

ALASKA STATE LEGISLATURE
SENATE RESOURCES STANDING COMMITTEE

February 8, 2013

3:30 p.m.

MEMBERS PRESENT

Senator Cathy Giessel, Chair
Senator Fred Dyson, Vice Chair
Senator Peter Micciche
Senator Click Bishop
Senator Anna Fairclough

MEMBERS ABSENT

Senator Hollis French
Senator Lesil McGuire

COMMITTEE CALENDAR

PRESENTATION: WHAT IT TAKES TO KEEP OUR LEGACY FIELDS ALIVE

- HEARD

SENATE BILL NO. 27

"An Act establishing authority for the state to evaluate and seek primacy for administering the regulatory program for dredge and fill activities allowed to individual states under federal law and relating to the authority; and providing for an effective date."

- MOVED SB 27 OUT OF COMMITTEE

SENATE BILL NO. 26

"An Act relating to the Alaska Land Act, including certain authorizations, contracts, leases, permits, or other disposals of state land, resources, property, or interests; relating to authorization for the use of state land by general permit; relating to exchange of state land; relating to procedures for certain administrative appeals and requests for reconsideration to the commissioner of natural resources; relating to the Alaska Water Use Act; and providing for an effective date."

- MOVED SB 26 OUT OF COMMITTEE

PREVIOUS COMMITTEE ACTION

BILL: SB 27

SHORT TITLE: REGULATION OF DREDGE AND FILL ACTIVITIES

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

01/18/13	(S)	READ THE FIRST TIME - REFERRALS
01/18/13	(S)	RES, FIN
02/02/13	(S)	RES AT 10:30 AM BUTROVICH 205
02/02/13	(S)	Heard & Held
02/02/13	(S)	MINUTE(RES)
02/04/13	(S)	RES AT 3:30 PM BUTROVICH 205
02/04/13	(S)	Heard & Held
02/04/13	(S)	MINUTE(RES)
02/08/13	(S)	RES AT 3:30 PM BUTROVICH 205

BILL: SB 26

SHORT TITLE: LAND DISPOSALS/EXCHANGES; WATER RIGHTS

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

01/18/13	(S)	READ THE FIRST TIME - REFERRALS
01/18/13	(S)	RES, FIN
02/02/13	(S)	RES AT 10:30 AM BUTROVICH 205
02/02/13	(S)	Heard & Held
02/02/13	(S)	MINUTE(RES)
02/04/13	(S)	RES AT 3:30 PM BUTROVICH 205
02/04/13	(S)	Heard & Held
02/04/13	(S)	MINUTE(RES)
02/06/13	(S)	RES AT 3:30 PM BUTROVICH 205
02/06/13	(S)	Heard & Held
02/06/13	(S)	MINUTE(RES)
02/08/13	(S)	RES AT 3:30 PM BUTROVICH 205

WITNESS REGISTER

SCOTT JEPSEN, Vice President
External Affairs
ConocoPhillips Alaska
Anchorage, AK

POSITION STATEMENT: Discussed the role that technology has played in the development and the off take of the rate on the North Slope.

ALAN CAMPBELL, Supervisor
Greater Kuparuk Area (GKA) Reservoir and Planning
ConocoPhillips Alaska

POSITION STATEMENT: Was not able to testify because of technical teleconference difficulties.

BOB HEINRICH, Vice President
Finance
ConocoPhillips Alaska
Anchorage, AK

POSITION STATEMENT: Talked about how the state's fiscal policy drives investment in Alaska's Legacy Fields.

DAMIAN BILBAO, Head of Finance
BP Exploration Alaska
Anchorage, AK

POSITION STATEMENT: Discussed how the state's fiscal policy drives investment in Alaska's Legacy Fields.

SCOTT DIGERT, Reservoir Management Team Leader
Greater Prudhoe Bay area
BP Exploration Alaska
Anchorage, AK

POSITION STATEMENT: Discussed how the state's fiscal policy drives investment in Alaska's Legacy Fields.

DAN SECKERS, Tax Counsel
ExxonMobil
Anchorage, AK

POSITION STATEMENT: Discussed how the state's fiscal policy drives investment in Alaska's Legacy Fields.

ACTION NARRATIVE

[3:30:17 PM](#)

CHAIR CATHY GIESSEL called the Senate Resources Standing Committee meeting to order at 3:30 p.m. Present at the call to order were Senators Dyson, Micciche, Bishop, Fairclough, and Chair Giessel.

SB 27-REGULATION OF DREDGE AND FILL ACTIVITIES

[3:31:24 PM](#)

CHAIR GIESSEL announced SB 27 to be up for consideration.

SENATOR DYSON moved to report SB 27, version A, from committee with individual recommendations and attached fiscal note(s).

CHAIR GIESSEL announced that, without objection, SB 27 passes from the Senate Resources Standing Committee.

[3:31:59 PM](#)

At ease from 3:31 to 3:34 p.m.

SB 26-LAND DISPOSALS/EXCHANGES; WATER RIGHTS

[3:34:01 PM](#)

CHAIR GIESSEL called the meeting back to order and announced SB 26 to be up for consideration.

