

**ALASKA STATE LEGISLATURE  
HOUSE RESOURCES STANDING COMMITTEE**

April 21, 2012

2:05 p.m.

**MEMBERS PRESENT**

Representative Eric Feige, Co-Chair  
Representative Paul Seaton, Co-Chair  
Representative Peggy Wilson, Vice Chair  
Representative Alan Dick  
Representative Neal Foster  
Representative Bob Herron  
Representative Cathy Engstrom Munoz  
Representative Berta Gardner  
Representative Scott Kawasaki

**MEMBERS ABSENT**

All members present

**OTHER LEGISLATORS PRESENT**

Representative Lance Pruitt  
Representative Dan Saddler  
Representative Chris Tuck (via teleconference)  
Representative Bob Lynn  
Representative Kurt Olson  
Representative Pete Petersen  
Representative Mike Hawker  
Representative Mike Doogan  
Representative Tammie Wilson  
Senator Cathy Giessel

**COMMITTEE CALENDAR**

HOUSE BILL NO. 3001

"An Act relating to adjustments to oil and gas production tax values based on a percentage of gross value at the point of production for oil and gas produced from leases or properties north of 68 degrees North latitude; relating to monthly installment payments of the oil and gas production tax; relating to the determinations of oil and gas production tax values; relating to oil and gas production tax credits including qualified capital credits for exploration, development, or production; making conforming amendments; and providing for an effective date."

- HEARD & HELD

**PREVIOUS COMMITTEE ACTION**

BILL: HB3001

SHORT TITLE: OIL AND GAS PRODUCTION TAX

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

04/18/12	(H)	READ THE FIRST TIME - REFERRALS
04/18/12	(H)	RES, FIN
04/20/12	(H)	RES AT 1:00 PM HOUSE FINANCE 519
04/20/12	(H)	Heard & Held
04/20/12	(H)	MINUTE(RES)
04/21/12	(H)	RES AT 10:00 AM HOUSE FINANCE 519
04/21/12	(H)	RES AT 2:00 PM HOUSE FINANCE 519

**WITNESS REGISTER**

WILLIAM BARRON, Director  
Central Office, Division of Oil and Gas  
Department of Natural Resources (DNR)  
Anchorage, Alaska

**POSITION STATEMENT:** Testified and answered questions during the PowerPoint presentation related to increasing production during the hearing on HB 3001.

TONY REINSCH, Senior Director  
Upstream & Gas  
PFC Energy  
Washington D.C.

**POSITION STATEMENT:** Testified and answered questions during the presentation by the PFC Energy on Global Strategy and portfolio overviews of major Alaska producers.

**ACTION NARRATIVE**

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**CO-CHAIR ERIC FEIGE** called the House Resources Standing Committee meeting to order at 2:05 p.m. Representatives Feige, Seaton, P. Wilson, Herron, Munoz, Dick, Gardner, and Kawasaki were present at the call to order. Representative Foster arrived as the meeting was in progress. In attendance from the House Special Committee on Energy were Representatives Pruitt, Saddler, Tuck (via teleconference), Lynn, Olson, and Petersen.

Also in attendance were Representatives Doogan, Hawker, and T. Wilson and Senator Giessel.

**HB 3001-OIL AND GAS PRODUCTION TAX**

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CO-CHAIR FEIGE announced that the only order of business would be HOUSE BILL NO. 3001, "An Act relating to adjustments to oil and gas production tax values based on a percentage of gross value at the point of production for oil and gas produced from leases or properties north of 68 degrees North latitude; relating to monthly installment payments of the oil and gas production tax; relating to the determinations of oil and gas production tax values; relating to oil and gas production tax credits including qualified capital credits for exploration, development, or production; making conforming amendments; and providing for an effective date."

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WILLIAM BARRON, Director, Central Office, Division of Oil and Gas, Department of Natural Resources (DNR), began his PowerPoint presentation titled "Potential for increasing production." He stated he thought that barriers have been thoroughly discussed [slide 2]. He stated that the next slide shows the length of time it would take for industry to pull projects together in Alaska [slide 3]. He explained that typically it takes from 10-15 years from the time of initial exploration to production, limited to the North Slope and new exploration, but not necessarily Cook Inlet, seismic, in-field drilling, or development drilling within an existing field. Referring to the graph timeline, he said obviously a significant number of years could be shaved off if the development is occurring in an existing field. For example, a lot of construction time could be removed, and a small add-on to a facility would also not require feasibility, permitting, financing, exploration and seismic studies so the project would begin with construction and production.

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REPRESENTATIVE KAWASAKI referred to an article he saw in Petroleum News several days ago that quotes the governor as saying a meaningful change in taxes could result in production a year or so out; however, he compared this statement to the comment Mr. Barron made regarding tax regime changes and a

significant time lag on projects. He asked for clarification on this.

MR. BARRON said he didn't think he could answer the question since he was unsure of the specific quote. However, if a company is working in Prudhoe Bay, Kuparuk, or Alpine - existing fields on the North Slope - a company could go to construction almost immediately. It also would depend on the size and scope of the project so the construction phase might only span one year or less. He suggested that adding on a small separator or de-bottlenecking could also be done in a relatively short time frame, so new well production could occur right away. He related his understanding if that is the governor's context it is correct; however if it is something different the lag could occur between engineering and construction before first production.

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REPRESENTATIVE KAWASAKI offered his understanding that Governor Parnell said he wants to see a proposal to incentivize new production in the existing fields along with new field production and he believes that with significant tax change in existing fields the state could see as much as 100,000 new barrels per day within a year and a half.

MR. BARRON said that does mirror his comment with respect to the overarching structure in the existing legacy fields. He explained the timeline on [slide 3]. If existing infrastructure is already in place, including roads, power, and facilities and the work is limited to adding new wells, then production could happen in a very short time frame. Further, work can happen year round if new facilities are being put on existing pads.

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REPRESENTATIVE KAWASAKI noted that much of the discussion has revolved around how to get new production out of the legacy fields, including more work and more local hire. He asked for comments with respect to HB 3001 and how the time frame would shrink and big producers would want to produce. He pointed out that even when the state had a low tax rate on existing fields under the ELF, the state did not see additional investment.

MR. BARRON referred to a graph from Commissioner Butcher's prior presentation. He said by going across the graph one can see a tremendous amount of work is being done in that time frame. He

characterized it as a highly capital-driven curve that changed the production profile for the North Slope, especially considering the satellite fields, such as Endicott, Alpine, and Kuparuk. Those fields were brought on during those same years, which represent hundreds of millions of dollars' worth of investment that stabilized the production profile. He acknowledged it doesn't appear to be stable, but a line could be drawn that would show the state would have been at 1 million barrels production in 1995 if it weren't for all of this work and if the state only had Prudhoe Bay. However, in 1995, production was at 1.5 million barrels per day. He reiterated that while 100 percent of the work might not have been specifically directed at Prudhoe Bay, work was associated with fields they were finding in and around that wonderful basin. He emphasized this discussion must be framed in the context that the Prudhoe Bay and North Slope area continues to remain as one of the great oil basins of the world. He pointed out there is an old cliché that says "If you are going to look for oil, look in an oil field." This is reflected in the aforementioned graph. The industry in total said that Prudhoe Bay is the largest oil field in North America; Kuparuk is the second largest oil field in North America; and North Star, Endicott, Lisbourne, and West Sak are all within the primary boundaries of Prudhoe Bay and Kuparuk. As companies continue to work, they continue to flatten the production curve and change the production profile with their investments. Every well that is drilled has an impact on the decline curve of the Prudhoe Bay field itself. Every time the company changes, it goes from primary development - drill the well and produce it - to secondary development, in which gas or water, or separation facilities that change the overall draw down will change the production profile. This is not a "no work" case, but rather reflects the hundreds of millions, if not billions of dollars in investments that have benefited both the state and the companies. He said, "They do work; we make money; they make money."

MR. BARRON asked members to consider, for example, that the cost of an exploration well is \$20 million if not more. He pointed out that the Mukluk well [Beaufort Sea] cost \$80 million, but it was a dry hole. Furthermore, ConocoPhillips experienced trials and tribulations to try to get a bridge on line at Alpine. He concluded that this graph shows a tremendous amount of effort to continuously flatten the decline out of our major fields.

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CO-CHAIR FEIGE, referring to the graph and the underlying Prudhoe Bay production, said it appears that in 2007 the decline rate was reversed for a brief time. He asked for clarification on the change.

MR. BARRON responded that he will be able to provide additional information at the next meeting, but at this point he is able to say this represents a mathematical aberration. He explained the Cartesian plot and production curves are either exponential decline, which most of the fields are; however, part of this effort was work associated with gas cap injection. He noted one piece of work had a significant change in the production profile in Prudhoe Bay. He again offered to address this further at the next meeting.

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REPRESENTATIVE GARDNER referred to slide 3 and asked whether the permitting time frame holds regardless of the type of oil field, or if there is a significant variation.

MR. BARRON responded that there would be variations. For example, if work is being done in an area which is primarily uplands the permitting process will be shorter since it is not necessary to obtain wetlands permits. He stated that with shale oil development permitting will be difficult and complicated unless it is located in high and dry uplands such as in Cook Inlet.

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REPRESENTATIVE P. WILSON offered her recollection the ratio was 1:6. She noted that for every six wells drilled only one would be "wet." She asked whether that statistic has changed due to advanced technology.

MR. BARRON explained the ratio is primarily driven focused on exploration, but not for development. He suggested a geologist wouldn't be employed long with that type of ratio of success. He said that with exploration the ratio can sometimes be 1:10 for successful wells.

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CO-CHAIR SEATON referred to the decline curve. He questioned whether the division disagrees with comments offered by the division to the U.S Senate Energy Committee. At the time the

division stated that with the exception of the development of heavy oil resources known to exist around Prudhoe Bay, Kuparuk, and Milne Point and the potential resource plays like the Bakken Reserve in North Dakota that may exist on the North Slope, natural field declines cannot be replaced without access to production from federal lands and Outer Continental Shelf (OCS). There are no known conventional resources on the state or Native lands that are likely sufficient to replace the decline in the existing production rates. He reiterated that this testimony was given less than a year ago by the director, Kevin Banks.

MR. BARRON explained that sometimes the testimony focus is obscured. He said those comments pertained to a plea to open up OCS, Arctic National Wildlife Refuge (ANWR), and federal properties to encourage that exploration effort - to open ANWR up. The key phrase in his testimony refers to "known fields" and just last year Brooks Range Petroleum (BRPC) has found a new discovery of about 40 million barrels. When Mr. Banks made that comment the field was an unknown field. He predicted that 40 million barrels will not reverse the decline at Prudhoe Bay, but it will be a piece of the mix that will flatten it and begin to turn the curve. He offered his belief that a change can be made in every field by increasing investment to a certain point. He suggested that a one percent change in Prudhoe Bay is 6,000 to 7,000 barrels of oil per day. That will be half of what the BRPC's production will be. He related his understanding what Mr. Banks was trying to convey to Alaska and the country is that there is a limited ability to reverse and flatten the curve of the major fields coming off of Prudhoe Bay and get back to 2 million barrels of production in existing fields; however, access to ANWR and OCS would change this profile dramatically. He agreed with Mr. Banks that no known field can reverse the decline in the legacy fields and increase production to 1 million barrels per day, but it is the unknown that Mr. Banks was trying to attack in his testimony.

