document the heterogeneity, or complexities, naturally associated with reservoirs. Geology is complex and reservoirs are too. In the past about 25% to 33% of a resource has been recoverable. Through improved integrated reservoir characterization technology we have been able to increase recovery to 50 %, but we are not done. Enhanced recovery methods will enable us to improve the recovery factor even further. In resources, or unconventional plays where the oil and gas is generated and contained in-situ, recovery factors are generally low (10%), but the potential to increase recoveries through integrated reservoir characterization technologies is substantial.

Technology is the single most important factor in finding and developing energy resources to fuel our economy in an environmentally responsible manner. New seismic technologies will enable us to find new resources, to develop old ones more efficiently, and to open up exciting new growth opportunities here in the US for current and future generations.

I have provided some examples of sensors and recording devices that are shown in the attached figures. The equipment is getting smaller and more sophisticated to the point that high definition images of the subsurface can be made with relatively little intrusion on the environment. The instruments can be left in place to monitor the subsurface over relatively long periods of time-like motion sensors that are used for in-home security systems. These systems allow us to listen to our reservoirs and to take proactive rather than reactive in the management of our reservoirs.

The CHAIRMAN. Thank you very much.

Mr. Hendricks.

STATEMENT OF ANDY HENDRICKS, PRESIDENT, DRILLING AND MEASUREMENTS, SCHLUMBERGER LIMITED, SUGARLAND, TX

Mr. HENDRICKS. Mr. Chairman and members of the committee, thank you. First I'd like to say I consider it a privilege to have been invited to speak to you today. I brought my son, Drew with me so he could see the government process and work as well. So thank you for that.

My name is Andy Hendricks. I'm from the Drilling division of Schlumberger. I have a degree in Petroleum Engineering from Texas A and M. My industry expertise is in horizontal drilling and extended reach drilling of oil and gas wells.

Schlumberger is the leading oilfield services provider. My division is responsible for supplying the oil companies with technology and services in order to control and navigate the direction of the oil and gas wells. To improve drilling performance to reduce the overall costs. To maximize the contact of the wellbore with the oil or gas bearing rock, or what we call, the reservoir.

So I'm here today to talk to you about today's high-tech drilling technology. Our industry is about high-tech tools and equipment these days, and the skilled engineers and geoscientists who run them. Drilling has become a sophisticated science as it has evolved over the years.

Back in 1858, the Drake well in Pennsylvania was the first U.S. oil well. This well was drilled with what we call a cable tool drilling rig, which compared to today's standards is a rudimentary concept that utilizes gravity and heavy steel bars that are suspended from a cable to pound and crush the rock. The result back then was a simple, vertical well with the drilling operation making progress in the ground at about 3 feet every day. Drake's well finished up at 69 1/2 feet of depth.

In 1901 rotary drilling rigs were the next big step change for the industry. Where pipe is lowered into the well and rotated from the surface in order to turn a drill bit at the bottom of the well. Fluid is circulated down the pipe in order to cool the drill bit as it rotates and crushes the rock and then to lift the drill cuttings from the well.

Again these wells were drilled vertical or straight down. But the early advancements allowed engineers to control the direction of the well with a technique that was based on placing a simple, triangular shaped deflection device down into the well and aligning this with a compass heading. At the time the technology was in its infancy and the progress was slow. Today we have full navigational and guidance instrumentation built into the drilling assemblies that we use at the bottom of the well. Much more advanced and precise than the navigation system in your car and with high speed communications through the drill pipe that allows us to direct the path of the well using robotic steering devices.

One of our state-of-the-art pieces of equipment, which we refer to as a Measurements While Drilling tool, contains an electronics package consisting of 2 high speed computer processors, memory boards collecting data from navigational instrumentation and sensors. It's powered by its own turbine driven generator. All of which is packaged and ruggedized to withstand 30,000 pounds per square inch of wellbore pressure, temperatures up to 400 degrees Fahrenheit and shock and vibration exceeding 150 Gs. So imagine baking your iPhone or your Blackberry in the oven. Then driving over it with your car and expecting it to continue to function.

An oil well drilled today will start off going straight down from the surface. But then it may gradually turn through a smooth curve until it is going horizontal or parallel with the surface. Then progress sideways, moving up and down or left and right in order to either maximize the reservoir contact or link together smaller reservoir pockets in a chain along this 3 dimensional wellbore path. When it comes to drilling performance, where the drilling of a well used to progress at 3 feet each day, today we drill the wells at hundreds of feet each hour. We finish after the drill bit has travelled several miles into the Earth.

With today's technology we can drill multiple wells from a single location at the surface. This is a process called pad drilling or template drilling. It's used in places like the Rockies on land or offshore on platforms. This reduces the footprint of the drilling operation on the surface by eliminating the need for multiple single well locations.

Another complex operation used more and more is extended reach drilling. In recent years the oil and gas industry has been increasing its ability to drill longer and longer wells with more complex, 3 dimensional paths. The horizontal lengths of these extended reach wells are measured in miles.

In Prudhoe Bay, Alaska, and in other parts of the world, extended reach drilling is used to access off shore reservoirs using drilling rigs from land. The drilling of these long horizontal sections requires expert engineering, planning and high tech equipment to steer the miles of pipe drilling underground. We currently hold the record for directional drilling in this type of well at 7.6 miles.

Now when it comes to placing the well in the productive zone, imagine that this room is a reservoir. It's miles down. It's dark. You're not even sure exactly what's in here. The walls, ceiling and floors are the borders and we want to drill within these to get as much reservoir contact as possible.

The steering is directed from 5 miles away. To do this we use a complex device called a rotary steerable system to steer the well path. We will also have a variety of high tech sensors collecting data in order to identify the reservoir boundaries and analyze the type of rock we are in and whether or not we have oil and gas.

Schlumberger is the leader in drilling services. We hire the best from the most prestigious universities in the U.S. and other countries. Our latest advancement further integrate technologies to improve drilling performance and to provide advanced techniques to allow the oil companies to reduce their costs.

In 2010, we invested $919 million in research in engineering. We worked with oil companies to drill more than 7,000 miles.

I'd like to thank you for your time and attention today.

[The prepared statement of Mr. Hendricks follows:]

PREPARED STATEMENT OF ANDY HENDRICKS, PRESIDENT, DRILLING AND MEASUREMENTS, SCHLUMBERGER LIMITED, SUGARLAND, TX

I have a degree in Petroleum Engineering, and my industry expertise is in the area of horizontal and extended-reach drilling of oil and gas wells. Schlumberger is the leading oilfield services provider, and my division is responsible for supplying oil companies with technology and services in order to control and navigate the direction of oil and gas wells, improve drilling performance to reduce overall costs, and to maximize the contact of the wellbore with the oil or gas bearing rock, or what we call—the reservoir.

I'm here today to talk to you about today's high-tech drilling technology. Our industry is about high-tech tools and equipment, and the skilled engineers who run them. Drilling has become a sophisticated science as it evolved over the years. In 1858, the Drake well in Pennsylvania was the first US oil well. This well was drilled with a cable tool drilling rig, which compared to today's standards, is a rudimentary concept that utilizes gravity and heavy steel bars suspended at the end of a cable to pound and crush the rock. The result then was a simple, vertical well, with the drilling operation making progress in the ground at 3 feet each day. Drake's well was 69 1/2 ft deep.

In 1901, rotary drilling rigs were the next big step change for the industry, where pipe is lowered into the well and rotated at the surface in order to turn a drill bit at the bottom of the well. Fluid is circulated down the pipe in order to cool the drill bit as it rotates and crushes the rock, and then to lift the drill cuttings from the well. Again, these wells were drilled vertical, or straight down, but early advancements allowed engineers to control the direction of the well, with a technique based on placing a simple, triangular-shaped deflection device down into the well and aligning this with a compass heading. At the time, the technology was in its infancy and progress was slow.

Today, we have full navigational and guidance instrumentation built into the drilling assembly at the bottom of the well-much more advanced and precise than the navigation system in your car-with high-speed communications through the drill pipe that allows us to direct the path of the well using robotic steering devices. One of our state-of-the-art pieces of equipment, which we refer to as a Measurements While Drilling tool, contains an electronics package consisting of two high-speed computer processors and memory boards, collecting data from navigational instrumentation and sensors, powered by its own turbine driven generator, and all of which is packaged and ruggedized to withstand 30,000 psi of wellbore pressure, temperatures to 400 degrees, and shock and vibration exceeding 150 Gs. Imagine baking your iPhone or Blackberry in the oven, then driving over it, and expecting it to continue to function.

An oil well drilled today will start off going straight down from the surface, but then it may gradually turn upwards through a smooth curve until it is going horizontal, or parallel with the surface, and then progress sideways, moving up and down or left and right in order to either maximize the reservoir contact, or link together smaller reservoir pockets in a chain along this 3-dimensional wellbore path. And when it comes to drilling performance, where the drilling of a well used to progress at 3 feet each day, today we drill wells at hundreds of feet each hour, and finish after the drill bit has travelled several miles into the earth.

With today's technology, we can drill multiple wells from a single location at the surface. This is a process called pad drilling or template drilling, and it is used in places like the Rockies on land or offshore from platforms. This reduces the footprint of the drilling operation on the surface by eliminating the need for multiple single-well locations. The challenge in this process is to navigate a dense cluster of well bores close to the surface, and we accomplish this through the use of the navigational technology mentioned previously.

Another complex operation used more and more is extended-reach drilling. In recent years, the oil and gas industry has been increasing its ability to drill longer and longer wells with more complex 3-dimensional paths. The horizontal lengths of these extended-reach wells are measured in miles. In Prudhoe Bay, Alaska, and in other parts of the world, extendedreach drilling is used to access offshore reservoirs using drilling rigs on land. The drilling of these long horizontal sections requires expert engineering, planning, and high-tech equipment to steer the miles of pipe drilling underground. We currently hold the world record for directionally drilling this type of well at 7.6 miles.

Now when it comes to placing the well in the productive zone, imagine that this room is a reservoir. It's miles down, and you're not even sure exactly what is in here. The walls, ceiling and floor are the borders, and we want to drill within these to get as much reservoir contact as possible-the steering is directed from 5 miles away. To do this, we will use a complex device called a rotary steerable system to steer the well path, and we will also have a variety of high-tech sensors collecting data in order to identify the reservoir boundaries, and analyze the type of rock we are in, and whether or not we have oil and gas.

The sensors include multi-frequency acoustic sound waves, electromagnetic radio waves, and magnetic resonance imaging that illuminate the reservoir, or in our case this room, so we can see where we are and steer the well to the most productive zones. All of this is done while we drill the well, by highly skilled engineers and geoscientists.

Schlumberger is the leader in drilling services and we hire the best from the most prestigious universities in the US and other countries. Our latest advancements further integrate technologies to improve drilling performance and to provide advanced techniques that allow the oil companies to reduce their costs. In 2010, we invested $919 million in research and engineering and worked with oil companies to drill more than 7,000 miles.

With our 2010 acquisition of Smith, we have complemented our existing technologies with drill bits, specialty drilling tools, drilling fluids and more, to provide a complete and integrated downhole drilling system. The next few years will be very exciting and see even more advancements.

I thank you for your time and attention.

The CHAIRMAN. Thank you very much.

Mr. Melzer.

STATEMENT OF L. STEPHEN MELZER, CO_2 CONSULTANT AND ANNUAL CO_2 CONFERENCE DIRECTOR

Mr. MELZER. Mr. Chairman and members of the Committee, my name is Steve Melzer. I come to you from the Permian Basin region of West Texas and Southeastern New Mexico, one of the largest petroleum basins in the world. I'd like to thank you for allowing me to bring our exciting advanced—enhanced oil recovery or EOR, technology to Washington.

We've been producing oil from West Texas and Southeastern New Mexico for more than 70 years. The region is known throughout the world as a leader in oil recovery. What I wish to talk about today, especially, CO_2 EOR.

The U.S. and our area, in particular, have some very new developments occurring not only for enhancing oil production but also a solution to finding a home for CO_2 emissions that are otherwise problematic. But before examining the new technology for CO_2 EOR, let's review together the stages of producing an oil reservoir.

When you drill into a subsurface formation and counter fluids within the rock pore spaces the fluids are under pressure. The wellbore being a low pressure sink allows the fluids to flow to it and then on up into the surface. We call this the primary phase of production. Hydrofracking technologies and extended reach drilling allow us to reach into more of the formation to produce oil or gas that way.

Eventually the fluid pressures are dissipated. The fluids cease to flow at a commercial rate. At this point the producing wells will be plugged and abandoned or we look for a method to re-pressure the formation and sweep fluids from what we call injector wells to producer wells.

This is the second phase of production and we call it secondary recovery. We generally use water as a pressuring fluid. The water is typically sourced from deep depths, a brackish or more saline formation water.

The water and oil don't mix. Much oil is swept, but a lot of oil is bypassed. After a good water flood is finished most projects will still have more than 50 percent of the oil left in place.

So what comes next? To get more oil we must somehow change the fluid properties. We can thin it. We can move it and even get the oil that is clinging to the rock surfaces. This would be our tertiary stage.

We do this with heat and heavy oils like in California or we can do it with CO_2 in deeper areas. We begin the process—we began this process in the field in 1970s thanks to some oiling entrepreneurial companies, some byproduct CO_2 from natural gas plants and a clever incentive from our Texas Railroad Commission to encourage the first move of projects. Today the process of CO_2 EOR has spread to many places besides the Permian Basin. We make 100 million barrels per year or about 5 percent of our needs in the U.S. from CO_2 EOR. We get our CO_2 from what is typically called anthropogenic sources which might include natural gas processing facilities, fertilizer or even a coal gasification plant like in North Dakota.

Our growth of the industry has been hampered of late as we are out of CO_2. We envision the new CO_2 coming from more anthropogenic sources. Many are in stages of planning today. Several of these are first in kind facilities that are being aided with DOE assistance.

CO_2 purchased is valuable. What we buy gets stored in a formation. We don't like to lose it.

You might be asking how much CO_2 can be utilized or stored in or its corollary question. How much oil can be produced? The answer resources international corporation has looked at these questions in considerable detail. Their projections can fall into 3 categories.

One using conventional technology and existing reservoirs.

Two, using next generation technologies.

Three, moving into residual oil zones.

These last 2 categories are what I really would like to speak to and since this is a technology hearing. Next generation CO_2 includes CO—things like viscosifiers, adding thickeners to the CO_2 to enhance the spread of CO_2 into the formation thereby contacting and sweeping more of the oil.

The last category is what I've spent a great deal of my time on in recent years. It is residual oil zones or intervals that lie below the oil water contact in a reservoir, below where you can produce oil normally. This—the mobile phase of the fluids in these zones are water and the immobile phase is oil.

The primary and secondary phases of production can produce only water from these intervals. It takes an injected such as CO_2 to mobilize the oil. We have nine projects in our part of the world and several more planned later this year to look at the specific technology.

Hess Corporation has one field that is just an hour north of my hometown where they have expanded the residual oil zone project 3 times and are planning a fourth for later this year. They are currently producing over 5,000 barrels of oil per day from an interval that would have produced only water in primary or secondary phases. Effectively they are working on what we call the fourth stage or quaternary oil and it will extend the production in the field for another 20 years.

This process requires CO_2 and deepening of the wells. Produce from an oil in place target of over a billion barrels. The ROZ resource is not present in just—in only the Permian Basin. We believe there are very large reservoirs of these type present in Wyoming and South Dakota, just to name 2, also many other places.

We've seen—we have a proposed study to address these matters awaiting formal notification to begin. It's somewhere stuck up here, somewhere in Washington. We haven't quite figured out where yet.

But I should say we also welcome public funding. The value of public money in this space is to regionally examine these ROZs and to make the industry results public. Heretofore the results have been very limited to very private studies and investigations.

In summary, CO_2 technology is clearly exciting and advancing rapidly. It addresses both energy security and environmental concerns. Thank you for the opportunity to speak to this. I would welcome any questions.

[The prepared statement of Mr. Melzer follows:]

PREPARED STATEMENT OF L. STEPHEN MELZER, CO_2 CONSULTANT AND ANNUAL CO_2 CONFERENCE DIRECTOR

PRINCIPLES OF CO_2 FLOODING, NEW TECHNOLOGIES AND NEW TARGETS FOR ENERGY SECURITY AND THE ENVIRONMENT

BACKGROUND ON THE U.S. AND PERMIAN BASIN OIL INDUSTRY AND THE NEW EXCITEMENT IN THE CO_2 FLOODING SUBINDUSTRY

The oil and gas industry is generally portrayed as dominated by drilling for new oil and gas fields. And, in fact, most companies could be called exploration companies and make their entire living doing exactly that. However, there is a sub-industry concentrating on getting more oil from a given discovery (field). We tend to brand them as production companies where engineering skills are put to test in trying to recover more and more oil from a "reluctant" reservoir. The rewards come to these companies slower and, in a fast paced world seeking immediate gratification; most companies opt for the exploration path to provide more immediate returns for their shareholders.

It is useful background to examine oil and gas production in a framework the industry has come to call the phases of production.

A. Primary Production

The first is the primary phase where a new field discovery is found and well penetrations are drilled into the formation. Oil or gas is produced using the pent-up energy of the fluids in the sandstone or carbonate (limestone, dolomite) reservoir. As long as you are good at finding new oil or gas and avoiding the "dry holes," the returns come quickly while the reservoir fluid pressures are high. Eventually, however, the energy (usually thought of as reservoir pressure) is expended and the wells cease to flow their fluids. At this point, in the case of oil reservoirs, considerable amounts of the oil are left in place.

B. Secondary Phase of Production

The field may be abandoned after depleting the pressures or it can be converted to what we like to call a secondary phase of production wherein a substance (usually water) is injected to repressure the formation. New injection wells are drilled or converted from producing wells and the injected fluid sweeps oil to the remaining producing wells. This secondary phase is often very efficient and can produce an equal or greater volume of oil that was produced in the primary phase of production.

As mentioned, water is the common injectant in the secondary phase of production since water is relatively inexpensive. Normally fresh water is not used during the waterflood and this is especially true today. The water produced from the formation is recycled back into the ground again and again. Ultimately, in most reservoirs, more than half of the oil that was present in the field at discovery remains in the reservoir since it was bypassed by the water that does not mix with the oil.

C. Tertiary Phase

If there is a third phase of production, it will require some injectant that reacts with the oil to change its properties and allow it to flow more freely within the reservoir. Hot water can do that; chemicals can accomplish that as well. These techniques are commonly lumped into a category called enhanced oil recovery or EOR. One of the best of these methods is carbon dioxide (CO_2) flooding. CO_2 has the property of mixing with the oil to make it lighter, detach it from the rock surfaces, and causing the oil to flow more freely within the reservoir so that it can be “swept up” in the flow from injector to producer well. Compared to the other methods of production, this technique is relatively new and was first tested at large scale in the Permian Basin of West Texas and southeastern New Mexico. The first two projects consisted of the SACROC flood in Scurry County, Tx, implemented in January of 1972, and the North Crossett flood in Crane and Upton Counties, Tx initiated in April, 1972. It is interesting to note that installation of these two floods was encouraged by daily production allowable[1] relief offered by the Texas Railroad Commission and special tax treatment of oil income from experimental procedures.

Over the next five to ten years, the petroleum industry was able to observe that incremental oil could indeed be produced by the injection of CO_2 into the reservoir and the numbers of CO_2 flood projects began to grow. Figure 1 illustrates the growth of new projects and production from 1984 through the present day.

The carbon dioxide for the first projects came from CO_2 separated from produced natural gas processed and sold in the south region of the Permian Basin. Later, however, companies became aware that source fields with relatively pure CO_2 could offer large quantities of CO_2 and three source fields were developed—Sheep Mountain in south central Colorado, Bravo Dome in northeastern New Mexico, and McElmo Dome in southwestern Colorado. Pipelines were constructed in the early 1980s to connect the CO_2 source fields with the Permian Basin fields (Figure 2). The new supply of CO_2 led to a growth of projects through the early 1980s and expansion to other regions of the U.S.

The oil price crash of 1986 resulted in a drop of oil prices into single digits in many regions. The economics of flooding for oil was crippled; capital for new projects was nonexistent. But curiously, as demonstrated in Figure 1, the industry survived the crash with fairly minor long term effects and resumed its growth curve until the next price crash in 1998.

CURRENT AND PROJECTED FLOODING ACTIVITY IN THE U.S. & PERMIAN BASIN

The recent decade has once again seen a flourish of new CO_2 floods. Today, 111 floods are underway in the U.S. with 64 of those in the Permian Basin. The numbers have doubled since the economically stressful days of 1998 (see Figure 1*). New CO_2 pipelines are being constructed in the Gulf Coastal region and in the Rockies promising to grow the flooding activity in both of those regions dramatically. The Permian Basin is effectively sold out of their daily CO_2 volumes and, as a result, growth there has slowed to a crawl.

