

SENATE FINANCE COMMITTEE  
April 2, 2012  
1:05 p.m.

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CALL TO ORDER

Co-Chair Stedman called the Senate Finance Committee meeting to order at 1:05 p.m.

MEMBERS PRESENT

Senator Lyman Hoffman, Co-Chair  
Senator Bert Stedman, Co-Chair  
Senator Lesil McGuire, Vice-Chair  
Senator Johnny Ellis  
Senator Dennis Egan  
Senator Donny Olson  
Senator Joe Thomas

MEMBERS ABSENT

None

ALSO PRESENT

Tony Reinsch, Senior Director, Upstream and Gas, PFC Energy, Contract, Legislative Budget and Audit Committee; Janak Mayer, Manager, Upstream and Gas, PFC Energy, Contract, Legislative Budget and Audit Committee;

PRESENT VIA TELECONFERENCE

SUMMARY

SB 192 OIL AND GAS PRODUCTION TAX RATES  
#sb192

SB 192 was HEARD and HELD in committee for further consideration.

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SENATE BILL NO. 192

"An Act relating to the oil and gas production tax; and providing for an effective date."

TONY REINSCH, SENIOR DIRECTOR, UPSTREAM AND GAS, PFC ENERGY, CONTRACT, LEGISLATIVE BUDGET AND AUDIT COMMITTEE, related that PFC Energy were consultants for large global oil and gas producers, major independents, national oil companies, governments, and regulatory agencies. PFC Energy focused on

above ground challenges to the oil and gas industry advising on strategy, policy, regulation, and legislation.

JANAK MAYER, MANAGER, UPSTREAM AND GAS, PFC ENERGY, CONTRACT, LEGISLATIVE BUDGET AND AUDIT COMMITTEE, provided members with a presentation, "Discussion Slides: Senate Finance Committee," April 2, 2012 (copy on file). He communicated that the presentation examined the tax credits available to producers under Alaska's Clear and Equitable Share (ACES).

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He outlined the tax credits available under ACES, Slide 2:

#### Tax Credits Under ACES

- Qualified Capital Expenditures Credit of 20 percent for qualified capital expenditures, including exploration
- Carried-Forward Annual Loss Credit of 25 percent for excess lease expenditures (where Production Tax liability is insufficient to deduct costs)
- Well Lease Expenditure Credit of 40 percent for Well Lease Expenditures (Intangible Drilling Costs) below North Slope
- Alternative Credit for Exploration of 30 percent for Exploration expenditures for wells more than 3 miles outside an existing area (if outside Cook Inlet)
- Alternative Credit for Exploration of 40 percent for Exploration expenditures for wells more than 25 miles outside an existing area (10 miles in Cook Inlet)
- Cook Inlet Jack Up Rig of up to 100 percent for the First 3 unaffiliated wells drilled by same jack-up rig in Cook Inlet (now unavailable)
- Education Credit; a maximum of \$5 million for cash donations to educational institutions.
- Transitional Investment Credit of 20 percent for Expenses before March 31 2006 (pre-PPT)
- Middle Earth Credit of \$6 million for production below North Slope and outside Cook Inlet (Expires 2016)
- Small Producer Credit of \$12 million for producers with less than 50 mb/d average production (expires 2016)

Mr. Mayer observed that small producers engaged in challenging projects yielding marginal economic returns benefitted most from the small producer credit. He noted that the first five credits were relevant to PFC's ACES discussion.

He related that the discussion would explore the difficulties of incentivizing exploration and the

interaction between the exploration credits coupled with progressivity under the current fiscal system. He would further examine the interaction of progressivity with exploration credits by removing progressivity from the production tax and imposing instead, a progressive gross severance tax. He would conclude with analysis of capital credits and the return on investments by the state.

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Mr. Mayer offered a brief summary of the credits analyzed in his presentation; capital credits and the alternative credits for exploration. He explained that there were two key components to ACES credits: credits claimed against tax liability by current producers that accounted as a reduction in state revenue and credits refunded to producers with no tax liability that accounted as expenditure by the state. He referred to Slide 3, "Total Impact of Credits," which depicted a graph displaying the total impacts of both types of credits to the state: credits claimed against tax liability and credits refunded. The impacts of credits claimed against tax liability varied from \$400 million in 2009 to \$475 million in 2013. The total cost to the state combining both tax credits as lost revenue and expenditures was approximately \$800 million per year from 2009 to 2013.

