ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE
April 23, 2012
9:07 a.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 Kurt Olson
Representative Dan Saddler
Representative Pete Petersen
Representative Chris Tuck
Representative Lance Pruitt
Representative Mike Doogan
Representative Steve Thompson
Representative Bill Thomas
Representative Mark Neuman
Representative Tammy Wilson
Representative Bob Miller
Representative Bob Lynn
Representative Alan Austerman
Representative Anna Fairclough
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)	Heard & Held
04/21/12	(H)	MINUTE(RES)
04/21/12	(H)	RES AT 2:00 PM HOUSE FINANCE 519
04/21/12	(H)	Heard & Held
04/21/12	(H)	MINUTE(RES)
04/23/12	(H)	RES AT 9:00 AM HOUSE FINANCE 519

WITNESS REGISTER

JANAK MAYER, Manager
Upstream and Gas
PFC Energy
Washington, D.C.
POSITION STATEMENT: Speaking as the project manager who has been hired by the Legislative Budget and Audit Committee, presented a PowerPoint, "Discussion Slides: Alaska House Resources Committee" and answered questions during discussion of HB 3001.

ACTION NARRATIVE

9:07:57 AM

CO-CHAIR PAUL SEATON called the House Resources Standing Committee meeting to order at 9:07 a.m. Representatives Seaton, Feige, Gardner, Dick, Foster, Herron and P. Wilson were present

at the call to order. Representatives Kawasaki and Munoz arrived as the meeting was in progress. In attendance from the House Special Committee on Energy were Representatives Olson, Pruitt, Saddler, Lynn, Petersen, and Tuck. Also in attendance were Representatives Austerman, Fairclough, Neuman, Thomas, Thompson, T. Wilson, Doogan, and Miller and Senator Giessel.

HB 3001-OIL AND GAS PRODUCTION TAX

9:08:56 AM

CO-CHAIR SEATON 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."

9:09:13 AM

JANAK MAYER, Manager, Upstream and Gas, PFC Energy, speaking as the project manager hired by the Legislative Budget and Audit Committee, reported that PFC Energy is a global energy consultancy which specializes in oil and gas with a focus on above ground risk, including fiscal terms, commercial risk, and geo-political risk. He explained that upstream refers to the exploration and development of crude oil, as opposed to downstream which refers to the refined product.

9:10:27 AM

CO-CHAIR SEATON asked the committee to save any philosophical questions until after the presentation.

9:11:23 AM

MR. MAYER introduced a PowerPoint presentation entitled "Discussion Slides: Alaska House Resources Committee," which was included in members' packets. He then said he would provide a brief background of Alaska's oil and gas competitive context, particularly in terms of the current fiscal system in the context of other hydrocarbon regimes. Drawing attention to

slide 3 entitled "Fixed royalty Jurisdictions in US Lower 48 Are A Key Competitor to Alaska for Investment Dollars," which compares the time periods, 2003-2005 and 2008-2010, for the areas around the world where companies were taking cash and significantly investing cash for a base of new production. He stated that for much of recent history, North America and Europe have been cash surplus regions of established production where investments have been made in the past. He noted that essentially, companies harvested cash from those mature regions and used it to build assets in new regions. During the first half of this last decade, a notable cash deficit area was Sub Saharan Africa where companies made significant investment in plays, particularly in deep water Sub Saharan Africa. He reported that in the last couple of years high oil prices and the unconventional oil revolution in North America, the Lower 48, has created a remarkable turnaround from an exporter of cash within companies' portfolios to a destination of cash. He declared that there is now a lot of investment in the Lower 48 to take advantage of the Lower 48's onshore unconventional play.

MR. MAYER stated that the fiscal regimes across the Lower 48 are by and large fixed-percentage royalty regimes. Five years ago major competitor jurisdictions for investment dollars were likely to be developing countries with large production sharing contracts in terms of their fiscal systems, relatively high levels of government take, and fiscal systems that negotiate terms directly with companies. The significant difference today is that one of the main competitive jurisdictions for Alaska is the Lower 48 as a destination for cash and there, in the Lower 48, is significantly lower government take. The aforementioned makes it more difficult for Alaska to compete within companies' portfolios for investment dollars.

9:15:37 AM

MR. MAYER moved on to slide 4 entitled "Alaska's Days of Easy Oil Are Gone: High Costs and High Government Take Present Challenges" and stated that there are steadily rising costs of oil development in Alaska. He listed the development cost for New Light Oil, Mid-High Cost Development, and High Cost Development in Alaska. He declared that capital costs of $17 per barrel and operating costs of $15 per barrel are reasonable estimates for the existing infrastructure. However, for those developments that are farther from existing infrastructure, target smaller reservoirs, require horizontal wells or hydraulic fracturing, or are reservoirs for viscous oil, the capital costs increase to $25 per barrel. In fact, for developments well

outside of existing infrastructure toward the National Petroleum Reserve-Alaska (NPR-A) the capital costs can be as high as $34 per barrel. In comparison, the Lower 48 capital costs for conventional onshore plays is $2-$5 per barrel, with the total operating and capital cost being less than $10 per barrel. The total [capital and operating] cost for unconventional oil plays in the Lower 48, such as the Bakken or Eagle Ford, could reach $20-$25 per barrel. Therefore, the cost for new development in Alaska is significantly more expensive than the Lower 48, regardless of the fiscal terms.

9:18:23 AM

REPRESENTATIVE GARDNER expressed her understanding that Alaska's very high costs had been a reason to move to a net profits tax. She asked if Texas, North Dakota, and Louisiana were based on a net profits tax.

MR. MAYER replied that those states are on a fixed royalty system with some variations in the royalty such that there is greater predominance of private land. He declared that fixed royalty systems can have high levels of government take when costs are high and prices are low because from any given barrel a fixed percent is being taken. However, when costs are low and prices are high, the fixed rate jurisdiction is more attractive than the net profit jurisdiction.

9:19:53 AM

REPRESENTATIVE GARDNER asked if, in comparison, net profit blunts the impact of high cost. She pointed out that Alaska is at risk when the price of oil falls, which was a trade off when the tax structure was initiated. Therefore, Alaska would take more at the high end and share the risk at the low end.

MR. MAYER stated that the impact of a net profit system of the sort that's in Alaska is to make the overall system relatively neutral with regard to cost. The presence of a fixed royalty component makes Alaska's system slightly regressive in terms of cost because as costs increase, the government take may increase slightly. However, fixed royalty systems are very regressive in terms of cost, and thus the greater the costs, the higher the government take. Mr. Mayer agreed then that a net profit system blunts some of the impact [of high cost], but it is not a progressive system with regard to cost. As costs increase, government take does not decrease, and he stated that the level

of government take in Alaska is high compared to many other regimes.

9:21:41 AM

REPRESENTATIVE SADDLER asked to clarify that the referenced high cost of development is not for viscous oil or future high cost of development.

MR. MAYER expressed agreement, adding that in the recent past there have been developments within the range of the new light oil to the mid to high cost. Although he was not aware of any developments at the high cost level, he suggested that there are projects in the planning and evaluation stages that could entail the higher costs. However, those projects are very challenged, he further suggested.

REPRESENTATIVE SADDLER asked for an example of an Alaska field that would fall into the specified categories: new light, mid-high cost development, and high cost development.

MR. MAYER offered his guess that Nakaitchuq and Oooguruk would fall somewhere between the new light oil and mid-high cost development, but opined that the oil companies would need to share the details. He anticipated that some of the viscous oil projects planned within existing fields by the current operators would also be in the mid-high to high cost of development. Similarly, projects in NPR-A as well as serious heavy oil projects could fall in the high cost of development.

REPRESENTATIVE SADDLER asked if there are any examples for new light oil or mid cost projects.

MR. MAYER responded that he did not have specific examples for new development, but characterized the estimated costs as a reasonable benchmark based on other recent developments.

9:24:09 AM

CO-CHAIR SEATON pointed out that the unconventional oil projects of the Bakken and Eagle Ford and new light oil projects in Alaska had the same capital cost requirements as specified on the chart. He asked if the Eagle Ford and Bakken projects, which required continuous drilling and capital costs, had capital costs related to the graph.

MR. MAYER replied that the figures on slide 4 were done on an annual operating cost per barrel produced, but the capital costs were based on per barrel of reserves. He pointed out that, depending on the size of the reserve, spending could come at the front or be stretched out, which could significantly impact the project economics. He stated that even though the unconventional projects have much higher capital costs than previously seen in the Lower 48, these costs were lower than many costs in the planning stages in Alaska. Other than having lower capital costs than in Alaska, the Lower 48 projects have the advantage of the capital costs being spread out over time. Therefore, with comparable costs between the new light oil and the unconventionals, it may look better for the unconventionals because the capital spending is spread out over time.