The aggregate production from CO_2 EOR has grown to about 18% of the Permian Basin’s 180,000 (see Figure 3) out of the 900,000 barrels of oil per day (bpd) or approximately 5% of the daily U.S. oil production. The oil industry rightfully brags about finding a billion barrel oil field. Such discoveries are very rare and non-existent today in the U.S. It is interesting to note that the billionth CO_2 EOR barrel was produced in 2005. The CO_2 bought and sold in the U.S. every day now totals 3.1 billion cubic feet or about 65,000 tons per year.

LONG TERM NATURE OF THE INDUSTRY

What may be evident is that the CO_2 flood industry is a long-lived industry. While fluctuation of oil prices have a de-accelerating effect, the steady baseline growth represents a refreshing exception to the otherwise frustrating cyclicity of gas and oil drilling/production. Both of the first two floods (SACROC and Crossett) are still in operation today and are producing nearly one million barrels per year today. After almost 40 years of operation under CO_2 injection, these floods are still purchasing approximately 300 million cubic feet per day (over six million tons per year) of CO_2. The long term nature of the floods continues to generate enormous economic power, provide local, state and federal taxes as well as employment and energy production for the area and nation. These barrels will be produced from reservoirs already developed and should represent about 15% of the original oil in place within the reservoirs. Without the advent of CO_2 flooding, the barrels would have been lost, i.e. left in the reservoir upon abandonment of the waterfloods.

PROJECT PLANNING UNDERWAY WITHIN THE PERMIAN BASIN

Many Permian Basin companies are currently planning new CO_2 projects. Denbury Resources has averaged two new startups per year in the Gulf Coast re-

[1] During the 1930s through 1972, the Texas Railroad Commission limited statewide oil production by granting production permits to well operators for a certain number of days per month.

* All figures have been retained in committee files.

gion for the last decade. Wyoming is another area with intense CO_2 activity. My "backlog" of projects in planning is estimated at more than 20.

Much of the impetus for planning new CO_2 floods results from a broader recognition of the technical success and economic viability of the CO_2 EOR process. The current oil price is a huge factor as well. The last factor relates to the maturity of the oilfields and secondary waterfloods of which many began in the 1950s.

Technological advancements are another major reason for the development of CO_2 flooding. Three-D seismic techniques have had a large impact on delineating heretofore unknown features of the reservoir. The ability to characterize and model the reservoir and in simulating the effects of CO_2 injection have clearly reduced the risk of a flood (economic) failure.

To date, the development of carbon dioxide flooding has clearly favored the Permian Basin. In addition to the extensive pipeline infrastructure and the nearby CO_2 source fields, it has a large number of large and mature fields which have been shown to be amenable to CO_2 injection

CO_2 SUPPLY AND DEMAND WITHIN THE PERMIAN BASIN

A. Demand for CO_2

Demand for CO_2 stems from the oilfield opportunities and the ability to reap financial rewards from the oil produced. Many believe that the long term demand for oil has never been greater except in times of imminent war. Additionally, technology has paved the path for moving a field into a new phase of production; such undertakings are considered both viable and desirable. But matching demand with a supply of CO_2 can be expensive and challenging. Historically it was done within an integrated oil company who recognized the oilfield upsides and was willing and able to develop the CO_2 source and connect the two with a pipeline. Today, with the departure of the oil majors, this connection must be accomplished between several corporate entities, each of which knows very little about the business of the others. This is especially true for the industrial sources of CO_2 where we think the large CO_2 supplies for tomorrow must come.

B. New Supplies of CO_2

A new report in preparation by the MIT Energy Institute[2] has examined the economics of CO_2 supplies coming from the fossil fuel power plants and concludes that a "gap" exists between the value of the CO_2 and the costs of capture. Perhaps technology can close that gap but the first few demonstration plants are multi-billion dollar investments and appear to be outside the risk portfolios of companies capable of making those investments.

Alternative sources are smaller but their economics are better. CO_2 value is a function of purity and pressure; some industrial sources can capture CO_2 for the value received. But what is more apparent every day, this all takes time and the cultures of the surface and subsurface industries are so different that barriers constantly impede the progress.

C. Supply/Demand Balance

For the first 25 years of the CO_2 EOR business, the underground natural CO_2 source fields were of ample size to provide the CO_2 needed for EOR. Pipelines had also been built of sufficient throughput capacity to supply the needs. Today the situation has changed. Either depletion of the source fields or limitations of the pipeline are now constricting EOR growth. Cost of capture of industrial CO_2 has not advanced to close the gap between the value of the CO_2 and the cost of capture.

NEW U.S. DEVELOPMENTS OUTSIDE OF THE PERMIAN BASIN

While the Permian Basin clearly dominates the CO_2 EOR development picture today, it is important to note that the Gulf Coast and Wyoming are "exploding" with new growth In fact, the Mississippi growth is a classic example of production growth where CO_2 supply was not a limiting factor. The Jackson Dome natural source field near Jackson, MS has been developed in very rapid fashion to provide the necessary new CO_2 to fuel the expansion of EOR. Wyoming has a similar story with their LaBarge field and Shute Creek plant.

RESIDUAL OIL ZONES DEVELOPMENTS WITHIN THE PERMIAN BASIN

A new revolution is underway in the CO_2 EOR industry. The oil industry is undergoing a significant shift in the way it calculates resources. New sources of oil are

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[2] MIT Energy Institute, July 23, 2010, Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration, 196 pgs.

being recovered today using techniques such as CO_2 EOR in intervals known as Residual Oil Zones (ROZs). Furthermore, these intervals appear to be very abundant.

The traditional phases of production, or Ternary view of oil extraction, have often been characterized by three phases. As shown in Figure 4, the bottom of the resource triangle (primary) represents production coming from conventional reservoirs where pent-up energy within the pore fluids is used to produce the oil (or gas). As mentioned earlier, the pressures in these conventional reservoirs eventually are depleted as the fluids are produced and the fluids no longer flow to the producing wells at a commercial rate. Some formations (a subset of the primary produced ones) are amenable to injection of a fluid to re-pressurize and sweep the oil from newly drilled injection wells to the producer wells. This is the second tier shown in Figure 4. Water is usually the chosen fluid for injection since it is relatively cheap and widely available. The oil and gas industry has had a long history developing best practices for optimizing waterflood oil recovery.

A lot of oil will remain in a reservoir even after the waterflooding phase. A common metric for the Permian Basin of West Texas, the largest oil and gas reserve in the US, is that primary processes will get about 15 percent of the original oil in place (OOIP) in the reservoir and secondary processes will get another 20-30 percent. Astonishingly, more than half of the original OOIP is left behind.

The next phase of resource recovery (tertiary) goes after the oil left in place and this is where the aforementioned EOR techniques are used. It is a more expensive process than waterflooding so fewer reservoirs make it to this stage and oil production here has been important but relatively small when compared to both primary and waterflood applications.

EOR typically aims for the oil bypassed during waterflooding. When CO_2 contacts the oil, it enters into solution with the oil. This alters the density and viscosity of the oil, expanding it, and changes the oil's surface tension with the rock. EOR using CO_2 is so effective at loosening and displacing oil that the process often leaves less than 10 percent of the OOIP behind. The engineering challenge to EOR using CO_2 revolves around the ability to contact large portions of the oil reservoir. To gauge success, engineers use a metric called "volumetric sweep efficiency." In the Permian Basin, where the techniques have been polished, CO_2 has been used in EOR processes to obtain an additional 15-20 percent of the OOIP.

A. ROZ Targets

Residual Oil Zones that are not man-made, but created by natural waterfloods in reservoirs, are being looked at as possible commercial targets for oil production today. Natural causes, such as ancient tectonic activity, can cause oil to move around in basins and water can encroach into a former trap. Industry is now looking at how much oil is left behind in naturally swept reservoirs and finding that these natural waterfloods can leave behind levels of residual oil similar to those left behind by manmade waterfloods. These ROZ targets can be very large and open a whole new resource for development.

Today, nine CO_2 EOR projects have targeted ROZs in the Permian Basin. Most notable among these are three projects being developed by Hess Corporation. The first two were Hess pilot projects designed to deepen wells into the ROZ to evaluate the technical and commercial feasibility of a 250-foot thick ROZ. The ROZ resource at the field is given nearly one billion barrels of oil in place and the results from the two pilots have led to a phased and full field project designed to recover 200+ million barrels of oil. Stage 1 of the full field deployment is two years old and budget approvals are being put in place to expand into Stage 2. Time will tell what the total recovery figures will be, but the current 29 patterns (injection wells) are already responsible for over 5,000 barrels of oil per day with rapidly upward trending production. The oil being produced in these wells could not have been produced except by EOR techniques since the target oil is the residual oil left behind when a natural waterflood swept out the originally entrapped oil sometime in the geological past.

B. Quaternary View

The new ("quaternary") view of oil production (Figures 4 and 5) are the new ways to visualize the ROZ opportunity. It can be called the fourth phase of oil resource production as in the Hess project or, alternatively, can offer production possibilities in swept reservoirs where primary or secondary production could not be obtained. How much oil is there to recover via EOR that would not otherwise be part of the recoverable reserves of a Nation? On-going Permian Basin studies suggest that these quaternary phase producible resources are enormous-perhaps as large a future production figure as the cumulative production of oil from this basin to date (30 billion barrels). A proposal to more closely examine the sizes of this resource in the

Permian Basin and extend the methodology to two other U.S. Basins is awaiting approvals at DOE.

SUMMARY

The technological innovations sweeping the world are also evident in the oil and gas industry. One of these developments is carbon dioxide flooding where oil that would be abandoned in existing fields is being produced. CO_2 EOR was shown to grow during times of $20 per barrel oil and is clearly demonstrating all the symptoms of rapid growth and expansion. Formerly led by the Permian Basin, new CO_2 floods are becoming commonplace. In the U.S. and Permian Basin today, the percentage of production attributable to CO_2 injection is 5% and 18% of total production, respectively. The numbers are capable of growing rapidly.

CO_2 EOR utilizes an injectant that is considered by many to be an air emissions issue. When pressured and purified, it becomes a valuable commodity that can produce oil and, when its work is done, effectively all of it can remain stored in the subsurface. CO_2 EOR becomes both a mechanism for oil production and an environmental tool for emission reductions.

Historically, CO_2 EOR has been cast in a framework where it is insignificant in terms of the emission streams that are to be captured. However, the truth is that it can provide an enormous "demand pull" for the needed CO_2 supplies. Additionally, the emergence of residual oil zones as viable EOR targets changes the dialogue. And, maybe best of all, it pushes the public discussion from waste disposal (sequestration) to resource extraction and energy security.

The CHAIRMAN. Thank you very much.

Mr. Banks.

STATEMENT OF KEVIN R. BANKS, DIRECTOR, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, ANCHORAGE, AK

Mr. BANKS. Thank you, Senator Bingaman and Senator Murkowski for inviting me to speak to the committee today. I feel privileged to be here. I've submitted written testimony to the committee but for my oral testimony I'd like to provide you with a brief summary.

I'm Kevin Banks, the Director of the Division of Oil and Gas as part of the Department of Natural Resources in Alaska. Our agency manages over a million acres of State land and most all of the oil production in Alaska comes from these lands. We are here today to discuss these improvements of seismic data technologies, advances in drilling techniques and enhanced oil recovery.

I want to talk about how these and other improvements in exploration and production operations have been deployed in the Arctic. My emphasis will be to describe the evolution of these technologies through time and how that has minimized the impact of industry operations on the Arctic environment.

Since the discovery of Prudhoe Bay in the 1970s the oil industry has had to invent engineering and scientific solutions to match the cold and remoteness and extraordinary values of the land and animals in the Arctic. It is a process where the industry has come up with new and unique ideas. Where industry has imported into the north, advances in technologies tested elsewhere every tool and concept that has been modified and specialized from the ordinary civil construction of man camps and roads and pipelines to the high tech science of oil exploration production.

Much of the exploration on the North Slope always occurs in the winter. Frozen tundra makes it possible to move across the land with minimal impact and to position very heavy drilling rigs. Winter operations means that impacts on wildlife can be minimized.

Polar bears have moved offshore. Most birds and caribou have migrated south.

Geophysical surveys represent the first step in exploration that contacts the land. As we've heard, 3D seismic surveys now differ from the old 2D seismic in the number of seismic lines laid out, the number of geophones and the number and placement of the energy sources used. The evolution of seismic technology in the field is in the intensity of data acquisition, the sensitivity of the instrumentation and precision that the equipment can be located using global positioning satellite system.

The biggest leap in seismic technology has been in the digital processing of the data and the result and the resolution of the subsurface stratigraphy. The current state-of-the-art seismic interpretation on the North Slope means that wild cat exploration has become much more successful. Better success rates for exploration wells means that fewer intrusions from these operations on the environment.

Exploration wells on the North Slope are drilled from ice pads and logistical support is conveyed over ice roads. In my submitted written testimony I have included photos of drilling in the Alpine field on page 5. When the well illustrated in these photos was completed the only visible sign of prior activity is the well house that was left because the well was going to be a part of a further Alpine field development. Most exploration wells are secured, cutoff below grade and buried, leaving no visible footprint.

While extended reach drilling is suitable for the production phase of oil development, vertical wells are still the best way to drill an exploration well. Even with the best 3D seismic information available there's still some uncertainty of the target depth for a wild cat objective. A highly deviated well can over shoot or under shoot the oil/gas zone. On the North Slope when the time to drill is constrained by the winter season an explorer can drill a vertical well faster and with better results. In the production phase it is the extended reach drilling that is so important.

The first drill sites drilled in Prudhoe Bay used well spacing to distance between the well heads of 160 acres. The drill site No. 1 there had a 65 acre impact on the ground and wells deviated from that particular site would only deviate about a mile or so. If you were to place DS–1 over the Capitol Building the drill site itself would cover the Capitol and all of its environs around here, the neighborhood around here. The reach of the wells would be no further than the Washington Monument.

By 2000 extended reach drilling was combined with horizontal drilling techniques so that the CD–2 site at Alpine field is just now 13 acres. 54 wells drilled on it with a well spacing of just 10 feet. The extended reach of these wells can intercept an area 8 miles across and penetrate 50 square miles of the field.

On a map of a Washington DC, if you're to drill those wells from here, the wells could reach south of the Anacostia freeway on the south and Adams Morgan on the north. The Liberty Project which is proposed by BP and the OCS is going to extend the drilling concept even further. If these wells were drilled from here the extent of those wells would reach out to Andrews Air Force Base in the south, Silver Springs in the north and well into Fairfax County in the West.

I will close with just a final comment about enhanced oil recovery. When applied to fields in the lower 48 people usually think of EOR as intended to simulate oil fields. On the North Slope every field was developed with EOR plans already in place before the field began production. This is the kind of secondary recovery that you heard about from the water flooding and gas injection.

Optimization of reservoir production is monitored using intensive surveillance tools and modeled using sophisticated dynamic simulations. These programs, in turn, have led to the use of missile injection, water alternating with gas, polymer treatments and the low salinity water injection project. In the Prudhoe Bay field, a truly ingenious gas cap water injection project that sweeps relic oil out of the gas cap and into the oil leg. These techniques have together achieved recovery rates that the North Slope developers could not have dreamed of when Prudhoe Bay was first brought online in 1977.

This concludes my oral testimony. I certainly appreciate having the opportunity to speak to you today.

[The prepared statement of Mr. Banks follows:]

PREPARED STATEMENT OF KEVIN R. BANKS, DIRECTOR, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, ANCHORAGE, AK

The indigenous people of the Arctic have demonstrated a unique skill in adapting to new technologies to survive over 10,000 years. The extremes of the climate and the terrain demand only the best performance of man to succeed. Ironically, the oil and gas industry has also learned that it must bring its best tools and brightest people to the Arctic to meet the challenges of the environment.

Since the construction of the Trans-Alaska Pipeline System and the development of the Prudhoe Bay oil field in the late 1970s, the oil industry has had to invent engineering and scientific solutions to match cold, the remoteness, and the extraordinary values of the land and animals in this place. This has been a process where industry has come up with new and unique solutions applicable to only the Arctic and where industry has brought north advances in technology tested elsewhere and adapted to the special conditions of the North Slope. Everything from the civil construction of man-camps, treatment and handling of the by-products of oil development, and the installation of roads and pipelines to the hightech science of oil exploration and development has been modified and specialized for the conditions found only in the Arctic. Even as the Inupiaq people of Alaska's North Slope have incorporated modern tools to sustain their subsistence lifestyle, so too has the oil industry adapted.

The North Slope represents America's toehold in the Arctic. Though Americans don't often think about it, Alaskans know that the US is an Arctic Nation with the same rights and concerns and aspirations as Russia, Norway, Greenland, or Canada. The North Slope of Alaska-the onshore region north of the Brooks Range-is truly vast; at nearly 150,000 square miles, an area larger than 39 states in the "Lower 48." (See Figure 1*) Offshore in the Chukchi Sea north of the Bering Straits and the Beaufort Sea on Alaska's northern coast are another 65,000 square miles in just the area of the outer continental shelf (OCS) managed by the Bureau of Oceans and Energy Management, Regulation, and Enforcement (BOEMRE). Onshore the State of Alaska owns only a small share of the total acreage; the Figure 1 2 federal government is, by far, the largest landowner in the region controlling 20 million acres in the Arctic National Wildlife Refuge, 23 million acres in the National Petroleum Reserve-Alaska (NPR-A), and all of the OCS.

This region holds incredible potential for oil and gas. According to the US Geological Survey, America's Arctic ranks as number one for undiscovered oil potential and number three for gas potential for the world's conventional petroleum resources north of the Arctic Circle. Nearly 50 billion barrels of conventional undiscovered,

*Figures 1–26 have been retained in committee files.

technically recoverable oil resources and 223 trillion feet of conventional undiscovered, technically recoverable gas resources may be found in the North Slope and the Arctic OCS off Alaska's northern coast. This represents 43 percent of the nation's total oil potential and 25 percent of its gas potential.[1] Figure 2 shows that these estimates fall within a range of wide uncertainty. This range is indicated in the size of the distribution between the 5 percent and 95 percent probabilities that oil or gas resources may exceed the amounts shown. For an area like Alaska's Arctic this uncertainty should be expected. Figure 3 explains why this is so.

The North Slope has barely been explored when compared to the intensity of exploration that has already occurred throughout out the rest of the United States. If we were to place a map of Wyoming over a map of the North Slope the discovery well at Prudhoe Bay-the largest oil field in the US-would lie at the eastern boundary of Wyoming. The Burger well in the Chukchi Sea that discovered hydrocarbons there in the early 1990s would lie at Wyoming's western boundary. For reference, the 150,000 square miles of onshore area of the North Slope is twice the prospective area of Wyoming. Wyoming has seen over 19,000 wells drilled over the years or about 250 wells per 250 square miles. Only 500 exploration wells have been drilled on the North Slope; just three wells per 250 square miles. Exploration activity in America's Arctic has just begun. Over the years, as exploration has continued in places like Wyoming the assessment of undiscovered resources often continues to grow. Today's estimate of remaining oil and gas reserves in Wyoming far exceeds the amount of undiscovered resources predicted years ago in spite of substantial actual production during the same time period. As exploration matures in the US Arctic the same history may be written.

We are here today to discuss advances in oil and gas exploration and production technologies, specifically improvements of seismic data acquisition and processing, advances in drilling techniques, and enhanced oil recovery. I want to describe how these and other improvements in oil and gas exploration and production operations have been deployed in the Arctic. My emphasis will be how the evolution of these technologies has through time minimized the impact of exploration and production operations on the Arctic environment.

Onshore exploration on the North Slope always occurs in the winter. The frozen tundra makes it possible to move across the land and to position drilling rigs. Winter operations have almost no impact on wildlife: polar bears move offshore, most birds and caribou have migrated south. Geophysical surveys represent the first step in exploration that contacts the land-and it is a relatively light touch. Tracked vehicles are used to spread the weight of the vehicles on the ground to avoid compaction and any scouring. Even conventional trucks can be modified with rubber track kits. Heavier loads are carried on roligons, special trucks with huge, soft tires. For those of us who remember typewriters, the wheels of a roligon look like a typewriter roller. The physical acquisition of seismic data is a labor-intensive process so the main impact on the land is the boots-on-the-ground of crews carrying geophones across the tundra. Vibroseis equipment is used whenever possible further reducing any impact to ground. The frozen tundra also provides a better medium to transmit energy into the earth.

From the perspective of land use, three-dimensional seismic surveys differ from 2D seismic in the number of seismic lines laid out, the number of geophones used, and the number and placement of energy sources used. The evolution of seismic technology in the field is in the intensity of data acquisition, the sensitivity of the equipment and improvements in positioning the equipment using global positioning satellite (GPS) system. The biggest leap of seismic technology has been in the digital processing of all of the data acquired and the resultant resolution of the subsurface stratigraphy. Not more than 15 years ago, super-computers were used to manipulate seismic data. Now desktop workstations are used at a cost that many more oil companies can afford.