Mr. Mayer noted that the qualified capital expenditure credit accounted for \$585 million in FY 2010 rising to \$640 million in FY 2011. In contrast, the exploration credit amounted to \$41 million in FY 2010 and \$13 million in FY2011. He remarked that the exploration credits represented a relatively small portion of the pie.

Mr. Reinsch turned to Slide 5:

#### Content

- Recent Trends in Exploration Activity and Basin Focus
- Credits and Incentives: Lessons from the Past
  - National Energy Program (Canada)
  - Norwegian Continental Shelf (Norway)
- Development Cycle Time: Incenting the Required

#### Activities

Mr. Reinsch announced that he would address the issues of exploration credits and incentivizing exploration in other countries, report on recent trends in explorations, review credits and incentives in light of government positions on exploration risks and discuss development cycles.

Mr. Reinsch remarked that the 1990's "set the stage" for a period of development capital expenditure through oil exploration and resource development. During the late nineties through approximately 2008, capital expenditure

funds were channeled into production growth and major resource development projects such as the Canadian oils sands and large scale liquefied natural gas projects in Qatar. He noted a recent rebound in global exploration spending.

Mr. Reinsch turned to Slide 6, "Rebound in Exploration Spending" that graphed total worldwide exploration spending by global oil companies from 1989 through 2011. He relayed that capital expenditure levels were flat in the first half of the 2000's. In 2007, a sharp increase in exploration expenditures occurred. Companies such as Statoil, Shell and British Petroleum (BP) significantly increased capital expenditures to capture new resource development.

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Mr. Reinsch cited Slide 7:

#### Trend in Worldwide Exploration: Global Players

- Exploration spending by many of the Global Players accelerated sharply in 2005-2006 as focus shifted to restocking the portfolio of development projects
- Statoil (North Sea) and Shell (Asia, North America) were early movers, quadrupling exploration spending since 2004
- The growth represents real activity gains, substantially outpacing the Exploration & Appraisal (E&A) Index

The slide also charted the net undeveloped properties of the global oil companies. He observed that Shell was the leader among global oil companies in securing any available lands for development. He explained that the oil companies predicted very limited access to new land for exploration. National oil companies were strengthening control over its resource base and severely restricting the global companies' exploration activity. The majority of the available acreage was located in Asia and Africa, including onshore and offshore sites. He commented that Shell and Exxon Mobil were dominant in North American holdings.

Mr. Reinsch declared that the global oil companies strategically accelerated exploration spending in recent years. He identified the regions where the majority of the global oil industry was expending capital on exploration, mapped on Slide 8, "Selected Global Players: Regions of Exploration Focus." He described the region as the Atlantic Margin Basins extending from the deep water in the Gulf of Mexico to Brazil, West Africa coastal deep water, and the Equatorial margin comprising of Sierra Leon, Cote d'Ivoire, and Ghana. He added that renewed emphasis in the Arctic had occurred in deep water offshore of Norway, the Barents Sea,

Northern Russia, and Alaska. He remarked that due to greater control by national oil companies, the Middle East with the exception of Qatar was no longer a growth driver in industry exploration.

Mr. Reinsch turned to Slide 9:

#### Trend in International Exploration: Independents

The International Independents are a more disparate group when it comes to exploration activity:

- Some, like Anadarko, have been material exploration players through the last decade;
- Some, like BG and Apache, have aggressively grown their exploration activities through the past decade;
- Others, like Occidental and Noble, have focused on development activity in a small number of play areas
- Exploration spending by Anadarko, BG, and Apache has hovered around the \$1.3-1.5 billion mark for the last few years, high for the Indies and ~60% that of the smaller Global Players

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Mr. Reinsch stated that besides the independent's interest in the Atlantic margin they are uniquely involved in opening new frontier areas. He pointed to Slide 10:

#### Selected International Players: Regions of Exploration Focus

The Independents are similarly positioned in the US/Canada onshore resource plays (oil sands, shale gas. Shale oil), and the deepwater plays of the Atlantic Basin

- The Independents are also at the forefront of new basin development, such as the Equatorial Margin, East Africa Deep water, South America "North Tier" deep water play, Argentina shale gas, and Lake Albert basin (Uganda)
- The Independents are not as prominent in the high cost, high risk exploration opportunities in the Arctic offshore

Mr. Reinsch directed attention to Slide 11, "IOC Growth Centered on Successful "New Frontiers"..." The graph displayed the projected growth in new frontier areas of development through 2010 and indicated a decline in conventional areas of development.

