

**ALASKA STATE LEGISLATURE
LEGISLATIVE BUDGET AND AUDIT COMMITTEE**

December 9, 2008

9:03 a.m.

MEMBERS PRESENT

Representative Ralph Samuels, Chair
Senator Lyman Hoffman, Vice Chair (via teleconference)
Representative Mike Chenault
Representative Mike Hawker
Representative Mike Kelly (via teleconference)
Senator Johnny Ellis
Senator Bert Stedman
Senator Gene Therriault
Representative Reggie Joule (alternate)
Senator Charlie Huggins (alternate)

MEMBERS ABSENT

Representative Mike Doogan
Senator Lyda Green
Representative Kevin Meyer
Senator Fred Dyson

OTHER LEGISLATORS PRESENT

Representative John Coghill
Representative Kurt Olson
Senator Con Bunde
Senator Fred Dyson

COMMITTEE CALENDAR

OVERVIEW(S):

ALASKA'S OIL AND GAS TAXES PRESENTATION: DAN DICKINSON, STEVE PORTER, LARRY PERSILY

- HEARD

PRESENTATION OF REPORT BY DAVID WOOD: FISCAL DESIGNS FOR THE DEVELOPMENT OF ALASKA NATURAL GAS

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

DAN E. DICKINSON, CPA, Consultant
to the Legislative Budget and Audit (BUD) Committee
Alaska State Legislature
Anchorage, Alaska

POSITION STATEMENT: Presented information regarding Alaska's oil and gas taxes and tax reform.

DAVID WOOD, PhD, Consultant
to the Legislative Budget and Audit (BUD) Committee
Alaska State Legislature
Lincoln, United Kingdom

POSITION STATEMENT: Presented key findings from his report, "Preliminary Report on a Fiscal Design for the Development of Alaska's Natural Gas".

ACTION NARRATIVE

CHAIR RALPH SAMUELS called the Legislative Budget and Audit Committee meeting to order at [9:03:17 AM](#). Representatives Hawker, Kelly (via teleconference), and Joule (alternate), and Senators Hoffman (via teleconference), Stedman, Ellis, and Huggins (alternate) were present at the call to order. Representative Chenault and Senator Therriault arrived as the meeting was in progress. Representatives Coghill and Olson and Senators Bunde and Dyson were also present.

OVERVIEW(S):

ALASKA'S OIL AND GAS TAXES PRESENTATION BY DAN DICKINSON

[9:04:20 AM](#)

REPRESENTATIVE SAMUELS announced that the committee hearing will be conducted over two days and is at the request of several members. He said the intent is not to debate the Petroleum Production Tax (PPT), Alaska's Clear and Equitable Share (ACES), or the Alaska Gasline Inducement Act (AGIA). Rather, it is to look forward and determine whether Alaska's current system for oil taxes will work for gas taxes, as well as to look at how Alaska compares globally on gas and how it interplays with oil.

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DAN E. DICKINSON, CPA, Consultant to the Legislative Budget and Audit (BUD) Committee, Alaska State Legislature, first noted that he spent seven years as Director of Tax in the Alaska Department of Revenue. He said today's presentation is the same one he gave at the September 2008 Fourth Annual Oil and Gas Symposium held in Anchorage where attendees were focused on a gasline and the periphery work associated with a gasline.

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MR. DICKINSON emphasized that the government of Alaska is very committed to supporting investments. He referred to page 2 of his PowerPoint presentation showing figures for oil priced at \$120 per barrel and noted that for every additional \$1 investment in upstream costs made by the private sector, the state of Alaska's effective contribution is \$.98. Because a lot of the government support is driven by progressivity, he continued, the state's commitment is reduced to \$.86 at lower price ranges.

MR. DICKINSON explained that the reason the state of Alaska pays \$.98 in support per investment dollar is because if the price per barrel goes up by \$1, the state will take, or receive, \$.93 of that additional \$1 in revenue [page 3]. This is due to the progressivity measure embedded in the oil and gas taxes. He said the state's very high tax rate is designed to do two things: investments are highly supported by the state; then, when new revenues flow in from those investments, the state takes a very large portion of the revenues.

[9:11:01 AM](#)

MR. DICKINSON pointed out that a danger of the progressivity feature is that the tax rate on the increased revenues from a company's investment can reduce the company's take to less than what it made before the investment [page 4]. It would therefore make no sense for the company to proceed with the investment. Thus, as the state moves into gas projects it needs to consider what happens on the incremental investments.

[9:13:03 AM](#)

MR. DICKINSON discussed the nine steps of government take. He said the figures shown [on page 5] are from the Department of Revenue's spring 2008 forecast. At that time the average price for the year was \$85.73 per barrel, which resulted in a forecast

of \$8.7 billion in state oil and gas take. He pointed out that the bulk of North Slope production has come from Prudhoe Bay [slide 6] and the decline in production is the decline from Prudhoe Bay. The new fields coming on do not offset the falloff of Prudhoe Bay.

MR. DICKINSON said there have been several pricing eras since Prudhoe Bay began [page 7]. When the state was producing two million barrels a day, the price per barrel was \$15. A couple of years ago the state produced only 700,000 barrels a day, but the price was \$40 or \$50 a barrel. If the price goes up more than the volumes have declined, the state comes out ahead in its revenues. However, he warned, the state is now seeing prices down in the \$30 range and the volumes are significantly lower than they were the last time the price was \$30.

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MR. DICKINSON related that state spending, in nominal dollars, ranged around \$2-\$2.5 billion a year up until 2005, then moved close to \$6 billion per year over the last four years [page 8]. State spending doubled after the tax reforms went into effect and prices went higher.

MR. DICKINSON recounted that from 1973 to 1981, Alaska's oil province switched from Cook Inlet to the North Slope [page 9]. He said the following things changed during the switch: a new oil and gas property tax (AS 43.56) came in; the corporate income tax switched from an apportionment method to a separate accounting method for four years, then went to a modified apportionment method (AS 43.20); the production tax had different sets of minimum and maximum rates; the rate mechanisms changed with the stair step and Economic Limit Factor (ELF); there was the rounding rule; and there was the special rate for the first five years. Additionally, a reserves tax was put into place when the pipeline was delayed and the state literally ran out of money.

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MR. DICKINSON said 1981-2006 was a period of relative stability when the corporate income tax and the property tax stayed the same. There were two production tax law changes. In 1989 the power used for calculating the Economic Limit Factor was raised. In 2003 exploration credits were introduced whereby a production tax of 15 percent of the gross value at the point of production - Prudhoe Bay - is assessed. The costs between Prudhoe Bay and

the Lower 48 were then deducted, resulting in an effective tax rate of roughly 7.5 percent of the gross value of the oil and gas produced.

MR. DICKINSON related that in 2006 the three largest taxpayers agreed to production tax reform as part of the Stranded Gas Development Act negotiations. Under this concept there would have been a 20 percent net tax where all costs would have been deducted, a 20 percent investment credit, and no progressivity measures. However, he continued, a very different set of rules was ultimately passed under the 2006 petroleum production tax (PPT) reform. These rules passed as a package in August 2006 but were retroactive to April 1, 2006. The changes included: switching the gross tax to a net tax based on net value, or production tax value (PTV), which is the value per barrel after deducting all costs; implementing a progressivity feature where anything above \$40 of PTV on each barrel is taxed at a rate of .25 percent per dollar; implementing a 20 percent investment credit and a 20 percent loss carryforward credit; incorporating exploration credits of 20 percent and true wildcat credits of 40 percent; establishing the transitional investment expenditure (TIE) credits; establishing the small producer credits of up to \$12 million a year which took several small producers off the tax rolls; and identifying 18 exclusions from upstream costs within the unit operating agreement.

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MR. DICKINSON presented a quick history of the next year [page 11]: in July 2006 the Alaska North Slope West Coast (ANS WC) monthly price broke \$70 for the first time; the 2007 legislative session focused on AGIA; in October 2007 the ANS WC monthly price broke \$80 for the first time; in November 2007 the ANS WC monthly price broke \$90 for the first time; and in November 2007 the special legislative session passed production tax reforms [under Alaska's Clear and Equitable Share act].

MR. DICKINSON outlined the reforms established under ACES [page 12]: the switch from gross tax to net tax was maintained; the tax of 22.5 percent of PTV was increased to 25 percent; the progressivity trigger was lowered from \$40 of PTV to \$30; the progressivity rate was increased from .25 percent to .4 percent per dollar; the 20 percent investment credit was spread over 2 years rather than one; the loss carryforward credit was increased from 20 percent to 25 percent and in certain conditions can be put over two years; exploration credits were raised from 20 percent to 30 percent; the transitional

investment expenditure credits were ended, except for a small number of companies; the small producer credits of up to \$12 million a year stayed the same; the upstream costs were shifted from the unit operating agreement to a standard in which the Department of Revenue would write regulations defining those costs and the number of exclusions was raised from 19 to 21. These reforms were retroactive to July 1, 2007. As a result of these reforms, continued Mr. Dickinson, production tax revenue collected by the state increased from [\$651.9] million in 2004 to a forecast of \$4.9 billion for 2008, a nearly eight-fold increase. However, he added, one must consider that while the price went up, the volume went down.

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MR. DICKINSON said a better way to compare production tax revenue is to determine the total value of Alaska product in the market. This is done by multiplying the total barrels produced annually by the price. In 2004 the value was \$11 billion and the 2008 forecast is double that amount at nearly \$23 billion. Although taxes went up eight fold, half of that increase stemmed from both the increase in prices and the decrease in volume, he explained. Therefore, the net effect of the rule changes was a four-fold, or 400 percent, increase.

MR. DICKINSON further explained that this can be crosschecked by looking at how much the state collected in royalty because the royalty rules did not change and would reflect the decrease in volume and increase in price. He said the royalty revenues show the same ratio with \$1.05 billion in royalty revenue in 2004 and \$2.1 billion forecast for 2008. Thus, this doubling of royalty revenue confirms that when there is an eight-fold increase in production taxes, the four-fold is due to the changes in the rules versus the two-fold increase as a consequence of prices.