9:26:27 AM

MR. MAYER moved on to slide 5 entitled "Relative Government Take," which defined relative government take as government take divided by divisible income. He explained that divisible income is gross revenues less all the costs, including operating and capital costs and transportation costs. The government take is that portion of the divisible income remaining after the private company's take. Dividing the absolute government take by the divisible income results in the percentage of the income the government receives on a project.

9:28:09 AM

CO-CHAIR SEATON inquired as to when private royalty comes into play.

MR. MAYER clarified that the benchmark slides he will present today treats private royalties as though the private landholder were government. From a company's perspective, funds that go to a private landholder or the government are the same because they are funds that the company does not receive.

REPRESENTATIVE P. WILSON asked how the private royalty can be determined when, in fact, some of the contracts are private.

MR. MAYER said that although there are significant variations between leases with the private contracts, there are fairly well documented reasonable averages available for estimations. Therefore, Mr. Mayer used the reasonable averages and when there was a question, he erred on the high side.

9:30:00 AM

MR. MAYER, addressing slide 6 entitled "Fixed Royalty v Profit Based Fiscal Systems," answered Representative Gardner's question regarding the impact of fixed royalty systems versus net profit-based tax systems. He compared the first example, which depicted five different projects each with a 30 percent fixed royalty to five projects with a 50 percent profit-based tax. He pointed out that these were five different projects with five different cost levels. He noted that each project included capital cost, operating cost, normal return to a private investor on capital, and economic rent or income surplus required to achieve a normal return on the capital that is sometimes known as super profits.

MR. MAYER declared that the amount of economic rent generated by a project would vary enormously depending on the cost structure of that project, and thus project one would generate a lot of economic rent while project five would generate a relatively small amount of economic rent. Referring to the graph of the 30 percent fixed royalty in terms of five different cost structures with five different projects for the same $100 per barrel price, he pointed out that the black rectangles represent divisible income, that is all of the cash and none of the costs. The bar graph depicts a line straight across the graph at 30 percent fixed royalty, which is at the $70 because $30 of the $100 barrel of oil goes to the 30 percent fixed royalty. In the case of project one, then, there is a lot of economic rent and an even larger portion is going to the private investor. In the case of project five, all of the economic rent is being taken through the 30 percent royalty as is all of the ordinary return on capital. Clearly, that's a project that wouldn't move forward under this stylized regime because there is no economic rent or even a basic ordinary return on capital to be made.

MR. MAYER explained that part of the notion behind a profits-based tax is that it eliminates the distorting impact such that there are relatively lower taxes on the highest cost projects and relatively higher taxes on the lowest cost projects, which generate the most economic rent. He noted that this is a stylized profits-based system, not like the Alaska system that is progressive in regard to costs and may take even more of the rent in certain cases. "The analogy being, in a sense, to the 25 percent ... base profits tax in Alaska. If we imagine a system that was that at 50 percent with no other fiscal element, that's sort of what we'd be looking at here," he said.

9:34:15 AM

MR. MAYER explained that the bar graph for the 30 percent fixed royalty could be viewed as a percentage of a barrel of oil for any given price per barrel, with each of the five projects reflecting different oil prices. Therefore, the graph could be viewed as the same project with the same cost structure in five different price cases such that price case one would have very high oil prices and price case five would have very low oil prices. He reiterated that in a high oil price environment fixed royalty is more attractive for investors, whereas the profit-based tax is more attractive in a lower oil price environment because the tax is reduced as the available profit is reduced. In that sense, the system on the [50 percent profit-based tax] is more economically efficient, as it does not distort the investment choices as much. However, that does not necessarily mean that it's competitive with what one can obtain as a private investor in a jurisdiction with the investment profile of [projects] one, two, or three. Mr. Mayer opined that that the aforementioned is important in understanding how a profit-based system, particularly one with a relatively high government take such as Alaska, looks as compared to a fixed royalty system elsewhere. A profit-based system with a relatively high government take is very attractive at lower oil prices, while less attractive, from a competitive standpoint, at high oil prices, particularly when those jurisdictions have relatively lower costs.

9:36:16 AM

REPRESENTATIVE GARDNER inquired as to the contextual definition for rent and normal return of capital. She asked if normal return of capital is part of the profit or the cost.

MR. MAYER explained that normal return on capital differentiates the perspective of accountants versus economists. For an accountant, profit is what remains after the costs are subtracted from the income; however, for an economist profit is what remains after all the capital invested in the project, including the physical structures and the working capital, is subtracted [from the income]. For an economist, anything above the normal return on capital is economic profit. Therefore, on the bar graphs on slide 6 the yellow and red bars represent accounting profit, but only the red bars are economic profit, which is the same as rent.

REPRESENTATIVE GARDNER asked what risk was calculated for a normal return on capital.

MR. MAYER explained that the required rates of return for capital are connected to the levels of risk, with lower risk investments requiring lower rates of returns. He pointed out that the standard benchmark is the U.S. Treasury rate, which is a completely risk-free rate of return on capital. Any rate of return required above the guaranteed return is considered a risk premium. The significantly higher rate of return required for an oil and gas project located in a stable jurisdiction versus a project that holds a U.S. Treasury bill is reflective of the risk one is taking in undertaking the project. Therefore, projects in jurisdictions that are viewed as riskier by investors require significantly higher rates of return to compensate for the risk involved.

REPRESENTATIVE GARDNER asked for the benchmark of the U.S. Treasury rate.

MR. MAYER replied that the rate varied depending on the investment time frame. He stated that, although 5 percent had historically been financially used as a risk free rate of return, the current economic environment is a substantially lower rate.

MR. MAYER, in response to Representative Tuck, said that Alaska is "progressive with regard to price, but not particularly progressive with regard to cost." He then turned to the bar graph in terms of the same project in five different cost environments and suggested layering in Alaska's progressivity would result in the diagonal bar curving down and taking more of the rent at the highest price environment.

9:41:33 AM

CO-CHAIR SEATON surmised that Mr. Mayer would be going into more detail on the Alaska price structure.

9:41:52 AM

MR. MAYER, in further response to Representative Tuck, clarified that he was referring to the chart entitled "Incidence of a 50% Profit-Based Tax on 5 Different Projects" on slide 6 with the angled line being a fixed 50 percent of the profit for a given project. A system that is progressive with regard to price would result in "1" being the highest price case that would

yield the most economic rent such that 60-70 percent of the [profit] is taken and perhaps less than 50 percent in the lowest price case, "5". Therefore, the line would steadily increase from right to left to reflect more economic rent in high price environments, which is what makes it progressive in regard to price. Alaska's system is deliberately crafted such that at oil prices net of cost above $30 per barrel, the share going to the state through the petroleum profit-based tax (PPT) steadily increases. He stated that although this is progressive with regard to oil price, it is not progressive in the same way for cost. Therefore, as costs rise, the amount of government take stays the same and may, in certain circumstances, slightly increase as costs increase.

9:43:20 AM

REPRESENTATIVE TUCK, recalling earlier testimony that a normal return of capital is about 15 percent, surmised that the yellow block on the bar graphs on slide 6 is 15 percent of everything below it.

MR. MAYER expressed agreement that the yellow block is 15 percent of the capital costs, shown in green, with some portion of the ongoing working capital required to maintain the project.

9:44:05 AM

REPRESENTATIVE HERRON asked how the bar graphs would change if Alaska became an investor, instead of approving the tax reduction in the proposed legislation.

MR. MAYER, directing attention to the equation on slide 5, said that government take does not include the government earnings directly from an equity stake. However, he said that government take would be impacted if the government, as Alaska does to some extent, provides tax credits as cost contributions to the project with a correspondingly high tax rate afterward.

9:45:27 AM

MR. MAYER offered a brief overview of slides 7 and 8, "Regime Competitiveness: Average Government Take," which compared Alaska to a range of global fiscal regimes at $100 per barrel of oil, slide 7, and $140 per barrel of oil, slide 8. He directed attention to the two red bars, which represented the Alaska take, under Alaska's Clear and Equitable Share (ACES), for new oil developments and for an existing producer. He noted the

difference: an existing producer could claim capital costs against existing costs for production, while a new development producer could only claim upfront incurred capital costs against net operating lost credit, which results in a slightly higher government take. He stated that the yellow bars were all Organization for Economic Cooperation and Development (OECD) jurisdictions, which are developed, not developing, countries. He explained that the benchmark analysis offers a range of actual economic modeled projects as opposed to how this exercise is frequently performed in which a single stylized field is run through a range of different regimes. The idea, he specified, is that in each regime there should be review of something that comes close to approximating the actual levels of cost, field sizes, and etcetera in order to view representative development for each of the basins in terms of field size, production, costs, and the resulting government take.

