

**MINUTES**  
**SENATE FINANCE COMMITTEE**  
**April 10, 2006**  
**9:03 a.m.**

**CALL TO ORDER**

Co-Chair Lyda Green convened the meeting at approximately [9:03:13 AM](#).

**PRESENT**

Senator Lyda Green, Co-Chair  
Senator Gary Wilken, Co-Chair  
Senator Fred Dyson  
Senator Bert Stedman  
Senator Lyman Hoffman  
Senator Donny Olson

**Also Attending:** SENATOR BEN STEVENS; SENATOR GARY STEVENS; SENATOR TOM WAGONER; MARIANNE KAH, Chief Economist, ConocoPhillips; ANGUS J. WALKER, Vice President, Commercial, British Petroleum Exploration Inc. Alaska; DAN DICKINSON, CPA, former Director of the Tax Division, secured as a consultant by the Office of the Governor; DAVID BRAMLEY, Vice President, Charles River Associates International Consultants; JOHN ZAGER, General Manager, Chevron/Alaska; MARK HANLEY, Public Affairs Manager, Anadarko Petroleum Corporation/Alaska; DANIEL JOHNSTON, Consultant to the Legislative; JOHN BARNES, Production Manager, Marathon Oil Company

**Attending via Teleconference:** From an Offnet Location: ANTHONY FINIZZA, Analyst, Econ One Research Inc.

**SUMMARY INFORMATION**

SB 305-OIL AND GAS PRODUCTION TAX

The Committee hosted a question and answer panel discussion consisting of oil and gas industry representatives and economic consultants. The bill was held in Committee.

#sb305

CS FOR SENATE BILL NO. 305(RES)

"An Act providing for a production tax on oil and gas; repealing the oil and gas production (severance) tax; relating to the calculation of the gross value at the point of production of oil or gas and to the determination of the value of oil and gas for purposes of the production tax on oil and gas; providing for tax credits against the tax for certain expenditures and losses; relating to the relationship of the production tax on oil and gas to other taxes, to the dates those tax payments and surcharges are due, to interest on overpayments of the tax, and to the treatment of the tax in a producer's settlement with the royalty owners; relating to flared gas, and to oil and gas used in the operation of a lease or property under the production tax; relating to the prevailing value of oil or gas under the production tax; relating to surcharges on oil; relating to statements or other information required to be filed with or furnished to the Department of Revenue, to the penalty for failure to file certain reports for the tax, to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue as applicable to the administration of the tax; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the tax, and to the deposit of tax money collected by the Department of Revenue; amending the definitions of 'gas,' 'oil,' and certain other terms for purposes of the production tax, and as the definition of the term 'gas' applies in the Alaska Stranded Gas Development Act, and adding further definitions; making conforming amendments; and providing for an effective date."

This was the ninth hearing for this bill in the Senate Finance Committee.

[9:04:03 AM](#)

Co-Chair Green communicated that the purpose of today's hearing was to conduct a question and answer session regarding the proposed Petroleum Profits Tax (PPT) legislation. A listing of 17 issues was distributed [copy on file]. The question and answer panel consisted of representatives of ConocoPhillips,

Chevron, British Petroleum, Anadarko Petroleum Corporation, Marathon Oil, and industry and State economic consultants.

Co-Chair Green communicated that the panelists would not be required to individually respond to each question. Instead the goal was to glean "new ideas" and/or determine areas of agreement.

Issue 1. The impact on exploration, investment and production at various proposed tax rates and credit rates (15% - 30%). Discuss the relationship between tax and credit to identify the best balance.

Co-Chair Green identified the percentage levels of the severance tax and credit rates and their affect on exploration, investment and production in the State as being the most important component of the PPT legislation.

MARIANNE KAH, Chief Economist, ConocoPhillips, agreed that the tax rate was the most important component of the bill. The adoption of an inappropriate PPT tax rate might jeopardize a company's growth plans. Companies have voiced their concerns in this respect. To that point, she "resented" the Fairbanks Daily News Miner newspaper's portrayal that ConocoPhillips was utilizing "terrorist tactics" in this regard as the company was "legitimately concerned". The company, which has operated in the State for more than 50 years, was the leading resource investor in the State. The PPT tax rate level could either incentivize or disincentivize investment.

Ms. Kah stressed that the PPT tax rate must "be commensurate with the prospectivity and cost structure" of the State. The cost structure of resource fields in Russia could be comparable to Alaska because they too experienced arctic conditions. Even though Russia's tax structure was high, ConocoPhillips could afford to operate there due to the economic value provided by the immense field sizes. In addition, large resource companies like ConocoPhillips and British Petroleum (BP) "are buying into" private Russian companies because they had access to 16 percent of the world's oil resources. The prospectivity of the area and resource access are two reasons investments have occurred there. In contrast, Alaska's oil fields were smaller. "That would be fine, but the tax rate needs to be reflective of that."

Ms. Kah noted that ConocoPhillips recently resumed its Libyan operations "under the same terms" in place in 1986 when it was "forced to leave because of U.S. sanctions". That field contained 25 percent of the country's oil production. Libya has a huge amount of known and undiscovered resources. For that reason, ConocoPhillips was a participant "in these big rounds that are coming out with really fairly outrageous tax terms".

Ms. Kah cited there being "a lot of exuberance in our markets now: exuberance by investors who are willing to bid away all their profits; exuberance by government who are trying to tax away profits". This was worrisome as it was "making it impossible for serious long term investors to invest in this business on a sustained basis".

Ms. Kah noted that while ConocoPhillips wanted to continue investing in the State, the 20 percent tax rate and 20 percent credit (20/20) provisions included in SB 305, the original version of the PPT as proposed by Governor Frank Murkowski, "was something that we really had to swallow hard to agree to". The State's current Economic Limit Factor (ELF) severance tax regime would equate to a 15 percent tax rate under a progressive tax regime structure. The company agreed to the 20 percent tax rate in SB 305 because of their desire to further the separately proposed North Slope gas pipeline project.

ANGUS J. WALKER, Vice President, Commercial, British Petroleum Exploration Inc. Alaska, presented BP's perspective on the resource situation in the State. Production was declining at an annual rate of six percent. In ten years, North Slope production would be approximately 450,000 barrels per day, were current investment levels maintained. This forecast also depended on "the big assumption" that the proposed PPT would not be detrimental to investments in the State.

Mr. Walker pointed out, however, that in order to allow the proposed North Slope gas pipeline to become sustainable, the State was actually seeking to "extend the life of its oil fields through the year 2050". BP estimated that, "in order to meet the Department of Revenue's (DOR) latest production forecast, investment in the North Slope" must double to approximately three billion dollars a year.

Mr. Walker communicated that "the lowest possible tax rate" would attract "the most possible investment". "A zero tax rate

would be best." A 15 percent tax with a 25 percent credit would be preferred to the 20/20 tax rate proposed in SB 305. The tax rate proposed in SB 305 would be preferred to either of the tax/credit rates proposed in the House or Senate PPT committee substitutes.

[9:11:18 AM](#)

DAN DICKINSON, CPA, former Director of the Tax Division, secured as a consultant by the Office of the Governor, appreciated Ms. Kah's determination that "the tax rate was probably one of the most important aspects" because he would like to emphasize the credit components proposed in the Senate committee substitute, CSSB 305(RES). [Note: CSSB 305(RES) is referred to as CSSB 305 in these minutes] While he and Mr. Walker might disagree with the numbers, "there is no question that to get the kind of volumes we all hope to see, significant investments are required in the State." For that reason, CSSB 305 would allow "a 20 percent credit for those investments as well as the allowance of a 20 percent deduction". Qualifying capital investments would be "underwritten by a 40 percent support by the State of Alaska". This is a "very very important feature" of the bill.

Mr. Dickinson pointed out that while the majority of the PPT discussion had focused on the tax rate, "the credit rate is equally as important".

Mr. Dickinson agreed with Mr. Walker's position that at \$60 barrel prices, "there's a distortion. We tend to look at prices as driving everything, but that's masking what's going on underneath. And underneath, at prices that are more ... historically expected, the credit looms as an ever more important part of that." The balance consideration must weight the tax rate with the credit rate. The credit provisions "would directly ... incentivize the investment".

[9:12:46 AM](#)

ANTHONY FINIZZA, Analyst, Econ One Research, Inc, an economic research and consulting firm hired by the Legislature, testified via teleconference from an offnet location. He reiterated Econ One's position that the PPT would incentivize new field exploration. Recent modeling calculations indicated that the discounted tax rate resulting from the application of the development credits in the PPT would not increase the government

take percentage significantly higher than that experienced under ELF. Neither the 20/20 tax/credit provisions included in SB 305 nor the 25/20 tax/credit provisions proposed in CSSB 305 "are in a range that would stifle significant investment".

[9:14:07 AM](#)

DAVID BRAMLEY, Vice President, Charles River Associates International (CRA), an independent resource consultant company under contract to BP, stressed that CRA was "not unmindful of the fact that our reputation is against what we say". "The question about investment and level of tax take is what economists would call a question of elasticity. That's where there is a disagreement of view about what is the impact of a change in tax take on investment."

Mr. Bramley voiced that CRA's analyses, which "are quite different" from some other consultants, were based on the "conventional economic theory" that, while "the oil business has its own peculiarity and its own complication, it was "fundamentally" like any other industry in that an increase in the level of tax would lower investment attractiveness, and thereby, decrease investment. Conversely, investment levels would increase were tax rates lowered. While the tax credits and deductions proposed in the PPT were important, the "net effect" of whether they would offset the higher tax take would influence decisions. Economic modeling analyses of the PPT thus far have indicated that the net effect would be to drive investments "downwards". Those who "contend" the PPT would not be detrimental to investment must substantiate their claim, as the laws of economics indicate otherwise.

Mr. Bramley observed that an analysis [copy not provided] developed by CRA presented an "illustrative number ... of what might happen if investment in the State of Alaska" declined by "a conservative estimate" of 20 percent as the result of SB 305.

Mr. Bramley reviewed some of the reasons CRA believed SB 305 would reduce investment in the State. While there had been much discussion on the "structural peculiarities of ELF" little focus has been given to the "level of overall tax take" levied under ELF.

[9:17:03 AM](#)

Mr. Bramley continued that, according to CRA's analysis, when the prospectivity and cost base of new investments in the State were compared "to a peer group of OEDC countries", Alaska "doesn't look attractive" even under the current ELF system. This, rather than the structural peculiarities of ELF, would be "the most powerful explanation of why present levels of investment in Alaska are low".

Mr. Bramley stated that information provided by ConocoPhillips would suggest that a 20 percent decline in investments might be a conservative number; specifically that the level of capital spent in the Kuparuk Unit over the last five years, increased as the severance tax rate there decreased. In contrast, both the investment and tax rates of Prudhoe Bay fields have remained flat. While he "wouldn't claim a direct elasticity relationship there", he would argue that the effect of the tax rates on investments in these two large fields would be a viable gauge of how investments in the State would be impacted by the net affect of the PPT. He concluded "that the impact of the new proposals would be more than a 20 percent reduction in investment".

[9:18:44 AM](#)

Mr. Bramley, an independent consultant, had worked with "governments and national oil companies as well as private oil companies". To that point, "the fundamentals of our analysis would not differ" were CRA to advise the Legislature rather than an oil company. While the PPT would increase taxes and thereby increase revenues to the State, investments in the State would be impacted. The level of that impact could be debated. He welcomed other's perspectives in this regard; however, those who claim the impact would be zero and that investments would remain constant or increase must prove their case.

[9:19:47 AM](#)

MARK HANLEY, Public Affairs Manager, Anadarko Petroleum Corporation/Alaska, would not disagree with the majority of the comments thus far. A PPT rate of 25/20 would be more detrimental than the 20/20 to his company, particularly in regards to exploration activities. Charts developed by Anadarko and Dr. Pedro van Meurs, a consultant to the Governor, indicated that a lower rate of return would be experienced under the 25/20 proposed in CSSB 305. Net present value (NPV) calculations indicated that the government take under either the 20/20 or

25/20 PPT proposals would be higher than that under ELF, as barrel prices increased. Even though activities become more economic as prices increase, the increase in government take under the 25/20 PPT would be substantial. He noted the argument that at lower barrel prices, the 25/20 would be better for exploration. In response, he stated that at prices ranging from \$20 to \$35, "generally at those low prices, we don't have prospects that are economic". As prices increase, prospects in Anadarko's portfolio would become more economic.

Mr. Hanley cautioned against increasing the tax rate without also adjusting credits, as, even though "it's not one to one", there "is some relationship there".

