

ALASKA STATE LEGISLATURE
SENATE RESOURCES STANDING COMMITTEE

February 6, 2013

3:30 p.m.

MEMBERS PRESENT

Senator Cathy Giessel, Chair
Senator Fred Dyson, Vice Chair
Senator Peter Micciche
Senator Lesil McGuire
Senator Anna Fairclough
Senator Hollis French

MEMBERS ABSENT

Senator Click Bishop

COMMITTEE CALENDAR

PRESENTATION: THE ALBERTA EXPERIENCE

- HEARD

PRESENTATION: PFC ENERGY

- HEARD

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."

- HEARD & HELD

PREVIOUS COMMITTEE ACTION

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

WITNESS REGISTER

MEL KNIGHT, representing himself
(former) Minister for Resource Development
Alberta, Canada

POSITION STATEMENT: Related how Alberta's fiscal decisions impacted the energy industries' investment there.

TONY REINSCH, Senior Director
Upstream Group
PFC Energy

POSITION STATEMENT: Provided PFC Energy review of capital allocation and portfolios of global oil and gas companies.

ANDY ROGERS, Deputy Director
Alaska State Chamber of Commerce
Juneau, AK

POSITION STATEMENT: Supported SB 26.

LISA WEISSLER, representing herself
Juneau, AK

POSITION STATEMENT:

JAMES SULLIVAN, Legislative Organizer
Southeast Alaska Conservation Council (SEACC)
Juneau, AK

POSITION STATEMENT: Opposed SB 26.

HAL SHEPHERD
Center for Water Advocacy and
Norton Bay Intertribal Watershed Council and
Native Village of Elim
Seward, AK

POSITION STATEMENT: Testified in opposition to SB 26.

RICK ROGERS, Executive Director
Resource Development Council (RDC)
Anchorage, AK

POSITION STATEMENT: Testified in support of SB 26.

ACTION NARRATIVE

3:30:07 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 Fairclough, Dyson, French, Micciche, McGuire and Chair Giessel.

Presentation: The Alberta Experience

3:30:47 PM

CHAIR GIESSEL announced the first order of business to be a presentation on how Alberta modified its oil and tax scheme.

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MEL KNIGHT, representing himself, former Minister for Resource Development, Alberta, Canada, said he wanted them to know how Alberta's fiscal decisions impacted the energy industries' investment there. In 2004/5, he said industry in Alberta was relatively robust with an average number of wells drilled per year and things were going along not too badly, but a political situation arose around a 1 percent royalty.

He explained that the energy industry has about three pieces to it and that the oil sands industry, a separate industry from conventional oil and gas, took a lot of R&D to get going and it is still managed separately from the rest. Conventional and unconventional oil and gas operations had been going on for about 60 years and some heavy oil was between bitumen and conventionals and is also treated a bit differently in Alberta.

So, the 1 percent royalty became a very hotly contested political lightning rod, Mr. Knight explained, because opponents to development of the oil sands and, to some degree, the media felt it was an issue and it began to be portrayed as the government of Alberta selling off Alberta's future resources for a penny on the dollar. In 2006, Alberta's leadership changed and Mr. Stelmach, from the progressive conservative party, came into power. He determined that a royalty review was needed and while it was done because of the oil sands, instead of containing it to that piece of business, the review went "carte blanche across the board," and all the structures in Alberta were reviewed at the same time. The Department of Finance conducted the review, which lead to some interesting circumstances relative to the

information and the understanding of how the energy industry performs other than the straight economics of the thing.

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Subsequently, a royalty structure was put in place that can historically be seen as having been a bit of an issue relative to industry investment in the province, because drilling decreased immediately. The energy players at the time were very dissatisfied with what had happened and felt that their net present value of projects going forward in the province was not going to leave them in a desirable situation. Now that Alberta government people understand more about the energy industry, they know that it moves its money wherever they can get the best return for their shareholders.

Unfortunately, Mr. Knight said, the global recession contributed even more to the decline. So, from 2007 through 2009 Alberta restructured its royalty and worked through various incentive programs that increased activity dramatically starting in 2009. As they were taking "a bit of a licking" from places like North Dakota and British Columbia, they targeted incenting new technologies that hadn't been applied in Alberta yet.

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A new 5 percent royalty rate for horizontal gas and oil drilling for one year and up to 36 months of production was put into place; the same for coal bed methane and shale gas. But what established the upward ramp in drilling activity in 2009/10 was a two-year drilling royalty credit from meter-age drilled on new wells or reentries with new formation targets. Anybody that was working with production in the Province of Alberta could apply and get credit for royalties owed to the Crown by hiring a rig and starting new drilling. They also brought in a natural gas deep drilling program looking for tight sands and shale beyond 2,000 meters (where information was lacking). That 5 percent royalty started out as a short term program for any new well, but it was subsequently established as part of the ongoing Alberta royalty structure.

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They have a progressive system that is capped. Prior to the 2010/11 adjustments the cap was at 50 percent, but it got lowered to 40 percent, which made a big difference to industry that was working on the new resources.

In his opinion, Mr. Knight said, they need to look at this thing from a pretty long term horizon, but politicians tend to look

from term to term. Alberta did a 30-year energy policy strategy all related to horizons that are out at least two decades and, in some cases, three.

SENATOR DYSON said he may be using the term "royalty" differently. For Alaska, royalty is part of the contract, he explained, and pretty standard at 12.5 percent, but Alberta's varies. Alaska has a severance tax on profits, and he asked how Alberta's system related to our system.

MR. KNIGHT said he didn't know how it would relate to Alaska's system and that Alberta doesn't have a severance tax at all. It relies on industry activity and feels that 60 percent is a fair receipt for having their resource developed by any individual or corporation. Alberta looks at this issue from three points of view: as the owner of the resource and getting a fair return, which doesn't mean just collecting royalties, and the development itself, which generates a tremendous amount of ancillary economic activity. Bonus bid activities went up to record highs, a couple billion dollars-plus in some years, with the change.