I've include three images to illustrate an example of the state of the art for seismic interpretation in use on the North Slope. (These are from paper written by a geoscientist from the Bureau of Land Management, US Department of the Interior. He presented this paper at joint session of the American Association of Petroleum Geologists and the Society of Petroleum Engineers held yesterday in Anchorage, Alaska. Figure 7 shows just how dramatic the resolution of 3D seismic interpretation can reveal the characteristics of the subsurface. The vertical dimension is exaggerated and what you can see in this figure is the deposition of layers of sandstones and siltstone in an underwater delta system as it crests over the continental shelf

[1] These estimates do not include the potential for undiscovered, technically recoverable unconventional resources: coalbed methane, deep-basin gas, gas hydrates (USGS mean estimate is 85 trillion cubic feet), or shale oil and gas.

of an ancient shallow sea. Figure 8 shows more detail of how these depositions occurred in channels and at the edges of delta fans. As material flowed through these systems, the sands were transported and sorted by turbidity washing out the fines in channels and at the distal edges of the fans. In these areas are found the best reservoir rock characteristics, the more porous and permeable sandstones.

Figure 9 shows what the geophysicist is looking for: anomalies in the seismic reflections that can be correlated to similar anomalies detected in surveys done an area nearby where extensive drilling has already occurred. In this case, within the Alpine oil field just east of the Colville River and just outside of the NPR-A. The "Class III anomalies" shown in the bottom of this graphic are filtered out of the data and provide information of not only the rock characteristics but also the fluid properties. These same anomalies are the "bright spots" highlighted back in Figure 8.

This kind of seismic interpretation is only possible because of the resolution and detail afforded from 3D. In this particular case drilling at Alpine provides the information from well logs and the fluids produced from the wells to identify anomalies in the seismic data where exploration drilling should occur. Because of this interpretation, the exploration program conducted in the northeast of the NPR-A was very successful in finding hydrocarbons. It also means that fewer "wildcat" exploration wells were needed to find oil and gas. Over the last twenty years, improvements in seismic technology and the application of better geological interpretation has meant that the dry hole risk has substantially declined. Better success rates for exploration wells means fewer intrusions from exploration operations on the environment.

Seismic surveys are not a replacement for actual exploration drilling. While 3D seismic surveys have fundamentally changed the exploration business, "The truth is in the drilling!" On the North Slope, onshore exploration drilling occurs only in the winter. Heavy equipment is brought out to remote sites on ice roads (Figure 10) and the drilling rigs are assembled on ice pads. Ice roads are built by hauling crushed ice to the road location to provide a substrate for trucks that spray water over the crushed ice to form a smooth hard surface. The flat terrain of the North Slope and the usually abundant water sources located there make it possible to build ice roads in most places. They are nonetheless expensive when considering that they disappear with the spring thaw. Ice roads have been used on the North Slope for decades.

Figure 11 shows a drill rig erected on a remote ice pad in the Alpine field. The rig itself weighs several million pounds, the large structure on the left is a 100 person camp, and adjacent to the ice pad is an ice airstrip. The pad itself is at least 12 inches thick and in many cases insulation and rig mats are placed on top of the ice to protect it and distribute the heavy loads. All drilling wastes and other discharges, e.g., domestic water from the camp, are trucked away for disposal in approved injection wells. At the end of the winter season, a front-end loader will scrape the pad down to pure ice to allow the ice to melt more quickly. When the ice melts, there is no trace left of the pad.

The only visible sign of prior activity is an eight-by-eight foot well house that will remain on location only because this well is part of a field under development and will one day produce oil. If the well were to be plugged and abandoned, which would be the case for most exploration wells, the well would be cemented-in to prevent any communication among any formations penetrated by the well and the surface. The well would be cut off below grade, marked with a plaque welded on the top, and buried. Note the recovery of the vegetation around the well house illustrated in Figure 13. It is possible to explore for oil on the North Slope and leave no visible footprint.

Figures 14 and 15 are photos of the "Hot Ice" platform erected at the edge of the foothills of the Brooks Range. This is also a temporary structure and actual drilling activity only occurred during the winter. This structure was tested because it afforded a way to store the drilling rig and to stage other equipment through the summer months. This exploration concept is intended to be used in very remote sites. The length of the ice road and the time needed to build it means that the drilling season is shorter for these sites. With the rig already in place, winter drilling can begin earlier and continue longer than could be accomplished by building an ice pad.

Extended reach drilling techniques have advanced tremendously in recent years and, as the technology has evolved, drillers have extensively used these techniques on the North Slope. While suitable for the production phase, vertical wells are still the best way to explore for hydrocarbons especially on the North Slope. The main advantage of a vertical exploration well can be seen in Figure 16. Even with the best 3D seismic information available, there is some uncertainty of the target depth for a wildcat objective. A highly deviated well can overshoot or undershoot the oil or gas zone whether the zone is a structural or stratigraphic trap. On the North

Slope when the time to drill is constrained by the winter season, the explorer can drill a vertical well faster and with better control. A deviated well is more difficult to drill, more difficult to log successfully, and is more expensive. Once measurements are taken, e.g., true depth established and correlated to the seismic information, delineation wells drilled to assess the areal extent of the prospect can be drilled using horizontal drilling techniques. In some instances delineation wells can be drilled laterally from the same borehole of the first exploration well.

As extended-reach drilling technology has evolved so has the deployment of the technology on the North Slope. From a land use perspective and as a way to minimize environmental conflicts, extended reach drilling combined with improvements in well design that allows for closer well spacing-the distance between the wellheads at the surface-has been incredibly successful. The evolution of drilling on the North Slope is another example of how industry has brought to the region technologies developed elsewhere and then improved upon for the unique conditions in the Arctic. These improved technologies are then exported from the North Slope to other regions where new improvements are made and new tools are developed. Then the resulting new technology is brought back to the North Slope. Figures 17 and 18 show the twin impacts of well spacing and extended reach drilling.

The first drill sites in the Prudhoe Bay field were built in the 1970s and used well spacing of about 160 feet and covered 65 acres of land to accommodate the footprint of the drilling rigs of the day. As many as 25 or 30 wells drilled in three rows from these sites could deviate to approximately one-mile from the vertical. By the time the first production wells were drilled in the Kuparuk River field in the early 1980s, improvements in rig design and drilling techniques and the materials used in the wells meant that the area of the drill sites could be reduced by more than one-half. The first drill sites in the Kuparuk River field had a well spacing of 60 feet and a 16 well drill site was just 24 acres. Wells from these first drill sites could deviate more than one-and-a-half miles from the vertical.

By the mid 1980's the technology employed in the Kuparuk River field had advance significantly. A 16 well drill site was reduced to just 11 acres and the wells could deviate by more than 2.5 miles from vertical and penetrate over 12,560 acres of the reservoir.

The Alpine field in the Colville River Delta represents the next stage in drilling advancement. From a drill site of only 13 acres, 54 wells have been drilled at a spacing of just 10 feet. The rig cantilevers over the well to avoid the wellhead of the neighboring well. The extended reach of these wells can intercept an area 8 miles across and penetrate 50 square miles of the field.

In just 30 years, surface footprint requirements have been reduced from over 2 acres per well at Prudhoe Bay, to one quarter (0.24) acre per well at Alpine.

The pairs of maps shown in Figures 19-24 show what this evolution means in terms of the areal extent achieved by the changes in extended-reach drilling capabilities over the years. Wells drilled from DS-1 in Prudhoe Bay could reach only a part of the field. In Figure 19 the spider diagrams represent the areal extent of the wells and their underground trajectory. The surface footprint of the drill site is much smaller, as was shown in Figure 18. Now superimpose the extent of the spider diagram from DS-1 on the US Capitol Building (See Figure 20). Some of these wells can't reach the Washington Monument and the drill site itself would dominate the area of the Capitol Building and the surrounding neighborhood.

Improvements in drilling technology during the 1980s and early 1990s extended well reach to about 3 miles. Modular rig construction reduced the space needed between wellheads and elimination of reserve pits further reduced surface impact. Figure 21 is the spider diagram of the DM-2 drill site in the Kuparuk River field. Again the spider image shows well trajectories and how far the wells can reach. The surface impact is only a very small part of the spider diagram. Wells from DM-2 produce oil from nearly 6,400 acres (10 square miles) and the drill site has a footprint of just 12 acres. Superimpose this diagram on the US Capitol Building (Figure 22) and the wells will reach beyond Reagan National Airport and up towards Washington Hospital.

By 2000 extended reach drilling technology was combined with horizontal drilling techniques that had become commonplace for most all production wells on the North Slope. The Alpine field is the latest excellent example of minimizing surface impact while maximizing resource development. The spider diagram in Figure 23 shows that extended reach/horizontal wells drilled from the 11-acre CD-2 drill site in the Alpine Field can produce from about 14,200 acres (22 square miles). Some of the wells in the Alpine field can reach out 4 miles from the drill site. On a map of Washington, DC with the drill site at the Capitol Building, the wells can reach well south of the Anacostia Freeway all the way to Adams-Morgan (Figure 24).

The Liberty project represents the next and latest phase: ultra-extended-reach drilling. Although these wells have not yet been drilled, the rig is up and undergoing final engineering and design assessments. It is likely be the largest land rig in the world. Figure 25 is a map of the proposed Liberty project. Green areas denote underground oil reservoirs. Yellow dots denote proposed drilling targets. Liberty will be developed from the existing Satellite Drilling Island (SDI) drill site originally constructed for the Endicott field. Six wells are planned that will reach up to 8 miles from the island. If successfully implemented, these wells will be the longest reach wells ever drilled.

Figure 26 shows the area that could be reached by the Liberty wells if the rig was set on the site of the Capitol Building. The wells could extend out to Andrews Air Force Base in the southeast, Silver Spring in the North, and well into Fairfax County in the west. If the Prudhoe Bay field were developed today using Liberty-type drilling technology, surface impact would be greatly reduced to possibly as few as two drill pads.

The climate, the remoteness, government regulation, and undoubtedly the cost all contribute to the industry's ability to drill in the Arctic with as little impact to the land as possible. The evolution and deployment of technological improvements over the years tell a story of innovation and adaptation that is demanded of the Arctic on all who live and work there.

Epilogue: A final comment about enhanced oil recovery (EOR). Testimony by others at this hearing will provide the committee with a description of incredible and fantastic applications of physics, chemistry, and engineering to squeeze every drop of hydrocarbons out of US oil and gas fields. When applied to fields in the Lower 48, people usually think that EOR is intended to stimulate old oil and gas fields and reverse their production declines. Note that every field developed on the North Slope, including Prudhoe Bay, had an EOR plan in place before the first drop of oil was produced. Water flooding and gas injection, miscible injection, water-alternating-with-gas (WAG) were designed into the facilities as they were installed and upgraded. The optimization of these EOR projects are continually monitored using intensive surveillance tools and modeled using sophisticated dynamic simulations of the reservoirs. The Saddlerochit reservoir in the Prudhoe Bay field maybe the most well understood reservoir in the world.

The Alaska oil and gas Industry is also implementing amazing new EOR ideas. The Gas Cap Water Injection Project at the Prudhoe Bay field is such an idea. By flooding water through the gas cap, relic oil will be swept into the oil leg of the reservoir where it can be produced. Monitoring the progress of the success of this project is achieved by employing the first of its kind micro-gravity 4D survey that can remotely detect the movement of fluids through the gas cap. Pilot projects are also underway including the low salinity water injection project and polymer treatments.

A variety of artificial lift mechanisms are employed throughout the fields on the North Slope including gas lift, jet pumps, electric submersible pumps, and progressive cavity pumps. The industry has also implemented many surface gathering and processing advancements, corrosion monitoring, and equipment condition based monitoring programs.

The CHAIRMAN. Thank you.

Ms. Epstein.

STATEMENT OF LOIS N. EPSTEIN, P.E., ENGINEER AND ARCTIC PROGRAM DIRECTOR, THE WILDERNESS SOCIETY, ANCHORAGE, AK

Ms. EPSTEIN. Good morning. Thank you for inviting me here to testify today. My name is Lois Epstein and I am an Alaska licensed engineer and the Arctic Program Director for The Wilderness Society or TWS, a national public interest organization with over 500,000 members and supporters.

My background in oil and gas issues includes membership from 1995 to 2007 on the U.S. DOT Oil Pipeline Federal Advisory Committee.

Appointment to the Bureau of Ocean Energy Management Regulation Enforcement or BOEMRE's newly formed Ocean Energy Safety Committee.

Testifying before Congress on numerous occasions previously.

Analyzing in detail the environmental performance of Alaska's Cook Inlet oil and gas infrastructure.

The purpose of this hearing is to discuss new developments in upstream oil and gas technologies. I will provide an Alaskan perspective. I will discuss several key issues.

One ensuring that upstream oil and gas operations do not result in spills.

Two, keeping the Trans-Alaska pipeline system or TAPS, operating.

Three, realistically assessing the impacts of directional drilling.

On the first topic both onshore and offshore oil and gas wells and their associated pipelines have unfortunately a troubling spill record and a highly inadequate oversight framework which needs to be addressed by Congress and the Obama Administration. Just last week the Administration and BP agreed to a proposed civil settlement for 2006 oil pipeline spills of $25 million. Plus, and this is what's important, a set of required safety measures for BP's Federal unregulated North Slope pipelines which are all upstream of transmission lines. That's part of oil gas field operations. While the settlement is certainly welcome and an important precedent, Congress and U.S. DOT need to require such measures for federally unregulated upstream lines operated by other companies in Alaska and the lower 48.

Lack of adequate preventive maintenance in North Slope operations is not a new issue. However, as corrosion problems in Prudhoe Bay's and other oil fields pipelines have been raised previously by regulators and others including as early as 1999 by the Alaska Department of Environmental Conservation. As additional evidence of the problems with upstream infrastructure, the State of Alaska recently completed a report in November 2010 which showed that there is a spill of over 1,000 gallons nearly once every 2 months. Of the spills included in the report, which I do have with me, a substantial portion or 39 percent were from federally unregulated upstream pipelines. Thus, there's great opportunities to make sure that those don't happen with the proper oversight, those spills.

Turning to offshore operations. Since the BP Deep Water Horizon tragedy is now well known at the Minerals Management Service and its successor agency BOEMRE need to upgrade regulatory standards and enforcement capabilities for offshore drilling. As I discuss in more detail in my written testimony.

Congress also needs to upgrade Federal legislation since the spill. I welcome this committee's work on that issue. Including in areas widely considered problematic. As just one example, current Federal law still has a low liability cap of $75 million.

On the second topic of the Trans-Alaska pipeline system, Alaska's North Slope oil producers and indeed, all Alaskans have a financial interest in keeping TAPS operating. There are several different ways of ensuring that TAPS continues to operate including technical upgrades to the pipeline such as heaters or liners and/or increases in conventional including heavy oil and/or unconventional including shale oil drilling on State lands. Though drilling in State waters may be problematic.

I want to, from the perspective of The Wilderness Society, I want to emphasize that despite in State and DC based rhetoric, drilling on Federal lands or waters is not necessary to ensure that TAPS remains viable for decades to come. There's been quite a bit of testimony along those lines in the State legislature recently. From an Alaskan perspective drilling on State lands generally provides far more revenue for the State than from Federal lands including outer continental shelf drilling beyond 6 miles where the State receives no revenue from leases.

On the third topic directional drilling for oil which is not a new technology has impacts in an area that are no different than conventional vertical oil drilling. Directional drilling requires surface occupancy for drill rigs and well pads as well as runways, roads, pipelines and other transportation and supply infrastructure. Because of its higher costs and the improved likelihood of accessing a reservoir using a vertical well, directional drilling may not be used for exploratory drilling. It might be, but it might not.

Additionally regardless of the type of drilling used there would be adverse impacts from seismic exploration which occurs directly above the subsurface being explored. In the Arctic seismic exploration typically involves heavy vehicles driving across the tundra in a great pattern impressing sensitive soil and plants. Tundra recovery from seismic activities can take decades.

Those familiar with directional drilling know that for technical reasons directional drilling only has a range of a few miles. As a result any bill proposing to use directional drilling to access federally protected areas may be said to potentially mislead decisionmakers by ignoring the need for repeated surface use across extensive areas for seismic exploration including 3D surveys and exploratory and delineation drilling. It may also cause decisionmakers to think that an area's full oil development potential could be realized through directional drilling.

It might also be perceived to mislead the public by implying that oil drilling in an area will be forever limited to the distance accessible via directional drilling. When oil production precedes using directional drilling there will be calls to expand the drilling to reach portions of the reservoirs not accessible via that approach. The bottom line with directional drilling is that it allows a region to become industrialized and adversely impacted to essentially the same extent as conventional drilling including surface exploratory activities which can have long term consequences.

Wildlife including marine mammals, caribou, migratory birds using federally protected areas do not recognize political boundaries. There's no question that conducting drilling activities immediately adjacent to federally protected areas, like the Arctic National Wildlife Refuge would have harmful ecological impacts.

Thank you very much for your attention to these important issues. I look forward to answering your questions.

[The prepared statement of Ms. Epstein follows:]

PREPARED STATEMENT OF LOIS N. EPSTEIN, P.E., ENGINEER AND ARCTIC PROGRAM DIRECTOR, THE WILDERNESS SOCIETY ANCHORAGE, AK

Good morning and thank you for inviting me to testify today. My name is Lois Epstein and I am an Alaska-licensed engineer and the Arctic Program Director for

The Wilderness Society. The Wilderness Society, or TWS, is a national public interest conservation organization with over 500,000 members and supporters. TWS' mission is to protect wilderness and inspire Americans to care for our wild places. My background in oil and gas issues includes membership from 1995-2007 on the U.S. Department of Transportation's Technical Hazardous Liquid Pipeline Safety Standards Committee which oversees oil pipeline regulatory and other agency activities, appointment to the Bureau of Ocean Energy Management, Regulation and Enforcement's (BOEMRE's) newly-formed Ocean Energy Safety Committee, testifying before Congress on numerous occasions, and analyzing in detail the environmental performance of Alaska's Cook Inlet oil and gas infrastructure. I have worked on oil and gas environmental and safety issues for over 25 years for three private consultants and for national and regional conservation organizations in both DC and Anchorage.

The purpose of this hearing is to discuss new developments in upstream oil and gas technologies, and I will provide an Alaskan perspective. I will discuss several key issues:

1. Ensuring that upstream oil and gas operations do not result in spills and pollution,
2. Keeping the Trans-Alaska Pipeline System, or TAPS, operating, and
3. Realistically assessing the impacts of directional drilling. Last, I will present The Wilderness Society's position on oil drilling in the Arctic National Wildlife Refuge.

Ensuring Upstream Operations Do Not Result in Spills and Pollution

Both onshore and offshore, oil and gas wells and their associated pipelines have a troubling spill record and a highly inadequate oversight framework which needs to be addressed by Congress and the Obama Administration. Just last week, the Administration and BP agreed to a proposed civil settlement for 2006 pipeline spills of $25 million plus a set of required safety measures on BP's federally-unregulated North Slope pipelines which are all upstream of transmission lines.[1] Under the requirements of the settlement, BP's federally-unregulated oil field pipelines, i.e., three-phase flowlines (gas, crude, produced water mixture), produced water lines, and well lines, now will be subject to integrity management requirements largely similar to those that must be met by transmission pipelines in 49 CFR 195. While this settlement certainly is a welcome step for BP's lines and an important precedent, Congress in its pipeline safety act reauthorization and the U.S. Department of Transportation need to move forward expeditiously on requiring such measures for lines operated by other companies in Alaska and the Lower 48.

BP's March 2006 spill of over 200,000 gallons was the largest crude oil spill to occur in the North Slope oil fields and it brought national attention to the chronic problem of such spills. Another pipeline spill in August 2006 resulted in shutdown of BP's production in Prudhoe Bay and brought to light major concerns about systemic neglect of key infrastructure. Lack of adequate preventive maintenance was not a new issue, however, as corrosion problems in Prudhoe Bay's and other oil field pipelines have been raised previously by regulators and others, including as early as 1999 by the Alaska Department of Environmental Conservation.[2]

As additional evidence of the problems with upstream infrastructure, the State of Alaska completed a report[3] in November 2010 which reviewed a set of over 6,000 North Slope spills from 1995-2009. This report showed that there were 44 loss-of-integrity spills/year[4] with 4.8 of those greater than 1,000 gallons/year.[5] Of the 640 spills included in the report, a significant proportion, 39%, were from federally-unregulated pipelines.[6]

In 2009, TWS issued its own report on North Slope spills entitled Broken Promises,[7] which I have with me here today. Broken Promises should be used in conjunction with the state's spill report. The TWS report shows a spill frequency on the

[1] Proposed settlement posted at http://media.adn.com/smedia/2011/05/03/1029-1%20consent%20decree.112830.source.prod___affiliate.7.pdf (downloaded May 8, 2011).

[2] Charter for the Development of the Alaskan North Slope, December 2, 1999, (BP ARCO Merger Agreement), http://www.dec.state.ak.us/spar/ipp/docs/Charter%20Agreement.pdf.