[9:22:57 AM](#)

JOHN ZAGER, General Manager, Chevron/Alaska noted that how the tax and credit relationship would impact a company would depend on where that company was in its business cycle. A large company with a relatively large percent of big production rather than exploration would be more interested in the affects of the tax rate. On the other hand, a company highly concentrated in exploration would benefit more from the credit component.

Mr. Zager exemplified the tax/credit rate relationship pertaining to a redevelopment program with good production potential Chevron was furthering in Cook Inlet. "In order to get the same net present value out of my combined business", an increase in the tax rate from 20 of 21 percent must be accompanied by a credit rate of 26 percent.

[9:24:00 AM](#)

DANIEL JOHNSTON, Consultant to the Alaska Legislature, declared that high oil prices was one of the primary reasons that changes in the State's tax regime were being discussed by the Legislature. While the PPT bills being furthered in the House and the Senate have been compared to the existing ELF tax regime, he opted to stop utilizing that comparison as the benchmark. "Once we saw that the producers were willing to agree to 20/20, as far as I'm concerned that's an appropriate benchmark." The Senate bill, with its 25/20 percent PPT rate "is the high side" of what is being proposed.

Mr. Johnston pointed out that increasing the tax structure from 20/20 to 25/20 would result in an overall government take increase of "two percentage points". That "is not a huge difference".

Mr. Johnston stressed that the State could not do much to counter the impact low prices would have on oil production in the State. Such things as royalty and severance tax holidays or an increase in credits would not alleviate the situation when prices were in the \$25 range. However, when prices increased to levels at which the economic modeling of prospects was considered "favorable" by the industry, "there's a whole lot of profit to be made by both the oil companies and the government".

[9:25:58 AM](#)

Mr. Johnston referenced Ms. Kah's remarks: there was "a whole lot of exuberance out there in the marketplace that she feels is inappropriate and that there are a lot of companies that are bidding too much, but I would submit that that's an acid test of the market place when you have licensed rounds in places like Libya and you see that kind of exuberance that drives those licensed rounds. Perhaps that is what the marketplace is trying to tell us, that there's justification for that exuberance." In his opinion, people "have been fairly conservative" in Alaska in respect to "their negotiations and their discussions and have used oil price forecasts and assumptions that compared to the world marketplace with its exuberance are fairly conservative". Were the State Legislature to make investment decisions "based on oil price forecasts that are substantially lower than what the marketplace perceives the future to be, then we are doing a disservice to Alaskans".

[9:26:59 AM](#)

JOHN BARNES, Production Manager, Marathon Oil Company, specified that his company's activities were limited to Cook Inlet, "a very old basin". Cook Inlet could be representative of "the marginal production" that would be occurring on the North Slope "in five or ten or 20 years".

Mr. Barnes communicated that Marathon "was not one of the producers" that had agreed that the 20/20 PPT provisions proposed in SB 305 "made sense"; particularly in Cook Inlet. The last time people anticipated \$50 to \$100 barrel oil prices,

their expectations had been incorrect and people were laid off. Thus, he urged the Committee to consider low price scenarios in their discussions. He agreed with Mr. Johnston that the impact of low prices was "difficult to fix". That should be a consideration, especially in regards to Cook Inlet. Other regions of the State might mirror Cook Inlet in the future.

Co-Chair Green noted that further discussion on Cook Inlet would occur when Issue 12 came before the panel, as Cook Inlet was the focus of that question.

[9:28:32 AM](#)

Mr. Walker informed that Committee that BP agreed to the 20/20 provisions proposed in SB 305 because "we, the producers, made an offer to the Administration of 12.5 percent tax rate with a 25 percent credit. 25 percent for exploration and challenged oil, and 15 percent for normal capital. The Administration's first offer was a 20 percent tax rate, ten percent credit. That is the operating range of the negotiations. At the end of the day, we agreed to 20 percent tax rate, 20 percent credit, along with all the other things that came with in that package including transition, start date, etc. We were at the end of our rope. We don't believe it's the best tax rate for Alaska, but we agreed to it. So why did we agree to something that we don't believe is the best tax rate for Alaska? We agreed to it as a means to moving ahead with gas. But we always said and we were very clear with the Administration that when we came to the Legislature, we would appeal to the Legislature and enter a debate and let the Legislature decide what the right tax rate for Alaska is."

[9:30:23 AM](#)

Mr. Bramley identified the "heart of the underlining issues in question one" as being that Alaska must compete in an "international marketplace, and in order to make meaningful comparisons" one must "understand the context in which those comparisons were made. People would be skeptical were people selling their house in Juneau for \$500,000 to say it was under priced because a similar house was for sale for one million dollars in New York. The "relevant question" for Alaska would be whether other areas in the international marketplace existed that had "similar prospectivity, similar cost bases, but higher tax rates and which are getting a good level of inward

investment". CRA's analyses of mature Organization for Economic Cooperation and Development (OECD) producing areas indicated there were no such areas. Even Alaska's existing ELF tax regime appeared "tough, specifically on new investments" in that analyses.

Co-Chair Wilken asked Mr. Walker to further explain BP's claim that production would decrease six percent annually, as the forecast on Chart 4.9, page 40 of the Department of Revenue's "Fall 2005 Revenue Forecast" book [copy not provided] estimated that production would decrease 1.5 percent over the next ten years. The lower of the three lines depicted on that chart represented the barrel forecast if existing wells continued to produce through 2016 and no new wells came online. The second line represented producing wells plus wells currently being developed. The third line presented the total of current producing wells, "those under development, and those under evaluation".

[9:34:01 AM](#)

Co-Chair Wilken understood the volume generated by the third scenario would decrease from approximately 900,000 barrels to 810,000 barrels by the year 2016. This would equate to a 0.9 percent per year reduction over the next ten years. The scenario depicting existing wells and wells under development would reflect a decrease from 900,000 barrels to 575,000 barrels in 2016; an annual decline of approximately 3.2 percent. The scenario solely depicting existing wells would reflect a decline from 900,000 to 400,000 barrels in 2016; an annual five percent decline. A five percent decline each year would therefore be the worst case scenario.

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Mr. Walker stated that Co-Chair Wilken had raised "a very important point". Were the industry to simply maintain surface facilities and halt other investments in the North Slope, existing North Slope field production "would decline at a rate of about 20 percent per year." Because the industry continuously conducted well work on existing stock in order "to optimize each well", it was able to "sustain the decline rate of existing fields to 15 percent per year". In addition, the industry continuously invested in capital projects on the North Slope, primarily in existing fields. Some investment has been made in

satellite fields. This allowed the industry to sustain an annual decline of approximately six percent.

Mr. Walker noted that because the industry was concerned about the differences between it's and Department of Revenue's (DOR) production decline projections, it requested a meeting to discuss the issue. The conclusion of that meeting, which was held last week, was that "the difference between our forecast and the DOR forecast is that their forecast will require significantly more capital to deliver it". All parties agreed that "the production on the North Slope was declining significantly" and that production would fall below 500,000 barrels a day in ten years based on the existing level of investment". It was also agreed that "significantly more capital" than what was currently being invested would be required to deliver DOR's forecast.

Mr. Walker stressed that any new tax regime being considered must be "designed to attract that capital as otherwise we will be declining at the existing rate or higher".

[9:38:14 AM](#)

Co-Chair Wilken understood therefore that were SB 305 adopted, fields that were currently "producing would continue to produce"; however, further investment in underdeveloped wells would be curtailed. This would cause production to decrease 3.25 percent per year, as depicted on the aforementioned chart.

[9:38:42 AM](#)

Mr. Walker noted that even though he did not have a copy of the chart being referenced, he was "familiar with the representation". The important thing to consider "is that a lot of the production that we will develop is in the existing fields. So it's not separate new accumulations that will be developed." In reality it would be "much more complicated" than simply looking at the numbers and "adding them up". The industry would make decisions "to invest in as many projects as we can" based on the economics as affected by whatever fiscal regime was adopted. The industry's belief was that "there's an opportunity to do more good business here in Alaska with the right fiscal regime".

Co-Chair Wilken appreciated the explanation.

9:39:50 AM

Co-Chair Wilken asked Mr. Finizza to explain the information depicted in the chart titled "Effective Average Tax Rates at various Price Levels Impact of Increased Investment (FY 2007 - 2016)" [copy on file] which was located on page 90 of Econ One's April 5, 2006 "Presentation on Alaska Gas Pipeline Project" to the House and Senate Finance Committees.

Co-Chair Green expressed that this question would be addressed once the chart had been distributed.

9:40:39 AM

Senator Olson declared that in the discussion "on the difference between development/exploration" and what effects the PPT legislation would have on production, a major factor was omitted. That being "the lack of emphasis" placed on the Arctic National Wildlife Refuge (ANWR) and National Petroleum Reserve-Alaska (NPR-A) areas. He questioned why such little emphasis was placed on these areas by either the State's consultants or the industry.

9:41:34 AM

Mr. Bramley communicated that BP had considered including the prospectivity in ANWR in their analysis. Were those areas to hold the resources acclaimed by the United States Geological Survey (USGS) and other authorities, their inclusion would have "changed the perspective of our analysis. However, ANWR is closed. And ... the question is does it make strategic sense to set the fiscal strategy in the expectation of ANWR opening." No response could be provided since the future of ANWR was unknown.

Mr. Bramley stated that while NPR-A and other areas were reasonably well licensed, little drilling had occurred. However, there was nothing to "to suggest that the authorities who've licensed the existing acreage in NPR-A and on the Slope and the people who have drilled there have done anything other than drilled the best prospects first." This would be typical of any maturing area. "So, I find it hard to see from an NPR-A point of perspective that there is additional economic prospectivity that would significantly change the equation that people are looking at."

[9:43:53 AM](#)

Mr. Johnston stated that a tremendous amount of discussion occurred in the effort "to clarify the dramatic difference between exploration and development". Had the PPT only affected fields such as Kuparuk and Prudhoe Bay, the subject of prospectivity and field comparisons would change significantly. "Half the time when we talk about prospectivity it's in the exploration context which is a lot different than looking at those two established known fields. It's not to say that there is no risk associated with trying to increase the production there, but it's a lot less risky and a lot less costly in many respects than typical high risk exploration." This is the reason Cook Inlet was "treated like such a step child up until now and why I agree" with Marathon's position that "they wouldn't have agreed to 20/20 and I wouldn't blame them. So sometimes we have to stand back and think in terms of development economics and the terms that would be appropriate for what will constitute 80 percent of the value of our work here on these bills and then the other problem and that's future exploration in various parts of Alaska."

[9:45:25 AM](#)

Mr. Walker addressed "the comparison on risk between exploration and infield development". "More and more expensive technology" was being required to garner the "maximum recovery" from the State's aging large fields. In addition, risks in developing a field were also increasing. BP's technology portfolio for Alaska included a \$100 million expenditure for enhanced oil recovery at the Endicott field. Were that technology successful, it would be applied statewide and an additional 450 million barrels might be recovered. Nonetheless, this was "a big risk" for BP. "The business is changing" and each barrel was getting harder to recover. Investments in technology and increased risks would be required to harvest the "huge resource that exists on the North Slope".

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Ms. Kah also pointed out that heavy oil comprised a significant amount of the remaining resources in existing fields. Increased risk would be required in order to develop technology which would allow that type of oil to be commercially extracted. In

addition, additional expenses would be incurred as remaining resources "are further and further away" from the existing pipeline infrastructure. BP, which had a larger percent of its portfolio in OCEAN countries than its competitors, was experiencing a much larger production decline than anticipated. An increase in capital costs for reinvestment on a global scale was also being experienced. "Nobody has properly forecast what the production decline rates are in the mature fields around the world, not just Alaska. I think it's a global issue."

[9:47:47 AM](#)

Mr. Hanley pointed out that, regardless of whether or not one considered ELF "broken", it had attempted "to identify less economic fields and factor in provisions to address less productive wells and smaller field size.

Mr. Hanley stated that sustainability per well and prospectivity considerations should be applied to any "possible discovery of a huge field in ANWR". The problem with the PPT bill is that it was a "one size fits all" bill. Anadarko was optimistic that there were more Alpine size fields in the State. However it was unlikely that those fields would be close to existing infrastructure. The PPT also did not "provide for risk factors or prospectivity". A developer would expect to pay a high severance tax under ELF were a large field found whereas a lower tax would be levied on a small, less productive fields.

Mr. Hanley stated that regardless of whether the tax structure of ELF was correct or not, "at least it tried to address the economics of a field". That consideration was absent from the PPT, such things as heavy oil, existing infrastructure, new exploration, and existing production, and exploration activities should be considered. While the tax rate was always important, credits would also be important to an explorer. One size fits all does not really apply to activities in Cook Inlet.

