SENATE FINANCE COMMITTEE
March 15, 2012
9:06 a.m.

9:06:19 AM

CALL TO ORDER

Co-Chair Stedman called the Senate Finance Committee meeting to order at 9:06 a.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

Gerald Kepes, Partner, Head of Upstream & Gas, PFC Energy; Senator Joe Paskvan; Senator Cathy Giessel; Senator Hollis French.

PRESENT VIA TELECONFERENCE

Janak Mayer, Manager, Upstream & Gas, PFC Energy, Washington, D.C.

SUMMARY

SB 192 OIL AND GAS PRODUCTION TAX RATES: Presentation by PFC Energy

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

#sb192
SENATE BILL NO. 192

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

9:08:44 AM

Co-Chair Stedman stated that this was the initial presentation by PFC Energy and that more detailed information would be provided in subsequent presentations.

GERALD KEPES, PARTNER, HEAD OF UPSTREAM & GAS, PFC ENERGY, related that PFC Energy was an expertise consultancy that dealt exclusively with oil and gas. He explained that PFC Energy was a global, 150 member consultancy that was focused on the nexus between governments and industry. He acknowledged that oil and gas were government businesses and that companies needed to learn work within government structure.

Co-Chair Stedman requested a definition of the term "upstream". Mr. Kepes replied that upstream referred to all activities associated with the exploration and production of oil and gas. He furthered that upstream included all onshore, offshore, deep water, and other activities.

9:10:52 AM

Mr. Kepes began a PowerPoint presentation titled "discussion slides: Alaska Senate Finance Committee" (copy on file), and discussed the slide on page 3 titled "fiscal regime design: finding the intersection of efficiency and competitiveness."

- Fiscal regime design is fundamentally about maximizing State revenues, subject to two important constraints:
    - Efficiency: Not distorting investment choices, or preventing marginal investments that would otherwise have been made
    - Competitiveness: There is a global market for upstream dollars

Mr. Kepes explained that competiveness was an important part of the context of fiscal regime design and that any

upstream opportunity had to compete globally with other opportunities.

Mr. Kepes discussed the slide on page 4 titled "fiscal regime design: finding the intersection of efficiency and competiveness." He shared that an overly efficient fiscal regime, which had a government take that was too high, would result in a loss of competitiveness and investment. He furthered that if the government take was lowered too far, the objective of maximizing government take would be lost. He related that the challenge was to find the "sweet spot" between competiveness and efficiency, given the other factors.

9:13:41 AM

Mr. Kepes spoke to the slide on page 5 titled "relative government take (definition)." He explained that in the context of the presentation, "government take" referred to the "relative government take". Relative government take represented the total government take over the "divisible income."

Divisible Income equals Gross Revenues less costs, including capex and transportation costs.

Government Take includes all payments the government mandates in its function as a sovereign:

- Royalties
- Land rental fees, property taxes
- Production taxes
- Income taxes

Government Take does not include amounts the government earns via a direct equity stake

Mr. Kepes discussed the slide on page 6 titled "fixed royalty systems: inefficient, but potentially highly competitive."

- Given varying project costs, and varying prices, fixed percentage royalty systems are inefficient because they distort investment, making previously economic projects uneconomic at a given price

- Government Take from a fixed royalty system can be very high when costs are high or prices are low – 100% in the example of project 5

- In high price environments, however, fixed royalty systems can be very competitive

  - Government Take can be very low when prices are high, or costs are low – only ~33% in the example of project 1

Mr. Kepes stated that the slide illustrated a 30 percent fixed royalty system on five different projects that had varying costs; it showed a fiscal system design that was very competitive, but was not efficient from the state's point of view. He pointed out that the black horizontal line on the chart was at 30 percent. He related that project 5 was a high cost development, while project 1 had a low cost. He furthered that in the case of project 5, the system was very efficient, but that it was probably not very competitive.

Mr. Kepes explained the slide on page 7 titled "profit-based fiscal systems: more efficient, but may be less competitive."

- A Profit-Based fiscal system may be:

  - A contractual arrangement, such as a Production Sharing Contract
  - A tax which applies to revenues less costs

- Such systems can be capable of raising greater revenue, while reducing inefficiency:

  - In low oil price environments, or high cost environments, Profit- Based Systems are less likely to make marginal projects non-economic

- By capturing more rent in high oil price environments, or low cost environments, however, they may also not compete with royalty regimes:

- Projects 1 and 2 would be significantly more attractive to undertake under a royalty regime

Mr. Kepes related that a profit-based fiscal system was more efficient in terms of generating more income for the state, but that it may be less competitive. He stated that the chart depicted a 50 percent profit-based tax on five different projects and that it showed the divisible income that was available from the scenario's projects.

Co-Chair Stedman requested a clarification of the term "rent". Mr. Kepes replied that rent was the divisible income and that it reflected the amount of revenue that the state would accrue. He added that the "normal return on capital" represented the amount of money that was returned the investor.

Mr. Kepes summarized that slides 6 and 7 illustrated the point of efficiency versus competiveness and that they were examples of two end member cases. Mr. Kepes reiterated that it was a challenge to find the proper combination of efficiency and competitiveness.

9:18:11 AM

Mr. Kepes stated that upcoming slides would comment on and analyze the global business environment for the Alaskan oil and gas sector. He explained that Alaska, like any other oil and gas sector, did not sit in a vacuum.