SENATOR DYSON asked if companies pay local property taxes or federal taxes and if that was included on his graph.

MR. KNIGHT replied yes they do, but it would be on top of what the state collects as depicted on the graph. Oil profit gets taxed provincially and federally and each municipality has a linear tax structure (not shown) on all the facilities including pipelines and any other infrastructure they have in place.

SENATOR DYSON asked if he meant the maximum for all taxes should be 60 percent.

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MR. KNIGHT said all the taxes are included in the cost of doing business. Royalty at the end of the day is the margin.

SENATOR FRENCH asked if their royalty system is based on the gross value of the oil coming out of the ground.

MR. KNIGHT replied yes; the revenue that someone would earn selling the resource becomes the focal point of the taxation, but they are allowed to credit the cost of getting there in the first place.

SENATOR FRENCH said he read a document called "Royalties in Alberta" to prepare for the meeting and it said that each oil well is unique, producing different grades and types of oil as well as different quantities. Consequently, the amount of royalties is calculated on each individual oil well and based on the volume of oil produced from the well, the density of the oil from the well, the well classification based on the vintage of when the oil was discovered and a royalty rate factor, and he asked if that system is still in place.

MR. KNIGHT replied yes.

SENATOR FRENCH asked what has been the economic impact on the finances of the Alberta provincial government since the 2010 changes were made.

MR. KNIGHT replied they don't know, because the benefits won't be seen until past 2015, mostly because of low royalty rates on a lot of the new work. Initially, a tremendous number of people went to work in Alberta, but the real benefit is to the longer horizon.

He said that companies need access to capital, the ground and markets, and Alberta is a bit constrained with respect to access to market, so some of the work that has been recently won't make it to the market place for a period of time. In about 10 years' time, they have attracted 600,000 new Albertans.

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SENATOR FRENCH commented that McClain's, a Canadian news service, reported that Alberta has a \$6 billion budget shortfall and asked if that was accurate.

MR. KNIGHT replied that was a good guess. He explained that most of the pre-budget work done for Alberta was predicated on them being able to deliver and sell certain amounts of oil at certain prices. Constrained access has led to a huge differential between the price of Western Canada Select and West Texas Intermediate (WTI) on the shipments going out of Alberta and that has caused the revenue shortfall, which he didn't think would be that dramatic. The government might have to withdraw money from a sustainability fund that they put money into knowing that things wouldn't be rosy forever.

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SENATOR MCGUIRE asked him to describe the competitiveness review process Alberta established. How did he formulate that committee and what did they do to become competitive again?

MR. KNIGHT said the situation they faced was quite dramatic. The people who did the review had not done a lot of in-depth work with the industry. There was a bit of a misunderstanding by the people who built the review in the first place of what the industry needed in order to stay robust in the province. They put the review in place, made a number of changes in royalty that were suggested in the review all the while in close contact with industry players.

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He explained that Alberta's situation is slightly different from Alaska's. Alberta has 20 or 30 large players and 1,200 or 1,500 small players. Through discussions with finance people in the companies of the majors and the junior players, it became quite evident that Alberta put itself in a situation where while the energy industry could make money there, more could be made in other places maybe using new technologies. They had a lot of good public meetings with individual companies, business and industry representation groups, digested the information and made some decisions on what they thought was prudent for Alberta.

SENATOR MCGUIRE asked him to summarize the most important changes and how long it took to get industry back.

MR. KNIGHT said it took about a couple of months and while there was never a guarantee in all of their discussions; industry always indicated that Alberta had good rocks, but what they needed was taking away the front end load a little bit so they could find out if the new technologies were applicable to formations there. So, that is what government did. They gave a drilling credit for spudding and drilling, but you had to hire a rig and drill a hole in the ground; it couldn't be used for anything else. The new well 5 percent royalty became a main piece that was important at the time, because it helped the players at the front end. In a lot of cases those energy companies put that money right back into communities around North America.

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SENATOR MICCICHE said the oil royalty rate dropped from 50 to 40 percent, but the price seemed to be bracketed at \$50, \$65, \$75, \$100 and \$120.

MR. KNIGHT said it wasn't bracketed, but it was just a matter of fitting into the curves. They have old and new oil and tier three oil, and a bunch of that was wiped away in the later iterations of the review.

SENATOR MICCICHE asked if the curves were the same.

MR. KNIGHT replied generally, but there were some slight changes at the top end where they hit the cap.

CHAIR GIESSEL thanked Mr. Knight very much for his remarks.

Presentation: PFC Energy

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CHAIR GIESSEL invited Tony Reinsch, PFC Energy, to talk to them about capital allocation and global portfolios.

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TONY REINSCH, Senior Director, Upstream Group, PFC Energy, provided a capital allocation and global portfolio review. He said while PFC Energy has staff geologists and engineers, they are focused on the above-ground issues, challenges and opportunities that are being faced by international oil and gas companies, regulators, governments and national oil companies worldwide.

He related that he works with the Upstream Group which focuses on the competitor landscape for the 30 or so largest oil and gas companies globally and about 25 of the largest national oil companies. They spend their time trying to untangle strategies, their growth plans and prospects and occasionally try to lend advice to the companies on where they might be going and to governments on how to best get them there.

MR. REINSCH had some thoughts on the Alberta fiscal system he had prepared last year for the Alaska legislature would be useful to go through. He started with a presentation entitled "Exploration Spending in Western Canada." The most material upheavals in fiscal systems in Alberta were the National Energy Policy, which was imposed on the provincial government by the federal government in the early 1980s, and the other was then Premier Stelmach's sharp imposition and reversal of fiscal change in the 2006/7 period. Both were the results of economists and otherwise clear thinking people losing sight for a moment of the market cycle and getting caught up in the idea that, in the

case of the 1980s and the National Energy Policy, oil prices would go up forever - requiring a change in the constitutional fabric of Canada - and the Finance Department's taking a position that oil production in Alberta would go down forever - therefore shifting to implement a fiscal regime that was really predicated on harvesting out the long tail end of a resource production curve and taking a larger share for the government as it was produced out. Both initiatives were incredibly ill-timed.

