

ALASKA STATE LEGISLATURE
SENATE RESOURCES STANDING COMMITTEE

March 7, 2006

3:39 p.m.

MEMBERS PRESENT

Senator Thomas Wagoner, Chair
Senator Ben Stevens
Senator Fred Dyson
Senator Bert Stedman
Senator Kim Elton
Senator Albert Kookesh

MEMBERS ABSENT

Senator Ralph Seekins, Vice Chair

COMMITTEE CALENDAR

SENATE BILL NO. 305

"An Act repealing the oil production tax and gas production tax and providing for a production tax on the net value of oil and gas; relating to the relationship of the production tax to other taxes; relating to the dates tax payments and surcharges are due under AS 43.55; relating to interest on overpayments under AS 43.55; relating to the treatment of oil and gas production tax in a producer's settlement with the royalty owner; relating to flared gas, and to oil and gas used in the operation of a lease or property, under AS 43.55; relating to the prevailing value of oil or gas under AS 43.55; providing for tax credits against the tax due under AS 43.55 for certain expenditures, losses, and surcharges; relating to statements or other information required to be filed with or furnished to the Department of Revenue, and relating to the penalty for failure to file certain reports, under AS 43.55; relating to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue, under AS 43.55; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the oil and gas production tax; relating to the deposit of money collected by the Department of Revenue under AS 43.55; relating to the calculation of the gross value at the point of production of oil or gas; relating to the determination of the net value of taxable oil and gas for purposes of a production tax on the net value of oil and gas; relating to the definitions of 'gas,' 'oil,' and certain other terms for purposes of AS

43.55; making conforming amendments; and providing for an effective date."

HEARD AND HELD

PREVIOUS COMMITTEE ACTION

BILL: SB 305

SHORT TITLE: OIL AND GAS PRODUCTION TAX

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

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|----------|-----|---|
| 02/21/06 | (S) | READ THE FIRST TIME - REFERRALS |
| 02/21/06 | (S) | RES, FIN |
| 02/22/06 | (S) | RES AT 3:30 PM BUTROVICH 205 |
| 02/22/06 | (S) | Heard & Held |
| 02/22/06 | (S) | MINUTE(RES) |
| 02/23/06 | (S) | RES AT 3:30 PM BUTROVICH 205 |
| 02/23/06 | (S) | Heard & Held |
| 02/23/06 | (S) | MINUTE(RES) |
| 02/24/06 | (S) | RES AT 3:30 PM BUTROVICH 205 |
| 02/24/06 | (S) | Heard & Held |
| 02/24/06 | (S) | MINUTE(RES) |
| 02/25/06 | (S) | RES AT 9:00 AM BUTROVICH 205 |
| 02/25/06 | (S) | -- Reconvene from 02/24/06 -- |
| 02/25/06 | (H) | RES AT 10:00 AM SENATE FINANCE 532 |
| 02/25/06 | (S) | Heard & Held |
| 02/25/06 | (S) | MINUTE(RES) |
| 02/27/06 | (S) | RES AT 3:30 PM BUTROVICH 205 |
| 02/27/06 | (S) | Heard & Held |
| 02/27/06 | (S) | MINUTE(RES) |
| 02/28/06 | (S) | RES AT 3:30 PM BUTROVICH 205 |
| 02/28/06 | (S) | Heard & Held |
| 02/28/06 | (S) | MINUTE(RES) |
| 03/01/06 | (S) | RES AT 3:30 PM BUTROVICH 205 |
| 03/01/06 | (S) | Heard & Held |
| 03/01/06 | (S) | MINUTE(RES) |
| 03/02/06 | (S) | RES AT 1:30 PM BUTROVICH 205 |
| 03/02/06 | (S) | Heard & Held |
| 03/02/06 | (S) | MINUTE(RES) |
| 03/02/06 | (S) | RES AT 3:30 PM BUTROVICH 205 |
| 03/02/06 | (S) | Heard & Held |
| 03/02/06 | (S) | MINUTE(RES) |
| 03/03/06 | (S) | RES AT 3:30 PM BUTROVICH 205 |
| 03/03/06 | (S) | -- Meeting Canceled -- |
| 03/04/06 | (S) | RES AT 10:00 AM SENATE FINANCE 532 |
| 03/04/06 | (S) | Presentation by Legislative Consultants |
| 03/06/06 | (S) | RES AT 3:30 PM SENATE FINANCE 532 |
| 03/06/06 | (S) | Heard & Held |

03/06/06 (S) MINUTE(RES)
03/07/06 (S) RES AT 3:30 PM BUTROVICH 205

WITNESS REGISTER

MICHAEL D. WILLIAMS, Chief Petroleum Economist
Tax Division
Department of Revenue
550 West 7th Avenue, Suite 500
Anchorage, AK 99501-3566

POSITION STATEMENT: Testified on SB 305 and answered questions.

DAN DICKINSON, CPA
Consultant for the Governor
Office of the Governor
PO Box 110001
Juneau AK 99811-0001

POSITION STATEMENT: Testified on SB 305.

ROBYNN WILSON, Director
Tax Division
Department of Revenue
PO Box 110400
Juneau, AK 99811-0400

POSITION STATEMENT: Presented Questions and Answers relating to SB 305.

ACTION NARRATIVE

CHAIR THOMAS WAGONER called the Senate Resources Standing Committee meeting to order at [3:39:25 PM](#). Present were Senators Ben Stevens, Bert Stedman, Fred Dyson, Kim Elton and Chair Thomas Wagoner; Senator Kookesh arrived shortly thereafter.

^#SB305

SB 305-OIL AND GAS PRODUCTION TAX

[3:39:25 PM](#)

CHAIR WAGONER announced SB 305 to be up for consideration. He noted the committee would begin with hearing a presentation from the Department of Revenue.

^DEPARTMENT OF REVENUE - Michael Williams, Chief Petroleum Economist

[3:41:08 PM](#)

MICHAEL D. WILLIAMS, Chief Petroleum Economist, Tax Division, Department of Revenue (DOR), gave some personal background and said he would speak about future crude oil production volumes in Alaska. First, however, he would address earlier forecasts.

SENATOR KOOKESH arrived at [3:41:08 PM](#).