Mr. Kepes discussed the slide on page 9 titled "fixed-royalty jurisdictions in U.S. Lower 48 are a key competitor to Alaska for investment dollars." He related that the slide made a very important point and that it examined the global oil players' aggregated sources and uses of cash flow. He stated that the graph on the left hand side of the slide showed that the listed companies had an aggregate cash surplus in the majority of the regions that they invested in. He pointed out that during the 2003 to 2005 period, the upstream cash flow for companies in Europe and North America was much higher than the capital being spent in the two regions and that there was a substantial cash surplus; over the three year period, companies generated $50 billion of upstream cash flow premium of the capital that they had spent in the two regions. He pointed out that Sub Saharan Africa was the only area on the slide that was

in cash deficit from 2003 to 2005; during that time period, companies in Sub Saharan Africa were generating slightly less upstream cash flow than they were spending on capital expenditures.

Mr. Kepes referenced the chart on the right hand side of the slide and stated that the North American investment area had changed radically for the large, global oil companies from 2008 to 2010; during this period, North America was no longer generating surplus cash flow, but instead had a cash deficit of $50 billion to $60 billion. He explained that developments in the shale plays[There are two definitions for "play" in relation to oil activity: The extent of a petroleum-bearing formation; also, it is the activities associated with petroleum development in an area.]in the Lower 48 were responsible for the change in North America's oil investment climate; as a result of the change, the larger, global oil companies had completely shifted their onshore investment strategies in the region. He offered that it was important to know where the capital from the global oil companies was going, specifically regarding the three major producers on the North Slope. He concluded that the investment opportunities for the onshore U.S. had changed and that the change was an important part of the context regarding how companies made investment decisions.

Mr. Kepes declared that the Lower 48 was "a very key competitor to Alaska for investment dollars", specifically regarding the large, global oil companies.

9:23:06 AM

Mr. Kepes discussed the slide on page 10 titled "all eyes on the price, but what about cost." He stated that the slide showed that over the last ten years, a lot of attention had been on the developments in the price of oil, but that there had not been much focus on the changes to costs. He furthered that the graph on the slide depicted the total spending for the global exploration and production (E&P) sector, the Brent Index price of oil, as well as the costs for exploration and development. He stated that onshore development costs, which were indexed to 100 in the year 2000, had increased to approximately 60 percent to 70 percent over that number. He pointed out that unit cost inflation had been occurring since the year 2000 and that it was occurring at a higher rate in offshore

projects; however, both onshore and offshore exploration and development costs were substantially higher than they were in the year 2000. He stated that it was important to note that the price of oil and the price of gas at the pump were very visible, but that sometimes the associated costs were not so visible; he pointed out that this was part of the global environment in the context of the investment decisions that companies made.

Mr. Kepes discussed the slide on page 11 titled "Alaska's days of "easy oil" are gone: high costs and high government take present challenges." He related that the slide was meant to bring observations into focus, make comparisons, and make some points about costs. He reiterated that Alaska was in a global oil market and referenced the previous slide's figure that the global industry would spend approximately $600 billion on E&P in 2012. He stated that the slide showed that Alaska was a "somewhat to substantially" higher cost environment in comparison to other oil sectors in the Lower 48; capital expenditures for Alaska conventional oil were approximately $17 to $18 per barrel and the operating expenditures in the area were almost as high. He related that the slide provided specific cost data for unconventional shale plays in the Lower 48 and for onshore, conventional E&P activities in Texas and Louisiana. The Bakken shale oil play in North Dakota was a high cost play, but was not as high cost as Alaska. He specified that Haynesville was primarily a shale gas play and that the Barnett play contained gas and oil.

9:27:35 AM

Co-Chair Stedman referenced the "new conventional" Alaskan oil on slide 11 and inquired how Alaska's "conventional" oil costs would compare to other sectors on the slide. Mr. Kepes replied that for infill drilling or new opportunities in the currently producing areas, the costs would be "closer to what you see here between the unconventional Bakken and maybe even around the Haynesville or less." He concluded that the costs for drilling in and around existing production on the North Slope were substantially lower than the costs for "new conventional" oil in Alaska.

Senator Olson asked for a clarification on slide 10. He noted that the header on the slide stated that oil prices would increase by 450 percent and queried if this meant that the price of oil would be in excess of $500 per

barrel. Mr. Kepes replied that the oil price on the slide was an index price and that it was based on the price in the year 2000. He explained that the prediction was a 450 percent increase to the $15 or $16 per barrel price of oil in the year 2000. He stated that PFC Energy thought oil prices could "drift" higher, but that it also saw "a bit of softness" in that price as well. He urged that PFC Energy was not forecasting that oil prices would be $400 or $500 per barrel.

9:29:20 AM

Senator Thomas inquired if revenue was considered a cost in the chart on page 10. Mr. Kepes responded that Alaskan state revenues were not considered on the chart and that the chart's costs reflected capital expenditures.

Co-Chair Stedman interjected that the costs on slide 10 were aggregate numbers. Mr. Kepes responded that Co-Chair Stedman was correct and pointed out that PFC Energy's databases covered the entire industry and examined global costs in aggregate. He reiterated that the numbers represented an aggregate amount and that there would be specific areas where costs did not increase as much, as well as areas where costs increased at a higher rate.

Mr. Kepes discussed the slide on page 13 titled "cost assumptions underlying fiscal analysis."