SENATOR MICCICHE said some of his constituents had concerns about their ability to appeal. His response was that they had to become engaged at some point before the appeal, and the second concern was water reservations. So, he wanted to respond that a person or NGO has never been given a water reservation and that hadn't changed. He also stated that experience has shown that groups or NGO's with a good case are generally able to convince a political subdivision to support their water reservation request.

SENATOR DYSON moved to report SB 26, version A, from committee to the next committee of referral with individual recommendations and attached fiscal note(s).

CHAIR GIESSEL announced that, without objection, SB 26 passes from the Senate Resources Standing Committee.

[3:35:48 PM](#)

At ease from 3:35 to 3:37 p.m.

SB 27-REGULATION OF DREDGE AND FILL ACTIVITIES

[3:37:31 PM](#)

CHAIR GIESSEL reconvened the meeting and recognized Senator Fairclough.

[3:37:47 PM](#)

SENATOR FAIRCLOUGH said she wanted to comment about a question that was asked on SB 27. She explained that when the department was before the committee she asked for a comparison of the 402 process where the state had successfully gotten waste water primacy, and she hadn't received that yet. She said she put a no recommendation on the [committee report] because she wanted to know what it looks like from an operating perspective.

Presentation: What it takes to keep our legacy fields alive.

[3:38:28 PM](#)

CHAIR GIESSEL announced that today's agenda was a presentation on what it takes to keep our legacy fields alive and she welcomed the first presenter, Mr. Jepsen from ConocoPhillips.

3:39:06 PM

SCOTT JEPSEN, Vice President, External Affairs, ConocoPhillips Alaska, Anchorage, AK, said he would talk a little bit about the role that technology has played in the development and the off take of the rate on the North Slope. He would focus on fields that ConocoPhillips operates; BP would focus on the other fields on the North Slope and that should cover other fields where ConocoPhillips has an interest. This topic is broad and deep, and today he was going to "tiptoe" through it. He hoped to give them a good idea just how leveraging technology is and how it will continue to be leverage as the fields continue to mature.

3:40:10 PM

The first slide was a timeline of the fields that ConocoPhillips has operated on the North Slope. It starts in 1981 with the Kuparuk Field and goes to their development at the CD5 drill site at Alpine. In between are major milestones related to technology (for simplicity the others were left off); he would give them some idea of how they work and the impact that they have on production and development. The major milestones related to technology are EOR (enhanced oil recovery) and seismic evolution (focusing on coil tubing drilling).

He showed how Alpine had benefited from all the historical technology that had been developed on the North Slope, first detailing how EOR works. For example, the original oil in place in the Kuparuk Field was about 6 billion barrels, gigantic by any standard. So, you can take the percentages for the various mechanisms and multiply it times the oil in place and come up with the theoretical amount of oil that one might get under the various recovery mechanisms.

He showed pictures of a rock that had undergone some original completion that had high residual oil in it (no EOR had had been applied). In a field like Kuparuk you might get in the range of 15 percent recovery without using any EOR, he said. After applying water flood, the most common type of enhanced recovery used and that has been around for many decades, the rock looked white. After applying a miscible injectant (MI) there wasn't a whole lot of oil left - and that's their goal. They want to make sure there is no oil left in each reservoir. But Mr. Jepsen said, the real world is not quite as clean as these pictures.

SENATOR FAIRCLOUGH asked how much recovery happened after water flood.

MR. JEPSEN replied about 35 percent recovery and injecting miscible gas results in about 8-10 percent more, but even under the best of conditions there are billions of barrels left in these reservoirs.

3:44:50 PM

The way water flood works, you drill a well, inject water into it and that provides pressure to push oil towards the producing well; the water itself tends to sweep the oil out of the reservoir. At Kuparuk they also employed a technology called immiscible water-alternating gas injection (WAG). He explained that in the early days Kuparuk produced a lot of gas but didn't have any place to store it. So, they injected it back into the reservoir, itself. This started to create a very large gas bubble, which made production a bit of an issue, because in the end a lot of gas might be produced and very little oil. So, the engineers got very creative and suggested injecting a slug of gas followed by a slug of water followed by a slug of gas and spreading this process out over the entire field. That allowed them to lower the gas saturation from what was in the gas injection area (which also helped push some of the oil out of the reservoir). After that they followed up with immiscible alternating gas process which means they took natural gas liquids NGL, some of which are produced indigenous to the Kuparuk field and some of which are brought in from Prudhoe Bay, and mixed it with the lean gas and created the miscible injectant. "Miscible" means if you could see this process in the reservoir you would see a really smooth interface between the two fluids which helps control the flood itself. Then the miscible injectant actually acts like it's washing the rock as it moves through the reservoir removing the residual oil that is left behind when the oil itself moves forward in the reservoir. This is followed with water and if another slug of miscible injectant is needed they will do that. About two-thirds of the Kuparuk field has undergone miscible injectant. The rest depends on technical analysis of how well it's going to work (a function of reservoir quality) whether all the facilities are out there and a number of other factors. It has been one of the key components to maintaining the recovery rate in the Kuparuk River field.