MR. WILLIAMS showed a slide labeled "Fall Oil Production Forecasts," pointing out that with the exception of one data point on the graph, forecasts have overestimated production in Alaska. There are two reasons. First, the Prudhoe Bay field, having produced for close to 30 years, is subject to problems associated with an aging field such as leaks in pipelines and second, the North Slope's viscous oil requires new technologies to develop. Many of these projects have been delayed as a result. The department's forecast for heavy oil production reflects this delay.

[3:44:53 PM](#)

In the near term, DOR has incorporated revised reservoir-performance analyses for declining fields, reviewed the uncertainty associated with the pace and scope of developing satellite fields and reevaluated unplanned downtime at all fields, especially Prudhoe Bay. This resulted in an average net reduction of about 30,000 barrels a day a year over the next five years. Roughly half this reduction relates to reservoir performance and facility downtime; the other half relates to the pace of development of heavy oil, primarily at West Sak. The forecast for ANS production averages slightly above 800,000 barrels a day for FY 07 through FY 11.

He explained that ANS crude oil production is characterized in three ways - 1) currently producing, 2) currently under development and 3) currently under evaluation - each with a discrete estimated confidence level. Highlighting the uncertainty of production forecasting, Mr. Williams indicated DOR continues to forecast production of only reserves that have already been discovered and that are being evaluated for development.

MR. WILLIAMS showed a graph labeled "ANS Historical & Forecast Production: Millions of Barrels per day, FY 1978-2005 & FY 2006-2016" and said the "currently producing" category includes baseline production and presumes a continued level of expenditure sufficient to promote safe, environmentally sound operations.

[3:47:50 PM](#)

He noted such expenditures include well diagnostic and remedial work, in addition to data acquisition and rate-enhancing expenditures such as perforating and acid stimulation, well work-overs, fracture treatments, artificial lift optimization and production-profile optimization. This category presumes continued gas and water injection for pressure support. Based on historical forecasting performance, DOR assigns a 98 percent confidence level for the current fiscal years.

He next addressed the "under development" area on the graph, which is based on new projects currently funded and in the design or construction phase, as well as development drilling and enhanced oil recovery, whether miscible or immiscible, injection projects currently funded or underway. It doesn't include those same projects if they are in the "currently producing" category. It also includes incremental oil expected from the long-term gas cap water-injection project at Prudhoe Bay and the low-salinity water flood at Endicott. Examples of production under development include the Fiord and Nanook satellite fields at Alpine, the remaining J Pad development at West Sak, development drilling at Schrader Bluff and certain satellite developments at Prudhoe Bay.

He reported that the pace of development at all heavy-oil fields has been slowed to allow proper mitigation of challenging commercial and technical issues. Because of timing and scope uncertainty, Mr. Williams said, DOR's subjective confidence for this category of production is lower, 80-85 percent.

He turned to the "under evaluation" category on the graph, noting it includes technically viable projects currently in the "pencil sharpening" stage where engineering costs, risk and reward are being actively evaluated. Although currently unfunded by the operators, these projects have a high chance of being brought to fruition. They include enhanced oil recovery at certain satellite fields, development drilling outside the core areas at West Sak and Schrader Bluff expanded development at Prudhoe Bay satellites including Orion, Polaris and Borealis, and Alpine West development. Also included are National Petroleum Reserve-Alaska (NPR-A) development, Point Thomson, Liberty and development of other onshore and offshore discoveries.

MR. WILLIAMS said DOR is forecasting production from four small pools in the vicinity of known discoveries currently named Lookout, Moose's Tooth, Spark and Rendezvous in the NPR-A.

Since these discoveries were announced, there has been ongoing exploration outside their boundaries and explorers continue to push further west in search of new development opportunities.

He explained that confidence levels vary by category of production. Certain heavy-oil drilling for Schrader Bluff, Orion or West Sak in 2007 may have confidence levels approaching those in the category "under development." In general, however, offshore development such as Liberty or potentially high-cost development such as Point Thomson deserve lower confidence; thus DOR's subjective assessment is 70-75 percent.

He noted all production from this category is subject to delays and scope changes that might impact reserves or production rates. For example, Point Thomson has been delayed in the forecasts three times since 2000. There are 65,000 barrels of day of natural gas liquids (NGLs) associated with Point Thomson. However, a delay at Point Thomson also delays 35,000 additional barrels associated with the satellite fields.

He informed members that many details surrounding this forecast are based on petroleum engineering knowledge. His advanced degree is in economics, but he has lived in Alaska only one year and isn't intimate with details regarding all these fields. Thus for the more involved questions relating to geology and engineering, he'd turn to the petroleum engineer who prepared these forecasts.

He concluded by saying developing crude oil resources will require significant investment in time and capital. Under the governor's proposed tax system, the petroleum production tax (PPT) creates a fiscal framework that provides strong incentives for exploration and reduces the risk in capital costs of development. Most important, it provides a long-term revenue stream to the state by encouraging new participants and supporting new developments.

[3:53:27 PM](#)

MR. WILLIAMS, in response to Chair Wagoner, indicated he'd just come from a press conference at which the summary data was released for DOR's revenue forecast. For FY 06, when all volumes are put together with the price forecast, it comes out to about \$4 billion; for FY 07 it's about \$3.4 billion; and for FY 08 it's close to \$3 billion. He agreed to e-mail his presentation to the committee aide.

[3:54:03 PM](#)

SENATOR BEN STEVENS requested clarification about the first slide, "Fall Oil Production Forecasts."

MR. WILLIAMS explained that the point estimates are forecasts for each fiscal year going out to 2010 that consistently overestimated what actually occurred on the production side.

[3:55:57 PM](#)

MR. WILLIAMS, in response to Chair Wagoner, indicated he could find out percentages relating to the aforementioned from the petroleum engineer.

CHAIR WAGONER requested that Mr. Williams send that to the committee along with the presentation.

[3:56:30 PM](#)

MR. WILLIAMS responded further about the graph on the first slide, saying those are just volumes. Affirming that the new forecast released today shows new production as well, he agreed the graph doesn't show the projected drop of 30,000 barrels a year for the next five years. He said the FY 06 forecast for the North Slope is 854,000 barrels a day; for FY 07 it's 825,000 barrels a day; and for FY 08 it's 803,000 barrels a day.