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MR. DICKINSON reviewed how the various pieces all fit together. The first step is to determine the destination value [page 14], he said. This value is either the actual market price received for the product or the price that the state perceives as the marketplace value, whichever is higher [page 15]. This "higher of" standard is also applied to royalty payments received by the state, he added. The next step is to determine the costs for transporting the oil from the North Slope to the Lower 48 [page 14]. Either the actual cost is used or a reasonable cost as determined by the Department of Revenue is used, whichever is

lower [page 16]. Deduction of the lower of the transportation costs from the higher of the destination values equals the gross value at the point of production [page 14]. This is now the point at which royalties are assessed.

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MR. DICKINSON said state royalties are paid on production from state-owned land and are exempted from production tax, i.e. 7/8 taxable and the 1/8 royalty nontaxable [page 17]. For federally owned land within the state, there are also federal royalties which are exempted from production tax, i.e. 7/8 taxable, but all other state taxes apply. Federal royalties may be shared with the state under federal legislation, he continued, but those rules have changed from time to time. For federally owned land that is not in the state, such as off shore on the Outer Continental Shelf, there are federal royalties but no state taxes. Federal royalties from the Gulf of Mexico are now shared with the gulf coastal states, he noted, and this means a precedent has now been set. On private lands, private royalties are determined by the contract and all other rules apply for taxability except that no royalty is paid to the state.

CHAIR SAMUELS asked whether the royalty for land owned by the University of Alaska goes to the university or to the state.

MR. DICKINSON replied he believes it goes to the university.

[9:38:50 AM](#)

MR. DICKINSON noted that most of the production comes from state lands between the Colville and Canning Rivers and the Cook Inlet [page 18]. A lease sale has been announced for Bristol Bay, he added. He explained that state land extends three miles off shore and that state royalties and state taxes apply to any drilling within that area.

[9:39:59 AM](#)

CHAIR SAMUELS surmised there is no state land within the geological structure of "BP's" Liberty Field, an island in federal waters. However, if there was state land, would there be a formula for splitting the state and federal royalties, he asked.

MR. DICKINSON responded a similar thing is the Northstar Unit which is off shore and includes both state and federal lands. A

formula was developed for this unit that says 18 percent is federal and the rest is state. Additionally, there are reopeners should either party want to change the formula. He offered his belief that there is no state land in the Liberty case, but that if there was, a formula would be developed similar to the Northstar situation.

[9:41:31 AM](#)

MR. DICKINSON continued his discussion of Alaska state royalties [page 19]. He explained that measurement is made at the point of production and royalty is 12.5 percent on older leases and higher on newer leases, resulting in a current average of 13 percent on all leases. Some of the older fields have a field cost allowance, he added. The royalty can be taken in-kind (RIK) or in-value (RIV). The state takes most of its royalty in-value, meaning it gets paid in money, but at some points in the past the state took a lot of royalty in-kind. Some of the newer leases have higher rates, he noted, and there are also some Net Profit Share Leases.

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MR. DICKINSON moved to the next four steps of how the pieces all fit together [page 21]. He said these steps include calculating the production tax value (PTV) and how production tax is applied to that. Production tax value is calculated by deducting upstream operating costs and upstream capital costs. For this purpose capital money is treated as being spent in that year, so there is no depreciation even though the money is being spent as a long-term investment. Thus, a \$100 million investment would be a \$100 million deduction in that year. Secondly, he explained, an activity does not need to be physically located on, near, or within the premises of the lease or property. This means that the costs of building a module in Louisiana for use in Alaska can be deducted at the time the costs are incurred rather than waiting until the module is actually brought into Alaska.

MR. DICKINSON defined lease expenditures as being costs other than the items listed in [AS 43.55.165(e)] incurred to explore for, develop, or produce oil or gas deposits located in the state. He said these costs must be allowed by regulation and they must be upstream of the point of production, ordinary and necessary, and direct. Additionally, there is a reasonable allowance as determined by the [Department of Revenue] for overhead. Right now, the issue is "allowed by regulation"

because the department must positively allow a cost by regulation before it is deductible. Those regulations have not yet been written, so it is not yet known exactly what costs will or will not be allowed.

[9:44:56 AM](#)

MR. DICKINSON said there are 21 disallowed kinds of costs under AS 43.55.165(e). He reviewed some of those disallowed costs [page 22, original punctuation provided]:

- depreciation, depletion or amortization
- (12) non third party transaction unless "the producer establishes to the satisfaction of the department that the amount ... does not exceed fair market value"
- (15) dismantlement, removal, surrender, abandonment, restoration
- (18) \$.30 a [British thermal unit (BTU)] equivalent barrel from Capital Expenditures for all production
- (19) any cost "that results in or is undertaken in response to a failure, problem, or event that results in an unscheduled interruption of, or reduction in the rate of oil or gas production ..."
Unless "solely necessitated by an act of war,...natural disaster or other natural phenomenon of an exceptional, inevitable, and irresistible character, the effect of which could not have been prevented or avoided by the exercise of due care or foresight ..."
- (20) costs incurred to construct, acquire or operate a refinery of crude oil topping plant ... however the producer's lease expenditures include the ... fair market value of the product

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MR. DICKINSON stated that once the production tax value is calculated, it is turned into a "per unit amount" by dividing the PTV by the total production. He reviewed other aspects of the production tax [page 23]. One aspect is the floor value of four percent [when the ANS WC price is above \$25 per barrel] which phases out to zero percent [between the ANS WC prices of \$25 per barrel and \$15 per barrel]. Hitting the floor has no effect on loss carryforwards, calculation of PTV, or the ability to carry credits forward. He noted there is controversy over whether credits can or cannot be applied against the floor. Other aspects are private royalty taxes, the conservation

surcharge of a nickel a barrel, the Cook Inlet and instate gas use ceilings, and monthly reporting, filing, and interest.

[9:51:43 AM](#)

MR. DICKINSON specified that after subtracting costs, the production tax value cannot go below zero [page 24]. When there is positive PTV, the tax rate on the PTV is 25 percent. When there is zero PTV, a loss carryforward credit is generated that is then applied in the next year.

MR. DICKINSON explained that a fair portion of the production tax rate comes from the progressivity add-on, not the 25 percent base rate [page 25]. The progressivity is generated from very high PTV's which, in turn, are generated by very high oil prices. Monthly calculation of the PTV per BTU equivalent barrel is done by taking 1/12 of lease expenditures, less current month prices, less current month transportation costs. Progressivity is then calculated by subtracting \$30 from the PTV per BTU equivalent barrel, multiplying the result by .4 percent for every dollar [up to \$62.50] or 25 percent. Once the 25 percent is reached, the rate becomes .1 percent for every dollar [up to \$250 or 25 percent]. The highest progressivity tax is 50 percent which occurs when the PTV reaches \$342.50. This progressivity is then added to the base production tax rate of 25 percent and applied against the entire PTV base.

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MR. DICKINSON further explained that as the amount of income goes up, the tax rate applied to everything increases, sometimes resulting in higher taxes than the amount of new revenue that is generated. This is different than the federal income tax system in which each increment of increased income has an increasingly higher rate applied against it. For example, at a destination price of \$115 per barrel [page 26], progressivity and the basic production tax would result in a combined tax rate of 47 percent, or a tax of \$39.95 per barrel.

MR. DICKINSON said the last piece after calculating the tax is applying the credits. Credits under AS 43.55.023 and AS 43.55.025 can be transferred and sold to another person, or they can be saved and applied against future liabilities. Under AS 43.55.028, credits can be sold back to the state, subject to two conditions. First, the company must reinvest that money back in the state. Second, this is only available to producers with less than 50,000 barrels a day of production, which excludes the

"big three". The original annual cap of \$25 million credit per taxpayer was repealed in the 2007 reforms.

MR. DICKINSON described the three kinds of production tax credits [page 28] provided under AS 43.55.023, AS 43.55.024, and AS 43.55.025. Investment credits are provided under AS 43.55.023. A credit of 20 percent of any qualified capital investment is provided by AS 43.55.023(a), with half of the credit taken in the year of investment and the other half taken the next year. A loss carryforward credit is provided by AS 43.55.023(b), and is calculated as 25 percent of lease expenditures that are not deductible in calculating PTV. A company can use the loss carryforward in the next year, but if it transfers the loss carryforward to someone else then that company must use it over two years. [Under AS 43.55.023(e)], credit purchased from another company may not reduce a company's tax to less than 80 percent of what would otherwise be due. The previously allowed transitional investment expenditure credits were repealed [under AS 43.55.023(i)].

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MR. DICKINSON discussed the credits available under AS 43.55.024 [page 29]. A new area development credit is provided under AS 43.55.024(a)-(b), whereby up to \$6 million a year can be applied against PTV from new area development, meaning development in areas other than the North Slope and Cook Inlet. A small producer credit is provided [under AS 43.55.024(c)-(d)], where up to \$12 million a year is applicable [against AS 43.55.011(e) taxes] for companies producing not more than 50,000 BTU equivalent barrels a year. This amount phases out between 50,000 and 100,000 barrels, although there is no one currently in that intermediate category. The small producer credit applies for any of the base tax and progressivity tax, but it does not apply to the private royalty tax. Mr. Dickinson noted that this has taken a lot of the smaller taxpayers off the tax roles and they only have to file informational returns. [The AS 43.55.024] credits are non-transferable, non-saleable, and cannot be carried over, he said. The credits will sunset in 2016; however, for a company that has no production before 2006, but production starts before 2016, there is a special rule [nine years of the credit].

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MR. DICKINSON read language [from AS 23.44.024(e)] and explained that this statute is designed to stop a large producer from

taking advantage of the small producer credit by becoming a lot of small producers in order to get a tax break for each one [page 29].

MR. DICKINSON said the exploration credits under AS 43.55.025 have been in effect since 2003 [page 30]. A 30 percent credit of exploration costs is provided by [AS 43.55.025(b) and (c)]. The Department of Natural Resources (DNR) must certify that these costs are for a new exploration target. Except in Cook Inlet, this exploration target must be [more than] three miles from an existing bottom hole. A credit of 30 percent of exploration costs is provided [under AS 43.55.025(b) and (d)] for exploration that is more than 25 miles from a unit boundary that existed in 2003. The purpose of this provision is to promote exploration in unexplored areas further west. [Under AS 43.55.025(b), (c), (d), a credit of 40 percent is provided on exploration costs] that meet both criteria.