Mr. Reinsch discussed the "Redirection of Free Cash Flow" depicted on Slide 12. He reported that the focus on new frontiers in nonconventional development was financed by a redirection of free cash flow. He described a reallocation of capital from maturing areas in Africa, Asia Pacific, and Europe to the United States and Canada.

Mr. Reinsch moved to Slide 14:

#### Exploration and Government Risk Taking

- By and large, Governments have refrained from engaging in the business of upstream risk

- In emerging basins, nascent National Oil Companies (NOCs) will usually have "back-in provisions" within production sharing contracts, allowing entry into development projects as an equity participant at the point of sanction. Are prohibited from engaging in exploration activity

- In more mature basins, the NOC may engage fully from license award to production (Petora in Norway, ONGC in India, PDVSA in Venezuela) assuming it has internalized the necessary degree of technical sophistication and dry-hole tolerance

- Exploration credits/rebates are, in essence, a direct engagement by the government in exploration risk. As such, they have been used sparingly outside of the context of the tax and royalty regime.

Mr. Reinsch offered that large amounts of capital were invested by oil companies without any returns. Governments are generally stewards of the resource and not comfortable with risk. He added that governments engaged in exploration risk through exploration credits or incentives by reduction in tax liability. Governments rarely extend exploration credits to non-taxable entities. Governments tend to adopt incentives and credits to broaden resource development where production was in decline.

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Senator Thomas questioned whether a direct relationship existed between exploration credits and up front risk in investments in high cost areas such as Arctic and off-shore. Mr. Reinsch responded that the opposite was true. He elucidated that the exploration credit represented a small portion of incentives offered by governments. Capital credits represented 80 percent of government credits. Exploration credits were found in areas where well costs were low. The credits had a persuasive impact with little

risk by the government. Deep water investments with high well costs carried significant risk for governments.

Mr. Reinsch cited Slide 15:

Canada's National Energy Program: An Experiment in Intervention Gone Awry

- The NEP was introduced to both enhance Canadian ownership in Upstream activities [exploration and recovery of oil and natural gas], and to accelerate the discovery and development of domestic resources to enhance security of supply and support energy subsidies to domestic consumers.

The slide included a chart that indicated the types of incentives, credits, and risk sharing activities offered through the National Energy Program (NEP).

Mr. Reinsch related that the program failed because the market turned against the National Energy Program (NEP). The program was not considered favorable to the business cycle. He opined that the best government incentives were "robust to the business cycle." The program was intended to "Canadianize" ownership in the upstream activities and to address decline. Oil production was in decline and oil prices were rising. He highlighted the program. The structure allowed greater incentives to Canadian companies. "Exotic" activity received greater incentives. Drilling deeper wells or farther from existing wells was awarded with more incentives. The result was to drive a typically efficient industry to place more effort into marginal areas.

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Mr. Reinsch discussed Slide 16:

National Energy Program (Canada) and Exploration Incentives

- NEP introduced substantial distortions into the E&P decision making process. In particular, incented Upstream activity towards less prospective and higher cost areas, and introduced "artificial" demand for Upstream services
- Drilling costs (seismic, rigs, etc.) accelerated rapidly as demand soared in new and unsupported exploration environments
- Many companies were effectively "drilling for PIP grants" with commercial discoveries representing the Failure case

Exploration      Well Canadian Arctic      Atlantic Offshore

## Costs

1966-1970	\$4.3 mm	\$1.2 mm
1971-1975	\$3.6 mm	\$3.8 mm
1976-1980	\$24.4 mm	\$22.4 mm
1981-1985	\$63.2 mm	\$45.8 mm
1986-1990	\$44.2 mm	\$20.5 mm

Mr. Reinsch noted the chart on slide 16 and observed that the program ended in 1985 in response to declining oil prices. He pointed out that the program "incented" companies to drill away from the established infrastructure into frontier areas. The Petroleum Incentive Payments (PIP) grants incentivized "drilling for nothing" or speculative drilling.