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MR. REINSCH explained that the shift in fiscal terms introduced by Premier Stelmach in 2006/07 at about the same time as ACES was put in place in Alaska. Both were harvest-type fiscal moves. The impact in Canada was a very dramatic shift in activity levels away from Alberta and into British Columbia and Saskatchewan. The chart on slide 43 showed Western Canadian exploration spending over the decade 2000 to 2010 broken into those three areas. Exploration activity recovered by 2010 and continued to climb. The question is if this relationship is causal or correlative and did fiscal systems drive all of this dramatic move or did a lot of factors come together to cause it.

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MR. REINSCH said one of the leading indicators that PFC used for exploration activity in Western Canada was land lease sales (the bid and bonus structures), and generally speaking Alberta has led the pack. Probably the sharpest response they saw terms of companies leaving Alberta was the drop in in lease sales and the equally dramatic rise to almost two-thirds of lease sales in British Columbia and Saskatchewan.

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Were oil and gas companies just running away from Alberta and going to B.C. and Saskatchewan? In reality it was oil and gas companies taking the opportunity to both send a message to the Alberta government that they weren't happy and also to start locking up land in what were going to be very important plays - like the emerging sort of Bakken North/Lower Chinvan Play - in southern Saskatchewan where shale oil plays are now impacting oil production throughout the Lower 48 and Canada, and in B.C. toward the northeast - locking up large prospective shale gas land that looked perspective for the kind of technologies that were being matured in the United States but hadn't really made it to Canada. There were definite opportunities the companies were chasing. But it was also a convenient time to push back on the government to suggest that they had miscalculated something significantly; and that miscalculation was that rather than

being at the tail end of a long resource curve, this industry was getting ready to reinvent itself on the basis of horizontal drilling, multi-stage fracturing, smart drill tools and the other techniques developed and matured in North Dakota and Montana, but every bit as applicable in Canada. But, while fiscal systems definitely had an impact here, the biggest driver "without question in terms of impacting activity levels" was commodity pricing over that time period.

Another chart showed all exploration development drilling activity in Alberta excluding the oil sands (because Alberta treats it as a different business). It showed that the western Canadian sedimentary basin had become a gas play by 2006 when oil drilling and production had been in decline for a long period of time. And from the viewpoint of finance this was an industry in a permanent, gradual, maturing decline, and therefore ripe for increase in government take (because it wouldn't impact any more exploration). In 2006/7 the Henry Hub natural gas price averaged \$6.74/mmbtu and the equivalent pricing point for Alberta, called CECO-C, was \$6.15 (a little less for transportation). In July of 2008, Henry Hub peaked at \$11.70/ mmbtu, but since the period of December 2008 to April 2012 that same price has averaged under \$4/mmbtu. Not only did the price crater, it stayed there. Not surprisingly, oil and gas-directed drilling responded exactly the same way.

Oil prices were rising, gas prices were falling. In April 2006 to March 2007, 11,500 gas wells were drilled in Alberta; over the equivalent period in 2011/12, 1,600 were drilled. What drove that was the returns coming to natural gas. He pointed out that one of the sharp distinctions between Alberta and Alaska is 11,000-13,000 wells a year. He said this industry can move money around very quickly and that shallow drilling is inexpensive and that makes it a different world.

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MR. REINSCH said today's presentation would come in two parts. He would first discuss PFC's thoughts on how oil and gas companies really make their decisions in terms of capital allocation budgeting and long range planning, not only specific to a given set of activities (such as in Alaska), but how they allocate their global funds, because the majority of Alaska's players have global reach in their portfolios. He was also asked to provide some thoughts around the particular global strategies in portfolios of three key producers: BP, ConocoPhillips and ExxonMobil. So, he thought it would be instructive to look at

companies' annual planning cycles that are common to all of the large oil and gas companies.

The oil and gas annual planning cycle:

Q1: Strategy review and update targeting long range plans

Q2: Session with the Board of Directors where they share their views and receive directives from that

Q3: Budget preparation

Q4: Budget review and approval

Then the cycle starts again.

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During the strategy review and update, companies that traditionally operate in Alaska take this approach: looking first to the future of the world and where the industry is going for a minimum of a decade and as long as 20 years. They look at the planning environment, key uncertainty forcing factors and what has really changed and where they might want to go as a result. So, global economics, supply demand balances and geopolitics are always very important. This analysis will be done broadly at first and then in more depth in each of the areas where a company is operating.

Above ground they look at operating environment ranging from safety to fiscal terms, market outlook, new resource activity, if the market growing and competitor landscape, and how a company is positioned to either gain or lose in that environment. With all the material pulled together the company applies its own filters; it has its targets and objectives and "no go places" that are a CEO's personal preference. Eventually it comes down to a set of strategic options that it then looks at in detail.

The budget cycle is when that information turns into capital allocation. In the accounting cycle the function of corporate (central agencies within these companies) is really to provide all of the business units with a set of common assumptions. For instance this is what we think about oil prices, gas prices, and about the Middle East. And they feed those down into each of the business units who in turn will look at their portfolio of opportunities and they will come up with a long range plan, a five year plan and a budget. Normally, it's expected that the budget is the first year of the five year plan, so there is good continuity and flow. That information and the capital required to execute those plans are rolled back up to corporate. They will almost always be well in excess of available capital, so

they are rolled back down to the business units that come up with a solution.

That solution or long range plan recommending capital allocation is taken to senior management and then to the board for approval and on that basis programs are funded and executed.