9:48:18 AM

MR. MAYER reported that oil price levels significantly below $100 per barrel would reflect an impact on fixed royalty regimes. He said when oil price was compared at $100 per barrel and above, Alaska's fiscal regime was significantly higher than all other OECD jurisdictions, with the exception of Norway; whereas, below $100 per barrel, ACES was comparable to many other jurisdictions. For an existing producer, [Alaska under ACES] has the second highest level of government take in the OECD countries. At a price of $140 per barrel, the government take [in Alaska] for an existing producer is about the same or slightly above Norway and is slightly higher still for new development. For oil prices higher [than $140 per barrel], Alaska finds itself among the very highest taxing jurisdictions in the world. He clarified that he had focused on $100 per barrel and $140 per barrel as these were the most recent price boundaries over the last few years. He stated that the fiscal regime in Alaska had been designed for high levels of government take for existing production, and is notably higher for government take of new development in the Lower 48.

9:50:32 AM

CO-CHAIR SEATON requested a copy of this same graph using an oil price of $80 per barrel.

MR. MAYER agreed to do so.

9:50:52 AM

REPRESENTATIVE GARDNER inquired as to why Saudi Arabia, Kuwait, and Iraq, which she opined to be some of the largest oil producers in the world, are not included on the chart.

MR. MAYER explained that Saudi Arabia entirely owns and produces its oil resource, and thus it is not relative to these other fiscal regimes. The aforementioned is true, to some extent, in Iraq and Kuwait as well. Iraq is a unique case because it has recently invited service contracts with overseas oil companies to invest capital and introduce new technology in an effort to increase the oil production of long existing mature oil fields that have been produced by the state. He offered his belief that those [existing mature oil fields in Iraq] have a relatively high level of government take, but that the fiscal structure rewards contractors for increases in production over certain benchmark levels. Companies have been willing to invest in Iraq because it is viewed as a long-term strategic investment.

REPRESENTATIVE GARDNER asked whether Norway is a hybrid model similar to Alaska.

MR. MAYER concurred, declaring that, although Norway has high levels of government take, it ensures ongoing investment regardless of the private sector appetite. Norway has a large, sophisticated national oil company, Statoil, which is a major participant in Norwegian oil development. Norway also has a state equity arm, Petoro, which also holds directly on behalf of the state in those projects.

MR. MAYER, in response to Co-Chair Seaton, said that PFC Energy has analysis of what HB 3001 looks like in comparison to ACES in terms of government take. Although he did not have it in terms of the benchmark chart [on slides 7 and 8], but he offered to provide it.

REPRESENTATIVE SADDLER asked to also see the countries ranked by annual volume of oil produced and cost of production.

MR. MAYER replied that it could be done, but it might be a significant process. He noted that there is a correlation between desirability of hydrocarbon basins and levels of government take.

9:55:43 AM

MR. MAYER, referring to slide 9 entitled "Effect of Progressivity on Price Upside," explained that the two graphs on slide 9 reflect net present value (NPV) and internal rate of return (IRR) over a range of various price environments. He explained that the cost profile used is from the average North Slope capital and operating costs directly from the Department of Revenue (DOR) Revenue Sources Handbook and was graphed under ACES versus with a flat 25 percent profits-based tax without any progressivity. The graphs illustrate that under progressivity as the price, economic rent, increases, the state is steadily able to take more and more. The graphs use a relatively low cost development and illustrate that the system works quite well such that there is a 15 percent rate of return around the $60-$70 price. As one reaches higher and higher price levels, the idea behind the progressivity is that more and more rent is taken for the state. In the low cost example, the impact of the state taking [more] economic rent should not impact the economic viability of the project. However, if one compares this to a more neutral or regressive regime, a very economic project does not alone make the project economic for capital. For example, there are projects in the Lower 48 at high price environments that look much better. Therefore, the question of competitiveness remains. He declared the basic lesson from this chart to be: ACES worked very well, in a harvest regime, when there were low development costs while maintaining existing production from existing fields with no significant new investment.

10:00:31 AM

REPRESENTATIVE GARDNER expressed her understanding that the desired outcome of the progressivity tax rate is to encourage the industry to re-invest its profits in Alaska, rather than elsewhere because their tax rates in Alaska would drop with each dollar re-invested. She asked for clarification regarding whether high prices were instead discouraging industry investment and that industry would prefer a higher progressivity rate in a harvest mode rather than re-invest and decrease the rate on everything.

10:01:20 AM

MR. MAYER, noting that there were the two approaches, said that progressivity is an approach to encourage investment such that the high level of taxation could be lowered through re-investment. The other approach would be for a lower level of government take with an upside for higher oil prices, which is

more desirable for capital investment. High government take, high costs, and the lack of an upside combine to make Alaska less competitive, he said.

REPRESENTATIVE GARDNER opined that this made sense for a new investment, without a broad infrastructure.

CO-CHAIR SEATON questioned whether progressivity would really make a difference if companies had decided prior to the current tax regime in Alaska that Alaska's mature oil basins were a harvest regime.

10:03:44 AM

MR. MAYER related that there are various gradations to determine that a jurisdiction is a harvest region, even if the investment is limited to a low cost, easy investment. The decision would be made at the corporate level, in large part, because of the interplay of costs and economics of a new investment. However, the fiscal system is but one component. There are issues over which the state has no control, including the cost environment and other competing uses of capital. He stated that the harvest designation is not made in the abstract, but is a function of the other possible uses of capital, returns available on the uses of capital, and the returns available given the cost structure and tax environment in Alaska. The question would be whether Alaska is a place to invest and draw the capital in the future, or to invest and draw cash now.

10:06:06 AM

CO-CHAIR SEATON asked if those decisions had been made prior to the current tax system in Alaska on a low tax environment, and whether lowering the taxes would reverse the decision made in a lower tax environment.

MR. MAYER expressed his agreement that the oil producers had taken cash out of Alaska long before ACES was implemented, as Alaska was a cash surplus region. Therefore, he said he would not suggest that the implementation of ACES created a harvest system where none existed before. On the other hand, since [the implementation of ACES], oil prices have become significantly higher, technological advances have been made, and the Lower 48 is no longer a harvest regime. The question, then, is whether there are projects that might be viable given the high oil prices and technology in Alaska that are less viable because of [Alaska's] fiscal system.

10:08:01 AM

CO-CHAIR FEIGE questioned whether it is the fiscal regime or the actual field mechanics driving [Alaska] toward a harvest mode, when it could be moving in a different direction with the current increase in oil prices.

10:09:29 AM

MR. MAYER moved on to slide 10 entitled "Low Cost Light Oil: Hypothetical 10 mb/d Project Cashflows ($13/bbl Capex, $10/bbl Opex)," which presents the stylized impacts of cash flow for a brand new development with a cost structure of $13 per barrel capital expense and $10 per barrel operating expense. He noted that the horizontal axis is at zero and anything above it is revenue, as depicted in the blue bars, whereas anything below the horizontal axis is capital development costs during the initial years and then ongoing operating costs of $10 per barrel. He specified that the black line is the after tax cash flow (ATCF). The graph relates that in the early years, the difference between the negative capital expenditure bar and the slightly less negative ATCF line is the impact of the 20 percent capital credit and the net overriding loss credit under ACES. He noted that this capital credit reduces the negative cash flow in the early years, thereby improving the overall project economics. However, if the costs are subtracted from the revenue [blue bar], that would amount to all the cash the project produces. On the other hand, the ATCF [black line] to the producer is "a relatively small portion of the overall revenues generated from the project." The difference in that is that the operating and the capital costs have to be covered as well as the almost 80 percent of the revenue that goes to either the federal or state government, which is a significant amount at $100 per barrel. The amount left is the ATCF [black line] to the producer that is shown at $100 per barrel in the graph, but a small table on slide 10 indicates the NPV and IRR for oil at $40, $60, and $100 per barrel. A hypothetical project, new development, at a cost structure equivalent to some of the current existing mature assets would result in a hurdle rate of return at about $60 per barrel and $100 per barrel would look quite attractive.

10:13:20 AM

MR. MAYER declared that this graph hypothetically reflects a new development with the cost structure of an existing field and an

attractive rate of return at $100 per barrel. However, this analysis for IRR would be different for actual existing production as there is no longer an [upfront] lump sum creating a return; the NPV would be higher, as there was no lump sum upfront investment and only annual capital and operating costs. The graph shows that this cost structure under ACES looks relatively attractive.

10:13:56 AM

MR. MAYER moved to slide 11, "New Light Oil: Hypothetical 10 mb/d Project Cashflows ($17/bbl Capex, $15/bbl Opex)," which uses the same production profile, but increases the capital expenses to $17 per barrel and the operating expenses to $15 per barrel.

REPRESENTATIVE SADDLER requested clarification that the blue bar below the ATCF [black line] represents the producer's profit, and above the black line represents the government take.

MR. MAYER replied that, although government take is not shown explicitly, divisible income is the difference when the red and yellow bars are subtracted from the blue bar. The divisible income is all of the cash a project generates.