[9:50:00 AM](#)

Mr. Dickinson stated that "a proxy for cost" for such things as per well productivity or the size of field existed in ELF. The reason to consider the net basis of costs as proposed in the PPT was to "avoid figuring out those proxies". Were the cost of extracting heavy oil to be "extraordinarily expensive to develop" then the credits would play a very large role in

getting that development". Mr. Hanley might be correct that a flat rate would not address the entirety of circumstances, however, "we believe that it does". It would be "more effective than using a proxy" in terms of "the range of things that have been looked" at. The hope is that barrel prices would maintain a price level which would benefit the industry and the State as the PPT would be detrimental to the industry were prices at the "at the lower extreme of for example \$20 per barrel".

[9:51:36 AM](#)

Senator Hoffman shared that he was a member of the Legislature when ELF was last revised in 1990. No one at the time anticipated oil prices to escalate to the \$60 or \$70 range. Last year ANS West Coast prices "fluctuated from \$41 to \$62 per barrel". For the first quarter of 2006, prices averaged above \$60 per barrel. "Part of the equation for incentives to look for new fields has to be the price, as well." That consideration must not be overlooked, for were oil prices to remain high for a long time, given what's happening over in China and India, I think many people believe that the \$50 per barrel price average might be the norm." It could also be the low.

Senator Hoffman, in order to further understand the issue, he asked whether BP could share the "types of profits" they experienced in the State in 2005.

[9:53:26 AM](#)

Mr. Walker responded that the \$50 and \$60 barrel prices experienced in 2005 allowed BP and the industry to experience "a very good year". Alaska had also benefited by those prices. BP paid in excess of 2.5 billion dollars in tax and its profits from its Alaska activities were slightly less than two billion dollars. It was the best year BP experienced "in decades". While that was "a lot of money", it should be noted that BP's presence in the State was large.

Mr. Walker characterized Alaska as "a price play. Alaska only makes sense at medium and high prices". The company's 2006 breakeven point in Alaska would be \$22.50 per barrel. State taxes equating to \$6.50 per barrel and federal government fees amounting to 47 cents would be paid at that price. "That is the nature of the regressive tax regime" the State has. "It is protected on the down side and gives a little bit extra to the

oil companies on the upside." The proposed 20/20 PPT tax regime "would significantly shift the balance at high prices. DOR estimated that, at \$60 per barrel, the State would receive approximately one billion dollars more a year under the PPT than under ELF.

Mr. Walker stated that "under the 20/20 proposal there has been a significant shift from the oil companies to the State at higher prices and that's something which we agreed to and is something which we think is appropriate and is part of the agreement that we came to with the Governor."

[9:55:34 AM](#)

Ms. Kah stressed that while "it is true that oil prices" increased 2.5 times since 1999 in real terms, industry costs "also doubled during that time period". The fact that costs increased, "but at a lower pace", would account for the industry's record level earnings. However, costs were catching up. "Replacement costs are quickly rising to the level of price so we won't be able to profitably invest even at this price level if tax rates continue to go up on top of that given that the cost structure is rising."

[9:56:13 AM](#)

Senator Stedman expressed that even though "the issue of taxes" was constantly being referenced, the issue was really one of establishing the appropriate "selling price of the people's commodity". Royalties and tax systems were two of the limited mechanics through which the State could "sell" its assets. The tax rate proposed in the PPT would increase the price of the people's commodity to acceptable levels. We should "not lose sight" of that effort. "There has been a global movement in recent years" to adjust the relationship between government take and oil and gas industry take. "We are not leading the pack; we are actually following a worldwide trend."

[9:58:00 AM](#)

Co-Chair Wilken asked Dr. Finizza whether his interpretation of the Slide 90 was correct in that the green line reflected the provisions of CSSB 305; the blue line indicated the affect of the House committee substitute; and the top horizontal black line at the 12 or 13 percent tax rate indicated the "average

historical" government take for the North Slope under ELF. The horizontal line slightly below the top line was the projected ELF rate going forward for the Prudhoe Bay Unit (PBU). The horizontal line at approximately the six percent tax rate was the projected rate going forward under ELF for all fields. Thus, at a barrel price of \$50 with no industry investment, the effective tax rate, as depicted on the chart, would be approximately 16 percent. The State was endeavoring to encourage investment.

[9:59:32 AM](#)

Mr. Finizza stated that the first solid line on the chart reflected the continuance of historical investment levels.

Co-Chair Wilken acknowledged. Were oil companies to increase their investments to \$2.5 billion a year, they would be entitled to the two for one incentive component included in the PPT. This could effectively reduce an oil company's tax rate to "the average historical rate at \$50 per barrel". This would be higher than the projected tax rate under ELF, but would be slightly above the range they had been paying under ELF.

[10:00:24 AM](#)

Mr. Finizza stated that Co-Chair Wilken's understanding of the chart was correct. The chart was intended "to show the effect of roughly doubling the investment rate". The industry could "decrease their effective tax rate" by increasing investments and using the deductible provisions proposed in the PPT.

[10:00:57 AM](#)

Co-Chair Wilken asked the producers their interpretation of the chart as he understood the chart to indicate a "win/win for you and for the State by increasing your investment with us".

[10:01:12 AM](#)

Ms. Kah stated that since the unpredictability of prices was a given, the industry would assume "a much more conservative mean and a very wide range around it, but we certainly would not invest at a \$50 a barrel price." Today, for instance, under the "current forward curve which appears to be at \$60 a barrel today, we have a series of new financial investors who are using

the commodity prices in the forward curve specifically to hedge their stock and buy portfolios".

Ms. Kah shared that this has resulted in "huge financial rotations into our markets" which "are inflating the entire forward curve". She was unaware of any analyst who believed "that the forward curve today is a true representation of forward price expectations because so much money is coming into the curve wanting to go long and there is nobody on the other side who wants to go short five years out. They're creating an imbalance and their prices are now higher than what true price expectations are in the forward curve." She knew of no one who would "use the forward curve for investments".

Ms. Kah stated that another consideration would be "cyclical factors" such as an increase or decrease in economic growth. While she knew of one research firm which predicted that 15 million barrels a day of oil would be added over the next five years, she was skeptical of that as she was aware of the delays that some projects were experiencing. Markets fluctuate and "supply and demand do respond". She doubted however that prices of \$20 a barrel would be revisited or that recent high prices would continue. Thus, extreme prices would not be used as the mean in industry investment decisions. She avowed that an increase in investment would not occur when oil prices were in the \$30 and \$40 range.

[10:03:15 AM](#)

Co-Chair Wilken understood therefore, that in order to obtain a ten percent tax rate at, for example, a \$40 barrel price, a company must increase its investment by \$2.5 billion. However, Ms. Kah has attested that a company would not make such an investment at that price.

Ms. Kah specified that the price point at which her company based its decisions was privileged and could not be disclosed in a public hearing situation. Nonetheless, a price of \$40 would "on the aggressive side for us". The economic analysis of projects in Alaska must be competitive with other projects in the company's portfolio. "The high cost of operating in the State and the smaller prospectivity ... just makes it tougher and tougher".

[10:04:09 AM](#)

Mr. Johnston thought that the terms "current prices and current price forecasts" had been confused in the conversation. He understood Co-Chair Wilken's question to be how might a long term stable forecast price of \$40 a barrel affect an investment decision as opposed to how would a current price of \$40 affect it.

[10:04:38 AM](#)

Ms. Kah stated that her remarks were to the long term forecast rather than to a today price.

Mr. Johnston ascertained therefore that the company would choose not to invest at a long term forecast of \$50 a barrel.

[10:04:52 AM](#)

Ms. Kah corrected her previous remark. Her response was not to long term forecasts.

Mr. Johnston asked Ms. Kah to further clarify her position.

[10:05:23 AM](#)

Ms. Kah qualified that the company's long term price forecast did not include a \$50 barrel price so therefore, no investment would be made on that assumption. However, regardless of price, the company would compare Alaska's projects to other projects in its portfolio. A multitude of factors were involved in investment decisions. BP would not invest at a \$50 outlook price.

[10:06:06 AM](#)

Mr. Walker spoke to the Slide 90 chart. He asked Mr. Finizza whether Econ One had adjusted the production volume resulting from increased investment when it calculated the affect of the additional investment on the tax rate.

[10:06:38 AM](#)

Mr. Finizza replied that the volume had not been adjusted. The chart presumed that production levels would remain consistent,

as the affect of the increased investment on production was unknown.

Mr. Walker offered to share his company's assumptions with Econ One, whose analysis had not accounted "for the extra production, the extra revenue, the extra State revenue, and the impact on both the oil companies and the State" of the extra production resulting from the development. The analysis must include the different volumes that would arise from differing levels of investment.

Mr. Finizza agreed. The graph should be revised to reflect the increased volume. "The lines on the chart depicting the level of tax experienced by a \$2.5 billion increase in investment "could actually fall rather than rise".

Mr. Dickinson understood that the graph was based on the Department of Revenue production forecast.

Mr. Finizza affirmed.

[10:08:51 AM](#)

Mr. Dickinson referred to Mr. Walker's earlier testimony attesting that absent increased investment, production would decline and the Department of Revenue forecast would not be met. In order to achieve the level of production included in the DOR forecast, more investment would be required. The graph should therefore reflect production levels resulting from that investment. This would be "consistent with that view" that more investment would be required to maintain that production. The graph would support the effort to encourage investment by allowing it to have "tax consequence".

[10:09:42 AM](#)

In response to a question from Co-Chair Green, Co-Chair Wilken acknowledged that his question had been answered.

Co-Chair Wilken noted that Slide 91 of the aforementioned Econ One presentation (copy not provided) addressed the differences in government take as affected by the 20/20 provisions in SB 305, and the 25/20 provisions in CSSB 305. The differences in government take would increase over time. He was struggling "with whether the demand and the competition for capital is so

competitive that an increase in the government take in Alaska of 3.8 percent, 4.3, 3.5 percent" would lower the State's "competitiveness and attractiveness down to the point where ... its' been suggested that we would lose 20 percent of the investment". Had the government take been projected to increase 13 or 14 percent he would have agreed; however, a three to four percent government take increase on oil prices in the \$40 and \$50 per barrel range would not be sufficient enough to "tank Alaska".

[10:12:15 AM](#)

Mr. Bramley recognized Co-Chair Wilken's question as targeting "the heart of what's really important here"; that being how investment decisions were made. As he understood the process, oil companies, regardless of size, "exercise capital discipline" throughout their capital allocation process. A variety of reviews were conducted on the competing projects in a company's portfolio of investment opportunities. "There is a constant churn of those opportunities and a constant process to rank and screen those in some way using all kinds of calculative budgeting techniques."

Mr. Bramley stated that the prospect of any change in a tax regime, regardless of the size of the change, would "act like a change of price into a market". Thus, the effect of an increased tax take on any Alaskan project in any company's portfolio would "relegate all of Alaska's proposals" and the outcome would be conflicted. A tax increase of 20 percent might have little or no impact on some of the best Alaska projects; some marginal prospects might be deferred or even dropped. The result of the change in the tax regime would be that "some would accept it, some won't, and there would be some kind of net affect". "If the net affect of the tax credits, deductibility, and tax rates is a negative one, then investment attractiveness can only go down, and consequently investment will go down, and there will be some effect on production."

[10:15:34 AM](#)

Mr. Johnston reminded the Committee "that Alaska is not the only province on this planet" that was considering changing its tax terms. "In that context, and particularly when you consider the modest change that being contemplated here, when all is said and done, and the dust settles, we will find that Alaska changed

much less than most of the other countries" discussing adjusting their rate structures. Since Alaska was not the only entity considering changes to its tax structure, the effort "is terribly appropriate" in consideration of Mr. Bramley's remarks. "In this context of all the changes that are taking place right now, it's a whole different matter."

Mr. Finizza noted that Mr. Bramley had provided a good perspective of the types of things a board room would consider. A chart developed by Ms. Kah [copy not provided] indicated that a change in the tax rate could transition the net present value (NPV) of some projects from being economic to being uncompetitive. However, the proposed tax structure might improve the NPV of some projects.

[10:17:15 AM](#)

Mr. Finizza stated that a project requiring "a front end loaded large capital investment" would benefit from the credits and tax sheltering the PPT would provide. Thus the NPV of that project "might actually rise relative to the same project under ELF". Therefore, he believed that "the shuffling that goes around in the boardroom" relating to a fiscal change could go the other way as well as there are other provisions in the PPT besides the tax rate.

