

**ALASKA STATE LEGISLATURE  
JOINT MEETING  
SENATE RESOURCES STANDING COMMITTEE  
SENATE FINANCE COMMITTEE**

March 26, 2009

2:39 p.m.

**MEMBERS PRESENT**

SENATE RESOURCES

Senator Lesil McGuire, Co-Chair  
Senator Bill Wielechowski, Co-Chair  
Senator Charlie Huggins, Vice Chair  
Senator Hollis French  
Senator Bert Stedman  
Senator Gary Stevens  
Senator Thomas Wagoner

SENATE FINANCE

Senator Lyman Hoffman, Co-Chair  
Senator Bert Stedman, Co-Chair  
Senator Charlie Huggins  
Senator Joe Thomas

**MEMBERS ABSENT**

SENATE RESOURCES

All members present

SENATE FINANCE

Senator Johnny Ellis  
Senator Donald Olson

**COMMITTEE CALENDAR**

Presentations: Natural Gas Fiscal Designs  
David Wood, David Wood and Associates  
Dan Dickinson, CPA

**PREVIOUS COMMITTEE ACTION**

No previous action to report.

## WITNESS REGISTER

DR. DAVID WOOD, Consultant  
David Wood and Associates  
United Kingdom (UK)

**POSITION STATEMENT:** Discussed natural gas fiscal designs.

DAN DICKINSON, CPA

**POSITION STATEMENT:** Discussed natural gas fiscal designs.

## ACTION NARRATIVE

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CO-CHAIR BERT STEDMAN called the joint meeting of the Senate Resources Standing Committee and the Senate Finance Committee to order at 2:39 p.m. Present at the call to order were Senators McGuire, Wielechowski, French, Wagoner, Huggins, Stedman, Hoffman, Stevens, and Thomas.

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CO-CHAIR STEDMAN announced the first presentation would be from Dr. David Wood on natural gas fiscal designs.

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DR. DAVID WOOD, Consultant, David Wood and Associates, United Kingdom (UK), said he had worked extensively on international gas and fiscal issues and his report is an eight-month study completed in December last year. His intention is to present highlights of that report and discuss some of the developments and issues that have arisen since the first presentation in December.

He said the aim of the report was to look at Alaska's natural gas fiscal regime and to compare it to other gas regimes around the world. The other parts of the report evaluated the components of Alaska's natural gas fiscal regime by looking at how it performs for 10 natural gas fields - both non-associated and associated gas fields. The mandate for this report was not to look at a gas line or existing fields in terms of those currently producing, but to look at a range of possible fields that could be developed in the future; the study is a series of hypothetical fields. It was necessary to build a fiscal model with a multi-year cash flow analysis to look at the economic performance both in terms of the fields involved and to analyze in detail the different elements of the fiscal system.

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SENATOR WIELECHOWSKI asked for more information about his background and if his typical clients are industry or government.

MR. WOOD responded that he is a geologist and worked in the 1980s for Phillips Petroleum, Amoco and a number of independent Canadian and UK companies. Much of his career in industry was conducted in South America, the Middle and the Far East. He is also trained in petroleum economics. For the last 10 years he has worked as an independent consultant focusing primarily on international gas and fiscal terms. He is published widely on fiscal analysis of both oil and gas. The clients he works for vary from oil and gas operating companies, but also governments and he does training for companies. He doesn't represent this issue from the perspective of a producing oil and gas company or from a government's perspective. He is trying to look at it from both perspectives, and he is used to doing that in the course of his work.

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MR. WOOD said his presentation is an analysis of more than 20 major gas producers and he will use five or six of those to illustrate the complexity and diversity of fiscal designs, specifically those elements that can be considered as regressive and progressive, around the world. Those countries are planning to deliver gas into North America and the fiscal systems that they operate will influence the cost of gas supply into the Lower 48 states. That gas will compete with Alaska gas.

He said he will also discuss the multi-year cash flow model and address the issues of fiscal instability, credibility, and fiscal certainty that are very important in terms of getting long-term off-take agreements with gas producing nations. As part of the conclusions and recommendations he would identify some of the issues that could be improved upon by further work in understanding the gas fiscal design in Alaska.

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MR. WOOD said fiscal designs are best driven by clear fiscal strategies and objectives. He showed a diagram with three key objectives: sovereign take, local focus/jobs, and investment.

SENATOR FRENCH asked what local content focus means.

MR. WOOD answered that "local content" means involvement with local companies or "local hire." His diagram showed where different countries prioritize their objectives. North America is very much focused on encouraging investment and work programs. Many of the OPEC countries focus very much on maximizing the sovereign take; other countries prioritize local content. Norway stands out in that regard for many decades.

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MR. WOOD said Alaska gas needs to get to the Lower 48 market by whatever means it can. In 2007, large amounts of gas were imported into the Lower 48 from Canada, as well as large amounts of LNG from a range of countries - at the point his diagram was created Trinidad and Tobago supplied 60 percent of the imports into the Lower 48. For obvious reasons that is one of the closest of the countries able to supply LNG.