- Two key forms of analysis have been undertaken on project economics and government take levels in this presentation
- Existing Producer Analysis examines the economics of the fiscal regime for an existing producer, producing 200 mb/d in 2012, with a 6% annual production decline rate, and with the following costs:
    - $12/ flowing bbl operating expenditure
    - $5/ flowing bbl maintenance capital expenditure
- New Development Analysis examines the development-forward lifecycle economics of the fiscal regime for the development of a new 10

mb/d development for a producer without existing base production. Assumed costs are:

- $17/ flowing bbl operating expenditure
- $17/bbl reserves development capital expenditure
- $1/ flowing bbl maintenance capital expenditure

Mr. Kepes related that the cost figures for the existing producer analysis were germane to Co-Chair Stedman's earlier question regarding how "conventional" Alaskan oil would compare to other sectors on slide 11. He explained that the costs in Alaska for the existing producer analysis on slide 13 were lower than the costs for the viscous and new conventional oil on slide 11.

9:32:16 AM

Co-Chair Stedman asked for a definition of "flowing oil." Mr. Kepes responded that flowing oil referred to the cost of a barrel of oil in production; it was exclusive of other cost factors outside of production and was specific to a field actually producing.

Mr. Kepes continued to speak to slide 13 and related that a production level of 10,000 barrels per day (bbl/d) would be indicative of a 65 million to 75 million barrel field. He furthered that the costs associated with the new development analysis were substantially higher than the costs in the existing producer analysis. The new development analysis examined new developments that were away from existing infrastructure and did not include activities like infill drilling.

Mr. Kepes shared that the next four slides simulated the existing producer and new development scenarios for the Alaska's Clear Equitable Share (ACES) and the Petroleum Production Tax's (PPT) tax regimes, both as proposed and as enacted.

Mr. Kepes explained the slide on page 14 titled "PPT as originally proposed (existing producer)" and related that the slide showed an analysis of PPT as it was originally proposed. He discussed the graph on the top left hand corner of the slide and stated that it was based on an existing producer that was producing 200,000 bbl/d. The

black line represented the "after tax cash flow." He referenced the table in the upper middle portion of the slide and stated that "PPT as originally proposed" had a net present value (NPV) of just over $20 billion at an oil price of $100 per barrel. He observed that the larger table to the right showed that the government take reached about 60 percent through the intermediate price ranges. He reiterated that the slide examined PPT as originally proposed, under the existing producer scenario.

Mr. Kepes discussed the slide on page 15 titled "PPT as enacted (existing producer)" and stated that it showed an analysis of PPT as it was enacted, under the same producing scenario as the previous slide. He switched back and forward between slides 14 and 15. He noted that under "PPT as enacted", the government take was 72 percent to 74 percent compared to the 60 percent government take figure from slide 14. He related that the NPV on slide 15 was approximately $17 billion and that it had decreased by about $3 billion over the lifetime of the field in comparison to the NPV on slide 14. He concluded that there could be differences in how a fiscal system was proposed and how it was enacted.

9:36:08 AM

Mr. Kepes explained the slide on page 16 titled "ACES as proposed (existing producer)" and stated that it showed an analysis of ACES as it was proposed, under the same producing scenarios as the two previous slides. "ACES as proposed" generated a NPV of $6.6 billion and had a government take ranging from 68 percent to 74 percent.

Mr. Kepes discussed the slide on page 17 titled "ACES as enacted (existing producer)" and stated that it showed an analysis of ACES as it was enacted, under the same producing scenarios as the three previous slides. "ACES as enacted" had government take of 75 percent to 83 percent and a NPV of about $4.5 billion; the NPV had declined by about $1.5 billion from the NPV in the previous slide.

Mr. Kepes explained the slide on page 18 titled "limitations on price upside: a probabilistic approach." He stated that the slide showed PPT as proposed, PPT as enacted, ACES as proposed, and ACES as enacted for existing base production, under the same producing scenarios as the four previous slides. He stated that ACES as enacted was

represented by the dark blue line and related that it was a progressive tax regime. The red bar graph on the bottom of the slide forecasted the probability of oil prices being within $30 per barrel to $230 per barrel over the lifetime of the field. He observed that PPT as originally proposed, which was represented by the dark yellow line, was neutral in terms of progressivity. He stated that changes to PPT and subsequent changes to ACES had generated more progressive tax regimes, which had a higher government take at higher oil prices.

9:38:41 AM

Co-Chair Stedman asked for a definition of "EV". Mr. Kepes replied that EV was the expected value of all future cash flows for the listed projects, under the listed producing scenarios. He further explained that the EV would be reflective of all aggregated cash flows that were generated over a 30 year period.

Co-Chair Stedman observed that the EV for PPT as proposed was $22.862 billion and that the EV for ACES as enacted was $14.988 billion; he noted the difference between the two figures and inquired where the missing funds were going. Mr. Kepes replied that the money went to the State of Alaska and the federal government and clarified that the EV on the slide represented the values for the investing consortium.

9:40:08 AM

Mr. Kepes discussed the slide on page 19 titled "limitations on price upside: a probabilistic approach." He explained that the previous slide was based on an existing producer that was producing 200,000 bbl/d; however, slide 19 represented a new development, which was producing 10,000 bbl/d in a 65 million to 75 million barrel field. He noted that a new development would have higher associated costs and reiterated that the EV was reflective of the values to the investment consortium. Under this scenario, PPT as proposed would generate an EV of $236 million in comparison to the $12 million EV that would be generated by ACES as enacted. He stated that a higher government take was occurring at higher oil prices because of the progressivity of the ACES fiscal regime; furthermore, a new development existed in a "much higher" cost environment.