[10:17:58 AM](#)

Ms. Kah could not identify any project that would benefit from the terms of the PPT with the exception of an unsuccessful exploration project. The only direction the PPT would drive projects would be in a "negative direction". Many Alaskan projects, particularly those relating to heavy oil, "are marginal to begin with". A project with high costs "would be more likely to slip across that line and get deferred" than a large robust resource that could absorb a tax increase. This was why she was "worried about Alaska". Changes to the tax system must be done "right" in order not to jeopardize projects.

Senator Hoffman revisited Co-Chair Wilken's remarks regarding how significant the impact of a three percent increase in government take might be. On April 3, 2006 the Committee heard a presentation from the DOR in which it was specified that at a \$40 barrel oil price, the PPT would garner \$20.4 billion over a 24 year period as opposed to \$15.4 billion under ELF; a five

billion dollar difference. At a \$60 barrel price the PPT would garner \$42.4 billion verses \$32.9 billion under ELF; a ten billion dollar difference. "Although the point percentages may be small, the numbers are quite large."

Co-Chair Green appreciated the dollar amount perspective because "the percentages can appear very small, but then multiply out".

[10:20:11 AM](#)

Senator Stedman contended that the dollar estimations were "the root of some of the finer points of the discussion" and arguments. In his opinion, "the incremental difference between" the 20/20 proposed in SB 305 and the 25/20 proposed in CSSB 305 would not be "ruinous to the State of Alaska". One might think that "we're making these gigantic changes" because of the level of money being discussed, however, accurate amounts could not be determined until the final PPT percentages were determined.

Senator Stedman reminded the Committee that the industry take in Alaska was \$1.8 billion more in FY 2006 than that of FY 2005. He communicated that as the discussion continued, there would be some, including himself, who would refer to discuss the issue in terms of percentages because decisions based on the intensity of dollar increases would not be "in the best interest of the citizens of the State of Alaska".

[10:21:42 AM](#)

Mr. Johnston "totally" agreed with Senator Stedman. He, for the most part, had never "spoken in terms of dollars". He "resented" those times that the Administration and the industry professed that the State would "get an extra, you know, so many zillion dollars a year because" of the PPT. While it might be a lot of money, it was "misleading" as large dollar amounts were the norm in the international business marketplace. "If you get an extra billion dollars a year, that's one thing, but if you get an extra billion dollars a year when perhaps you should have been getting an extra billion and a half now that's quite another matter". Such distinctions should be addressed as large dollar amounts could result from "very small percentages". The effort should be to determine the proper percentages, "and then let the chips fall where they may". He avowed that the PPT proposal being considered "was not even close" to being detrimental to the State.

Mr. Walker took "exception" to Mr. Johnston's remarks. "These are very large numbers, indeed". The House and Senate PPT committee substitutes would garner significantly more revenue for the State than the one billion dollars expected under SB 305.

Mr. Walker voiced that, in percentages, ELF would provide Alaska 32 percent of the proceeds at barrel prices of \$60. The 20/20 PPT proposal in SB 305 would provide the State 40 percent. According to BP's numbers, the company's share would reduce from 43 percent to 38 percent. This could be viewed as an industry marker. The transition from ELF to the PPT would result in "a significant shift in share". This shift in percentage take would result in a significant shift in dollars.

[10:24:13 AM](#)

Mr. Bramley addressed Mr. Johnston's remarks about the tax regime changes that have been occurring on the worldwide market. The higher price environment prompted some changes in tax take: the one most comparable to Alaska would be the United Kingdom (UK). The UK increased its take from 30 to 50 percent. Venezuela and China also increased their terms. However the overall systemic changes would not be considered "clear cut". Numerous investors actually experienced "improvements" or "softer terms" during the last several years in countries such as Indonesia, India, Peru, and Syria. While this would not support there being a downward trend occurring, "it is not a clear cut picture of an increase in tax terms".

Mr. Bramley responded to Mr. Finizza's point that NPV might, in certain cases, improve under the PPT. The only "convincing case" substantiating this would work conducted on a dry well. In that regard, the State would support a portion of "the cost of dry hole drilling". That would be attractive at higher tax rates. CRA could not identify any other situation in which NPV would increase as a result of credits provided to, for example, a 50 million barrel field, which would be the size of a typical field in the State. PPT would be less attractive for investment under any other scenario modeled by CRA. He asked that supporting evidence of the improved NPV situation suggested by Dr. Finizza be presented.

[10:27:12 AM](#)

Mr. Finizza acknowledged Mr. Bramley's remarks. He asked Mr. Bramley about the modeling CRA had done; specifically whether it had modeled a plan with the 5,000 barrel allowance as proposed in CSSB 305, as that was the scenario contemplated in his remarks.

Mr. Bramley stated that CRA's modeling had concentrated on the provisions of the original bill which provided a \$73 million fixed allowance against the severance tax. The \$12 million credit and the "company wide" production allowance by the House and Senate committee substitutes, respectively, were discussed. While the provisions in the committee substitutes would provide incentives "to new investors on their early investments", those provisions would "migrate towards that of all existing taxpayers" who had "substantial positions" "built up" over time. Since it would benefit new investors, CRA did not consider the 5,000 barrel allowance proposed in CSSB 305 "to be central to the issue", as, over the last five years, more than 90 percent of the investment occurring in the State was conducted by the four largest resource companies. While small companies might grow and make "a real contribution" to the State, that scenario should not be "the primary question in looking at the effect on investment" resulting from these new proposals.

[10:29:01 AM](#)

Mr. Finizza anticipated that a similar response would have greeted another incentive proposal that had been considered but not furthered. That proposal, which would have forgiven the tax on "X" number of barrels from new fields, would have also increased the NPV of a field "early on".

Mr. Bramley responded that a thorough analysis would be required to determine the affect of such a proposal specifically on new fields and new participants. However, he anticipated it would have a positive affect on the economics of "early investments".

Co-Chair Green stated that the panel discussion would now address Issue 2. One and a half hours had been devoted to Issue 1.

Issue 2. WTI vs. ANS.

Co-Chair Green stated that whether to base the PPT tax structure on the West Texas Intermediate (WTI) price or the Alaska North Slope (ANS) price should be carefully analyzed. The effort should be to utilize a price system that would best serve the State.

[10:30:29 AM](#)

Ms. Kah recommended the tax structure be based on a wellhead price, as that would be "the only way you can really insure you're actually getting at the revenues of the project". She stressed that at times, there was a "disconnect" in ANS and WTI. This disconnect would increase over time because the sulfur content in the world's crude supply was increasing. A premium was being placed on light sweet crude oil as compared to oils with higher sulfur levels. This was the result of such things as global environmental restrictions that required reductions in products' sulfur levels.

Ms. Kah revisited her previous analogy of selling a house in Anchorage or Juneau at a price set in West Texas. "It doesn't compute. You'd expect to see disconnects," regulatory issues and tax structure alterations due to that disconnect. Utilizing a wellhead price would avoid a multitude of problems. "It is closest to the real value of the project."

[10:31:47 AM](#)

Mr. Dickinson agreed that the tax should be levied at the wellhead. The WTI debate primarily evolved around the rate triggering the Progressivity factor included in CSSB 305.

Mr. Dickinson stated that when determining which index to use, one should consider that both WTI and ANS had experienced "major swings" and the difference between the two could range between five dollars to "parity". "There is no question that ANS is typically going to be trading several dollars below WTI." A concern with ANS was that it was narrowly traded. There could be as few as zero and as many as three trades a month. ANS and WTI move in "lockstep" approximately 27 days per month. The relationship between the two was revisited when a sale of ANS occurred. "The ANS market simply isn't liquid." While he disagreed with it, he noted there was concern that ANS could be manipulated; a person could demonstrate that companies with large internal refinery operations could make a sale at a loss

that could "lower the differential and move things around". "The question really should be "is the thinness of the market for ANS more of a set-back or more of a detriment than the fact that WTI is not ANS and is measuring something different".

[10:34:35 AM](#)

Mr. Zager also supported utilizing a wellhead price as the tax basis. In a previous presentation, he had suggested the Committee consider developing a system based on net profits, as this would avoid the discussion of how to determine the appropriate marker between WTI and ANS. This issue could be readdressed when Issues 10, 11, and 12 were discussed.

[10:35:02 AM](#)

Issue 3. \$73 million allowance vs. \$12 million credit vs. 5000 bbl plan. Discuss the different impacts each option has on the state, the majors and the independents.

Mr. Walker communicated that how the different basins in the State would be addressed in the PPT would be a matter of policy. His company would support some basins being excluded from the provisions of the PPT. While he appreciated there being concern as to how applying the PPT to Cook Inlet might affect investment there, he noted that "large tax increases" would also affect investment in the North Slope.

Mr. Walker spoke to the \$73 million credit proposed in SB 305, and urged that a "level playing field" be considered for all basins including operations in Cook Inlet and on the North Slope. He spoke against including the \$73 million exemption, the \$12 million credit, or the 5,000 barrel per day allowance in the bill.

Co-Chair Green asked for confirmation that Mr. Walker preferred to eliminate all allowances from the bill.

Mr. Walker affirmed that to be the request. Excluding such provisions from the bill would create a level playing field. "I recognize that we won't necessarily be aligned with other panelists" in this regard.

[10:37:21 AM](#)

Mr. Hanley understood that the \$73 million allowance was included in SB 305 to "mitigate some of the tax increase" that would be experienced by companies that had "lower tax rates already because they had less productive levels" or, who were, under ELF, "paying no severance tax on their field". In addition, as attested to by Dr. Pedro van Meurs, the consultant to the Governor, the allowance would be an incentive to new entrants in the resource development industry in the State. However, the allowance was limited in that "once you've used it once, or to the extent that you have production, it no longer can be used in future exploration, you have to use it against existing".

Mr. Hanley explained that his company was "kind of in the middle". Since his company had existing production, the allowance could be applied "to decrease the increase in the taxes at Alpine". The allowance would have more impact on producing companies with small production levels than it would on larger operations. The elimination of the \$73 million allowance would increase the tax rate on his company's entire portfolio by five percent.

Mr. Hanley compared the \$73 million allowance and no termination date included in SB 305 to the \$12 million credit proposed in the House PPT committee substitute. That \$12 million credit would be equivalent to a \$60 million allowance at the 20 percent tax rate proposed in that bill. However, the House committee substitute credit would not be of much, if any, value to "new players" because a termination date was attached to it. The credits would expire before they could be utilized by a new player because of the time required to bring a new project to production.

Mr. Hanley opined that the 5,000 barrel per day exemption included in CSSB 305 would only be of value to perhaps two existing companies. The seven year termination date accompanying it would "assuredly" provide no value to a new player.

Mr. Hanley considered the request for a level playing field to be interesting; particularly as one does not currently exist. The \$73 million allowance proposed in SB 305 could be interpreted as a leveling of the playing field as it would apply to any company. It could provide the equivalent of \$12 to \$14 million in credit each year for ten years to companies with existing production such as Anadarko, BP, and ConocoPhillips.

"The irony is" that "it would be worth zero" to a new player "until they actually had production, which might be ten years in the future." He considered the \$73 million allowance in SB 305 to be more valuable than the 5,000 barrel per day exemption proposal in CSSB 305.

[10:41:25 AM](#)

Mr. Dickinson communicated that the Administration chose the \$73 million allowance provision because it would be of value to producers with small levels of production or those conducting "very expensive operations". While it would be a factor in the economics of larger operations, it would not be as significant. An incentive based on volumes had been considered by the Administration but rejected. The \$73 million allowance in SB 305 could be compared to the credit provision included in the House committee substitute, which would equate to approximately a \$60 million allowance.

Mr. Dickinson addressed an issue of concern with the credit provision included in the House committee substitute. A producer with a ten million dollar investment that qualified for the credit could elect to increase their investment to \$12 million and thus qualify to receive approximately three million dollars in tax benefits. "There is a time period" in which there "is a perverse incentive" in that a producer could "receive more than a dollar for dollar benefit". This technical issue could be corrected.

Mr. Dickinson noted however that even a company benefiting to the maximum under the House provision would receive "a smaller deduction than they would" under SB 305. Thus, most companies would prefer the \$74 million allowance provision.

Mr. Dickinson qualified that companies with production levels below 5,000 barrels a day and profits below \$73 million a year would be neutral on the issue. A company with production below 5,000 barrels per day but revenues exceeding \$73 million dollars in profits a year would prefer CSSB 305. Generally though, a company would realize that the SB 305 would provide more benefits than CSSB 305.

Mr. Dickinson specified however that "from a revenue point of view", the State would determine that, under the Senate plan, "the only revenue we are allowing to leave as a consequence of

this are for the smallest players at the beginning of their growth cycle". In summary, the Administration believed that the 73,000 allowance should be the preferred approach.