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MR. WILLIAMS reported he and the petroleum engineer, Dudley Platt, figured out that the aging field at Prudhoe Bay and the heavy oil caused virtually all the problems with overestimating; thus Mr. Platt was taking those two factors into account and trying to be more realistic. Expressing support for the good job Mr. Platt had done, Mr. Williams said these issues also highlight the fact that the state needs investment to maintain and possibly increase production.

[4:00:21 PM](#)

SENATOR BEN STEVENS opined that as much as the production has been overprojected, revenue has been under projected. He added that the new release says revenues are up, even though production is down.

MR. WILLIAMS replied that in the last ten years, prices were underestimated four times and overestimated four times. The Office of Management and Budget (OMB) compared DOR's price forecasts with those of three other organizations - U.S. Department of Energy, NYMEX, and Cambridge Energy Research Associates - and found DOR's to be the best, though not to a

statistically significant degree. Thus he encouraged positive thinking about DOR's ability to forecast crude oil prices.

4:01:41 PM

SENATOR BEN STEVENS asked about the accuracy of oil-price forecasts and its relationship to the Henry Hub price or "futures prices of gas." He asked whether Mr. Williams was familiar with a "six to eight times" multiplier and if he had used it as part of the formula.

MR. WILLIAMS replied he was familiar, but not intimate, with it. Crude oil is an international commodity traded on exchanges worldwide; a price for crude oil in London will be the same in New York and everywhere, accounting for transportation differentials. For natural gas - different in this country from liquefied natural gas (LNG) shipped around the world - there are two large oceans on either side and very little gas comes north or south. Thus the gas price at Henry Hub has constraints based on the available supply within this country. There aren't enough import facilities to import enough gas to balance supply and demand, part of the reason the relationship between gas and oil is so difficult to forecast.

He affirmed there is a six-to-one relationship, based on Btu content and the ability to substitute natural gas for certain products. For example, gas or petroleum could be used for feedstock in production of petrochemical products. In the bigger picture, however, natural-gas prices at Henry Hub are constrained because there isn't enough supply.

The natural gas industry has been regulated in this country from 1969 to 1998; many industries were established and built pipelines to bring gas in. In 1996-1998, that changed. Many of those companies are now having difficulty because gas prices have gone so high. For instance, the petrochemical industry has about a third fewer people than ten years ago. He said he doesn't know what will happen with gas prices or whether that six-to-one ratio will be there in the future. Forecasting natural gas for the U.S. is far more challenging than oil because of the limited time in which it has been available on the free market. Since December 13, for example, the price at Henry Hub has dropped 57 percent. Furthermore, Mr. Williams said he didn't know how the industries would "play out." For instance, would petrochemical just shift their production capacity to someplace like Qatar? That would influence demand for natural gas on the commercial side.

SENATOR BEN STEVENS expressed appreciation for hearing something he hadn't heard before.

[4:06:04 PM](#)

SENATOR STEDMAN asked whether Mr. Williams planned to do a "trumpet-type" graph depicting a low, medium and high range in terms of price and volume, to show what might reasonably be expected.

[4:07:13 PM](#)

MR. WILLIAMS replied he was looking at that and believed it had been done in the past. It's rather challenging to do, however, because if distribution range is too wide, it provides almost worthless information. In further response, he said the long-term crude oil price forecast after FY 09 is \$25.50 a barrel.

[4:08:07 PM](#)

SENATOR STEDMAN asked what time period was addressed when Mr. Williams talked about DOR's accuracy in forecasting when compared with the other three organizations.

MR. WILLIAMS answered, "The only period we've evaluated is the one-year out."

SENATOR STEDMAN suggested the \$25 estimate could move, then, as time marches forward.

MR. WILLIAMS concurred that the further into the future DOR looks, the less accurate the forecasts likely will be.

CHAIR WAGONER thanked Mr. Williams and agreed it was nice to hear something new.

[4:10:32 PM](#)

^ADMINISTRATION - DAN DICKINSON, CPA

DAN DICKINSON, CPA, former director of the DOR Tax Division, began by reacting to issues raised by testifiers in the last couple of days. With regard to auditing direct expenditures, he told members that in auditing "upstream" costs, substantial weight is given to the industry practice as of December 1, 2005, before people were entering into arrangements perhaps as a consequence of this bill. He also mentioned ways of dealing with costs that were subject to negotiation with working-interest owners that were not the operator and who had substantial bargaining power. Out of perhaps 20 ANS units

including exploration units, maybe only three meet that criterion. He explained:

What we're looking at are places where you have a BP and an Exxon or a ConocoPhillips. One of those is the operator; the other two are looking over their shoulder and they don't want a penny spent more than has to be spent. My point is if we have those kind of things going on, if we have that kind of auditing going on, is there some way we can take advantage of it?

MR. DICKINSON proposed that, although it would be great if the state had a field of auditors looking at every invoice, that isn't realistic and if safeguards can be created to ensure that the state's interests aren't compromised, then the thorough work already being done by industry can be used.

He emphasized that the right policy choice is to give substantial weight to what the producers do when dealing with each other, but do it in a manner that leaves the state in the proper position. He highlighted the need to look at what data can be used effectively and to look at internal controls like how the auditing is being done and any changes the producers make in the operating agreements. He disagreed with Jim Eason's [Legislative consultant] suggestion that giving substantial weight to how the producers do things might hinder the state's ability to question what has been going on.

He addressed a second issue: Mr. Eason's concern that if there is only one agency doing the work, there won't be crosschecking. Mr. Dickinson agreed that having two people do something is better than one, but limited resources don't make that necessarily practical. Currently, two groups of state auditors apply slightly different rules to the same set of calculations to come up with royalties and severance taxes. Mr. Dickinson proposed that one set is probably good enough, especially with the market's transparency and if the DNR commissioner has the authority to set the conditions under which a calculation can be made.

He explained that the DL-1 leases were written before spot markets became transparent and the royalty value in them was the higher of four measures: 1) the value of the oil, 2) what the company sold the oil for, 3) what others sold the oil for or 4) the posted price. However, when it came time to settle the Amerada Hess royalty issues in the 1980s and to establish a

"going forward" basis, DNR said the following: it believed there was a transparent market for the value of oil; it didn't believe transactions were being done which hid that; and it would start with this publicly reported number of what oil sells for in the marketplace, using it as the netback, instead of the aforementioned number based on the higher of the four values.