REPRESENTATIVE SADDLER asked what the blue bar above the black line represents.

MR. MAYER replied that the blue bars represent the total revenue for the project.

REPRESENTATIVE SADDLER agreed that he understood that the blue bar is the total revenue, but he asked again for an explanation of the blue bar above the ATCF [black line].

MR. MAYER said that the black line itself represents the ATCF to the private investor.

REPRESENTATIVE SADDLER asked again what was represented by the blue bar above the ATCF black line.

MR. MAYER replied that the portion of the blue bars above the black line does not represent anything specifically. He explained that if the operating expenses [red bar] and the capital expenses [yellow bar] are subtracted from the revenue [blue bar], the difference between that result and the black line, would be the government take. In this hypothetical case,

the government take would be a bit less than 80 percent of the total.

10:16:31 AM

CO-CHAIR SEATON stressed the need to better understand this graph before moving forward with testimony.

10:17:14 AM

MR. MAYER said that to explicitly plot government take as a third cost component, along with operating and capital costs, there would be another negative bar which would roughly counterbalance the blue revenue bar. He pointed out that, as the result would not be as negative as the blue was positive, the difference would be the ATCF black line. He clarified that the difference of the total of the operating cost, the capital expense cost, and the government take with the revenue would be the "cash that the producer themselves gets."

10:18:11 AM

CO-CHAIR SEATON surmised then that the blue bar is for revenue, and the cash for the producer is between the black ATCF line and the axis. He asked if the area of the blue bar above the ATCF black line is equivalent to government take.

MR. MAYER replied that it is equivalent to government take plus costs. In response to Representative P. Wilson, he confirmed that government take is not included on the graph.

REPRESENTATIVE TUCK related his understanding that the graph doesn't include any tax structure or government take structure; the graph, he surmised, is not explicit to one taxation system versus another rather it is total costs and expenditures.

MR. MAYER specified that the after tax cash flow (ATCF) line, which is based on ACES, is specific to a given tax structure.

10:20:20 AM

MR. MAYER directed attention to the graphs on slides 11, 12, and 13 that reflect the same production profile and revenue as slide 10, but each slide depicts increased operating and capital expenses. Referring to the graph on slide 11 entitled "New Light Oil: Hypothetical 10 mb/d Project Cashflows ($17/bbl Capex, $15/bbl Opex)" that includes capital expenses of $17 per

barrel and operating expenses of $15 per barrel, he determined that the acceptable rate of return begins at the $100 per barrel price, whereas any lower price is "actively destroying economic values." At $60 oil per barrel, the NPV is negative and the rate of return is 9 percent, which is less than the 10 percent discount rate that is used in this case. The graph on slide 12 entitled "Mid-High Cost Project: Hypothetical 10 mb/d Project Cashflows ($25/bbl Capex, $15/bbl Opex)" depicts capital expenses of $25 per barrel and operating expenses of $15 per barrel, and states that the rate of return at the $100 per barrel price is only 11 percent. Finally, the graph on slide 13 entitled "High Cost Project: Hypothetical 10 mb/d Project Cashflows ($34/bbl Capex, $15/bbl Opex)," reflects a capital expense of $34 per barrel and an operating expense of $15 per barrel, with a 7 percent rate of return at $100 per barrel. The initial yellow bars depicting the capital being spent on the project become more and more negative and to obtain a rate of return on that a correspondingly relatively higher amount of cash flow afterwards is necessary. However, the cash flow only changes marginally after the initial investment, which is why the very low rates of return are experienced. In fact, at $34 in capex per barrel, there is a negative NPV at a 10 percent discount rate, even at $100 per barrel of oil.

10:22:20 AM

CO-CHAIR SEATON, directing attention to slide 11 with the $17/bbl capex, posed a scenario in which there is new light oil new field development with a 65 percent exploration tax credit and convertible tax credit. He then asked if the exploration tax credits would affect the 2011 and 2012 bars on the graph.

MR. MAYER responded that this graph depicts a development forward basis and does not include exploration costs, only the capital costs required for development and the resulting revenue. He declared that the 20 percent capital credit and the 25 percent net operating loss credit should both be applied, but he noted that, they may be applied with a year lag. Furthermore, under ACES, those credits are spread over two years. He reported that the biggest impact should come in the third year, 2013, after there have been a couple of years of capital spending.

10:24:11 AM

CO-CHAIR SEATON pointed out that one provision of HB 3001 is that the credit would be for one year, instead of spread over

two years, which he surmised would move the cash flow line (indisc.) negative for the first two years.

MR. MAYER agreed that for a new project it would make a small difference in the first couple of years.

REPRESENTATIVE TUCK related his understanding that on the graph development is represented prior to the blue bars and the blue bars are production.

MR. MAYER expressed his agreement, but reminded the committee that there are ongoing capital expenses for drilling.

REPRESENTATIVE TUCK surmised then that the blue revenue bars reflect the usual peak and then subsequent decline as an oil field moves into production.

MR. MAYER replied yes, noting that the decline would be more dramatic if it represented volume rather than revenues. The graph is an illustration based on a nominal cash basis, and thus there is about 2.5 percent inflation, which offsets the actual underlying decline of the production by the 2.5 percent inflation and each year the value of the dollar is less and the revenue from it is 2.5 percent greater. He pointed out that the graph is a stylized hypothetical profile which could look different under different circumstances, or relative to unconventional production fields. In certain places one may be able to achieve a production profile with a faster and higher peak and a faster decline, which is in many ways economically preferable. Such a situation would mean that one could recover cash much faster, which improves one's economic metrics. However, production profiles for Oooguruk, for example, do not look particularly like earlier "peakers" with sharp declines but rather steadier producers with a shallower decline and a less significant initial peak, which makes projects more economically challenged than those with higher initial production. On the other hand, the unconventional resource plays in the Lower 48 would require less initial capital for any given level of spending but more ongoing capital spending throughout the life of the project as more wells are drilled, which is not necessarily the case in conventional oil development.

10:28:04 AM

MR. MAYER, referring to slide 13, stated that as the yellow bar [capital expenses] increases the corresponding cash flow [revenue] needed to offset the initial expenses needs to be

higher, but is not. As is evidenced on the slide, the rates of return and present values are steadily lower. Referring to slide 12, Mr. Mayer said that the $25 per barrel capital cost was not attractive to oil producers, even at a price of $100 per barrel, and, noting slide 13, said that $34 per barrel capital cost is "actively destroying economic value," even at a price of $100 per barrel.

10:29:05 AM

MR. MAYER, moving on to slide 14 entitled "Project Value Under ACES: Cost and Price Sensitivity", compared project present value over time under a number of different cost cases, including low cost light oil and capital costs of $17 per barrel, $25 per barrel, and $34 per barrel. He pointed out that, as costs increase, the break even points of these high cost developments increase, such that the $25 per barrel capital cost did not break even until a price of almost $90 per barrel. In terms of the internal rate of return, the graph entitled "IRR" on slide 14 illustrates that a 15 percent rate of return was not achieved until the price per barrel was $130-$140, whereas a constant government take would achieve a 15 percent rate of return at a price less than $100 per barrel. He declared that ACES works well for existing, mature, low cost, light oil fields that capture the most economic rent for the government from the production while ensuring that production remains ongoing and economic. However, this structure could be a significant inhibitor for developing new projects with higher costs.

10:31:27 AM

REPRESENTATIVE P. WILSON asked how much this would change at a price of $120 per barrel.

MR. MAYER explained that the horizontal axis of each graph is the oil price. The graphs illustrate the sensitivity of four different projects of project value measured by two different economic metrics, NPV and IRR, in different price environments and what the specified price increase does to the project value. The bending of the curve, he pointed out, is the impact of the progressivity such that the marginal benefit of each additional dollar is less and less.

10:33:00 AM

MR. MAYER, in response to Representative P. Wilson, explained that when oil is priced at $120 per barrel, the economics is challenging for all the heavier [oil] projects, except for low cost light oil. For example, in the $34 capex case it has yet to break even on a 10 percent discount rate, and therefore it has negative NPV at the $120 price per barrel.

REPRESENTATIVE P. WILSON opined that it would be easier to understand this if the current prices were used.

MR. MAYER reminded the committee that the aim of the chart is to show a broad range of prices and how, as prices changes, the value of the project is impacted. The curvature is from the progressivity, which takes away the upside of high oil prices. The chart reflects that the higher cost cases impact the basic breakeven economics of the project, which makes it challenging for a project to meet the basic hurdle rate for returns on capital, not to mention being cost competitive with investments in other jurisdictions. In further response to Representative P. Wilson, Mr. Mayer explained that the IRR chart reflects a healthy rate of return, approaching 25 percent, for the low cost light oil project at a price of $120 per barrel, whereas the most expensive development, $34 per barrel for capital expenses, results in less than a 10 percent rate of return on the project.