[10:45:26 AM](#)

Senator Stedman noted that the Senate Resources Committee had been reluctant to further the \$73 million allowance plan after they realized the measurements were based on oil prices of \$40 a barrel. The value of the allowance must be viewed in terms of actual oil prices.

[10:45:51 AM](#)

Mr. Finizza supported Mr. Dickinson's remarks favoring the \$73 million allowance.

[10:46:16 AM](#)

Ms. Kah advised that any benefit should be equally applied to all companies or at least all companies within a geographic area. Her concern regarding CSSB 305's 5,000 barrel plan was that it would "penalize the very companies who are most likely to provide most of the investment, most of the production decline mitigation, and most of the jobs in the future".

[10:46:51 AM](#)

Mr. Zager agreed that SB 305's \$73 million allowance plan "would be the most accommodating" to companies. The House's \$12 million credit, or \$60 million dollar allowance equivalent, would not be. Since there was a "tax on profits and a tax on dollars" the "exemption should be based on dollars as otherwise you get into barrels and a lot of barrels in the State have very different profitability's associated with them, so the most profitable barrels would actually get the biggest exemption. The least profitable barrels would get the smallest exemption if it's based on barrels."

[10:47:33 AM](#)

Issue 4. Point of Production. Further explanation.

In response to Co-Chair Green's remark that visual aids would assist the discussion on Issue 4, Mr. Dickinson advised that

visual aids were being developed and would be available in the afternoon. [See Time Stamp 12:17:45]

Co-Chair Green stated therefore that the discussion on Issue 4 would be postponed until the visual aids were available.

[10:47:58 AM](#)

Issue 5. Credits and deductions applicable for capital investments in the gas pipeline. What is, what isn't.

Mr. Dickinson stated that CSSB 305 would allow "anything upstream of the point of production", which would be any activity "involved in getting the gas out of the ground and moved to a point where it moves into typically a common carrier pipeline" to qualify for deductions and credits. The exception would be that the gas treatment facility in which the resource would be processed into a pipeline ready condition, would not qualify. To that point, he advised that discussions were continuing in regards to "certain aspects of treatment verses processing".

[10:48:45 AM](#)

Mr. Dickinson also noted that the gas transmissions lines that move gas from fields such as Alpine or North Star "would not be considered upstream" activities under the terms of CSSB 305, and therefore would not qualify for credits or deductions. They would receive downstream deductions.

Co-Chair Green asked whether diagrams distinguishing the point between upstream and downstream gas activities were available.

Mr. Dickinson assured the Committee that diagrams would be provided.

[10:49:55 AM](#)

Mr. Hanley agreed with Mr. Dickinson and characterized the distinction between upstream and downstream activities as being "a policy call". Neither SB 305 nor the House or Senate PPT committee substitutes would allow the gas treatment facility to qualify for credits. The industry would argue that any process required "to get our gas into pipeline quality shape" should qualify for the credits and deductions.

Mr. Hanley understood that the PPT's credit and deduction components were intended to "offset the gas tax increase" the PPT would impose. Therefore, "to leave out a significant portion of our costs in getting that gas ready and eligible for going into a pipe seems to us not to make sense". While a Prudhoe Bay/Point Thomson treatment facility had been considered part of a proposed gas pipeline contract, there were other places such as the Nenana Basin and Cook Inlet that would also require gas treatment facilities. This would substantiate the industry's request that the point of production be downstream of the gas treatment facility.

[10:51:23 AM](#)

Co-Chair Green asked Mr. Dickinson whether this issue was part of the on-going discussions he had mentioned.

[10:51:47 AM](#)

Mr. Dickinson responded that diagrams would be provided that would "crystallize the issue" raised by Mr. Hanley. A large facility close to the location of the proposed gas pipeline was currently being considered part of the transportation system. A large treatment facility located in a remote location might be considered differently. Further information would be provided to the Committee regarding this issue.

Co-Chair Green understood therefore that language to address this issue was being developed.

Mr. Dickinson affirmed.

[10:52:24 AM](#)

Senator Dyson expressed the "struggle" Legislators have had in determining whether the PPT bill should be "a general application oil bill" or an oil and gas bill. "Allowing deductions or credits for conditioning gas that's specifically for a pipeline further blurs the line of whether this is a oil bill or is an oil and produced gas ... or is an oil and ... gas monetization bill." However, he considered this "the first step in maybe a three-part play that gets us to a gas pipeline". His worry was that the deductions and credits included in the PPT might be "manipulated to the point where the producers are

paying very little more if anything at high prices for the extraction of the people's gas".

Senator Dyson shared his desire to design a program that would either disallow "downstream or midstream" processes pertinent to a gas pipeline from qualifying for credits or, if they were, that the process be clearly defined.

[10:54:19 AM](#)

Mr. Hanley responded that the issue primarily revolved around the economics of existing fields and exploration economics. One of the challenges was whether a 20 or 25 percent tax rate would be "appropriate on gas". His company considered the PPT to be a tax bill on gas and oil. The current ten percent ELF tax rate on gas would increase to 20 or 25 percent under the PPT. That rate would be modified by the credits included in the bill. "On a relative basis, you could argue that the tax rate is 12.5 and 15 for oil, modified by its ELF, and a relative basis gas just went up higher."

Mr. Hanley stated that his company viewed things from an exploration perspective. "We have exploration risks, development risks, and all those types of things on gas. Same thing in the Nenana Basin, I think you'll see some of the folks down there looking at it a little bit differently than an existing field that we're trying to get developed. And that's exactly our concern. There's some difference potentially."

[10:55:45 AM](#)

Senator Stedman stated that when the PPT was initially discussed, "there was a de-linking between the oil and gas pipeline knowing that eventually there's going to be a connection, within months not years. So that is a issue on the table as far as how connected this bill is to gas". Legislators were unsure about "what's coming at us, if it is". This uncertainty caused him to hesitate. "Clearly, if this is connected into that, directly with gas, I would expect that that'll get revisited here in our Special Session because we can't make those decisions without seeing what's underneath the shells that are being moved around the board right now". This legislation was the only "piece" that the Legislature was provided.

[10:56:51 AM](#)

Co-Chair Green recalled Mr. Johnston recently declaring "that there should definitely be a distinct PPT for gas".

[10:56:53 AM](#)

Mr. Johnston could not recall the exact context of that remark. However, the State has treated "Cook Inlet like a stepchild" as the effort has focused on the North Slope which is the primary production area in the State. Gas exploration on the North Slope has also been overshadowed.

Mr. Johnson continued that in most areas of the world "where there is not a well-established gas infrastructure or market for gas, the terms are typically better for gas than for oil because it's so much more difficult to make a living with a gas discovery than an oil discovery". Therefore, he agreed with Mr. Hanley's position on the gas issue. The treatment of gas for exploration should be "handled with care".

Co-Chair Green expressed that she might have misinterpreted Mr. Johnston's recent remark.

[10:58:08 AM](#)

Mr. Dickinson reminded the Committee that even though "Anadarko is not a party to a stranded gas contract negotiation, these rules will be the rules that will govern their situation." Provisions might be developed that could allow other companies to participate in areas of the Stranded Gas Act.

[10:58:38 AM](#)

Mr. Johnston understood that the rules Mr. Dickinson was referring to were those in the PPT legislation.

Co-Chair Green affirmed.

Mr. Johnson expected that different rules would apply to the 35 trillion cubic feet of known gas reserves on the North Slope.

Mr. Dickinson responded in the affirmative. "The narrow point is there are three producers who are in negotiation with signing a

contract relative to their tax obligations, their royalty obligations. Anadarko is not one of those three."

RECESS [10:59:26 AM](#) / [12:17:45 PM](#)

Co-Chair Green called the meeting back to order.

Issue 4. Point of Production. Further explanation.

Co-Chair Green stated that Issue 4 would now be addressed as visual aids were now available.

Mr. Dickinson distributed a diagram labeled "Figure 9. North Slope Pipelines" [copy on file]. The diagram depicted the current North Slope pipeline based on information collected from a study on upstream facility costs conducted by the Department of Natural Resources. The Trans Alaska Pipeline Service (TAPS) running south from Pump Station 1 was depicted in the lower middle portion of the diagram. "Practically all the oil marketed from the North Slope is in the Trans Alaska Pipeline." Oil from Prudhoe Bay, which supplied a significant percent of the oil in TAPS, runs through gathering centers and flow stations to Pump Station 1. West of Pump Station 1 was the "publicly regulated" Oliktok Pipeline "which carries crude from Kuparuk". Feeding into the Oliktok Pipeline from the north was the Milne Point Pipeline which carried oil from that field. Oil from the Alpine Field Processing Facility fed into the western end of the Oliktok Pipeline via the Alpine Pipeline. East of Pump Station One was the Endicott Pipeline which flowed from Duck Island. The Badami Pipeline fed into the Endicott Pipeline from the east. East of the Badami Field was the Point Thomson field. The hope was that when that field was developed, its oil would feed into the Badami Pipeline.

Mr. Dickinson identified the point of production for oil as the point at which the oil in the gathering lines from the various fields moved into the Alpine Pipeline, the Oliktok Pipeline, the Endicott Pipeline or the Badami Pipeline.

Mr. Dickinson stated that the point of production for gas "would be very similar". Gas transmission lines would flow "from each of the separate units to the head of the gasline heading down to the Lower 48". Some of the gas processing and gas treatment would be conducted at stations in the various fields. As currently proposed, the gas pipeline project would have "a very

large gas treatment plant" located at "the inlet to the main line". That plant would primarily treat gas from Prudhoe Bay, but might handle additional gas from other places including Point Thomson.

Mr. Dickinson stated that the costs associated with the pipelines would qualify as a deduction "when calculating the gross value at the wellhead".

Mr. Dickinson also noted that each pipelines would have a tariff assigned to it. That tariff as well as the TAPS tariff would be subtracted from the gross value at the point of production for a field.

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Mr. Dickinson stated that the gathering lines would be considered upstream of the point of production. The pipelines would be downstream of the point of production.

Mr. Dickinson then distributed a map titled "North Slope Oil & Gas Activity & Discoveries January 2006" [copy on file], which depicted areas in which development was currently occurring or might occur in the future. Additional pipelines would be required to link these fields to TAPS.

Mr. Dickinson addressed another diagram, titled "Figure 8: Point of Production for Gas - Prudhoe Bay - December 1986 - Present" [copy on file] which was based on a DOR study regarding current operations at the Central Gas Facility (CGF). Points of production in the gas process were depicted on the flow chart by circles with a slash through them.

Mr. Dickinson explained the current production process on the North Slope. Well fluids flowed to separation facilities in which oil and gas separating would occur. The oil would then flow to a LACT Meter at Pump Station No. 1 where it would enter TAPS. Some of the gas would move to meters indicated on the diagram by circles with a slash through them and containing the letters "A" or "A/A". That gas would be utilized to support North Slope operations. The majority of the gas currently flowed though the meter depicted on the diagram as a circle with a slash through it and containing the letter "B". That gas would move to the CGF. Currently, "at that point, all the things that

occur from then on, including the production of natural gas liquids (NGL)" were considered gas.

Mr. Dickinson understood that the issue of concern raised by Mr. Hanley was to certain processes that occur in the separation facility such as the "dehydration" process that well fluids are subjected to in order to prevent hydrates from forming in the gas and "interfering with pipeline operations". The concern was to whether "there are certain things that go on now in a separation facility that might be considered under the definition we're proposing 'gas treatment', and because that's upstream of the gas processing, would that make a problem in our definitions".

Mr. Dickinson stated that Mr. Hanley's second point was to suggest that the State should make a policy call and recognize all treatment processes as being upstream operations. This would allow them to "be available for credits".

Mr. Dickinson stated that under the proposed set of definitions, approximately half of the gas stream, depicted on the diagram as "gas to reinjection", leaving the CGF facility would move to a gas treatment plant and then to the proposed gas pipeline. This stream currently amounted to approximately nine billion cubic (BCF) feet per day. As proposed in the PPT, the point of production for gas would be the point where the gas left the CGF and entered the gas treatment plant (GTP).

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Co-Chair Wilken understood that the "MI-NGLs and Blendable NGLs" gas streams flowing out of the CFG, as depicted on Figure 8, would be unaffected by the changes being proposed in the PPT.

Mr. Dickinson affirmed that "not all the gas" emitting from the CGF would flow to the GTP. Some would be used for reinjection.

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Mr. Hanley pointed out that a component was missing from the Figure 8 diagram. Gas used for reinjection purposes would not require having CO2 removed from it as gas going into the pipeline would. Thus, the diagram should locate the GTP after the point at which gas designated for injection was emitted from

the CGF. Gas coming from the CGF would not be pipeline quality; gas leaving the GTP would be.

Mr. Hanley specified that the point of production for gas would be between the CGF and the GTP.