He indicated, similarly, that AS 43.55.020(f) gives the DOR the ability to look at the sales price and then impose a tax based on it or on the prevailing value if the production wasn't sold at market value. Mr. Dickinson opined that while the concerns expressed by Mr. Eason were valid, they are met by putting sufficient safeguards in place.

[4:19:44 PM](#)

MR. DICKINSON turned to comments by Daniel Johnston suggesting the state shouldn't be worse off after the change than before. One possibility is to leave the economic limit factor (ELF) in place and do a "higher of" calculation. However, Mr. Dickinson spoke against leaving the ELF in place saying he believed what was being done with the bill made sense and that some places cited by Mr. Johnston had a tax system as their only way of getting revenues. Nova Scotia, for example, has no additional royalty, income tax or property tax.

He noted half the state's general revenues come from the royalty and that isn't affected in this bill, which turns the severance tax into a different vehicle to be used to incentivize production; when there is a fair amount of profit from that production, the state will take its fair share. Mr. Dickinson opined that having an alternative tax or an alternative ELF tax isn't as critical as it would be if it were the only source.

[4:21:04 PM](#)

MR. DICKINSON began his slide presentation, saying he'd talk about the point of production and how it affects both royalty and tax for oil and gas. He said the current tax system has been pretty simple. The state knew what it wanted and put it into statute in the 1970s. The definitions are not being changed in the proposal, but rather being simplified.

He showed the slide "Oil or Gas - Why does it matter?" and explained that under current rules it matters a great deal. Gas is taxed at 10 percent of the gross, and a gas ELF looks only at how productive each well is. In contrast, oil is taxed at 15 percent times an ELF that takes into account both the well's productivity and the field size.

Another aspect under current rules is that gas used for production operations on the North Slope is free; this condition is found in practically all gas-producing states. The condition says if the ultimate purpose of an operation is oil production, the gas can be used as fuel and for heating at no charge. Using oil for those purposes is not free.

He corrected a second slide, relating to proposed rules that should say "past" rather than "post" production. Mr. Dickinson reported that each barrel of oil has a conservation surcharge of 3 to 5 cents, depending on various conditions; however, there is no conservation surcharge for gas.

[4:23:39 PM](#)

MR. DICKINSON explained that in part the bill says perhaps some of those shouldn't matter quite as much and taxes both oil and gas at 20 percent of the net with free use of both gas and oil for production purposes. He found in 1996 research that of the 20 oil-producing states, seven have tax-free use of gas and oil as long as it's for production purposes; the other 14 only give that to gas, while oil is taxed. He noted the conservation surcharge would be creditable.

[4:24:32 PM](#)

SENATOR DYSON asked what production purposes oil could be used for.

MR. DICKINSON answered that some products are made at a "crude oil topping plant" - for example, low diesel that is used in well work and as fuel for vehicles. Another major use is as miscible injectant.

[4:24:57 PM](#)

MR. DICKINSON recalled that this morning Mr. Mintz had suggested using just one category - "produced hydrocarbons" - and thus no distinction between oil and gas would be needed.

CHAIR WAGONER asked the reason for making the conservation surcharge creditable and why the recent North Slope oil spill could be used as a credit.

MR. DICKINSON replied that right now the actual costs of the emergency response, including cleaning up and "fixing" that event, aren't deductible. However, the resulting decreased production would decrease the amount of tax and royalty the state gets. Under the proposal, the state would allow both

preparing for such a crisis and then, if it did happen, responding to it would be deductible.

CHAIR WAGONER pointed out that several state positions are being funded from that revenue stream that will be reduced.

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MR. DICKINSON replied that the proposal wouldn't reduce the revenue stream to the spill fund; 3 to 5 cents per barrel will still go to the fund. The money going to the fund would actually increase a little bit because the definitions are changing to just look at profits. However, with the credit, the total amount of general fund revenues would be smaller.

CHAIR WAGONER asked, "Why are we saying that?"

[4:27:38 PM](#)

MR. DICKINSON replied that they were trying to do a profits tax that minimized the small regressive components. The intent of the tax is to look at profitability and tax that 20 percent. If you're not profitable, it's nothing. They were trying to get rid of the philosophically point of view of some smaller additions to the base tax.

[4:28:19 PM](#)

MR. DICKINSON emphasized that concerns about the point of production relate to the definitions of oil and gas and for oil, there is no real change. But, for gas the point of production is driven by the "point of final separation."

He asked, "Why does the point of production matter?" Historically, the point of production was very important because costs incurred downstream of it were deductible for calculating production tax, while costs incurred upstream weren't. You could deduct tankers, TAPS and the Kuparuk pipeline, for instance, but as soon as you hit the Kuparuk boundary, costs were no longer deductible. A billion dollar facility within the boundary was not deductible.

In a parallel situation with royalty, the point of production made all the difference. In 1978, the point of production on a royalty lease form was ambiguous and therefore, was negotiated between the state and the producers who said that it was at the wellhead where the oil comes out of the ground and that all costs were deductible. A field cost settlement was established at that time to cover upstream costs that included inflation and it is currently at about \$1 a barrel. His point was that as you

move the point of production upstream, then something downstream of that becomes deductible. That is why, until now, the point of production has been critically important.

This bill's intent is to incentivize those costs beyond being just a deduction. The point of production remains important because, even though costs are deductible from both sides of the point of production, how they are recaptured is still very different. Downstream costs remain traditional, but upstream costs are different. The state is saying you spend a capital \$1 and you get to deduct it immediately and, furthermore, you get a 20-cent credit that can be applied against profits for any obligation. The point of production is still a critical issue. This is one of the reasons gas processing, which used to be downstream of the point of production, now moves upstream.

[4:32:57 PM](#)

MR. DICKINSON said under the old rules, the state gives gas processing a reasonable allowance. Now in the proposed bill, the investment for the gas processing plant would be both a deduction and a credit. Moving to the next slide, he opined that the point of production would matter particularly for a newcomer without heritage facilities who has found gas ten years down the road and wants access to the production facilities. Even now, some folks who are discovering oil have alleged that access is difficult. He stressed that the dynamic would dramatically change and a new producer would be able to just build his own plant, knowing he'll get 40 percent credit for it from the government.