10:36:06 AM

CO-CHAIR SEATON related his understanding that the chart represents a stand-alone project. He also related his understanding that under ACES, a high cost environment would be written off against existing production, which would lower the tax rate on the oil. He then asked how [ACES] changes the chart for incremental production at the higher tax rate when there is no higher cost investment to lower the overall tax rate by lowering the marginal tax rate on progressivity.

MR. MAYER returned attention to slide 13 and said that it is related to the impact of the capital credits, particularly in the early years when there is very little oil production. He said that on a stand-alone basis, for a company with no existing production, the most credit that could be claimed would be the 20 percent capital credit and the 25 percent net overriding loss credit. He stated that this would be the same for an existing producer in a price environment without progressivity; however, once the existing producer has triggered progressivity, the capital could be written down at a higher rate, because of the higher rate that comes with progressivity. He declared that in

the first few years an ATCF line would appear less negative for an existing producer if this was viewed as a stand-alone, with the ability to write it off against the existing portfolio.

10:38:52 AM

MR. MAYER, in further response to Co-Chair Seaton, said that the curves might shift up a teeny bit if the existing production is considered with higher costs and the marginal tax rate, but that overall there would be no change in the deduction.

10:39:04 AM

REPRESENTATIVE GARDNER asked if the model for capital and operating expenses used by Mr. Mayer is in anticipation of realistic expenses.

MR. MAYER explained that the figures were similar, as they are an average of all capital expenses divided by all production across the North Slope in any given year. He allowed that the average did hide a lot of variation, as projects would differ. He explained that, for an aggregate analysis to the generated revenue of a taxation system, "plugging in that sort of average number is a good way of getting an approximate answer." However, just looking at the aggregate did conceal the enormous disparity between the capital expenses required for existing and new developments.

10:41:41 AM

REPRESENTATIVE GARDNER asked to verify that the evaluation and calculation of NPV and IRR for a prospective investment does not include the state participation in capital costs. She also asked why that should be the case when the decision is not impacted by it.

MR. MAYER opined that project economics are determined by after tax cash flow (ATCF), which credits definitely impact. He pointed out that Alaska is unusual as its credits are paid at the outset, as opposed to being deducted from future production, which has a significant impact on project economics. Although Alaska is a high government-take regime, these upfront credits work for low cost production.

REPRESENTATIVE GARDNER, confirming that the prompt payment of credits is "a plus in an evaluation," asked whether [the credits] are included in NPV or IRR.

10:43:06 AM

MR. MAYER established that the credits are included in the NPV and the IRR and are implied by the ATCF black line on the chart. Directing attention to slide 13, he pointed out that to the extent in the early years that the black line is not as negative as the capital expenses is the positive impact generated by the credits and improves the economic metrics of the project.

CO-CHAIR SEATON suggested that this same question be asked to the upcoming oil industry witnesses for verification.

10:44:17 AM

REPRESENTATIVE TUCK, directing attention to slide 14, related his understanding that the low cost light oil is equivalent to the $13 per barrel costs. He then asked if all of the lines on the graph are for newly developed fields or wells.

MR. MAYER replied that they represent newly developed fields at different cost structures.

REPRESENTATIVE TUCK surmised then that these aren't existing fields but rather are fields in which the find is known and it is set to be developed and come online.

MR. MAYER agreed, and explained that the red line for the low cost light oil is used to compare the hypothetical development of a new project at that cost structure in order to be able to compare it to the other cost structures.

10:45:23 AM

MR. MAYER summarized that slide 14 reflects ACES in various cost environments. Moving on to slide 15 entitled "ACES - Effective as a Harvest Area Fiscal Regime," he declared that ACES works well as a harvest regime, particularly when the policy goal is for maximum extraction and economic rent and the belief is there is no significant additional oil production, regardless of price or technological advancements. However, ACES inhibits the development of new projects and resources that have higher costs than the existing production base for a number of reasons. As has been mentioned, ACES is not progressive with regard to costs and it is a high government take system that has a high government take, even for very high cost projects. He acknowledged that ACES has capital credits that go far in making

a lot of existing capital work and takes projects from a 15 percent natural decline of fields to a 6 percent level. Although that combined with the high government may encourage some of the renewal capital expenditures, it is not enough for new high cost development to be economic or competitive in a broader global company portfolio. Furthermore, although progressivity can be effective in capturing maximum rent with low cost projects, it can have a "significant detrimental impact on break even prices and hurdle rates of return, and all the rest for high cost projects at current oil prices."

10:47:58 AM

MR. MAYER, moving on to slide 16 entitled "Options to Spur New Developments," suggested there are different approaches, including uniform lowering of government take and differentiation between old and new production. In order to lower the uniform government take one can bracket progressivity as was the case with HB 110, increase the thresholds for progressivity, reduce the coefficients on progressivity, cap progressivity at different rates, or lower the base rate tax. He offered that there are some advantages to a lower government take; as ACES is already a complex system, thereby lowering the government take would not add any increased complexity or ambiguity with regard to which projects apply for the various tax regimes. He declared that this could even present opportunities for simplification.

10:49:50 AM

MR. MAYER then pointed out that a big disadvantage of proposed HB 3001 is that incentivizing new high cost resources through lowering government take alone would require lowering government take quite a lot, and thus give back substantial economic rent on the already producing low-cost assets that were clearly economic.

10:50:16 AM

MR. MAYER reflected that the simplest approach, with the least ambiguity and possibility for misalignment for unintentional consequences, requires returning the most cash back for activities that are currently economic. An alternative to the aforementioned is to find ways of differentiating between old and new production. He acknowledged that it is relatively easy to differentiate completely new production from areas that are not currently in production, which is included in HB 3001.

Although it is more difficult to differentiate existing production that is the result of existing levels of investment in legacy fields versus production from increased investment in the legacy fields, it could be achieved by defining the base decline rate and applying a significantly lower level of taxation. The regulatory process could also be used to apply a lower rate of tax, but not to the base production. The advantage of the regulatory process is that it does not require returning a lot of cash for existing activities that are currently economic. However, it is more complex administratively and increases the opportunities for "perverse incentives, whether that be ... alignment of partners on different projects ...."

10:53:49 AM

MR. MAYER provided that there is a third option to further enhance some of the cost progressivity of ACES, although this would also increase the already high complexity and opacity of the system. He declared that almost any solution would exacerbate existing problems of relatively poor incentives for cost control that currently exist. He emphasized that there are no perfect answers, as it is a policy trade-off between the degree to which one is willing to return cash for currently economic activities versus the degree to which one tries to avoid that and reaches greater complexities and greater likelihood of "perverse incentives" by trying to create a system that preserves as much cash as possible for the government while providing significant new incentives for development.

10:55:43 AM

The committee took an at-ease from 10:55 a.m. to 11:21 a.m.

11:21:11 AM

CO-CHAIR SEATON brought the committee back to order at 11:21 a.m.

11:21:20 AM

MR. MAYER moved on to the section of the presentation entitled "Analysis of HB 3001." He directed attention to slide 18 entitled "Options to Spur New Developments," which he declared to be a range of imperfect options to spur new developments, with specific attention to the uniform lowering of government take versus the differentiation between old and new production.

He stated that proposed HB 3001 overwhelmingly takes the approach of uniform lowering of government take, but with more complexity by putting in place a gross revenue exclusion that applies in calculating the progressive tax. The overall effect is to reduce the progressive tax on the existing base of North Slope production. The legislation also includes an allowance for new oil production areas outside the legacy fields, which is from the Senate's initiative at the end of the regular session. The allowance for new oil production areas outside the legacy fields uses a gross revenue exclusion at a lower rate, while applying both to the 25 percent base tax and the progressive tax, all of which results in the uniform lowering of government take. He then turned to the approach of HB 3001 that offers enhancements to the cost progressivity of ACES and said it increases the capital credit from 20 percent to 40 percent for well capital expenses.

11:23:28 AM

MR. MAYER then directed attention to slide 19 entitled "HB 3001 - Main Aspects," which specifies that the main aspects of HB 3001, as follows: a 30 percent gross revenue exclusion for production from new North Slope fields, which would apply to the calculation of both the 25 percent base tax and the progressive tax amounts, but would not apply to the progressivity rate calculation and would apply for 10 years; a 40 percent gross revenue exclusion for all other North Slope production, which would only apply to the calculation of the progressive tax amount, not to the base tax or the progressivity rate calculation and would apply indefinitely. Additional features of HB 3001, are as follows: the maximum progressive tax rate is capped at 60 percent instead of 75 percent; the well lease expenditure credit of 40 percent would now be applied to the North Slope; and the capital credits could be redeemed in a single year rather than spread over two years.