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MR. REINSCH explained that a project attracts capital by the same basic process. Creation of project approval review represents discrete business decisions. Each business unit will send one up to sometimes dozens (depending on how active the unit is) of these individual project approval requests (PAR). For example, you may have a project approval request that relates to the capital required for asset positioning (entering a new basin and doing initial analysis and seismic acquisition), another and separate approval request for exploration with an expected outcome, another approval for appraisal of exploration success if there is any, and a movement to development. All of these are stage gates at which point senior management can approve the next step of development, have it amended, have activity suspended or decide to exit or divest. A classic industry example of this is BP's decision to divest the Forties Oil Field in the UK North Sea to Apache.

He explained that the Forties Oil Field is an Alaska-type asset; when it was discovered in the early 70s it had 4.5 billion barrels of original oil in place. BP produced that field until 2003 and sold it to Apache for \$670 million when the field went into decline for a number of years. When the sale was agreed on, it had 144 million barrels of remaining reserves. In the period of 2003 to 2012, however, Apache has produced 170 million barrels of reserves from that field and has estimated that it has another 150 million barrels. This is a classic case where BP looked at the world, its portfolio and global assets that were asking for capital (large scale deep water developments in the Gulf of Mexico and West Africa) and it made a decision that production at Forties was at 40,000 barrels a day and (what they thought) was declining unless significant capital, management expertise and time was put towards management of that reservoir and that field. They made the right decision for them to sell it to Apache. Apache has maintained production from that field at 5-60 thousand barrels a day ever since and have spent \$3.6 billion in doing that.

He explained that BP knew the resource was there, but they would not have done the work Apache did to increase recovery rates. Companies go through this churning of assets every year.

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The business control architecture (portfolio) might look like this:

Exploration PAR - Appraisal PAR - Development PAR

Appraisal PAR - Development PAR

Basin/Country Entry PAR - Exploration PAR

Year One - Year Two - Year Three - Year Four - Year Five

Approvals for Expenditure (AFE) are listed under those years and culminate in a budget for each year. As you go forward the budget gets recalculated.

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MR. REINSCH explained that the basis on which this process for capital allocation leads to investment decisions within basins and across the portfolio - in Alaska, for instance, an enhanced recovery project needs to compete against what ConocoPhillips and ExxonMobil having ongoing elsewhere in Alaska (competition within the portfolio), is also competing against similar types of capital expenditures and Capex investment broadly from exploration through to production activities.

Importantly, capital programs also have to compete against the other uses of the funds outside of oil and gas activity like debt repayment, share buyback, and dividend policies. For instance, over the last 10 years ExxonMobil has spent significantly more on share buyback and dividends than it has on oil and gas investment activity, creating an artificial scarcity of capital. Mr. Reinsch said this company generates so much money that it could undertake everything that their business units want, but doing that would be funding potentially uneconomic or inefficient activities.

MR. REINSCH said the basis on which companies assess the relative and absolute attractiveness of their portfolio's constituent parts is in five ways: growth, profitability (ability to manage the bottom line), efficiency (ability to manage capital), cash flow and risk.

Growth: Ability to manage the "top line"

-quality of growth: where, how, consistent or not, plowback rate

Profitability: Ability to manage the "bottom line"

-cash flow, net income, production costs

-absolute and on a per barrel basis

Efficiency: Ability to manage capital: growing or destroying it?
Cash Flow: Ability to manage investment/re-investment in the portfolio

-ability to finance undertakings, making adequate net income, debt ceilings, are fiscal systems turning against you in core areas of operations

Risk: Ability to manage a diversified portfolio

-debt to capital ratio, financial flexibility

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He said energy companies employ the following variety of benchmarks to rank their investment opportunities and then allocate their investment capital to them:

-Payout period: how long to get money back (more critical to smaller companies).

-Internal rate of return: time value of money; for instance, you can have your capital exposed for four or five years before seeing any initial production for oil sands. All those revenues need to be brought to a single point in time to compare against other opportunities.

-Net present value: try to bring all activities to a current point in time.

-Recycle ratio: a popular metric used in the industry is profit divided by defining the development costs. Basically, corporate profitability wants that ratio to be greater than one (if they invest a dollar, they want to get more than a dollar back).

Some metrics are also used for cash flows:

-Availability of free cash flow for follow on or alternative investments

-Maximum negative cash flow exposure

-Net booked reserves: critically important, because if you can't book the barrels it has no value to your company

-Capex: incremental costs of the development along with shared costs of existing infrastructure

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Internally, a company will take these metrics and use them to allocate capital to projects and, very importantly, allocate no capital to many projects.

For a project to even be eligible for a budget Mr. Reinsch said, it already has to have passed absolute hurdles; for instance, it has to have a NPV greater than zero; there has to be an expectation of net returns generated; you want to see a 30

percent return on investment and possibly a short payback period.

A company will have a number of metrics across its portfolio that are used as hurdles: an IRR hurdle rate of return against a set of capital projects that is stacked highest to lowest.

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SENATOR FRENCH asked what happens to this process when companies want to become joint ventures.

MR. REINSCH replied that within any joint venture technical planning committees will come together around a set of planned capital expenditures usually developed by the operator who takes the lead role and the others contribute. Once the joint venture committee has agreed, they go back to their respective senior management teams and boards and try to attract the share of capital they will have to put up. Often one will see the planning committee request from a joint venture not being able to move forward because one or more of the partners simply doesn't have the capital or disagrees fundamentally with the direction.

He explained that in many of these joint ventures, the operator can cash call the participants in the sense that "we're proceeding; here's the amount you have to pay. If you don't want to play, that doesn't mean you are out, but it means you will forfeit the benefit that may come from that Capex spend" - or some other penalty (for instance, you have to spend three times your capital allocation upfront cash).

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SENATOR FRENCH asked how it works at Prudhoe Bay that has three major owners: BP, ConocoPhillips and Exxon. How does the nature of their legal structure enhance or impede the development of new projects?