He submitted that if existing heritage facilities are underutilized, its owner would know how much it would cost to build and that knowledge could help frame negotiations with a new entrant. He offered the belief that moving the gas processing costs upstream of the point of production would significantly change how people think about costs and facility sharing. He advised this isn't the only solution members should think about for that particular problem, but to the degree the tax code can be used, he thought it would make a significant difference.

[4:35:00 PM](#)

SENATOR ELTON asked what the most important thing for a new entrant would be for access to a facility or the pipeline.

MR. DICKINSON replied that it's not his job to say that. But what the department says is that pipelines are publicly

regulated and access to them should be based only on the charge for that access, which should reflect a cost recovery methodology - in other words, standard rate-making procedures. The question with TAPS has been whether those processes were circumvented in the settlement or aren't representative of true costs. He wouldn't recommend suddenly moving all the points of production downstream of the pipeline. Where the line is drawn between gas (and oil) processing, treatment and pipeline is a choice that folks have to make.

[4:36:57 PM](#)

The next slide deals with what happens when you have production and post-production facilities in the same building. Under the current rules, if a central gas facility has both gas processing (which removes valuable liquid hydrocarbons that will end up in TAPS) and production activity (which is simply taking the gas and conditioning it so you can put through compressors and put it back down in the ground again), together and because one is deductible and one isn't, costs have to be allocated. Under the proposed rules, both of those activities would be deductible.

[4:39:57 PM](#)

Slide 9 gets into what is the point of production for the gas or the oil. The statute says that oil must be in the pipeline quality condition and that has been defined as being in good and merchantable condition. Gas that is produced in association with oil is actually metered downstream from the point of final separation. Both of the definitions remain unchanged, but they are dealing with the point of final separation.

The question has been raised that the state has this great standard for oil. So, why can't the same be done for gas? His observations were that historically, gas is often sold with the liquids still in it (wet) and so it doesn't have the clear merchantability standard that crude oil has. Secondly, if you did that, you would be essentially saying that gas treatment and the gas treatment plant would now move upstream of the point of production and would be allowable for these credits and deductions.

So, we believe that having this condition of pipeline quality good and merchantable emission is good for oil. We're going to leave it for oil. We don't think moving that over to make it the same standard for gas makes as much sense.

MR. DICKINSON said the definition of gas in the proposal includes what happens if a big facility is built for gas treatment and the point of production would be in the middle of that facility. The point of this slide was that is true and the state may end up in the same kind of cost allocation issues.

[4:42:11 PM](#)

He recommended keeping the gas treatment as part of transportation and the downstream where it is deductible, but doesn't need the additional credit or upfront help.

[4:43:36 PM](#)

The next slides dealt with where the point of production (POP) is for gas and oil now. This bill proposes moving the POP for gas, not oil, which would put the central gas facility upstream from the POP. Everything going through it would be considered a production operation. When the NGLs are taken out of the gas, the LACT meter is the point at which they become oil.

[4:46:16 PM](#)

He said the question was asked if this was absolutely critical to the PPT and the answer was no. The goal is to simplify definitions that will not lead to low value-added conflicts and to incentivize all production activity including gas processing.

Another question was could the state retain the same definitions of POP and still get most of the benefits of the PPT? He answered yes and emphasized that the administration is trying to create a clear way of dealing with the issues.

[4:47:20 PM](#)

SENATOR DYSON asked where gas and oil were taken off for in-field use in each of the diagrams.

MR. DICKINSON replied under the current plan that oil will be diverted to a topping plant as it is flowing from the facilities. The topping plant has another little meter where it begins to be taxed.

In the separation facilities some gas is used for gas lift and things like that, but it is simply recycled in the separation facilities. The major streams of fuel that are used go through all the processing at the central gas facility and are essentially identical to what is put down in the ground to pressurize the reservoir. By that time it is basically methane.

MR. DICKINSON explained:

The new scheme should be the exact same thing. Again, what would happen is, even though it would be downstream of the point of production for gas for the stuff that is used on the lease, it will be as if it were not produced.... They will, in fact, meter it and they have to figure out as to who has done what - so it will go through that meter, but it won't trigger a point of production or taxability.

He said that oil would be treated the same way.

CHAIR WAGONER thanked him for his presentation. He announced that they would next go hear the Tax Division's answers to the Legislature's remaining questions.

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^DEPARTMENT OF REVENUE - Robynn Wilson, Director, Tax Division - Addressed legislature's questions - with Dan Dickinson

ROBYNN WILSON, Director, Tax Division, Department of Revenue (DOR) explained that she would address the remaining questions plus a few more.

[4:52:13 PM](#) at ease [4:53:30 PM](#)

1. Identify values/amounts for the "look-back" or transitional deduction per year according to the actual by type (exploration, development, production).

The Department of Revenue model uses \$1 billion per year as capital costs. So for the transitional period, there would be about \$5 billion. These annual costs are based on compilations of historical data. [Graph is in bill file.]

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SENATOR DYSON asked where she drew the line between exploration and development.

MS. WILSON replied the bill has no definition for exploration versus development. The IRS code makes a distinction, because generally, exploration costs are fully deductible; whereas development falls under the category of "intangible drilling costs" and those are capitalized.

SENATOR DYSON asked what the difference in the equipment or activity in the field was.

MS. WILSON replied that the exploration would include things like seismic, geologic and geophysical.

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MR. DICKINSON added that the information is collected from a number of sources, but basically for their purposes, exploration would be pretty close to wildcat drilling of delineation wells.

SENATOR DYSON asked if development water, EOR (enhanced oil recovery) and all those things were considered development.

MR. DICKINSON replied that was correct.

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SENATOR ELTON asked if she had numbers for 2005.

She replied that she didn't have finalized numbers for 2005.

SENATOR ELTON estimated the number to be in the \$6 billion range for 2005.

MR. DICKINSON responded that 2001 would only be one-half the cost because they are using calendar year costs that run from July to July. The department's extrapolations indicate that the downward trend is continuing through 2005 and 2006. He thought the number would be closer to \$5 billion.