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CHAIR SAMUELS asked whether the frontier credits provided in 2003 under AS 43.55.025(b), (c), and (d) were changed in the reforms of 2006 and 2007.

MR. DICKINSON answered the credits were there but they were 20 percent instead of 30 percent. He added that there have been a number of forms of the provision that require additional certification by the commissioner of DNR.

CHAIR SAMUELS inquired how much these provisions have been used since 2003.

MR. DICKINSON replied the provisions are used and are not window dressing, but he does not know how much different the picture is as a consequence of those credits.

MR. DICKINSON continued discussing exploration credits, noting that seismic costs are allowed at a 40 percent credit [under AS 43.55.025(b) and (e)]. He explained that [AS 43.55.025(1)] is a different form of the TIE, and provides a 5 percent credit for work done prior to 2003 in those cases where DNR decides that making that information public is in the state's best interest. Essentially, it is a purchase of the information, he said, but the well data is held confidential for two years and the seismic data for ten years before being released to the public. If a producer does not want the information to become public then it will not qualify for this [5 percent] credit. Mr. Dickinson

further noted that all of these exploration credits are fully transferable, saleable, or carried forward. He presented an example depicting the effect of credits and loss carryforward on the amount of production tax due when an investment is made in a second project [page 31].

[10:06:38 AM](#)

MR. DICKINSON returned to his illustration of how the pieces all fit together [page 32]. He said the \$2.8 billion of royalty shown in the example includes the Permanent Fund and that the base production tax of \$3.4 billion was calculated at 25 percent of the PTV. The \$1.8 billion shown for progressivity is an estimate because there are not yet any figures for the last couple months of the year. The credits shown are \$400 million, bringing the total [production tax] to \$4.9 billion. The last two pieces, he continued, are lines 8 and 9. Property tax did not change.

MR. DICKINSON said the last two pieces are lines 8 and 9 [page 32] regarding the Alaska corporate income tax and property tax. While these two taxes did not change, there are often misunderstandings about them. He specified that under the Alaska corporate income tax there is not separate accounting; rather, it is modified apportionment [line 8, page 32, and page 33]. This means a company's total worldwide income is calculated, then a factor is determined as to how much of that is applicable to Alaska, and then that is multiplied by 9.4 percent.

MR. DICKINSON presented a sample calculation [page 34] of the Alaska corporate income tax. He said he used a sales ratio of 1 percent in the sample because Alaska is a production state with very little in sales, along with a ratio of 10 percent for plant production equipment (PPE) and 25 percent for production. These three factors - sales, property, and production - are averaged to come up with an Alaska apportionment factor of 12 percent. This 12 percent is then applied to the company's worldwide income. Thus, he continued, in this sample calculation 12 percent of \$2.5 billion of worldwide income amounts to an Alaska apportioned income of \$300 million. At an Alaska tax rate of 9.4 percent, the Alaska corporate income tax is \$28 million.

MR. DICKINSON stressed that one cannot just look at how much money is generated in Alaska; rather, one must look at the effect on the factors. Most of the additional income taxes that flow to the state from development here come not because of the

additional cash flow in-state, but as a consequence of new property or new production in Alaska. He read from the paragraph at the bottom of page 34 which states [original punctuation provided]:

For incremental analysis: Most "separate accounting income" generated in the state will be apportioned off and taxed elsewhere; most of the income taxes collected in the state will have been generated from "separate accounting income" generated elsewhere.

MR. DICKINSON further explained that the algorithm for doing quick estimates of income tax multiplied by 9.4 percent is an average of about 4 percent in income taxable flow from a project in the state of Alaska.

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MR. DICKINSON discussed exploration, production and pipeline transportation property tax [line 9 on page 32; AS 43.56 on page 35]. He said that while the state determines the value of all the assets in the state, the actual mechanism is that each locality that has a taxing authority levies its own tax. The state levies a 2 [percent] tax and a credit is given for anything that is paid locally. So, the net effect is a 20 mill tax. There is no statutory limit, he continued. There is a 30 mill limit for operations. The "supreme court" has ruled there is no limit on repaying debt service and that constitutes a lot of the money that is being collected. But, there is essentially an informal cap of 2 percent and anything above the 2 percent would be under a separate set of engagements.

MR. DICKINSON outlined the three classes of property [under AS.56.060, page 36]. Exploration property, [1 percent of the 2008 roll], is looked at at sales value. Costs for production property, [62 percent of the 2008 roll], are used during construction and after construction it goes to replacement cost new less depreciation based on the economic life of the proven reserves. Pipeline property, [37 percent of the 2008 roll], uses a methodology with due regard to the economic value of the property. He said state regulation [15 AAC 56.110] provides for determination of this value through the use of "standard appraisal techniques such as replacement cost less depreciation, capitalization of estimated future net income, analysis of sales or other acceptable methods". This can open the door widely, he added, so the state has generally now gone to a cost base.

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MR. DICKINSON again returned to his illustration of how the pieces all fit together [page 37]. He pointed out that in this example the [Alaska corporate] income tax is about \$600 million. The property taxes are about \$287 million and, of that, about 80 percent will go to North Slope, Valdez, Fairbanks, and other places. About 20 percent will go to the state because a large portion of the [Trans-Alaska Pipeline System] is in an unorganized borough where there is no taxing authority other than the state. Mr. Dickinson said there is an asterisk beside all the cost pieces because operating costs, capital costs, and transportation costs all typically include property taxes. He reminded members that there may be a difference between the costs incurred and the allowable costs, and that when the regulations are written it will be seen what that difference is. What is on a company's income statement or financial analysis may not be reflected in what is finally deductible. Another huge piece for a company is federal income tax, he continued. Basically, all costs get deducted and all state taxes get deducted, and then a marginal federal income tax rate is applied, which in this example would be about \$2 billion.

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MR. DICKINSON delineated what is going to happen next [page 38]. There is going to be a real in-state energy focus, he said, because the voters approved the Alaska Natural Gas Development Authority (ANGDA) and there are numerous other initiatives out there as well. The Department of Revenue is continuing its regulations project for nailing down costs. Mr. Dickinson predicted a general fund deficit for fiscal year 2009. He said there might also be a focus on the fiscal issue suggestions that are being made by the Denali and TransCanada gasline projects.

MR. DICKINSON reviewed the Department of Revenue's regulations project [page 39]. He said the department's procedure for each of the five projects is to first release a discussion draft, then release a more formal public comment draft, and last is adoption. The first project regarding lease expenditures - the critical issue of what can be deducted - has not moved beyond the discussion draft stage. For civil penalties and mid year statutory changes [project two], there are 35 sections to which changes have been proposed. Two of those sections are still in discussion and more formal rules have come out for the others. A regulation regarding gas net present value (NPV) [15 AAC 55.173] went quickly and was adopted in August [2008].

Reporting requirements [project three] also went through very quickly and were made effective [as of June 2008]. Reasonable transportation [project four] is still in discussion and exploration credits [project five] are in their first public comment. Thus, he said, there are a lot of issues for which the specifics are unknown until the department rules [page 40].

10:20:40 AM

MR. DICKINSON looked at the general budget for fiscal year 2009 [page 41]. He pointed out that an [ANS] oil price of \$80 or \$85 is necessary to sustain the budget without a deficit.

MR. DICKINSON read the following suggestion written by TransCanada in its AGIA application [page 42, original punctuation provided]:

- TransCanada would rely on the State of Alaska to take all feasible actions exclusively within its authority as a sovereign power to ensure a favorable economic environment for potential Shippers on the Project. Those actions include:
 - engaging with the ANS producers to reach agreement on a commercially reasonable and predictable upstream fiscal regime that balances the needs of the state and the ANS producers;
 - and encouraging robust exploration for and development of new natural gas resources and the commitment of such resources to the Project.

Mr. DICKINSON related that TransCanada is relying on the state to create this kind of an environment since only the state can do it, and TransCanada thinks this environment is critical for getting folks to engage with them and transport gas on the line. He said ConocoPhillips, one of the owners of the Denali gasline project, made a similar point in a handout [page 43, original punctuation provided]:

The predominant lessee risk that should be the focus of discussion with the State is the risk of unclear, unpredictable State taxes and royalties. In order to enable shippers to make long term shipping commitments, prospective shippers need clearly defined natural gas fiscal terms and an understanding of the period during which these terms will apply. Addressing these issues remains a critical component

necessary to develop ANS natural gas resources and make this Project a reality.

MR. DICKINSON surmised that both TransCanada and ConocoPhillips are saying the state needs to create a fiscal environment in which those kind of upstream investments make sense. He said one of the questions that he would have is, "Does the current fiscal regime make sense?" When the work was done on oil - which included tax by definition - everyone understood that the oil was the huge financial driver and there was little focus on what happens if half of the value or half of the BTU's is coming from gas.

[10:24:22 AM](#)

MR. DICKINSON illustrated what happens to progressivity under the current regime. He presented an example for the month of June 2008 [page 44]. At that time, he said, the average monthly [ANS oil] price was \$133.78 [per barrel] and the Henry Hub gas price was \$12.69 per thousand cubic feet (mcf), a high price for gas. He explained that the translation between 1 mcf of gas and 1 barrel of oil is roughly a 6:1 ratio. This 6:1 ratio is applied to all calculations for gas. The downstream costs of \$4.73 and upstream costs of \$2.71 for 1 mcf of gas are multiplied by 6 to come up with per barrel of oil equivalent costs of \$28.38 and \$16.26, respectively. At the current progressivity trigger of \$30 per barrel of oil equivalent PTV, this results in \$.25 per mcf, or \$1.50 per barrel of oil equivalent, being subject to progressivity [as compared to \$81.25 per barrel of oil]. Thus, if a gasline is built and the current tax system for oil is used for gas, progressivity will be severely diluted and could disappear. Would it be considered a stable situation if gas sales dramatically lowered oil taxes, or would folks call for change? The question is whether this current fiscal regime contributes to the kind of fiscal situation that both TransCanada and ConocoPhillips were talking about.