MR. REINSCH answered that that he wasn't an expert, but he thought unanimity was required for approval.

SENATOR FRENCH asked Mr. Reinsch to give some thought to roadblocks E&P can put in place when you have companies have wildly different moments in financial time.

MR. REINSCH remarked that they are paragons of internal upheaval right now.

SENATOR MICCICHE asked if there is a partnership and one has an IRR hurdle at \$60 and one at \$80, if there generally is a compromise or would they go for the highest hurdle.

MR. REINSCH explained that IRR hurdles are established internally for each company. The project joint venture team will also have an IRR that truly reflects the economics of the project itself. It may be difficult to do, but the project has to live and die on its own merit. A project is ranked at very different points of companies in their corporate lives. IRR is an outcome of an individual project, but the corporate IRR for ExxonMobil versus BP, for instance, for a project in North America would be internal to its own corporate determination.

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He explained that if you rank a series of projects on IRR from highest to lowest and if you had an IRR hurdle based on \$60/barrel, four or five projects may be undertaken, but all other projects do not attract capital within that budget. If you increase the oil price - hence more cash flow and more investment capital becomes available - you will tend to see a reduction in that hurdle rate as companies feel themselves able to take on more projects that perhaps have a lower threshold in terms of IRR because they are now in a higher revenue environment. However, as prices get to \$120/barrel (recent Brent crude) if you didn't put some sort of break on that, all projects could be undertaken and hence the larger E&P companies, international oil companies in particular, take very large shares of their revenue and distribute them back to shareholders to artificially create some scarcity in capital allocation to make sure they are being efficient as they make these decisions.

Efficiency in capital allocation measures for the big three companies in Alaska vary from those of a smaller independent - the tradeoff being efficiency and growth. It is measured by return on capital employed (measuring the profit being generated by a company divided by how much capital is being exposed). Capital can be measured in terms of the value of assets and investments or in terms of share capital, reserves and debt.

Basically, the higher the return on the capital employed, the more efficiently you are using your capital and that metric changes over time revealing whether profitability is improving or eroding, and if it's eroding, what are you going to do about that.

MR. REINSCH next showed a chart of upstream corporate return on capital employed for what PFC calls the "global players" in terms of size, reserves and et cetera. Another chart showed the Tier I independents, a large group of independents that are within striking distance of 1 million barrels a day production. They consistently have a very different return on capital.

The period of 2009-2011 showed a little over 20 percent growth for the global companies; for the Tier I independents it was a little over 11 percent and the next group drops down to 9 percent. However, what the smaller companies give you is growth. One of the anomalies in this industry is to find a company with both high return on capital employed and high growth. The reason comes out of the equation of "return on capital employed." Basically this penalizes major capital investments. So, anything that makes the denominator bigger makes the return on capital employed smaller. On the other hand, it benefits from anything that makes the numerator (higher volume) larger. Large capital projects tend to be structured with three to five years of very intensive capital spend during which the return on capital employed is being drawn down, because you're investing heavily with no return, followed by (generally speaking) high production from that investment, because companies want to get the money back as fast as they can - outside of a very few projects such as mined oil sands plants and LNG facilities.

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So companies move in and out of that space of high return/low return on capital employed and high/low growth.

Importantly for Alaska, Mr. Reinsch said, depreciation creates bias in favor of a mature portfolio, so the older your assets the better return on capital employed, because the denominator has been accounted away. So, all else being equal, your return on capital employed is improving just by doing nothing other than maintaining activity levels (and price).

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Shifting gears, Mr. Reinsch spent some moments talking about the portfolio strategy of Alaska's three major players. He said it is remarkable that these are three of the ten largest international oil and gas companies globally that have all over the last three to four years been subject to and continue to go through transitional change in strategy, in positioning and approach to the future. These are companies you would expect to have everything thought through and in control of the situation,

including ExxonMobil, which has once again become the largest publicly traded company in the world with the collapse of Apple.

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He next talked about how Alaska fits into these portfolios starting with BP saying everyone was familiar with the Macondo blowout in the Gulf of Mexico, which triggered a transformation of BP. BP largely addressed the liabilities stemming from that incident by pledging point forward production from its very large and lucrative Gulf of Mexico portfolio to the Macondo fund.

This company took advantage of a period of upheaval and change to fundamentally restructure their global portfolio, taking some \$26 billion of divested assets globally, entire portfolios in the Asia/Pacific region, the majority of their conventional onshore oil and gas in North America, stripping all of those - what they considered mature non-core immaterial assets - out of their portfolio and buying back or reinvesting in about \$30 billion in new positioning in new basins with new companies, like their joint venture with Reliance in India. So, they came out with a smaller portfolio, but a much more growth oriented one than prior to Macondo, and interestingly not only recommitting to their deep water basin growth platform, but in fact deepening their commitment to deep water activity. This is the outcome of a company that many were suggesting would be broken up or never allowed to operate in deep water again.

BP has a three-pronged growth strategy that continues in deep water basins, global gas and giant oil fields, and Alaska fits in the later currently and may fit in the second category of global gas depending on the future of LNG in this state.

He said BP's most recent move was the sale of its interest in the TNK-BP consortia in Russia that will net the company some \$22 billion. By doing so, BP will become arguably the second private company to make money in Russia (the first being Marathon, which made money by buying and selling out of Russia twice). As a second step, BP is looking to take an equity stake (20 percent) in Rosneft, the acquirer to TNK-BP moving them into much more perspective growth areas and solidifying their position in the Arctic resource development - sort of the long run play of which Alaska is a part, as is northern Canada, Norway and Russia.

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CHAIR GIESSEL asked why Alaska was shown as a harvest area for BP on a slide he presented on April 21, 2012, eight months ago; but now it is shown as a core area. What changed?