[3] North Slope Spills Analysis: Final Report on North Slope Spills Analysis and Expert Panel Recommendations on Mitigation Measures, Nuka Research & Planning Group, LLC for the Alaska Department of Environmental Conservation, November 2010, 244 pp., http://www.dec.state.ak.us/spar/ipp/ara/documents/101123NSSAReportvSCREEN.pdf.

[4] Ibid., p. 21.

[5] Ibid., p. 23.

[6] Certain types of spills were not included. See p. 14 of the North Slope Spills Analysis report.

[7] Broken Promises: The Reality of Oil Development in America's Arctic (2nd Edition), The Wilderness Society, 2009.

North Slope of 450 spills/year during 1996-2008, with the difference being that the state included only "production-related" spills in its analysis and excluded North Slope toxic chemical (e.g., antifreeze) and refined product (e.g., diesel) spills—many of which are related to oil development—as well as spills indirectly related to oil production infrastructure, such as those from drilling or workover operations and from vehicles.

Turning to offshore operations, since the BP Deepwater Horizon tragedy, it is now well-known that the Minerals Management Service and its successor agency, BOEMRE, need to upgrade regulatory standards and enforcement capabilities for offshore drilling. Since the BP spill, BOEMRE has issued several new drilling safety regulations and is in the process of developing new policies regarding the environmental analyses required for offshore drilling. The conservation community is most concerned with the following currently-inadequate BOEMRE practices: lack of transparency in permitting, the limited nature of its enforcement, the need for real-time electronic monitoring of offshore operations by regulators, the insufficiency of key regulations (e.g., covering blowout preventers), and the problematic implementation of National Environmental Policy Act and oil spill response requirements. Additionally, Congress has not upgraded federal legislation since the spill including in areas widely considered problematic; as examples, current federal law has a low liability cap of $75 million, inadequate financial responsibility requirements, and there are no whistleblower protections for the offshore drilling industry.

Notably, BOEMRE recently released a technical memo[8] showing that a hypothetical blowout in the Chukchi Sea lease sale 193 area could result in a spill of 58-90 million gallons, meaning that there could be a spill of approximately the same scale as that from the BP Deepwater Horizon in the Arctic where cleanup would be extraordinarily more difficult. This information sends a strong message that the legislative and regulatory failures which in part led to the BP upstream spill—as discussed in the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling report[9]—need to be remedied expeditiously.

Keeping TAPS Operating

Alaska's North Slope oil producers and, indeed, all Alaskans have a financial interest in keeping TAPS operating. There are several different ways of ensuring that TAPS continues to operate including technical upgrades to the pipeline such as heaters[10] or liners and/or increases in conventional (including heavy oil) and/or unconventional oil drilling on state lands. I want to emphasize that—despite in-state and DC-based rhetoric—drilling on federal lands or waters is not necessary to ensure that TAPS remains viable for decades to come.

Oil industry's plans to operate TAPS for many decades to come were highlighted recently in the Alaska legislature by Senator Joe Paskvan:

> There is reliable information that the likely operation of TAPS is at least until 2047. This is likely without any potential contribution to throughput from heavy oil or shale oil or ANWR oil or NPRA oil or OCS oil. Based on the available evidence, Mr. President, I am confident saying that TAPS will continue to operate for decades. There are billions of barrels of conventional crude remaining in Alaska's Central North Slope.[11]

Over 5 billion barrels in conventional oil reserves remain on Alaska's North Slope according to the Alaska Department of Natural Resources.[12] Additionally, viscous and heavy oil reserves of 30 billion barrels, largely in strata above the existing

[8] Memorandum on Estimate for Very Large Discharge (VLD) of Oil from an Exploration Well in the Chukchi Sea OCS Planning Area, NW Alaska, March 4, 2011.

[9] DeepWater: The Gulf Oil disaster and the Future of Offshore Drilling, Report to the President, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, January 2011, see http://www.oilspillcommission.gov/final-report.

[10] Which could, according to TAPS owners, ensure TAPS viability using current proven reserves through 2042 (BP Pipelines (Alaska) Inc., et al. v. State of Alaska, et al., Case No. 3AN-06-8446 C1, Superior Court for the State of Alaska, October 26, 2010 p. 129).

[11] A Math Problem and Alaska's Production Tax System, Senator Joe Paskvan, Alaska Legislature, Senate Floor Session, Special Orders, May 3, 2011. Also listen at http://gavelalaska.org/media/?media__id=SFLS110503A&type=audio; see also Comments on Judge Gleason's Decision: BP Pipelines, et al. v. State of Alaska, et al. op. cit., Alaska Legislature Senator Joe Paskvan, April 27, 2011, 4 pp.

[12] 2009 Annual Report Updated, Alaska Department of Natural Resources, May 2010, p. 8, see http://www.dog.dnr.state.ak.us/oil/products/publications/annual/2009__annual__report/updated__2009annual__report/Annual%20Report%202009%20Updated%205-18-10.pdf.

Prudhoe Bay oil fields, have begun to be produced.[13] At West Sak, viscous oil has been produced for the past few years.

From an Alaskan perspective, drilling on state lands provides far more revenue for the state than from federal lands, including Outer Continental Shelf drilling where the state receives no revenue from leases. Today the oil industry holds roughly 3.9 million acres in active State of Alaska leases on the North Slope. Millions of acres of existing leases on state lands have not yet been developed. Each year, the state holds area-wide lease sales covering 11 million acres between the Canning and Colville Rivers on the North Slope.

I'd like to speak for a moment about the potential for shale oil fracking in Alaska on state lands. Underlying lands close to TAPS infrastructure are three shale oil formations with high potential for unconventional oil production. The geology in this area is similar to North Dakota's prolific Bakken Shale and the South Texas Eagle Ford Shale. Great Bear Petroleum LLC recently leased over 500,000 acres of state land near TAPS south and southwest of Prudhoe Bay to pursue shale oil fracking. This relatively new technique to produce oil from shale rock could result in substantial volumes of additional oil entering TAPS from state, rather than federal, lands. Shale oil production needs to be well-regulated by both the federal and state governments to protect the Arctic's waters and wildlife habitat—lack of adequate state regulation always is a concern in a state seeking to attract oil producers.

The following graphic[14] from Great Bear Petroleum taken from its presentation to the state legislature in 2011 shows projected oil production over 150,000 barrels/day beginning in 2015 with nearly 300,000 barrels/day in 2029 and sustainable long-term production of 450,000 barrels/day beginning in 2044. Note that Phase 1 would include drilling 200 wells per year for 15 years beginning in 2013, a substantial additional economic boost to Alaska.

Importantly, Great Bear Petroleum is not asking the state for any changes in the state's oil tax rates.

Increased conventional oil production on state lands also is possible as the extensive discussion on how to encourage such production during the 2011 state legislative session made clear.

Realistically Assessing Directional Drilling

Oil and gas drilling and production is an inherently complicated and messy business. Even the best and most well-financed operators cannot ensure they will not have oil or other spills because they may encounter unexpected or changing conditions which have not been adequately addressed. Additionally, there is always a tension between reducing operating costs while still maintaining safety and environmental protection.

Directional drilling for oil, which is not a new technology, has impacts that are no different than conventional oil drilling. It requires surface occupancy for drill rigs and well pads as well as runways, roads, pipelines and other transportation and supply infrastructure, albeit at a location near but not immediately above oil and gas reservoirs. Because of its higher cost, directional drilling may or may not be used for exploratory drilling. Additionally, regardless of whether directional or conventional drilling is used, there would be extensive adverse impacts from seismic exploration which does occur directly above the subsurface being explored. In the Arctic, seismic exploration typically involves heavy vehicles driving across the tundra in a grid pattern, compressing sensitive soil and plants. Tundra recovery from seismic activities can take decades.

Those familiar with directional drilling know that for technical reasons directional drilling only has a range of a few miles. As a result, any bill proposing to use directional drilling to access federally-protected areas:

1. Misleads decision-makers by ignoring the need for repeated surface use across extensive areas for seismic exploration, including 3-D surveys and exploratory and delineation drilling,
2. Misleads decision-makers by having them think that an area's full oil development potential could be realized through directional drilling, and
3. Misleads the public by implying that oil drilling in an area will be forever limited to the distance accessible via directional drilling. When oil production proceeds, there will be calls to expand drilling to reach portions of reservoirs not accessible via directional drilling.

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[13] BP puts test horizontal well into operation in the Ugnu at Milne Point, Petroleum News, May 1, 2011, see http://www.petroleumnews.com/pnads/40812990.shtml.

[14] Title changed for purposes of this testimony.

The bottom line with directional drilling is that it allows a region to become industrialized and adversely impacted to essentially the same extent as conventional drilling. Wildlife including marine mammals and ungulates using federally-protected areas do not recognize political boundaries. Moreover, wildlife movements are not always predictable from year to year, particularly with the advent of climate change. There's no question that conducting drilling activities immediately adjacent to federally-protected areas like the Arctic National Wildlife Refuge would have harmful ecological impacts.

The Wilderness Society's Position on Oil Drilling in the Arctic National Wildlife Refuge

Opening the Arctic National Wildlife Refuge to oil leasing, exploration, and production unacceptably threatens the Refuge's globally significant wilderness and wildlife values. Oil drilling activities—even with directional drilling as one component—would undermine the Refuge's fundamental purposes: to protect wilderness, wildlife, and subsistence.

Thank you very much for your attention to these important issues.

The CHAIRMAN. Thank all of you for your excellent testimony. Let me start with a few questions.

You know one of the impressions I get is that the new technologies that have been developed have had 2 big—they've obviously had a lot of impacts, but 2 of those are that it's much less likely that you're going to be drilling dry holes because of the new information that the industry has from all the seismic technology Dr. Davis spoke about. That once you do drill a well, your ability to actually access more of the resource, whether it's oil or gas, is substantially improved. Is that a fair characterization of what has changed in the industry,

Dr. Davis.

Mr. DAVIS. Yes. I'd like to speak to that with a few statistics. Historically in the past we've averaged for wild cat drilling in one in 8 successful wells. Now we're well below one in 4 using 3D seismic technologies. But with the advent of the new recording systems, the new technologies, we're down to less than that.

I haven't seen any recent——

The CHAIRMAN. You mean out of every 4 wells that are drilled, 3 of them will be dry holes still?

Mr. DAVIS. That is correct for wild cat drilling. That's in areas that are, you know, that haven't been drilled in before. Most of our drilling though is in areas where we already have reserves. In those areas we have also accelerated our success ratios to generally the other way around that is 3 out of 4 wells would be successful.

So in this regard then our success has certainly accelerated. Also as you've already indicated we've also, you know, found additional reserves in areas that we didn't necessarily think were there. In other words there are satellite fields proximal to the main fields that we've now been able to find.

So as a result we've increased the recovery of those general fields substantially. So before we basically booked reserves on the framework of the geometry of the reservoir and that and we found out that the reservoir is much more extensive than before we thought. We now are also using enhanced oil recovery methods like Mr. Melzer indicated to even recover oil below the oil water contact.

So again, what has been astonishing is the accelerated, I guess we'll say, intake of the recovery here that's occurred in these fields.

The CHAIRMAN. Am I right that these new gas findings that in the deep shale that are being drilled in Pennsylvania and all around these days. Those are—you don't get dry holes with those. I mean, you pretty much know the gas is there. It's a question of making the investment to access it.

Is that a fair statement?

Mr. DAVIS. It is a fair statement. We know that we're going to not have a dry hole. But whether we have an economic well or not is the issue.

The CHAIRMAN. Right.

Mr. DAVIS. So another use of the new technology is to optimize the drilling for what we call "sweet spots," those areas that will be economically attractive.

The CHAIRMAN. Let me ask Mr. Melzer. Your comment that you're out of CO_2 at this point. Could you elaborate on that a little bit? I mean, how much enhanced oil recovery activity currently uses CO_2 and how much could use CO_2 if the CO_2 were available?

Mr. MELZER. The question is an excellent one. I get this asked of me quite often. The answer is a bit subjective to match supply and demand.

It regards—I'm pretty well connected to the industry so I understand where pent up projects are. Many of them, I don't know them all. But what I see in our basin is that we could probably double our CO_2 utilization today if we had double the supply in a matter of 5 years we could probably find the projects to implement.

Some of that is due to enhanced pricing, oil pricing today, where it is. We were growing this business at $20 oil. CO_2 EOR was growing at 1990s which averaged $19 a barrel in that decade. So maybe that's a $40 barrel today.

The CHAIRMAN. What does——

Mr. MELZER. Certainly.

The CHAIRMAN. What does the CO_2 cost?

Mr. MELZER. The old contracts that were around back in the 1980s and 1990s, many of those are still there. I just heard of a new contract which was a record setting price. I think in terms of MCF, thousands of cubic feet, $2 a thousand is probably a current price that's going around.

The average price because of the old contracts is closer to a dollar on that order. That's $20 a ton for the latter and $40 a ton for the former.

The CHAIRMAN. Thank you.

Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman.

Gentlemen, thank you for speaking to some of the advances in the technology that have really taken us to where we are.

Ms. Epstein, I had hoped—I understand where you're coming from on oil. But I had hoped that you too would recognize, we really have made some transformational, transformational movement in how we access our resources and reducing that footprint and reducing our emissions and really trying to do a much, much better job.

Mr. Hendricks, I wanted to ask you about the extended reach drilling. You mention that Schlumberger, the furthest you've gone out is 7.6 miles. Mr. Banks has indicated that in Alaska we're up to about 8 miles in all different directions.

Is there any physical limitation in terms of your ability to go further, to push it out or are the limitations more from an economical? Is it technical? What's keeping us from going further than the 7.6 or the 8 miles?

Mr. HENDRICKS. Thank you for the question, Senator. So as engineers we like to take on these types of challenges. We like to solve these types of technical problems. But yes, there is an economic factor as well that comes into play.

There are limits eventually as to how far out we can drill. I don't think we've met those limits yet. We're at a little over 7 miles now and some of our records.

Senator MURKOWSKI. Has anybody gone further?

Mr. HENDRICKS. No, not yet. We've done that so far. But, you know, soon we'll see 8, 9, 10 and maybe 15 or 20 someday in the future. We'll take this step by step.

As engineers we like to take these a little bit at a time and make sure that we've done the calculations so that everything works out like it's supposed to.

Senator MURKOWSKI. Appreciate that.

Mr. Davis and Mr. Melzer, you both talked about the—well, and Mr. Banks as well, the EOR and kind of what the technologies are now allowing us to do. One of the discussions that we have around here we're always arguing over how much resource is really out there. If you believe what the President says, you know, you've got 2 percent of the reserves out there.

In fairness, do we really know? It seems like the more our technology advances us, the more we are able to not only access, but really it seems like it's unlimited. Am I being too "pie in the sky" about this or are there really more for us in terms of the opportunities?

Either one of you, I mean, any of you?

Mr. Melzer.

Mr. MELZER. It's a great topic, Senator. It's—we are kind of on the verge of trying to understand the resource that would be in these residual oil zones. I can really say that the commercial resource that's in those zones at $100 a barrel it's enormously higher than it would be at $40 a barrel.

We did a real quick calculation. Admittedly it was back in the envelope in one county in West Texas, it's a large county, but it's one county. We had $30 billion barrels of oil in place. We could calculate from that residual oil zone in that county.

I suspect that parts of Wyoming, maybe some of Utah have the same resource that we just are, just now understanding that we ought to go study. South Dakota, I mentioned, southern Williston Basin and into Canada as well. So, now it becomes a question of where you going to get the CO_2 to do that?

I like to think in terms of the gap between the cost of capture and the value of the CO_2 for EOR. We have shrunk that because the price of oil is up and because technology is advancing thanks to a lot of the work that DOE is doing. So it's not closed for coal plants today. But it's getting closer.

It is close for some industrial processes like ammonia and natural gas byproducts CO_2. So it's a complicated answer because it depends on the supply of CO_2 as well as the total resource in the ground.

Senator MURKOWSKI. But isn't it more than just, I mean, the CO_2 is what has enabled us to really gain the advantage with the enhanced oil recovery.

Mr. Davis, is there more out there that, I mean, you mentioned that the time lapse imaging and better understanding where it is. Are we just now beginning to understand in being able to identify what the true resource might actually be?

Mr. DAVIS. We truly are. We've been involved with monitoring these enhanced oil recovery projects since 1995. To give you an indication of the amount of recovery that is incremental recovery that's occurred, generally the enhanced oil recovery framework involves about a 15 percent incremental.

In other words if you have oil, original oil in place of say, 3 billion barrels, you can escalate that by additional, well normally you'd recover about a quarter of that with secondary and primary. But going with enhanced oil recovery you'd have an incremental recovery of 15 percent. But we found out through monitoring that we can escalate that even farther to 17 to 20 percent.

We don't know what the limits are. You're quite right in your observations. So in some fields, for example we've gone from 12,000 barrels to 35,000 barrels a day incremental recovery. That's on a day basis. There's a field in Oklahoma that we've worked that we've taken from 10 barrels to over 3,000 barrels a day. Many, many examples like that exist.

We now want to focus on the so-called unconventional reservoirs and push those. Where we've had incremental, you know, recoveries of 3, 4, 5 percent. We think we can double or even perhaps triple the recoveries in places like the Bakken in North Dakota, for example, with the introduction of carbon dioxide.

So we have similarities of the residual oil zone there. But we're pushing into areas where we have up dip water in that system. Now by introducing carbon dioxide in that system we can push the boundaries of these fields out and recover a lot more resource.

Senator MURKOWSKI. Thank you. I'm over my time.

The CHAIRMAN. Senator Udall.

Senator UDALL. Thank you, Mr. Chairman. Good morning to the panel, particularly I want to welcome Dr. Davis. It's always wonderful to have a faculty member of the esteemed Colorado School of Mines. We're very proud of the work you do. Thank you for making the trip to Washington.

Let me turn to you first, Dr. Davis, if I might. You talked about the fact that new seismic technology can be used to monitor well in completion integrity. I believe those are the terms you used.

Does that mean you can use seismic data to test the integrity of cementing and casing and could this technology perhaps be also used to monitor older abandoned wells?

Mr. DAVIS. Absolutely. We actually lower detectors down into the wellbores and do that monitoring. We can also put them, these sensors, on the outside of casing if we want. We can also do some kind of integrity measurements by just surface measurements or in what we call water holes or water wells nearby. In other words drill shallow holes and put these sensors nearby and just monitor.

So in this regard, yes. Even completion technologies right now. We're just talking about it with Mr. Hendricks here and that is that generally only 5 percent of these wells that are completed in hydrolytic fracturing are monitored. I'm forecasting that we're going to see more and more of this in terms of monitoring going forward. We have to, from an environmental point of view.

Senator UDALL. So you're saying in the context of the story even today about wells being contaminated with methane in the Marcellus area that those water wells could be monitored with these sensors as well.

Mr. DAVIS. Absolutely.

Senator UDALL. Perhaps we can get a more pinpoint accurate idea of where this methane is coming from.

Mr. DAVIS. That is correct.

Senator UDALL. Thank you. WThank you for that.

Let me turn to Mr. Banks and Ms. Epstein to talk about the Arctic National Wildlife Refuge.

I understand that in order to potentially develop oil production through directional drilling, seismic testing and the like, exploratory drilling would be necessary first. In the refuge what would this look like? How would the seismic testing and the exploratory drilling be conducted? What equipment and infrastructure would it require?

Maybe in turn you could each give your point of view to the committee?

Mr. BANKS. I thank you for the question, Senator.

Senator UDALL. If you turn on your mic that'd be great.

Mr. BANKS. Thank you. I'll try to touch on that. The—I would expect seismic activity would have to be done, of course, on the surface, just as has been described.

I also spoke about the preference of drilling vertical wells for exploration because of the timing and also the precision that we can achieve in doing so. It helps us to describe what the layer cake looks like, so to speak, to help us interpret better what the seismic is telling us. Exploration and development of ANWR, if it were to proceed, would likely occur in a step wise fashion.

There are some resources that we know of on the west side of the Canning River on State land that may extend, in fact, into the ANWR land. We don't know for sure. But that would be a likely spot to begin looking.

Senator UDALL. Miss Epstein.

Ms. EPSTEIN. I would agree with Mr. Banks about the fact that there would be surface impacts. I would like to emphasize that depending on how the seismic exploration is done those impacts could last quite a long time, decades in fact. That it does pose a concern.

I would like to follow up just briefly on Senator Murkowski's comment a moment ago about appreciation for the technological advances. As an engineer I am absolutely respectful and appreciative of technological changes that have been made over the years. Ones that have in fact, reduced environmental impact.

I would also add and I think we're all aware it's a very complex industry. There are lots of things that are going on. As essentially a watchdog on some of the nitty gritty regulatory matters involving pipeline safety in particular, and now involving offshore issues. You know, there's a lot of details in a lot of areas where we can make additional improvements. That was, sort of, the main emphasis of my testimony.

Senator UDALL. Let me ask a follow on question more broadly to both of you. I understand that extended reach drilling is being utilized on the North Slope which is, as you know, a vast area. What kind of access do the oil and gas companies have to Alaska's North Slope?

Ms. Epstein, maybe start with you and then turn to Mr. Banks?