11:24:44 AM

MR. MAYER reviewed slide 20 entitled "Understanding the Gross Revenue Exclusions." He said that the framework used by the Department of Revenue (DOR) in the Revenue Sources Handbook considers the total annual production and subtracts the royalty barrels to reach the taxable barrels. He compared the resulting calculations under ACES versus proposed HB 3001. The results are the same for the gross value at the point of production (GVPP), which was the gross revenue from production minus the transportation costs. He explained that the capital and

operating expenses were also deducted to determine the production tax value (PTV), which is the same under ACES and HB 3001 for both existing and new fields.

11:26:29 AM

MR. MAYER pointed out that he had included the calculations for both new fields and existing fields under proposed HB 3001 to show how they would work and how they would differ from each other and ACES. He pointed out that the bottom line [of the chart] represents the likely revenue from the state in 2013 under ACES and HB 3001 for existing fields. However, the bottom line of the [column entitled "HB 3001 New Fields"] is a hypothetical bottom line that would apply if the regime for new fields was applied to all production. He clarified that the [column entitled "HB 3001 New Fields"] is included to illustrate how the calculation works. With a PTV of $12,385 million, under ACES that is the PTV used in calculating the 25 percent base tax amount and it's the amount used in calculating the progressive tax. He then explained that 25 percent of $12,385 billion amounts to about $3 billion under ACES and if the 16.72 percent, which is the progressivity that would apply at the 2013 forecast number, is multiplied by the PTV, it amounts to a progressive tax just over $2 billion and a total production tax before credits of about $5.167 billion.

11:28:08 AM

MR. MAYER said, in comparison to HB 3001, the calculation of the 25 percent base production tax is the same for both ACES and HB 3001 for existing fields such that the $12,385 billion PTV is multiplied by 25 percent, which amounts to $3,096 billion in base tax. The difference, however, is the amount that's calculated for the progressive portion of the profits based tax, which amounts to $12,285 billion under ACES and $5,423 billion under HB 3001 [existing fields]. Under HB 3001, 40 percent of the GVPP is taken from the PTV to reach $5,423 billion. As a result, the progressive production tax under HB 3001 is much less than under ACES, and thus the total production tax liability before credits decreases from about $5.1 billion to $4 billion. Under [HB 3001] there is also an increase in the credits, which he partly attributed to the question of claiming credits for one year versus two years but mostly because of the 40 percent well credit. Therefore, the overall impact to the state amounts to an estimated $4.7 billion of income to the state in 2013 through the production tax in 2013 versus $3.2 billion under HB 3001 for existing production. In terms of

calculating the exclusion for completely new areas, the difference is that gross revenue adjustment is calculated at a lower level of 30 percent rather than 40 percent but it applies to both the production tax value as it is used to calculate the base and the progressive tax. Therefore, the 25 percent base production tax for existing fields is significantly lower than it is in the aforementioned two cases because of the 30 percent gross revenue exclusion. The progressive tax [under HB 3001 for new fields] is higher than it is under HB 3001 for existing fields but lower than it is under ACES because the 30 percent exclusion but not the 40 percent exclusion applies. The fact that it applies to the base as well as the progressive tax means that overall the tax liability is lower than is the case for HB 3001 for existing fields. Therefore, in the purely hypothetical case [HB 3001 for new fields] applying a regime that would apply to all production would result in production taxes of oil credits decreasing from $5.1 billion [under ACES] to $4 billion [under HB 3001 for existing fields], and ultimately to $2.9 billion [under HB 3001 for new fields].

11:31:30 AM

CO-CHAIR SEATON, referring to slide 19, related his understanding that the 30 percent gross revenue exclusion does not apply to the progressivity rate calculation.

MR. MAYER concurred, and stated that it applies to the progressive tax but not to the rate calculation. He highlighted the importance of the fact that the 16.72 percent tax rate is the same for all three scenarios and that the price per barrel is calculated by dividing a PTV by the number of available barrels, which amounts to PTV per barrel of $71.80. He said that this calculation is done before the GVPP allowance, which is the reason it does not affect the progressive rate. However, in the new fields case [the 30 percent gross revenue exclusion] does impact the progressive tax because although the rate does not change, the taxable base does by the 30 percent.

REPRESENTATIVE SADDLER inquired as to whether saying that the 30 percent gross revenue exclusion does not apply to the progressivity rate calculation means it does not apply to the gross revenue as reduced by progressivity. In response to Mr. Mayer, Representative Saddler clarified that he is referring to new fields.

MR. MAYER replied that it applies to the calculation of the progressive tax base, but it does not change the rate that is calculated through progressivity.

REPRESENTATIVE SADDLER surmised then that the 30 percent applies to the gross revenue, exclusive of the progressivity rate calculation.

MR. MAYER clarified that the amount of progressive tax paid is lower because the taxable base is less, even though the percentage is the same.

11:33:57 AM

CO-CHAIR SEATON surmised that 30 percent of the barrels are not taxable and the rate calculation based on price does not change.

MR. MAYER expressed his agreement, but noted that although 30 percent of the revenue is not taxable, the cost deduction that came from those barrels remains.

11:34:22 AM

REPRESENTATIVE SADDLER, referring to slide 20, inquired as to the basic assumptions of the hypothetical case presented for HB 3001 new fields.

MR. MAYER replied that the column entitled "HB 3001 New Fields" is hypothetical in so far as there are no known fields producing in 2013 that meet the criteria for new production under HB 3001. Therefore, the figures merely reflect how the calculations work as there is no production that is new.

11:35:14 AM

CO-CHAIR SEATON inquired as to whether the exclusion of 30 percent of the oil from taxation allows the cost to be offset against the other 70 percent and essentially becomes an uplift or escalation of costs by 30 percent. In other words, instead of making that calculation on the production tax value, the 30 percent is taken prior to the costs and basically allows a 30 percent increase in the cost per barrel that will be taxed.

MR. MAYER offered his belief that the "basic intuition of what you said rings true to me," although he expressed the need to run a few numbers before providing a conclusive answer.

11:36:29 AM

REPRESENTATIVE TUCK returned attention to slides 16 and 18 and the statement that ACES inhibits the development of new projects. He also recalled that it is possible for the State of Alaska to go "upside down" on these tax credits. He questioned how that's not an incentive to go into these new oil fields.

MR. MAYER agreed that there could be cases in which the tax credits, on a discounted basis, could outweigh the production tax from those credits in the future. However, the government take across the entire system still does not change very much whether it is a low cost or a high cost project. He declared that the initial investment by the state through the tax credits pays off through taxes and royalties on future production and in almost all cases the cash flows/income from those revenue streams is usually greater than the investment from the credits. For example, if the initial tax credits are considered a roughly 35 percent tax credit investment in the project, the cash flows from those are usually significantly greater than 35 percent of other project cash flows, though the production tax itself in a very high cost project may not be. That said, Mr. Mayer said that he has not observed many cases of consistently high enough costs that overall the value from the project, just in the production tax, would not be greater than the initial credits. He reminded the committee that high costs mean that there isn't very much divisible income because much of the barrel is taken out in costs. There is a cost and price case for which the 12.5 percent royalty alone would take all the divisible income. Therefore, some high cost projects need a lower government take than the system offers in order to be economic, but the problem is providing incentives without sacrificing the overall government take structure.

REPRESENTATIVE TUCK surmised then that it is a greater advantage to an existing producer than to a new developer for investment in heavy oil.

MR. MAYER expressed agreement, as there is a bigger benefit for writing off those costs against an existing progressivity tax base as opposed to the tax credits.

11:41:04 AM

REPRESENTATIVE TUCK asked whether reserve taxes are a viable option for increasing production.

MR. MAYER answered that he is aware of reserve taxation as an idea in principle, but not aware of many regimes that practice it. It is more common for jurisdictions to include into lease agreements more powerful relinquishment clauses for development within a given time period or the rights to the asset are relinquished. He said he has not seen enough modeling on reserve taxation to offer any insight to the efficacy of it. However, he offered his belief that it is more likely to have adverse impacts.

11:43:31 AM

REPRESENTATIVE SADDLER, addressing slide 20, asked if there is any significance to the red and blue colors assigned various numbers.

MR. MAYER explained that the idea is to illustrate in color where there had been a change due to the application of the allowance. The three numbers in red are the result of the 30 percent gross revenue exclusion applied to the base calculation and the blue numbers represent the resulting tax calculations, whereas the black numbers are "common across all regimes."