Mr. Kepes explained the slide on page 20 titled "ACES impact on oil-price upside, and on high cost development economics." The slide examined how ACES impacted the upside to high oil prices, particularly regarding high cost development economics. He reiterated that Alaska was a high cost environment. He referenced the overall cost increases to the industry at large and offered that it was appropriate to look specifically at the high cost development economics regarding new development production scenarios. He noted that a new development was based on a production level of 10,000 bbl/d in a 65 million to 70[75] million barrel field. Under this scenario, a new development in the ACES regime, which was reflected by the dark yellow line, achieved a positive NPV at an oil price of $100 per barrel; a project like this would presumably not be pursued when the price was under $100 per barrel because the conditions made it uneconomic. He pointed out that the profitability of base production under ACES, which was reflected by the dark red line, was much higher than the profitability of a new development under ACES. He pointed out that the dotted blue and green lines showed a representation of possible changes to the ACES progressivity structure and that the two lines showed the high impact of the changes to the project economics of a high cost investment scenario. He concluded that under ACES, the base production on the North Slope was attractive and profitable, but that there was an issue of higher costs in new developments.

9:44:43 AM

Mr. Kepes related that the next section of slides examined the global competitiveness of ACES and offered that the state needed to be aware that the market for E&P investment dollars was global.

Mr. Kepes discussed the slide on page 22 titled "regime competitiveness: average government take." He stated that slides 22 through slide 25 showed the average and marginal government takes at an oil price of $100 per barrel and $140 per barrel of oil.

Co-Chair Stedman asked for a brief explanation of where PFC Energy had received the data for slide 22. He explained that there were similar presentations, which used data that did not include production tax. He pointed out the importance of knowing what information was in the slides

and where the data had come from. Mr. Kepes replied that the data came from PFC Energy's global databases, which PFC Energy had been constructing for over 25 years. He stated that PFC Energy's slides differed from other presentations the committee had seen, both in the specificity of the fiscal structures and the specificity of the opportunity sets in the localities in question. He further explained that a similar analysis might use a generic size field to calculate the returns or government takes in 60 different government jurisdictions. He offered that an analysis that applied a generic, 100 million barrel field in a fiscal system and region like New Zealand, where the field size was closer to 10 million barrels, did not generate useful comparative knowledge. He concluded that PFC Energy's analysis used field sizes that were specific to the target locations; furthermore, the fiscal system estimates were inclusive of property taxes, costs, and other parts of the government take structure that were particular to that jurisdiction.

Co-Chair Stedman stated that there had been confusion during previous presentations regarding the inclusion or exclusion of private royalties in calculations and asked for a clarification regarding how PFC Energy calculated royalties. Mr. Kepes responded that in all cases, PFC Energy included royalties in its calculations. Even when a royalty accrued to private land owners, PFC Energy considered it part of the government take because the royalty was not available to the investment consortium. He pointed out that in most of the world, very little oil and gas production was taking place on private land and that the onshore Lower 48 was unique in that respect; 97 percent of shale play production activity in the U.S. was on privately held land. He concluded that the matter of private royalties was a "big issue", but that it mostly applied to the onshore Lower 48.

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Mr. Kepes continued to discuss slide 22 and stated that it showed the costs, field sizes, and fiscal tax structures that were specific to the localities; the slides did not input generic field sizes or generic costs. He offered that PFC Energy's method gave a better measure of what actually occurred in the jurisdictions. He pointed out that the Organisation for Economic Co-operation and Development (OECD) countries were labeled in yellow. He noted that OECD

countries generally had a lower government take, while non-OECD countries tended to have a higher government take. He commented that oil and gas tax policies differed in design; some policies were designed to generate revenues for a government, while some were structured to provide energy "feedstocks" for an economy.

Mr. Kepes continued to speak to slide 22 and stated that it showed, at a price of $100 per barrel, the government take of the ACES Alaskan new development and existing producer scenarios relative to other tax regimes around the world. He added that the field sizes and production levels for the specific Alaskan scenarios were as outlined in previous slides.

9:52:17 AM

Co-Chair Stedman pointed out that there had previously been work done that compared Alaska to other tax regimes and mentioned in particular a comparison to the North Sea. He observed that at an oil price of $100 per barrel, Norway had a slightly higher government take than the Alaskan existing producer scenario, but that the two regions were pretty close in that respect. Mr. Kepes replied that Co-Chair Stedman was correct and that Norway was directly in the middle in terms of government take relative to the Alaskan existing producer and new development scenarios.

Co-Chair Stedman furthered that there had been prior testimony indicating that the government take for existing production should range from 70 percent to 75 percent, and pointed out that the existing producer scenario on slide 22 was at government take of 73 percent. Mr. Kepes commented that Norway was a standout in comparison to other OECD countries because it had two national oil companies that held equity stakes in oil and gas production and that as a result, Norway was generating additional income via the national oil companies. He added that the revenue generated via Norway's nationally owned oil companies was not included with the government take on slide 22. He pointed out that there were other factors at play that were not reflected in the slide and that aspects such as competiveness, the number of operating investors, or the participation of nationally owned companies were not represented.

Co-Chair Hoffman queried why the slide did not show the existing producer and new development scenarios for other countries, such as Norway. Mr. Kepes responded that PFC Energy had the requested data and could provide it in the future.