MR. DICKINSON said the pendulum swings and the way people think is always changing [page 45]. The old way of thinking was that taxes are a drag on business activity so should be as low as possible, with the only constraint being that state needs are met. He offered his belief that the current way of thinking is that the taxes are more like a royalty because "it's our oil and gas" and therefore the government take should be as high as possible, the only constraint being that the taxes not drive

away investment. This currently predominant thinking, he continued, is mirrored by movements to make taxes more contractual and like a royalty, and less like a tax with rules that apply to everyone. Mr. Dickinson concluded with the question, "As the state shifts from an oil base to ... a gas base over the next 15 or 20 years ... is the pendulum going to swing, is that going to continue to be a paradigm that is used?"

[10:32:22 AM](#)

SENATOR THERRIAULT offered his understanding that the current structure would act as an incentive to bring gas into production because it would help a company with its oil taxes.

MR. DICKINSON responded absolutely correct. There is no question that it would lower taxes. He said his point is that if it has the effect of completely wiping out the oil progressivity tax, would that be a stable version? Some of the modeling suggests there might be effects that are out of proportion to what is anticipated and this could result in some people thinking it is a step too far.

[10:34:21 AM](#)

SENATOR FRED DYSON said it looked to him that the state's spending in nominal dollars had tripled, rather than doubled as stated by Mr. Dickinson during his discussion of page 8.

MR. DICKINSON replied correct, it triples between the years 2000-2009. He said his earlier statement was focused on the years 2005-2008.

SENATOR DYSON agreed and said the information for 2005-2008 was also useful.

[10:35:43 AM](#)

The committee took an at-ease from 10:35 a.m. to 10:58 a.m.

PRESENTATION BY DAVID WOOD

[10:58:21 AM](#)

CHAIR SAMUELS announced the next presentation would be from Dr. David Wood. He said the committee asked Dr. Wood to study how the state's current system would affect gas taxes and provide comparisons to other jurisdictions. He reiterated that this is

not a hearing on the Alaska Gasline Inducement Act (AGIA), Alaska's Clear and Equitable Share (ACES), the Petroleum Production Tax (PPT), or the Economic Limit Factor (ELF). Rather, it is looking forward to what the legislature will do on oil and gas issues in the next two years.

[10:59:32 AM](#)

DAVID WOOD, PhD, Consultant to the Legislative Budget and Audit (BUD) Committee, Alaska State Legislature, stated he is presenting highlights from his report [entitled, "Preliminary Report on a Fiscal Design for the Development of Alaska's Natural Gas"]. He said he spent eight months studying Alaska's fiscal design for natural gas in the context of the international gas industry [page 4 of his PowerPoint presentation]. He steered clear of gasline issues and focused his study on where Alaska will be in the upstream for natural gas in a decade when the gasline has been built, and how the fiscal design will impact the production from that gas.

DR. WOOD related that he has a doctorate in geology and technical experience at an international level in geology, reservoir, and facilities engineering. For the past 20 years he has worked extensively around the world on fiscal systems design and evaluation. He said he has the breadth of looking at the issues from a technical perspective as well as commercial and economic perspectives, and in putting this report together he has drawn on all of these perspectives. His worldwide oil and gas work has involved looking at large gas projects by pipeline and liquefied natural gas (LNG).

DR. WOOD said it is important to look at where Alaska gas fits into the international gas arena. He noted that for the past 10 years he has worked as an independent consultant for international oil companies (IOC's), national oil companies, and governments or government departments; thus he looks at things from both perspectives and steers an independence course. He said he was also selected because he had no previous involvement in Alaska which was useful in putting this report together. He acknowledged there is a lot to learn about the scale of operations in Alaska - the physical and cost objectives to bringing North Slope gas into the Lower 48 markets - but this is offset by his independence and fresh eyes which bring perspectives that would not have been there if he had had previous involvement. He stressed that while he has conferred with other consultants to the [Legislative Budget and Audit (BUD) Committee], the opinions he is expressing are his own

[page 5]. Some of the information he will be providing will not please the legislature and some will not please the producers.

[11:09:39 AM](#)

DR. WOOD stated it is important to first talk about Alaska gas in the context of North America and then broaden that to international implications. He used 2007 figures to illustrate the amounts of natural gas being imported to and exported from the U.S. [page 7]. He noted that gas is both imported from and exported to the countries of Canada and Mexico. There is huge domestic production in the U.S. from the Gulf of Mexico and from unconventional gas such as shale gas and coalbed methane. Alaska gas will ultimately be competing with this domestic production, as well as with LNG that is imported from around the world. There are LNG receiving terminals primarily around the East Coast and many are being built around the Gulf of Mexico. An LNG terminal is currently being built in Oregon and more LNG will likely be coming in through the West Coast in the future. He pointed out that LNG terminals in Mexico will be receiving gas from Russia and Indonesia and that this LNG will be imported into the Lower 48. Some of the imported LNG has high cost associated with it, he added. For example, the transportation cost alone for LNG from the Arabian Gulf to the Lower 48 is \$2 per million BTU.

[11:15:00 AM](#)

DR. WOOD specified that 60 percent of the LNG imported into the U.S. comes from Trinidad and Tobago. Egypt has a large share of imports to the U.S. market even though it only began producing LNG in 2004. Algeria has been a traditional supplier for decades. There are projects sanctioned by major U.S. companies to build new liquefaction plants in Angola and in Papua New Guinea, and these projects may well bring LNG into the U.S. in a decade. In the 1960's Alaska pioneered the export of LNG to Japan and this continues today. Export of one cargo of LNG to Russia to help commission a terminal there emphasizes the flexibility of LNG in its movements, he noted. Although Alaska is currently focused on the gasline, he said he hopes that by 2020 and beyond there will be potential for new LNG from Alaska. Internationally Alaska is going to be competing not only with sources of LNG, but will hopefully be competing itself in the longer term as a provider of LNG as well.

[11:18:10 AM](#)

DR. WOOD said that just as the oil market has had a spike in 2008, so has the international gas market [page 9]. The international gas market has been highly volatile. Much less LNG came into the U.S. in 2008 as compared to 2007 because of the increase in production from unconventional shale gas and the substantial increase in gas prices and gas demand in Asia. Spot prices as high as \$20 per million BTU has led to many LNG producers electing to divert cargos to the Asia market. This emphasizes not only the flexibility of LNG, but also the vulnerability of gas consumers to other markets that are prepared to pay more, creating competition and high prices for the LNG.

DR. WOOD discussed where North America sits in terms of natural gas developments across the world. He said the information shown [one page 8] comes from forecasts from the International Energy Agency's (IEA's) reference case of 2007. While the IEA has downgraded the forecast going forward several times this year, the global forecast for the next 20 years is still for substantial growth in demand for natural gas. The U.S. will have to compete quite hard with the other main markets, he warned. There is massive expansion of both LNG and pipeline gas coming into Europe and Asia. In 10-20 years time there is going to be huge competition for gas and huge investment in both pipeline and LNG infrastructure. The sources for LNG coming into North America will be much more diversified than they are today.

[11:23:23 AM](#)

CHAIR SAMUELS asked whether an inability to obtain capital right now will slow down construction of some of the worldwide infrastructure.

DR. WOOD answered that the current financial situation is already resulting in a number of postponements and delays in the building of gas infrastructure, refineries, and everything else across the whole of the industry. However, some of the big international gas projects are still moving forward, such as the Papua New Guinea LNG project. He offered his belief that many of these projects will move forward. Many of them are of regional strategic importance and are backed by governments and it is in the governments' interests to see those projects move forward.

DR. WOOD reiterated that gas has been suffering volatility just like oil and will continue to do so [page 9]. He said this

volatility has been in both price and demand. Given this volatility, and that progressivity works well for oil, it makes sense to have some type of progressivity that works for gas so that the state is able to achieve revenue from price spikes. In terms of fiscal design, he advised, the volatility issue must be kept in mind because over the next couple of decades periods of volatility will repeat themselves.

[11:27:54 AM](#)

DR. WOOD addressed the problems with Alaska's current progressivity tax from the gas perspective [page 10]. He said models from his work for a wide range of gas field sizes found three main points [associated with calculating production tax values using a combined oil and gas barrel of oil equivalent (BOE) revenue stream]. One problem is that in a combined stream, large gas production volumes dilute the PTV on a BOE basis. Regarding the earlier question about this being a good thing because it will encourage the development of gas, he pointed out that there is a progressivity component that can effectively deal with a very high gas price spike and at the same time not dilute a very high oil price spike. It is important to see gas and oil work independently within the fiscal design because if they work together they can actually work against each other and this seems to be how it works currently. He said another problem is the threshold [trigger point] at which the progressivity tax for gas comes into play because it is measured on a barrel of oil equivalent basis, as was pointed out by Mr. Dickinson. This threshold is too high for gas. A third problem is having a production tax floor in the mechanism because this leads to a regressive influence in certain circumstances. Dr. Wood stressed that gas progressivity is important because in the future there will be price spikes and it needs to capture revenue for the state while at the same time not "disincentivizing" the producers from investing and developing gas.

[11:31:35 AM](#)

REPRESENTATIVE HAWKER inquired whether the aforementioned information is predicated upon there being a disconnect between the energy equivalency and the price equivalency. For example, on an energy equivalency it is 6:1, but the price equivalency has been far greater than that for the value of a barrel of oil. If this is the predicate, how is the analysis changed when there is a reconnection of the energy and price equivalency, he asked.

DR. WOOD concurred that a period of dislocation has occurred and is the reason why this dilution effect is showing up, and that the situation could move back to where there is a greater equivalency between those prices. However, he warned, while gas and oil prices do follow each other from time to time, this equivalence can change very quickly because there is so much competition around the world. North America is quite different from Europe and Asia. Consequently, he advised, Alaska needs to build a fiscal design that does not assume an equivalence exists. In further response to Representative Hawker, Dr. Wood said an equivalence could dominate over time, but that Alaska needs to plan for those periods when there is a disconnect. "More than likely it will occur when there is a price spike either in oil or in gas, the very time at which progressivity becomes important." In the current scenario of low prices, progressivity falls away and becomes a non-issue, he continued. In those periods where there are price spikes, progressivity becomes a very important source of revenue and the state does not want to be in the position where its fiscal design is unable to appropriately capture the potential revenue.