3:47:09 PM

MR. JEPSON said seismic is another type of leveraging technology for recovery. In 1967, 2D seismic gave them a very rough idea of

geology, but no detail; it gave a poor idea of faulting in the Kuparuk field at first. Back then they would run 2D swat data, which means they ran a number of lines fairly close together and then skipped tens of miles and did another set of lines close together and then ran another set that was at a 90 degree angle to that and so on. The information from this kind of data gave a very rough idea of the subsurface; you could see large geological structures and might be able to pick out some sands, but no fine detail. They had a very poor idea of how faulted the Kuparuk field was when they first started developing it, but after shooting 3D seismic in the mid-1980s they found a lot more. So that radically changed how they developed the field; it meant they were going to drill a lot more wells and do a lot more analysis to make sure they efficiently swept the oil out of the field.

Fast forwarding to this decade, Mr. Jepsen said 4D seismic is now being done. This means they shoot a seismic survey and then come back some time later (one or three years) and shoot another survey over the same area. They compare those surveys and, based upon some processing technology, they can see areas where the character of the acoustic signal has changed. That can mean a lot of things. So, the engineers go back in and look at geological and production data from the well pattern and reservoir models and try to decide if it means they bypassed some oil or where they need to add injector. The real leverage is that it highlights the areas where they need to focus because it shows more potential.

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SENATOR FAIRCLOUGH asked if switching technologies is why wells aren't being drilled on the North Slope now, because people are trying to determine the best place to pursue a resource.

MR. JEPSEN answered the amount of drilling they are doing now is a function of the tax system in the state. Between Kuparuk and Alpine three and half rigs running and the decision to bring more drilling tools up to the North Slope will be a function of how the state competes overall with other places where money is being invested right now.

SENATOR FAIRCLOUGH asked if all things were equal inside of a taxing environment if they are drilling as many wells with this new technology as they have in the past.

MR. JEPSEN replied that they didn't have this kind of technology 15 years ago, but they are trying to work through the candidates they have in a reasonable fashion.

[3:52:45 PM](#)

SENATOR MICCICHE asked if they are producing more water because of the EOR specifically or just because of what is in the formations as oil becomes scarcer.

MR. JEPSEN replied that the water rate is going up because of the water injection. The initial drive for the field was primarily solution drive meaning expansion of the oil through gas expansion.

SENATOR BISHOP asked if he meant the water adds no value.

MR. JEPSEN said he meant the water adds value through the role that it plays in producing more oil. He moved on to describe a breakthrough in coil tubing drilling that is employed primarily on the North Slope because of its unique circumstances. The North Slope was developed from an onshore platform on gravel pads, drilling directionally to access the reservoir. As these fields matured and other places were identified for drilling, it became a lot more cost effective to think about using an existing well bore not only because drilling a new well is more expensive, but because of the constraints on pad size, facilities and permitting. This technology was developed primarily at Prudhoe Bay to go back into Prudhoe Bay well bores and do "side traps." Coil tubing itself has been around for a while, but the real breakthrough came from trying to downsize the drilling tools to put on the end of it. The steel coil is stored on a reel and is continuous for thousands of feet; it's highly flexible, so very short radius turns can be made to get into a reservoir after milling through the well bore. In the late 90s that technology was pushed further by downsizing the tools more to get into even smaller 3.5 inch tubing (from 4 inch tubing) that existed in most of the Kuparuk wells. Today this technology is being used for some really exotic things.

[3:57:00 PM](#)

He showed a graph of Kuparuk field production and noted that they are getting about 22 percent, 25,000 barrels a day, out of EOR and 27,000 barrels a day out of what was labeled "Base." They got other production out of well workovers, stimulations and "refracs" that are called "well interventions." The top layer indicated production from the satellites.

MR. JEPSEN said Tarn was brought on in the late 1990s along with Tabasco, Melt Water and West Sak, which have contributed substantially to production. If they hadn't done any of that work and just stayed with the base production, they would be producing about 27,000 barrels a day rather than 112,000 barrels a day. Clearly, he said, ConocoPhillips had been investing and putting a lot of time and effort into maintaining production and increase recovery.

[3:58:33 PM](#)

MR. JEPSEN moved to the "Alpine story". It was discovered in 1994 and came on stream in 2000. It really represented a breakthrough in terms of field development as he couldn't think of any other field that was developed from day-one using horizontal injector producer pairs; it saved on the number of wells that are needed. It was a tough sell within ARCO at the time, which is where he was working. But the other thing that was a little unique about Alpine at the time is that the Secretary of the Department of Interior didn't want anything they built in the wetlands of the Coleville River to be connected with the Kuparuk or the North Slope infrastructure. So they agreed to do this as a means to get the permit for development and even now there is no road that permanently connects Alpine to the rest of the North Slope. That results in increased costs, particularly during the summer time when they have to fly or boat everything in. In the winter time they build an ice road and try to move as much stuff over there as they can.

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Alpine has benefited from all the technology he had described so far, Mr. Jepsen explained. ConocoPhillips does 4D seismic and EOR and uses extended reach drilling, and is moving ahead with its next development out there, the CD5 drill site (NPR-A). It took about five years to get the permit and this will be the first production out of NPR-A that gets to one of the key issues that producers face in Alaska, which is cycle time from first deciding to do something to first production, because it takes years. In other places in the Lower 48, like Texas, you are talking months.

SENATOR FAIRCLOUGH asked if that is because land is in private ownership in other places versus state ownership in Alaska.