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CO-CHAIR SEATON related his understanding that a tax change for the known fields of Prudhoe Bay could reverse the decline. He pointed out this seems quite different than Mr. Bank's testimony in May when he said it will not be possible to reverse the legacy field declines without federal lands and OCS. He asked for clarification as to whether solely a tax rate change could reverse the decline from legacy production - not incremental - and provide a 10 percent increase in production.

MR. BARRON attempted to clarify that to reverse the production profile in a field is possible with investment. He related that the amount of the investment is dependent upon the type of project and the point in the timeline of the life of the field, since as one advances in time it becomes harder to change the decline rate as the resource base is more limited. He asked whether the producers can begin to flatten the curve of their existing fields with increased investment. Technically, yes, it is possible, he said. He asked whether the fields can be reversed and become positive and he answered, yes, in some of the fields it is possible although he cannot be specific since he has not done calculations in terms of the total aggregate. Further, he has not yet researched that particular issue; however, all the production profiles can be flattened with more investment.

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CO-CHAIR SEATON commented that is the crux of what the legislature is trying to figure out, to decide whether a fairly simple change in tax policy will reverse and incrementally add ten percent above where the state is currently producing at Prudhoe Bay. He said it seemed the division was saying a year ago that incremental production within the known fields would not reverse the decline and it would not be possible to achieve accelerated production without federal properties or OCS.

MR. BARRON said that for him to say one percent change in profile is 6,000 to 7,000 barrel per day translates to a meaningful change. He was uncertain of whether one percent increment is possible without the investment occurring to prove it. Further technologies are available and new reservoir management companies are engaged with could make it possible. Additionally, areas that can continue to be developed can impact production; however, it must be within the economic boundaries and parameters of the companies to move forward with those kinds of projects. He asked whether one company can stop the decline and answered that according to the work agreement it is possible. Therefore the state's goal should be to strive for a collaborative and competitive basis so companies will want to bring investment to the state and not send it somewhere else.

CO-CHAIR SEATON said he appreciated this since these are pieces of the puzzle the state needs. He stated that what drives the state is revenue. He acknowledged that production, price and costs, and tax rates are part of the formula. The legislature must work on revenue to the state. The legislature is trying to

construct a scenario to move the state to the right place in the long term. He did not think there was a disagreement, but the state is trying to figure out if the decline rate can't stop the decline with in-field legacy drilling, then the state cannot use a figure of "positive 10 or positive 20" on top of legacy production to generate revenue curves. He summarized this committee is trying to understand if it is possible to produce 10 to 20 percent more out of Prudhoe Bay by a meaningful tax change.

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MR. BARRON acknowledged that point, and turned members' attention to the next slide titled "Reasonably expected time to production" [slide 4]. He suggested that part of what is being discussed is the phasing of developments and exploration work being brought into production. He said within the next 5-10 years - noting the darker the shade represents the more likelihood of an impact - three primary areas can be brought in to meaningful production. First and foremost, that can occur in the legacy fields and some others within the geographic area. This gets back to the heavy and viscous oil and the importance of understanding the dilutant needed to produce it. Some of that dilutant could be the lighter oil being produced at Prudhoe Bay and Kuparuk today. Therefore there must be an orchestrated effort between heavy and viscous oil and the light oil that is produced. He highlighted that the industry is currently examining how much light oil is needed to produce the viscous oil so the companies' development plans have sufficient amount of lighter crude to allow them to ship the heavier crude down the line. He characterized this as all part of the same mix. He noted the last well BP had running on a test produced 650 barrels per day of viscous crude, which is probably double the world wide number for viscous crude. He said, "That is incredibly positive." However, to so companies must have an equal amount of lighter crude. He cautioned this process is still in the pilot test phase, but their pump failed when it had a tubing failure. They are working through that issue, but if this work plays out, it represents a significant potential step change for that area and it lies within the boundaries of the legacy field. This would be a new probable development area that is very robust, he stated.

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MR. BARRON stated the next potential is shale oil. He reported that Great Bear Petroleum is on the cutting edge of shale work

and plans to drill three to four wells in the next quarter. Thus the state will find out whether shale oil can be produced and what kind of fracking must be done to develop those wells. He stated that within the next five years these aforementioned projects are the three primary areas that can be brought to bear.

MR. BARRON turned to new discoveries as the next phase. He pointed out that Brooks Range Petroleum Corporation is working on viscous oil and more shale oil, which is not to say the legacy fields are not important - the bar on the graph continues - since they will still produce and provide infrastructure as an advantage for some of the new discoveries.

MR. BARRON said the 5-10 year plus window will produce new fields, more viscous oil, and shale oil. Outside of that, the 10 to 15 plus years, will be the Outer Continental Shelf (OCS), Beaufort, OCS Chukchi, Arctic National Wildlife Refuge (ANWR) and the National Petroleum Reserve-Alaska (NPR-A). He suggested this in terms of how the industry and developments will be staged, and in terms of the legislature's discussion relative to tax policy. He summarized that this slide represents the natural staging of impact to the production profiles.

REPRESENTATIVE KAWASAKI commented that despite the changes the legislature makes, companies will make decisions based on a grand plan, for example, companies will likely be using light oil for heavy oil production in the future. He emphasized, from a policy standpoint, the legislature wants to ensure that the incentives are directed to provide more jobs, construction on the North Slope, reduction on the decline curve, and local hire. However, the recent testimony indicates the oil and gas companies aren't considering those issues. He wanted to ensure that the policy group will focus on the state's interests.

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MR. BARRON attempted to clarify that his testimony could be misconstrued. He related his discussions with the project team for heavy oil indicated the companies are cognizant that they will need the lighter oil production as a dilutant for their production. This isn't to say that the industry is not producing what they can produce today, but rather that industry understands some of their mechanical limitations will require additional production. He related his understanding that industry wants to ensure as the work is staged and orchestrated with existing development - as it moves forward - to ensure the

product can be produced in a timely manner. Again, he emphasized that industry is not withholding production or simply not developing. The team he met with was saying was, "I need that to be able to do what I need to do." He suggested that waiting 15 years to produce heavy oil and staging it instead of doing it concurrently might mean viscous oil production may not happen. In fact, it's actually just the opposite of what might be inferred since the team has been trying to figure out how to accelerate their work to increase production in a timely manner by pushing the technology and marrying the two projects together.

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REPRESENTATIVE DICK referred to fracking and asked how that technology could impact Alaska. He asked whether new technology to extract viscous oil would ultimately have a negative impact on Alaska if the technology is used globally since it might be easier to use heavy oil in other places. He said he struggled to understand the impact.

MR. BARRON explained that new technologies happen every day. He highlighted that fracking is not new technology and has been used by industry for over 100 years. He pointed out over 25 percent of Alaska's wells have been fracked, which most people don't know; however it is the combining of technologies that continues to advance the industry. He said he has been an engineer and has worked in the field for over 35 years. This is the third time the Bakken fields have come up as a development play. Each time, it has stopped because of low production and product price - primarily due to those two drivers. He said low production was also due to technology since long-reach horizontal drilling had not been invented nor did the company have the ability to stage 20 or 30 fracks. He emphasized that multi-stage fracks have been used in Alaska; however, in his personal experience five or six fracks were all that was needed and not 20-30 in a horizontal section. He asked whether it will it ever be detrimental to the state to gain the foothold of knowledge and he offered his belief that it is probably not a disadvantage. He predicted that if the state's fiscal system and the infrastructure in Alaska are competitive, the industry will participate in the competitive environment. He has held discussions with one company who came to Alaska due to the huge resource basin, existing facilities and infrastructure. The operators struggle with the cost of production, the cost of labor, and product price. If one were to put aside the fiscal regime, one would still have the three obstacles just mentioned.

He pointed out that the economic limit for shale oil wells will be a key driver in the overall development and how much is developed. For example, he stated the economic impact will affect whether it will be economic to put on rod pumps. He was unsure whether it would be possible in Prudhoe Bay due to cost. He concluded that cost of operation is one of the biggest hurdles in Alaska.

MR. BARRON related that the Permian Basin in West Texas has been around for hundreds of years and it is still a prolific basin with hundreds of rigs running. This is possible because operating costs are significantly lower in Texas than in Alaska. So, again, from a technology standpoint it would not ever be a disadvantage and he predicted companies would aggressively pursue viscous oil if Alaska developed advanced technology in coordination with the development of the rest of the field.

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MR. BARRON referred to an exhibit from Bakken field passed out previously by Co-Chair Seaton indicating a production profile of a typical well in the Bakken field. He pointed out that this profile represents one producer's average. He turned to the Eagle Ford analog in the oil zone of Eagle Ford shale for comparison [slide 5]. He said the graphs look a little different, but if you take off the first part and compare it to the curve of the Bakken field the curves are similar. It's important to consider the scale on the bottom is in months and not in years. He stated this is information received from the Texas Oil Commission, which is his counterpart in the state of Texas. He noted the scale on the bottom of the slide is months not years. He predicted that the Eagle Ford basin is closer to production than the Bakken field. He projected that in ten months the Eagle Ford will be at 100 barrels per day. He emphasized this goes back to Representative Dick's comments on technology and his response relative to cost. In a very short order those wells will be producing at 100 barrels per day.

MR. BARRON referred to several comments that people have made. He explained the assumptions of the graph, which is the potential for Shublik. The Eagle Ford analog is based on six rigs drilling six wells per month or 30 days per well. He said "drill, frack, complete, put on line. That's doable, but that's six rigs - so six new wells - a month." He said this graph assumes that every well has a 20 year life. This graph shows the potential of 2,000 wells being drilled in that formation. The initial production (IP) is 500 barrels per day. He pointed

to the graph, noting he has been a bit conservative with his estimation; however, the final production at 30 barrels per day and is projected at that rate for 20 years. However, he cautioned that no one knows whether the wells will be around for 20 years. Eagle Ford and Bakken basins haven't been producing horizontal fracked wells for 20 years. He asked members to consider carefully what occurs when drilling is ceased and the precipitous decline that ensues, which goes from 65,000 barrels per day to 10,000 barrels in a matter of 20 years [slide 6]. He said, "All of these wells are crashing - one right after another." Of course, this is what one would expect to happen based on the decline curve; however, by changing it just a bit, based on five years of life, the red curve represents 20 years whereas the blue curve reflects the change if the well only lasts for five years and continues to drop and becomes un-economic. Thus the profile would be even more dramatic [slide 7]. He said while shale oil is a very robust potential - and Eagle Ford basin is only one of three zones - in the context of impact, these wells are not highly prolific for very long, which is important to understand as a state.

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MR. BARRON turned to slide 8 as his final slide, titled "What will it take to reach the goal?" First, he emphasized the importance of a collaborative and competitive environment to reach the state's goal, noting the industry will respond to environments that are collaborative and competitive. Second, he stressed the importance to minimize barriers as much as is possible especially within the agencies. Third, he emphasized the importance to access all fields and recover all types of oil. He highlighted that an integrated mix of fields and developments will reverse and change the decline - whether it is existing legacy fields or new discoveries in some form or fashion. He concluded that technology will play a part in the role.

REPRESENTATIVE GARDNER related he discussed things that Alaska offers. She asked what role water would play since the use of water and growing concern about disposal of waste has been a critical issue. She asked whether water would be an issue of concern.