[11:35:46 AM](#)

REPRESENTATIVE KELLY referenced page 44 of Mr. Dickinson's PowerPoint presentation and asked how the gas royalty situation could reach over and drive the oil royalty and progressivity.

DR. WOOD offered his understanding that page 44 of Mr. Dickinson's presentation was focused on progressivity, not royalty, and this is a progressivity issue.

REPRESENTATIVE KELLY acknowledged that point.

Dr. WOOD replied it certainly is the case that the gas can impact oil and he will be presenting those details later.

[11:38:05 AM](#)

SENATOR THERRIAULT surmised that one of Dr. Wood's main tenants is the state should look for a system that can accommodate price swings and be perceived - on both the upper and lower ends - as being fair to the producers and to the sovereign.

DR. WOOD agreed a fair system is needed. He said he will be coming back to that in terms of the stability issue. The state needs to capture higher prices through progressivity, he reiterated, but it must also recognize that when prices are low

it is difficult not only for the state but also for the producer because there is much less to share.

11:40:06 AM

DR. WOOD stated his report looks at details of the fiscal designs applied by other countries, but today he is only presenting the general points [page 12]. He said it is important to look at the fiscal designs of countries from the strategic level - what are they trying to achieve with those fiscal designs - and then work down into the detailed mechanisms of those designs that actually raise the revenue through the fiscal instruments. The three main strategic objectives are to optimize government take through taxation; encourage inward investment, resource development, and industry infrastructure; and develop indigenous industries, communities, and employment. To address all three of these strategic objectives, there needs to be balance to provide stability and consistency, alignment to achieve credibility with all stakeholders, and flexibility to change the fiscal design to meet changing circumstances.

DR. WOOD said that, in reality, most fiscal designs are trying to establish more than the aforementioned. He illustrated this point with the diagram on page 13, explaining that the three bubbles depicted on page 12 are represented by the apexes of the triangle depicted on page 13: sovereign take, local content, and investment/work program. He said it is interesting - conceptually and generically - to see where different countries and different regions lie [in the page 13 diagram] in terms of their strategic objectives for their fiscal designs. He noted that not everyone may agree with where he has placed the state of Alaska within the diagram, but his point is that Alaska sits in a different position from the rest of North America based upon the changes in Alaska's fiscal design in recent years.

DR. WOOD pointed out that many of the countries in the Organization for Economic Cooperation and Development [OECD] are focused on upstream design in terms of trying to optimize investment. That investment will ultimately lead to development and development will ultimately lead to revenue and take through larger scale activity. On the other hand, a key part of the fiscal design for Norway and north African countries is developing their local industry and maintaining control over the activities that are conducted within their regions. The focus of many of the big OPEC countries is maximizing sovereign take.

DR. WOOD stressed he is not advocating that Alaska should be located in any particular area on the diagram, but he is advocating that the state should know where it is located within the diagram and where it wants to be. These high level considerations - where does the state want to be and how does it want to get there - have implications in the type of fiscal instruments that Alaska will choose to put into its fiscal design.

[11:47:25 AM](#)

DR. WOOD told members there are more fiscal designs throughout the world than there are countries because many countries operate several fiscal designs for different regions [page 14]. He said the details of fiscal design in the upstream oil and gas sector are huge. Many gas fiscal designs evolved by modifying oil designs. It is possible - at a high level - to separate out the main types of fiscal design. Many OECD countries use a type of system where the government vests its right to producers to produce production and reserves through a leasing, licensing, permitting process. Sometimes they are referred to as concessionary agreements and sometimes they are referred to as tax and royalty agreements. However, he continued, the tax and royalty description is not very good because there can be tax and royalty in other systems as well; thus, he prefers to use the term "mineral interest".

DR. WOOD said production sharing is the other main type of fiscal mechanism that is used internationally, particularly by developing nations. Title to the reserves remains with the government and the producers are remunerated through the processes of production. This was first introduced in the mid-1960's in Indonesia. At first, the major IOC companies and producers were very resistant to signing production sharing agreements (PSA's) because they feared it would take away their ability to gain access to reserves. Now, four decades later, many of the IOC's prefer production sharing agreements over mineral interest agreements, and the situation in Russia is a classic example of that. "One of the reasons for that preference is that, superficially, production sharing agreements that are issued under contract enable the producers to lock in some form of fiscal stability for a period a time, ... whereas the mineral interest systems there is much more ability for the state to change the ... rates of the fiscal instruments over time." Therefore, in terms of the fiscal stability debate, there is a contrast between these two.

[11:50:49 AM](#)

DR. WOOD stressed he is not advocating one or the other mechanism and is not advocating that Alaska adopt a production sharing agreement. He said it is important to recognize, however, that many of the countries that are receiving billion dollar investments in gas infrastructure are operating their gas assets under these types of contracts. Not only are these production sharing agreements covering the upstream, in many cases they are also integrating upstream, downstream, or midstream pipeline LNG treatment facilities within those contracts. Thus, big gas investments are being conducted under both production sharing and mineral interest agreements.

SENATOR THERRIault questioned how much of that is because of very stringent time requirements imposed on the producers under production sharing agreements.

DR. WOOD replied that might be the case in some instances, but one can still see situations in which there are many years before projects under production sharing agreements get sanctioned. Production sharing agreements do not necessarily speed up the process, but they focus the producer's attention because most of the agreements have a very limited term associated with them. At the extreme, a producer might have 20 years, but sometimes no more than 30 years, to produce a 10 trillion cubic foot (tcf) gas field. This is very difficult to do in that time frame, he said. So, once signed, the contract forces the producer to move forward very quickly because when the contract expires the resource in the ground and the infrastructure that has been built will revert to the state.

[11:54:18 AM](#)

DR. WOOD stated that the government take for these two main types of fiscal mechanisms is not 50:50, although it is somewhere close. While there are other types of agreements, these are the main two under which big gas reserves are being developed.

DR. WOOD said fiscal designs that use a range of fiscal instruments provide the state with quite a range of take if the take is looked at in percentage terms [page 15]. He said he prefers not to take the approach of saying that such-and-such a contract leads to a state take of such-and-such a percentage because it all depends on a variety of issues such as price, the type of cost base for a particular field, the depth of the

reserve, and the quality; thus, it is not possible to take a particular percentage. In the more prospective areas it is not unexpected for the government take to be higher percentages and, likewise, when market conditions are poor and reserves are small the fiscal designs in many cases allow for that and provide better incentives for the producers to develop. A fiscal design needs to pay attention to progressivity at higher prices as well as the implications of lower prices.

The committee took a recess from 11:57 a.m. to 1:13 p.m.

CHAIR SAMUELS called the meeting back to order at [1:13:48 PM](#).

[1:14:54 PM](#)

SENATOR THERRIAULT said that in the case of a harvester that is paying tax and progressivity, he could see why Dr. Wood placed Alaska in the location shown on the page 13 diagram. However, a article talked about the current tax system being very advantageous to small players because it helps them underwrite investment costs. He asked how Dr. Wood took that into consideration when determining where to place Alaska on the diagram, because there is a difference between actively investing back into the state and just being in harvest mode.

[1:16:10 PM](#)

DR. WOOD replied that is a good point because the various investment credits do play an important role in encouraging investments by small producers. He guessed the effectiveness depends on how big or small a producer is. Perhaps, that has a lesser impact for larger producers, he said.

SENATOR THERRIAULT responded that it depends on the level of investment that a company wants to make in the state. He asked whether Dr. Wood factored in only the level of taxation in determining Alaska's placement, or did he include the investment credits and deductions.

DR. WOOD answered he did consider the investment credits and will be returning to those since they are important and do provide a key element to encourage investment. He accepted that his positioning of Alaska in the triangle is conceptual and said there is not a detailed numerical analysis behind this particular diagram.

DR. WOOD [next discussed why regressive elements and fears of instability can limit investment (page 16).] He stated that in terms of considering fiscal designs, it is useful to look at the components of what is available for the parties involved in production and the ultimate cost of the projects [page 17]. The cost elements involve bonuses to secure the licenses, exploration costs, appraisal costs, development costs, and operating costs. Divisible profit is what is left after accounting for those costs from the total revenue of a project. From divisible profits, one can talk about economic rents, which establish which party gets which share of the divisible profits. He said it is generally accepted that there is a reasonable profit element that has to be considered as part of the production process, but establishing what is reasonable depends on one's perspective.

DR. WOOD explained that the economic rents component is made up of royalty, property taxes, special petroleum taxes such as the production tax in Alaska, plus corporate taxes. All of these make up the government's take and what is left after that take is called excess profits to the company or producer. So, government take of profit is a part of the economic rent. Fiscal design tries to optimize the government take of profits at an appropriate level, but it is difficult to establish what that appropriate level is.

DR. WOOD pointed out that oil and gas behave quite differently on this diagram [page 17], particularly in Alaska. The oil context has quite a large portion of economic rent, so there is a large portion here to play for. The area of excess profits has historically been quite large to producers. In the situation for gas, he continued, the costs are substantially higher, the economic rent level is smaller, and there is less room to make adjustments than for oil. Citing his modeling for the Alaska fiscal system, Dr. Wood said the government take for gas runs at about 30 percent of the total project revenue because the costs are so high. For oil, that percentage is perhaps closer to 60 percent. That percentage of total project revenues is much higher because that cost is much smaller. On the other hand, under the current system the percentage of divisible profits is about 75 percent for oil and about 67 percent for gas. So the current system works more effectively for oil in taking a larger share of the divisible profits than it does for gas. But for gas, there is less to play for because the costs consume such a large share of the revenues, and much of that cost is transportation and tariff for moving that gas.