9:55:26 AM

Co-Chair Stedman requested that PFC Energy provide the committee with a slide that reflected existing production scenarios and another slide that showed new development scenarios. Mr. Kepes responded that PFC Energy could run the separate slides based on 200,000 bbl/d and 10,000 bbl/d of production, but that the information generated might not be very applicable. He related that in some cases, within specific localities, there were no 200,000 bbl/d fields; in other instances, a 10,000 bbl/d field would not be economic. He stated that in the case of the Norwegian operating environment, a 10,000 bbl/d field would not be economic as a stand-alone development. He offered that using the exact same field sizes as the Alaskan scenarios would generate a less applicable analysis. He concluded that PFC Energy could design a specific analysis that was appropriate to the localities, which would more closely reflect the reality on the ground. Co-Chair Stedman observed that the committee wanted the information that was presented to be "as reality based as possible."

Co-Chair Stedman asked for an explanation of how PFC Energy factored in very small oil wells, such as stripper wells in Texas. Mr. Kepes replied that the U.S. probably had the most complex sets of applicable tax regimes due to the nexus between private, federal, and state lands. He added that regarding stripper wells, fiscal terms on private lands were often were more stringent for investors than the terms on public lands. He noted that King Ranch, Texas consisted entirely of privately held land and that the region might have a government take in excess of 50 percent or 60 percent. He concluded that typically, fiscal terms on private lands were higher than the terms on federal or state lands.

9:59:00 AM

Senator Egan asked how a small well for an Alaska existing producer would compare to the other localities on the slide. Mr. Kepes referred back to slide 20 and replied that

a small well in Alaska would probably be in the form of an infill well, which was tied to existing infrastructure and was not a stand-alone development. He furthered that a smaller well in Alaska could also be in the form of an older well that was reentered or reconstructed. He explained that some of the original producing wells were 35 to 40 years old and that the producers sometimes reused these wells with "coiled tube" drilling rigs, which had a lower operating cost; He added that for an Alaska existing producer, these types of projects were relatively profitable and would generate a government take of around 70 percent as implied on the slide's dark red line.

Mr. Kepes continued to speak to slide 20 and pointed out that investing in existing production, infill drilling, and replacing old wells were very profitable activities for companies. He concluded that under ACES, investing in existing infrastructure was "quite profitable", but that the challenge was the higher cost of new production in Alaska.

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Mr. Kepes explained the slide on page 23 titled "regime competiveness: average government take." He stated that the slide examined the average government take of different regimes at $140 per barrel. He related that under this analysis, both the ACES new development and ACES existing producer scenarios had gone up in government take relative to the other regimes on the slide. He observed that both of the ACES scenarios had a higher government take than Norway on the slide.

Mr. Kepes discussed the slide on page 24 titled "regime competitiveness: marginal government take." He related that slide showed the marginal government take, which examined the difference in government or investor take when the price of oil increased $1 per barrel. On a marginal take basis and an oil price of $100 per barrel, the ACES new development and ACES existing producer scenarios were even

higher [when compared to the average government take], relative to the other jurisdictions on the slide.

Co-Chair Stedman referenced comments that were made in a prior presentation, which had indicated that Argentina had a 100 percent marginal government take at an oil price of $60 per barrel or over. He requested Mr. Kepes to comment on Argentina and inquired why companies would invest there. Mr. Kepes replied that as a result of export tariffs and other more complicated factors, Argentina had created an environment where very little investment was occurring. He explained that the 100 percent marginal government take in Argentina maximized efficiency from a government take perspective, but that it resulted in a non-competitive environment with "almost no investment." He noted that there were political battles currently occurring in Argentina over the issue of its high marginal government take.

10:11:14 AM

JANAK MAYER, MANAGER, UPSTREAM & GAS, PFC ENERGY, WASHINGTON, D.C. (via teleconference), stated that a particular aspect of Argentina's tax structure that was peculiar to the country was its export tax; the tax limited exported oil to a specific maximum price level. He concluded that investing in Argentina's export tax regime was "very undesirable" and noted that there had been a corresponding impact on investment levels in the country.

Co-Chair Stedman observed that there seemed to be a relationship between the prospectivity of regional basins and how jurisdictions' tax structures were organized. He noted that Ireland was at the bottom of slide 24 and inquired how much oil Ireland had. Mr. Kepes responded that Ireland did not have "much oil" and explained that prospectivity was not well represented on the slide. He stated that generally, the lower government take systems existed in jurisdictions where prospectivity was low. He explained that governments with low prospectivity oil basins had to offer "some of the best fiscal terms available to investors on the planet" in order to attract more investment. He stated that there had been no commercial production to date in Greenland's frontier play. He pointed out that in Greenland, despite the high cost environment, a single company had been attracted to the very low government take and had drilled seven "dry holes"

offshore. [dry hole: An exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well]

Mr. Kepes concluded that generally, higher government take regimes had substantial known reserves or high prospectivity; at a minimum, higher government take systems had known or existing commercial production.

Mr. Kepes discussed the slide on page 25 titled "regime competitiveness: marginal government take" and stated that it showed the marginal government take of the global fiscal regimes at a price of $140 per barrel of oil.

Co-Chair Stedman noted that there had been claims that Alaska's government take was the highest in the world and inquired if that was true. Mr. Kepes responded that Alaska did not have the world's highest government take and that Turkmenistan had the highest government take on slide 25.