MR. BARRON responded that at this juncture interesting changes have occurred, with respect to the chemistry that would allow using brackish water, and if so, he did not think water source should not be a problem since even using sea water becomes

technically possible. The disposal of that water would then fall under the purview of the Alaska Oil and Gas Conservation Commission (AOGCC) and injecting and disposing wastewater becomes their responsibility. He offered his belief that it is technically doable, and in fact, many companies are considering technologies to reuse a lot of that water for re-frack operations.

REPRESENTATIVE GARDNER referred to slide 4. She described the significance of the color fade and she wondered if there is any significance to the different color text also.

MR. BARRON explained that he was attempting to illustrate that it's not possible to estimate when gas infrastructure will be in place. He acknowledged the gold band darkens over time. He referred to the first green band on slide 4, which shows the primary areas of impact as legacy fields, followed by heavy and viscous oil, and shale oil, but still not necessarily a prime drive. He highlighted that the coloration fades over time.

REPRESENTATIVE GARDNER surmised, therefore, that the legacy fields would be the biggest expectation for new oil in Trans-Alaska Pipeline System (TAPS).

MR. BARRON concurred.

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REPRESENTATIVE KAWASAKI asked whether a legacy field the size of Prudhoe Bay and Kuparuk has ever increased or if the straight line curve is to be anticipated.

MR. BARRON pointed out that Prudhoe Bay is unique since it is the largest field in North America. He questioned finding an equivalent analog. However, in terms of whether the field could flatten or reverse the decline of the field, the answer is yes, but it is very difficult. He mentioned that he will have some exhibits at a later hearing that will demonstrate how the primary producing area of Prudhoe Bay has been changed with development and activity. He further suggested the team hopes to provide similar examples from other areas to show the effects of continuous work and technology.

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REPRESENTATIVE SADDLER referred to slide 7 and noted the estimated 5 or 20 year life; however he also noticed a 32 and 47

year production life. He asked whether the change is due to drilling ceasing after 5 or 20 years.

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MR. BARRON explained that slides 6-7 illustrate the time frame based on an assumption of six rigs with each rig drilling one well every month: drill, frack, complete, put on line in 30 days. He said he built the exhibit assuming 2,000 wells would be drilled so once the 2,000 wells have been reached the drilling would stop. He explained the production profile existing from the curve. Thus as the individual wells producing on this curve are cumulative, at the end of the day 2,000 wells may not be producing, since some of the wells may have reached their 20-year life and dropped off. The goal is to continue to drill to reach the production profile; to reach the 2,000 wells; stop; and finally achieve the natural decline. He highlighted this would be an excellent example after drilling ceases of "a no work case - for shale, not for conventional." He pointed out that the graph shows the profile if the company stopped drilling at year 28; however, if the company drilled more wells the cumulative profile would change again.

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REPRESENTATIVE SADDLER asked whether high taxes cause a field to stop producing at a certain point that otherwise would be considered economic.

MR. BARRON suggested the commissioner said it best, that high taxes, and high costs change the economic limit for a well. The higher costs, including taxes, tend to drive the point when the well is shut down since the company will not be making any money. He agreed it can very easily change the value of when the well is shut in.

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REPRESENTATIVE PETERSEN referred to slide 4, to the heavy and viscous oil with shale oil right below it. He highlighted that shale oil is a lighter type of oil so the development of those two types of oil together could help solve the problem of oil flowing down the pipeline. He asked whether that is a possibility.

MR. BARRON agreed that is a possibility. He added that when he met with the viscous team, the team was excited about the

prospects, but also recognized some of the technical challenges - ensuring adequate dilutants. He recalled the ratio needed would be 1:1. He related the team is still studying it and they need latitude for continued research; however, if it is a 1:1 ratio, if the shale crude is of the right quality it could be used to produce the viscous oil.

CO-CHAIR FEIGE announced that the final testifier would be a PFC Energy presentation "Overview of oil and gas companies' Capital Allocation Processes, Investment Decision Making & Global Portfolios" by Tony Reinsch.

3:02:00 PM

TONY REINSCH, Senior Director, Upstream & Gas, PFC Energy, stated that PFC Energy is an independent consultant and advisor to the oil and gas industry, exclusively. The company counsels and discusses strategy, planning, and development with governments, regulators, industries, national oil companies, and oil and gas producers on a global basis, and through the entire value chain from upstream oil and gas development to refining, distribution product markets, and the service industry. He said he has been asked to share thoughts around company decision-making as it pertains to budgeting, planning, and capital allocation in order to shed light on how companies internally make their decisions about capital allocation within portfolios. This could extend to global comparisons of basins and investment opportunities. He offered to discuss the metrics used for capital allocation and de-integration to significant oil and gas producers, such as Marathon and ConocoPhillips Corporation (ConocoPhillips) separating their upstream and downstream operations, including identifying drivers, pros and cons to that fairly significant change in corporate structure. Additionally, he said he will discuss capital allocation over the life of basins and fields and net free cash flow moving from basin to basin as the industry moves forward over time [slide 2]. The second part of his PowerPoint presentation will cover the global portfolios of the three large integrated major oil producers in Alaska: BP Global, ExxonMobil Corporation, and ConocoPhillips Company.

3:06:00 PM

MR. REINSCH discussed the "Annual Planning Cycle" [slide 3]. He referred to the annual process that all oil and gas companies follow in their annual budget cycle process. He pointed out this slide illustrates that in the first quarter of each year

companies will undertake a review of their strategy vis-à-vis the world. He related that in the second quarter companies review the new things they might begin, followed by budget preparation in the third quarter, and lastly by the budget approval process.

3:07:33 PM

MR. REINSCH referred to "Strategy, Planning, and Positioning [slide 4]. The strategy begins with an outlook for the future of the world, usually covering a 15-20 year outlook taking into account the global economic performance and impacts on energy demand, competitor analysis, and geopolitical considerations that may impact oil and gas global markets. Each company has preferences for basins and jurisdictions they work in and review these options with an eye towards above ground risks, changes in the operating environment, and potentially defining new no-go geographical areas where companies will not do business or open basins in which companies were not previously interested in engaging such as the shale oil gas plays in North America. The companies will consider the operating environment issues, including discussions of any blockers, enablers, gaps, and logjams that could get in the way of their plans. Companies will review the environmental, including taxation systems, market outlooks and what competitors are doing, which is an area that PFC Energy engages in to a considerable extent. Companies are interested in knowing who else is doing what they are trying to do and where they might run into competition. Companies will assess information and come up with options and plans for where they will move next and what they will engage in.

MR. REINSCH referred to the "Annual Planning Cycle" [slide 5]. He stated this information would be transferred into dollars and cents in the budget preparation. He referred to the "Planning Cycle and Capital Allocation" Corporate Input: Common Assumptions on External Environment" [slide 6]. He indicated each business unit will update its long-range plan, five-year plan, and ultimately the budget preparation on the basis of common assumptions. He related that this capital allocation competition begins this process since each unit highlights opportunities they believe are in the best interest of their company and are best able to impact and deliver the strategy and objective for the company. The corporate section rolls it into discretionary and non-discretionary capital expenditure (Capex), and it is recycled until the figures are appropriate and it moves to the board for approval, to allocation of capital, and project approval and execution. In response to Representative

Saddler, Mr. Reinsch answered that no importance should be given to the color gradations on slide 6.

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MR. REINSCH related the final piece of the annual planning cycle is the budget approval and allocation of capital in November and December of each year and then the cycle begins again [slide 7]. The question, within that cycle then becomes how a project - large or small - attracts capital within that process. He stated a number of considerations come into play: materiality to the company, full-cycle economic performance metrics, and all of the considerations of whether an oil and gas company "IOC" will position or continue to invest in a particular asset, basin, or country [slide 8]. He identified the types of projects that Alaska is accustomed to seeing are multi-year duration projects and long-term production. He pointed out that all projects can be broken into discrete investment decisions or stages. This creates a stage-gate that the board of directors and senior management can stop, amend, or accelerate for the ongoing activity.

MR. REINSCH related the buckets of discrete investment activities are considered project approval requests and companies will take those forward for approval by senior management. Clearly, if the issue is drilling a set of technically difficult wells, the project approval request can extend beyond a given budget year. He said what defines the activities is that they are discrete in a larger body of work with a beginning and an end. Each project approval request (PRA) has an approval for expenditure attached to them for specific activities. These stage-gates are points in which the company will make a determination regarding whether to continue, amend, or suspend activities on a given project and field or basin. This allocation level represents the point at which Alaska competes within the portfolios of all other companies to attract capital - not in the absolute sense - but in a relative sense in competition with all other parts of the world.

[3:15:38 PM](#)

MR. REINSCH discussed the "Business Control Architecture" which illustrates six budgets laid out on the center of the charts and three competing streams of activities over time [slide 9]. He pointed out the green bars, and noted this company is looking at a new basin in year two and at the end of that work the board makes a decision regarding whether to continue to exploration.

In this instance, they decided to move on to exploration with the Approval for Expenditure (AFE). He clarified one way to consider their process is that the finances lie in the project approval process and the approval for expenditure (AFE) is just presenting the paperwork for payment and no decisions are made during the AFE process.

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MR. REINSCH referred to the beige bars on the slide titled "Appraisal PAR" and "Development PAR" which move beyond exploration to appraisal [slide 9]. Fields will often be appraised and a decision will be made not to develop the project, but instead to divest or "park" the project and await infrastructure maturation. For example, the McKenzie Delta is a classic example in which ample resource was discovered, but it stopped at the appraisal stage. The top bars on this slide indicate "Exploration PAR", "Appraisal PAR" and "Development PAR." He pointed to the vertical capital slices in year three, shown by the dotted line. He indicated that adding up all of the AFE approvals represents the capital budget for the project and this process is the process used within these companies to develop their budget.

MR. REINSCH highlighted that some activity "bleeds" into the fourth year, which becomes non-discretionary capital to the "Year Four" budget. He noted a certain amount of the capital budget that has already been approved and committed will show up in subsequent years.

[3:19:49 PM](#)

MR. REINSCH discussed the "Upstream Financial Metrics: Measuring Performance" [slide 10]. He noted this slide shifts to assets, how asset performance is measured, and how attraction is determined when securing capital within a budget. He highlighted that performance is measured in different ways, including growth, profitability, efficiency, cash flow, and risk. He defined growth as the ability to manage the top line, or increasing the volume of production. He identified the first measure of performance as growth, and the compound average growth rate (CAGR) relative to target, or the measure of whether the project has been able to deliver according to the plan. The quality of the growth includes the ability to maintain growth and whether the acreage is inadequate to maintain growth. The plowback rate would really be a measure of how much is being reinvested back into the assets and shows the relative growth

intentions between different regions. Second, would be profitability or the ability to manage the bottom line. He stated that upstream cash flows, upstream net income, and upstream production costs are all measures of how well the company is doing in a bottom line sense or the revenue net of cost. Third, he defined efficiency as the ability to manage capital with the most common metric being the return on capital employed (ROCE). He highlighted that finding costs - resource found relative to exploration dollars - is finding and development costs (F&D) to bring the resource to market and replacement costs, such as how much it costs just to stay even or the per barrel cost of production. Fourth, he identified cash flow measures as the ability to manage investment or re-investment in the company's portfolio. Issues such as debt-to-capital ratio and dividend requirements also become important, too. He pointed out some companies are focused on dividends whereas others - particularly smaller independent companies - are mandated to reinvest all of their net revenue. In response to Co-Chair Feige, he clarified several acronyms.