MR. REINSCH explained that in that material Alaska was broken out from the U.S. in BP's portfolio as a harvest area as it exists today, but the U.S. is core to BP. Alberta was a harvest area for 15 or so large players until the technology of horizontal drilling and multistage fracturing and smart drill tools allowed them to access shale oil, tide oil and shale gas. Everyone knew it was there, but they just didn't know how to produce it commercially until the technology developed to that level. As an example, a material LNG development in Alaska would become core to the company's future.

CHAIR GIESSEL asked if by showing Alaska as core on the current map was he combining it with the U.S., but if he were to separate it out, would it still be harvest.

MR. REINSCH answered yes.

CHAIR GIESSEL said earlier he had mentioned that ACES was a "harvest type of a fiscal regime" and asked if that was the element that would make made Alaska a harvest area or if there are other factors.

MR. REINSCH replied that a harvest area may continue to have capital investment, but the production is in a sustained and unlikely-to-be-reversed decline and the free cash flow being generated is being moved outside of the jurisdiction and invested elsewhere.

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SENATOR FRENCH said last year this committee was presented with a 2004 BP memo, which predates ACES by three years, that said Alaska's role in BP's portfolio is to provide a stable production basin cash flow to fuel growth elsewhere in the business. So it was in harvest mode even back in 2004.

MR. REINSCH replied that is consistent with how they define harvest mode. To re-interpret the bars, 2001 is the lightest blue, 2011 is the middle blue and 2016 is PFC's forecast using their modeling of the global portfolios of the global companies. PFC models all current producing assets and all discovered and/or underdeveloped resources in each of these companies' portfolios annually. This analysis excludes the TNK-BP sale which concludes at the end of this quarter. BP has said their

intention is to have a production floor of around 2.4 million barrels a day following the TNK-BP divestiture that will take about 1 million barrels a day of production with it. Post the TNK-BP divestiture, BP will be a materially smaller company pending their equity investment in Rosneft.

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He said this chart showed where BP is looking to grow on a regional basis, and their growth is likely to come from North America (Gulf of Mexico deep water and Lower 48 on shore) and Latin America where it may be larger depending on how aggressively they engage in joint venturing of strategic associations with Petrobras in the Brazil pre-salt deep water play. By acquiring the \$30 billion of assets, BP is positioned aggressively in that particular deep water basin, consistent with their growth platform.

TNK-BP in Russia was a mature portfolio and one of their challenges was limited growth in terms of opportunity, but they also faced a very difficult fiscal environment in which it was a struggle to show growth or return on capital employed. They are hopeful that by re-investing in Rosneft that will change.

MR. REINSCH said BP is churning their assets in regional areas, which usually means for companies of this size is that they are investing to keep up with decline. It's hard to grow a large portfolio significantly.

CHAIR GIESSEL said in being able to look at his presentation eight months ago and now she appreciated how dynamic all of this is. For instance, on April 21, Azerbaijan (Central Asia) was the largest source of new source volumes through 2015 and that changed very rapidly in just a few months.

MR. REINSCH agreed and added that this chart doesn't make clear that these numbers show the net outcome of portfolio decline and new source production. If they looked at simply new source, incremental production going forward, Russia absolutely was the largest area of new source even though overall production wasn't expected to move very much. That is because the active onshore basins were TNK-BP that is very mature. It's hard to keep up with the decline, but if you do, that means you are generating a lot of new production. And if the Rosneft deal doesn't transpire, then BP will have \$22 billion to do something else with.

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The next slide was PFC Energy's assessment of how BP fits Prudhoe Bay into its global portfolio. They see it as a harvest asset; production volumes are modest and have been declining for a while. There is long term potential in Prudhoe Bay and Point Thomson gas resources, because with the Denali Pipeline now canceled, BP is positioned as a potential supplier to some alternative commercialization options such as a large pipeline LNG scheme that would access high value markets in the Asia region.

BP's Challenges:

- Portfolio rationalization is coming to an end. Analysts are looking at how to re-ignite growth.

- BP needs a new core area if Russia isn't going to be one. Even in the absence of that they are heavily exposed in the deep water in a couple of areas. The deep water partnership with Petrobras may be that new core and they have enormous unconventional gas resource holdings and unexplored acreage in the Lower 48 and the Canadian oil sands where they have been relatively slow to develop on their leases for whatever reason.

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Shifting to ConocoPhillips, Mr. Reinsch said, their upheaval has been equal if not greater than BP's. Just a few years ago, mired in low share value and uncompetitive earnings multiples, they embarked on a different strategic pathway - the shrink to grow strategy. They essentially sold \$15 billion of joint venture obligations and assets and returned those funds to shareholders one way or another, either through dividends, buybacks or debt reduction. Part of that was their 20 percent equity investment in LUKOIL in Russia and repositioning their global portfolio to a focus on the OECD or industrialized companies, a relatively safe haven when other competitors were taking on more and more above ground risk (moving into Interior Africa, the East Coast, and the Middle East). These areas all tend to be expensive and very competitive in terms of accessing acreage and opportunity. It's not a low cost strategy, but a differentiating strategy. Then in July 2011 they took the step of separating the company into two distinct entities: Phillips 76 (downstream assets) and ConocoPhillips the largest pure play independent oil and gas company. The question now is where this company is going from here as it is very difficult to take a company like this apart. Their latest corporate investor presentation of 2013 will be their bottom point with some growth returning over the subsequent two to three years.

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ConocoPhillips' global portfolio includes Canada, United States, Norway, and the United Kingdom and a number of areas where the company is looking to exit (as is the case in Russia). ConocoPhillips has now moved out of the group of global players and into a new competitor space which are the independent oil and gas companies of which it is the largest. Its peers are: BG Group, Occidental, Apache, Anadarko and Suncor.

SENATOR FRENCH asked if the Burlington Resources purchase was a good move.