He said the orange dots and yellow squares indicate the LNG regasification terminals, most of which are located on the East and Gulf Coasts. In the last year the Costa Azul terminal in Northern Mexico received LNG from across the Pacific and it will soon receive it from the Sakhalin project in eastern Russia, but also potentially from Australia and Indonesia and a wide range of other countries. The cost of LNG is dependent on the cost structure of the developments, but it is also influenced by the fiscal designs that each of those countries has in place.

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SENATOR HUGGINS said that Dr. Myers' overview yesterday described that presently, because of the cost of gas in the U.S. that Europe and the Pacific Rim are more attractive to LNG producers; so not much will be coming into the Lower 48 in the near future. "Could you help us out with that?"

MR. WOOD said that is a good point. The justification for building all the capacity for LNG receiving terminals didn't envision gas at less than \$5/mmbtu. At the moment, the volumes coming into the U.S. are much lower than they have been, but most in the industry believe that is a relatively short term situation.

The next slide showed a huge amount of gas coming from domestic production - conventional gas and large volumes of deep water gas from the Gulf of Mexico. He remarked that Dr. Myers also mentioned unconventional gas - deep tight gas, coal bed methane, and shale gas - playing significant contributions. Even with all that, there is still a requirement for more gas and forecasts of

demand increasing. There is an expected roll for LNG, he said, with small amounts from Norway and potentially larger ones from the field north of Russia, when it is developed, but particularly from North Africa and the Middle East. Qatar Petroleum and Exxon Mobil are planning to move LNG long distances into both Europe and North America. Large projects in West Africa - Nigeria, Equatorial Guinea already - and Angola are under development. The major companies - ExxonMobil, Shell, BP and others - are all heavily investing in these projects - in many cases tens of billions of dollars - and moving large reserves of gas - not all destined for North America, but other markets in Europe and Asia. Clearly, they will be competing sources of gas into North America.

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MR. WOOD said Australia, Indonesia, Papua New Guinea, Peru, Qatar and Sakhalin projects involving major oil and gas company investments have the North American market as part of their long term development plan. It is important to recognize that there will be competition from conventional and unconventional Lower 48 gas and from LNG coming from a wide range of sources around the world. The cost of supply of that LNG is strongly influenced by the fiscal designs of each of those countries. However, these designs differ quite significantly and are "quite complex supply chains."

One of the differences between moving gas by LNG and by pipeline is that a pipeline moves gas from point "A" to point "B," but one of the beauties of LNG technology is its flexibility in being able to go to a wide range of destinations. Because of the high cost, most LNG is actually contracted on long-term basis take or pay contracts to two or three customers. But the possibility of moving some of the LNG to other markets exists. The main markets for LNG are East Asia (particularly Japan and Korea), Europe, and North America. It is mostly indexed to oil prices, particularly into Japan, and in Europe it may be related to oil products if not directly.

In 2007/08, nuclear plants went down in Japan; it had a shortfall of LNG and was prepared to pay in excess of \$20/mmbtu for short term cargoes of it. This is significant because for that period of time, those producers that were able to divert their cargoes diverted to Japan because they could double their value. That meant there was less gas coming to the U.S. and Europe for almost a year.

This flexibility comes at a price; it's less reliable because if someone else in the world is prepared to pay a higher price, that LNG will, if contractually possible, be diverted to that location. This flexibility makes it less reliable.

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MR. WOOD said the last year has seen dramatic changes in demand and prices. Slide 9 should be labeled "Natural Gas Imports to the U.S." and over a decade the numbers rise progressively with a lot of spread particularly in 2001/02. In 2008, for the first time the volumes of gas imports fall. It is not related just to the economic downturn, but to the increase of unconventional gas production, particularly shale gas - particularly during 2007, and the increase of domestic gas production.

Slide 10 shows an excess of 2 bcf/day of LNG being imported into the U.S. in 2006/07, but it was fairly flat, about 1 bcf/day in 2008 and is remaining that way. The drop is due largely to the increase production from unconventional Lower 48 gas. But more recently it has been influenced by the economic downturn.

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MR. WOOD said another influencing factor was that most LNG producers, particularly in the January to April 2008 period, were more enthusiastic about selling their gas to Japan at \$20/mmbtu than selling it into the U.S. So a number of factors are at play, but the overriding one is the increase in domestic gas production.

SENATOR FRENCH asked the average daily natural gas consumption in the United States.

MR. WOOD replied that the 2 bcf/day amounts to about 5 percent of total consumption. Two different slides show how imports have changed in 2008, and going forward how they are dominated by gas from Canada until 2030 when it then significantly declines, along with a significant increase in the amount of gas forecast from LNG, but more than trickling in in the post-2020 period. So, there is the expectation for a significant amount of LNG to fill that imports requirement.