MR. JEPSEN answered partly, but it has more to do with the fact that on North Slope if you're going to put a drill site down, you can't just put it down and drive on it. If you do, your rigs

will sink up to the tops of their wheels and you won't be able to get them out; your trucks will sink in, too. You just can't operate. So, if you are going to operate efficiently on gravel, you have to mine it, dry it and place it; after it has "seasoned" then you can move on it. In addition, a lot of the North Slope is pretty fragile ecosystem and require wet land permits. "It's just the environment they are in."

MR. JEPSEN said he would let Mr. Campbell talk about future EOR technology, since he is an expert. He stated that they aren't done trying to innovate in these fields, but it won't be cheap.

[4:02:02 PM](#)

ALAN CAMPBELL, Greater Kuparuk Area (GKA) Reservoir and Planning Supervisor, ConocoPhillips Alaska, introduced himself.

[4:03:34 PM](#)

At ease from 4:03:34 to 4:03:46 p.m.

[4:03:46 PM](#)

MR. JEPSEN said he would cover for Mr. Campbell, because of the teleconferencing difficulties. Some of the problems they deal with are just making sure they inject things like miscible fluid or water that moves through the reservoir in a flood-like fashion, meaning it doesn't move through certain portions faster than others. So, they look at things like polymers to make sure of getting a smooth front when using injections. They also look at chemical EOR where additional chemicals are injected into the reservoir to further get more oil off of the rock particles themselves and thermal and non-thermal techniques for heavy oil recovery (like steam injection and propane). There is no economically viable process for producing heavy oil on the North Slope even though it is a very large resource and that is probably still decades away.

SENATOR DYSON said he had been told that CO2 is really helpful in lifting heavy oil and wanted him to comment on that in addition to telling him what "Darcy" is.

MR. JEPSEN replied that "Darcy" is a measure of permeability. The higher the Darcy number the more permeable it is and the easier fluids flow through it. CO2 can be beneficial in getting heavy oil, but where ConocoPhillips is working it won't be miscible like he described earlier. It can do things like swell the oil or reduce viscosity, but there are lots of issues in terms of trying to inject CO2 and have it contact very much of the fluid. Because there is such a vast difference between the

viscosity of the CO2 and the viscosity of the oil that typically when you inject it, it's just going to the highest permeability zone like a dart resulting in "conformance issues." They do it in small areas, but you're just not efficiently or effectively contacting much of the reservoir. That's not to say it's not one of the tools that they continue to try to look at.

SENATOR DYSON asked if he thought we ever will be able to get credit from the feds for injecting carbon.

MR. JEPSEN replied he hoped so, but he also hoped they didn't have to get into that world either. He wanted to leave them with the thought that there is a lot of potential still out there and that they are working on it, but it's going to be expensive. The Legacy Fields are the big target and that is where they can get a quick return for their investments, much quicker than in other places.

[4:07:52 PM](#)

SENATOR MICCICHE asked if he was talking about more expensive octa-lats (octalateral well) and that sort of technology for infield legacy production.

MR. JEPSEN answered yes, that is what they are doing these days. As they move toward the flanks of the field, they are now developing 10 ft. thick sands that weren't economic 30 years ago. The easy oil is gone. Initially, when they drill the wells at Kuparuk they'd get a 5,000 barrel a day well, no water and a little bit of associated gas; at Prudhoe Bay you'd get 15,000 to 20,000 barrel a day well. Today they don't get those rates and often times after they have drilled some pretty complex sophisticated wells they get some water back with it as well. It doesn't mean the target isn't there, but that it's more expensive and more challenged.

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SENATOR DYSON said many of the new fields do not produce as much as one well at Kuparuk.

MR. JEPSEN agreed that these fields are prolific and continue being so. For an idea of how much costs have gone up, he compared the initial Alpine development and a picture of what the CD-5 will probably look like. Alpine had 92 wells and a full production train, living quarters and an airport, two drill sites and cost about \$1.4 billion. Thirteen years later CD-5 is 16 wells (maybe as much as 21), a small drill site, a short bridge, a road and a couple of pipelines that connect it back to

Alpine and cost about \$1 billion. The price of doing business on the North Slope has gone up and there is more competition for the equipment needed up there as well. He could drill way more than 15 wells for \$1 billion anywhere else in the Lower 48 and not have to wait years to get it on stream.

SENATOR BISHOP asked for examples of cost drivers.

MR. JEPSEN answered steel, labor, day rates on wells, and cost of fluids; everything up here has just gone up much faster than the rate of inflation.

[4:12:11 PM](#)

BOB HEINRICH, Vice President, Finance, ConocoPhillips Alaska, Anchorage, AK, said he would set the stage on why ACES inhibits investment. He showed the PFC analysis of different countries' fiscal regimes on an average government take calculation using \$100/bbl price of oil. The average government take is the ratio of the amount of compensation paid to taxing authorities or third parties for third-party royalties compared to the available cash.

[4:13:13 PM](#)

PFC broke ACES into new developments and existing production activities. Under both cases ACES shows up at the higher end of the taxing jurisdictions that average 70-75 percent. This is typically higher than OECD countries that carry similar political risk and places where ConocoPhillips spends a big part of its capital budget each year.