In response to a question from Co-Chair Wilken, Mr. Dickinson clarified that the point of production for gas should be between the CGF and the GTP.

In response to a question from Co-Chair Green, Mr. Dickinson stated that under current Statute, the point of production for gas was after the final separation of oil and gas, as specified on the diagram by the circle with a slash over the letter "B". That point was currently between the separation facility and the CGF.

Co-Chair Green understood that under the PPT the point of production for gas would be after the CGF.

Mr. Dickinson affirmed. He also noted that under the PPT any fluids leaving the CGF and flowing to Pump Station No. 1 and into TAPS would be considered oil. Gas would transit from the CGF to the GTP where it would be processed into pipeline quality.

Mr. Dickinson referred to the location of Pump Station No. 1 on Figure 9. Mr. Hanley's concern was to development that might occur a vast distance away from that area. Specifically whether the point of production would be a practical one or a good policy call in regards to gas in a remote area that might be "taken out of the ground, run through a set of processes" and transited to the main pipeline or utilized for industrial uses.

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Mr. Dickinson referred to language in Sec. 28 (B) page 24 lines 9 through 19, of CSSB 305, which defined the point of production for gas. The point of production for gas would be after processing when it was "recognizable and measurable as gas". The "notions of complete separation", which were included in current definitions, were eliminated.

Mr. Dickinson noted that the definition of gas processing was specified in Sec. 30 subsection (D)(18) page 25, lines 6 through

16; gas treatment was defined in Sec. 30 subsection (D)(19) page 25, lines 18 through 21 of CSSB 305. Gas processing would be considered upstream of the point of production and that investment would qualify for credits. Gas treatment would be downstream of the point of production and while those expenses could be deducted, investments in the gas treatment plant would not qualify for credits. The "series of gas processes" were also listed in Section 30 subsection (D)(18). As specified in Sec. 30(18)(A)(ii) and (iii), the purpose of gas processing was to extract and recover liquid hydrocarbons. That process would be upstream of the GTP or "an inlet to a system taking gas to market".

Mr. Dickinson continued that gas treatment would "render that gas acceptable for tender and acceptance into a gas pipeline system". This would include the incidental removal of liquid hydrocarbons (CO<sub>2</sub>) from the gas.

Mr. Dickinson stated that the Committee might consider "more closely" defining the gas treatment process in order to further separate it from the processing process. Specifically that the definition of the "GTP for a major gas sale may not replicate as easily if you take it to other places around the slope, particularly ones that don't have any infrastructure already".

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Co-Chair Green asked whether language could be crafted to CSSB 305 to address that issue.

Mr. Dickinson affirmed that effort to further narrow the "restrictions in gas treatment" were occurring.

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Senator Stedman asked that the Figure 8 flow chart be revised to include the GTP and the point of production final metering point. The effort should provide a clear distinction to whether an activity would be considered upstream or downstream. In addition, acronyms should be defined. The Legislature should clearly depict those processes rather than having a "closed club on what we're talking about".

Senator Stedman specified that "the point of production and where the credits and the amount of credits are applicable to

which portion of this pie gets extremely important". "The earlier we start solidifying some of this stuff the better". The increased detail on Figure 8 was an improvement over earlier diagrams.

Co-Chair Green asked whether the glossary of PPT terms [copy on file] which had been previously provided to the Committee would suffice as an acronym definition page.

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Senator Stedman opined that printing the definitions of acronyms on each handout would be more beneficial to the public. Legislators were advantaged in this regard, as they had more resources.

Mr. Dickinson stated that an effort had been taken to reduce the number of acronyms in today's handouts. For example, CGF was defined on Figure 8. However, an effort to continually update the glossary of terms would occur.

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Senator Hoffman asked how the gas treatment and gas processing diagrams pertaining to the North Slope would apply to Bristol Bay.

[12:39:06 PM](#)

Mr. Dickinson explained that a pipeline or a tanker facility would be constructed in Bristol Bay. The point of production would be the point at which the gas or oil could be accurately metered. Since those facilities would be independent of other infrastructure, a diagram specific to them would be helpful.

Mr. Dickinson expressed that Mr. Hanley's concern would apply to this area; specifically were a new facility built that held both a treatment and processing plant. The Committee should develop "the best tool" through which to identify where the separation point between upstream and downstream processes would be.

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Mr. Hanley opined that part of the confusion was that the definition of the processing activity made no reference to a

CGF. Thus, a person could not clearly distinguish whether the CFG would be considered processing or treatment. Thus, he "encouraged" the Committee to further clarify the distinction between the CGF and the CTP.

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Co-Chair Wilken pointed out that CGFs were not unique to Alaska. He inquired as to whether processing facilities were traditionally considered part of the upstream or downstream process.

Mr. Dickinson communicated there being no single industry-wide standard. 100 pages of one [unspecified] publication were committed to this "long litigated issue". Furthermore, the North Slope differed "from most other places because of its isolation." Thus the effort regarding the North Slope "has been trying to take a series of market based definitions and then work at them within the context of the North Slope ..." In general, the rule had been to "draw a difference between transportation costs and getting ready for transportation costs," such as treatment and further upstream activities. The laws have had to adjust to advancements in technology.

Co-Chair Wilken understood therefore that this had been "a subject of discussion and negotiation for every major ... area".

Mr. Dickinson concurred.

[12:42:33 PM](#)

Issue 6. Re-openers. Discuss 30 year commitments and suggest alternatives.

Mr. Hanley shared that it was "unclear" to some in the industry whether "we will be able to get the certainty" of a long term commitment. While it has been implied that certainty would be provided in the gas pipeline contract, some companies viewed the increasing tax take level proposed in the PPT to result from Legislative concern "over a longer period that it may be locked in". It was unclear as to how the gas pipeline contract would affect this issue.

Co-Chair Green stated that addressing this issue at this time might be "premature". It might be more appropriately addressed in the gas pipeline discussions.

Mr. Dickinson communicated that "there is nothing in this statute which is ... different from any other statute; there's no re-openers in this statute per say. People are obviously looking ...down the road."

Issue 6 was withdrawn from the discussion.

[12:44:23 PM](#)

Issue 7. Incremental Cost/ bbl by ANS Cost (Sensitivity). Discuss the incremental costs of lifting a barrel of oil as ANS rises.

[12:44:32 PM](#)

Ms. Kah reiterated her previous remarks regarding the global resource industry: barrel prices have increased 2.5 times and costs have doubled. While prices might be becoming more stable, costs have continued to increase. It would be expected that over time, costs and prices would "equalize" even though "they might not be the same in any given year". ANS expenses had increased faster than other areas in ConocoPhillips' portfolio due to aging infrastructure and the production declines in certain areas.

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Mr. Hanley proclaimed there to be a problem with establishing a base trigger for Progressivity without a consideration of costs. His argument would be that there was not a direct relationship between the standard "consumer price index (CPI) and the costs that occur in the oil industry". Dr. Kah had shared that in the 1980s, costs to the industry had actually decreased below the CPI. Were a gas pipeline to come to fruition, he suspected that drilling costs and development costs on the North Slope would increase due to competition for steel and labor. Thus, basing such things as Progressivity on net figures rather than on an index would more appropriately reflect actual industry costs.

[12:47:09 PM](#)

Mr. Walker agreed. Such things as increased fuel costs, steel costs, inflation, and global demand on industry goods and services would increase industry costs as barrel prices rose. In addition, "as volume declines, the unit cost per barrel increases", for, as volume declined, the fixed costs of running the infrastructure on the North Slope increased. This would "underscore the need" to increase volume in the pipeline.

Co-Chair Green understood therefore that no standard formula could be applied to "the relationship between the cost of a lower price per barrel and a higher price per barrel".

Mr. Walker affirmed it would be difficult to apply a formula to that process. Nonetheless, there was a clear relationship between the two.

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Mr. Zager stated that as prices remained high, other types of production would become more economical. He also noted that the panel members, being producers, could not represent the entirety of the oil industry in the State. Missing from the equation was a vast number of service businesses. Like the State, the service sectors "see the producers making lots of money". Therefore, they are going to get their rent out of it. The value of their stocks would increase faster than those of the industry because "they are going to continue to extract rent out of the equation. That drives their profitably." This would support Ms. Kah's theory that other costs would eventually catch up.

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Senator Stedman expressed that more concrete rather than abstract information should be gathered. The percentages of cost increases for such things as labor and equipment should be known rather than simply to accept a "blanket statement" that costs would accelerate as prices increased. While there might be "pressure on certain areas", the cost comparisons from last year to this year would indicate that costs decreased. He advised against generalizing.

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Mr. Walker questioned there being a decrease in costs, as his company "has seen very significant pressure on costs in the upward direction".

Co-Chair Wilken agreed with Senator Stedman that a more in-depth discussion should occur regarding the relationship between increasing revenue and costs, as he doubted that a 100 percent increase in revenue would be accompanied by a 100 percent increase in costs. He acknowledged that "incremental costs" would be associated with an increased market place price for oil.

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Mr. Dickinson affirmed that a more detailed answer to this question would be provided.

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Ms. Kah disclosed that BP experienced 15 to 20 percent cost increases over the past year. Those increases had affected every aspect of their operation including drilling rates and other services and labor. She shared that an intense competition for manpower has also occurred.. "There is a serious manpower shortage given the level of activity we have in our company today." She identified replacement costs as being "the biggest factor" in setting "prices in the long term". Those costs would "affect what we actually see as an oil price in the market".

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Mr. Hanley could not disagree with Senator Stedman and Co-Chair Wilken: costs might increase or decrease. They were difficult to measure. However, costs would be taken into account were they applied to the net, as actual expenses would be deducted from the gross. This approach would remove the need to determine "an index". The basis upon which the Progressivity trigger price would be established was a separate issue.

Senator Stedman stressed that, during a more thorough discussion on the mechanics of the Progressivity element, the issue of net must include whether to "include or exclude the use of the credits before we do the calculation". He would support excluding the credits.

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Mr. Barnes observed that prices for products being sold "lead the price for the services that are required to produce it". The experience of the industry had been that "when prices are very high, our costs went up". The "industry contracted" both times prices decreased in the past 15 years. Experience has shown that there is "an intrinsic lag time" following a price increase in which there would be a shortage in personnel and material such as steel. Care must be taken when seeking a relationship between cost and price because of this.

Ms. Kah agreed with the concept of a net profit basis. There was no single indicator to the question of cost. The effort would require a manpower indicator, a drilling indicator, a material cost indicator, and a fuel cost indicator. Utilization of a general inflation indicator would not suffice as there was no relationship between CIP inflation rate and the industry. Therefore, the conclusion was that a net profits basis would be the most appropriate means through which to account for industry costs.

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Mr. Johnston asked for clarification as to whether the references a net basis were to "the escalator for the Progressive feature or are we taking about something based on net verses gross as the tax base for this progressive based tax". To further clarify his question, he stated that "if you had an escalator that was based on just price increases" as was the design presented in both the House and Senate committee substitutes, "that's one thing and it doesn't take into account costs. We know that and that's one of the weaknesses, there's no doubt. In fact there's a bit of irony in inconsistency there to try and create a progressive feature that's going to then govern an ordinarily regressive tax that's a severance tax."

Mr. Johnston continued. "Now you could still leave the progressive element based on oil prices as they've been designed, but have that apply to a profits based tax. And that way, if you have a producer that's agonizing over heavy oil with the higher costs and the lower prices associated with that you'd still use the same escalator but they have a lower profit and therefore they pay less in taxes. Their tax rate might still be too high perhaps, but... so there's two different ways of viewing

this issue of gross verses net, and I'm not exactly certain in the minds of us here which one you guys are actually contemplating, if not both perhaps".

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Mr. Zager replied that the "short answer is both, in that we've got a net profits tax. Its going to be nominally set at 20 percent and the idea is that as profits per barrel grow then not only will the amount you pay grow but the percentage of that tax will grow. And so, that was the concept that you use a net profits trigger to decide when you're making larger profits or windfall profits and then you escalate that percentage as you go".

Mr. Johnston understood therefore that the concept would be to apply the tax rate determined by that to profits.

[12:58:51 PM](#)

Mr. Dickinson understood that the concept being proposed by the producers would be to change both the tax rate base and the progressivity element proposed in both the House and Senate committee substitutes.

Co-Chair Green asked whether the Senate Resources Committee had discussed utilizing net verses gross in the formula.

Senator Stedman affirmed that discussion had occurred.