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MR. REINSCH identified the compound average growth rate (CAGR) as a measure of compounded growth over time as opposed to average growth, which is taking the end year and initial year and simply dividing it. He explained that compound average growth provides more of a rate or acceleration measure. He stated that the return on capital employed (ROCE) will be discussed in more detail, but is used to determine whether a company will undertake an activity using a number of benchmarks or metrics. He discussed the "Project Selection and Decision Metrics [slide 11]. He highlighted a few metrics that are common in the industry and defined them: Pay-out period is the length of time required for capital return, which is a major consideration for smaller oil and gas companies, but is important for all companies; the internal rate of return (IRR) is one of the most common measures used to rank projects; and the net present value (NPV) is the measure of how much value the investment activity is bringing to the company. He noted that the present value of cost minus the present value of revenues should be greater than zero. He pointed out this as another way in which a hurdle rate can come into play.

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MR. REINSCH highlighted that net present value is often expressed relative to production or barrel of oil equivalent

(BOE) to obtain the present value per barrel of oil produced, which provides a different measure of investment efficiency. He said the net present value (NPV) is what would be generated relative to the amount of investment or dollar of investment for a project. He clarified that it is often referred to as a present value per investment (PVPI) dollar measure, as well.

REPRESENTATIVE GARDNER asked whether the assessment of return to the investment dollar incorporates various internal goals that companies may have.

MR. REINSCH answered that a particular asset may fit within a portfolio in a different way between companies. For example, ExxonMobil may review the long investment strategy and may notice a hole in the company's portfolio in ten years that a particular technology could fill. Thus investing in that technology may help acquire a wall of cash flow that the technology would generate. He acknowledged some technologies may have a place in one portfolio, but not in another. In further response to Representative Gardner, Mr. Reinsch agreed metrics must be taken in context and must fit together in a certain way. He was unaware of any company that makes investment decisions based on one measure of performance, but rather will decide how these different measures fit together vis-à-vis the rest of the assets in the portfolio. He related that some of it depends on timing, but also depends on when the company can undertake large scale or capital projects or development.

[3:29:03 PM](#)

CO-CHAIR SEATON asked whether any average expectations are held by industry for infield drilling on the payback or payout period or return on capital versus new development or if it is company specific.

MR. REINSCH answered that it is very much asset and activity specific decision. He related that reviewing capital projects with six-year investment cycles would typically have a longer payout. For example, one of the reasons deepwater developments are currently sized rather than sized to have an extended production plateau is to generate the return to that capital as fast as possible. He suggested that one would need to make a strong case to industry if the capital is exposed for three or more years.

CO-CHAIR SEATON related the legislature has been considering legacy fields versus non-legacy fields. He questioned whether 90 days is the typical payout period or if that would be considered a short time frame. He reiterated he is interested in the payout period and what it would mean to investment decisions.

MR. REINSCH offered that if he saw a capital investment activity with a 90-day payout period he would want to check the IRR, the NPV, mature reality, and PVPI to determine how the other measures line up. He suggested that the payout periods represent the simplest and least instructive of the many hurdles a project will need to go through to attract capital. He concluded that if the payout period is over three years for almost any investment that management will look hard at what the project is attempting to accomplish.

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CO-CHAIR FEIGE sought clarification regarding the factors and subjectivity for which projects go forward and which don't.

MR. REINSCH answered that he has been describing the science of the decision-making process. He agreed all of the metrics are assessed for available projects, which are put into the models and ranked in many different ways. The science has been taken to the extent of creating efficiency frontiers and portfolio analysis, but generally speaking what is missing is the art. He said that solely modeling has not been found to be optimal for the company's strategy. Furthermore, what is being invested will impact what the company will be in three, five, or ten years from now, which needs to be taken into account. He characterized the process as a combination of science and art. He suggested that if one can't overcome the hurdles then the project isn't considered. He highlighted that a certain minimum requirement exists for assets to compete for capital and passing all the hurdles doesn't necessarily mean capital will be attracted; however, at least the project would be in the running.

[3:34:55 PM](#)

REPRESENTATIVE P. WILSON related her understanding that any tax regime must be fair since it is up to the companies to decide which project fits into their portfolio best.

MR. REINSCH answered that one of the challenges faced by resource owners is that assets compete with each other within their portfolios and with basins around the world; similarly, the fiscal system in Alaska competes against all other fiscal systems in which these companies are engaged. He said the presentation will cover what each of these three companies is looking for with respect to growth by examining their portfolios. He noted in some cases, companies will focus on North America and for others the focus is somewhere else. He described this as part of the challenge that the business owners face. For example, an asset may be a great asset, but it may be located in Iraq so that specific asset will compete with a deepwater well in the lower tertiary of the Gulf of Mexico. Clearly, this example represents an "apples and oranges" comparison, but that is what is involved. He responded that there is an onus which increases depending on how reliant a jurisdiction is on oil and gas revenue for its budget and future to ensure they have the ability to have a dialogue with industry - financial and technical - to arrive at comfort on both sides of the table. He emphasized the importance of understanding these assets, such as an enhanced oil recovery program or terms, such as ultra-heavy oil to fully understand where the challenges lie and to be able to determine when the challenges are not as severe as being represented. He characterized the process as client-contractor negotiations.

[3:38:46 PM](#)

CO-CHAIR SEATON asked where on the chart the net income per barrel of oil equivalent (BOE) comes in terms of comparing regions or projects.

MR. REINSCH asked for clarification on whether the question is if the number could be compared between basins or projects.

CO-CHAIR SEATON answered yes. He said the state has reports of net income per BOE from Alaska versus other jurisdictions in the U.S. The legislature has been making judgments on tax systems. He asked which relationship the legislature should examine with respect to net income barrel of oil equivalent (BOE) on Alaska's projects versus other projects and whether that should be a metric that is considered.

MR. REINSCH answered it is not an either-or metric such that the highest net income per barrel of oil equivalent (BOE) wins. He highlighted that the materiality element is one in which the net income per BOE doesn't really shed any light on. Further, small

fields with substantial infrastructure can generate good net income for BOE numbers since they may only need to bring the product to surface since pipelines and the processing plants already exist. He said the infrastructure has been paid for by prior activity based on tariff so it is difficult to compare that scenario against development that brings fields into production without any infrastructure. The first development may have net income per BOE numbers that are not particularly attractive, but every subsequent development will benefit from the infrastructure. He also said this is almost a "more is better" argument, but it doesn't necessarily make the project a better one from the company's perspective. In further response to Co-Chair Seaton, he agreed it could be due to scale, materiality, or growth issues and if a project can be turned into something core and material to the company.

The committee took an at-ease from 3:41 p.m. to 3:59 p.m.

[3:59:18 PM](#)

CO-CHAIR FEIGE called the meeting back to order.

MR. REINSCH referred to the term "maximum negative cash flow exposure," which he defined as really a measurement of financial capital requirement. Clearly, major capital projects such as LNG developments or integrated mined oil sands can involve billions of dollars of capital exposure prior to any revenue being generated. The question of the maximum exposure for a company and how much the company can afford to undergo is critical. He emphasized two major companies have almost "come to the wall" by having major capital programs that were exhausting their ability to finance - Chevron [Corporation] and Shell [Global]- and in both cases high oil prices saved the moment. He stated that net book reserves are important because bookable reserves determine the value of an oil and gas company. One of the reasons companies are not willing to engage in fee for service contracts such as Mexico offers - where the company is not allowed to book barrels to take ownership - is because without that ownership there isn't an increment of value to the company. Finally, the capital expenditure per barrel of oil equivalent (Capex/BOE) or the cost per barrel of production capacity burdens the project by the cost of infrastructure and facility requirements necessary to get the product to market. He concluded this tends to favor projects that are less complex, being undertaken in well-established geographic environments with ready access to infrastructure.

4:02:18 PM

MR. REINSCH focused on "Net Present Value (NPV)" and "Internal Rate of Return (IRR)" [slides 12-13]. He explained NPV as the value of a project when all future net cash flows are discounted to the present at an appropriate rate or discount factor such as cost of capital to the company. It may be the company's cost of equity or debt, which is the difference between all of the revenues anticipated from a project and all costs that will burden a project are discounted to a single point in time. For example, he stated that if an NPV is greater than zero, arguably the project is worth undertaking in an economic or commercial sense. That means the specific project is expected to at least generate a competitive return to the capital being invested or what it will cost to invest in that project. Clearly, NPV that is less than zero would represent a project the company would not even consider, but NPV in and of itself is not a selection criterion.

MR. REINSCH related the advantages of NPV, including that it can be calculated exactly, risk can be accommodated, for example, to enable a comparison between an investment in Alaska with one in Angola, Uganda, or Russia. This is done by "risking" those flows of capital and revenue, or to discount the revenue flows to reflect likelihood of interruption. He stated that the discount rate allows a company to identify cost of investment capital to undertake the projects, such as using the cost of equity, raising funds in the capital market, and the cost of debt or a weighted average of the two to use as the discount factor.

4:05:02 PM

CO-CHAIR FEIGE asked whether the discount factor or appropriate rates are interest rates.

MR. REINSCH answered not necessarily, and in fact, very seldom would it refer to the interest rate. While it is reflected in a formula as an interest rate, normally a company would use some representation of the cost of capital. It could be the interest rate to borrow or it could be the difference between long-term versus short term borrowing. Further, it could represent the cost of equity to the firm. He suggested that if a company must raise capital as opposed to borrowing, it would be much more expensive. Companies want to reflect when an undertaking will require the company to go to capital markets and raise equity to undertake the development. Thus, the discount factor will vary

pretty significantly from company to company. The one most often used in the literature around the industry is an NPV 10, which means a 10 percent discount factor. He noted each company would have its own representation for the NPV.

[4:06:35 PM](#)

CO-CHAIR SEATON said he was struggling with the discount rates. He related his understanding that if one area was secure the company wouldn't use an NPV 10, but if there are problems or insecurities that a company might use an NPV 12-15, but he was unsure how to incorporate discounting the cost or the revenue flows.

MR. REINSCH explained that this is being debated in the industry. There are situations in which a company will use a discount factor of 10 for North America and 15 for Uganda and 22 for Mozambique. The problem with taking that approach is the discount rate has such a huge impact - since it discounts present value. He characterized it like using a blunt instrument when looking at the portfolio of opportunities. He noted that as soon as the discount rates are changed it basically takes away the ability to compare projects. More appropriately, it would be better to use a single discount rate. He pointed out that in a risky environment what is at risk is the revenue flow. He suggested discounting that or adding a factor which would still allow an "apples to apples" comparison.

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REPRESENTATIVE FOSTER asked whether the profit premium is included. For example, if you are using the NPV 10 percent since the shareholders are requiring as a return, the effect is to back it up to zero, which would be the breakeven point. He asked whether the profit premium is built into the revenue stream or the NPV figure. He suggested that operating in Angola would require including a risk premium. He reiterated he is trying to figure out where the profit premium is built into the NPV.

MR. REINSCH answered that the NPV is the amount greater than zero. Ideally, a company would not want any profit margins or add-factors built into the base cost and revenue stream. Thus the revenue should strictly be the price times the quantity, with costs being the operating costs estimated over the life of the project. The interest rate would be applied to that and if the NPV is greater than zero this project is generating a profit

margin; then it would depend on the NPV amount greater than zero. Then the company would start comparing projects.