11:46:21 AM

MR. MAYER, returning to his presentation, directed attention to slide 21 entitled "Purpose of Gross Revenue Exclusion Concept." He began by highlighting that the ACES production tax is a profit-based tax as it taxes wellhead revenue net of costs. Under the ACES structure, varying the base amount of tax, the progressive rates, or anything to do with the production tax for different streams of production is extremely difficult and would require "ring fencing" to allocate different costs to different streams of production. The aforementioned adds complexity to ACES. He reported that the basic concept of the Gross Revenue Exclusion would allow a reduction in government take on some streams of production, but not others, without the requirement for "ring fencing." He explained that it could reduce the progressive tax without having to account for the costs that accompany a particular asset, by subtracting the gross revenue as an allowance in calculating the overall production tax liability for a producer. The aforementioned would be used as a way to reduce the base in the progressive tax on a particular stream of production that is desired to be incentivized. Mr. Mayer reminded the committee that the Senate worked the aforementioned into its legislation at the end of the regular session as a way in which to address incentivizing completely

new areas without ring fencing. However, if one wants to utilize ring fencing, then progressivity can be reduced or eliminated altogether for specific assets while maintaining a 25 percent base. If one wants to avoid ring fencing, the Gross Revenue Exclusion is a useful concept to obtain similar economics over the life cycle by taking out the gross revenue that comes from a particular stream of production from the producer's overall tax liability. He said that this would provide a simple manner in which to calculate the impact of new assets without needing to know what costs went where. Interestingly, HB 3001 applies the gross revenue exclusion across all North Slope fields. He noted that [the gross revenue exclusion] was only applied to the progressive tax not the base tax, which basically results in lowering progressivity. Drawing from his initial analysis, he related that reducing progressivity from .4 to .15 [percent] would result in about the same impact as the 40 percent gross revenue allowance in HB 3001, and would do so in a simpler, more transparent way. The benefit of a gross revenue exclusion is the ability to only apply the benefit to a specific stream of production and it is easy to implement within the structure of ACES. "It seems to me, an odder way of achieving the aim of lowering government take overall when one could achieve the same aim just by reducing the progressivity coefficient," he opined.

11:51:08 AM

CO-CHAIR SEATON, referring to modeling, inquired as to how viewing a 30 percent exclusion as being equivalent to a 30 percent increase in costs is different than having a higher cost field.

MR. MAYER answered that [viewing a 30 percent exclusion as equivalent to a 30 percent increase] increases benefits to the producer from the higher costs, particularly early on. For instance, the overall economics of a 30 percent gross revenue allowance for new production under HB 3001 versus eliminating progressivity under ACES for the early years looks fairly similar to the producer, in terms of net present value and internal rate of return. However, the overall government take on a discount basis is probably higher under the gross revenue exclusion because the impact of the exclusion is that the cash flow looks better in the early years. Capital expenses are higher in the early years of production, while there are more operating costs in the later years. He pointed out that the high capital expenses combined with the gross revenue exclusion results in low tax payments in the early years. However, when

all that is left is the operating cost, the level of tax paid is probably more than would be paid under ACES with no progressivity. The fact that the benefit is front loaded to the early years makes the project economics look relatively good, while the overall undiscounted government take is probably higher than it would be, for instance, under a flat 25 percent base tax.

11:53:36 AM

MR. MAYER then turned to slide 22 entitled "FY 2013 Revenue Comparison," which charts the overall impacts on revenue to the State of Alaska from HB 3001 with oil prices ranging from $40 to $200 per barrel. He listed the various categories to include Production Tax, Total State Take, Total Government Take, Cash to Companies, and FY 2013 % Government Take. He then pointed to the example in the chart of the revenue generated from the production tax at $110 per barrel, which relates the revenue generated: Under ACES $4.782 billion; under HB 3001, without the 40 percent well credit, $3.597 billion; under HB 3001, with the 40 percent well credit, $3.302 billion; and under HB 110, $3.210 billion.

11:55:42 AM

REPRESENTATIVE TUCK asked whether the examples are for existing production or for new fields.

MR. MAYER replied that this is the same high level calculations the Department of Revenue presents in its Revenue Sources Book, in particular in the appendix pages. "If one assumes away all of the data, all of the complexity of different producers and different fields and different costs, and just says 'We can get pretty close to the overall tax liability here, from assuming all of this production comes from one enormous field with one owner, with ... a cost that's equal to the average cost of the Slope.'" In that case it's going to be around $13 a barrel in capex and ... under $10 a barrel in opex, if you do it on a per barrel rather than a per taxable barrel basis."

11:56:50 AM

REPRESENTATIVE SADDLER inquired as to the amount of production.

MR. MAYER replied that the total production amount equals the 2013 DOR forecast of 555,000 barrels per day or annual production of just over 200 million barrels.

REPRESENTATIVE SADDLER surmised then that slide 22 is a stylized chart based on 555,000 barrels of daily production, with a capital expense of $13 per barrel, and an operating expense of $10 per barrel.

MR. MAYER expressed his agreement, and noted that these figures were all based on Department of Revenue fiscal year (FY) 2013 forecasts.

11:57:51 AM

MR. MAYER, continuing his review of slide 22, pointed out the similarity in the revenue generated by both ACES and HB 3001 without the 40 percent well credit when oil prices are $60 per barrel and below, as progressivity has not yet been triggered. The difference illustrated is the result of the increased capital credit. He noted that the impact is magnified as the price per barrel increases, with a revenue difference of almost $4 billion between ACES and HB 3001 when the price of oil is $200 per barrel. The impact is greatest when the progressivity is greatest. He then directed attention to the FY 2013 percent of Government Take columns, and explained the difference between the take for the life cycle of a project and for a fiscal year. He explained that the life cycle of a project is impacted by inflation, but since the thresholds at which progressivity kick in for ACES are not linked to inflation the impact under ACES is such that government take steadily increases over time as in real terms the threshold through which progressivity kicks in comes down. Therefore, the life cycle analysis of government take for ACES is more likely to be 82-83 percent, whereas for only FY 2013 the high reaches about 78 percent for ACES. He reiterated that the government take at the $60 barrel price is the same, about 66-67 percent, for HB 3001 without the 40 percent oil well credit. The 40 percent oil well credit in both HB 110 and HB 3001 is what makes the difference at the $60 level. Still, HB 110 and HB 3001 look relatively similar in terms of overall government take, and therefore progressing at a much lower slope from a level in the mid 60 percent to a maximum of about 70 percent versus ACES, which reaches 78 percent in the highest price cases.

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MR. MAYER, in response to Representative P. Wilson, explained that the columns entitled Total State Take represent the total take to the State of Alaska that is all of the components of the

fiscal regime, including production tax, royalty, property tax, state income tax, and federal income tax. The federal income tax in Alaska is calculated assuming the nominal rate of 35 percent.

12:01:21 PM

MR. MAYER addressed slide 23 entitled "FY 2013 Government Take Comparison." Comparing the government take in more detail for FY 2013, he pointed to the steeper upward slope of the ACES graph until the percentage of take reached 75 percent and it began to flatten. He then pointed out that the government take for HB 110 and HB 3001 for existing production is very similar, especially for $100 per barrel and above although HB 3001 has slightly lower government take for existing projects in the $50-$80 per barrel price range, which he attributed to the 40 percent well credit. With regard to new production, HB 3001 looks better than HB 110 at low price levels, but at higher price levels of $120 per barrel there is a higher level of government take than occurs for HB 110 for new production.

12:03:11 PM

MR. MAYER moved on to slide 24 entitled "$17/bbl Field: Project Value Under Different Fiscal Options," and compared the graphs for NPV and IRR at $17 per barrel under various fiscal regimes. He noted that a flat tax would create a straight line, as opposed to the curved line from progressivity. He pointed out that all of the proposed changes effectively reduces progressivity and gets closer to the straight line. Although the $17 price per barrel does not make a huge difference in terms of breakeven economics, the IRR is affected such that the level at which the 15 percent rate of return is achieved moves from about the $90 range to the $80 range, if the field is taxed under the existing production level and down to the $70 range if it is taxed under the rate for new production. Those differences become further magnified for the higher cost fields, as shown on slide 25 entitled "$25/bbl Field: Project Value Under Different Fiscal Options." If the same exercise is performed for the $25 per barrel field, the NPV10 breakeven when the economic value starts moves from $90 to $80 and then to the high $70s, depending upon which tax regime is applied. Again, there is a large difference at the level at which the 15 percent rate of return is achieved, such that the $130-$140 per barrel can decrease to $100 or $90 per barrel. Similarly, in the highest case, a $34 per barrel field [as illustrated on slide 26 entitled "$34/bbl Field: Project Value Under Different Fiscal

Options,"] the NPV10 breakeven was not achieved until $130 per barrel. That price can be brought down to $100 or below in the difference that is made through progressivity. He attributed that to the divergence such that the ACES line bends away due to the high progressivity and the breakeven point is significantly reduced as is the point at which the 15 percent IRR is achieved. For a project this challenged, particularly on a stand-alone basis without the benefit of some of the other benefits, the economics remain challenged at the various cost levels presented, even under HB 110 or HB 3001 for new production. He declared that this is the impact on improving the economics on new higher cost development.