Mr. Reinsch reviewed Slide 17:

### Canada's National Energy Program

- The decline in crude prices in the mid-1980s forced the withdrawal of virtually all aspects of the NEP
- Alberta:
  - PIP grants replaced by Royalty Tax Credits (75% rising to 90% with maximum credit per well)
  - Exploration Incentives restructured as either:
    - 12 month Royalty holiday on eligible wells to a maximum per well;
    - Royalty exemption on cumulative production, linked to well depth and location
    - Exploration Drilling Incentive Program: 50% credit set off against subsequent royalties
  - Moved away from credits/rebates outside of the royalty and tax environment => reward success, not simply effort.
- Federal:
  - PetroCanada back-in eliminated;
  - Royalty linked to "payout" of development
    - 1% royalty rising to 5% at rate of 1% per 18 months
    - Royalty jumps to 30% net CF after Payout
  - Exploration Tax Credit of 25% for well costs above \$5 mm, used to reduce Federal Income Tax. If not taxable => direct refund of up to 40% of non-utilized credit

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Mr. Reinsch referred to Norway's oil and gas industry, which was similar in nature to Alaska, Slide 18:

## Norwegian Continental Shelf: Incentives in a Modern Context

- Oil production in Norway peaked in 2001 and has fallen by ~45% since then. Growth in gas production allowed BOE volumes to rise till 2004, and have been in decline ever since
- Fiscal system provides incentives for exploration activity

### Base Production Tax - 25%

- Applied to net income from Petroleum activities

### Special Tax - 50%

- Applied to net income generated from petroleum activities, to capture resource rent above "normal profits"

### Government Investment - Petoro

- Engages in exploration and development activity as full equity partner; pays share of costs and receives 100% of revenue from its working interest position

### Exploration Incentives - 78%

- Applies to companies in non-taxable position. Since government allows uplift of loss carry-forward at a risk-free interest rate, it is indifferent between refund or offset
- Introduced to expand the competitor landscape, bringing in new Upstream companies

### License access

- All companies require pre-approval for financial, technical, and operating capability prior to bidding on a License in the Norwegian Continental Shelf (NCS)

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Mr. Reinsch predicted continued decline in Norwegian oil and gas production. He explained that the special tax was levied on income over and above normal profit margins. He identified Petoro as the Norwegian government's equity firm for oil and gas development. He detailed that the Norwegian license requirements were arduous, which was not the case in Alaska. He observed that the process was straightforward in Alaska. Conversely, Norway's ability to rigorously screen license applicants was the foundation for their incentive program.

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Mr. Reinsch referenced Slide 20, "Cycle Time to Production," that contained a graph illustrating the project cycle time from discovery to commissioning based on the type of development project. He revealed that directing incentives to produce the desired outcome was challenging, and commonly referred to as "tool and target."

Mr. Reinsch outlined the various types of oil development projects and its project cycle time.

- Integrated Mined Oil Sands are long term development projects expected to take 10 or more years to establish due to protracted regulatory process and the scope of the project.
- Off Shore Frontier developments are areas offshore that do not have access to established infrastructure and take 6 to 8 years to develop.
- Onshore Frontier projects are land based areas without access to infrastructure such as Uganda. Cycle times are 4 to 6 years.
- Offshore Tieback Wells connect new discoveries to existing infrastructure and shorten cycle time to 3 to 5 years. The majority of time to reach production was spent on appraising project for financial viability.
- Enhanced Oil Recovery (EOR) Onshore areas are mature oil fields with infrastructure in place; only testing was necessary. Project cycle time was very short.

Mr. Reinsch judged that the immediate challenge for Alaska lied in the medium three to five year time frame to increase the volume of oil flowing into the pipeline to a level that maintained government revenues. He concluded that mapping tools to targets was an important factor in developing exploration incentives for Alaska.

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Co-Chair Stedman asked for clarification on the licensing requirements in Alaska compared to Norway. Mr. Reinsch commented that Alaska does not screen the applicants for financial, operational, or technical capabilities. Norway's restrictive licensing disallowed any entity from bidding on a license until pre-approved for financial, technical, and operating capability.

Mr. Mayer furthered that incentives worked, but not necessarily in the way that the government intended. He exemplified Canada's failed attempt to incentivize exploration that led to speculative and non-productive predatory drilling practices. He stated that Norway controlled that outcome by ensuring the applicant was a

credible producer with the intent to produce. A well-structured incentive program encouraged desired outcomes.

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Senator Thomas relayed that the Albertan government in Canada had raised taxes on oil production around the same time that ACES was enacted. Production in Alberta began to decline; subsequently taxes were decreased and oil production increased. He wondered if that scenario was reflected in the previous slides and was an accurate assessment. Mr. Reinsch clarified that the presentation focused on Canadian's National Energy Program in the 1980's. The Alberta scenario happened in recent years and represented a miscalculation of tools and timing. He explained that the Alberta government had implemented a "harvest fiscal system." Alberta believed that oil production was nearing the end so the government acted to increase its share of the revenue. Simultaneously, the industry was ready to launch new production opportunities employing new technologies such as horizontal drilling and multiple stage fracturing of wells in conventional fields. He elaborated that the Alberta government failed to recognize the impact the new technologies could have on reversing the long-term decline in conventional production. The industry responded by moving investments to new horizons in British Columbia and Saskatchewan in shale oil. Alberta soon realized that the industry needed support in fostering new technologies in traditional fields. The government redirected its tax structure to incentivize exploration utilizing the emerging technologies.