Gas from Mexico is gradually declining. The net imports represent a relatively small component of U.S. gas consumption, but the December forecast indicates net imports declining quite significantly from 2010 through 2030. The main reason for the decline is the massive increase in expected volumes from unconventional gas. Alaskan gas begins to play a much more

significant role by 2030 than the net imports. But clearly in terms of volume comparisons, Alaska will be competing with the net imports of which LNG is going to be a big component.

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SENATOR FRENCH asked if Alaska is using 22-23 tcf/annually.

MR. WOOD answered yes, and the slide indicates that LNG is less than 1 tcf/annually. The economic downturn is impacting internationally traded LNG. The expectation is that the LNG market will be oversupplied for two or three years and that will impact world gas prices and influence commitments to develop new LNG projects. This delays investment in new capacity, and that means as demand increases less capacity will be available; so in the longer term, 2015-2020, we might have another marked gas price increase. So, expectations for the next decade probably are oversupply going to a shortfall, and that suggests that we're in for a period of volatile gas prices.

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SENATOR WIELECHOWSKI asked if his graphs take potential cap and trade or carbon tax legislation into consideration.

MR. WOOD replied that these particular ones have not, but cap and trade legislation should benefit gas, because of being the least carbon emitter of the fossil fuels. It is competing internationally in most cases against coal for power generation, and the cap and trade mechanisms will penalize coal in preference for gas - unless carbon sequestration technology enables coal to continue at current levels. So, most cap and trade scenarios would suggest that gas demand globally should increase rather than decrease in this period of time.

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MR. WOOD said North America is competing with other regions to secure supply of LNG. Historical data indicates the big markets for gas imports in Europe have experienced significant growth in the last 20 years and expectations are that it will continue to grow at similar rates because the indigenous gas supply is declining.

OECD Pacific includes Australia, Japan, Korea and Taiwan. So in that group they have an LNG producer (Australia) and big LNG consumers (Japan and Korea). They also have increased their demand for imported natural gas over the past two decades, but with massive investment going into Australia, the expectations

are that the net import position for LNG will not grow as fast for that particular region.

The 2020-30 forecast indicates natural gas imports into North America are going to grow rapidly, but still in comparison with Europe and OECD Pacific until 2030 they are much smaller in overall volume.

China and India start from very low current import volumes, and expectations are that their demand for LNG will grow significantly. So, the LNG sector has competition from these areas, and delaying investments in the large LNG projects during that shortage of supply in the 2020/30 period is going to mean it won't be so easy for North America to secure that LNG should it want to at that particular time. That gives Alaskan gas some competitive advantages in trading into the North American market in the 2020/30 period.

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MR. WOOD said to illustrate what is happening at the moment in the international gas liquifaction sector, several new projects are just about ready to come on stream or have already. But over the next three years large capacities are in advanced stages of construction in various parts of the world - in Qatar, Sakhalin, Indonesia, and Yemen. A fifth train off the Northwest shelf of Australia came on stream at the end of 2008 and it is ramping up to full capacity. Other projects in Algeria, Angola, Nigeria, and Peru are under construction and due to come on stream in 2011. Almost half of the 99.5 mm/tons of capacity coming on stream during the 2009/12 period is coming from Qatar, which will become even more significant in terms of its contribution to worldwide LNG capacity.

Beyond 2013, a large number of projects are at the stage where investment decisions are about to be made. Of course, with the current economic situation investment decisions on many of these projects is now under question. They may well be delayed and it's this delay for the projects listed on the right of slide 14 that could lead to a shortfall in energy capacity and potential price increases going forwards.

MR. WOOD said he hoped he had convinced them that LNG is going to compete with Alaska gas for the additional capacity, and consequently, LNG from almost all of these countries will have cost of supply issues that will be influenced by their set of fiscal designs. So understanding how these countries tax and put their fiscal designs together is a worthwhile exercise.

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MR. WOOD said his reports outlines a number of countries and structures. In overview terms, petroleum fiscal designs are divided into two main generic types of structures - mineral interest concessionary systems with terms of tax and royalty. This is the North American system and the system in Alaska and many other OECD countries. They have leases, licenses and fiscal mechanisms that are driven by royalties and taxes. The other structure is contractual terms.

The contractual systems (as opposed to lease and license systems) and production sharing agreements (PSA) and productions sharing contracts (PSC) are very much the dominant type of alternative. Service contracts and hybrid contracts are in between. PSAs originated in Indonesia in the 1960s and very much from the concerns of the producing nations over their title to reserves. Under PSAs, the producers at no time have title to reserves and gain their share of revenues from production.

On the other hand, in the mineral interest systems, the producers gain title to lease arrangements and hydrocarbon laws to the reserves as they are produced. Some of countries use PSAs, some use mineral interest agreements and some are using both. The world has a wide diversity of operating fiscal systems.

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MR. WOOD said his report has detail regions (with stars) that already have major gas developments and very large reserves, and a few are included because of the novelty of the fiscal designs that are relevant to gas systems.

He said he selected six countries from the list to review fiscal design structure. They are countries that can potentially supply LNG into North America and are where the major oil and gas companies have or are about to invest tens of billions of dollars into developments. These fiscal designs are of especially of interest because they are designs that oil and gas companies can live with.