REPRESENTATIVE FOSTER clarified his understanding is the profit is built into the revenue stream that is being discounted.

MR. REINSCH responded that profit is built in to the extent that those discounted streams represent revenue and cost. For example, if the NPV exceeds the NPV of cost, the company is generating a profit. He stated that if the discount is an appropriate discount rate representing the cost of capital, the returning capital would already be accounted for a returning capital - normal or competitor return - which is why the appropriate discount factor would be the cost of capital so companies make sure that is in the analysis as part of the calculation.

4:10:50 PM

REPRESENTATIVE GARDNER asked where lease clauses and mandatory development time lines would be factored into the decision matrix.

MR. REINSCH said he would expect them to be reflected in the revenue stream. In the particular NPV calculation this would be part of how to determine the quantity number by which price is multiplied. He explained that if a requirement to develop within a certain time frame existed then, presumably, those volumetrics being modeled represent adhering to those requirements so those types of restrictions would help define the project as its being modeled.

REPRESENTATIVE GARDNER surmised, then, that if by this date there is not a flow then the leases would be pulled; however she asked whether something more nebulous like a commitment or obligation to develop - a duty to develop - have any place in these calculations.

MR. REINSCH said it wouldn't have such a place and to model a project somehow violating that wouldn't make sense. He said that any project being considered would presumably be adhering to the regulatory or legislative requirements for pace or scale of development. For example, if the government imposed a unilateral adjustment in government take in Israel from 35 percent up to 60 percent, basically, this would be saying the company found the resources so now the take will increase since the basin is de-risked. He suggested that that type of

unilateral move is very difficult for companies to accommodate since it wasn't in their modeling in the first place. He offered his belief that changing the rules part way through without grandfathering in the terms creates a real challenge for this industry on a global scale.

REPRESENTATIVE GARDNER surmised that risk was also factored in the modeling.

MR. REINSCH responded no, not in that case; however, he noted the quid pro quo for that is if the fiscal terms change to allow for another avenue of commercialization. In that case the company in question is arguably in a much stronger position for export. He said, "Yes, we've discovered all of this resource and yes, we've built up 35 years of domestic coverage at projected growth rates for your country, now let us export the rest - so there's give and take in this."

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REPRESENTATIVE HERRON questioned what the ideal NPV would be if an NPV greater than zero is the minimum result in the formula.

MR. REINSCH answered that NPV is a dollar measure so it would be in the millions or billions of dollars. He explained that you can't rank with the NPV since it's not a hurdle in that way, but it gets the company on the table. A large NPV doesn't necessarily mean that this is the best project either. Sometimes revenue streams can be so far in the future that they are heavily discounted so looking at one metric in isolation would lead a company not to undertake a project that really should be undertaken from the perspective of the treasury, such as an LNG development in Qatar being a case in point.

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MR. REINSCH moved to the second metric, which is the internal rate of return (IRR) [slide 13]. He explained to reflect back on NPV as the amount greater than zero, or the net positive contribution of a project using a given discount rate across all projects, that the IRR calculates what discount rate it would take in order to equate all revenue flows to all capital costs or costs incurred. The higher the rate at which those two flows are equal, the more valuable is a given project. He highlighted that IRR lends itself to a comparison across projects and is one of the hurdle rates often used in industry. The biggest disadvantage to the IRR is that multiple rates of return are

possible for any project when volatility in cash flow exists. He noted that large positive and negative swings in revenue over the life of a given project - decision makers like to have unique decisions - and IRR does have that weakness, but clearly it is for an exceptional type of project. He highlighted that for the majority of project the IRR is a metric that can be used for project comparison.

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MR. REINSCH gave an example of a project moving through this process, with a number of metrics brought to bear, including an NPV 10 greater than zero, a PVPI greater than 1.3, and payback less than three years. This appears to be a good project and looks like a project that should be undertaken [slide 14]. However, a common situation may arise - as is often the case - that the company has more projects than capital. He pointed out even with \$100-\$130 per barrel oil that a good chief financial officer will impose discipline on a company by setting an IRR level as one of the thresholds that the project will need to succeed. Projects which don't meet that would become capital returned to shareholders. He suggested it isn't just about the projects, but that at some point it makes more sense to buy back shares or give the money back to shareholders than it does to invest in new project developments. He emphasized that ExxonMobil is very disciplined and aggressive about this vis-à-vis its shareholders and division policies.

MR. REINSCH suggested that whether you are a smaller company where capital constraint is a reality of life, or a much larger company where capital constraint is being created through financial discipline, every company has more opportunities than available capital. To bring that discipline to bear, the company subjects its portfolio to different financial or performance metrics, for example, showing IRR with a hypothetical hurdle rate at \$60 per barrel. He pointed out higher IRR is better. Thus by aligning all projects from highest IRR hurdle rate to lowest, and applying a metric or cutoff such as using \$60 per barrel as the IRR hurdle rate will determine which projects receive funding. He pointed out the little green bracket shows the subset of projects which will receive funding and all other projects below that rate will not.

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MR. REINSCH discussed issues with the IRR hurdle rate. He said that an increase in cash flow due to a rise in energy prices in

turn increases the capital budget and leads to a lower hurdle rate in order to undertake additional projects. Thus the company would be increasing its financial capability. Generally speaking that will in turn lower the overall quality of the portfolio. He explained the company would be undertaking projects the company wouldn't otherwise have undertaken simply because the company has more money at its disposal. He suggested that at some point the company will have a floor to reach or the project will not be funded. He pointed out that cycles of value destruction within the industry do occur when companies have a lot of money and "go out looking for the next big thing" such as the six wells drilled by Cairn Energy offshore Greenland. He asked members to consider how many times wells have been drilled offshore Greenland. He surmised it is in the geologists' minds that something is there so geologists continue to look, but examining periods with high prices with a lot of surplus available allows companies to chase some of the higher-risk potentially higher-return opportunities.

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MR. REINSCH pointed out that IRR is a measure which if used too exclusively can lead to "gaming" within the internal competition for capital. Project managers would have an incentive to overstate the "size of the prize" to attract investment capital to a proposed project, which could boost the IRR. He stated this as one of the reasons industry in the past 5-10 years has been increasing the degrees of discipline within exploration analysis to try to minimize this from happening. He said one of the many elements that IRR does not speak to is materiality. He stated that projects can have equivalent IRR's but much different Capex or revenue profiles. Thus a small Capex development with a relatively small revenue stream can quite easily have the same IRR as a very large project with a very large revenue stream, but those two projects will have very different meanings to the treasury.

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REPRESENTATIVE HERRON asked whether the companies decide to set a specific percentage.

MR. REINSCH answered yes. He suggested that a few companies have been using a domestic versus an international IRR hurdle, such as 15 percent for domestic and 20-25 percent for international projects. He described this as arriving at a level of corporate comfort or a different way to reflect

differences in the aboveground environment. Additionally, for many companies, such as TransCanada, it may result in never receiving any share value of an enviable portfolio for international pipelines since its shareholder base didn't care about it at all. For example, at one time TransCanada was in Argentina, Chile, and Australia, but it didn't bring the company any value. He agreed that discipline will be imposed differently by companies when setting the hurdles.

[4:26:31 PM](#)

MR. REINSCH referred to "Portfolio Efficiency: Return on Capital Employed (ROCE)" [slide 15]. He explained that the return on capital employed (ROCE) is what the company receives from capital it is exposing. He defined it as the net profit divided by gross capital times 100 to arrive at a percentage. He explained that ROCE is positively correlated with production and commodity prices. These two elements will increase the numerator, all else being equal, and it is negatively correlated with capital spending. If a company spends a lot of capital without positively impacting production, it will show up as deterioration in the ROCE - and companies are very sensitive to this. He characterized ROCE as a measure of how well management uses the capital that has been put at their disposal by the owners and creditors.

MR. REINSCH said over time, the ROCE will develop a pattern of time series that will give investors insights into whether this company is becoming more profitable or less profitable. He suggested analysts would question whether management is creating value or if it is it destroying value. He pointed out that ROCE on an annual year-by-year basis isn't an overly meaningful variable, but the implications are inescapable when viewed over time.

MR. REINSCH referred to the chart on slide 16 "Portfolio Efficiency: Return on Capital Employed (ROCE) One of the issues arises when a company has been investing a lot of money in a development that has yet to return production - a major capital project - the ROCE will penalize the company. This measure penalizes companies for that type of undertaking, which is why it is seldom to see companies with high growth rates in terms of production and high capital efficiency. He said with the exception of a very few types of assets, such as oil sands or LNG development of a large scale gas resource development, nearly all other development assets have decline rates. He pointed out that a significant amount of money is spent to bring

these projects into production, but as soon after production they fall away in terms of production volumes. He highlighted that companies will move in and out of the high-growth quadrant versus high-efficiency quadrant, it is pretty hard to live on the upper right hand side of this chart.

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MR. REINSCH said large capital project developments that deliver lots of production for a year or two are projects that provide ROCE. Thus ROCE is biased against major capital undertakings, but it has a bias towards large assets. This puts companies in a bit of a dilemma. Finally, anything that makes the denominator smaller while the numerator is unaffected will be a positive so depreciation creates a bias towards mature portfolios. Generally speaking, the more mature the asset portfolio, the higher the return on capital employed numbers.

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REPRESENTATIVE HERRON referred to the graph on slide 15 and asked whether the best place would be at the intersection of the two graph lines.

MR. REINSCH answered that best place to be is in the upper right-hand quadrant as far as possible. In this particular analysis, the axis is the average of growth and the average of return on capital employed. Each year the axis moves, but high growth and high return on capital employed is where companies want to be so, referring to the graph "Global Players Peer Group: Growth v. Efficiency," where Petrobras and ExxonMobil live versus where ConocoPhillips has been for a period of time.

REPRESENTATIVE HERRON asked whether ideally, for stability, a company should be located close to the intersection of the axis.

MR. REINSCH explained if a company has a very large portfolio, producing 4 million BOE that it is very hard to grow. These companies do not pay a lot of attention to growth, but instead pay more attention to the ROCE. He suggested with large portfolios that are difficult to grow, the company is just trying to keep up with declines in an efficient manner; otherwise shareholders will walk.

MR. REINSCH suggested that a chart describing Apache, Anadarko Petroleum Corporation and others of that size would show much lower ROCE numbers, but much higher growth numbers. Those

companies tend to focus on growth. The objective is to grow the portfolio more efficiently, but at a rate competitive with or superior to their peers, which is how they attract shareholder loyalty and capital.

REPRESENTATIVE GARDNER referred to the net profits tax. She asked whether that would make the state stronger in terms of ROCE.

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MR. REINSCH answered if a company is involved in new field development and is placing capital at risk and the government is supporting the company by reducing that denominator - return on the capital and capital in the denominator, the ROCE - once producing - will be better than without that incentive. However, the impact of this type of government engagement in asset development will be better measured in IRR, and NPV for specific projects than it will in ROCE only because ROCE is more of a portfolio-wide measure. Even in the context of the Alaska business unit for one of these companies the measureable impacts will be on a project-by-project basis.

[4:36:41 PM](#)

CO-CHAIR SEATON asked whether the credits would be calculated in the denominator, or whether the total project cost will be shown no matter whether a credit exists or not.