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Co-Chair Stedman announced that the Department of Revenue had declined to participate in the policy discussion regarding tax credits.

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Mr. Mayer concluded that the lesson from the Canadian and Norwegian scenarios showed that high levels of exploration credits without strict evaluation of the producer resulted in a boom, either in speculative exploration or exploration activity merely to obtain the credit. He declared that under ACES, exploration credits coupled with progressivity provided a high level of effective government support for exploration activity.

Mr. Mayer reviewed the graph on Slide 21, "High Levels of Exploration Support under ACES." The graph depicted crude oil prices in the bottom axis and the left axis represented percentages of after tax effective government exploration contribution based on a 40 percent credit. He demonstrated how the exploration incentive tax structure worked combined with progressivity to the point where it benefited the producer to drill "dry holes." He began at \$55 per barrel (BBL.) price of oil (progressivity was not applicable) exemplifying an existing producer with existing production tax liability. The producer spent \$100 million on an exploration project that resulted in a dry hole. The applicable 25 percent production tax credit immediately reduced \$25 million from the tax liability paired with \$40 million in exploration credits, which resulted in an after cash flow liability of \$35 million for the producer, out of the \$100 million investment. The state reduced the producers risk for exploration by 65 percent.

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Mr. Mayer furthered that the effects were multiplied with progressivity. He exemplified that at \$110/bbl. an existing producer that invested \$100 million in exploration activity receiving the same credits coupled with progressivity incurred a \$10 million dollar cash flow liability. The state bore 90 percent of the burden in reduced revenue from production tax and expenditure with exploration credits. He maintained that at \$215/bbl. the after tax cash flow liability on \$100 million spent on exploration (progressivity was capped at 75 percent) was zero. The state's contribution was 100 percent. At the unprecedented price of the mid \$200/bbl., a producer would receive an after tax cash flow benefit. He warned that the result encouraged a producer "to drill as many dry holes as possible."

Co-Chair Stedman wondered how the immediate write-off of capital expenditure influenced the tax structure and what resulted from reducing the 40 percent credit to 20 percent. Mr. Mayer answered that if the existing structure of ACES was maintained with a 20 percent credit, the 75 percent cap in progressivity would prevent a 90 to 100 percent contribution by the state at any price for oil. He added that the immediate write-off of capital expenditures against production liability enabled the high levels of exploration support when coupled with the 40 percent exploration credit.

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Co-Chair Stedman observed that the current structure could drive the state's production tax value negative. He recalled that the same conclusion was pointed out by Dr. Pedro Van Muer in previous testimony ["Policy Options for Alaska Oil

and Gas" Senate Finance Committee presentation, February 12 - 13, 2012 (copy on file).] Mr. Mayer agreed that negative value was one of the unintended side effects of the inclusion of progressivity in the production tax structure combined with high levels of exploration credits. He noted that a severance tax option eliminated the unintended consequences of excessively high support at high oil prices. As progressivity increased it raised the production tax, which qualified for immediate write-off of capital costs. He exemplified progressivity levied on gross production (at 25 percent) instead of a profit based production tax. Costs were no longer relevant for the gross progressive calculation. Costs against the immediate write down of capital were accrued on a flat 25 percent production tax. The tax remained at 25 percent regardless of how high the price of oil was. The after tax effect on government contribution with a 40 percent exploration credit at \$100/bbl. of oil was 60 percent. The effect was further reduced to 45 percent if the exploration tax was reduced to 20 percent. He added that another unintended consequence of net progressivity within the current structure was on potential large scale gas development. The average prices paid on a BTU (British thermal unit) equivalent could further decrease revenues on existing oil production by diluting production tax value with a lower value product. He noted that SB 192 attempted to "decouple"; accounting of oil and gas into separate streams of production, in order to remedy the inclusion of progressivity in the production tax.

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Co-Chair Stedman asked what the downside of progressivity from net to gross was. Mr. Mayer stated that the only principle downside was the transition time of the current fiscal system to convert and administer a new tax structure. He opined that a net severance tax system was less complicated than the existing structure. He furthered that it was far less complicated than the existing system combined with decoupling as a way to remedy progressivity.