[1:25:01 PM](#)

DR. WOOD said there is a spectrum of fiscal instruments that can be used to extract that share of economic rent. It depends on the nature of those instruments as how effective they are at making the system fair and appropriate for the parties involved in a range of circumstances. Progressive taxation - progressivity - is used in the context that when prices are high/costs are low and projects have high value, then a high share of the revenue goes to government take. He said the kind of fiscal instruments that lead to that are shown toward the right side of the diagram [depicted on page 18], and include those that operate on a profit, or net, basis. The production taxes in Alaska fit into the right side of the diagram. On the other hand, Dr. Wood continued, instruments that impact the revenue on a basis before costs have been deducted tend to be more regressive. This is because these instruments operate on a percentage basis and in high cost/low price situations they are going to take large shares of the revenues irrespective of whether or not there is a large share of divisible profits. Regressive instruments include royalties, property taxes, resource taxes, and any instrument that operates pre-production or irrespective of profitability and cost.

DR. WOOD noted that when looking at fiscal designs the elements that cause systems to move in a regressive or progressive sense need to be identified. From a government perspective there is a risk in having all of the fiscal design in [the progressive] end of the spectrum because the government does not see any income until profitability is achieved and costs have been deducted. On the other hand, a fiscal design that is weighted more heavily to [the regressive] end of the spectrum, causes a much higher risk for the producer because when prices are low/costs are high the producer will have to pay these fiscal instruments irrespective of profitability. Balancing fiscal designs often means combining these elements so both parties can achieve realistic returns, i.e. some should be at either end to achieve the objectives.

[1:29:37 PM](#)

DR. WOOD explained that under a truly progressive fiscal design the percentage of government take increases during situations of high profitability and decreases during situations of low profitability [page 19]. A highly regressive system tends to be the reverse: in situations where costs go up and prices go down, the percentage of government take of divisible profits

actually goes up. This is more punitive for the producers and is a greater disincentive to reinvest and to keep projects going. It also makes the break-even reserve size of fields higher in terms of developing them, he added. A highly regressive system can result in situations where government take reaches or exceeds 100 percent of the divisible profits. Also, progressive systems have a much greater range of flexibility.

DR. WOOD reiterated that he is not in favor of defining and comparing fiscal systems purely on government take because each field shows a whole range of cost structures and prices may change. Under a progressive design the percentage of take can vary quite significantly depending on the specific conditions. Therefore, it cannot be said that a particular design gives so much to the government because that would mean picking a particular scenario, a particular price, and a particular cost and this would not necessarily represent the whole spectrum of possibilities that could occur. It is important to understand how progressive or regressive a fiscal system is, he advised.

[1:33:30 PM](#)

DR. WOOD said progressivity is a progressive element of Alaska's fiscal design, but it also has regressive elements such as royalty, property tax, and the floor in the production tax calculation. Investment credits are a progressive element, he continued, or they at least mitigate the regressive tendencies of certain fiscal instruments.

DR. WOOD expanded on his earlier statement that regressive systems impact the minimum reserve size by pushing up the minimum field size [page 20]. A highly progressive fiscal system acts to bring down the minimum field size, aids in the development of marginal fields and small fields by encouraging investment, and helps to keep those fields in production. The more regressive the system, the greater the state take and the higher the minimum threshold. Alaska's 2006 and 2007 changes increased the state take and slightly increased regressivity in terms of increasing the minimum field size, he said. The 2007 rise in the base production tax rate from 22.5 percent to 25 percent is the element that has particularly increased field size, although this is partially offset by the tax credits. When making fiscal changes, it is important to identify whether they are progressive or regressive, he advised.

[1:37:23 PM](#)

DR. WOOD said the three main regressive elements of Alaska's prevailing fiscal design - royalty, property taxes, and production tax floor - are partially offset by investment credits, production taxes that are levied after deduction of allowable costs, and progressivity tax that is levied on high value streams [page 21]. The progressivity tax works well when prices are high, but the issue is that when prices are low and costs are high the three [regressive] elements come into play to a much larger extent.

DR. WOOD discussed some of his modeling for gas fields based on Alaska's prevailing fiscal system [pages 22-26]. He said he used 10 hypothetical fields - 5 of them non-associated gas fields and 5 of them oil fields with associated gas, with each of those ranging from small reserves to large reserves. For example hypothetical Field 1 has relatively low gas reserves, perhaps 1/2 tcf, and hypothetical Field 5 has a gas reserve of 10 tcf.

DR. WOOD displayed a pie diagram for hypothetical Field 4, a gas field of 5 tcf [with base case assumptions in Year 0 of a gas price of \$7.5 per thousand thousand British thermal units (MMBTU), an oil price of \$80 per barrel, and nominal inflation of 2 percent per year (page 22)]. He said the costs for transport, tariff, and treatment (TT&T) of the gas take up 42 percent of the divisible revenue, with the total for all costs being over 50 percent. Dr. Wood clarified that his models do not look at individual taxpayers, but at the field over a field life of maybe 15-20 years of production, and the diagram is a summary of the total returns over that producing life.

[1:40:43 PM](#)

DR. WOOD explained that the left side of the pie chart for Field 4 represents the divisible profits and that two-thirds, or 67 percent, of the divisible profit is effectively going to gas. This divisible profit is comprised of the Alaska state take [22 percent], the federal take [9 percent], and the producer take [16 percent].

DR. WOOD compared the diagram for Field 4 to a diagram for Field 10 [page 23], which is a model for a large oil field of 500 million barrels of reserves and substantial associated gas. He said both models used the same base case assumptions and Alaska's prevailing fiscal design, yet the costs for transport, tariff, and treatment of the gas from Field 10 constitute a much smaller portion of the whole divisible revenues [6 percent].

Together, the capital costs, operating costs, and transportation costs for Field 10 are less than one-fourth of the revenue. If the cost element is excluded, [state and federal] government take is about 75 percent of Field 10's overall divisible profits. So, he continued, the situations are quite different for large gas fields and large oil fields. The big difference is the high cost of moving the gas. A lower absolute amount of divisible profits is available for the gas projects.

[1:44:18 PM](#)

DR. WOOD contrasted the components of the Alaska state take for Fields 4 and 10 [pages 24 and 25]. He reminded the committee that this is for the whole life of the fields, not one snapshot. When looking at fiscal designs, he said, it is sometimes more useful to look at how are the takes established over the whole life of the field, rather than looking at marginal takes or individual periods. He explained the acronyms depicted in both of the diagrams: BPT, basic production tax, is the separate 25 percent component of production tax; and CPT, combined progressivity tax, is the progressivity component of production tax under the current fiscal system. Under the base case assumptions that are used for both fields, royalty and production tax provide the state with the largest share of its fiscal take. However, he pointed out, the CPT for the gas field is a relatively small component of the take [4 percent], while for the oil field the CPT is much more substantial [31.7 percent].

[1:47:51 PM](#)

DR. WOOD noted that while it is all very well to show the previous diagrams using a certain assumption, what is important is that fiscal designs work over a whole range of price and cost conditions. It is important to carry out the models so they look at a whole range of assumptions, not just best guesses of what prices might be.

DR. WOOD displayed a graph showing the sensitivity of a gas field to project and market variables [page 26]. He explained that the diagram [for hypothetical Field 4] is from a producer's perspective and analyzes the net present value (NPV) for a whole range of sensitivity cases. For the sensitivity cases on the horizontal axis, the first number [on the left] is the base case assumption which is varied up to a factor of three [last number on the right]. The variables depicted on the graph are gas TT&T, oil price, gas price, operating costs, capital costs and

the condensate yield from gas liquids, he explained. It can be seen how those different components influence the returns from the producer perspective. Similar diagrams could be drawn for the state take perspective and for various stakeholder positions. Dr. Wood further explained that this diagram shows gas price is the variable to which this particular field is most sensitive. As gas prices go up, returns to the producer go up. If gas prices go down, returns fall dramatically. The oil price component is less significant because liquids are a much smaller component of this particular field; but, if it was an oil field, then the greatest sensitivity would be to oil price. He noted that this particular field is highly sensitive to operating costs and gas transportation costs. It is more sensitive to operating costs than to capital costs because investment credits offset some of the impact of higher capital costs.

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DR. WOOD said his model is set up such that production is shut down when operating costs exceed operating revenues because an operator would shut down at this level. The sensitivity analysis is important, he stressed, and the second volume of the report goes into detail in this regard for the 10 fields. Additionally, the report details the sensitivity of each of the fields to the different fiscal elements. Detail modeling is an important approach to identifying how fields of different nature are profitable or unprofitable.

DR. WOOD moved from modeling to the issues of fiscal instability and fiscal credibility [page 27]. He said he is addressing these issues from a global perspective because oil and gas producers, particularly the IOC companies, have experienced unprecedented levels of fiscal instability over recent years. At the extreme end of instability is expropriation, or nationalization, of the assets, which most of the IOC's have experienced. A milder form of instability is having changes in taxation levels. These changes can also be in various grades, such as changes in the terms for new licenses but not existing licenses or changes in fiscal terms that are retrospective so they impact existing leases and contracts. These are the elements of fiscal instability that are the most difficult for producers because they have brought fields into production under certain assumptions, and changes to the terms invalidate the basis on which their decisions were originally made.

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DR. WOOD stated that in addition to instability due to changes in fiscal terms, the IOC's are facing much more competition from the national oil companies that are moving to the international stage. This includes Chinese, Russian, and Indian national oil companies. The position for IOC's internationally is much more difficult than it was a decade ago. In recent years, many IOC's have chosen to invest in North America on the basis that it is lower risk, particularly for retrospective fiscal changes. These IOC's have made large investments in unconventional, oil sands, and offshore in the Gulf of Mexico. Part of that is driven by fiscal and political instability around the world and this benefits Alaska because the U.S. is still considered to be of much lower political risk than many other regions.

DR. WOOD conveyed that his report identifies political risk at the international and national levels and distinguishes that from risk at the regional and local level. In terms of local and regional political risk, Alaska does not score quite as well as the rest of the U.S. Changing of fiscal terms does lead to a certain amount of instability, he advised. Conducting changes in a way that is perceived as "short-termism" and with frequent changes of the elements leads to a perception of poor credibility. This will likely be a disincentive to encouraging IOC's to invest in new projects. So, from a government's or state's perspective, it is important to try to establish fiscal credibility. One way to do that is to encourage fiscal stability as much as possible.