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MR. WOOD said Algeria operates both mineral interest structures and PSAs. A new hydrocarbon law introduced in 2005 toughened its fiscal take; it has multi-layers of tax both on revenues (gross), income (net), and an extraordinary income windfall tax on oil, which is effectively a sliding scale tax. It has an

agency dedicated to monitoring gas contracts so they have minimum take or pay inclusions that are signed. One of the significant points is that state equity participation is 51 percent. He said state participation is a key feature in many countries.

SENATOR FRENCH asked if Algeria when it changed its tax in 2005 prohibited itself from making future tax adjustments.

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MR. WOOD replied that he understands that they didn't lock it in and are open to making further changes if they wish to.

SENATOR FRENCH asked him to let them know if they do.

CO-CHAIR STEDMAN asked him to let the committee know about changes by all the countries he is covering.

MR. WOOD said the report generally mentions stability clauses, which are more likely to be in PSAs.

SENATOR FRENCH reminded him that Alaska is under a tax and royalty regime.

MR. WOOD noted that most tax royalty regimes usually don't have a commitment to not change tax in the future. The issue very often is if they are going to be retrospective in terms of impacting licenses and leases that have already been given out.

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MR. WOOD moved on to Angola (slide 19), which has a production sharing fiscal system. For contrast, Algeria has large onshore non-associated gas fields and gas condensate fields. In Angola, much of the industry development is associated with deepwater oil fields with associated gas. There are large volumes of associated gas, but the primary reserves and the primary field developments are associated with oil.

Alaska has associated gas with oil and it is located in deep water; so the issues of developing that gas are quite different from developing the onshore gas in Algeria. Of course, the context of where the gas is located, whether it's associated or non-associated, whether it has natural gas liquids and condensate with it or not, will also have a bearing on the fiscal design. A key part Angola's fiscal design is the involvement of large signature bonuses associated with licensing rounds equivalent to the lease sales that will occur in North

America, but these are competitive bidding rounds and some of the signature bonuses paid for large areas have reached almost one billion dollars for some of the more prospective licenses. Some of the companies bidding at those levels, not just the major international oil companies, but also the national oil companies - Petro-China, and the semi-privatized national oil companies like ENI - have bid multi-hundred million dollar signature bonuses as part of acquiring the rights to drill and develop in these areas. So, from the government's perspective, the very high upfront revenue from the signature bonuses is a significant component of their fiscal system and it's a low risk part of that design.

MR. WOOD said Angola has the large signature bonus component, cost recovery and uplift of capital costs. The key driving mechanism for the profit sharing is a mechanism linked to rate of return. The more profitable the project becomes the greater the share of revenues that go to the state. In periods of very high profitability, both the Algerian and the Angolan state take is well in excess of 80 percent of the revenue stream.

Norway (slide 20) operates a mineral interest system, and has no royalty or bonuses; all of its taxation components are very much at the income or profitability end of the cash flow. They have a corporate and special tax, and since 2004, investment uplifts over a four-year period were introduced that provide shelter for the smaller fields have been introduced against their special tax. So, what is interesting here is that many large and small companies have been attracted in recent years to sign licenses with Norway being attracted particularly by the investment uplift, which works a little bit like Alaska's investment credits. It also has taxes on CO<sub>2</sub> emissions.

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Norway's stated fiscal strategy is interesting in that they have no fiscal stability clause and they have the right to change and exercise that right to change their mechanisms from time to time. But they have certainly convinced the industry of their intention of being a "sleeping partner" with their role being to keep projects commercially viable, but at the same time maximize the position of the state. Marginal tax rates are a little short of 80 percent, a relatively high take that is at the profitable end.

Papua New Guinea (slide 21) has a mineral interest system; it is a very isolated and relatively underdeveloped country, but it has wrestled with the development of large gas reserves for the

past few decades. It spent maybe five years trying to get a gasline from Papua New Guinea to Queensland and then shifted its strategy to LNG; it is now in the feed stage of several LNG projects, the largest one being with ExxonMobil. The final investment decision on that is expected within the next year or so. The fiscal mechanism has gone through legislation to ratify and fix for a period of time. So, in this case there is a fiscal stability associated with these particular terms. Again, he said, the terms are small royalty, income tax, and additional profits tax, which is driven by the rate of return generated by the project and that additional profit tax goes up as the project becomes more profitable.

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MR. WOOD said state equity participation is a feature of this fiscal regime - 22.5 percent with 2 percent of that going to the local landowners.

Qatar operates under PSAs; and Qatar Petroleum has 65 to 70 percent equity participation in its projects. Fifty percent of the revenue allocation is for cost recovery, but the main profit sharing component is linked to volume of production, and gas is sold at a relatively low price from the field to the liquifaction terminal. The liquifaction terminal pays a corporate tax. The NGLs are taxed according to an "R factor" that is the ratio of cumulative revenues to cumulative expenditures. This is a fiscal feature used in many contracts around the world to drive the profit sharing.