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Mr. Johnston acknowledged there being "weaknesses" in the House and Senate PPT proposals; however, as Mr. Dickinson had noted, "the credits do apply to costs and, so, when you do have the higher cost environment, that isn't accommodated with this Progressive sliding scale, we do have the progressive element from the credits themselves that do accommodate in a fairly direct way a higher cost situation rather than a lower cost situation. Dollar for dollar though it doesn't have nearly the dramatic affect that the severance tax would, or the PPT tax would".

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Senator Stedman reminded the Committee that the primary purpose of the Progressivity issue "was to keep the regressive nature of what we'd have without it at bay so as prices advanced, the State's share stays relatively flat or slightly increases. Without it we'd have a regressive system in place when we add our taxes and royalties along with our PPT tax. So this is a piece in there to fix an overall problem. And when we get in and start meddling with going from gross to net and taking credits in it and these other issues and setting different trigger points that slide up and down with costs, at the end of the day we still need to make sure it does what it is intended to do and my concern is it gets neutralized and then we're at a regressive state where prices advance and our percent goes down."

Co-Chair Green advised that the discussion had advanced to include Issue No. 9.

Issue No. 9 Progressivity on net vs. gross. Discuss options.

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Mr. Zager agreed with Senator Stedman's perspective; the exception being that he would replace the phrase "when prices go up" to "when profits go up". This distinction would address the "underlying assumption that profits and price are directly linked. They are not, especially" over a lengthy time frame. There could be a scenario "where your prices might go up, costs could stay in parallel so our profits have not increased at all, yet we're getting hit with an excess profits tax because the price is much higher than originally conceived".

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Mr. Johnston specified however, that profits could increase even in a scenario where both price and costs doubled. An example would be a scenario in which barrel prices increased from \$30 to \$60 and costs increased from \$10 to \$20 a barrel. The doubling of prices and costs scenario would generate \$40 in profits as opposed to \$20 in profits at \$30 per barrel price with a ten dollar cost per barrel.

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Mr. Zager communicated that a scenario in which a company's actual profits doubled would trigger an escalator, as it was tied to profits rather than to a percentage of profits. However, were a \$20 profit margin experienced at a barrel price of \$60 as well as \$120, no escalator would be triggered. However, were the rate structured on a percentage change, an increase in the rate could be triggered.

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Mr. Johnston professed there being "a lot of virtue and solid logic behind trying to make this more profits based as opposed to a proxy for profits based" system. However, "getting from the one", as Dan Dickinson would agree, "to the other" was a "complex" process which would require a significant amount of consultant time. The complexity of this process had been challenging and "agonizing" to not only the Legislature but to consultants as well.

Co-Chair Green acknowledged.

Mr. Walker added to the discussion pertaining to the Progressivity question in Issue 9. The question revolved around net verses gross. His company would prefer net "because it is reflective of the profits".

Mr. Walker stated that the PPT provisions proposed in CSSB 305 were "too complicated. Alaska has a extremely complex fiscal system and we would certainly encourage you to ultimately select something that is transparent and as simple as possible".

Mr. Walker did not support the Progressivity component in CSSB 305. "We think the regressive nature of Alaska's tax regime combined with Progressivity makes it less attractive. But if you were to have progressivity, if you really feel that progressivity is part of the ultimate solution, then we would suggest steering you towards something very simple." A two tier or three tier system has been suggested in which "you choose a different production tax for different tiers, depending on the price. And that tax rate could be chosen in the broad operating band of prices as a tax rate that would genuinely attract investment to Alaska so therefore we would say something lower than 20 percent." When prices were high, the State "could afford to adopt a slightly higher tax rate and get higher share, and then at the very low prices, where everybody acknowledges

the industry is really struggling, perhaps adopt a significantly lower tax rate when industry really does need some serious help."

Mr. Walker concluded that there were numerous ways to revise the tax structure. "And we would just say that if you are determined that progressivity is part of the final solution, that we would suggest something very simple. We'd also give credit to John's [Hanley] proposal around trying to tie it to profits, because moving it towards actual profits is always a good thing."

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Mr. Johnston specified "the conflict though" would be that keeping it simple and having it based on net would be difficult. It was actually quite simple as proposed. It's "one flaw" was that "it's not profits based, not fully profits based. If we depart from what has been proposed, it ain't going to be simple."

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Ms. Kah characterized the original PPT bill, SB 305, as being regressive and the Committee was "talking about making it even more regressive". The industry considered CSSB 305's Progressivity element, which would be triggered by higher oil prices, to be a windfall profits tax. "We think its adding complexity, particularly because it's on a different basis, it's on the gross whereas the PPT itself is on profits. It's taking away the upside which I think really does hurt our project economics, so it will discourage investment and it will reduce the production and jobs in the long term, even if it does have a short term revenue benefit." However, were the Committee to support the Progressivity component, the industry would urge basing it "on a net basis. Do it on the same basis as the PPT itself, and that would get rid of some of the complexity." In addition, she urged that the trigger price for Progressivity be set "at a high enough level that it would have minimal interference with our project economics..."

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Mr. Johnston disagreed with the majority of Ms. Kah's statements. He would not characterize a windfall profits tax as "an evil thing". Since the provisions in the House and Senate

committee substitutes would slightly increase the State's take beyond that proposed in SB 305, it would be "unfair" to suggest that the State would be taking away the "upside" when prices increased. The House and Senate's effort were for the State "to participate a little bit more in the upside". He preferred the progressive nature of the House and Senate bills to that proposed in SB 305.

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Ms. Kah reminded the Committee that the windfall profits tax levied by the federal government in the 1980s had been detrimental to the nation's economy. Studies found that "it did reduce investment in production and greatly increased imports in the United States". BP's prospective projects were evaluated under prices ranging from \$20 to \$80 a barrel. Probabilistic weightings were applied to the various prices. Removal "of the upside would lower the expected value of the project". It would be unrealistic to think that that might not hurt a project's economics.

Senator Stedman expressed that "the devils in the detail in this one". There would be "a smaller probability of prices at \$60 and \$80 than there is at \$40 and \$50 and \$30". The proposal being furthered in CSSB 305 differed from the federal windfall profits tax as it would implement a tax to keep "the government take basically flat".

Senator Stedman requested that the State's consultants provide an analysis that would consider the lower probability of prices ranging in the \$70 or \$80 range. He expected that the impact would not be "very big". The progressivity issue was "not even remotely close" to the federal windfall profits tax scenario. This purpose of this effort was "to keep the government take figures flat as prices" advance. A system that would balance the State take over a range of prices would be preferred to one that "was unbalanced into the disfavor the State".

Co-Chair Green asked whether the information requested by Senator Stedman might have been previously provided.

Mr. Johnston affirmed that the information had been included in one of the earliest PPT presentations.

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Mr. Johnston characterized the tax structures proposed by the House and Senate as progressive in that they would not hold the government take neutral as oil prices increased.

Mr. Johnston stated that the windfall profits tax levied by the United States government "in the 1970s and 1980s was poorly designed and didn't meet the objectives for which it was designed". The United States' windfall profits tax was only one of several nations' efforts that have existed. "Most of them have worked fairly well at least in the eyes of the countries that have them now. Most countries wish they had had them at this point in time and most of them did not behave as poorly as ours did back then."

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Mr. Zager revisited the "complexity issue". The PPT would require companies to calculate their net profits each month through a complex calculation methodology. Companies maintain an accurate accounting of the number of barrels of oil produced each month, "so the additional step of dividing the net profits by the barrels and coming up with a number doesn't seem to add a lot of complication".

Mr. Barnes stated that the complexity issue was a concern. "We can all accept being taxed. We do that as citizens. We can all accept a tax rate that changes, but you'd like to be able to manage the issues that you manage." He was "worried about taxes that are linked with either outside indices or events that are outside of my control as an operator. If I can control my costs better and I actually increase my profitability per barrel then perhaps it is okay for that to be shared with the State".

Mr. Barnes stated that basing the PPT on basing the PPT on a net basis "more accurately reflects the operator's ability to do his business correctly and share whatever benefit he might create."

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Mr. Walker disclosed that BP had determined that, under CSSB 305, the State take would be 63 percent as compared to a 61 percent tax rate under SB 305. That 63 percent would increase to 67 percent were barrel prices to increase to \$100. The Senate system would be progressive. The objective of holding government

share flat as prices increased "would be a very different thing that what is currently proposed". He would appreciate BP being advised were its interpretation of the bill incorrect.

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Mr. Dickinson shared that the Administration would prefer to make the windfall profits issue irrelevant, either by removing the Progressivity element or by moving the trigger point to such a high point, \$100 or \$120 for example, "that you're truly dealing with extraordinary price interruptions. At that point, net verses gross is not a real difference."

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Senator Stedman communicated that, absent the Progressivity component, the State would experience a regressive tax system at prices in the \$40 to \$70 a barrel range. This would not change were the trigger point moved to a barrel price of \$100 or more.

Senator Stedman stated that the goal was "to keep everything kind of stable through the price ranges".

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Mr. Dickinson cautioned against confusing total government take with State take.

Issue 8. Acceptability of 2 for 1 provision and appropriateness of a sunset

[1:18:02 PM](#)

Co-Chair Wilken recalled that in prior meetings, Mr. Hanley, Mr. Barnes, and Mr. Zager suggested that the seven year timeframe for the two for one provision be increased. Thus, he inquired how extending the time period to ten years would affect the State. Currently this provision would allow investments made five years prior to the effective date of the bill to qualify on a two for one basis for seven years after the effective date.

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Mr. Johnston communicated that, while it was be unlikely that the industry could recoup those costs in seven years, the State

would experience little, if any, difference were the time frame extended to ten years. The two for one provision would offer "an additional incentive for investment". He supported the look-back provision to a certain extent. He was less concerned about the termination date relating to this provision than he was to the timeframes of such things as the \$73 million allowance or the \$12 million credit or the 5,000 barrel per day exemption provisions addressed in Issue 3.

Mr. Dickinson further clarified the math pertinent to this provision. The two for one five year investment/seven year recoupment period would require a producer to "spend 40 percent more per year to make the total recoupment". Were the provision to specify a one dollar recoupment for each dollar spent in a five year period, the producer would have to "spend 70 percent in each year to recoup the same amount over seven years". Therefore, the two for one recoupment formula would require a producer to double that expenditure to 140 percent per year over seven years to recoup their investment. Were the seven year recovery period expanded to ten years, a producer would be required to spend the same amount per year "in those ten years as you did in the five years prior because you'd be doubling on the one end and halving on the other".

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Mr. Walker considered transition provisions to be appropriate and appreciated the two for one recoupment provision included in CSSB 305. It would be a good solution as more investment would be required in the State. Industry requested that the transition provisions be designed in a manner through which a company which had invested capital could "genuinely take the benefit" of the provisions. In addition, BP would suggest that "the \$40 test" be eliminated in order to allow the full benefit of the transition provisions.

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Mr. Hanley stated that one's view of the transition provisions would depend on "where you are in a point of time, and what your plans are already". His company worked with ConocoPhillips on many projects, including a 22 percent ownership of a \$400 million dollars investment in two satellite fields in the State during the past year and a half. Depending on what projects were being considered, it might be unrealistic for his company to

invest an additional 40 percent. Companies planning to participate in the construction of a gas pipeline would be able to make such expenditures.

Mr. Hanley stated that his company's position would align with that of the Administration. The desire would be to allow investment recoupment without consideration of such things as the two for one provision. In order to allow "the State to pick up 40 percent of the costs", his company would have delayed its recent work a year. Instead, his company's investment decisions were based on the rules of the existing tax regime and high oil prices.

Mr. Hanley acknowledged however that the two for one provision would be an incentive for a company to invest more. His company would be better served by a ten year recoupment timeframe.

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Mr. Johnston asked Mr. Hanley whether the pipeline expenditure opportunity he had referenced was to Point Thomson and the central processing facility pipeline expenditures, as only those pipeline projects "would be eligible for the credits and applied to this as well".

Mr. Hanley affirmed. A lot of dollars would be spent in existing fields as well as in future fields.

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Mr. Hanley reiterated that the timing of a project's expenditures was a consideration. A recent \$100 million dollar investment made by Pioneer Natural Resources was an example of a project that would benefit from the two for one provision. That company would be able to recoup that expenditure since it had plans to spend an additional \$300 million on the project in the next few years. On the other hand, Mr. Hanley's company's expenditure was made too early to benefit from this provision. This was an example of the timing issue associated with the provision.

Ms. Kah agreed with the remarks pertaining to this issue. BP was appreciative of the two for one transition provision as its plans would accommodate such expenditures. However, "as a matter of fairness", a one for one recoupment provision would be "more

fair in terms of rewarding people who haven't delayed their projects, who have been investing in the past".