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DR. WOOD noted that a guarantee of fiscal stability through contract is one of the reasons why many of the major IOC's have been attracted to the production sharing system. However, in recent years many countries have managed to persuade the IOC's to accept changes to the contracts. Thus, production sharing agreements haven't proven to be as tight as they were 5-10 years ago.

DR. WOOD related that from a government's perspective there are risks associated with issuing guarantees under contract of fiscal terms [page 28]. It is preferable to establish a fiscal design that is both progressive and has allowances or investment credits that enable the regressive elements of that fiscal design to be offset in hard times of low prices/high costs. He said it is important from a government's perspective to establish credibility and stability through a progressive and flexible fiscal design and a consistent strategic statement of

fiscal intent, rather than be drawn into long term contractual commitments. If a government is drawn into long-term commitments then there should be some compensations for that, such as the involvement of more regressive elements.

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SENATOR THERRIAULT asked what percentage of worldwide reserves the IOC's have access to. He said he recently read that 25 percent of world reserves are available to IOC's.

DR. WOOD responded he thinks IOC's hold about 5 percent of the world's reserves and have access to about 20 percent of the world's production. Through massive investment and efficiency over the years, the IOC's have built up good production of revenue bases from the reserve bases that they have had historically, but now their reserve base is actually quite small. The IOC's increasingly are under pressure to replace reserves so they can maintain their production level, and they now have massive competition from the national oil companies (NOC's) that are particularly interested in the very large resources that are available. So, it is becoming harder rather than easier for the IOC's to get access to large reserves.

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DR. WOOD added that Russia, Iran, and Qatar have formed a loose alliance called a gas "troika". Gas reserves internationally are held very tightly and those three countries hold about 55 percent of the world's proved reserves. Seventy percent of proved reserves are held by about 10 countries. Of those 10 countries, there are very few that the IOC's have access to.

SENATOR THERRIAULT understood that not only do governments sometimes force modification to the terms of production sharing agreements, but some of the contracts include provisions for the government to come back and buy a bigger percentage of production should the producer strike it big.

DR. WOOD answered this is a good point. He said his report addresses the issue of state participation with either direct participation or a "back-in" option. For example, after an IOC signs a production sharing contract and is successful in development, the government has the option to buy back in by paying a share of the development costs and taking an equity portion. That is a very effective fiscal instrument in terms of obtaining low risk shares of successful discovery, he commented.

By having it as an option rather than a built-in equity participation, the government's risk is lower. The government can also sell that interest later on. He said he knows that on a general level state participation is politically contentious, but it is used very effectively as a fiscal instrument by many governments around the world. In situations where states are forced into guaranteeing fiscal certainty through contract, this might be the kind of instrument that the state wants to negotiate.

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SENATOR THERRIAULT said it seems strange to him that companies would want an agreement where the government is going to come in only if development is successful. He inquired whether companies enter into this type of agreement because they have no other option.

DR. WOOD replied that in signing up for these contracts, the IOC's will evaluate the state back-in and will assume in their analysis that that option will be exercised if they strike it big. Producers are happy to sign up to quite harsh fiscal terms if they know about it in the beginning and can factor it into their analysis, he said. So, it is not instability built into the contract because the producer is aware of it at the time of signing the contract. If that stability and certainty is built into the contract, then it is perhaps appropriate that the conditions are harsh because the governments are taking the risk by locking into those terms and removing their ability to be flexible in the future.

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DR. WOOD addressed the topic, "What are the fiscal options worthy of consideration by Alaska from its gas fiscal design?" He displayed a two-page diagram [pages 30-31] illustrating the flow of the different elements in Alaska's current [oil-focused] fiscal design, and related that when he builds fiscal models he likes to be able to visualize the logic of where the different components of the destination value, or divisible revenue, go. In terms of how Alaska's prevailing fiscal system works, this flow diagram should complement and agree with the tables presented by Mr. Dickinson, he noted.

DR. WOOD explained that the flow diagram starts with the destination value (DV), the sale of the gas into the market, and proceeds downward with the various costs and fiscal elements

that are taken from the DV. The point of production value (PPV) is determined by deducting the treatment, transport & tariff (TT&T) costs. The production tax value (PTV) is calculated by removing royalty costs and the allowable operating and capital costs. He said the left side of the diagram shows the producer position and the right side shows the Alaska government position.

DR. WOOD emphasized that the production tax value is important because it determines how the production tax (PT) is levied and how the two components of the production tax - BPT and CPT - work together. In addition, state regulations set a floor for the BPT and CPT together, as well as a ceiling for the BPT and CPT together. The production tax is offset by carryforward, investment, and exploration credits, and then the ultimate production tax is paid.

DR. WOOD stipulated that much of his modeling focuses on how this works from the gas perspective. In the prevailing design, the CPT is calculated on a combined stream of oil and gas together on a barrel of oil equivalent basis. He pointed out that on the diagram, the closer a fiscal instrument is to the destination value, the more regressive it is. Thus, property tax and royalty are the most regressive instruments.

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DR. WOOD explained that after subtracting the production tax from the production tax value, the Alaska Corporate Income Tax (CIT) is determined using the complex set of rules for worldwide taxable income and Alaska apportionment described earlier by Mr. Dickinson. Lastly, federal income tax (FIT) is taken. In fiscal design terms, he continued, modeling can be done for variations in all of the aforementioned elements and at some stage it may well be worth doing that. However, he said that for this particular time as part of this particular report he has focused specifically on looking at how this portion of that design might be varied.

DR. WOOD stated that the progressivity element can be driven by a range of criteria [page 32]. He said the left end of the diagram shows the more regressive elements that could be used and the right end shows the more progressive elements. He noted that the green square on the diagram, located toward the progressive side of the scale, shows the PTV [per production quantity unit] method that is in [Alaska's] prevailing design. However, he said it is by no means the only alternative. Many

fiscal designs around the world use other instruments such as rates of return and revenues to investment ratios to drive their more progressive taxes.

DR. WOOD added that many systems also use regressive instruments such as production volumes, reserves produced, destination values to drive their progressive elements. It is possible to have an element that is progressive but driven by regressive criteria. He said he has modeled these alternatives, but they are much less effective at achieving a progressive outcome. Progressivity can be targeted to larger producers by using accumulative production tax value to drive progressivity so that when larger projects achieve certain thresholds they pay higher rates. This comes back to fiscal strategy and what is trying to be achieved with the fiscal design. If the state wants to distinguish different taxation levels for the large players/small players and large projects/small projects, then that will influence the choice of a particular driver.

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DR. WOOD reiterated that the three key regressive elements in Alaska's fiscal design are offset by the progressive elements such as investment credits [page 33]. Other potential offsets can be used, he continued, such as allowances that compensate for some of the influences of property taxes and royalties in adverse conditions. He said he has done a small amount of modeling in this regard in his report, but there is much more that could be done in terms of identifying the exact kind of allowances that might work best for Alaska.

DR. WOOD specified that another factor that is important around the world is that many of the large gas projects that have received investment from the IOC's are integrated with upstream and downstream components that are all tied into one single contract [page 34]. This has occurred in Algeria, Nigeria, Russia, Qatar, and many other countries, he said. Some, but not all, of these projects are driven by production sharing contracts. He offered his opinion that the IOC's like to have projects where they are in control, not only of the reserves and the production of those reserves, but also over the infrastructure that ultimately is taking those reserves into the market.

DR. WOOD stated that IOC's are more likely to invest in projects if those opportunities to integrate upstream and downstream are involved than if they are not. While this runs into issues such

as third party access and contractual guarantees, among others, it is something that needs to be considered in fiscal design. It is also something that becomes more complex in terms of arranging incentives and allowances to compensate for these issues.

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CHAIR SAMUELS presented a scenario that assumes a [gas] pipeline has been built and the state is trying to drive exploration. He said that in places like Prudhoe Bay, the state cannot take a whole lot of risk and needs to protect itself by having a slightly less progressive system, such as where the green dot is located in the diagram [on page 32]. However, on new fields, would a middle of the road approach make more sense for the larger fields, he asked. If the state protects itself at the low end and takes at the high end, there is no incentive for things to happen in fields like Prudhoe Bay, Point Thomson, and the Kuparuk River Unit, he argued. The state has two different things going on. To incentivize, the state needs a different method for gas without putting the state on the hook completely.

DR. WOOD said he sees the chair's point and he thinks that is clearly one of the reasons why the state needs to have flexibility in its system. The state often needs the ability to run more than one fiscal design for different situations. But, it is probably unrealistic to go totally to a fully progressive system and get rid of all of the state's regressive elements on frontier exploration because 20 years from now today's new fields might be filling the roll of Prudhoe Bay. He said he thinks the state does need to protect itself and retain some of those [regressive] elements. This can be done through allowances and investment credits that are time limited and encourage investors by providing them with cover while they are making the big investments. Then, once the return on investment is made for those fields, the progressive elements become much more critical and the regressive elements that are there will also come into play but they don't inhibit incremental investment.

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DR. WOOD acknowledged that Chair Samuels is saying the state cannot afford to take risks for projects that are currently generating revenue, so it is important for those regressive elements to be there. It is very easy for a producer to want all the systems to be totally progressive, he said, but in

reality most governments cannot do that and they protect themselves by using royalties or some elements that are production related as opposed to profitability related.

SENATOR THERRIAULT understood that it is a gas play for the countries of Algeria, Nigeria, Russia, and Qatar, and that there is not much, if any, oil. He related that during previous legislative debate, consultants said the state has a mixed resource stream that comes out of the same pipe. He inquired whether Dr. Wood will be suggesting how to separate the two as they come out of the same pipe.