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ACES is part of the problem making not only the average tax rate, but the marginal government share part of the problem, too. The state's share includes royalties, property tax, production taxes and state income taxes; then there is the federal portion. To illustrate the marginal tax concept, Mr. Heinrich said under ACES when oil prices increased from \$100 to \$101 at a marginal state/federal tax rate of 80 percent, the producer only retains 20 cents of that dollar increase in price. Due to the fact of progressivity as prices increase, the producer receives less and less of the incremental dollar. For every dollar end cost they can reduce at today's prices, only 28 cents of that dollar comes back to their bottom line.

MR. HEINRICH said as they evaluate projects across the range of prices, the concept of marginal share actually impacts their analysis of investment decisions.

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SENATOR BISHOP asked if he had authorization for expenditures in Kuparuk that aren't funded at this time.

CHAIR GIESSEL interrupted saying they are talking about the cost of technology today and would get into the fiscals at another time.

SENATOR DYSON said even though it costs a lot more to produce the oil now that he thought the state let them deduct all the expenses. Was he missing something?

MR. JEPSEN answered yes; they get to deduct Capex when calculating the production tax value on which ACES is based and then see what the average tax rate would be. But from his perspective, that was done because ACES is so egregiously high that they are still talking average tax rates of 70 with all those deductions.

SENATOR DYSON asked him to clarify the 20 percent they didn't get paid back on.

MR. JEPSEN explained that he was describing that ACES is based on the production tax value of the oil, a net cash type of system. So, if ConocoPhillips does something to save a dollar in operating costs they will only see 20 cents of that, because it increases production tax value, which increases their tax rate.

[4:20:06 PM](#)

In summary, he said technology and innovation have been a key role on the North Slope and will be important in the future. He encouraged the legislature to consider the fact that they are at a disadvantage because of Alaska's remoteness, high costs, transportation costs and putting the framework of the state in a way that makes other regimes look good. But if you are looking to level the playing field, given all the other things they have to contend with, looking at production incentives for Legacy fields is going to be important.

[4:20:16 PM](#)

SENATOR MICCICHE asked looking 30 years out if things are more economical and ConocoPhillips continues producing, is increased production on the perimeter of those fields more likely because the probability of infrastructure being built might make outer areas more attractive.

MR. JEPSEN answered as they move towards the "feather edge" of the reservoir, he couldn't speculate on what else might be out there. But right now, because these are marginal, infrastructure is being minimized now. The only place ConocoPhillips has expanded so far is in the southwest portion of Kuparuk the 2S development.

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CHAIR GIESSEL thanked him and said they would hear next from BP Exploration Alaska, one of the operators in Prudhoe Bay on technology and efficiencies since 1977 and how it has affected production.

[4:22:25 PM](#)

DAMIAN BILBAO, Head of Finance, BP Exploration Alaska, Anchorage, AK, introduced himself.

SCOTT DIGERT, Reservoir Management Team Leader in the Greater Prudhoe Bay area, BP Exploration Alaska, Anchorage, AK, introduced himself. He had worked in Alaska but was working in London for ARCO when it merged with BP and "jumped at the opportunity" to come back here.

MR. BILBAO said that BP had a long track record of employing technology, which he would go into in depth today. While they operate other fields on the North Slope, today he would focus on Prudhoe Bay, North America's largest oil field. He said that BP operates Prudhoe Bay with a 26 percent working interest on behalf of co-venturers, ConocoPhillips ExxonMobil and Chevron.

He said that Prudhoe Bay covers over 300 square miles and when it was originally discovered the oil in place was estimated to be approximately 23 billion barrels with an additional 40 tcf/gas. With the technology of the time, BP estimated they would be able to recover approximately 9 billion barrels, but they have recovered 12 billion barrels so far and see opportunity to produce up to 14 billion in total using some new technologies.

[4:25:09 PM](#)

They have not only improved the recovery at Prudhoe Bay but have also been able to share the learning from Prudhoe with other fields on the North Slope and elsewhere in the world, evidenced in part by the more than 200 Society of Petroleum Engineers technical papers that have been written about it. BP's operations at Prudhoe Bay are a case study in oil field

development where young and up-and-coming technical folks get trained, many from the University of Alaska system.

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MR. BILBAO said BP always starts by looking to their strategy for guidance; it defines what opportunities they focus on. Billions of barrels can be recovered and the question is what order they are recovered in, which ones meet all the multiple criteria that have to be met in order for them to compete locally for investment. First they ask themselves what can be done in the area of efficiency and they have already heard today about some of the challenges faced in Alaska and growing costs. They are also very proud of their good safety performance; 2012 was the safest year on record, a 60 percent reduction since 2009. The other areas they look at are technology and fiscal policy, but today they would focus on technology. He turned the conversation over to Mr. Digert.

MR. DIGERT took them to a cartoon illustration of how their Prudhoe Bay reservoir is laid out and what they have done to develop it on the surface. Underground Prudhoe Bay is a very large oil reservoir with a very large gas cap overlying it and water underneath oil. Their wells produce a mixture of oil, gas and water that comes up through their flow stations and gathering centers. Those process the oil and prepare it for sale down the TAPS to Valdez where they export by tanker primarily to the West Coast for refining and marketing.