Trinidad (slide 23) is a major LNG supplier to the U.S. It runs both a mineral interest system and a PSA system with sliding scales of taxation in both and those are linked to price and volume in the production sharing structure.

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The committee took an at ease at 3:43 p.m.

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The meeting was called back to order at 3:52 p.m.

MR. WOOD continued his presentation saying the report not only takes into account the size of the reserves, fiscal designs and structures, but risks and opportunities associated with developing in the large resource areas as well. The positions of various countries are linked to reserve size on the slide. Once a gasline is developed, a higher opportunity of developing

additional resources would improve investment opportunities and decisions. So, risk and opportunity is an important component.

The overall government take is easy to use to compare the different fiscal systems, but each gas resource, the size of that resource, the cost to develop it, and the prices that are prevailing will influence the state take. However, in general, he said, as prospectivity and reserve size increases, government take typically increases as well. Certainly in the big gas producing countries government takes in excess of 90 percent are seen. On the other hand, in less developed countries the take is lower.

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MR. WOOD mentioned that different fiscal elements can be combined to optimize the government take. His diagram showed that some of the project revenues from selling Alaskan gas are used for development and operating costs; the profit component that is left and the rent component is key to the fiscal designs. The various instruments used can be classified as regressive or progressive. Regressive means when the costs go up and prices go down; a regressive tax often leads to a much larger share of profits falling into the taxable portion. So typically property taxes and royalties are regressive in nature, but on the other hand those taxes that are levied on profits and further through the cash flow system are more progressive in nature.

Norway's fiscal design was very much focused on the progressive end of this scale whereas other examples, like Egypt, have a fiscal design based on production volumes and falls on the regressive end. But generally, the two are mixed. He explained that for governments it's much lower risk to have regressive taxes. On the other hand, producers prefer to have progressive taxation because it means that they pay taxes when the projects are profitable, but none when they are not profitable.

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SENATOR FRENCH asked him to speak a little more about the need to have a commercially attractive environment and what degree of fiscal stability is needed. This has been one of the struggles in coming to terms with the state's gas pipeline. AGIA offers ten years worth. How much fiscal stability should Alaska offer and to what degree are the requests for fiscal stability offered up in the bargaining and then let go as an element of bargaining between industry and governments?

MR. WOOD replied that is a very involved topic and question. "Fiscal stability is clearly important." His view is if you have a fiscal design that is flexible and has progressive elements and also some regressive elements to provide security of base level revenues, that design can significantly reduce the need for a clause that guarantees that the fiscal regime won't change. Because if it is structured such that it works over a wide range of economic and production conditions, then the need for a guaranteed statement of fiscal certainty falls away.

So, my view is that you're better to address it by having a flexible fiscal design, but clearly in certain circumstances, where we're talking about a billion dollars in investment and tens of years before returns on that investment are going to be achieved, then it may be necessary to enter into clauses that guarantee certainty for a period of time. If you do, as a government, have to offer those guarantees, then my view is that you have to be sure that your baseline regressive elements are adequate to meet changing conditions.

4:00:30 PM

SENATOR FRENCH asked whether he thinks in his professional opinion that Alaska has such a system in place now in the ACES legislation - as well as the royalty regressive elements.

CO-CHAIR STEDMAN interrupted to say that Mr. Wood had spent time looking at 10 hypothetical fields and is in the process of getting established with LB&A to look at Prudhoe, Kuparek and Pt. Thomson, which will give him a better feel for Alaska/Pacific issues. He clarified that this is the first step in many steps and that Mr. Wood could answer that question in any manner he is comfortable.

MR. WOOD responded that he sees the need for Alaska's tax regime to be more flexible and to target incentives and allowances more easily against the regressive elements in certain circumstances. The issue of gas and oil being very tightly linked together in that system reduces the flexibility.

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CO-CHAIR STEDMAN said LB&A would soon get a request for further analyses by Dr. Wood with a preliminary discussion in late summer early fall and a final report in the middle of November. He repeated that this is early in the process.

MR. WOOD said his slide illustrates the difficulties with regressive elements. Royalty can take a relatively small share of the profit at low prices, but the same percentage royalty can eat up a huge part of profit - the problem of regressive elements for producing companies. Sometimes allowances and incentives are needed to limit their downside impacts.

He showed a schematic of Alaska's prevailing fiscal design that he had worked on with Dan Dickinson to try and illustrate the different levels of taxation in Alaska to highlight the fact of several layers of taxation that are calculated on different tax bases: property taxes, royalty that is calculated on a point of production value (gross value) after an allowance for transportation costs, production taxes that are calculated on a production tax value base (net base), and a progressivity component that comes into play at higher production tax values. Making assumptions of \$25/barrel of oil equivalent (BOE) in costs would mean that the progressivity element would kick in at around \$55/BOE. In 2008 the progressivity element played a significant role in raising revenues for Alaska. Then it has Alaska corporate income tax and federal income tax on top of that.