MR. REINSCH related his understanding the question is whether a company will incorporate government exploration credits or other incentives in its project analysis. He answered that that good companies will conduct their project analysis "clean" using 100 Capex and 100 percent revenue flows as a stand-alone and then consider government incentives. If a project passes muster and is economic without incentives, clearly incentives will improve the economics. If a project only becomes economic due to government incentives, then it becomes a management decision because government incentives are more or less stable depending on the regime involved. So at a minimum there would be an alert that the project is not economic without the incentives being offered. This "flag" would be attached to a project regardless of the location.

CO-CHAIR SEATON asked for clarification on the ROCE calculation. He asked whether the ROCE is put forward by the companies or

whether the companies will consider the total capital of the projects and therefore it will not show up as credits.

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MR. REINSCH answered that the ROCE is a measure of portfolio performance so the capital employed is the exposed capital. Further, ROCE represents a data point not a forecast; so what is being measured is actually corporate capital expended. The denominator will consist of the company's capital commitment relative to the returns being generated from the investment. To the extent that incentives mean the company has been able to leverage its capital, they will enhance the portfolio from an efficiency of capital perspective. He said, "Absolutely, if the government is going to assist with project development that should improve the performance of that portfolio from a company perspective."

REPRESENTATIVE MUNOZ asked whether PFC Energy is able to assess the impact that Alaska's Clear and Equitable Share (ACES) has had on the capital allocation decisions for Alaska.

MR. REINSCH deferred to his colleague, Janak Mayer, who can better address that question.

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MR. REINSCH noted that PFC Energy was asked for insight on the issue of integration versus de-integration within the major oil and gas companies. He asked to layout the context for this discussion. He reported that in 2010 Marathon Oil Corporation (Marathon) and in 2011 ConocoPhillips both took steps to separate the downstream operations - refining and marketing operations - from the upstream. The result was to de-integrate their upstream operations from the downstream operations, which was a significant move for any company to make. This essentially created two stand-alone trading entities, which raised questions on whether this would be the next move by all of the major integrated companies like Shell [Global], Chevron [Corporation], BP, and ExxonMobil. Further, he was asked whether de-integration would have an impact on ConocoPhillips and Marathon's decision-making process and the potential impact on the dialogue between Alaska and these companies. He answered that several slides illustrate arguments for and against integration and provide reasons for the companies' actions and if this will become widespread [slides 17-18]. He stated that

companies have integrated and asked whether the arguments are still in place.

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MR. REINSCH discussed the "Special issue: Integration versus De-Integration." One of the founding arguments for integration is that over the course of the commodity cycle as oil prices fluctuate product cycles can move counter or provide a buffer. In other words as oil prices decline, product prices don't respond as quickly so if products, sales, and oil sales within a company's portfolio, the company has a bit of a buffer for those cycles. The counter argument is that even though downstream profitability has collapsed, there have also been "pure play" refining companies that have been quite capable of operating in this environment. So it doesn't appear to be an argument any longer for integration.

MR. REINSCH highlighted that molecule management has long been another argument. He explained that molecule management ensures sophisticated refining capacity is in place for particular crudes - very waxy, very acidic requires a certain type of refinery feedstock - so integration allows companies to build refineries for the specific crude. The counter argument is independent energy producers have not had any problem interacting with the refining sector so that doesn't appear to be an issue, as well. Additionally, there are specific oils in which molecule management seems to be necessary, but companies are addressing the issues through contract and joint venture rather than through integration.

MR. REINSCH related another argument has been that integration is a technical differentiator amongst energy companies to enhance their ability to secure projects. For example, companies could build a large refinery so they are viewed differently by national oil companies or stewards of the large non-equity accessible resources globally. The counter argument is that the ability to build a refinery doesn't have a whole lot to do with the ability to efficiently operate in the upstream so what credit would integrated companies obtain versus a pure refining company who only performs refinery development. The most recent argument is that integration allows participation in the downstream [Organisation for Economic Co-operation and Development] (OECD) growth story. He said that in the developing economies of China, the Middle East, and India, being able to operate in the downstream by building refineries and manage product markets allows companies to participate more

directly in the development. The counter argument is that in these regions, many of which are dominated by national oil companies or something similar, these companies are choosing partners on the basis of what they bring to the table. He pointed out that if companies need upstream development, they will go to the best exploration and development companies and if they want a refinery built, they will go to refinery specialists. He acknowledged there was a time 20 to 30 years ago, one company would provide all of the [upstream and downstream] work. Thus time has eroded much of these arguments.

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MR. REINSCH discussed the arguments against integration [slide 18]. One of the biggest arguments against integration is that capital markets appear to value integrated company below the sum of its parts. He said that much discussion was held with regard to BP Exploration (Alaska) Inc. with respect to the aftermath of Macondo when BP's share price was in decline. He recalled analysts suggesting that BP should be broken into pieces and sold off because the individual assets were worth more than the company was worth. He said the argument against this is that costs are incurred so it is expensive to split a company. He suggested that if any value can be derived by keeping these assets together one should do so. One strong value that continues to exist is the synergy between refining and petrochemicals. He highlighted that Total Company [French energy] and ExxonMobil have large refining and petrochemical operations and would be reluctant to split those operations.

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MR. REINSCH related that the second argument has to do with strategic focus. In many integrated companies, the downstream sector is neglected strategically at the expense of upstream positioning and growth, particularly in the current climate of narrow refining margins and sustained, high oil prices. He suggested that by taking these companies apart and creating a management team dedicated to downstream they should be able to create more value with that capital base than in the larger company.

MR. REINSCH offered the third argument against integration is materiality. There are very few materially, physically integrated oil companies left. For example, by removing Marathon and ConocoPhillips out of the mix, the exhibit on slide 18 shows refining capacity versus upstream production. He

highlighted that there are only a handful of companies with significant refining capacity and secondly these companies are not just refining the company's own product. He emphasized that there are two business models going on here. As he previously mentioned ExxonMobil and Total Company both have a strong integration between refining and petrochemicals and would not likely want to break those functions apart.

MR. REINSCH noted that the three other large players - Statoil , ENI, and Repsol YPF - are companies that were to a greater or lesser degree national or quasi-national oil companies for their respective countries: Norway, Italy, and Spain. He suggested these companies would likely face considerable government opposition to de-integration. The final and fairly significant argument against integration would simply be that the world has evolved. There was a time when it was important to control the value chain from the barrel produced to the gallon sold at the service station, otherwise one risked exposure. He pointed out that in this world of more flexible and liquid trading, futures contracts, contract sanctity, and product differentiation specialization have eroded the benefits from integration that really defined this industry years ago by and large isn't there.

MR. REINSCH provided an example. Forty years ago the debate about security supply was a debate about physical barrels, but now security supply is about contract terms. The dialogue has changed about integration.

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MR. REINSCH summarized the discussion by relating how PFC Energy sees the pros and cons concluding. He said it certainly appears that share appreciation is the number one driver for de-integration. Within certain companies there is a belief that by separating the management teams, management focus, and strategies of these operations which have no driving need to be integrated that there is more value to be created than the cost of taking them apart. Therefore de-integration makes sense from that perspective. The market development arguments that existed in the past for a downstream presence have largely ended and arguably one of the last frontiers that was the case was in Africa, and even there BP, Total, Shell are divesting their refining and product marketing activities to pure play refiners and marketing companies who perform these services as a business.

MR. REINSCH noted his third observation is that internal decision making and the increased sophistication of regulation of this industry on a global basis has really taken away any value companies may have derived from cross-subsidization or barriers to competitor entry that being integrated allowed them to secure. Those activities simply don't exist to the extent they did so the value has eroded in terms of a return to integration argument.

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MR. REINSCH said that although there are technical drivers for integration, the same benefits can be secured through joint venture agreements and contracts where third party refiners don't need to be secured through physical ownership. He offered PFC Energy's overall conclusion is that to the extent there is further pressure for companies to de-integrate, it will come from share appreciation arguments, with Chevron and Shell being the companies that PFC Energy thinks will most likely be the recipients of this type of pressure.

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REPRESENTATIVE PRUITT asked, related to materiality, for the reason that companies such as Statoil, Eni, and Repsol would have considerable government opposition to de-integration. He asked for clarification on whether they feel a need to have the upstream and downstream connection.

MR. REINSCH explained in all three companies that the governments no longer have a majority share. It is more of a legacy sense of responsibility for managing their domestic market environment. So while all three companies are no longer in the national oil company arena, they are all still dominant players in their domestic current markets. Governments and people consider them as champions of the energy sector so to de-integrate and sell off one element or another would be construed either a weakness or counterproductive.

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REPRESENTATIVE PRUITT related his understanding that even companies such as BP and Shell were at one point nationally owned. He asked whether the three previously mentioned companies would be moving towards de-integration if it were not for the political pressure.

MR. REINSCH stated that since all three are European companies the dialogue would progress because pure play refining companies and pure play marketing companies that would pay to access the assets. The companies are not receiving a premium to own along the value chain. He offered his belief that the discussion would advance, but the legacy element and culture in the domestic markets are not worth the expense relative to what it would cost to take that step.

REPRESENTATIVE PRUITT recollected his conversations with Statoil confirmed that it is a pride issue.

REPRESENTATIVE HERRON referred to product demand growth regions of China, Middle East, and India [slide 17]. He asked whether the committee should keep these countries in mind as members consider HB 3001, since they will pay a premium for petroleum products.

MR. REINSCH responded that regardless of what happens in Alaska, the state will remain exposed to international pricing. He explained that in the past a company could offer to develop the hydrocarbons, build the refineries, and manage another country's products, which presented a powerful argument; however, in these high demand growth jurisdictions that cachet no longer exists. These countries have their own national oil companies and refineries since all are capable of managing their upstream, midstream, and downstream businesses. For example, BP recently executed with Reliance Limited Industries (Reliance) in India for pockets of expertise BP doesn't have. He stated that BP, a premier global deepwater developer, struck partnership with Reliance to gain access to a large swath of acreage in the Krishna Godavari (KG) Basin in India. This made sense for India because India didn't have that degree of deepwater expertise; however, for BP to build a refinery might elicit the response of whether BP could do it any better than a refining company, and if not, BP must compete with everyone else. He summarized that to be a downstream player the company must compete with other downstream competitors.

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REPRESENTATIVE PETERSEN related his understanding the old school of thought about vertical integration was that a company would have control of the product from the beginning through retail. He sought clarification that more countries are moving to specialization because there is less capitalization involved in being vertically-integrated, since more business segments are

necessary, but specializing would allow a company to be better able to make a profit.

MR. REINSCH acknowledged that is part of the argument. He said that until relatively recently there weren't specialized refining companies or specialized product marketing companies since it wasn't easy to break into the stranglehold held by the integrated players. The only real success people had was in the upstream. He agreed that companies who are allowed to focus on one end of the value chain who perform well can be more competitive than integrated companies that spread management expertise, focus and strategy across all elements of the value chain. Some integrated companies are recognizing this fact, as well, since the competitive forces will improve returns and result in more efficient capital expenditures.

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CO-CHAIR SEATON related that this part of the presentation will discuss ConocoPhillips de-integration and the difference in ConocoPhillips's perspective as an upstream company versus as an integrated oil company. He expressed interest in hearing PFC Energy's perspective as well as the relationship between the three North Slope integrated oil companies, who will become two integrated oil companies with a partner just upstream. He pointed out that ConocoPhillips did not normally buy leases for exploration, but currently did so. He asked whether this is the type of thing the state could expect from an upstream materiality focus.