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MR. MAYER, referring to slide 27 entitled "40% Well Credits Create High Levels of Government Support," said the question of how much revenue one is willing to forgo to have that impact and whether that impact should be targeted at new incremental production as opposed to all production remains. He then spoke about the high levels of effective government support which occur under the 40 percent exploration credit combined with progressivity under ACES, or the 40 percent well expenditure credit. He reported that the tax benefit of writing off an expense against the existing taxable production base, including the ability to reduce the payable tax under progressivity, and then include the 40 percent credit, would result in very high levels of government support. For example, when the oil price is $120 per barrel, under progressivity an approximately 50 percent production tax is being paid. Further, if a company spends $100 million on work that qualifies for the credit and can, in addition, obtain a 40 percent credit, the after tax cash flow would only be worse off by 10 percent of the cost of the well work, with the remaining 90 percent of expense covered by the 40 percent credit or the 50 percent effective production tax that the company is not paying on that amount. A 60 percent cap rather than the 75 percent cap on progressivity results in exceeding 100 percent when the price of oil reaches $210-$220 per barrel. Overall, the 40 percent well credit creates very high levels of effective government support.

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CO-CHAIR SEATON asked whether the state corporate income tax reduction would be added to this as well.

MR. MAYER replied that he was unsure, as it would depend on what portion of the spending is capitalized and hence, depreciated, and what portion is expensed. To the extent that it is capitalized and depreciated, it would be spread over a longer time and have a lesser impact.

CO-CHAIR SEATON surmised that government support referred to state dollars used in the project, whether they are offset by reductions in property tax and credits.

MR. MAYER answered, "That's certainly one way of looking at it." However, it is a view that the companies would not necessarily agree with because they are spending the actual dollars. Still, at the end of the year, when all the tax implications come to bear, the after tax cash flow is only worse off by 10 percent of the total cost at the $120 price per barrel.

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CO-CHAIR SEATON replied "if they're looking at it in those terms when they are calculating the competitiveness of the project, do all those terms get added in on the competitiveness of the project ...?"

MR. MAYER replied that the economic metrics of IRR and NPV are impacted when the after tax cash flow is minimized. To the extent that this minimizes the impact on ACTF of significant new spending, of which only a small amount appears as a negative to the company, then it has a significant impact on the ACTF for the IRR and NPV of that spending. He offered his belief that there are other important economic metrics, including return on capital employed, are not affected. The return on capital employed is important to large oil and gas companies, particularly of the sort that operate the major assets in Alaska, that tend not to be "high growth companies" but rather rely on the efficiency of their operations. One of the most important measures of efficiency, from the perspective of uses of capital, which is frequently used in judging oil companies, is the return on capital employed. The question of implicit government support does not impact that metric because it is about what was spent, that is actual dollars the company spent by the company without taking into account the after tax benefits, and what return was gained from it.

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CO-CHAIR SEATON surmised that the effect on the competitiveness of a project would be influenced by the structure of the modifications to the entire fiscal regime.

MR. MAYER replied yes, but added that some economic metrics will be more impacted than others.

12:14:17 PM

MR. MAYER, concluding with slide 28 entitled "Key Issues," summarized that the largest question with regard to proposed HB 3001 is the merit of across-the-board reduction in government take versus trying to limit a benefit from reduced government take and possibly even greater reduced government take that is limited to a more targeted production stream. An across-the-board reduction in government take is the simplest approach and avoids the potential for complexity, adverse outcomes, or perverse incentives; however, it requires foregoing significant revenue on activities that are currently economic. The alternative is a more targeted approach that forgoes less revenue on activities that are currently economic, but also has a greater risk of creating a less significant incentive or creating particular perverse incentives or adverse outcomes. He noted that, although the current proposed across-the-board reduction in government take would be about $1.2-$1.5 billion at $110 per barrel, if the decline on the legacy fields could be reduced from 6 percent to 2 percent by [proposed HB 3001], then the revenue from FY 2020 onward could be higher than the current projected scenario. Even with such a reduction in the decline of the legacy fields, revenue until 2020 would be significantly lower than under maintaining the current tax structure; however, there would be a cross-over point at which the possible reduced decline could result in increased revenue.

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MR. MAYER declared that this critical question, which is difficult to answer without the details that only the operators have, is with regard to how viable it is to the decline from 6 percent to 2 percent. He opined that although it is "not beyond the scope of imagining, but also far from certainty." He offered that the only alternative would be to differentiate between existing and incremental production in the legacy fields, and there are significant complexities and administrative difficulties to doing this effectively so that when the benefit is provided companies are able to run the economics on their project applying the economics that come from

that benefit rather than the economics of the base production. Mr. Mayer opined that the key issue with proposed HB 3001 is the approach to take to reduce government take to stimulate new investments, while keeping in mind that in the future with heavy oil there may be even higher [production] costs and even greater reductions in government take necessary to stimulate some things. There comes a point at which it is clear that one does not want to apply a regime, for example, that incentivizes heavy oil to the light, highly economic, existing production from the base fields. He further opined that HB 3001 does not address other key issues that have been raised with ACES, such as oil and gas decoupling. If there is large scale gas production, because under ACES progressivity is assessed on a per Btu basis based on the price of an average barrel or Btu equivalent barrel of production, at significantly lower prices, then gas prices vary far below oil parity. The aforementioned can reduce a taxpayer's production tax value per barrel, and therefore substantially reduce the amount of progressivity they pay. In effect, there would be a cross-subsidy between gas and oil such that the simple fact of gas production reduces the tax the taxpayer pays on oil. This legislation does not address the aforementioned issue nor does it address the issue of high levels of spending support for particular activities through the interaction of high credits with progressivity, which has principally been the case with the 40 percent exploration credit in the past. The legislation only addresses [the 40 percent exploration credit] in so far as it reduces the maximum rate of progressivity from 75 percent to 60 percent. Although that reduction in the rate of progressivity takes "the very worst of it out ... there's a lot that still remains." Furthermore, taking the 40 percent credit probably contributes to that problem further.

12:20:48 PM

CO-CHAIR FEIGE, referring to the incremental and existing oil production, asked whether the application of a credit or a reduction in the gross value would have more impact on a company's decision at the point of production or some other point. He acknowledged that there is an increasing complexity for the various proposed points of application.

MR. MAYER stated that there are a number of issues to consider. He explained that to some extent the gross revenue allowance avoids the complexity of determining the costs to specific fields and assets. He suggested that one way to target a substantially reduced government take to a specific production

stream and then differentiate between existing production and new production would be to draw the decline curve using past production data, calculating the decline, and extending it forward. He pointed out, "The more granular the level of calculation is done at, the better the forecast one can produce." He clarified that a decline curve using past production data for specific wells is far more accurate than using the data for an entire unit or an entire company. He considered that this analysis, although complex, would only have to be performed once. He allowed that the complexity would arise for an investment decision today knowing that there is the potential for substantially reduced government take above a target rate set by a decline curve, the question is where is the [company] in relation to the target today. If a company is already substantially over the target with a comfortable buffer, then any new investment made can run on the lower rates for the production over the decline curve. However, if a company is substantially underneath [the target of the decline curve] or even close to it and uncertain about the performance of some of the company's base assets, the company could think the decline would be worse than the forecast predicts. There are many circumstances under which a company, driven by caution, would be more likely to run its base case economics using the government take that applies below the line than above it.

12:27:14 PM

REPRESENTATIVE HERRON asked where Alaska would be ranked on the bar graph on slide 7 should proposed HB 3001 pass.

MR. MAYER responded that although he would have to perform some analysis and get back to the committee, he offered his belief that Alaska would be ranked close to the average government take of "US - LA (Haynesville)."

12:27:55 PM

REPRESENTATIVE HERRON, referring to slide 23, recalled that last year there was a proposed amendment to HB 110 that would flatten out ACES at a certain price per barrel. He asked if other regimes do the aforementioned.

MR. MAYER replied that many financial regimes are neutral at specified price levels, and many also have a steady downward slope. He declared that it was easy to structure a financial system with the cost parameters to achieve neutrality at a specified level of government take.

12:29:46 PM

REPRESENTATIVE PETERSEN, referring to slide 28, recalled the comments regarding the high amount of credits that would be involved with the development of heavy oil, which should also apply to shale oil development because of the significant amount of drilling required to maintain production levels of shale oil. He then asked whether Mr. Mayer was suggesting that Alaska should propose a separate tax regime for those types of oil developments.

MR. MAYER, drawing from his limited work reviewing the likely cost of [heavy oil and shale oil development], offered his belief that the development of heavy oil and shale oil would require a level of government take lower than what is currently proposed in HB 3001. Therefore, he surmised that one would not want a structure that applies one level of government take to everything because that would result in applying a low level of government take to existing profitable production.

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CO-CHAIR SEATON held over HB 3001.

12:31:16 PM

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 12:31 p.m.