Mr. Mayer directed attention to capital credits. He reminded the committee that capital credit was a 20 percent credit on qualified capital expenditures as an immediate write off of capital. He explained that the timing of credits and cash flow; the ability to immediately expense or claim capital credits in the current year to lessen the impact on the producers cash flow was built into ACES and preceding tax structures. The credit structure enabled a high government take but mitigated the cash burden on producers at the early stages of a project. The early stages impact the rate of return on the project. The credit allowed a relatively high rate of government take without penalizing the rate of return for the producer who can claim the credit in the first years of project development. He cautioned that

changes to the capital credit should be carefully considered. Changes to the capital credit structure could "deteriorate" the rate of return for marginal projects. The ability for a producer to claim capital credits in the early years of a project was critical to the timing of cash flow especially on high cost developments with marginal rates of return.

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Mr. Mayer addressed the Australian system that consisted solely of state and federal income tax and a profit based tax. He offered that the Australians wanted to structure a fiscal system where government take was equal to the equity stake in a project. The tax was levied at 40 percent of cash flow but contributed 40 percent of the costs. The costs were fully deductible each year. The 40 percent deduction acted as a 40 percent investment by government but did not bear risk. If the project failed the government was not responsible for the costs.

Mr. Mayer reviewed Slide 25, "Capital Credit -Return on Investment Under ACES at \$50 Oil." which provided a graph that depicted the project cash flows and returns to the state. He reminded the committee that two capital credits were available to new producers without existing production; the qualified capital expense at 20 percent and the carried-forward annual loss credit at 25 percent. He delineated that the graph was based on cash flow economics after state and federal income taxes. A yellow line depicted the total divisible income from a project. The total divisible income was revenue less expenses. A red line depicted government take. Government take dropped as capital credits were taken in the beginning of a project then rose with fixed royalties, production, and property taxes. A blue line depicted a 35 percent equity stake. The line was similar to the government take. The 35 percent equity stake represented the combined capital credits minus federal and state income taxes.

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Mr. Mayer concluded that at \$50/bbl. the government take was higher; 8 percent rate of return (IRR) and negative 36 percent of the net present value (NPV), than the equity stake; 5 percent IRR. He turned to Slide 26, "Capital Credit - Return on Investment Under ACES at \$100 Oil." He noted that the return on investment under ACES for \$100/bbl. oil was even greater for the government take at 29 percent IRR and three times higher NPV than the 35 percent equity stake.

Mr. Mayer remarked that the trend continued upward at \$150/bbl. oil, depicted on Slide 27, "Capital Credit - Return on Investment Under ACES at \$150 Oil." The trend

increased dramatically at \$200/bbl. displayed on Slide 28, "Capital Credit - Return on Investment Under ACES at \$200 Oil" [57 percent IRR for the government take and; 33 percent IRR for the 35 percent equity stake]. He surmised that the state of Alaska received a significantly high cash return on its initial investment of capital credits for a project.

Mr. Mayer highlighted Slides 29-32, "Capital Credit - Return on Investment Under Severance Option 1 at \$50, \$100, \$150, and \$200 Oil" sequentially. The slides portrayed the same graph using the severance tax scenario. He pointed out that at \$50/bbl. the numbers were similar to the ACES capital credit return on investment. As the price of oil climbed to \$200/bbl. the difference in the net present value between the capital credit and severance options narrowed.

Co-Chair Stedman compared slide 30 to slide 26 which graphed the rate of return for both scenarios at \$100/bbl. oil. He asked if the net present value represented the cash flow to the state. Mr. Mayer confirmed the statement and added that state and federal income taxes were factored into the net.

Co-Chair Stedman observed that the net present value to the state was more favorable under ACES. Mr. Mayer confirmed that both options had similar outcomes but were more favorable under ACES.

Co-Chair Stedman asked if the severance tax option included the seven year tax holiday. Mr. Mayer replied that the model only examined the 20 percent rate.

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Senator Olson referred to slides 32 and 28. He requested clarification on why the divisible income was represented as a notch on the graph at \$200/bbl. oil for both options. The line peaked at approximately \$750 million in 2012 then dipped to approximately \$650 million in 2014, slightly rose in 2016 and leveled out over the subsequent years.

Mr. Mayer responded that in general a notch represented a reaction to the impact of depreciation on a project or federal income tax kicking in and reducing cash flow.

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ADJOURNMENT

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The meeting was adjourned at 2:55 PM.