8. Which other tax regimes - worldwide - have a progressivity structure?

Ms. Wilson cautioned that she had heard a lot of references to progressivity and each person may have a slightly different definition. For example, in the income tax world, progressivity generally means as your net taxable income goes up, the tax rate goes up. But, she has also heard talk about progressivity with respect to the price of oil per barrel. That means if the price of oil is \$60, you would have a different tax rate than if it was \$40. She suggested that they might be ignoring the cost. So, the taxpayer that is doing what the state wants by reinvesting is suddenly being taxed at a rate that is higher on what is left than the taxpayer that doesn't reinvest. She cautioned them to be careful on what they are measuring the progressivity about. Dr. Van Muers' pointed out that a lot of countries base progression on production. "So, are we talking about increasing tax rate based on net profits? Are we talking

about increasing it based on price per barrel or are we talking about, maybe, production? I don't know that there is a right answer."

SENATOR STEDMAN interrupted to say that regimes that were regressive in nature were royalty tax-based systems. The regimes around the world that are rate-of-return based are production profit sharing and are progressive in nature. So as the price of oil goes up, the split between the government and the industry rises to the advantage of the government.

MS. WILSON continued saying that progressive features are relatively common around the world. She presented the committee with a list of the main fiscal regimes with such features.

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18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues. Have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the legislation on the State's legal position in past agreements, current disputes, or future disputes?

Yes, such counsel (not all of them) have been consulted and such assessments have been discussed but have not generally been generated in formal written form.

Did such advice result in any changes to the legislation?

The bills reflect discussions with counsel that took place during the drafting process, so in that sense such advice did affect the legislation.

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SENATOR BEN STEVENS asked if royalty is a progressive system in price and recalled that Dr. Van Muers' said the PPT flattened it out. He asked if he interpreted that wrong. He asked if they were benchmarking the progressivity against profit or the price or the total government take.

MR. DICKINSON replied that using it they way Senator Stedman did, generally the royalty would be considered regressive, because no cost is deducted and it's based only on revenue. As the dollar per barrel increases, the take stays constant. And because no costs are deductible, as you get close to not covering costs, the state is still taking dollars.

SENATOR BEN STEVENS said he thinks of progressivity in terms of total dollar value. The state's share either stays the same or increases (significantly in some instances) - compared to the status quo. He asked if that was accurate.

MR. DICKINSON replied:

I think that as prices go up under our current system, the state makes a lot more money. The forecast just released said \$1.6 billion. But our percentage of the gross has fallen.

SENATOR BEN STEVENS said, "Right, so that's regressive."

MR. DICKINSON agreed.

SENATOR BEN STEVENS said he was comparing the old system to the new system.

MR. DICKINSON responded that the proposed system would be less progressive than the old system. Technically speaking it is not progressive at 20/20.

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SENATOR STEDMAN supposed that even under a regressive system, the state's total dollars might increase, but the percent of government take would decrease. At the London seminar he attended, he learned from industry to think of progressivity or regressivity in terms of percentages rather than dollars as the dollar prices moved. "From their viewpoint, no matter where the money was spent, it didn't matter. If it didn't go to them they didn't care - call it a tax, call it a royalty, call it anything you want to."

He said Dr. Van Muers combined the proposed bill using 25/20 with the current royalty and tax structure and it resulted in a virtual flat government take. He said the discussion was should the government take have been upward of that, flat or regressive. At a minimum he thought it should be flat and that's what he presented. They need to remember that as the price goes up, more revenue would come to the state even under a regressive system.

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SENATOR ELTON picked \$40 at 20/20 and said for every \$1 increase in a barrel of oil a quarter point was added. He asked if that would have more progressivity.

MR. DICKINSON replied yes.

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SENATOR BEN STEVENS said he was fascinated that the Legislature was mesmerized on the percent of government take. Government depends on a flow of money, not a percent of a declining resource. He kept coming back to what the government should frame its policy on when it tries to secure a reliable revenue stream. He thought in a true progressive system the government gives up more as the price goes down - all the way down to zero tax at zero profit.

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SENATOR STEDMAN steered thinking back toward Senator Elton's discussion on progressivity. If the state takes a higher percentage when prices go up, it takes away the upside from the industry and it is only fair to go back to the other end of the curve and adjust for it. "You can't have an extremely progressive system and then go back to the low price side and start putting in floors. There's no balance there."

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MS. WILSON jumped in with an example to hopefully add clarity. If oil is at \$100 a barrel and the producer produces one barrel and has expenses of \$90 and, therefore, a net profit of \$10. Next year the price of oil falls to \$10 a barrel; he produces one barrel and doesn't invest anything and his net profit is still \$10. So, if the state is talking about basing an increasing tax rate simply on the price of oil, those two \$10-profits are going to both enjoy - for instance, a 15 percent rate when oil is \$10, and a 25 percent rate when oil goes to \$100 - both scenarios have a \$10 profit, but in the first instance when oil is \$100 a barrel, the producer has \$2.50 in tax and for the second example, \$1.50 in tax. She emphasized that both taxes are on the same profit. She cautioned people to keep intent in mind.

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SENATOR BEN STEVENS said he wanted to get attention off the government take, because that's not what the change does.

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SENATOR DYSON reminded the committee that under the Constitution and the Statehood Compact the gas belongs to the people and they should be rewarded on the upside.

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SENATOR STEDMAN said keeping an eye on the cash flow - at the end of the day - was important.

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MR. DICKINSON reminded them that they were discussing the long-term cash flow and how to make sure it's robust under all conditions.

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MS. WILSON continued with the questions and answers.

24. What standard will be used to determine whether oil or gas is of 'pipeline quality' under the definition of 'gross value at the point of production'?

MS. WILSON said that Mr. Dickinson covered this question in his presentation and this is a written description of it. She wanted to skip that one. The Chair indicated that way okay. [The following answer was provided in her letter.]

The current production tax statute taxes the "gross value at the point of production" of oil and gas. The quoted phrase was enacted in 1977 and replaced the previous statutory phrase "gross value at the well." This change was aimed at ensuring that costs of production operations downstream of the well would not be deductible in calculating the taxable value of oil or gas; rather, taxable value would be calculated at the point that production is complete.