The gas produced goes to the central gas facility where it is chilled and processed to remove the natural gas liquids (NGL) which gets blended back into the oil pipeline also for transport through TAPS and sale. A portion of the NGLs is mixed with gas to make miscible injectant. The rest of the gas is used as fuel for Slope operations: compression (mostly), power and light. The majority of the gas, dry residual gas, goes to the central compressor plant where it's compressed back to 4,500 psi and injected back into the gas cap where it is used to support the reservoir pressure that helps produce out the oil.

In addition to re-injecting the gas Mr. Digert said they inject water, initially, sea water that pushes the oil sideways to the producing wells. As water is produced out with the produced fluids, it gets processed and re-injected all back into the reservoir for pressure management.

[4:30:18 PM](#)

A northeast slice of the reservoir through the southwest revealed the same volume of gas cap as in the oil rim, a massive amount of reservoir pressure sitting on top of the oil. If you drilled a vertical well down through this part of the reservoir Mr. Digert said, you would basically hit oil and gas and not much else. This is called the gas cap area. In the main part of the reservoir you would drill down and find some gas, but you would also find a very large oil column called the gravity drainage area. Farther to the south is an area where all you would hit was oil and that is what they use as their water flood area.

[4:32:30 PM](#)

He explained that a couple of different methodologies and technologies are employed to produce the oil. In the gravity drainage area the gravity drainage itself is used to produce the oil. The gently dipping structure was exaggerated in the cartoon, but it actually dips at about 1-2 degrees so the oil actually drains downhill and gets produced at the bottom - the pressurized gas on top pushing down on the oil to the producing wells.

MR. DIGERT said the gas cap area has some oil. Originally, the reservoir was much flatter and was filled with oil. When it tilted, it left some oil behind in the gas cap. So, if they re-inject their lean gas up there in addition to supporting the gravity drainage mechanism, they get something called lean gas injection that vaporizes those remaining barrels that are very low saturations and produce them as well.

MR. DIGERT said a lot of technology is used with water flood not just in injecting but what they add to the water. Can they inject into different layers or inhibit the more permeable layers and force water to go into the less permeable layers. So, they use a technology now called bright water, which is actually a polymer that is injected out into the reservoir that goes out with the water and reaches fairly deep into the reservoir (1,000-1,500 feet) and then the polymer pops open and starts to block off the preferential flow paths and divert the water off into other flow paths and push more oil up and around it.

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The use of miscible gas injection was pioneered at Kuparuk; initial patents were all filed around the Prudhoe Bay and Kuparuk process. Having the gas available to use as miscible injectant is very effective. At Kuparuk they use the water alternating gas (WAG) technology that alternately injects water

and gas. The gas mobilizes the oil that has been left behind by the water and the water comes behind it and pushes it out towards the producing wells.

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Today the gas has moved down into the reservoir, but not in a uniform manner. The shale zones are impermeable (water and oil can't pass through them) and some of the gas has moved down underneath and left oil sitting on top. In places where they are injecting it tends to ride on top of those and leave oil below the shale, and a very complex area in the center called the gravity drainage water flood interaction zone has both things occurring. So, both water and oil are intermixed with very thin layers of oil.

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So, these days instead of having one well to the bottom of the reservoir they need to go find the oil and that is very difficult, because it is so intermixed now. A lot of technology - seismic, drilling logging - is employed in finding it. They are looking for oil up against faults or around shales that has been left behind. And then use horizontal drilling technology to put the bit into those unswept areas of the reservoir. In Kuparuk they are now drilling targets that are around 10 feet thick with remaining oil (with potentially a lot of gas on top of it) in some places and wondering how to get below that. When he left Alaska the first time in 1992, if the oil column was less than 100 feet, they didn't even bother trying to drill there, because it was considered sub-commercial.

Mr. Digert said in 1980 they produced 1.5 million barrels a day from the field with a little bit of water and handled about 2.5 bcf/gas a day to produce that oil. By 1990 they were on decline making 1.3 million barrels a day and producing a substantial volume of water (from the water floods), and had increased their gas handling up to about 7.5 bcf/day. By 2000, gas had further expanded to the almost 9 bcf/day on peak days and oil was down to 550,000 barrels with far more water being produced than oil. Today, they are producing about 300,000 barrels of oil a day and up to 1.2 million barrels of water a day, bringing and injecting another 900,000 barrels of sea water that brings that up to almost 2.1 million barrels of water a day. So, today they have an oil field that is masquerading as a gas field, producing gas with a lot of water that has a bit of oil coming out with it.

SENATOR MICCICHE asked as the oil gets thinner does it become more technically challenging.

MR. DIGERT answered yes. By "thinner" he meant two things: some of it is some oil remaining between thin layers of sand stone, but typically that oil column is a small band of oil with either gas or water sitting on top of it, both of which they will try and comb through and preferentially produce the gas.

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He explained that when they first discovered the reservoir they thought they had about 23.1 billion barrels of oil in place and believe that is still accurate. With the technology they have in place assuming they were going to cycle gas and re-inject it and perform water floods, they expect it to produce about 9.6 billion barrels, a 42 percent recovery expectation. Today they have produced 12 billion barrels, about 52 percent recovery. They have hopes of getting up to around 14 billion barrels if they can execute their 50-year future and that would exceed 60 percent recovery, which would be a phenomenal increase from where they thought they would be initially.