10:15:47 AM

Mr. Kepes stated that slides 26 and 27 examined another way of looking at progressivity and that the slides showed the marginal government take minus the average government take for the same regimes that were in previous slides.

Mr. Kepes explained the slide on page 26 titled "benchmarking progressivity for a range of global regimes." He noted that at an oil price of $100 per barrel, Columbia was at the top of the slide and was a highly progressive regime in terms of the impact of higher prices on government take. He pointed out that the ACES existing producer scenario was just underneath Columbia on the slide.

Co-Chair Stedman queried if the regimes on the bottom half of the slide were regressive systems, in which the government takes went down as prices went up. Mr. Kepes responded in the affirmative and added that in a regressive system as oil prices went up, a larger proportion of the divisible income when to the investor.

10:17:08 AM

Co-Chair Stedman asked if the state could manipulate the upper part of the graph by changing the base tax rate and the slope. He further inquired if decreasing the state's progressivity, increasing its base tax rate, and keeping its cash flow the same would "shorten those bars" and drive the progressivity closer to zero. Mr. Kepes replied in the affirmative and offered that Janak Mayer might have comments to add.

Co-Chair Stedman asked if Mr. Mayer had any comments on slide 26. Mr. Mayer replied that Columbia was a progressive regime, but that it was progressive on a much lower base rate of government take. He referenced previous slides, in which Columbia was in the bottom half of global fiscal regimes in terms of government take. He offered that just looking at progressivity was only one part of the equation and that progressivity in relation to the basic level of government take was a critical factor to examine. He concluded that in contrast to OECD countries, Alaska's regime had a relatively high government take and had a significant progressivity feature.

Co-Chair Hoffman stated that the committee was trying to encourage new development and new oil in the pipeline. He noted that there was a large cost spread between new developments and existing producers under ACES and queried if the same disparity between the two scenarios existed in other oil producing countries.

Co-Chair Stedman asked PFC Energy to include the requested information in future slides that it was preparing for the committee.

Mr. Mayer stated that the disparity in costs between existing developments and new production was particularly important for Alaska due of the impact of the deductibility of capital expenses and the production tax credit. He clarified that a new producer had no prior production and that as a result, new developments did not have a production base against which to write-off capital credits or net operating loss credits. He offered that the inability to use the deductions was the principle reason why the government take was significantly higher in Alaska's new developments than with existing production. He added that the difference in progressivity between new and existing producers was a result of the actual government

take being higher for new developments, while marginal rates stayed the same for both new and existing producers.

10:20:52 AM

Mr. Kepes spoke to the slide on page 27 titled "benchmarking progressivity for a range of global regimes" and stated that it showed the same analysis as the previous slide, but at an oil price of $140 per barrel; under this analysis, Turkmenistan had the highest progressivity. He pointed out that a "big take away" from slides 26 and 27 was that all of the Lower 48 regimes were regressive regimes and that when the price of oil went up, more of the divisible income in the Lower 48 went to the investor consortium.

Co-Chair Stedman commented that Alaska differed from other jurisdictions in its land ownership and tax structure. He furthered that it was his understanding that that most of North America had a tax and royalty system, while Alaska had a hybrid system of tax and royalty, plus a concession system. Mr. Kepes responded that Co-Chair Stedman was correct.

Co-Chair Stedman requested a clarification of the differences in land ownership and tax structure between Alaska and the Lower 48.

Mr. Kepes stated that 97 percent of the shale play activities in the Lower 48 were on privately held land and that each of the private land holdings could have a different fiscal structure. He pointed out that private land owners did not offer capital credits and did not incentivize companies to make large investments. Many of the investments were incremental for smaller, privately held tracks; investments under this scenario might be spread out over a large area of land, a long period of time, and involve multiple land owners. He explained that Alaska had a concession system, while the Lower 48 had leases that were conditional and had a shorter time frame. He stated that lease holds in the Lower 48 had conditional language, which specified that investment had to take place within a certain period of time or the lease would revert back to the land owner; relinquishment provisions were in place to insure asset liquidity and require companies to invest. He concluded that the nature of the duration of lease hold agreements in the Lower 48 were different than

the concession agreements in Alaska. He noted that the size of the leases in the Lower 48 were usually smaller than the leases in Alaska. He explained that in the case of Louisiana's private land holdings, there might be hundreds on land owners involved in a play that was similar in size to the "footprint for the North Slope."

Mr. Kepes addressed the slide on page 28 titled "ACES - effective as a harvest area fiscal regime."

- ACES appears to work well as a “harvest” regime
    - Existing mature fields remain profitable, including capital work required to achieve ~6% decline (renewal capex)
    - Maximum ‘rent’ extracted from a declining production base is captured for the state
- ACES inhibits the development of new projects and resources that might help stem or even reverse the decline
    - ACES is not progressive with regard to costs, so high government take applies even to very high cost projects
    - Existing system of capital credits etc appears to do more to encourage ‘renewal capex’ than it does new production spending
    - Progressivity can have a major detrimental impact on breakeven prices for high-cost projects at current oil prices

10:26:19 AM

Senator Thomas noted that the production decline had been in place prior to ACES being enacted, but that ACES had been blamed for the lack of investment. He observed that prior to ACES, concerns had already been raised over the age and constraints of the facilities in Prudhoe Bay, "as well as the pipeline situation that has arisen." He furthered that the industry might have been looking at projects that were aimed at reversing the decline around

the same that ACES was enacted and inquired whether ACES had unfortunate timing. Mr. Kepes replied that he was not in a position to comment on the political process at the time. He offered that the natural rate of production decline on the North Slope was roughly 15 percent a year and that quite a bit of capital was spent to maintain a 6 percent rate. A lot of capital was going towards replacing old infrastructure, some of which was over 30 years old. He furthered that significant capital was being used for things that did not generate new production, but that maintained the decline rate. He stated that the question was whether Alaska wanted to increase production above a 6 percent rate of decline.