MR. REINSCH explained that what has happened with ConocoPhillips and what he predicted would increase in the next two planning cycles is emergence of a de-integrated pure upstream player; however it is one with a new chief executive officer, new board, and a new executive fully exposed to the discipline of the market. Clearly, he said, the company will be looking for a new strategy and direction. He also said, "One of the questions I know - I have no doubt it's asking itself - is what role does Alaska play in that new direction." He pointed out that the Alaska portfolio has a different meaning in materiality within the ConocoPhillips upstream portfolio, global, than it does for BP and ExxonMobil. He said Alaska can "turn the dial" on the ConocoPhillips global portfolio, more so than it can for either BP or ExxonMobil given the same change in investment environment or change in production volumes. Alaska fits well with the strategy that ConocoPhillips has as a company with the majority of its assets resident in industrialized, developed economies.

Thus relative to its peers ConocoPhillips resides in safe haven environments. The other side of the coin is that safe haven environments tend to be mature basins, with relatively high costs which makes it more difficult to balance the issues, thus engendering discussions of fiscal systems. He suggested that other than a sharpened focus on upstream metrics by the management team, it doesn't really change the dialogue - Alaska still needs to fit within that portfolio, and Alaska needs to show that it is part of the solution to their strategy, targets, and objectives since that is what these companies look for to an extent.

CO-CHAIR SEATON asked whether ConocoPhillips's participation in exploration leases was in anticipation of this new focus.

MR. REINSCH was uncertain, but acknowledged their de-integration has been planned for some length of time so certainly it would fall within that time of influence so arguably it would represent some positioning with de-integration in mind.

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MR. REINSCH discussed the "Special Issue: Basin Designation and Allocation of Free Cash Flow" [slide 20]. He stated that there has been a fair amount of discussion in prior presentations in the Senate Finance and Resource Committees about designations of areas. He highlighted six definitions to allocate basins within the global portfolios. The "core area" is really an area that produces a stable stream of net cash flow and is material to the company. He pointed out that a core would be of a much larger size for ExxonMobil than for Apache. He referred to them as the driving portfolios for growth for these companies.

MR. REINSCH defined a "focus area" as an area where companies are investing capital with an eye towards growing through new source production and reserves growth into cores. Typically, a focus area is a net consumer of free cash flow. Cash flow would come from other areas of the portfolio and would be a portfolio in the investment phase. He defined "new venture" areas as areas new to the company and less mature assets, such as initial exploration and positioning, but still are consumers of capital. Generally speaking there would be little or no production, he said.

MR. REINSCH highlighted the fourth area as "harvest areas." These are areas that produce net cash flow - revenue greater than costs - with investment at or below a replacement level.

In other words, the company would be investing to maintain production or manage a decline. All harvest areas have some form of limit to growth, whether that would be due to geological potential, competitor landscape, or limited room to run. These areas tend to be the areas of "portfolio churn" where larger companies will gradually sell off assets for a variety of reasons, such as the asset is not performing well, or the company cannot put management time or technical time towards continuing to develop, or the asset doesn't represent as an attractive an opportunity as something else in the company's portfolio. He emphasized that when speaking to harvest areas, he is not talking about entire countries or basin areas. Within any given basin, mature fields may be going into decline that perhaps could be managed through intensive enhanced recovery, but generally speaking these consist of the mature fields in a company's portfolio.

MR. REINSCH suggested that within those same basins new field developments or new opportunities may represent "focus areas" or "new ventures". He provided a classic example, noting the Gulf of Mexico shelf region has been in production decline for an extended period of time. The majors were largely leaving the shelf and the assets were picked up by smaller companies who have been working the assets more intensively. At the same time, the most recent examples in the lower tertiary, in the ultra-deep water areas, have seen very large resource discoveries taking place. So while the Gulf of Mexico has definite harvest assets and components, as a basin it also has significant areas of new venture activity and focus activity. It is important that everyone understand what is meant when speaking of harvest areas. He explained when one is managing a decline, or investing at or below replacement of production, as an ongoing business practice, that would be defined as a harvest asset.

MR. REINSCH pointed out that in a competitive operating environment the assets would gradually be rolled over. He defined "sit & hold" as a category that applies more to the national oil companies than the publically-traded oil and gas companies. Some companies hold large amounts of acreage and just sit and wait for a variety of reasons, including that the fiscal terms don't make sense to engage, or the aboveground risks - political, social, or military - are too great to engage in now. Finally, he defined the "exit/potential exit" areas. He related that PFC Energy takes the portfolios of the companies they follow and allocate them into these definitions of basin designations.

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REPRESENTATIVE PRUITT referred to harvest areas and recalled him mentioning companies typically sell off harvest area holdings. He acknowledged the state has seen this happen in Cook Inlet, but not on the North Slope. He asked whether he foresees this as moving in that direction.

MR. REINSCH characterized Alaska as a whole as being in a harvest mode. Alaska has had a set of legacy assets in decline for some period of time, yet those assets are still valuable for reasons beyond the producing horizons - due to the infrastructure - which will allow for commercial development of close-in fields of less attractive resource in terms of viscosity or crude oil type. Yet the leveraging of the infrastructure for prior investments can allow those resources to be brought to production in the most efficient and economic manner. So companies are staying because they still see potential, he concluded.

MR. REINSCH raised the argument, in terms of the context of this discussion, noting companies have opportunities for investment, but not all resources are alike. For example, very heavy crude oil has a different value than light, sweet, crude oils and that difference must be reflected. Additionally, high-cost enhanced recovery has a different cost base than natural reservoir pressure in terms of producing the next incremental barrel of crude oil. He pinpointed this as the argument being focused on.

MR. REINSCH said the legacy fields are in decline, and companies are investing to keep the decline rates at 6 percent, rather than 12 percent, but all of the capital in the economic investment has been vetted, approved, pitted against all other opportunities in the portfolios, and has succeeded in attracting capital. The next step is "the next dollar" where the discussion moves to, which is all commercial. He cautioned that will be taking the decline rate from 12 percent to 6 percent. He wondered about the next step, noting Alaska has potential new growth in and around the legacy asset, and some potential in the Chukchi Sea, where a new set of considerations come into play, particularly from the perspective of this committee.

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MR. REINSCH suggested the real question is how to maximize revenue for all parties. He referred to the chart titled

"Global Ares of Upstream Operations" to Alaska, which is depicted as the blue "harvest" areas. He explained the blue reflects the assets that are generating free cash flow from the production fields and generally speaking, in a global portfolio, will go to other opportunities.

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MR. REINSCH discussed the "Special Issue: Basin Designation and Allocation of Free Cash Flow" [slide 21]. He indicated Alaska's oil fields were built from the net free cash flow generated from other producing jurisdictions globally. He referred to two charts "2003-2005: Sources & Uses of Cash Flow" for a large representative set of companies and "2008-2010: Sources & Uses of Cash Flow." He explained the first chart represents a macro look at the industry, in which North America and Europe were the cash engines driving deepwater development in Sub Saharan Africa. Five years later Europe has still been producing cash, but it is largely Sub Saharan Africa that has been generating a large wall of cash directed to North America. He predicted as the clock rolls forward three years, that cash will be used to develop the next basin, whether it is Angola pre-salts or the equatorial margin of Northern South America, since billions of dollars of capital will be required. He highlighted that Europe has typically been the cash cow of this industry for two decades.

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REPRESENTATIVE HERRON noted that Repsol YPF is listed on the bottom of slide 21. He asked whether yesterday's events in Argentina by [President] Kirchner will affect Alaska.

MR. REINSCH predicted that the events will impact Repsol. He explained that three days ago on April 10, the president of Argentina enacted the renationalization of YPF - the state oil company that Repsol purchased in the late 1990s and has operated ever since. Over the years Repsol bought 92 percent of that company, and while Repsol has reduced its equity position to about 57 percent, it still represents 60 percent of its total global production. By renationalizing YPF it took over 51 percent of the company from Repsol - not from publically-traded shares in the market - but from the Peterson Group - an Argentine owned company with 27 percent of the company it holds. He predicted the law will be enacted by May 6th or May 7th, noting the legislation has a three-year negotiation window of

settlement with Repsol before arbitration in an international court.

MR. REINSCH stated this impacts Repsol in two ways. First, Repsol lost 60 percent of its base in one fell swoop. On the other hand, Repsol lost the element of their portfolio that was dragging it down as a corporation. While YPF generated cash flow, the asset was still a difficult, mature operating environment. He explained that Repsol has been a very successful exploration company the past four or five years and has assets the company can grow. The advantage has been that Repsol's portfolio looks much better, although it could use \$10 billion to invest in the company. While the Argentine government may settle with Repsol, it is uncertain if this will happen and it might occur after a lengthy legal contest. He concluded that this is a very difficult situation for Repsol. Outside of Repsol, a number of companies in Argentina are likely wondering whether this represents a great consolidation opportunity or if it is time to step quietly to the side and focus elsewhere. In response to a question, he answered that PFC was not the consultant the Argentinians used.

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MR. REINSCH, in response to another question, explained the reasoning in the legislature is that security of supply is an issue of national interest. He said that arguably the drivers for that decision were reflected in the twin capital account deficits and an inability to raise international finance since Argentina defaulted on their debt three years ago. Further, Argentina did not have access to capital markets and already eliminated expropriation of profits from the energy sector for any company operating in the country. At the same time Argentina operated under a system of subsidized oil and gas prices to protect consumers from international prices. Therefore, Argentina prompted energy demand growth at a time when they were importing significant amounts of natural gas. He recapped his belief that Argentina was in a box and observed free cash flow being generated by the YPF portfolio and saw an opportunity to address two issues. First, Argentina could secure the cash for the government; and second, by allocating the 51 percent - half to the provinces and half to the federal government - it could address some long-standing federal provincial issues plaguing the country. He pointed out that by hammering YPF for six months prior to the legislation being put forward drove the share price down to a point where the government will have a good argument during the settlement to

Repsol. He referred to it as policy in a crisis and he surmised that everyone will argue at the end of the day it probably wasn't the best policy move, but it is too late to change the decision.

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MR. REINSCH discussed slide 22 titled "Example: Nexen Inc." He explained the portfolio allocation of free cash flow in action. He explained the bottom right hand side of the slide is a chart which reflects the global representation of Nexen Inc.'s portfolio (Nexen) and the status of the company. The left-hand side bars show combinations of cash flow and Capex over time starting in 2000 and moving to 2010. He pointed out that Nexen had an asset in Yemen - the Masila block - that generated a tremendous amount of cash flow with relatively little capital expenditures and on the basis of the cash flow were able to secure and develop the North Sea Buzzard assets. The very generous cash flow from their North Sea portfolio has allowed them to pour capital into the development of their Long Lake oil sands and unconventional gas assets in Canada, and in the U.S. Gulf of Mexico deepwater assets. One can see how the company has redirected its free cash flow from one set of assets within its portfolio to develop another and it will continue to do so over time. He pointed out that reviewing any upstream exploration and production companies will demonstrate that same movement of cash flow over time. Clearly, part of the discussion has been that Alaska wants to be part of the portfolio that is receiving capital and wants to grow production as opposed to being part of the portfolio that is only contributing to developments elsewhere.