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MR. WOOD pointed out that like a number of other countries Alaska has a number of layers of taxes calculated on different bases; of these, the royalty, property taxes, and production tax floor are the regressive elements. The investment credits, the production taxes, the progressivity components are the progressive elements.

MR. WOOD stated that the changes introduced into Alaska's design in 2005 through 2008 have generally introduced levels of progressivity, but because of the higher production tax rate of 25 percent, they have also increased the overall state take which has made some of the smaller fields less commercial.

Part of the study was focused on the progressivity elements of Alaska's fiscal design, particularly the combined progressivity tax, because it combines the revenue streams of oil and gas and calculates them on a BOE basis with a simple 6:1 gas to oil ratio. Much of the report looks at how that progressivity tax is currently structured and how it might be modified by separating the calculation for gas and oil.

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MR. WOOD said one of the problems the report illustrates is that by having progressivity calculated on a combined basis, Alaska can end up with a situation of having large production volumes of gas when gas is at a relatively low price to oil - effectively diluting the combined production tax value on a BOE basis, thereby reducing the progressivity elements of the taxation.

The progressivity tax trigger is difficult to set at a point where it is effective for both gas and oil on a combined basis, and he thought it would be easier to set progressivity if they were separate. Also tying the production tax floor to the gross level (the point of production value) can lead to some complications to the way in which the production tax calculation works.

The outcome for progressivity for natural gas can create a dilution effect if the gas prices are low and oil prices are high, but the relative volumes of oil and gas make a difference, too, Mr. Wood said. On the North Slope, oil production will decline and gas production will increase. So the issue of varying prices and volumes will come into play with those two products there. Reinvestment can reduce the liability for progressivity quite significantly, but again that varies depending on volumes and prices. His slides summarize the analysis of how gas potentially dilutes the production tax and progressivity values on a combined basis.

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SENATOR FRENCH said he didn't really understand the charts that well and suggested getting both charts and a numerical printout so they can see the net effect on the tax.

MR. WOOD agreed to do that and went on to explain that gas production tax values below \$20 BOE generally act as a diluting effect. The other significant point qualitatively to get from this diagram is that the lines aren't straight; the curve relates to the structure of the progressivity tax, but it also makes it quite difficult to exactly predict the influence. That influence depends on the relative prices of oil and gas.

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MR. WOOD said the more that is reinvested, the more dilution is involved. He said these diagrams are showing how difficult it is for investor's to predict the outcomes of their investment. Will producing more gas have a positive or negative effect on a particular field? Having oil and gas combined together makes

some of these decisions quite difficult from both the state's and the producers' position. He said the magnitude of the impact will vary because of the price and volume differentials and the amount reinvested.

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MR. WOOD said his report looks at the prevailing case of combined progressivity tax and at nine other cases where the tax is separated. He has shown many different mechanisms - a range of possibilities - that could be used alternatively to calculate that progressivity while not advocating for any one of them.

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MR. WOOD described his graphs saying that he used a multi-scenario, multi-year cash flow model to carry out the analysis. He looked at 10 hypothetical fields and carried out multi-year fiscal performance on each of them. Five of the 10 fields look at non associated gas fields ranging from .5 to 10 tcf of reserves. The second half were all fields with associated gas the largest of which was a .5 bb/oil and 700 bcf/associated gas. Economic assumptions were the base case gas price of \$7.5/mmbtu in the first year of the analysis and \$80/barrel for oil; inflation assumptions were used.

A key point of this modeling is that it uses a base case, but it uses very wide ranges of sensitivity analysis; so it looks at prices down to very low levels and up to very high levels for both gas and oil, along with costs and other economic factors.

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MR. WOOD said in summary, the base case shows that the world of the oil field is quite different from the world of the gas field in Alaskan terms. The government take of destination values (gross) is about 60 percent for oil fields and 75 percent of the net portion of the cash flow. For natural gas fields the government take is just 30 percent of gross value and take of the net is at 67 percent. So, in revenue terms the gas world is taking half of the gross revenue stream compared to what is taken by oil. The reason is that the transportation, tariff and treatment costs for oil are much smaller at 20 percent than for gas at 50 percent. This is why the government take is 60 percent as opposed to 30 percent of total revenue.

He said it is important to realize that the world of gas is quite different from the world of oil primarily because most of the costs in the transportation element. That is another

argument for considering looking at gas and oil tax individually rather than trying to combine them into one system.

The base case assumption for the gas example shows that royalties and base production tax are the largest components of taxation. On the other hand, for oil it's royalty, the base production component and progressivity (a significant component).

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MR. WOOD said he used \$80/barrel as the base case oil price. If he used \$55/barrel the CPT would be non-existent. His pie diagrams show that the contributions from the different fiscal components are quite different for an oil field compared to a gas field. The fiscal designs go far beyond the upstream issues, and his mandate for this report was to focus very much on the upstream issues, but integrating the gas field production with the infrastructure - whether it be LNG or a pipeline - treating, exporting and transporting that gas are also important components.