To get here there they had several major advances starting with water flooding in 1981, which required construction of two water treatment plants, new injection wells and a pressurization facility to pressurize the sea water, a series of gas handling expansions (GHX) and another project to expand their MI with another bcf/day. In 1986, they also started up a central gas facility, which allowed them to go from 2.5 bcf/day to 3.9 bcf/day. This is also where they started making miscible injectant and the NGLs which are blended with the oil and the EOR process with the WAG cycles.

MR. DIGERT said all this EOR took a lot of continued investment but it also allowed them to extend the field life substantially. They originally built with a 30-year design standard and that was passed in 2007 and they are still here sustaining those facilities and working to ensure safe and reliable operations in the future.

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In addition to the facility work, he said the initial wells were completed in the first decades with well spacing of 160-acres. Prudhoe Bay produced 1.5 million barrels a day and then they doubled the spacing so they are now down to 80 acres per well. Today BP is drilling to target "unswept zones," areas that haven't drained effectively. Like at Kuparuk, most of those wells are being done as side tracks with either a rotary rig or

coil tubing rig to try and reuse existing facilities, pad space and flow lines. This has been a very effective focus.

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They also found a couple of decades into the field, the use of rigs and coil tubing units and other non-re-activities for well work became increasingly important, because they were very mature aging wells.

MR. DIGERT said he would like to show them new activities and facilities BP had built since 2007, but they don't have any. They have not been able to find the right combination of fiscal climate and production target to justify going forward with long term investments at Prudhoe Bay. That 2007 coincides with ACES. It's very difficult to go back and look at these sorts of long-term investments - investing billions of dollars in water expansion - because they pay out very slowly. So, their focus now is on well work and rig activity, which has a relatively short payout and allows them to continue to be cash flow positive in today's environment.

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MR. DIGERT went to slide 7 that showed a 6 percent decline of production at Prudhoe Bay Ivishak, but it would have been much steeper (more like a 21 percent) without their rig activity. BP is proud of the fact that they have been very diligent and finding ways to innovate and bring on the additional barrels through using rigs and existing technology.

SENATOR FAIRCLOUGH asked if the decrease in production every July is because they are getting ready for the next season.

MR. DIGERT replied that was a good observation and the decrease in activity is a combination of two things: their rates are general lower in the summer because they actually make less energy through their big compression gas turbines with warmer temperatures, so they can't produce as much gas (their peak rates are in the winter), plus that is usually combined with turnaround at their facilities for maintenance.

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MR. BILBAO took up the presentation touching on what investments looked like over the last six years or so for BP - excluding a couple of items around mid-stream and the Liberty Project - and broke it into capital investment each year between rates sustaining versus rate adding. He said although their investment had increased through 2008/9 their overall investment had been

declining since 2008 and before ACES their rig count was approximately 10-12 rigs and that has dropped as low as 5 rigs since then.

Today TAPS is three-quarters empty, he said. One of the issues they need to recognize is that policy drives investment decisions, which drive technological innovation. While the producers control efficiency and technology, only the state government directs fiscal policy and that is what allows the opportunities to compete for investment, and those opportunities must compete globally for that investment. There is not an unlimited amount of investment available.

SENATOR MICCICHE asked if Liberty is a technology issue, a fiscal policy or both.

MR. BILBAO replied that Liberty is a large technology challenge and a challenge in other respects as well. What makes Liberty different is that it actually sits in federal waters and is not subject to ACES. So even though it is technologically challenged it is still an attractive project that competes globally.

SENATOR MICCICHE asked if Liberty had been cancelled or set aside for a brief period of time.

MR. BILBAO answered that the Liberty leases received a suspension of production from the federal government at the end of 2012; BP is evaluating the most efficient and technologically appropriate manner for developing that resource and progress the Liberty project appropriately next year.

SENATOR DYSON said they heard earlier that the state went to a net profits tax with ACES hoping that being able to deduct all the expenses would encourage people to go after the challenged oil. At the time, Pedro van Meurs told them that the negative thing they did was removing the incentive for more efficient production, because the more efficient you get the more of the total money is subject to taxes. If they figured out a way to not penalize them for being more efficient, he wanted to know what that would do to the decision process. They have also heard that the permitting process takes five years and he wanted to know how permitting impacts industry's decision process.

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MR. BILBAO said he was trying to stay focused on the committee's request to focus on technology today and would write down his question to respond to at another hearing, but basically they

look at the state's policy along with other factors and manage their opportunities most efficiently and effectively within that.

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MR. BILBAO summarized that BP is proud that it had been a member of the community in Alaska for over 50 years and had invested billions in development and technology advancements. They have leveraged technology to exceed their original production expectations, but it is becoming increasingly difficult to pursue the next barrel. Increasing production will need new long-term technologies, and opportunities drive technology; and the policy must insure it supports opportunity.

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CHAIR GIESSEL thanked him and invited ExxonMobil to offer its perspective on what it will take to keep the Legacy fields going.

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DAN SECKERS, Tax Counsel, ExxonMobil, Anchorage, AK, said they support what the field operator said at about Prudhoe Bay and Kuparuk. His perspective is that it is really in the state's hands as fiscal policy makers to determine the future of the Legacy fields in Alaska. He said Alaska has been and continues to be a very important component of ExxonMobil's global portfolio. They have had a presence in Alaska for over 50 years and are the operator at Point Thomson, the largest working interest owner in Prudhoe Bay and the lease holder of all the known discovered Alaska gas. They are committed to Alaska and its future and expect to be here for many years to come.