Ms. EPSTEIN. Actually along the coast about 90 percent is available to be drilled right now. There's a mere 10 percent that's off limits. So I think that's a pretty significant statistic.

Senator UDALL. Mr. Banks.

Mr. BANKS. Senator Udall, I think the issue of how much you can reach with extended reach drilling from State lands and a figure like 90 percent. I'm not exactly sure 90 percent of what that is. Speaking to the kinds of extended reach drilling that has been extended so far.

There's still a need for manmade islands in the very near shore. Two more—most of our recent developments on the North Slope have occurred from manmade islands. In part because extended reach drilling is possible when the—and the reach that you can achieve is possible as long as the objective is deep. But in some of the most recent discoveries on the North Slope, some of those reservoirs have been rather shallow. So there is some need for access on to State lands, State submerged lands in order to develop our resources.

With respect to the activities in a place like the National Wildlife Refuge, I'm a bit—I think it's fair to say. I think the photos in my written testimony indicate that it is possible to move a drilling rig onto the surface from an ice road and an ice pad and leave the area relatively untouched when the operations are completed.

Ms. Epstein has talked about the heavy trucks that are used for seismic surveys. In fact the equipment used is designed to be able to be used in the winter time when there's sufficient snow cover and the ground is hard enough. So that in fact there is not much of an impact from those kinds of operations.

Now that has evolved over time. Early on equipment was different. But now the equipment has transformed and evolved to limit that kind of damage.

Senator UDALL. These are important questions. The committee wants to seriously consider these. I'd welcome and I know the committee would, and the leaders of the committee, additional comment before the record is closed.

Thank you for being here today.

The CHAIRMAN. Senator Portman.

Senator PORTMAN. Thank you, Mr. Chairman. I thank the panelists today. Very interesting testimony.

I come from the Midwest, from Ohio. Unlike my western and Alaskan colleagues here on the panel we're looking now with the new finds in Marcellus and Utica particularly at the possibility of drilling in some pretty densely populated areas. It creates additional challenges, as you know.

Mr. Davis or Dr. Davis, I was interested in your testimony and talking a little about some of the seismic technologies that can be used with regard to drilling. How can those technologies be used to reduce some of the footprint and some of the potential intrusion on private landowners in a place like Eastern Ohio where we have these potentially huge new finds with Marcellus and Utica?

Mr. DAVIS. One of the things that we've studied along the way are where are these "sweet spots" in these types of plays, these unconventional gas plays. We've been working in Western Colorado in the area of the Piceance Basin. There the technology, as of a few years ago, was drilling wells at ten acre spacing, 660 feet apart, vertical wells to access the resource.

Now, once we've identified the "sweet spot" with seismic techniques. We define a "sweet spot" as an area of increased productivity, higher productivity, which translates to the higher permeability in the rock, the ability of the rock to flow hydrocarbons. So we've been able to analyze that from surface seismic techniques.

Sensing those areas and then locating pads on which to drill these extended reach deviated wells, now fairly highly deviated wells, off of one particular pad. Then we'll look at now pad locations which are environmentally permitted, working with landowners and that framework and working with State regulatory agencies. That's allowed the industry to move forward in that particular area. I see that happening in areas like your homeland.

Senator PORTMAN. So instead of 660 feet what is the spacing or distance typically?

Mr. DAVIS. They are extending now over distances of a mile, for example.

Senator PORTMAN. We talked about horizontal drilling.

Mr. Davis Yes.

Senator PORTMAN. Being up to 7 or 8 miles.

Mr. DAVIS. Yes, so, you know, maybe, we'll see further separation in these pads.

Senator PORTMAN. As the Marcellus production is ramped up in Pennsylvania and Upstate New York. Both of those States have raised some environmental concerns. Ohio is starting to develop more Marcellus in Eastern Ohio and then Utica because of the incredible new technologies and therefore the new finds it looks like it could be even broader into Central Ohio, potentially and certainly up in Northeast Ohio.

What advice and maybe, Mr. Hendricks, you might have some thoughts on this or any of the panelists? But what advice would you have for Ohio as we begin our natural gas production which by the way we're very much looking forward to because it's very much tied to jobs in Ohio. We produce a lot of things that go into the drilling, the pumps, the pipes and so on. So this is something we want to be sure is successful.

What lessons can we learn in Ohio from what's happened in Pennsylvania and certainly in Upstate New York where there have been some environmental concerns raised? Can you comment on that?

Mr. HENDRICKS. So thank you, Senator. When it comes to, per say, the drilling operations and let's say the footprint of the drilling unit, you know, certainly it's up to the people of the municipality and of the State to determine how they would like this to happen. You know, we certainly encourage open dialog in this process.

We do have experience where we've drilled in suburban neighborhoods whether it's in Southern California, North Texas, Oklahoma, different places. It is possible to set up certain types of specific drilling units that are quiet. It will work daylight hours that don't take up much space.

These are all possibilities and, you know, verses what we might traditionally do in West Texas where your nearest neighbor is 50 miles away. In some places your nearest neighbor is 15 feet away. All these things have to be taken into account.

Senator PORTMAN. How about specifically? Senator Udall talked about Marcellus and some of the technology to determine where methane might be coming from. I guess there was a recent report on that.

What are your thoughts on the CO_2 emissions from particularly the natural gas drilling that might be done in connection with Marcellus or Utica?

Mr. HENDRICKS. For me specifically I'm directly involved in the drilling operations. We prepare the wellbores for what needs to be done in the completion phase. Then we take our operations and our expertise and we move on to the next well.

So by the time the well comes on production my team is usually working on drilling the next well. So I'm not directly involved in the production.

Senator PORTMAN. Mr. Banks, do you have thoughts on that? I know you're from an Alaska perspective, but you've gone through some of these same issues.

Mr. BANKS. I think some of the issues—sorry. Some of the issues that we may be dealing with will—some of the issues we may be dealing with are similar with respect to concerns about produced fluids and that sort of thing. But in Alaska these drilling fluids are ejected into approved Class Four wells. There's nothing that remains on the surface.

Like Texas there's not too many neighbors nearby and with respect to managing the kind of drill works and equipment that's used on the surface. Extended reach drilling, as I've mentioned, is extremely important for us in terms of minimizing the impact of surface access. Such that even the most recent, or one of the most recent developments of the large alpine field is not even road connected to the rest of the system in the North Slope, it sits out by itself on a fairly small 150 acre pad in an airstrip.

Senator PORTMAN. Thank you. My time is up. But I appreciate the testimony today and the technological advances, not just the horizontal drilling and not just the fracking which has been around for 50 years, I guess. But some of the refinements are really important to us in Ohio.

We're excited about the prospects of being able to develop these resources and we look forward to your continued input.

The CHAIRMAN. Thank you.

Senator Hoeven.

Senator HOEVEN. Thank you, Mr. Chairman. I guess I'd start with a question that each of you could maybe touch on. Your thoughts on how should EPA handle regulation of hydraulic fracturing. They're doing a study now.

What's the right role in terms of EPA and how should they approach hydraulic fracturing? Obviously States have primary responsibility for regulation. What's EPA's role?

Mr. Davis, do you want to start? I'm very interested in responses from Mr. Hendricks and Mr. Melzer from a private industry standpoint.

Mr. DAVIS. I'll start but to what extent I can actually comment on remains to be seen. I'm on the Science Advisory Board or panel that is evaluating the proposed plan/study of the EPA on hydraulic fracturing. Generally the framework is that, since I'm on that panel that I shouldn't comment on this while this study is underway.

So I'm going to dodge that question.

Senator HOEVEN. Ok. Mr. Hendricks.

Mr. HENDRICKS. Thank you for the question, Senator.

Senator HOEVEN. This is your chance to advise Dr. Davis.

[Laughter.]

Mr. HENDRICKS. So, you know, it's true that the hydro fracking has assisted greatly in enhancing the production of gas and oil wells in the United States. As an industry we continue to learn these lessons of what works best and the safest and best methods of doing this. We encourage open dialog and discussion.

I, per say, am not a policymaker. But we certainly, as an industry, would like to encourage, you know, the open dialog and discussion with the policymakers and the people that live in the area to continue this effort.

Senator HOEVEN. Mr. Melzer.

Mr. MELZER. Yes, sir. Thanks for the question, sir.

I am a very strong advocate of State involvement in these regulatory regimes. For reasons of balance perhaps in State employment verses the environment and there is a role for EPA I think in a regional sense. One of the factors that I tend to think doesn't get evaluated as much as it should is the specific case by cases.

When you get shallow and you get shale underlying the aquifer, that's one alarm bell that goes off. When the shale is underneath tens or hundreds of feet of salt, that alarm bell should not even be present. So I'm a very strong advocate of some criteria to establish the level of monitoring, for example, we've discussed this morning being very much site based. Perhaps EPA could play a role in that.

USGS could play a role in that. Certainly the States need to have a role in that.

Senator HOEVEN. So you are specifically commenting on the difference between perhaps the shallow gas play and a deep oil and gas play?

Mr. MELZER. Correct. Yes, sir.

Senator HOEVEN. Mr. Banks.

Mr. BANKS. Senator, thank you for the question. If I may just as an aside, I may be from Alaska but my son graduated from UND just a couple of years ago.

Senator HOEVEN. Outstanding.

[Laughter.]

Mr. BANKS. I think that the States have a particularly important role to play. I have a lot of confidence in my sister agency, the

Alaska Oil and Gas Conservation Commission in whose wheelhouse the management of oil well drilling and integrity and management falls. I think there's been a fairly long history demonstrated by that particular agency on the success of well drilling in the North Slope and elsewhere in the State. As Mr. Melzer has mentioned there are a lot of differences. Different States, different site issues that each State, I think, has a better opportunity to examine and strike the right balance.

Now I will go a little bit out on a limb. I think that one of the issues that has arisen because of say, oil shale—shale oil development, gas shale development, around the issues of produced fluids has to do with some of the fears based on lack of information. I certainly would advocate that the States, or even in Alaska, that as we move forward into a shale development, should that occur soon, that we have a better reporting for what kinds of fluids are being put into the ground so as to alleviate some of those concerns.

Senator HOEVEN. Ms. Epstein, I noticed that you'd raised your hand. So I'd better give you an opportunity to comment.

Ms. EPSTEIN. Thank you, Senator.

Just briefly, as someone who lives in Alaska and has been there for 10 years having moved there from DC. I just wanted to raise a concern of mine which is that when you have an important industry in a State there can be the possibility of conflict of interest at the State level in terms of some regulatory decisionmaking enforcement, etcetera. So I do believe that this is an important enough issue that EPA could play a strong, analytical role in terms of providing information to States.

Like Mr. Banks, I do think our Alaska Oil and Gas Conservation Commission does a good job. But they are only able to do what they have the staff and resources to do. This is—we don't have any sort of large scale gas or oil fracking going on in Alaska at this point. But it's possible we may in a very short time.

So information coming from the Federal Government and the scientists there who are putting together the report could be enormously helpful to the State.

Senator HOEVEN. You see a differentiation in the plays throughout the United States and Alaska as, I think it was Mr. Melzer pointed out, is that correct? Do you see a differentiation in how hydraulic fracturing should be handled from a regulatory standpoint based on the nature of the play or not? Do you think it's generic, a one size fits all?

Ms. EPSTEIN. There are some important similarities. I've been studying what's going on up north in terms of the potential for shale oil fracking. I've been talking to counterparts in North Dakota and trying to understand the differences and the similarities. I think there's no easy answer to that question. No black or white.

Senator HOEVEN. OK. Thank you.

The CHAIRMAN. Thank you very much. Let me ask a couple more questions.

Mr. Melzer, I asked you before about the fact that you're out of CO_2. Is the problem there that's there no production of—not adequate production of CO_2 or availability of natural CO_2 or is it a question of getting it to where it can be used? We've talked some in this committee about the need to have policies to facilitate the building of CO_2 pipelines.

Is this an issue that we need to spend time on or is this not an issue from your perspective?

Mr. MELZER. Yes, it is, sir. I think one of the issues that we'll face, as we always face, is that a lot of these resources are regional. A lot of the sources of CO_2 are regional. Sometimes those regions don't match.

You're exactly correct in that those cases pipelines will be necessary. Interstate Oil and Gas Compact Commission's report addressed this recently. I think it was published last year and looked at how to do that, how incentives might help do that.

I actually believe in more to your first part of your question that the source of CO_2 is limited today because of both the natural sources which we use are maxxed out or their pipelines serving them are maxxed out. The fact that we haven't, and we haven't as an industry or a dual industry, the surface facility industry and the subsurface industry are 2 different cultures. We're having a lot of difficulty getting those folks to work together.

They just—one of them has grown up in a utility environment and one of them has grown up in an entrepreneurial environment. It's amazing how different those groups of companies are. But we're making progress. DOE is working on that very hard.

So what we're trying to do is take the low hanging fruit on the CO_2 source which would be industrial by product like ammonia plants and the ones I've mentioned. Get those into the system to meet the needs of the EOR. Then, hopefully, down the road we'll change that gap, the cost capture and the value of the CO_2 to get the coal plants on gasification or post combustion capture perhaps will evolve to commercial operation.

The CHAIRMAN. Let me ask a different kind of question. I was visiting with a fellow who is very involved in the training of people to work in the oil field in my State. He made the point, which I thought was an interesting one. He said, you know, you can't make a living cutting people's hair in New Mexico without a license, but you can operate a drill rig without a license. Nobody requires any.

I mean the individual companies do. But there's no official requirement that anyone be trained to any particular level before they operate a drill rig. Is that an accurate circumstance as you understand it, Dr. Davis? Should it be? I mean, in Colorado, for example, where you're located are there requirements for drill operators that we ought to try to persuade other States to adopt?

Mr. DAVIS. Thank you for the question. Generally, it is true that you can, you know, go out and work on a drilling rig without any kind of training.

The CHAIRMAN. I'm not talking about working on one. I'm talking about operating one, being, the operator.

Mr. DAVIS. Yes. In terms of operations, I'm not knowledgeable about the extent, in other words, that individual States have on the allocation of, you know, training, the number of hours of training, that kind of thing. But again, as an educator I'm of course, would be in favor of that kind of a framework.

But I imagine it's going to change State by State.

The CHAIRMAN. Any of the rest of you have a comment on that or any knowledge about it?

Mr. Banks.

Mr. BANKS. As an agency that does some regulation I would say that a barber doesn't have to meet the same kind of regulatory oversight that most oil drilling operations do. In Alaska that includes not only my agency that is concerned about the effect on the land, but also from our Department of Environmental Conservation. As I mentioned before, our Conservation Commission and several other agencies, Federal and State agencies that oversee the activities of a drilling operation that are highly scrutinized by the industry.

What we do with barbers, I guess is certify them and let them go about their business and not trouble them too much after they begin.

The CHAIRMAN. But wouldn't it be wise if you've got a very complicated, risky business someone is engaged in, such as drilling a well, to have some requirements up front before they start the operation?

Mr. BANKS. Senator, I think that that is the case from a, sort of, prescriptive regulatory point of view. That does happen with drilling activities. But I think—there's room I think for oversight to include performance based kinds of approaches to the oversight of these activities. Ones in which the responsibility of managing risk, for identifying risk is made by the operator. It is up to the agencies that regulate them to then make sure that the plans and the activities that the operator chooses to employ are conducted in a way to meet and minimize those risks.

The CHAIRMAN. Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman.

A lot of information before us today. Again, I really appreciate it. Listening to the conversation about how little we really know at this moment in terms of what really is accessible because the technologies are changing. The pie just appears to be growing bigger or expanding. I think that that's a good thing for us.

It reminded me that when we were talking about production in Prudhoe Bay, some 30 years ago plus, when we first discovered oil up there. The belief was that we would be lucky. We were going to be seeing somewhere between one and 5 billion barrels coming out of Prudhoe. We're now at about 15 billion barrels that has been delivered over the course of these years and with the potential of yet more to come from that same field.

So, again, it was not because we just really, really misjudged. It's because of the technologies that allow us to access more and to access it in a way that does respect that environment, that does work to minimize that footprint. Of course this takes us back to what we discuss so often here and have for decades. That's whether or not we can successfully move to open up portions of ANWR, something that I feel very, very strongly about.

Yet we don't get credit for the fact that the technology has advanced as it has over these decades. Mr. Hendricks you introduced your son just back there. Just in the time period that he's been here what we've been able to do because of the technological advances has been remarkable.

Mr. Banks, I want to ask you. You went into some detail about how we explore up north in the wintertime. It's not because we like to explore when it's the coldest and the darkest. It's because that's when we can be most considerate of the environment. We want to do things respectfully. I think we've demonstrated that we can.

In recognizing that the legislation that I'm advancing, we've got 2 different proposals that are out there.

One says, you know, basically little to no surface occupancy. We will access using directional drilling going in to reduce that impact.

The other one says go onto to the coastal plain in the non wilderness areas and explore that way.

Mr. Banks, is there recognizing that we want to try to be good environmental stewards up there. Want to try to reduce the footprint. Could the existing well drilled at Sourdough be a logical location for us to tap in using the technologies that we've talked about here today to gain access to some of that reservoir, that resource under ANWR?

Mr. BANKS. Senator Murkowski, if I were to predict what part of ANWR would be most interesting right now to the industry it would be the Sourdough prospect. It is one that about which we know a fair amount. I believe that——

Senator MURKOWSKI. Can you describe where that is?

Mr. BANKS. I'm sorry.

Sourdough is part of the Point Thomson unit. It lies on State land just west of the Canning River which is the boundary, western boundary of ANWR in the State of Alaska. This prospect that was discovered some years ago has not been developed yet.

However, we believe that there is some potential that the prospect itself could reach into the ANWR territory. So it's a logical spot to begin looking for or for producing oil. Extended reach drilling could certainly make quite an impact on being able to drill from there.

I might also add that the well that was drilled in the 1980s by, called the KIC No. 1 well, after the Kaktovik Inupiat Corporation, the ASRC and a landowner of the area. That also could be accessed from drilling on State submerged lands in the Beaufort Sea off the coast. It's close enough, I think, using today's technologies to reach into that area.

However we don't know very much about what the prospect there looks like.

Senator MURKOWSKI. We wish that we did. We know that somebody out there knows a little bit more than you and I. Certainly wish that we could have access to that information. But again, I think it is important to recognize that we are not operating, we are not exploring and producing as we did 30 years ago when Prudhoe first came on and as we did 50 years ago in some of the other fields that you gentlemen are discussing whether it's in Texas or North Dakota or elsewhere in the Rockies.

I think, again, we need to recognize that our technologies have allowed us to do it safer, better, faster. That was the purpose of this hearing this morning. So I thank you for your testimony.

Mr. Chairman, again, I thank you for scheduling it.

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

Senator HOEVEN. I did, Mr. Chairman. Thank you.

I would like to ask members of our panel what do you think the key regulatory piece is for us, for Congress to put in place that would help produce more of the shale play, both oil and gas in a responsible way. How do we continue to develop this in a responsible way and how can we advance that ball legislatively?

In my State of North Dakota, I think we're up to about 350,000 barrels a day of—in terms of our oil production, significant natural gas as well. We expect to double that within a few years primarily out of the Bakken and Three Forks and so forth, these shale plays, where we do use hydraulic fracturing and so forth. There are other areas being developed and discovered.

So what do we do to make sure that we continue to develop this domestic production? How do we do it responsibly? What are the key things Congress needs to do? I start with Mr. Hendricks and Mr. Melzer, but give anybody, give everybody an opportunity to respond.

Mr. HENDRICKS. You know, certainly from a drilling standpoint, you know, we're all very aware and sensitive to how busy things are in North Dakota between Williston and Minot especially and the number of active rigs that are there. For our standpoint, as an industry, when we want to be able to minimize the footprint and the impact that we have in the area, we know that it's good farmland and we want to make sure that we're protecting that going forward.

So we want to continue, as industry, to work together with government, local and State, to make sure that we have the best outcome for everybody.

Senator HOEVEN. Is there only one key piece of legislation you'd like to see that would help?

Mr. HENDRICKS. Uh.

Senator HOEVEN. Or just generically what would help?

Mr. HENDRICKS. That's a very fair question, but unfortunately I'm not sure that I'm in the best position to answer that.

Senator HOEVEN. Alright.

Mr. HENDRICKS. But again, you know, as an industry we certainly want to proceed with that dialog.

Senator HOEVEN. Mr. Melzer? I mean, are there some key things that would help advance the ball?

Mr. MELZER. Thinking back, I'm fairly familiar with what is going on in North Dakota through the Pikor Group out of Grand Forks. I think I would say that the primary facilitators have been put in place. I guess I'm not seeing any holes.

We've got one in Texas we've got with unitization. It's a real obstacle in our State. But you don't have that.

So I'm at a loss to say that there's something that really has to be put in place to maximize your recovery.

Senator HOEVEN. So that Isla Barro and some of these other new possibilities, you think, can move—Colorado can move forward and get developed under the current legal and regulatory regime?

Mr. MELZER. I believe so, sir.

Senator HOEVEN. Alright.