Mr. Kepes responded to Senator Thomas' second question and stated that there was a timing issue involved. He pointed out that much of the capital equipment on the North Slope was 35 years old and needed to be replaced. He stated that another timing aspect was the age of the North Slope Basin; as the basin ages, the opportunities in the field become higher cost and more limited. He furthered that improvements in production technology and maturing resources had resulted in a different investment picture for Alaska. He pointed out that the investment opportunities had also changed throughout the world and that there was a "massive shift of capital" from West Africa and Alaska to the Lower 48. He offered that the shift in capital was a "driver" that was not present 10 years ago. He concluded that timing was an issue and that he "would not conclude that ACES was responsible for everything." He offered that ACES was a very appropriate regime for an area in harvest mode. He observed that under ACES, the government was getting a higher percentage for every barrel that was being produced and that the industry was making profit on existing production. He added that without respect to the long-term impacts of the production decline, ACES was working for the state and remained profitable for industry. He stated that ACES worked well in a harvest area situation. He offered that the question facing the state was whether it wanted a different result and how the system could be changed to encourage growth.

10:34:13 AM

Co-Chair Stedman related that he had directed the Legislative Finance Division to prepare historical data of Alaska's oil basin for PFC Energy and that there would be a

presentation in the committee based on the data; the presentation would determine the value of the basin, the funds that had gone to the state from the basin, as well as a rough calculation of what the government share had been. He furthered that in the future, there would also be a presentation that would parcel out the current production; the presentation would show the increment that was being spent to keep the North Slope's natural decline rate of 15 percent at the current rate of 6 percent and would identify, relative to current production, what was needed to move the decline rate to minus one percent, zero percent, or plus one percent. He pointed out that there would be a discussion on policy after the committee had seen the two presentations. He noted that the current presentation was "laying the foundation" and that the committee would look at the subject matter in greater detail at a later date.

Co-Chair Hoffman referenced the bullet point on the lower half of slide 28 and inquired if Mr. Kepes had any recommendations to address ACES' inhibitions on developing new projects. He queried if there should be a different tax structure for new projects. Mr. Kepes replied that the different ways to approach the issue were laid out in later slides, but that PFC Energy had not made a specific recommendation yet.

10:37:23 AM

Co-Chair Stedman pointed out that he had provided PFC Energy with the packet on the "tax holiday", which Senator Wagoner had worked on in the Senate Resources Committee. He noted that PFC Energy was currently working on incorporating the tax holiday document and the "$10 allowance", which was in the current version of SB 192, into future models. He furthered that the substance of the current bill, options from committee members, options from the Senate Resources Committee, and new ideas from PFC Energy would all be considered. He concluded that the committee would be open for concept discussions and that the discussions would be "a subject in and of itself" in hearings.

Mr. Kepes observed that PFC Energy had not yet completed its analysis on the "gross minimum tax", but that it had completed its analysis on the "$10 dollar, new oil allowance." Co-Chair Stedman stated that the "floor"[in

reference to the gross minimum tax] subject matter was in flux, and that changes within the system had a corresponding impact on the floor. He offered that the floor would probably be one of the last items that the committee would work on.

Mr. Kepes continued to speak to slide 28. He stated that the slide depicted the ACES base production in the dark red and the ACES new developments in the dark yellow. The slide compared the progressivity in ACES to progressivity of a neutral and a regressive regime.

- ACES appears to work well as a “harvest” regime
    - Existing mature fields remain profitable, including capital work required to achieve ~6% decline (renewal capex)
    - Maximum ‘rent’ extracted from a declining production base is captured for the state
- ACES inhibits the development of new projects and resources that might help stem or even reverse the decline
    - ACES is not progressive with regard to costs, so high government take applies even to very high cost projects
    - Existing system of capital credits etc appears to do more to encourage ‘renewal capex’ than it does new production spending
    - Progressivity can have a major detrimental impact on breakeven prices for high-cost projects at current oil prices

Mr. Kepes noted that the dark yellow line suggested that a new development under ACES, which was based on 10,000 barrels per day of production in a 65 million barrel field, broke even at $100 per barrel.

10:43:38 AM

Mr. Kepes discussed the slide on page 29 titled "options to spur new developments." He stated that PFC Energy had laid out three broad approaches to encourage new developments, under the assumption that ACES had challenges regarding higher cost, new developments. He observed that each approach had its advantages and disadvantages.