DR. WOOD pointed out that natural gas liquids are a substantial part of the projects in Qatar and a significant amount of revenue is coming out of NGLs in those projects. Due to the way the contracts are driven, revenue from the NGLs is a substantial part of the producers' revenue and profitability streams. Thus, liquids do play an important role in Qatar as well as in Algeria. Nigeria is primarily an oil province and much of the gas going into the liquefaction plants is associated gas. Almost every province has to deal with both liquid and gas revenue streams, he explained. And, usually, there are three revenue streams - crude oil, NGL's, and gas - so the fiscal design must address all three. He said NGL's are complicated because sometimes some of them, like liquid petroleum gas (LPG), end up in the liquids stream and are exported with the crude oil and other times they may be exported to a petrochemical plant. So, there may be totally different revenue streams and that may change from time to time. He said he will be addressing the importance of looking at them separately.

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DR. WOOD specified that under Alaska's current fiscal design, the point of production is a critical point distinguishing the upstream part from the downstream part [page 35]. A clear point is defined for oil going into the Trans-Alaska Pipeline System, and this includes the NGL's that are being blended into the crude oil stream. Likewise for a gas stream, once there is a gasline the position between gas processing and gas treatment is quite clear. However, he advised, a clear point of division for natural gas may not be as straight forward once a gasline is built and there is new development. For example, in a complex project such as carbon sequestration, capture, and reinjection, a facility gathers gas from many different fields and reinjects it into fields to enhance recovery. The ownership of that infrastructure makes the point of production difficult to

define, he said. Other scenarios are compression facilities, treatment facilities, and taking gas from one field and storing it in another field before sending it into a gasline. So, the clear definition of third party access may not be as clear cut as the diagram suggests. He said that in many projects around the world, encouragement of major producers to invest in infrastructure very often requires integrated projects. Alaska may need to address this from a fiscal design perspective in the future when there is a gasline.

2:40:06 PM

DR. WOOD [moved to the topic of how the performance of fiscal instruments can be measured.] He said he will address some of the modeling and focus on production tax, particularly the progressivity tax components that Mr. Dickinson earlier identified as being a specific issue in terms of the effectiveness of progressivity for gas. He explained that the modeling looked at the current fiscal design [pages 37-38] to see how it works for gas using a combined revenue stream. The modeling also looked at calculating oil progressivity and gas progressivity as two separate streams. To look at the streams separately, the gas and oil revenue streams must be separated as well as the gas and oil cost streams. Thus, there needs to be some allocation basis for apportionment of cost between gas and liquids. He said that the oil component in the diagram includes the liquids C5+ Pentane Plus, the heavier NGL components, and condensates.

DR. WOOD related that the modeling looked at all 10 of the hypothetical fields and evaluated them using the existing rules and [nine] other alternatives [page 39]. He said he used different drivers to drive the progressivity element to illustrate that the production tax value does not necessarily have to be used. This is more an illustration than a recommendation of which one should be used, he continued, in order to demonstrate that if different drivers are used to drive the progressivity element the outcomes are quite different in terms of the division of the divisible profits to the state and to the companies. Dr. Wood described some of the alternatives: Alternative 2 simply separates out the two revenue streams into gas and oil and uses the same barrel of oil equivalent mechanism to drive the tax; Alternatives 3 and 4 use the PTV for gas calculated on a BTU basis; and Alternative 10 introduces elements of allowances that counter some of the regressive elements of royalty and property tax for marginal fields and high cost/low price situations.

2:45:20 PM

SENATOR THERRIAULT asked whether Dr. Wood took into account that the state has statutory allowance to modify the royalty rate. For instance, for a marginal field the state can negotiate a "spot reduction" on that specific acreage.

DR. WOOD answered he did. He offered his view that "royalty holidays" are very effective, but should be either time limited or driven by profitability so the state does not give away a lot of value if prices go up. He said that [for this example] he focused specifically on the progressivity element rather than changing the royalty rate or other aspects.

SENATOR THERRIAULT responded that for the state's two most recent modifications the reductions are time limited and provide that once costs are recouped the regular royalty either phases or kicks back in.

DR. WOOD replied that that is almost exactly what he factored in under mechanism 10 as the allowance.

2:48:32 PM

DR. WOOD displayed the diagram on page 40 and explained that it is just one example for one field, the field being Field 4 with 5 tcf of reserves. He said the report has much more detailed descriptions of how the different mechanisms are modeled. He said mechanism 1, the grey curve on page 40, has a price window at which the state gets significantly lower components of the take, whereas several of the other mechanisms that are more progressively driven provide for an increase in state take as prices go up. But, he noted, they also have a state take in the \$7-\$10 range which is more effective than when it is calculated on a barrel of oil equivalent basis through the combined progressivity element.

DR. WOOD explained that the curves behave as shown on the graph because the tariff used in the model is close to \$5 and as soon as that level is approached all of the project becomes uneconomic. The designs are still regressive at low prices and this is the impact of royalty and property taxes. He referred to the curve for the gas progressivity tax driven by cumulative reserves and the curve driven by production, and explained that because these are not progressive drivers there is little impact on the state take when the gas price goes up. Therefore, it is

not a very effective way of capturing extra value for the state when prices increase, but it could be very effective at discriminating between large and small projects on a volume and production basis. The mechanisms can be adjusted to produce the desired take. He reiterated that these diagrams simply give a flavor of the kind of analysis that he has done and it has been focused particularly on progressivity.

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DR. WOOD presented the report's recommendations regarding how Alaska could improve or focus its fiscal design specifically for natural gas in the upstream sector in the future [page 42]. He recommended development of a long-term statement of fiscal strategy and objectives. The objectives should be clear and transparent to address what the state is trying to achieve through its gas design - this will help improve credibility. He related that Norway doesn't have fiscal certainty built into its contracts, but through very clear strategic statements it has persuaded industry that it is in favor of modifying its fiscal structure to maintain commerciality. Even though Norway has a relatively high fiscal take, it has convinced industry to invest in new projects and infrastructure by having a clear statement of its long-term strategic objectives and that it will not use short-term changes to achieve short-term objectives. Malaysia has similar statements in terms of convincing industry of its intention to keep projects commercial.

DR. WOOD recommended having a simple, flexible, and progressive fiscal design. This enables fiscal stability to persist in the long term because a design that is flexible and progressive enough will not need continual change to its fiscal elements, regardless of gas price or cost. Dr. Wood allowed he is perhaps being a bit idealistic, but that the best systems are the simplest. The more complex the system - the larger the number of fiscal elements and the more complexity in how allowances are calculated - the more difficult the system is to understand and administer. There is also more likelihood that there will be loopholes that can be exploited and gray areas that may lead to litigation. While complex systems keep the tax lawyers and tax accountants in business, they are not necessarily very efficient at achieving their objectives. The Alaska fiscal design is relatively complex, he noted, and it is difficult to remove that.

DR. WOOD advised that some level of fiscal stability and credibility are required to secure investment. The IOC's are

under greater pressure to replace reserves and greater pressure of competition. They have been willing to go into contracts in relatively politically and fiscally unstable countries. So, while stability is important, it is not the only driver to securing investment.

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DR. WOOD maintained that flexible and progressive fiscal designs - progressive on the up side, flexible to have allowances to encourage investment in the harsher environments - can be more effective than locking in long-term guarantees. Long-term contractual guarantees may be necessary in some situations, he acknowledged, and in these cases the state must protect itself from the high risk and include more regressive elements.

DR. WOOD recommended a fiscal design that is focused on gas and driven by a production tax value that is on a BTU basis rather than a BOE basis. He said this would solve the problem of dilution and would be a relatively easy fix.

DR. WOOD counseled that for promoting investments in the longer term, it may be worth the state looking at progressivity driven by other methods, such as return on investment. Some of those methods are considered in the modeling, he said.

DR. WOOD stated he does not advocate focusing only on progressivity. He recommended also focusing on the regressive elements and building in allowances and incentives to mitigate those regressive elements, certainly over the key investment periods.

DR. WOOD said it is important to clarify natural gas liquids and how they fit into the fiscal design. The fiscal design needs to address how natural gas liquids are accounted for, how they are taxed, and whether they fit into the oil stream, the gas stream, or a separate stream.

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DR. WOOD recommended the state consider equity involvement in infrastructure projects in certain situations. He said state equity involvement has proved around the world to be an effective fiscal element for extracting revenue as well as improving control over certain infrastructure. He pointed out that a significant part of the gas supply is outside of Alaska. It is much more difficult for Alaska to obtain revenue through

its fiscal design from value that exists outside of the state, he said. So, debate should occur on whether the state should take equity interest in gas storage and other types of infrastructure.

DR. WOOD advised that cost control is another issue for progressivity, particularly if it is driven on profitability. Cost control is important for certain fiscal instruments because it is possible to manipulate progressive elements that are based on return on investment by increasing the cost in order to reduce the return on investment and subsequent tax liability.

DR. WOOD said many countries have wrestled with the issue of resources being tied up for long period of time and therefore have contracts that apply very strict time constraints on the length of time that reserves can be held by companies without producing them. He recommended that new licenses, in terms of future upstream leases, put time constraints on how long resources can be held before they are developed. This will avoid complex litigation in those cases where the producer does not develop the resource.

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DR. WOOD stated that it is in the long-term interest of both producers and the government to have these large gas production and infrastructure projects work [pages 43-44]. By having long-term views and long-term fiscal strategies, it is more likely that there is going to be alignment and cooperation to develop assets over the longer period. Since projects can take over 10 years to develop, and more than that to see a return, it is very difficult to have a successful project if the relationship is adversarial throughout that time period.

DR. WOOD pointed out that fiscal design is only part of the decision making process in the investment decision the producers have to make. A company must do detailed technical, environmental, economic, and risk and opportunity analyses for the projects it is considering, and fiscal design clearly impacts this. A flexible fiscal design, with established fiscal stability and credibility, will be much easier. A fiscal design that makes projects commercial over a wide range of conditions will help that positive investment decision irrespective of what is the ultimate division of profits.

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CHAIR SAMUELS reminded committee members that at 9:00 a.m. tomorrow, Mr. Porter, Mr. Persily, Mr. Dickinson, and Dr. Wood will be available for questions and a round-table discussion. He reiterated that the purpose of these discussions is to provide an overview of how to get more exploration and how to do things assuming a gasline is in place.

ADJOURNMENT

There being no further business before the committee, the Legislative Budget and Audit Committee meeting was adjourned at 3:09 p.m.