Mr. Davis.

Mr. DAVIS. Yes, I guess my point here is that again with the framework of primary recovery we're going to only access so much of the resource. But as we go forward we're going to have water flooding, secondary recovery in the Bakken and in the Niobara and in these other places. But we're going to eventually have to move very quickly I think to enhanced oil recovery.

In doing so we're going to be able to amazingly change the economics here. We've been involved with some of the monitoring north of the border, right in the Manitoba/Saskatewan.

Senator HOEVEN. The Wayburn Field?

Mr. DAVIS. In the area of Sinclair Field. This field operated by tundra exploration out of Calgary. Just the injection of CO_2, even though it's far removed, they've been able to have industrial sources of CO_2 injected. We've been monitoring that injection. We've been doubling and tripling the production of those wells.

So the framework, I guess from a governmental point of view is enhancing the availability of the CO_2 perhaps not necessarily through regulatory agencies and that, but in just some kind of incentive that would allow us to capture the CO_2 and be able to use it in these resource plays could have a tremendous uplift.

Senator HOEVEN. I think that it has tremendous potential particularly because of the convergence with CO_2 capture and carbon sequestration. We're already doing some of that. I'd be intrigued if you have some ideas I'd sure like to see them in that regard as far as incentives that might work.

As you know we're a little budget challenged around here.

Mr. DAVIS. Yes.

Senator HOEVEN. So incentives that pay for themselves are the ones that probably stand the best chance to advance. But I'm interested in those ideas.

Mr. DAVIS. There's been, you know the cap and trade and that kind of thing. But again whether that goes to different States or how that's managed. Again just some incentives that could be to capture the CO_2 and use it, not just store it, I think would be very, very helpful.

Senator HOEVEN. I want to give the others an opportunity.

Mr. Melzer, did you have something else to add, though?

Mr. MELZER. Yes, sir. In that vein I think there's ideas floating around for a tax credit that would do exactly what Dr. Davis is talking about. I actually look at that and think that would close this gap. It's really not related back to your shale question so much as it is the EOR question and carbon capture and storage.

So I really would encourage people to look at that proposal that's going around.

Senator HOEVEN. Mr. Banks or Ms. Epstein.

Mr. BANKS. Senator, I already mentioned that I thought that better information about what kinds of products are being used in hydraulic fluids as they are used might help to relieve some concerns. Because I think a good deal of what's being injected in the ground is actually benign. I also mentioned too that I think in terms of managing for shale development the States are uniquely positioned to manage for that.

I'd also say that I'm a little bit Alaska centric while there's still a lot of oil to be produced off from State land and around the existing infrastructure in the North Slope, most of the undiscovered potential lies outside of that area and on Federal lands. It's not a question so much of how much oil there is, but what kind of rates we can achieve so that the TAPS pipeline can remain operational and run successfully for a lot longer time. So that's of a very important matter for us.

Senator HOEVEN. What's the capacity on the pipeline?

Mr. BANKS. The pipeline when it was fully used or I should say at peak throughput was 2.1 million barrels today in 1989. Today it's down to 640,000 barrels a day.

Senator HOEVEN. Ms. Epstein.

Ms. EPSTEIN. Yes, thank you.

I've spent my career trying to bring the laggards within the oil and gas industry up to the level of leaders. Which I think is incredibly important in terms of increasing the public's confidence in the industry itself. To answer your question, I would say that the targeted changes that Congress could make that would absolutely increase the public's confidence in the industry are—include potentially getting rid of the exemption that was created in the Energy Policy Act to the Safe Drinking Act that allowed fracking to move forward.

If that was removed again, basically reverted back into what it used to be, you know, all of a sudden there will be increased confidence that drinking water would be protected, the well design requirements of the Safe Drinking Water Act would be in place. Then I do also agree that disclosure seems to be incredibly important to the public of fracking fluids. That's not, you know, in some sense a regulatory requirement. It is, in fact, just shining some sunshine onto what's going on.

Then the discussions around that can take place. Those that are doing something that's different than what the leaders are doing will become apparent. That would be helpful.

Senator HOEVEN. I want to thank the panel. Mr. Chairman, thank you.

The CHAIRMAN. Let me thank all of you for your testimony today. I think it's been very useful. We appreciate it.

That will conclude our hearing.

[Whereupon, at 11:35 a.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Questions

RESPONSE OF KEVIN R. BANKS TO QUESTION FROM SENATOR BINGAMAN

Question 1. As a regulator for Alaska—do you feel that there are adequate safety and oil spill prevention and mitigation technologies available for E&P operators and drillers in the advent that a blowout or some other type of oil spill should occur onshore in arctic areas?

Answer. Since the Exxon Valdez oil spill, oil spill response planning and equipment staging and availability have improved dramatically. As a direct result of the State's oil spill response program outlined in AS 46.04.200, the Alaska Department of Environmental Conservation, (ADEC) develops, annually reviews, and revises, as necessary, the State Oil and Hazardous Substance Contingency Plans (Unified Plan and Subarea Contingency Plans). These plans address all oil and gas related contingency planning activity in the state. The Unified plan is a coordinated and cooperative effort by government agencies and was written jointly by the Alaska Department of Environmental Conservation, the U.S. Coast Guard and the U.S. Environmental Protection Agency. The Unified Plan is then divided into 10 Subarea Contingency Plans (SCP) that concentrate on issues and provisions specific to that region or subarea.

As identified in the Unified Plan, ADEC, as the State of Alaska's lead agency for responses to oil and hazardous substance spills, has developed a network of response equipment packages positioned in at-risk areas throughout the state.

ADEC also requires that all municipalities, operators of facilities and private owners be able to respond to spills and must itemize all spill response equipment required in their respective spill response contingency plans. Through the Unified Plan and the Subarea Contingency Plans, the ADEC has a comprehensive list of spill response equipment available to be deployed throughout the state.

In the North Slope subarea specifically, BPXA, ConocoPhillips Alaska and other companies operating in the North Slope oilfields have a substantial amount of spill response equipment, as identified in their respective contingency plans. In the event of a spill in this area, the industry spill response cooperative, Alaska Clean Seas, would provide much of the required response equipment and personnel. Industry equipment would also be utilized, especially when the company is identified as the responsible party for the spill.

While appropriate response equipment is staged throughout Alaska and the North Slope, due to its vastness and sometimes extreme weather conditions, there is always the logistical challenge of getting the right piece of equipment to the right location at the right time.

RESPONSES OF KEVIN R. BANKS TO QUESTIONS FROM SENATOR MURKOWSKI

Question 1. As you are aware, there has been a strong effort to find new sources of oil to keep the Trans-Alaska Pipeline System operating at sound levels. With Prudhoe Bay, Alaska has a super-enhanced oil recovery operation because so much gas is being re-injected into that huge field.

a. Can you address how Prudhoe was originally estimated to be maybe one third its size or less, and how much greater the recovery has been as technology has advanced?

Answer. A reference to Alaska Department of Natural Resources (DNR) report from January 1982—TAPS start up was June 1977—estimated that the Prudhoe

Bay, Sadlerochit reservoir in 1980 contained 7.8 billion barrels of recoverable oil. (DNR January 1982. Historical and Projected Oil and Gas Consumption) The most recent report published by DNR says that by the end of 2009, the Prudhoe Bay Unit produced 12.6 billion barrels of oil and still had remaining reserves of 2.4 billion-a total of 15 billion (DNR 2010 Annual Report). Total production to date from all of the fields on the North Slope exceeds 16 billion barrels.

This growth of the Prudhoe Bay field over time can be attributed to two causes: technological advances in recovery methods, and the fact that as drilling progresses, additional reserves were added with discovery and development of over-and underlying horizons, and around the periphery of the field.

Question 1b. Can you describe the progress that has been made, through the use of modern technologies, in shrinking the footprint for drilling areas, roads, and other facilities?

Answer. In my written submission to the committee I provided several examples that show how the drilling technologies, including especially the use of extended reach drilling has significantly reduced the size of drill sites on the surface and the number of drill sites required to reach the oil reservoirs underground. To illustrate the point, one of the earliest drill sites built in the in the 1970's at Prudhoe Bay (DS-1), covered 65 acres of tundra. Well spacing, the distance between the well heads on the site, was 160 feet. Each early Prudhoe Bay drill site could accommodate 25-30 wells. These wells could be deviated from vertical only about a mile.

The Alpine field (the Colville River Unit) is a recent example of how far the technology has advanced to reduce the industry's onshore footprint. The typical Alpine drill site is only 13 acres and supports 54 wells. Extended reach drilling means that the wells can reach four miles from vertical and intercept 50 square miles of the reservoir from a single location on the surface. Alpine is also the first oil field on the North Slope that is not supported by a year-round road. During the winter, the operator builds an ice road to the central Alpine facility and equipment is staged there for summer work. Operations during the summer months are supported by air.

Question 2. Is it fair to say that the technologies born in Alaska have grown out of necessity? In other words, has the combination of strict environmental laws and the economic considerations of not wanting to drag many new rigs and new equipment that great of a distance caused a natural inclination to make the most of seismic data, shrink footprints, reach further from one pad, and try to squeeze as much from one well as possible?

Answer. Yes, it is fair to say that these technologies have been born out of necessity. We would add that the driving forces behind technological advancements reflect regulatory insistence and industry commitment to maximize economic benefit and recovery while minimizing the development footprint. It has been necessary to engineer the development of smaller fields at reduced costs, adopting more innovations to increase recovery efficiency, both at the level of individual wells and entire fields.

The fact that the in-place oil volumes in several of the North Slope's largest fields (Prudhoe Bay, Kuparuk, and the various heavy oil reservoirs) are so enormous means that the economic return associated with increasing total recovery by even 1-2% is worth major investments in new technologies that make that additional recovery feasible. On the other hand, many of the North Slope's smaller fields face major economic challenges that were mitigated in large part by technological advances and efficiencies that originated in the giant fields nearby.

The following are examples of some of the many technologies that have been created or refined in developing the major oil fields of the North Slope:

Technology	Impact
Extended reach drilling	Dramatically fewer surface pads needed to access reservoir.
Horizontal/designer wells	Improves reservoir drainage relative to vertical wells.
Coiled tubing drilling	Reduces noise, fuel consumption, emissions, cost, surface area.
Multi-lateral drilling	Drains more of reservoir per surface well location.
Grind-and-inject	Zero surface discharge of drilling wastes.
Reservoir modeling	Models oil-in-place, drainage, injection, pressure, etc. in 3-D over time.
WAG, MWAG, MI, etc.	Enhanced oil recovery methods, beyond simple waterflooding.
Gas cap water injection	Stabilizes reservoir pressure, increasing oil recovery.
Gravity survey surveillance	Monitors movement of reservoir fluids over time.
3-D and 4-D seismic	Sharper imaging of reservoir compartments, fluid movements, etc..
BrightWater EOR treatments	Improves waterflood efficiency by blocking off thief zones.
Low-salinity water injection	Liberates oil molecules bound to clay particles in the reservoir rock.
Heavy oil extraction methods	Several different methods in development to enhance recovery, depending on reservoir temperature, oil viscosity, etc..

a. Would the other witnesses like to comment on the Alaska experience and how it's allowed operations elsewhere to advance?

Question 3. Some have suggested that the Trans-Alaska Pipeline System is perfectly capable of operating soundly until mid-century, even with no access to federally controlled oil deposits. As one of the State's leading oil experts, can you describe the throughput decline of TAPS and what it will take to maintain its operation through that point in the future?

Answer. TAPS was originally designed to move about 1.5 million barrels per day. Throughput peaked at 2.03 million barrels per day in 1988-a rate achievable with the application of drag reducing agents and other improvements. Throughput has declined in all but two years since 1988. Current throughput is about 0.6 million barrels per day. Most forecasts show continued decline into the future.

The TAPS line has already begun to be impacted by lower throughput. During the shut-down in January 2011 (leak at Pump Station No. 1), there was concern about being able to restart the line due to the temperature. TAPS will have some material operational issues as the flow rate reaches 0.3 million barrels per day. The operational issues are primarily related to the temperature of the crude as it moves through the pipeline. With less flow and without mitigating investments, the temperature may fall below 32 F. Lower temperatures may allow ice to form inside the pipeline that could damage equipment and cause possible frost heaving on buried sections of the pipeline route. Lower temperatures will also lead to more build-up of wax on the inside of the pipeline, and increase the viscosity of the crude moving in TAPS.

More than 99% of TAPS throughput comes from fields on State or Native lands or from State waters. Production from Federal lands and the OCS today amounts to less than two thousand barrels per day.

With the exception of development of the heavy oil resources known to exist around the Prudhoe Bay, Kuparuk, and Milne Point fields, and potential resource plays (like the Bakken in North Dakota) that may exist on the North Slope on State controlled lands, the natural field declines cannot be replaced without access to production from Federal lands and the OCS. There are no known conventional resources on State or Native lands that are likely sufficient to replace the decline in the existing production rates.

Conoco-Phillips and Anadarko want to expand the Alpine field by developing a new drill site (CD-5). New production would come from State, Native, and Federal lands (~60 miles west of TAPS). This development is on hold awaiting permits from the Corps of Engineers to allow construction of a bridge over the Colville River. The permit was first requested in 2005. Development in the National Petroleum Reserve Alaska (NPRA) can only proceed once the Alpine bridge over the Colville River is complete. Thankfully, the Administration has proposed having lease sales in the NPRA annually. We hope that these sales will be accompanied by a willingness of federal agencies to allow permits for development (e.g., CD-5 project) and that lands with high resource potential (e.g., north of Teshekpuk Lake) can be made available for leasing with appropriate environmental safeguards.

There are current plans to develop an oil and gas field on State lands at Point Thomson (Miles east of TAPS). Development at Point Thomson has also been delayed due to Corps of Engineers permitting issues. Development of resources at Point Thomson would extend the feeder lines for TAPS about 30 miles east of the Badami field. This would lessen development costs and could lead to development in this relatively unexplored area. It is also at the boundary to ANWR and the 1002 area.

Question 4. Can you talk about the new technologies we're hearing about in terms of allowing for development of an area where the law doesn't currently allow for conventional access? In other words, are there applications for this technology that would provide an opportunity to extract resources from the 1002 area subsurface without having any permanent or significant impacts on the surface area?

Answer. Although it remains unclear how far, if at all, the Sourdough or Pt. Thomson reservoirs discovered on State leases near the Canning River delta might extend beneath the 1002 area, there is the potential that extended reach drilling could at least partially develop these reservoirs. Without more detailed subsurface data on these and other prospects along ANWR's western border and along the coastline adjacent to state submerged waters, it will not be possible to accurately evaluate how much of these reservoirs would benefit from extended reach drilling techniques. Three-dimensional seismic acquisition and near-vertical exploration and delineation drilling would have to occur inside the 1002 area. These activities can be conducted in the winter with zero or minimal permanent surface impact. Allowing these activities would help answer the question of whether how much oil extended-reach production wells drilled from outside ANWR would be economically viable.

Responses of Thomas Davis to Questions From Senator Bingaman

Question 1. Are there recent advances that will help reduce the footprint of seismic activities in environmentally sensitive areas, both in terms of active seismic data acquisition and passive?

Answer. Yes, major advances have occurred with the advent of wireless seismic technology and increased sensitivity and numbers of seismic sensors. Wireless recording systems now leave only human footprints in terms of placement of recording systems. The weight and power consumption of these wireless recorders is such that a person can carry several devices and plant them in environmentally sensitive areas provided they are accessible to humans. There has been recent experimentation with dropping these devices from helicopters as well, but retrieval remains an issue. These devices can record up to a month without being serviced. They contain GPS receivers and the clocks in the devices are synchronized and are highly accurate. The devices can be placed in active recording mode to record generated sources from hydraulic vibrators, weigh drops, or dynamite, for example. They can also be placed in continuous recording mode when the intention is to record passively the natural seismicity or induced seismicity, for example, from drilling or completion operations.

Question 2. Have there been any recent advances in downhole seismic instrumentation that allows an operator to see further into the formation from the wellbore to areas that may not have been adequately imaged using conventional 2-or 3-Dimensional seismic data?

a) Or to areas that cannot be accessed at the surface due to environmental sensitivities?

b) In other words, is there a borehole version of conventional seismic?

Answer. Yes, major advances have occurred in downhole seismic recording technology as well. We have developed capabilities to record with borehole arrays of receivers spanning different intervals and within different wells. The closer we can get to the formation the higher the definition that can be achieved. Fiber optic links to the sensors result in greater bandwidth and recording capacity. New fiber optic sensors are being deployed as well. Slimhole drilling devices are being used to embed arrays of sensors in the subsurface for permanent monitoring if wells are not accessible for installation of receivers. The distance can seismic events can be reliably detected varies dependent on area and background noise conditions. Generally distances are limited to less than one-mile between source and receiver. A personal preference is to record both surface and downhole arrays simultaneously. In some instances we can place vibratory sources or airguns in wells and record the wavefields in other boreholes and on the surface. Drill bits can also be used as active sources for wavefield imaging. Downhole seismic recording independently is more expensive and time consuming than surface seismic recording. As a result, there is less demand in the industry for this service. It is gaining momentum, however, as more companies are seeing value in monitoring hydraulic fracturing operations, for example.

RESPONSES OF THOMAS DAVIS TO QUESTIONS FROM SENATOR MURKOWSKI

Question 1. Can you talk about the new technologies we're hearing about in terms of allowing for development of an area where the law doesn't currently allow for conventional access? In other words, are there applications for this technology that would provide an opportunity to extract resources from the 1002 area subsurface without any permanent or significant impacts on the surface area?

Answer. Oil and gas resources still need to be accessed by well drilling. Other than extended reach drilling there is no other means that can be used to access resources under environmentally sensitive areas. Targeting these resources more precisely prior to or during drilling operations is a prudent operational procedure. Seismic while drilling offers a "look ahead" procedure to optimize target specific drilling objectives. In this instance the drill bit is used as the source and receivers are placed in the drilling assembly.

Question 2. Judging by your location I'd guess that a lot of the field work you're doing with seismic is in the Rocky Mountain region. There are obviously some sensitive areas adjacent to the oil reservoirs which you've worked to explore. What kinds of precautions are necessary to minimize the impacts of seismic work on a landscape, and do you consider these operations to be unnecessarily impactful on wildlife?

Answer. We have conducted seismic operations in various areas in the US and Canada and have worked in environmentally sensitive areas in the Piceance Basin of Northwest Colorado and more recently in northeastern Louisiana. As a landowner and farmer I treat every area as environmentally sensitive. I spend a great deal of my time speaking with landowners in designing the surveys we conduct to assure minimal environmental impact. There is little reason to believe that seismic operations cannot be conducted in an environmentally responsible manner especially with the advent of wireless recording systems. We work closely with all of our stakeholders to assure environmental preservation and conservation associated with our time-lapse operations. Knowing that you are coming back to an area time and time again means that you are truly a stakeholder in dealing with all aspects of the process. Proper pre-planning and coordination is essential along with on-site monitoring. In the Piceance Basin operations in 2003-2006 we have hired a wildlife specialist to monitor the influence of seismic operations on wildlife. We timed our operations to have minimal impact on wildlife, the operator, and landowners. We observed that there was little or no impact on wildlife due to our seismic operations and our wildlife specialist confirmed this observation. Minimizing the number of "moving parts" on a seismic crew operation is essential to operating in an environmentally responsible manner.

Question 3. Thank you for your testimony. Mr. Melzer's chart on page 8, showing the third and fourth production peak at about 60 and 80 years after an oilfield has been developed. Combined, those third and fourth heights of production are more than the main (secondary) production peak. That certainly fits with Mr. Melzer's other chart , showing the huge increase in EOR activity in the US and worldwide.

Answer. We now realize the importance of oil and gas fields as "assets" that require responsible management. Asset teams of geoscientists and engineers have been created to manage the life-cycle of these resources. There is no question that many of these peaks are related to employing new technologies in accessing new reserves in old fields. The fundamental cause of our inability to access more resource in the past has been the reservoir heterogeneity. New drilling and completions technologies, EOR, and seismic monitoring have helped us increase the recovery factors in many of our fields substantially. These efforts are important to our country and to the world.

Question 4. So, are we doing an adequate job as a government in identifying what our true resource potential is? To clarify, is there an issue with the characterization that the US has only 2 percent of the world's oil reserves, in that it doesn't take into account unexplored areas, and it apparently doesn't take into account what impact EOR could have on current estimates?

Answer. I believe that there is substantially more resource that is recoverable from mature fields and we are demonstrating that hypothesis. I also believe that more effectively exploration will be conducted in the future to access new reserves. Technology is key and educating people to use that technology wisely is key as well. There is an old adage that oil is found in the minds of men and women and to a large extent I believe that to be a fundamental truth. I have the responsibility as an educator to help champion that cause. I don't believe we are running out of oil. At times we tend to run out of ideas, but it is up to us to change the ideas and to challenge dogma. I try to do that through emphasizing the development of new technologies and employing these technologies where it can make a difference. We are seeing vast new reserves emerge from unconventional resources, EOR, etc. In addition, we have vast resources to access in remote areas and at greater drilling depths provided we can handle the environmental challenges that are associated. The key to meeting these challenges is working together to bring innovation through education. I welcome the opportunity to serve in this capacity and appreciate your insightful questions in this regard.