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REPRESENTATIVE GARDNER asked whether other companies were in harvest mode or exit mode in the UK North Sea during the time Yemen cash flow was used to bring new volumes on line in the UK North Sea.

MR. REINSCH responded that Nexen was able to secure the UK portfolio of a company called EnCana that had decided to shift its strategy from becoming the largest global independent to becoming the largest gas producer in North America. This resulted in strategically stranding some very high-value assets outside North America. Nexen was able acquire the asset portfolio on the strength of its Yemen cash flow and financing capability. He pointed out that Buzzard at that time was just

being developed as the largest oil discovery in the North Sea in the prior 20 years. He characterized it as a real jewel, which Nexen could acquire since Nexen had the Yemen asset developed and has been generating large amounts of cash flow on an annual basis. Thus Nexen could afford to make that move, develop the asset, and then afford to make the next move.

MR. REINSCH, in response to Representative Gardner, confirmed that the sale of the UK North Sea portfolio by EnCana was a classic case of arguably commercial economic assets being divested for a strategy purpose. He said that EnCana took the money it generated from the North Sea and invested it into North America because EnCana believes North America's gas prices were heading to \$5 and higher in 2000-2001. He suggested that EnCana had a different vision of the future than other companies did. He suggested that no one would have sold those assets purely for economic or commercial reasons, but the assets were sold as a strategy driver.

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REPRESENTATIVE DICK acknowledged that the oil companies say they need a more favorable tax regime, which is fairly broad. However, the legislature is trying to determine what specific changes will bring about the desired outcome.

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MR. REINSCH suggested that part of the challenge in Alaska is that Alaska has quite a diversity of investment opportunities from well-established legacy fields, to untapped gas resources, to high viscosity heavy crudes, and to frontier exploration plays. He offered his belief that the question becomes much more subtle, such as what are Alaska's goals in one to three years, in three to five years, and in five to seven years. Further, it's also a matter of how Alaska can align those with the capability of the industry to deliver. For instance, if the state's goal is to achieve production to the extent it can be flattened in the next three to five years, the goal can't be met by exploration. He pointed out the cycle time from exploration to discovery to new production. One of the reasons PFC Energy can speak so firmly about portfolios is that if it will "turn the dial" for any of the companies in the five- to seven-year time frame, the resource is already discovered and PFC Energy has already modeled it. He said, "That's what we do." If the state is looking beyond that the next exploration potential in the next two to three years will have an impact 7-10 years from

that time. He stressed that it is what the state already has in the bank - enhanced recovery on those assets - or what is soon to be brought into production, which is the focus. He acknowledged that may take a different set of fiscal action responses. Then the state must review its portfolio and recognize that these assets will decline. No one wants to destroy capital so the question becomes what can the companies deliver and what do they need to attract that capital. Companies can invest here, but have the choice to invest in another jurisdiction.

MR. REINSCH said the great advantage Alaska has in this global gas discussion is that Henry Hub is completely irrelevant to Alaska; however, that it not the choice at Lake Charles [Louisiana], since Henry Hub is everything to them. He asked whether anyone is going to liquefy LNG in the Lower 48 and send it off to Europe or Asia, with a \$4 spread. He pointed out it wasn't that long ago that gas was at \$7 and there were reasons it dropped. The beauty of being in Alaska is that gas isn't gas in Alaska, instead it is oil. He characterized gas as S-shaped curves sold into an Asia market at crude prices so it is a different dialogue; however it will also require a different set of incentives. He asked whether the state would only benefit from revenue or if it would be possible for the state to benefit through gasification as happened in Columbia, Argentina, or Brazil. He pointed out that these countries used the gas to wean themselves off petroleum products which were expensive for them. He cautioned that although no company can predict if the state does this, the companies will do that; all they can really say is that if the state does something it will help. Beyond that, it is important to consider reasonable scenarios so everyone involved is coming out of this in good shape, which is the art of fiscal economics. He said, "Don't kill the golden goose, but on the other hand, you are the client; they are the contractor."

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REPRESENTATIVE SADDLER asked for clarification on slide 22 for the example for Nexen, Inc.

MR. REINSCH explained that the chart on the left reflects on the horizontal axis cash flow in millions of dollars, and on the vertical axis shows capital expenditures (Capex) with \$2.5 billion at the top and \$2 billion in cash flow on the right. So in reviewing Yemen - note the thickness indicates tracking, which starts thin and gets thicker over time. He explained the

large capital expenditure in the 2000s in Canada, before the cash flow moves the bar to the right. This is the time that Nexen was spending building up its Long Lake oil sands development, which came into production only three to five years ago. The result is the line moves to the right and down showing the cash flow with relatively less investment. He referred to the UK on the cart, and noted Nexen bought the asset when it was already in production, and basically it developed a large wall of cash flow and they've been able to maintain it. He pointed out the U.S. Gulf of Mexico reflect asset sales and purchases, large capital expenditures and cash flow resulting from production. The dominant assets are in the UK and Canada. He pointed out that after bringing the Masila block into production in the early 80s when it came to the end of its license life, the government decided to take it back. He said the contribution of Yemen was the North Sea and Canada portfolio, as well as the seeds of the West Africa portfolio that hardly show on the graph since the asset is just now coming into development. He related that Nexen leveraged that legacy asset into a lot of growth elsewhere in the world. In further response to Representative Saddler, he explained that Nexen spent \$2.7 billion to buy the asset in about 2006 and in the second year of capital expenditure spent about \$700 million. Nexen has basically been spending an annual amount of \$700 million per year on the asset. In 2010, Nexen performed new platform development and field work so the Capex was a little higher and cash flow a little lower.

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CO-CHAIR SEATON asked what relevance the aforementioned discussions on cash flow have to do with Alaska's situation since Alaska is trying to incentivize in-field drilling and legacy fields. He offered his belief that these evaluations on cash flow would have more to do with company board room discussions. He said he did not think Alaska would base its decisions on incremental in-field drilling since it is unlikely a 600-million barrel field will be produced in three or four years.

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MR. REINSCH explained that sometimes the scale muddies the process; however the process would be exactly the same. He pointed out with certainty the 600 million barrel fields lie in places that companies don't want to be operating. For example, a company does not want to drill in 6,000-7,000 feet of water

through 500 meters of salt to get to production formations that have never been produced in the world before to drill wells that cost millions of dollars - whether it is in Brazil, Angola, or the Arctic - if it is ExxonMobil. On the complete other end of the spectrum, an investment of \$6-8 million for horizontal multiple-fracked shale gas in a liquids-rich shale basin in the U.S. represents a small investment with a nice competitive return, albeit not as nice at 3 Mcf.

MR. REINSCH acknowledged the company would want to obtain a high volume of liquids at that rate, and if so, portfolios would move as a result. Alaska would like to see the investment in enhanced recovery in in-field drilling or other reservoir sweeps, such as more sophisticated water handling techniques to increase recovery rates, which is every bit as comparable to opportunities the committee has referenced. It would just be a matter of scale at both ends. This is why companies don't look only at [net present value] NPV, except from a strategy sense, such as considering investment in Angola over a 20-year forecast of the basin. At the end of the day, part of this analysis will boil down to a pure barrel of oil equivalent (BOE) metrics. He said, "I'm going to put a dollar in here, what am I getting out of it." The company will run the economics at \$40, \$60, \$80, \$100 and \$120 per barrel of oil pricing. He recalled the term "harsh oil" or "severe oil world," which has been used since the easy oil has all been exploited. All of these developments carry risk so companies will always consider their analysis. He was asked how an Alaska enhanced recovery project compares to all of these and answered that it truly competes for capital. If that's what Alaska wants to incent, there are ways of incenting an enhanced recover project, which seems to be the crux of the debate, he said. He cautioned members against concluding that companies are involved in very large scale developments all around the world so how could Alaska possibly compete, which is not the issue. Instead, the issue is that - outside of the strategic aspects of positioning - these metrics give senior management and executive boards a way of comparing a dollar in Alaska to a dollar elsewhere within the global portfolio, to allow them to make the most efficient, effective, profitable decision in the interests of their shareholders and their investors. He concluded this is essentially exactly the same thing Alaska is doing.

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REPRESENTATIVE P. WILSON said she has heard complaints in the legislature that legislators did not obtain any commitment from

companies. She related her understanding from Mr. Reinsch's testimony that companies cannot give Alaska a commitment because companies must take their decisions back to their boards.

MR. REINSCH confirmed this.

REPRESENTATIVE DICK suggested the analogy that the legislature is being asked to pull a lever, but they don't know how hard to pull. He expressed interest in learning more about the cause and effect between what the legislature decides and the desired end result.

MR. REINSCH agreed with Representative Dick. He clarified that legislators will lay out terms of engagement for the contractor. In other words, the legislature will essentially be saying that this is the proposal the state is prepared to offer companies. He agreed it is similar to pulling a lever. He highlighted that the legislature must make a decision on how competitive the state's fiscal system is compared to those in other jurisdictions. The complication is that Alaska has more than one type of asset and one lever. It would be a straightforward exercise if it did. Therefore, the current challenge is more complicated since there are different asset types and different timeframes, which add dimensions that go beyond the one-lever pull. He predicted the action would be the same, but "you need more hands than the one you had up." He anticipated the modeling work will bring some insight to the decision-making process. He emphasized the best outcome in the discussion would be the sense that in the foreseeable future the contractor will get a risk return reward that is competitive and the government is stewarding its resources on behalf of the people in the most efficient way as it possibly can. He was unsure of the variables and whether it would be the realities of fluid motion through rock formation or it would be that Iran decided the Straits of Hormuz would be just fine as is.

REPRESENTATIVE GARDNER asked what forthcoming information would be included in future presentations from PFC Energy.

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REPRESENTATIVE MIKE HAWKER, speaking as the chair of the Legislative Budget and Audit Committee, explained that during the past summer the committee issued contracts with Pedro van Meurs and others. Various committee chairs indicated the legislature would need professional consulting advice with an international perspective. He worked with the Legislative

Budget and Audit Committee's Vice Chair Stedman to identify PFC Energy as a company with premier qualifications, and they requested to engage PFC Energy specifically for the Legislative Budget and Audit Committee, but also on behalf of the legislature. Subsequently, PFC energy has been engaged in a five-point work plan to prepare the state's fiscal model to allow the committee to evaluate different proposals to come before the legislature. However, that kind of modeling must evolve over the course of an engagement, since various committees may want to try a new/different mechanism. He highlighted that PFC Energy's contract calls for an evolving model, but one designed in a manner and presented in an open and transparent manner. He noted the commitment with PFC Energy required vetting. Further, PFC Energy was instructed to discuss their model with other modelers, such as ones in the state's Department of Administration and Department of Revenue. He explained the idea is to ensure that arguments don't surround the model. He surmised this question arose from the misinterpretation that Commissioner Butcher made in the Senate Finance Committee, which gave the impression that the Department of Revenue is using PFC's modeling, which is absolutely false. He emphasized that PFC Energy continues to work solely on behalf of the legislature through the Legislative Budget and Audit Committee.

REPRESENTATIVE GARDNER thanked him for his thoughtful response.

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The committee took an at-ease from 6:04 p.m. to 6:15 p.m.

[6:15:05 PM](#)

[HB 3001 was held over.]

[6:16:56 PM](#)

#### **ADJOURNMENT**

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 6:16 p.m.