In the case of oil, "gross value at the point of production" was defined as the value of oil where it is metered "in a condition of pipeline quality," and "pipeline quality" was defined as "good and merchantable condition." This definition essentially adopts commercial standards of marketability for oil. HB 488 and SB 305 would simplify and shorten the definition of gross value at the point of production for oil but do not materially change it. In addition, the definition of "oil" is broadened to include liquid hydrocarbons recovered by gas processing in the case of leases or properties whose production is subject to gas processing. The bottom line is that the point of production under these bills would still be the point where oil is metered in a condition of pipeline quality, and "pipeline quality" would mean the same thing it has always meant under the production tax statute.

In the case of gas, neither the existing statute nor the new bills use the phrase "pipeline quality" or "good and merchantable condition" with respect to gross value at the point of production. Rather, the statutory definitions of "gross value at the point of production" for gas, as interpreted and clarified by the Department's regulations, 15 AAC 55.900(a)(6)(B) and (C), focus on where gas is accurately metered after separation from oil. The new bills retain this concept but, in effect, expand "separation" to include gas processing, so that in the case of leases or properties whose production is subject to gas processing, the point of production for gas recovered by gas processing is the point where it is metered downstream of the processing.

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25. Provide an historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior. She asked Mr. Dickinson if that had been covered. He suggested going to the last paragraph [But the whole answer has been included for clarity].

While there is much that is parallel in the calculation of gross value at the wellhead between royalty and tax, many differences have developed. Both start with destination value in the market and then subtract the tankering, pipeline and other costs to arrive at a wellhead value. The Department of Revenue's valuation for tax comes from statute and regulation. The Department of Natural Resources' valuation for royalty comes from lease contracts supplemented by Royalty Settlement Agreements (RSAs), which set forth different methods for each large North Slope producer. (Cook Inlet valuation is not covered in this answer.)

Destination value, for the Department of Revenue, is what the oil was sold for or when the oil is not sold or is sold for a below market price - the so-called prevailing value or spot price. Destination value for the Department of Natural Resources is a formula driven by the ANS or a basket of similar crudes.

From the destination value, each method subtracts marine transportation costs, TAPS costs (including tariffs, losses and quality bank changes from mid-point refineries), feeder line costs (including tariffs, losses and quality bank differences), and other miscellaneous costs. DOR deducts the costs specific to each taxpayer, while for royalty, some of

the RSAs have formulaic deductions and others use the royalty payers' actual cost. In addition, DNR subtracts field costs for most DL-1 lease form leases on the North Slope whereas DOR does not.

The differences between wellhead values narrow across time. The average difference for the period FY00 through December 2005 is 3.9 percent. However, the average difference for the last 12 months is 6.1 percent while the average difference for FY00 through FY03 is 3.0 percent.

The critical point is that DOR uses actual proceeds, and only resorts to the Prevailing Value (PV) when the conditions of 020 (f) are met, thereby taxing on the higher of proceeds or PV. For each of the three producers, DNR uses a single destination formula based on spot prices, not actual proceeds.

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34. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

- a. Only two credits that have been issued have been sold to another party.
- b. The Division will first obtain a waiver of confidentiality from the seller allowing the Division to confirm the credit amount to the prospective purchaser. Once sold, the Division makes the transfer and issues a new credit certificate to the purchaser upon receipt of documentation and confirmation of the transaction from the seller of the credit. The credit exists as an electronic entry in a Division database, therefore only the Division can make the actual transfer of the credit in that database. A new certificate is entered in the database to the purchaser and the old certificate is marked as transferred and its balance is zeroed out. The Division then notifies both the purchaser and the seller, in writing, of the completed transfer of the credit, at which time the purchaser may then apply the credit to its own production tax liability. When a credit is applied to a tax liability by a producer, the Division then verifies the holder and amount of the claimed credit against the credit certificates in the database.

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40. Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

a. Net profits systems in the world typically work on the basis of three different concepts:

(a) Monthly payments based on actual production, revenues and expenditures, without an annual true-up, as is the case in most production sharing agreements

(b) Yearly payments based on a yearly return, filed within a few months after the year, without a need for monthly payments on account, as is the case for the Thai SRB, for instance. This means there is only a single annual payment.

(c) Yearly payments based on a yearly return, filed within a few months after a calendar year or a lease/contract year, with monthly payments on account. In this last case, the monthly payments could be based on:

a. Estimates for each month, as for instance with the Nova Scotia profit sharing royalty. These estimates can be challenged by government and different estimates may be required.

b. Payments based on a mixture of actual information from the previous month and estimates, such as in Algeria

c. Corporate income tax style procedures, whereby payments are based on taxes paid in the prior year (Norway for the Hydrocarbon Tax).

The 90 percent rule proposed for Alaska is unique. The overall economic impact would depend on the taxpayers' cost estimates for each month. We expect that taxpayers will experience underpayments in some months, but will experience overpayments (because of estimates used) in other months. In addition, falling production amounts, or unforeseen costs will serve to likely create overpayments in later months. Overall, we do not expect any material net economic impact.

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66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO₂ re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

At Prudhoe Bay, about 8.5 billion cubic feet of gas a day is reinjected into the field for pressure maintenance. After stripping out certain hydrocarbon liquids, CO₂ is reinjected along with the other hydrocarbons (and non-hydrocarbons). When an export line is built on the North Slope, the CO₂ will

be stripped (in "gas treatment"), and there is some question about what will happen with that CO2.

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CHAIR WAGONER asked why is there a question about what will happen to Co2.

MR. DICKINSON replied that the question is that the co2 is either a valuable product or a waste product and are modeled differently for the different applications. For this question, CO2 is just with the gas and is not part of the tax picture. When a gas line occurs, that would be one of the issues to focus on.

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67. What happens if the "Big Three" sell off their assets to 20 smaller companies? Will the significant tax benefits ever be realized?

Assume 20 new companies suddenly showed up on the North Slope and each qualified for the \$73 million dollar allowance. A total of \$1.4 billion in profits would be sheltered from taxes. If these companies had simply purchased their way in, then taxes would be lower by \$280 million (20 percent of \$1.4 billion) than they would be otherwise. At current prices, or say even at \$40 oil, this could be a material portion (though not all) of the tax.

If that is the future of the North Slope and the sell off was for business purposes, the Legislature may choose to act and make it less attractive to new firms coming in. If these were tax-motivated sales, we hope the powers of the commissioner that are built into the bill would prevent the new entrants from using the \$73 million allowance. The commissioner gets to approve qualification for the \$73 million allowance.