RESPONSES OF LOIS EPSTEIN TO QUESTIONS FROM SENATOR BINGAMAN

Question 1. You mentioned hydraulic fracturing as it relates to Alaska and unconventional oil shale development similar to that of the Bakken in North Dakota. You state that there is great potential for this resource, but development should be handled with care and good environmental planning. What, in your view, would that entail?

Answer. Hydraulic fracturing (or "fracking"), whether of shale oil or shale gas, can have the following adverse environmental impacts if not well-regulated and done in a compact fashion:

1. Contamination of groundwater that may be used for drinking water and other purposes with methane and/or fracking fluids which can contain toxic chemicals;
2. Contamination of surface water from fracking wastewater or drilling wastes including drilling muds which can contain toxic chemicals;
3. Groundwater flow or surface water quantity changes, with associated ecosystem impacts, due to the large quantities of water needed for fracking operations;
4. Wildlife habitat disturbance and destruction from the presence of fracking operations and associated pipelines, roads, and related infrastructure; and,
5. Conventional health-related air pollution[1] and greenhouse gas pollution1 from fracking operations and associated pipelines, roads, and related infrastructure.

In addition to environmental impacts, typically there are adverse social impacts associated with rapid industrialization (e.g., communities can become unaffordable to long-time residents), increased local drinking and crime,[2] and lowered quality of life due to nearby industrialization including additional traffic, traffic accidents, road and bridge deterioration, school crowding, and noise.

Both the federal and state governments can and should play a role in regulating hydraulic fracturing. For decades, the federal government has employed its scientific and technical expertise—which states often are lacking—to develop requirements that protect surface and groundwater under the Clean Water and Safe Drinking Water Acts. There should be no unique exceptions to this framework for fracking operations, especially if we want to restore confidence in governmental oversight of this industry. This means that the Energy Policy Act of 2005 exemption from the

[1] A recent Cornell University study showed that shale gas development results in significantly more greenhouse gas generation than conventional natural gas production, "Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations," Bob Howarth, et al., Climatic Change Letter, 2011, see http://graphics8.nytimes.com/images/blogs/greeninc/Howarth2011.pdf.

[2] Jacquet, J. 2005. Index Crimes, Arrests, and Incidents in Sublette County 1995 to 2004: Trends and Forecasts. Report Prepared for Sublette County Wyoming.

Safe Drinking Water Act for fracking wells needs to be repealed to help ensure well integrity. Likewise, federal requirements for uniform disclosure of fracking fluid chemicals would be appropriate as a baseline that could be added upon by states, rather than having each state develop its own chemical disclosure standards and format. State-level regulatory oversight could include areas where state-specific conditions might result in a need to exceed federal requirements (e.g., requiring zero-discharge of wastewater to the surface through mandatory use of wastewater injection wells) or areas where the federal government has not acted (e.g., well-spacing and well-pad requirements to limit adverse effects on habitat). Governmental oversight also must include sufficient and effective enforcement of federal and state requirements. Federal and state enforcement personnel need adequate funding and the will to ensure widespread compliance or compliance will not happen uniformly. Strong governmental regulations are not valuable unless they are enforced.

Question 2. Is it possible to do all aspects of oil and gas exploration and production through directional drilling or does the initial exploration to identify the resource require surface occupancy above the oil or gas reservoir? Is surface occupancy required for other purposes?

Answer. It is not possible to conduct all aspects of oil and gas exploration, development, and production solely through directional drilling. Seismic activities (which provide information about the subsurface using sound waves) and exploratory well drilling take place directly on the surface above oil and gas reservoirs. As discussed in my May 10, 2011 testimony, directional drilling for oil has adverse impacts that are essentially no different than conventional oil drilling (with the single exception being reducing the number of well pads required to access oil deposits).

Seismic activities involve convoys of exploration vehicles traveling over extensive areas. In the Arctic, large seismic vehicles crisscross over a fragile tundra ecosystem. Longterm studies have documented severe impacts from seismic trails to tundra vegetation and permafrost lasting over 20 years.[3] Newer 3-D seismic surveys involve more vehicles in a very tight grid profile with a line spacing of a few hundred meters, resulting in greater surface disturbance of vegetation, bears in dens, and other wildlife. Although seismic exploration would only be conducted in winter in the Arctic, snow cover on the Arctic National Wildlife Refuge's coastal plain, for example, often is shallow and uneven, providing little protection for sensitive tundra vegetation and soils. The impact from seismic vehicles and lines depends on the type of vegetation, the texture and ice content of the soil, the surface shape, snow depth, and the type of vehicle.

According to the U.S. Fish and Wildlife Service's webpage discussing the potential impacts of proposed oil and gas development on the Arctic National Wildlife Refuge's coastal plain, "Current seismic exploration methods require numerous vehicles to move in a grid pattern across the tundra. Maternal polar bears with newborn cubs can be prematurely displaced from their winter dens by the noise, vibrations and human disturbance associated with oil exploration activities. This displacement may result in potentially fatal human-bear conflicts, and may expose the cubs to increased mortality due to harsh winter conditions for which they are not yet prepared."[4]

As discussed by Mr. Kevin Banks of the Alaska Department of Natural Resources during the May 10, 2011 hearing, companies likely would not use directional drilling for exploratory wells because doing so would provide less technical information about subsurface conditions. Exploratory well drilling requires the use of large drill rigs on gravel and the building of associated transportation infrastructure (potentially helicopter or aircraft access), drilling mud/waste infrastructure, and human-support facilities. If ice is used instead of gravel for foundations, there will be water withdrawals from lakes, rivers, or constructed reservoirs. Note that there's insufficient winter water in the Arctic National Wildlife Refuge's coastal plain to assist in drilling operations.[5]

Statements that claim exploration can be conducted in a way that would leave "no trace that we were ever there" are simply not true. In the Arctic National Wildlife

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[3] Jorgenson, J.C., VerHoef, J.M., and Jorgenson, M.T. 2010. Long-term recovery patterns of arctic tundra after winter seismic exploration. Ecological Applications, 20(1): 205-221 (long-term studies of impacts from the onetime seismic exploration surveys mandated by Congress in the 1980s).

[4] See http://arctic.fws.gov/issues1.htm#section4 (accessed May 25, 2011).

[5] U.S. Fish and Wildlife Service, 1995. A preliminary review of the Arctic National Wildlife Refuge, Alaska, coastal plain resource assessment: report and recommendation to the Congress of the United States and Final Legislative Environmental Impact Statement. Anchorage. This report concluded, "Additional investigations since 1987 substantiate the fact that water in the [coastal plain] area is very limited and the impact upon water resources should be considered major."

Refuge's coastal plain, exploration would cause severe and long-lasting damage to tundra and permafrost and would disturb the very wildlife and wilderness that the area was set aside to protect, such as denning polar bears and the Porcupine caribou herd which calves there.

Question 3. Would you expand upon your testimony about current technology for directional drilling to explain the distances over which directional drilling is currently possible? Are there examples of current projects that demonstrate the state of the art for this technology?

Answer. According to BP, the company will use directional drilling (angled drilling) along with horizontal drilling to reach up to eight miles to the Liberty reservoir,[6] resulting in "the longest extended-reach wells ever attempted."[7]. BP has had technical problems completing Liberty's extended-reach wells, however, with multiple postponements of the proposed dates of operation.[8] Currently, BP is undergoing a "design and engineering review to evaluate the project's safety systems."[9] There are significant technical challenges that need to be overcome before extended-reach drilling will extend beyond a small number of miles, i.e., approximately two to four miles.

Appendix C of the Cook Inlet (Alaska) Best Interest Finding regarding the 2009 Cook Inlet Areawide Oil and Gas Lease Sale, developed by the State Department of Natural Resources Division of Oil and Gas, provides factual information on the limitations of directional and extended-reach drilling including the significant additional costs involved compared with conventional drilling.[10] This document shows a maximum horizontal departure of approximately 4 miles; as of June 2009, however, only one well on the North Slope exceeded 4 miles, and just barely at 4.025 miles.[11] Fewer than 2% of the North Slope wells extend horizontally more than 3 miles, while 94% of the wells extend less than 2 miles from drill rigs.[12] Even at ConocoPhillips' Alpine oil field, often touted for its use of directional drilling, the average horizontal distance drilled is only 1.74 miles.[13]

In 2009, The Wilderness Society produced its Broken Promises report. Chapter 3, attached, is entitled "Directional Drilling is no Panacea" and provides additional information on the limitations of directional drilling. Key limitations are financial, as discussed above, and geologic. In some locations, directional drilling is not possible geologically due to, for example, unstable shale which could collapse drill holes, conditions that are present near the Alpine field on the North Slope.[14]

RESPONSES OF L. STEPHEN MELZER TO QUESTIONS FROM SENATOR BINGAMAN

Question 1. You explained the role of CO_2 in the next generation of enhanced oil recovery. Has the more widespread use of CO_2 led to a decrease in the other types of enhanced oil recovery that has been used—such as the use of solvents or surfactants?

Answer. Each of the enhanced oil recovery (EOR)[1] methods has developed somewhat independently in their applications to various types of oil and reservoirs. For example, steam injection has had widespread application in shallow depths for heavy oils (San Joaquin Valley in CA as the best example). Carbon dioxide (CO_2) works best on lighter oils and at deeper depths so the processes have not competed. Chemical EOR (ChEOR) such as surfactants (also alkaline and polymers) could have

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[6] Reaching Out to Liberty, BP, undated, p. 2, see http://www.bp.com/liveassets/bp__internet/us/bp__us__english/STAGING/local__assets/downloads/l/final__liberty70808 .pdf.

[7] "Liberty well," BP Magazine, Issue four—2009, see http://www.bp.com/sectiongenericarticle.do?categoryId=9031686&contentId=7058099.

[8] "BP's Liberty project delayed again," KTUU-TV, February 1, 2011, see http://www.ktuu.com/news/ktuu-bp-oilrig-in-beaufort-sea-postponed-again-20110201,0,3719434.story.

[9] Ibid.

[10] Final Best Interest Finding, 2009 Cook Inlet Areawide Oil and Gas Lease Sale, January 20, 2009, Appendix C: Directional and Extended-Reach Drilling, see http://www.dog.dnr.state.ak.us/oil/products/publications/cookinlet/ciaw__2009__final__finding/CI%20PrelimBIF%20AppC.pdf.

[11] Alaska Oil and Gas Conservation Commission well database. Data analyzed by Doug Tosa, Alaska Center for the Environment, using known tophole and bottomhole latitude/longitude locations of 5,549 completed wells. Data retrieved June 16, 2009. See http://wilderness.org/files/Broken-Promises-3.pdf.

[12] Ibid.

[13] Ibid.

[14] The Wilderness Society. 2009. Broken Promises: The Reality of Oil Development in America's Arctic (2nd Edition), Chapter 3, p. 13, see http://wilderness.org/content/broken-promises-reality-oil-development-americasarctic.

[1] Industry often uses the terms "enhanced oil recovery" and "flooding" interchangeably

competed with the same reservoir and oil types as CO_2 but widespread application of ChEOR has never taken off. Some excitement exists out there for today but much of it seems to be concentrated in reservoir depths too shallow for miscible CO_2 applications (generally around 2500-3000' depth) or where affordable CO_2 is not available.

Other historically utilized methods of EOR are hydrocarbon miscible gas flooding (HCMF) and Nitrogen EOR (N_2EOR). HCMF injects an injectant (methane + ethane + Butane . . .) that has significant market value. The most common application for HCMF has been in Alaska and Canada where it was impossible to get the gaseous hydrocarbons pipelined to a market. Therefore, the produced gas was reinjected to maintain pressure in the reservoir and perform the sweep of the liquid commodity, crude oil. As the pipelines for natural gas developed in Canada, the HCMF process lost its commercial appeal and possible new flood applications opted to sell the gaseous products. The number of active HCMF projects are very close to nil today except for the North Slope of Alaska.

N_2EOR works in a miscible process only at much deeper depths than does CO_2 EOR. The depths are generally in excess of 9000'. The advantage of N_2EOR is that an air separation unit can be collocated at the field and the injectant, nitrogen, extracted from air, thus requiring no long distance N_2 source pipeline. Mexico employed N_2EOR at their Canterell offshore field in Mexico and Exxon employs it at their Hawkins field in East Texas. New reservoir applications are fairly limited and CO_2 has effectively displaced N_2EOR as the flooding technique preferred by industry in light oil reservoirs.

Question 2. Can you discuss briefly the volume of water that is generally used in a waterflood prior to utilizing CO_2? What happens to the wastewater from a waterflood? Is the water reclaimed or reinjected into a disposal well? What volume of CO_2 is being utilized annually for CO_2 EOR on a per field basis?

Answer. The easiest way to visualize the volumetrics of injectant utilized during waterflooding or in EOR is to think of it in the sense of maintaining a volume (pressure) balance within a reservoir. For example, if a reservoir is producing 1000 barrels[2] of oil per day, the oil company will want to replace the produced volume of oil with a substance so as to maintain the reservoir pressure. Hence, in a waterflood, 1000 barrels of water per day will be injected. And, over the life of the reservoir, the cumulative volume of produced oil will have seen about that much "new" water introduced into the reservoir. Confusion often arises from the fact that the normally reported injection volumes are total injected barrels which does, of course, include the produced (or recycled) volumes of water plus what we call the new (aka "make-up") barrels. As mentioned in my earlier testimony, the new water injected today is generally brackish water, sea water, or formation water from deeper formations and not from an Underground Source of Drinking Water (USDW). Some exceptions to that rule are present today but not many.

The wastewater in a waterflood is reinjected since the flood operator needs the water to return to the formation in order to maintain reservoir pressure. When a new CO_2 flood is implemented, we are effectively replacing formation water and oil with CO_2. So there is some wastewater in CO_2 flooding. That water is handled in one of two fashions: 1) injected into a deep disposal well or 2) reinjected back into the reservoir being CO_2 flooded in what we like to call our water-alternating gas (WAG) process where water is used intermittently to assist the CO_2 in spreading out within the reservoir.

As to the question related to the average size of CO_2 injection volumes on a field basis today, probably the best way to answer is to use the total volumes of CO_2 being purchased today and the number of active fields under flood. According to a recent report and our own studies, approximately 3100 million cubic feet (ft^3) of CO_2 are purchased daily in the U.S. for 111 flood projects (there are some situations where there are multiple and separate flood projects in a field). That gives us an average metric of ~28 million ft^3 per day of purchased CO_2 per project. That is about 1450 MT per day or 530,000 MT per year of new carbon dioxide[3] per flood project. A good rule of thumb for the Permian Basin is that, in a mature project, we ultimately recycle about the same volume of CO_2 that we have purchased. If all the fields currently under flood were very mature (of course not the actual case since many are immature), we would expect to be recycling about the same volume we

[2] There are 42 gallons in a barrel of oil

[3] There are ~19,250 cubic feet (ft^3) of CO_2 in one MT and ~17,500 ft^3 in one english ton; A handy, quick conversion to remember is 50 million ft^3 per day is roughly equivalent to 1 million tons per year (slightly less (.95) for metric and slightly more (1.04) for english)

are purchasing which is 1.8 billion ft^3 per day. In actual practice, my estimate of recycle volumes in the Permian Basin is 1.1 billion ft^3 per day.

RESPONSES OF L. STEPHEN MELTZER TO QUESTIONS FROM SENATOR MURKOWSKI

Question 1. Your chart on page 8, showing the third and fourth production peak at about 60 and 80 years aft[3]er an oilfield has been developed. Combined, those third and fourth heights of production are more than the main (secondary) production peak. That certainly fits with Mr. Davis' other chart, showing the huge increase in EOR activity in the US and worldwide.

So, are we doing an adequate job as a government in identifying what our true resource potential is? To clarify, is there an issue with the characterization that the US has only 2 percent of the world's oil reserves, in that it doesn't take into account unexplored areas, and it apparently doesn't take into account what impact EOR could have on current estimates?

Answer. Coincidentally, I left the Washington hearing to attend a workshop conducted by the U.S. Geological Survey at Stanford University where I had been asked to address this "size of EOR resource" question. A lot of folks (like the USGS and the National Petroleum Council to name two) are attempting to reassess our resources right now. First, we have new, on-going projects that are proving that we can economically target and produce the residual oil zones (ROZs) with EOR techniques. Second, we now have a new understanding that these ROZs are more widespread than previously imagined. These two new developments emphatically confirm the reality that our published U.S. oil resources are badly understated today. The USGS is currently charged with reassessing our EOR resources but they, like anyone else, will need some help from industry and an extended time frame to accomplish such a wholesale reassessment. The linkage between the availability of affordable CO_2 and those potential resources is a matter of great importance to many of us in the industry and state and national policies will be critical to ensuring adequate availability of CO_2.

Can we realize the large EOR potential? We have an oil and gas industry that is busy drilling for new fields and a very, very small subsector of it concentrating on getting more oil out of an existing reservoir. Some of that has to do with the long term nature of the EOR projects—something that does not appeal to public money looking for fast returns. However, I often argue that a better balance is needed; i.e., some quick adds to the reserve base and some long term additions. We need to have the long range interests of a country to be better placed on long term reserves and not just the flash effect of quick returns. I view this 'quick return' partiality not as a market failure problem; it is probably better characterized as just a market bias.

Finally, I have never been involved in anything with as large a potential as CO_2 EOR. What started out as an interesting "trip" into the science of the ROZs has turned into a revolutionary opportunity for the industry and our Country. As I mentioned in the questions session near the end of the hearing, our group has done a "back-of-the-envelope" estimate of the size of the ROZ resource in just one West Texas county. The numbers are shocking: 30 billion barrels of in-place oil. We believe that 20% to 30% of this ROZ in-place oil resource could be recoverable.

Question 2. Please describe how much oil is recoverable using next-generation CO_2 EOR in the US.

Answer. Work is currently underway to attempt to get a handle on the size of the new EOR resources. A proposal has been submitted to the Research Partnership to Secure Energy for America intended to assess the size of the San Andres formation ROZ resource in the entire Permian Basin and utilize the new methodology developed to begin looking at the Bighorn Basin in Wyoming and the southern Williston Basin (SD, ND, MT). Additionally, Advanced Resources International has been following the ROZ studies since the original report in 2005[4]. They performed a survey of fields in five U.S. basins and reported the results of the ROZ studies in a series of five reports[5]. Most recently, they have authored a report looking at the potential of all next-generation CO_2 EOR technologies. In addition to a new limited look at the ROZ resources, they are examining the use of additives to the WAG injection water to improve sweep efficiency in complex reservoirs via additional wells and utilizing higher volumes of CO_2 injection. They have just submitted a draft[3] for review

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[4] Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR)", Activity 04001.420.02.03, Jun 2011.

[5] Stranded Oil in the Residual Oil Zone, Advanced Resources International Corp and Melzer, L.S. (2008), Feb '06, http://www.fossil.energy.gov/programs/oilgas/eor/Stranded—Oil—in—the—Residual—Oil—Zone.html

at DOE and the CO_2 economically recoverable numbers are very large, on the level of 37 billion barrels from the conventional reservoir targets and almost double that to 66 billion barrels using next generation flooding technologies—more than three times the current proven oil reserves. The technically recoverable total including the limited look at ROZ resources would be on top of these figures and, based on the early work done to date, would double that again to an estimated total of 135 billion barrels.

Question 3. How much CO_2 is needed to realize the domestic oil production potential of next-generation EOR?

Answer. The same ARI report[5] discussed the CO_2 requirements for producing these recoverable resources. The total mass required is 19.5 billion MT (375 trillion ft^3)[6]. They looked at where the CO_2 will come from and conclude that only 12% is likely to come from existing sources.

Question 4. How much of this new CO_2 would be needed from anthropogenic sources?

Answer. Most of our industry counterparts are convinced that natural sourced CO_2, albeit very reliable and affordable, is likely not to expand beyond its current levels of 2.5 billion ft^3 per day (45-50 million MT per year). Some observers, including myself, are very concerned about the industry's ability to maintain these current natural CO_2 production levels. The required growth in the CO_2 supply market must come from anthropogenic sources. The existing anthropogenic and short term growth is from the easier sources; i.e., natural gas, ammonia, and ethanol plants. The more difficult ones use coal or petroleum coke as the fuel and will be more expensive sources of CO_2. Incentives like the ones currently being provided by the Department of Energy through their US Industrial CCS Projects Initiative[7] are a good start but another set of incentives is worthy of mention and will be addressed in the next question/ answer.

Consistent with an industry average net utilization factor of 3 barrels of oil per MT of CO_2, the volume of CO_2 needed is 45 billon MT to realize the technically recoverable oil and about 20 billion MT to realize the economically recoverable oil available from "next generation" CO_2 EOR technology. Existing natural sources and gas plant supplies of CO_2 can only provide a little over 2 billion MT. As such, the capture and productive use of anthropogenic CO_2 will be essential for realizing the vast domestic oil production potential available from our existing oil fields through application of "next generation" CO_2 EOR.