- Approach: Uniform lowering of Government Take
    - Implementation Options: Bracketing, Reduced base rate, Increased progressivity thresholds, Reduced progressivity rates, and Progressivity caps
    - Advantages: Does not require increased complexity of the fiscal structure, May not present opportunities for simplification
    - Disadvantages: Incentivizing new high cost resources through this method alone requires giving substantial "rent" back to producers on the mature producing assets
- Approach: differentiation between old and new production
    - Implementation Options: Allowance for new oil, Switching in part away from net profits taxation to gross revenue taxation to enable different tax rates for different production streams without separate cost accounting and tax returns, and the use of some combination of definitions for incremental production above the base decline rate(regulator-agreed new programs and new areas)
    - Advantages: Allows significant reductions in government take on new and costlier developments (including heavy oil etc.) without requiring significant reductions on mature and producing assets

- Disadvantages: Administrative difficulties around definitions of "new production"

- Approach: enhancements to cost progressivity of ACES
  - Implementation Options: Changes to allowable cost deduction or credits mechanism etc. to provide greater "uplift" for high capital and operating costs while restricting negative production tax in marginal cases, Enhancement to royalty relief
  - Advantages: Does not require structural changes away from ACES
  - Disadvantages: Increases already high complexity and opacity, May exacerbate problem of poor cost control incentives, Increases likelihood of unintended consequences, Likely less significant impact than new production differentiation.

Mr. Kepes discussed the advantages of the first approach on the slide and related that more complex fiscal structures are not generally to the advantage of governments. He furthered that it was PFC Energy's global experience that companies invested what was needed in order to understand the complexity of the fiscal terms that existed. He explained that a company generally had a better capacity to understand and manage its side of a complex fiscal regime than the government had capacity to administer the system. He shared that enhancements to royalty relief, which was an option under the third approach, could be granted on an "investment by investment basis" for higher cost developments.

10:49:34 AM

Co-Chair Stedman requested a definition of "uplift." Mr. Kepes responded that uplift was often part of a cost recovery or credits mechanism and explained that it meant that a company received a higher credit realized for each

$1 of capital that was spent. He offered that if a company spent $2 billion, an uplift mechanism on costs might be that for every $1 spent, the company received tax credits or advantages that were worth $1.20; the 20 cents on the dollar is a uplift. He stated that there were cost or capital uplifts in other fiscal environments and that the uplifts were usually part of production sharing mechanisms.

Mr. Mayer added that uplift gave credits, such as the capital credits under ACES, as a mechanism for making a fiscal regime more progressive with regards to costs.

Mr. Kepes continued to speak to slide 29. He discussed the second disadvantage of the third approach and clarified that an entity was not getting the targeted impact of granting credits if it was unsure what the credits would be used for. He spoke to the third disadvantage of the third approach and related that it was not good to have a system that rewarded high cost operators or operators who may not be as focused on cost control as others; a system like this could result in investments being made that might not have occurred otherwise.

10:53:54 AM

Senator McGuire requested that amendment B.7, which was from the Senate Recourses Committee, be included the next time PFC Energy presented models to the committee. She specified that the amendment would make the HB 110 approach of bracketing and reducing the progressivity rate apply only to new production. She requested advice from PFC Energy on how to define new production.

Co-Chair Stedman stated that PFC Energy was going to do an analysis on progressivity and that bracketing would be a discussion item. He referenced that there were at least two amendments in the Senate Resources Committee and that there were a number of ways to approach bracketing. He noted that future presentations would examine the effects of slope changes, base tax adjustments, and triggers. He furthered that the presentations would not be in the direction of the bill in front of the committee, but that the committee would look at all of the options. He offered that presentations might cover something that was already in the bill, something that was changed, or might be a whole new concept. He added that he had already met with PFC Energy regarding the direction of future discussions and that "at

the end of the day," the state needed to make sure it was counting its net cash flow. He referenced earlier comments regarding the producers' high level of sophistication and related the importance of the state understanding its own fiscal regime.

10:56:23 AM

Senator Thomas asked for a clarification on slide 28. He referenced the "renewal capex" on the slide and the increased exploration activity that was currently occurring on the North Slope. He queried what the likelihood was of a sophisticated oil company making significant investments, without understanding the existing tax system in Alaska. Mr. Kepes requested a clarification of the question.

Senator Thomas inquired why Alaska would see increased activity from companies that had opportunities elsewhere around the world. He furthered that some companies had claimed that they did not fully understand Alaska's tax system at the time, but that companies had still purchased or leased large tracks of land and had made significant investments; he inquired if this scenario seemed likely. Mr. Kepes offered that there were one or two cases where companies were not fully aware of the commercial arrangements that were required to commercially develop reserves, at the time they took the exploration licenses. He opined that the exploration tax credits and incentives for exploration within ACES make it "appear to be a reasonably attractive proposition." He stated that the comments on slide 28 were not offered with respect to the exploration activities that Senator Thomas was referring to. He noted that companies had been attracted to the incentives for exploration activity under ACES. He observed that if an explorer made a 65 million barrel discovery, the challenge to the company became how it would tie that production into existing infrastructure and what commercial arrangements needed to be made with the existing operator of the evacuation infrastructure; furthermore, commercial arrangements like this could be an unknown in terms of costs and could be less attractive than more apparent aspects. He furthered that it could be difficult to calculate commercial development costs during an initial exploration decision and offered that these unknown costs could change a 65 million barrel success into a sub-marginal economic investment. He pointed out that the major and independent oil companies had different investment

criteria and that they might take different types risks. He offered that it was possible that a company would invest in a project that offered a lower return because it believed that subsequent opportunities would be more profitable. He concluded that a company not understanding what it was getting into can and does happen. However, in reference to the situation that Senator Thomas had inquired about, he opined that the companies had less of an understanding of what it took to be commercial success versus an exploration success because of the "access to infrastructure issue."

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

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ADJOURNMENT

11:02:32 AM

The meeting was adjourned at 11:02 AM.