MR. REINSCH replied it was a good move but bad timing. In 2006 ConocoPhillips found itself in the "never, never, land" which is they were much larger than the next group down of independent and integrated oil and gas companies, so they couldn't compete with them on growth. Their production was too large to grow it 3-5 percent whereas the smaller companies can do that. But their portfolio wasn't deep enough with large scale capital projects to compete with the big super majors on return on capital employed and they found it was hard to get the value they believed was in their portfolio reflected in their share price. So they bought Burlington Resources, a big North America conventional oil and gas player. Unfortunately, that acquisition closed within a month of the peak of the gas price in the U.S. They thought prices were going to stay at these high levels if not increase further, because demand was strong, but within three years of shale gas commercialization the bubble was gone.

Demand is still there he said. The collapse in the U.S. gas prices is absolutely not a demand story; it is completely a technology and supply story. ConocoPhillips was just at the wrong moment and has spent the last few years trying to manage that decision.

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MR. REINSCH said ConocoPhillips is a significant Asia player, but its dominant position is in North America having exited out of Central Asia and Russia in 2011. Unlike BP, Alaska is core ConocoPhillips' portfolio; its core to their strategy and to their significantly smaller global production base; hence it is viewed differently within their decision making process.

SENATOR FRENCH said ConocoPhillips is the only one of the three majors in Alaska that reports its Alaska numbers separately and a document with those numbers was run through Legislative Research a couple of times and come back with really strong

profit numbers in Alaska relative to ConocoPhillips' holdings in other parts of the world. He wanted to ask him at some point in the future whether that was accurate and how that might affect ConocoPhillips's investment strategy in Alaska.

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MR. REINSCH went on to ExxonMobil that has been the most surprising circumstance of dramatic portfolio change, because it's not a company that wants its text to change in any substantive way. It found itself in a "bit of a box." The decade of very strong growth that ExxonMobil delivered until 2011 was really driven largely by their very large LNG portfolio in Qatar. The Qatari government put a moratorium on incremental further development from their enormous North Field gas resource base that continues today. So, that growth engine ended for ExxonMobil in 2012 when the last of their LNG trains and developments came on stream. So facing a flat production future in Qatar, declining production from both Europe and Asia Pacific, the company looked elsewhere for growth.

5:20:56 PM

Venezuela had been closed and ExxonMobil was unable to strike a deal with the new Chavez administration some years ago when it exited the country. Brazil deep water looked to be the perfect growth platform for ExxonMobil until the government introduced new legislation that gave Petrobras operatorship and a 35 percent working interest in all future licenses and developments in the very large pre-salt deep water play. ExxonMobil is not a non-operator participant when it can avoid doing so, so Brazil has become much less interesting to them. They tried to position in the equatorial margin, a frontier basin that is being de-risked, but was rebuffed by the Guyanese government when it tried to buy its way into the Jubilee Development in the offshore gas resource.

Where is a company of ExxonMobil size going to grow? They took a daring move and aggressively positioned themselves in unconventional resource play in North America through the acquisition of XTO Energy, really exposing this company substantially into an area that is not what it has been known for (big large scale field developments, execution excellence and cost control and reduction). Moving instead into an area that may have large global reach, but it involves tread mill drilling, moving capital very aggressively from play to play and sub-play to sub-play, a minute micro focus on capital and drilling costs that are very much changing how this company is looking to grow moving forward.

MR. REINSCH said ExxonMobil is the largest of the global players by a significant margin. The XTO purchase had material impact on it and in 2010 BP moved slightly above ExxonMobil in terms of total production.

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Regional growth trajectories are continuing to decline in Europe, flat production for Middle East and North Africa (really meaning flat production in LNG developments in Qatar), but big annuity projects. Interestingly, their growth is really coming from North America. It's interesting to see the biggest of the big moving back to their home basins to take advantage of the technological changes to fuel their growth for the upcoming decade (oil sands development).

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SENATOR MICCICHE asked what "other" means in terms of "technological competencies" for ExxonMobil.

MR. REINSCH answered that it is a grab bag of "other" categories that ExxonMobil exploits at the technology margin, or the frontier, instead of predominantly conventional oil or gas plays. In ExxonMobil "other" is a very small amount of future looking technology.

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He said that PFC sees Alaska as a harvest area within ExxonMobil's overall globally portfolio subject to that same proviso of changing opportunities like commercialization of the large gas resource base in this country.

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SENATOR FRENCH asked what it suggests if Prudhoe Bay investment decisions require all three partners to agree and yet by his analysis, two out of three view Alaska as a harvest area and one perhaps wants to be more aggressive.

MR. REINSCH answered the combination of unanimity within the joint venture and also the absence of any sort of relinquishment provisions creates an environment where capital needs to be attracted by being competitive. Higher prices and changes in fiscal terms may or may not move that lever. None of the companies individually can guarantee that any change that takes place is going to result absolutely in a certain action response. "Unanimity makes it harder," but is a facet of that agreement that has been in place from the beginning, so much has

been invested and done to the benefit of the state with that structure.

CHAIR GIESSEL thanked Mr. Reinsch.

[5:27:38 PM](#)

At ease from 5:27 to 5:34 p.m.

SB 26-LAND DISPOSALS/EXCHANGES; WATER RIGHTS

[5:34:19 PM](#)

CHAIR GIESSEL announced the consideration of SB 26 and opened public testimony.

ANDY ROGERS, Deputy Director, Alaska State Chamber of Commerce, stated that for the last several years regulations and permitting processes have risen to being the top three state priorities for the Chamber and the membership generally supports SB 26. He applauded DNR efforts to evaluate processes and make incremental improvements to make Alaska more successful.

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LISA WEISSLER, representing herself, Juneau, AK, said she has 20 years of natural resource experience as an attorney. She reviewed the bill section by section and had suggestions to amend each.

She started with the general permits section and said this section gives the commissioner the authority to authorize activities through a general permit if the commissioner finds that the activity is unlikely to result in significant and irreparable harm to state land or resources. The laws generally will help establish a consistency and predictability in agency's decisions which is important to the public, the agencies and the applicants. But here, according to DNR, decisions about what constitutes a significant and irreparable harm is going to be made on a case by case basis, which creates the potential for inconsistency and uncertainty in decisions made by both this commissioner and future commissioners.