Question 5. What kinds of federal policies are needed to build the CO_2 supply needed to realize the domestic oil production potential from next generation EOR?

Today, favorable market forces and complimentary federal policies have an opportunity to create dramatic increases in domestic oil production while sequestering this CO_2 that otherwise be emitted. Unfortunately, with some exceptions, the parties representing climate concerns and those capable of CO_2 EOR can be accurately characterized as being on opposite sides of a wall separating CO_2 capture and sequestration from resource recovery. Again with very few exceptions, both sides seem intent on keeping the respective playgrounds to themselves. Federal policies can help remove this ill-conceived barrier.

In today's world where giving any benefit to the oil industry is difficult because of the perceived poor reception by the public, we believe the best approach for realizing the carbon emission reductions and oil production enhancements is to incentivize CO_2 capture. For the oil (injection) industry, the effect of making captured and pressurized CO_2 affordable can have roughly the same positive effect of "discovering" new reserves, not unlike the revolution occurring with technology and unconventional shale formations today. I will say however, there are two exceptions to the principle that only a capture incentive is needed. The first is avoiding unnecessarily onerous additional requirements on a CO_2 EOR project to prove storage when such verification can be done with only a modest enhancement of standard industry practices. The second involves elevating the EOR investments in the oil industry to more effectively compete against those short term rates of return available to them in the new world of unconventional shale exploration. With these issues in mind, it is best to examine the policies and incentives for the a) capture and b) CO_2 injection sectors separately.

First, is there an approach wherein future Federal tax revenues from EOR production can be used to finance the upfront investments in the capture of CO_2? It is my understanding that Senator Lugar's office is developing a proposal that would

[6] A common metric used is that a typical existing 1 Gigawatt coal power plant would yield 10 million MT/yr at a 90% CO_2 capture rate

[7] http://powerplantccs.com/blog/2010/03/12-us-industrial-ccs-projects-pursue-1-4-billion-in-doe-funding.html

extend tax credit for CCS linked to future CO_2 EOR revenues to come to the federal government. There are two problems being addressed with this approach:

- The jump start needed for addressing capture economics and risks and
- Addressing a classic "chicken and egg" syndrome: it takes available CO_2 to get the oil projects planned and implemented but, on the other hand, one will not go to the risks and expense to capture the CO_2 unless the oil projects are there. Both parties sit around waiting on the other. By addressing the incentivized capture from future oil revenues, you should get both.

The justifying concepts are that the enhanced oil revenues for the economy and tax base will not materialize unless the CO_2 supply is available for the projects to be implemented. And leadership in CO_2 capture for the U.S. can occur at a less expensive cost to the economy than the non-EOR alternatives.

According to recent studies, the U.S. Treasury directly receives $23 from a domestically produced $100 oil barrel[8]. It should be noted that this amount does not count the employment, state and local taxes paid; i.e., the wealth creation reaching well beyond the federal receipts. Knowing that a MT of captured CO_2 delivered to the oil field will yield, on average, 3 barrels of crude oil production and, given current and projected oil prices, the future federal oil revenues are highly likely to exceed the upfront cost for the capture. The anthropogenic CO_2 projects must qualify and the details of such eligibility are being studied.

Available CO_2 is an absolute key to realization of the EOR barrels but it is not sufficient. CO_2 EOR is already a long rate of return and labor intensive proposition. And, the EOR industry can be characterized as having an apprehension that 'business as usual' EOR will be altered in such a fashion as to make it more difficult to undertake new projects. For example, the state of Texas chose to address this exact concern in two ways: 1) with an incremental production tax credit of 1.125% of the oil revenues when using anthropogenic CO_2 and 2) to have the regulatory agency familiar to the industry provide the permits to qualify the project for "incidental" storage. What is meant by 'incidental' is that storage of the purchased CO_2 automatically occurs as a result of the CO_2 EOR process. And this process now has a body of rules very similar to the rules already in force for CO_2 EOR wells and project operation. Thus, by formalizing the "new" CCS rules for all to see, the barrier of regulatory uncertainty was essentially removed. I should add here that the federal rules published by the EPA, while attempting to consider the Texas approach, effectively added a complexity and uncertainty that has not been useful to qualifying storage during CO_2 EOR. I am hearing that one particular plant company and a separate injection organization have chosen to opt out of the CCS + EOR pathway for these reasons.

One additional comment I would make has to do with long term stewardship and liability. Texas tried very hard to keep CO_2 out of the waste world. It is enormously difficult for the Environmental Protection Agency to accomplish that goal considering their name and mission. They are to be commended for creating a separate class of injection wells (Class VI UIC) rather than dropping CO_2 injection wells into waste Class I but the EOR industry has thoroughly examined the specifications of Class VI and drawn the conclusion that it is effectively a renamed Class I. I am led to believe that the pressures that were exerted on the EPA in Washington were so intense that the EPA erred in being overly prescriptive to accommodate the worst case scenarios. The result is that CO_2 EOR + CCS is still "stuck in the mud."

Because of the dual value of CO_2 EOR and the new developments as to the size of the resources available to EOR plus CCS, Congress, industry and markets could benefit from more detailed, timely and broadly available information. One possibility would be a "National CO_2 EOR Center", able to foster the development and deployment of "next generation" EOR. This entity could help accelerate the use of advanced CO_2-based oil recovery technology in domestic oil fields, with great benefits to the nation's energy security, economy, and environmental goals. Such a "Center" should be located near the oilfield laboratories for CO_2 EOR. On the one hand, such a "Center" would be a most valuable resource center for smaller independents looking to implement CO_2 EOR in their mature fields. On the other hand, such a "Center" would also provide timely studies and information to Congressional members and their staff, assisting formulation of sounder policies and possibly legislation of great benefit to U.S. energy security, jobs and economic progress.

The CCS world is an expensive one. It can also be made to be a very complex place to do business. Because of the U.S.'s wonderful endowment of coal and oil resources, a unique convergence of the dual needs for domestic oil and reducing green-

[8] Op Cit, Improving Domestic Energy Security and Lowering CO_2 Emissions

house gas (CO_2) emissions is in front of us. The wall between CO_2 capture plus waste injection sequestration and the experienced companies doing resource production does a disservice to both CCS objectives and resource production.

APPENDIX II

Additional Material Submitted for the Record

BROKEN PROMISE #3

DIRECTIONAL DRILLING IS NO PANACEA

The Promise

New directional drilling technology enables drilling without any surface impacts.

The Reality

Directional drilling is not new and requires the same infrastructure with the same impacts as all oil development, including surface impacts.

Proponents of oil and gas development in the Arctic National Wildlife Refuge and other sensitive areas of Alaska assert that new advances in directional drilling will reduce, and even eliminate, environmental impacts. In fact, directional drilling has limitations, and its impacts are no different than those of conventional drilling.

> "The industry touted roadless development as the way of the future, and is now abandoning the concept."

Community of Nuiqsit, 2004[1]

Directional drilling is not a new practice

According to the U.S. Department of Energy, the fi rst true horizontal well[2] was drilled in 1929 in Texas.[3] Since then, thousands of horizontal wells have been drilled across the world. But as of 1999 horizontal boreholes accounted for only fi ve to eight percent of all U.S. land wells, and extended-reach horizontal drilling is still uncommon.[4] In Arctic Alaska, oil companies have rarely drilled horizontal distances of more than a few miles. Of the 5,549 wells drilled on Alaska's North Slope to date, only 41 have reached horizontal offset distances of three miles or more.[5]

Exaggerated claims

Claims that directional drilling can reach eight to ten miles away are exaggerated.[6] Oil companies have drilled distances over seven miles, but such distances are still extremely rare in the industry.[7] On the North Slope, 94% of all existing wells

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[1] U.S. Bureau of Land Management. 2005, January. Final Amendment to the Northeast National Petroleum Reserve: Integrated Activity Plan/Environmental Impact Statement. Vol. 2, Response to comments. Kuupik Corporation, Native Village of Nuiqsut, City of Nuiqsut, and Kuukpikmuit Subsistence Oversight Panel. Comment Letter No. 197616. P. 6-262.

[2] The terms horizontal and directional drilling are used interchangeably in this document to refer to non-vertical drilling.

[3] Horizontal and Multilateral Wells. Frontiers of Technology. (1999, July). Journal of Petroleum Technology. Retrieved March 18, 2009 from website: http://www.spe.org/spe-app/spe/jpt/1999/07/frontiers__horiz__multilateral.htm#.

[4] Pratt, Sara, (2004, March). A Fresh Angle on Oil Drilling, GeoTimes.

[5] Horizontal offsets calculated by Doug Tosa, GIS Analyst, Alaska Center for the Environment. August 2009. Source data: Alaska Oil and Gas Conservation Commission well database, http://www.state.ak.us/local/akpages/ADMIN/ogc/publicdb.shtml.

[6] Senator Lisa Murkowski's website claims that her directional drilling bill will enable "oil wells to be drilled from the western Alaska state-owned lands, outside of the refuge's boundary, or from state waters to the north, and still to [sic] be able to tap oil and gas deposits located between eight and 10 miles inside the refuge. http://murkowski.senate.gov/public/index.cfm?FuseAction=IssueStatements. View&Issue__id=8160a71d-9c6e-945d-f605-a8959dfbf80b (last visited April 8, 2009).

[7] British Petroleum's Wytch Farm set the current world extended reach drilling record in June of 1999 when its well M16 reached a "horizontal displacement distance of 10,728 m[eters] a total

Continued

extend less than two miles from the drill rig, and fewer than 2% extend more than three miles. As of August 2009 the maximum horizontal distance drilled was 4.025 miles. Even at ConocoPhillips' Alpine oil fi eld, which is touted as a model of new directional drilling technology, the average horizontal drill distance is only 1.74 miles.[8]

Longer-reach drilling is expensive and often presents geologic and engineering challenges

Truly state-of-the art practices are often impractical if not impossible for oil companies. Factors such as where the oil or gas deposit is in relation to the drilling rig, the size and depth of the mineral deposit, and the geology of the area, are all important elements in determining whether directional drilling is possible.[9] Drilling a horizontal or extended-reach well can cost two or three times more than drilling a vertical well in the same reservoir.[10] In 2000, British Petroleum "stopped drilling extended reach wells-those that reach out a long distance from the pad-after oil prices crashed in the late 1990s, because extended-reach drilling is expensive."[11] In a 2003 draft environmental impact statement for the National Petroleum Reserve-Alaska, the Bureau of Land Management (BLM) wrote:

> "The cost of extended-reach [ERD] wells is considerably higher than conventional wells because of greater distance drilled and problems involving well-bore stability. Alternative field designs must consider the cost tradeoffs between fewer pads with more extended-reach wells as opposed to more pads containing conventional wells. In most instances, it is more practical and cost effective to drill conventional wells from an optimum site, [than] it would be to drill ERD wells from an existing drill site."[12]

ConocoPhillips' Alpine oil fi eld is an example of how optimistic claims about directional drilling technology can quickly fall fl at. Alpine was advertised in 1998 as a state-of-the-art roadless development. But the oil field already has several miles of permanent gravel road, and plans for expansion could add as much as 122 more miles.[13] In 2004 the federal government approved plans to expand Alpine from two to seven drill sites.[14] Also in 2004 the Bureau of Land Management granted ConocoPhillips an exemption from a lease stipulation that had previously prohibited the company from building a drill site in a 3-mile buffer zone along Fish Creek.[15] The agency cited economic and geological limitations of directional drilling as the reason:

> "Drilling from outside the setback would require directional drilling for long distances through geologically unstable shale. This drilling approach is very problematic because shale in this area tends to collapse holes. Maintaining drill holes would be diffi cult and expensive."[16]

In 2008 British Petroleum announced its plans to drill distances of seven miles or more to reach its offshore Liberty oil field. But the technology remains to be proven. It will also demand doubling the size of Endicott Island-an offshore, man-made

length of 11,278 m[eters] and a depth of 1638 m[eters]." http://www. bpnsi.com/index.asp?id=7369643D312669643D313531 (last visited March 18, 2009).

[8] Directional drilling data analysis by Doug Tosa, GIS Analyst, Alaska Center for the Environment. August 2009. Source data: Alaska Oil and Gas Conservation Commission well database retrieved June 16, 2009 from http://www.state.ak.us/local/akpages/ ADMIN/ogc/publicdb.shtml.

[9] Judzis, A., K. Jardaneh and C. Bowes. 1997. Extended-reach drilling: managing, networking, guidelines, and lessons learned. SPE Paper 37573 presented at the 1997 SPE/IADC Drilling Conference, Amsterdam. March 4-6, 1997.

[10] Horizontal and Multilateral Wells. (1999, July); Van Dyke, Bill, petroleum manager, Alaska Department of Natural Resources. Quoted in Pratt, Sara. (2004, March).

[11] Petroleum News Alaska. (2000, 0ctober). BP plans busy exploration season, both in NPR-A and satellites.

[12] U.S. Bureau of Land Management. (2003). Northwest National Petroleum Reserve-Alaska Draft Integrated Activity Plan/Environmental Impact Statement. Sec. IV, p. 20-21.

[13] U.S. Bureau of Land Management. September 2004. Alpine Satellite Development Plan Final Environmental Impact Statement. Vol. 1, Sec. 2. Pp. 69-71.

[14] U.S. Bureau of Land Management. (2004, November). Alpine satellite development plan Record of Decision.

[15] U.S. Bureau of Land Management. (2004, September). Alpine Satellite Development Plan. Final Environmental Impact Statement. Vol. 3. Appendix I, CPAI request for exception to stipulations. ConocoPhillips letter dated April 8, 2004 to BLM. Pp.3-4.

[16] BLM. November 8, 2004. Alpine Satellite Development Plan Record of Decision. p. 17.

island-to make room for extended pipe racks, the massive drilling rig, and a worker's camp.[17]

- Directional drilling is not a new practice.
- Claims about distances directional drilling can reach are exaggerated.
- Directional drilling is expensive and often limited by geology.
- Directionally drilled wells require the same infrastructure and have the same environmental impacts as conventional wells, including surface impacts.

Claims that directional drilling will incur no surface impacts are misleading

Before production wells are drilled, seismic testing is conducted and exploration wells are drilled to refi ne the location of oil deposits. These activities have direct surface impacts.

Seismic exploration typically involves many vehicles driving across the tundra in a grid pattern. Sensitive tundra soil and plants are easily compressed under the weight of these heavy vehicles, even in winter.[18] Seismic lines are often visible on the Arctic tundra for years after exploration, and studies have shown that fragile tundra plants can take decades to recover.[19] Despite industry claims to the contrary, winter exploration can also disturb wildlife.[20]

The notion that directional drilling allows for a smaller footprint is misleading

Although directional drilling may reduce the number of well pads required to access an oil deposit, it requires the same infrastructure and has the same environmental impacts as conventional drilling. Permanent gravel roads and air strips are still used for access, long pipelines are still required to connect the well sites, and pollution and toxic spills are still inevitable.

Oil production is a high-impact activity, regardless of how you drill. New technology has yet to demonstrate that it can minimize, mitigate, or eliminate the inevitable impacts of oil development to America's Arctic and other sensitive ecosystems.

STATEMENT OF PAMELA A. MILLER, ARCTIC PROGRAM DIRECTOR, NORTHERN ALASKA ENVIRONMENTAL CENTER, FAIRBANKS

PUBLISHED FRIDAY, MARCH 20, 2009

March 17, 2009

To the editor:

It is welcome news that President Obama's Interior secretary has clearly rejected the approach of Sen. Lisa Murkowski's latest scheme to open the Arctic National Wildlife Refuge to oil exploitation. At a U.S. Senate hearing today, Interior Secretary Ken Salazar said "ANWR as a national refuge needs to be absolutely protected," contradicting your erroneous headline printed this morning.

Secretary Salazar was right to question the efficacy of directional drilling to reach potential oil in the Arctic refuge from outside its boundaries. In fact, a closer look at Sen. Murkowski's bill reveals exploratory drilling and disruptive seismic exploration could be allowed directly on the refuge coastal plain; operations would be exempt from many of the nation's laws to protect clean air, clean water and environmental quality. Furthermore, even if the bill jibed with its PR spin, offshore drill rigs and pipelines along nearly a hundred miles of refuge coast pose risks of oil spills and disruption to the coastal habitats and migratory movements of threatened polar bears, birds and Porcupine Herd caribou.

The truth is that this is just another in a long line of drill bills for the Arctic refuge. Oil and gas exploration and development simply cannot be done without harming the people, plants and animals depending on our Arctic refuge for survival. At a time when there are nearly 100 million acres of land and water already open

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[17] Delbridge, Rena, "BP begins development of Liberty oil fi eld project on North Slope, Fairbanks Daily News Miner, July 14, 2008, http://www.newsminer.com/news/2008/ jul/14/bp-begin-developing-liberty-oil-field/ (last visited June 30, 2009). http://www.alaskajournal.com/stories/050109/oil__img__oil001.shtml (last visited June 30, 2009) http://www.alaskajournal.com/stories/060509/oil__10__001.shtml (last visited June 30, 2009)

[18] Jorgensen, J.C. 1998. Emers, M., J.C. Jorgenson, and M.K. Raynolds. 1995. Response of arctic tundra plant communities to winter vehicle disturbance. Can. J. Bot. 73: 905-917.

[19] U.S. Fish and Wildlife Service. 2001. Potential impacts of proposed oil and gas development on the Arctic Refuge's coastal plain: historical overview and issues of concern. Web page of the Arctic National Wildlife Refuge, Fairbanks, Alaska: http://arctic.fws.gov/issues1.htm.

[20] Ibid.

to the oil industry in America's Arctic—with little to no baseline science supporting such expansive development—the last thing Alaska needs is to open our only protected lands on Alaska's North Slope.

Who do you think operates leases next to the Arctic refuge? Exxon. Next week is the 20th anniversary of the Exxon Valdez oil spill. It also has been more than 20 years since the debate to drill the Arctic refuge was first brought before Congress. It seems that, by now, we would have heeded the lessons learned—oil development is a risky, dirty business that has no place in or around what Secretary Salazar called one of our "special and treasured places we will not disturb."

STATEMENT OF THE ALASKA COALITION, ON S. 503

DEAR SENATOR, On behalf of the millions of conservationists our organizations and businesses from across the country represent, we write in opposition to S. 503, the 'No Surface Occupancy Western Arctic Coastal Plain Domestic Energy Security Act' introduced by Senators Murkowski (AK-R) and Begich (AK-D). This legislation would undermine the fundamental purpose of the Arctic National Wildlife Refuge to protect wilderness and wildlife by opening the area to oil leasing and development.

At a time when Congress has a historic opportunity to pass legislation focused on clean, renewable energy sources, energy efficiency and conservation, and reversing climate change, we are deeply disappointed that the Alaska delegation is trying, once again, to divert attention from necessary policy to rehash the unproductive debate over developing the Arctic National Wildlife Refuge.

Our nation is already on a path to significantly reduce its oil addiction through sustainable clean energy solutions. In fact, changes in policy and practices from just the past few years have set us on track to reduce our oil consumption by an amount 17 times that of the speculative oil potential estimated from the Refuge over the same period. And with the current legislation being considered in Congress, there is so much more that can be done. With the right leadership, America can have energy policy that continues to reduce our use of fossil fuels, while ensuring that our most important wild places are passed on to our children and grandchildren.

The Arctic National Wildlife Refuge is a national treasure, and protecting the Arctic Refuge has long been a top priority for the members of our organizations. The Refuge's coastal plain sustains hundreds of species of wildlife, as well as the culture and way of life of the Gwich'in Nation and other Alaska Native communities. S. 503 would seriously threaten these resources. The bill's sponsors tout unproven, exaggerated oil potential from the Refuge's speculative reserves, sought ostensibly through directional drilling and pipeline technology that is currently untested in Alaska. At the same time, S. 503 would allow surface activities including seismic and exploratory drilling across the biological heart of the Refuge, disturbing denning habitats used by imperiled polar bears and harming sensitive tundra vegetation. The legislation promotes increased development focused along the Canning River and across the entire Refuge coast, activity which risks dangerous spills in key wildlife and subsistence areas of the coastal plain. Furthermore, the bill would waive vital environmental laws and destroy the very values for which the Refuge was originally set aside nearly 50 years ago—its unparalleled wilderness and wildlife.

With so many loopholes and exaggerated claims, it is hard to take this legislation as much more than a Trojan horse aimed at opening the entire Arctic Refuge Coastal Plain to oil leasing, exploration, and development.

Americans deserve a cheaper, quicker, safer and cleaner energy policy that safeguards the wild places we care so deeply about. Congress has repeatedly rejected attempts to open the Arctic Refuge to oil drilling. Instead of trotting out dead-on-arrival proposals, it's time for America to prioritize clean, renewable energy solitons that move our country away from our addiction to oil and protect the Arctic National Wildlife Refuge as Wilderness.

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