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73. Will the new confidentiality provisions extend to or have an effect on any other taxes besides the production tax?

The new confidentiality language added by secs. 4 and 16 of the bill applies only to information relating to the oil and gas production tax, not other taxes. This is because:

(1) AS 43.55.040(1) addresses information "necessary to compute the amount of the tax," and the phrase "the tax" is used throughout AS 43.55 as referring only to the production tax; and

(2) AS 43.55.040(1) deals only with information obtained from persons "engaged in production," or their agents, and with purchasers "of oil or gas," and with owners of a "royalty interest in oil or gas."

77. How much gas was flared so as to trigger taxes and/or penalties in recent years?

During FY 2005, 351,000 Mcf of gas was flared that was considered gross taxable production. Of that, only 120,000 Mcf was from fields with a positive ELF and subject to tax. During the same period 31,000 Mcf was flared and considered waste and subject to both tax and penalty.

80. When the 1989 ELF change was enacted, was it retroactive and were there transition provisions?

The 1989 ELF changes were made retroactive to January 1, 1989, and applied to oil produced after December 31, 1988. There was a transition provision to the effect that tax payable as a result of the retroactive changes would be due on the 20th day of the calendar month following the effective date of the Act. (The effective date of the Act was August 6, 1989.)

82. Under the new gas and oil definitions, what will the net change to the spill fee be? In other words, looking at FY 2005, how much, if any (a) oil did we tax for its use in production operations and (b) how many NGLS were put in TAPS?

During FY 2005, tax was collected on 1,222,400 barrels of crude oil used in production operations. During FY 2005, 16,445,000 barrels of NGLS were put in TAPS.

83. For sales of credits by the smaller interests, estimate the price at which those credits will no longer have a market among the big three?

Credits may be used in the year of expenditure, carried forward to following years, or transferred (they are fungible). If transferred, the credit cannot lower a severance tax rate below 80 percent of what it would otherwise be [AS 43.55.024(e)]. These credits will have market value that would not exceed 20 percent of their face value (\$1,000 in capital expenditures would save \$200 in State severance taxes). A company generating them but unable

to use them would face a choice - sell them or use them the following year (if they have taxable income).

Use the next year reduces the value of the credits due to discount rate. Oil companies typically try to use a 15 percent discount rate but will often settle for less, say 10 percent. This means, all other things equal, they would be willing to sell a \$1,000 credit (\$5,000 capital expenditures) for \$900 (10 percent discount rate) or more. Conversely, another company would be willing to pay up to \$999 for the credit to save \$1,000 in State severance tax.

If we assume a billion in spending, assume that 10 percent of that was for little companies that would want to sell their credits, so \$200 million in credits are for sale. With our 20 percent limit, that implies that if the big three had a billion dollar in tax obligations, that market could absorb all the credits. As our fiscal note shows, if the price of oil is \$40 or above, all of the credits would be usable in the immediate year. If oil falls below \$40, then we expect that the credits would be fully utilized within two or three years. While the time-value of money means that those certificates would be discounted, we believe that the certificates would still be marketable.

84. If aggregation at Prudhoe Bay had been implemented on July 1, 2001 [the start of the claw back period], how much more would the State have received between then and the actual aggregation date?

The State would have received \$430.4M additional revenue. She provided a graph of estimates.

85. Why are the status quo lines in the three graphs presented by Ms. Wilson flat once the forecast price effect is adjusted for? Wouldn't falling production and ELF move those down?

The status quo drops from \$378 mm in 2009 to \$291 mm in 2012. It looks flat because of the scale on the graph.

86. What will the actual cost to the investor be for these upstream investments and what is the total government underwriting, state and federal, all tax types included. Is it different for large companies and small companies?

After state and federal tax, the investor would bear about 38 percent of the marginal capital. There is no reason to think

it would differ appreciably between large and small investors.

87. Lord Browne famously said two years ago that any profits over \$20 a barrel were being returned to shareholders as they weren't needed in BP's business. What tax rate, credit rate would be needed to have a cross over [unspecified period] at \$20 [presumably Brent].

With a 20 percent credit, it would take a tax rate of about 51 percent to affect a crossover at \$20 Brent.

88. Please explain how the conservation surcharge is affected by oil price and what affect this bill has on the surcharge.

a. The conservation surcharge is a 3 cent per barrel charge on all oil produced less royalty barrels, so therefore it is not sensitive to price.

b. There will be changes in the quantity of oil subject to both production tax and conservation surcharges under the bill. One change will be positive, one negative. The positive change is that natural gas liquids extracted by gas processing and blended in the TAPS stream that are now taxed as gas, will be treated as oil under the bill.

The negative change is that oil that is used in lease operations will not be taxed or subject to surcharge under the bill. Oil may be used to make fuel for lease operations and perhaps used for other production purposes. The overall result is an expected increase of the total surcharge amount of \$444,000 per year, based on FY 2005 amounts. (See Question 82.)

The bill should not affect the assessment or collection of the surcharge, other than the quantity-of-oil effects described above. Any surcharge paid will be allowed to be credited against production taxes, but that would only reduce the amount of tax collected, not the amount of surcharges collected.

89. Why are we including gas in the PPT calculation?

The bill includes gas in the PPT calculations because it is a stand-alone bill. The bill does not require implicitly or explicitly that a Stranded Gas Contract be subsequently concluded. Therefore, a PPT law would be entirely functional in case a Stranded Gas Contract is not presented to the

Legislature or in case the Legislature rejects such a Contract.

The ELF system for gas is "broken" just as the ELF is "broken" for oil. The gas ELF does not encourage reinvestment and it is not sensitive to price.

It should be noted that under high gas prices, the Alaska State take for gas would increase significantly relative to the status quo. This would be beneficial in case significant gas reserves would be developed outside the scope of the Stranded Gas Development Act.

The inclusion of gas in the PPT is therefore a strong incentive for producers to conclude a Stranded Gas Contract that is in the interest of the State of Alaska. Including gas in the PPT enhances the bargaining position of the State for a good Stranded Gas Contract.

CHAIR WAGONER thanked everyone for their comments and adjourned the meeting at [5:46:13 PM](#).

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