He said it is interesting that the major companies in Nigeria, Algeria, Russia, and Qatar have been very prepared to sign up for big projects on the basis that the upstream and downstream components of those projects are integrated and that there has been some limitations on third-party access.

His large project scenarios last three or four or more decades; the alignment between the organizations that are developing and producing the assets together with the state entities that are controlling them is very important. Fiscal design will get them only part of the way to a successful project. These scenarios will show the division of the profits, which is quite important in terms of attracting investment into particular field projects.

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SENATOR WIELECHOWSKI said Alaska has been accused of changing its tax system too many times and creating an unstable fiscal environment. He asked if Alaska changes its tax structure again - to delink oil and gas - would that open it up to more criticism.

MR. WOOD replied that while it is true the fiscal system has been changed several times, and that has lead to criticism from certain quarters, if you can clearly identify why the changes are being made and that they are beneficial to the overall

structure and not purely designed as penalties - that the overall structure is being changed to enable the tax to reflect more accurately the production situation for gas - but also to enable allowances and credits to be targeted specifically at the gas or the fields trying to be developed - if changes can be justified and identified with clear strategies in mind - that overcomes the potential for criticism of instability.

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Conclusions and Recommendations of the preliminary study:

Regarding the progressivity tax structure: under the current production tax rules the impact of gas revenue on the magnitude of combined production taxes is difficult to predict making tax planning difficult (for both state and producers). Because gas and oil prices are volatile now, over time it is likely that structure will become unstable. His conclusion on his work so far is that there are clear benefits from separating the taxation of oil and gas on a progressivity basis. It would make sense to use North Slope fields as examples of what the impacts of separating oil and gas taxation mechanisms would be. In the longer term there may be opportunities to look at LNG and GTL developments as alternatives to see what they do under different fiscal structures and combine that with the hypothetical field work that has been done already. It would also be informative to compare Alaskan gas delivered into the Lower 48 with its regime to gas delivered by shale gas producers based on their particular fiscal designs.

MR. WOOD said that a number of approaches could be made to improve performance and credibility of Alaska's fiscal design. Frequent changes and instability can be overcome by having very clear statements of the state's strategy and objective for its fiscal design, by having a simple, flexible and progressive fiscal design that is easy to predict, and having some levels of fiscal stability guaranteed. However, flexibility is very important. He said that focusing progressivity on gas and oil separately can also be a significant improvement on the current system.

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SENATOR WIELECHOWSKI said one of the concerns about delinking oil and gas has been that it would create an accounting nightmare for the administration to try to monitor expenses. He asked if other countries have had trouble with that and if they had effectively dealt with it.

MR. WOOD replied that the industry is used to separating costs for oil and gas in many areas of the world. It can be done many ways, but the simpler the better. Industry could do allocations based on volumes or values, but the accounting doesn't have to a nightmare.

SENATOR WIELECHOWSKI asked if most countries that have similar types of fields with intermingled oil and gas, like Alaska has, have their oil and gas taxes delinked.

MR. WOOD replied that many do. They do it because of the very reasons he discussed - because the gas is going through a different supply change with a whole series of different cost structures and elements and sold into quite different markets. By not separating them out it is very difficult for the fiscal system to work on a combined basis.

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DAN DICKINSON, CPA, said he and Rich Ruggiero, Gaffney Cline, have both presented analyses on this issue over the last year. The dialogue has really focused in on a single example that was presented from Dr. Wood's work that has taken on a life of its own. It is just one example, and it is a situation in which the oil price boomed (in 2008), and at the same time the gasline came on stream. Because that gas is added, total state revenues do not increase, but decrease, particularly in this one example that just deals with the production tax.

SENATOR FRENCH asked where his model could be found.

MR. DICKINSON said he believes it is on the LB&A website. Assuming oil production is half of what it is today at 350,000 barrels/day (this is also assuming it is 10-15 years in the future when a gasline might actually be coming on stream), 128 mm/barrels/yr. of oil are produced (progressivity is calculated on the 128 mm/barrels/yr.). The next cell set the price of oil at \$135/barrel (close to the highest price). From that the combined average costs to get it off the North Slope and to the West Coast were subtracted - about \$6/barrel. That leaves a gross value at the point of production of \$129/barrel.

You then have to account for a royalty share, which leaves approximately 87.5 percent (the taxable wellhead). This amounts to about \$14 billion. In this example he assumed \$3 billion in costs to run the North Slope fields and that gets subtracted from the taxable value (net) and that is about \$11 billion. Now the progressivity gets calculated. If the oil is stand-alone,

you divide the taxable value by the taxable volumes, which in this case this results in \$99/barrel. Under progressivity \$30 of that is sheltered; so you come up with \$69.48, and then .4 percent on the first \$62.50 is taxed for every dollar; above that it's .1 percent for every dollar. In this example the progressivity charges add 25.7 percent. He explained that the base tax rate is 25 percent, another 25 percent is added because of progressivity; so the total tax rate is about 50 percent. If you multiply 50 percent times the tax base (\$11 billion), you come up with about \$5.5 billion.