He said that ExxonMobil continues to support reforming ACES. The need for Alaska to develop a competitive stable fiscal regime that attracts the level of investments that the North Slope requires is one of the most important issues facing the state. The governor's four core principles that he emphasized in the State of the State speech - that any reform of ACES be fair to Alaskans, encourage new oil production, simplify and restore balance to the fiscal regime to make Alaska competitive for the long term - can form the foundation of a successful long-term tax policy for the state.

ExxonMobil believes that the changes made to Alaska's oil and gas tax regime since 2005 have had a negative impact on business activity in Alaska and Alaska's overall investment climate. The progressivity component of the ACES tax regime on top of an

already-high base tax rate creates a major disincentive to invest in the high risk, high cost opportunities that are here. These two features must be addressed for any tax policy to be successful in meeting the state's desired production and long term revenue goals, Mr. Seckers said.

Two aspects of the tax policy, however, are pro-development: deduction of operating and capital expenditures before applying the tax rates recognizes the high cost of doing business here and the further tax credit for capital expenditures which rewards those who invest in production and infrastructure. These two components of ACES should be reflected in any revised tax policy.

MR. SECKERS said he agreed with the state's own consultants that Alaska has one of the highest and most punitive tax systems in the world. It is essential that the tax structure encourage long-term development of all its potential resources. He said ExxonMobil values a predictable fiscal environment in which to make long term investment decisions. Their capital investment decisions are evaluated over decades and any change in the fiscal regime has a direct impact on them.

Because of the nature and magnitude of the risk associated with any oil and gas development coupled with the long lead time generally required to recoup that investment, he said a stable fiscal environment is key to any investment decision. Today Alaska produces more than 16 billion barrels of oil from the North Slope and there well over 5 billion barrels of known resources remaining. These undeveloped resources represent a substantial opportunity, but their development is at risk under the current ACES system. Their production today is less than one-third of peak production in 1988 and continues to decline.

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MR. SECKERS stated that industry currently invests well over \$1 billion - a majority of which is in the Legacy fields - every year just to maintain that North Slope oil production decline at 6-7 percent. Without that investment the decline would likely be 12-15 percent or greater. Without meaningful tax reform that includes and applies to the Alaska's Legacy fields, Alaska can expect production declines to continue. The Legacy fields not only provide the majority of the state's revenues, they sustain the current North Slope infrastructure and the operation of TAPS, which are critical to enabling any new production. The infrastructure from these legacy fields has already been leveraged historically for satellite developments such as Point

McIntyre, Orion, Borealis, and other non-Legacy fields to economically process and transport their oil from the North Slope to refining destinations.

Without helping Legacy fields, he said the prospects of any future new fields or development become even more economically challenged and make the probabilities of Alaska reaching its desired goal of long-term sustained production levels that much more difficult. Encouraging increasing investments to keep these Legacy fields healthy is therefore as important as encouraging investment in any new field or development.

MR. SECKERS said emphasis has been placed on making Alaska competitive relative to other regimes, but that is only part of the overall picture. Benchmarking government take against other producing areas also is a very useful tool for gauging basic competitiveness, but it doesn't provide the full picture of investment health. The majority of the spending on the North Slope has been for maintenance of existing operations not new development. The state simply has not attracted the new investment needed under ACES.

Complicating Alaska's production decline are its high exploration, development and production costs. It is one of the most expensive places in the world to develop and produce oil and gas and a stable tax structure would allow and encourage investment and ensure a corresponding opportunity for upside potential. Upside factors such as increased production and higher prices can compensate for the risk taken by investors because companies are certainly negatively impacted when lower than expected production or prices occur. High marginal tax rates under the progressive structure of ACES takes away the upside potential and reduces the attractiveness of those capital intensive investments compared to other locations where the upside benefit of investments can be retained.

MR. SECKERS said that ExxonMobil recognizes the state's difficulty in tackling the it's tax policy while protecting the current revenue streams and addressing the revenue problems just over the horizon as production continues to fall. In many cases, today's production rates are a result of government policies, technical work and investment decisions that were made decades ago. Increasing production rates in the decades to come will result from sound policies, decisions and commitments that are made by this legislature.

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He reiterated that ExxonMobil is committed to Alaska and fully supports the governor's and this legislature's efforts to reform ACES and to make Alaska's investment climate globally competitive. Alaska needs a long term resource policy that will encourage increasing investment in all remaining resources that are economically challenged both in new fields and in existing and particularly Legacy fields. The reform needs to create a balanced program using a combination of changes to progressivity, the high base tax rate and capital expenditure tax credits to provide a competitive balance of government take across all price bands.

MR. SECKERS said ExxonMobil looked forward to working with the administration, this legislature, industry partners and people of Alaska to pursue the development of Alaska oil and gas resources.

CHAIR GIESSEL found no questions and thanked Mr. Seckers for his presentation.

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There being no further business to come before the committee, Chair Giessel adjourned the Senate Resources Standing Committee meeting at 5:06 p.m.