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Mr. Barnes spoke to the investment scenario in Cook Inlet. It would be difficult to determine whether a significant amount of investments would occur there. "Not only is it being timed out, but there is also the operating environment that you're in". Thus, while the two for one provision would be of value, the proposal included in the original bill would be the preferred approach.

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Co-Chair Green asked Mr. Dickinson whether consideration had been given to allowing a company to choose between two options. A company such as Anadarko might be better served by a five year look-back program while a company such as BP or ConocoPhillips might be better served by the two for one provision.

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Mr. Dickinson stated that providing two options could be considered. SB 305 specified that a company would "get the recovery if you had come in and spent". If the company left the State, no recovery would be forthcoming as "you would need something to take it against so there would have to be continuing economic involvement". That was a very important consideration to the Administration.

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Co-Chair Wilken stated that it was a struggle to keep abreast of "all these moving pieces" in this legislation., To that point, he asked whether the two for one component would be considered "a major or minor portion of moving from the 16 percent net tax ... closer to the historical rate" depicted on Chart 90.

Discussion ensued between Co-Chair Wilken, Mr. Dickinson, and Mr. Johnston about how two for one component might impact the graph lines on Chart 90.

Mr. Walker joined the conversation and specified that a company would only benefit from the two for one component were it to continue investing in the State.

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Mr. Dickinson clarified that the information on Chart 90 was based on SB 305, which did not contain the two for one provision. That provision was included in CSSB 305.

Issue 9. Progressivity on net vs. gross. Discuss options.

Co-Chair Green stated that this issue had been addressed earlier in the discussion.

Issue 10. Cap on Progressivity. Discuss options

[1:31:53 PM](#)

Mr. Walker stated that "clearly the concept of having uncapped progressivity would be very dangerous" because of such things as market conditions, and price and cost changes.

Co-Chair Green understood that the industry was opposed to Progressivity. Thus, were one included in the PPT, the industry would support an upward limit on it.

Mr. Johnston stated that consideration of a limit should "depend on the nature of the Progressivity". However, imposing a limit would be "a contradiction in terms" for "if you're going to be progressive, you're progressive".

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Co-Chair Wilken assumed chair of the meeting.

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Issue 11. Progressivity trigger. Discuss options

Co-Chair Wilken noted that a variety of trigger points from \$40 upwards had been discussed.

Mr. Dickinson emphasized the fact that the higher the dollar amount of the Progressivity trigger, "the less impact there

would be on investment decisions". Thus, he hoped the Committee would "take it out of the range where it would negatively impact investment decisions".

Co-Chair Wilken expressed that that point would be "a function of modeling and a general comfort level of those who have to make the decision".

Mr. Dickinson stated that even though investment decisions consider a wide range of oil prices, the industry would not rely on the high price to support a project's basic economics. The decision would instead be "how robust is this under various prices".

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Mr. Johnston stated that the issue of how far to increase the price of the Progressivity trigger would be "a function of the slope of the progressivity element. He would be uncomfortable with a starting point much greater than \$40 per barrel, considering the slopes being discussed.

Co-Chair Wilken stated that one factor in making the "final decision" would be whether the ultimate goal was to maintain "a relatively flat" or to slightly increase government take.

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Mr. Johnston stated that the inclusion of a Progressivity element in the PPT would indicate that the Legislature was not content to maintain "a relatively flat overall" or neutral government take. The progressive element "must be sufficiently aggressive to overcome the regressive affect of the royalty, but it is aided to a certain extent by the progressive affect of the credits. The credits almost in and of themselves neutralize the royalties that exist and that's why the system as it's proposed by the Governor was fairly neutral". SB 305 actually held Government take fairly constant under most circumstances.

Mr. Johnston stated that "if we agree that it should be a system that's progressive" then the question was how progressive should it be. "Part of the answer to that question is looking around the world to see how progressive systems are when they are progressive. About 20 to 25 percent of the systems in the world are progressive to one degree or another". He considered a

Progressivity feature that increased government take by five percent to be "fairly modest by world standards as far a progressive systems go". A five percent increase, in his perspective should be the "absolute minimum". The State should not impose "the least progressive of all the progressive systems on this planet. And I don't think we necessarily need to be average in that regard, but the slope has got to reflect our views of what would be appropriate and we're just on the low side in my opinion as its designed now in both the House and the Senate".

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Ms. Kah rebutted that it would be "particularly important to minimize shaving off the upside for Alaska" because Alaska "is viewed as a price play in our portfolio" due to the high cost of doing business. Imposing Progressivity on "the upside above \$40 a barrel" would be detrimental to the "attractiveness of Alaska in our portfolio". She urged the Committee to increase the Progressivity trigger point to the upper range of the prices considered in the industry's economic modeling".

Mr. Walker noted that the government take at \$40 a barrel under a 20/20 tax regime would be 66 percent. At \$20 per barrel it would be 115 percent. "It takes a long time for you to move away from the fact that you already have a regressive regime that takes royalties from gross revenue. And the government take at low to medium prices is very high". Therefore, setting the Progressivity trigger point within a \$40 to \$60 a barrel price would curtail the benefits to industry and "therefore the attractiveness of Alaska."

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Co-Chair Green resumed chair of the Committee.

Co-Chair Wilken asked regarding the calculation supporting the 66 percent government take number.

Mr. Walker stated that that number was based on "BP's financials".

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Senator Hoffman also asked for further information in this regard.

Mr. Walker stated that at \$20 per barrel, the government take was 115 percent. At \$40 per barrel the government take was 66 percent and at \$60 per barrel the government take was 62 percent. BP had previously provided this information, but could redistribute it.

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Mr. Johnston communicated that revisiting these numbers would be helpful. BP's government take statistics at those prices differed from information provided by ConocoPhillips.

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Mr. Bramley expressed that Mr. Johnston might be referring to ConocoPhillips' statistics which were specific to a new 50 million barrel field. That calculation indicated that both the existing system and the PPT as proposed in SB 305 "were quite severely regressive at lower prices". At a price of \$20 per barrel the government take on that new field would be approximately 70 or 80 percent.

Mr. Walker clarified that the information provided by BP reflected how the PPT would affect the entirety of BP's operations in the State.

Co-Chair Wilken referred to an unspecified chart [copy not provided] and asked Mr. Walker to confirm that at a \$40 barrel price, the total government take under ELF would be 63 percent. Total government take under the PPT at that price would be 66 percent. The total government take at \$60 would be 57 percent under ELF and 62 percent under the PPT. The State's portion of the government take at \$40 under PPT would be 44 percent and the State take at \$60 would be 40 percent.

Mr. Walker affirmed.

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Senator Hoffman clarified that these numbers pertained to SB 305 and therefore would "not reflect the higher numbers" in either the House or Senate committee substitutes.

Mr. Walker appreciated Senator Hoffman's clarification. BP's statistics were based on the 20/20 PPT as proposed in SB 305. The State take would increase under the House or Senate committee substitutes; BP's take would decrease.

Co-Chair Wilken clarified that the BP statistics reflected the government take under the original PPT bill.

Mr. Walker affirmed.

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Issue 12. Cook Inlet Provision, Should Cook Inlet be treated differently

Mr. Zager recognized Cook Inlet as being "very different from the North Slope", since Cook Inlet does not compete for capital on the global market, and a comparison to other regimes with escalators would not be applicable. Cook Inlet competed only for domestic capital. It would be appropriate to treat Cook Inlet differently as it was very mature in its life cycle.

Senator Hoffman asked whether the Nenana Basin and Bristol Bay should also be treated differently.

Mr. Zager stated that would be a policy call. There was "good rationale" for treating those new and isolated basins differently.

Senator Dyson asked how providing royalty relief would affect Cook Inlet, as he understood that the credits and other provisions in the bill would provide "a significant boom for Cook Inlet explorers" in both their successful and unsuccessful exploration efforts. That was not currently the case. He asked for further information about how the tax credit and royalty might interplay and what the Legislature might do to royalties that might further incentivize gas exploration and production in Cook Inlet.

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Mr. Zager understood that the royalty reduction would apply to certain Cook Inlet oil platforms were they to fall below certain production levels. This bill would expand incentives; only

remote fields or successful efforts had previously "enjoyed" such benefits. The PPT would provide additional incentives for gas exploration in Cook Inlet. He had not considered how the royalty structure could be changed to further encourage gas exploration, as he understood they were to continue status quo.

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Mr. Barnes stated that the provisions of CSSB 305 would provide "better predictability" about credits and royalties. This would allow a company to make knowledgeable decisions to things within their control or things that "are predictable as opposed to what's going to be discussed or negotiated". Anything that could be factored into a projects' economics would be beneficial to investment decisions.

Mr. Barnes reiterated that Cook Inlet should be treated differently, particularly in consideration of its marginal and aging fields. These considerations were addressed in ELF and should be considered in the PPT. Credits might not be the appropriate tool for a company might find itself in a position "where you will not spend money to try to recover lost taxes. That's the future of every oil field and gas field in the State." Taxes would increase operating expenses, and as a result, increase what would be "required to pay your bills and you'll shut in fields sooner, you'll reduce ultimate recovery, which is reserves, and you'll reduce near term production."

Mr. Barnes appreciated the discussion regarding "how steep the State take is at low prices", as the term "low prices was surrogate for the word low margins". Cook Inlet "is a test case for what will become of all the other basins in the field, its' just a matter of time".

Mr. Barnes responded to Senator Dyson's question by stating that any tool that was "predictable and that works around the margins" "would be worthy of discussion.

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Mr. Johnston observed that while the credit provisions contained in the bill "have a lot of virtue" in regards to furthering exploration and development investment in the State, they would not offer "downside protection" to oil companies or assist in

"extending the life of an otherwise marginal field or dealing with a situation where oil prices get quite low".

Mr. Johnston pointed out that the concern about government take exceeding 100 percent was not limited to Alaska. This scenario would "more likely" occur in Alaska's since many of its marginal fields were approaching their economic limit. A profits based tax system would not provide relief on a marginal field because it was tied to profits. In contrast, royalty taxes could be adjusted downward as they are not based on profits. This mechanism has been used under ELF to "accommodate the marginal platforms in the Cook Inlet".

Mr. Johnston stated that the credit provisions contained in the PPT proposal would assist in furthering exploration; however, "at \$20 a barrel or \$25 a barrel there's nothing you can do with this fiscal system, as far as Cook Inlet is concerned for sure. And as far as the North Slope, and some of those places, as \$20 to \$25 a barrel, there's almost nothing you can do with this fiscal system and so I say don't worry about that so much."

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Senator Dyson could not pinpoint the cause of his frustration: it could be "his ignorance" of the subject, his inability to properly pose his question, or "the feeling that you guys didn't answer my question". Continuing, he asked for confirmation that the State's royalty tax on gas in Cook Inlet was approximately 12.5 percent.

Mr. Barnes affirmed that the royalty tax rate in Cook Inlet was 12.5 percent.

Senator Dyson thus questioned whether lowering that tax rate further would encourage gas exploration in Cook Inlet.

Mr. Barnes apologized for not directly answering Senator Dyson's earlier question. The complication on "straight royalty relief" in Cook Inlet was that there was also private and federal royalty taxes in addition to the State's royalty tax. Thus, while the State had alleviated some of its royalty impact, "in the past, the track record on actually achieving royalty relief" had been mixed. This was a complicated issue.

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Senator Dyson asked Mr. Johnston to explain why more effort had not been applied to the gas royalty issue.

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Mr. Johnston responded that "royalty relief, if it could be accomplished, would make a difference, no doubt". However, one should be mindful that gas royalty rates were not a significant issue in Alaska as its gas reserves were remote and less valuable than oil. On a worldwide scale the typical government take on gas was ten percent lower than the oil tax rates. Alaska's terms were inline with the majority of other gas tax terms.

Mr. Johnston thought that the \$73 million credit provisions included in SB 305 would have encouraged gas exploration when gas prices were "sufficiently high". Even though that provision was changed in the House and Senate PPT bills, were the royalty rate cut "in half ... you'd get these guys attention".

Issue 13. Transitional Capital Look-Back. Discuss options

Issue 14. Impact on PPT on Facility Access Fees

Issue 15. Profit in Tankering/Pipeline. Should profit in transportation be included as a cost.

Issue 16. Effective Date. April 1, 2006 or July 1, 2006

Issue 17. 95% safe harbor and quarterly true-up. How the industry is treated by other tax collectors

Co-Chair Green noted that due to other Legislative commitments, the hearing must conclude. To that point, she asked the panelists to provide written responses to the five issues that had not been addressed, particularly Issues 13, 16 and 17.

Co-Chair Green thanked the panel for their participation.

The bill was HELD in Committee.

#

**ADJOURNMENT**

Co-Chair Lyda Green adjourned the meeting at [1:54:56 PM](#).