If general permits are going to be allowed, a better approach might be to establish them as a separate provision in law that identifies what activities qualify and the process for establishing the permits. The DNR currently has a regulation that specifically identifies activities that don't require any permit, so she didn't think it unreasonable to ask to have the same level of clarity here.

Moving on to appeal rights that are all through the bill, currently a person who is aggrieved by a DNR decision generally has the right to appeal to the agency. The legislation changes that so that a person must be substantially and adversely affected, and that will be determined on a case by case basis, which creates a potential for inconsistency and possibly inequitable decisions in how the statute is applied.

On Monday, Mr. Menefee said there is a problem because some people say they don't like the decision and that's all they get. But most people aren't well versed in state permitting law; they don't know it like the agencies do, so they don't know how to make their appeal more effective and they do what they can. Now DNR is asking them to describe how they are substantially affected without any definition about what that means; DNR doesn't seem to know what that means either. He also said there are about 43 appeals a year out of the hundreds of permitting decisions they make. Out of those 43 about 25 percent of the people don't have anything more to say than that they don't like it; maybe 10 a year. So, it doesn't look like this is really a big enough problem to make such a big change.

MS. WEISLER said the reservation of water section is a solution seeking a problem and DNR really just needs the staffing to process reservations. In terms of tendered water use permits, the proposed language gives the commissioner the authority to issue an infinite number of temporary water use authorizations and Mr. Menefee said it's a better way to do it, because the state retains control of the water. But the problems are with the temporary water use statutes, because while you can make adjustments whenever a new permit is being issued, that is discretionary on the part of the commissioner, but the public never gets a chance to weigh in on issues the department might not know about. A better way to do this is something in between, she said, if DNR wants to authorize a temporary water use that has passed five or ten years but not a water right appropriation, then develop a permit that includes public notice and criteria.

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JAMES SULLIVAN, Legislative Organizer, South East Alaska Conservation Council (SEACC), testified in opposition to SB 26. He said the proposed revocation of all personal use reservations is problematic. SEACC wants to ensure that the environment is protected and that anadromous streams have highest priority when permits are issued. He proposed that when any entity applies for a water right on an anadromous body of water, that DNR issue a

water reservation on behalf of the fish; it can refer to the Anadromus Waters Catalogue, which is already there; once they do that they can put in an appropriate reservation. This would align DNR with the State Constitution, Article 8, Section 3, on the common use issue and protect its public trust responsibility; it would ensure protection for our salmon and enhance sustainable economic development across the state as salmon is our greatest renewable resource. It is in the state's best interest to put a mechanism in statute to protect the fish resource as other entities apply for water rights.

He also noted that DNR had spoken at length about permitting problems, yet the 2012 Frasier Institute Report ranks Alaska fourth in the mineral entities around the world when combining the composite policy and mineral potential; over 90 different regions in the world fall below us. He expressed hope that the committee would address that great discrepancy when the CEO's who fill out Frasier's form rank Alaska so high and the DNR commissioner provides such a low response.

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HAL SHEPHERD, Center for Water Advocacy, Norton Bay Intertribal Watershed Council, and the Native Village of Elim, Seward, AK, testified in opposition to SB 26. He expressed concerns regarding past hearings in which statements by the Division of Mining, Land and Water as to who this bill would affect, particular in reference to the limitations on who can now apply for in-stream flows. The testimony he had heard so far noticeably omitted Native Alaskan tribal governments of which a few had applied for in-stream flows on waters in Alaska specifically to protect subsistence uses. But there has been no discussion about the fact that this bill would limit those applicants, including several tribes who have already submitted applications, from applying for in-stream flows. This seems to be a continuation of the administration's efforts to privatize water rights in Alaska, but also severely limiting the standing for individuals who can appeal applications that have been issued for mining permits, oil and gas drilling or hydro power plants, which again noticeably leaves out the substantial majority of individuals, tribes or NGOs who may be impacted by the issuance of such water rights.

MR. SHEPHERD urged the committee not to strip the rights of individuals' constitutional rights, specifically Article 8, saying the state can issue water rights subject to a general use for fish for all of Alaska's citizens.

RICK ROGERS, Executive Director, Resource Development Council (RDC), Anchorage, AK, testified in support of SB 26. He said RDC is a statewide business association representing the forestry, oil and gas, mining, tourism and fishing industries with the overall of mission to grow Alaska through responsible resource development. One of their top legislative priorities is to encourage the state to promote and defend the integrity of Alaska's permitting process and to advocate for predictable timely and efficient state and federal permitting processes based on sound science and economic feasibility.

He said the legislature to its credit provided DNR with additional resources in past years to address what had become an untenable backlog of permits and authorizations. Such backlogs negatively affect our resource industries, but they also affect many individual Alaskans who are seeking the required state authorizations. It's important to recognize that Alaska land entitlement is over 100 million acres plus jurisdiction over submerged lands and the permits that DNR adjudicates go far beyond the mineral industry and he was puzzled why the discussion is so focused on that one industry. He was also curious about how permits are adjudicated for mining projects versus everyday Alaskans trying to cross tidelands to get to a dock.

MR. Rogers said ramping up staff to adjudicate the backlog was a great idea, but it's addressing a symptom rather than systematic improvements. Now, we have a very complex set of statutes that have been developed over five decades of statehood and they need some improvements. Commissioner Sullivan had done a good job of identifying specific means of improving the efficiency of this complex system and the administration should be applauded for proposing numerous changes to DNR enabling statutes in order to make their processes more timely and efficient.

CHAIR GIESSEL closed public testimony and held SB 26 in committee.

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There being no further business to come before the committee, Chair Giessel adjourned the Senate Resources Standing Committee meeting at 5:53 p.m.