Now looking at gas in the example; it's producing 4.2 bcf/day (a figure people talk about being the size of the pipeline) at 365/day/yr.; that comes to 1,500 bcf/yr. Current law says the way combined progressivity is calculated you take all the gas and convert it to barrels of oil as if there were 6,000 cf/gas generated by one barrel of oil. That is called thermal parity because if you burn that much oil, that is about right. In this example, you end up with 255.5 billion barrel equivalents of oil from the gas. That results in a 2:1 ratio.

But assume there is just stand-alone gas. You would look at how much it is selling for. He chose \$6 gas as a way to illustrate an extreme point. The price of gas would probably be higher if oil was \$135. So, he assumed a 75 cent adjustment from Alberta to Lower 48 markets, a \$2.75 transportation charge to get the gas from the North Slope to that point, and so there is a gross value at the point of production of about \$2.50. You multiply that times the volumes and come up with a \$3 billion charge. So he explained, at this level there is no progressivity on the gas; in other words it doesn't escape "the \$30/barrel equivalent of oil collar." If the gas were generated alone, it would generate about \$800 million in tax.

But the critical issue is what happens when the two are combined. If gas is contributing about two-thirds and the oil is contributing about one-third. The taxable value line shows that the oil is contributing about \$11 billion and the gas is contributing about \$3.5 billion. So the ratio is reversed to 3:1 with gas being the 1. Divide that by the taxable equivalents and you come out with a barrel of oil equivalent of \$43 for (combined) purposes of progressivity.

So the oil stand-alone is \$99; the gas expressed on a similar basis is \$15 and combined \$43/barrel. Subtract the \$30 trigger and you come up with \$13.16. That generates about 5 percent progressivity instead of 25 percent, a huge drop in

progressivity. You add the 5 percent to the base rate of 25 percent and come up with a 30 percent combined rate instead of 50 percent rate. Because that rate is so much lower, in effect, the amount of tax generated (because of the drop in progressivity) is smaller with the gas.

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MR. DICKINSON said he and Mr. Ruggiero had both discussed this example and it is important for members to know that they are both looking at the same glass of water and one of them is saying it's half full and the other saying it's half empty. They both agree it could happen. The more oil you have, the more pronounced this effect is. Mr. Ruggiero had pointed out that the price spike had only happened 7 months out of the 14 prior years.

MR. DICKINSON observed that the adopted and passed legislation has special language that says what progressivity is going to be and that it would "bend over" when production tax value is at \$92. If you add costs to that, that means oil prices are at \$115. When people wrote that legislation, that number was "nuts." No one thought oil would ever be that high. Prices have gone above that 3 times in past 14 years and they all happened this summer. The point is that some of these things are rare, but it's worth making sure you are dealing with rare situations.

MR. DICKINSON went back to 1995 when there was a huge gap in oil and gas prices. But who cares, because in March 1995, gas was selling for \$1.50 at the Henry Hub and oil was \$17. That would have nothing to do with the world of progressivity. He is focused on what happened in the last 6 months of FY/08. His graphic was of January 1994 through the end of 2008. The blue line represented the ANS price; the purple line (gas) takes the Henry Hub price and multiplies it times 6 for thermal parity. From 1994 through 2006, when this rule was made law, it looked good; fundamentally the two kind of moved around each other. But something happened in 2006, and from then on, oil has sold at a huge premium over gas. Interestingly, the lines come back to the 6:1 ratio in January 2009. His point is that you can have extreme situations in the current tax system, but that didn't mean it was unstable.

He said they both agree that a single month or a one-year snapshot only tells part of the story, particularly if you are dealing with progressivity. So, he did include a month snapshot; and where his annual one showed a loss of \$1.2 billion, the

single month one showed a loss of \$100 million (oil and gas). But you wouldn't expect that to be maintained over a year.

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MR. DICKINSON said the main place he disagrees with Mr. Ruggiero is the question of whether further investigation of a distinct gas tax is warranted. If the main issue is the cross subsidy between oil and gas and what happens in progressivity at high prices, the solution is simple. You simply calculate oil and gas progressivity distinctly, using the exact same rules. So, if there is no progressivity in gas, the story ends there. Then you calculate the progressivity on oil, but you don't take the gas at its lower value and make it part of the oil calculation.

The second bullet point on cost structures were done when people were thinking about oil, and then moving the gas to the 6:1 ratio. When you lose that ratio or if you look at the actual markets that gas are being sold and transported into, you "have to scratch your head about whether the structure is appropriate for both."

His last point was, if the main issue is competitiveness, government take and how that fits into the overall cost structure, then you may need to look at other aspects of the gas tax. But he thought creating separate taxes for oil and gas would require fairly narrow changes.

MR. DICKINSON reiterated that Transcanada and ConocoPhillips both made the point that they think there is additional work that could be done on taxes but before they get to an open season structure.

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CO-CHAIR STEDMAN thanked everyone for their testimony and adjourned the meeting at 4:56.