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TESTIMONY OF THE ALASKA OIL AND GAS ASSOCIATION TO THE HOUSE RESOURCES COMMITTEE ON CS FOR HOUSE BILL 2001(O&G)

November 1, 2007

Mr. Chairman and Members of the Committee. Thank you for the opportunity to testify before you today on the Committee Substitute for House Bill 2001(O&G).

My name is Marilyn Crockett and I am the Executive Director of the Alaska Oil and Gas Association ("AOGA"). AOGA is the trade association for the oil and gas industry in Alaska. Our 17 members account for the majority of oil and gas exploration, development, production, transportation, refining and marketing activities in the state. In addition to Alaska's instate refiners, Agrium and Alyeska Pipeline, our membership includes companies new to Alaska hoping for the opportunity to explore, companies which are exploring today but do not yet have production (but hope to in the future) and those companies which are producing today.

One of the important functions the Association performs is to provide a forum for member companies to consider regulatory and legislative proposals, and to reach agreement on an industry position on those proposals. To establish an AOGA position, a 5/6 vote of the members is required. What this means, of course, is that when AOGA voices that position, regulators and legislators can be assured that that position is the position of the overwhelming majority of Alaska's oil and gas industry.

But on tax issues, AOGA's Tax Committee has taken this approval process to the highest level. AOGA positions on tax-related issues require 100% consensus of the Committee, with no dissent. This is true for my testimony today.

With me today is the Chair of the AOGA Tax Committee, Tom Williams. He is a tax attorney here in Alaska for BP. However, for anyone who may not know his background, in 1975 – 79 Tom was the director of the division in the Department of Revenue ("DOR") known today as the Tax Division, and during Governor Hammond's second term from 1979 – 82 he was Commissioner of Revenue. In these roles he was the architect or co-architect of many aspects of Alaska's oil and gas revenues that are still in place today, from the methodology for determining "gross value at the point of production," to the methodology for determining shareable net profits under state net-profit share leases. Tom wrote the regulations that successfully implemented the State's former separate-accounting tax, as well as statutory language in the State's present income tax on oil companies enacted in 1981 to replace separate-accounting. He supervised the first property-tax valuation of the trans-Alaska oil pipeline after it came into production, and he administered the State's temporary two-year reserves tax in 1976 and '77. He was the last Commissioner of Revenue to administer the state personal income tax, and the first to send out Permanent Fund Dividend checks to Alaskans. He was also on the original Board of Trustees of the Permanent Fund. Most notoriously, Tom became the "father of the ELF" in December 1976. He was Vice President & General Counsel for Cook Inlet Region Inc., or "CIRI", for almost four years before joining BP in 1987.

The focus of our testimony today will be on the practical impact of declining production levels on industry operations and the State of Alaska. And while we are not in a position today to provide you with a complete analysis of the many components of CSHB 2001(O&G), we will describe for you but a few of the troubling aspects of this legislation.

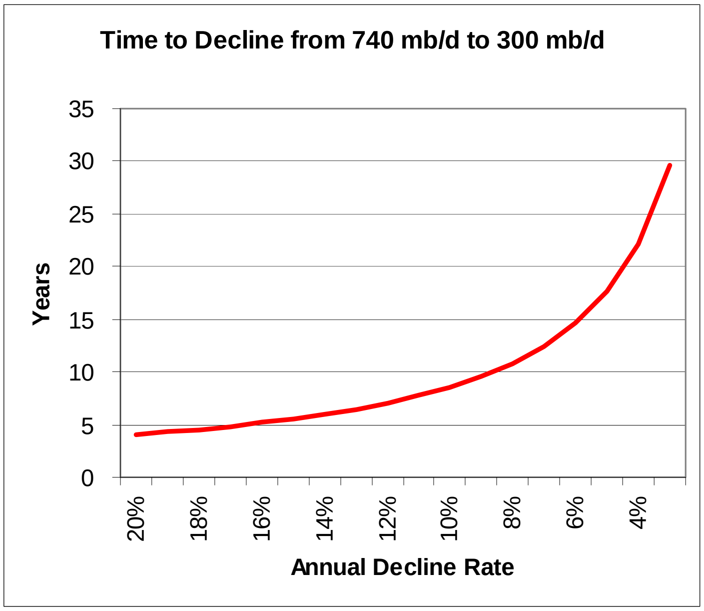
Last year the Legislature passed the Petroleum Production Tax, or PPT. Now, less than a year later, the Administration is telling you that the PPT is broken. They say it's too complicated to forecast, it isn't bringing in the revenue that was forecast last year, and they don't have enough capable auditors to enforce it.

In discussing the merits of CSHB 2001(O&G) versus PPT and the Administration's concerns, we must always keep in mind the real-world situation that Alaska faces. The greatest challenge that confronts this generation of Alaskans and the next is the ongoing decline of oil production, which has been, is today, and promises to remain the cornerstone of the finances of state government.

Production decline is eroding this cornerstone. It is a historical fact that even with the massive investments being made, North Slope production declined an average of 6.2% a year from FY 1997 to FY 2007, and Cook Inlet oil production declined at 8.0% a year.[1] Without those investments, decline would have been 15%.

With respect to the future of the North Slope, there is going to be a major challenge when ANS production gets down to about 300,000 barrels a day. According to Alyeska Pipeline Service Company, which operates the trans-Alaska oil pipeline (TAPS), the minimum mechanical capacity of the new electronic pumps that are being installed is about 300,000 barrels a day.

Here is a graph showing how long we have before ANS production reaches this 300,000 barrel-a-day mechanical threshold, depending on what the rate of decline is. If decline continues



at the historical rate of 6%, ANS will decline to 300,000 barrels a day in about 15 years, or FY 2022. On the other hand, if decline can be held to 3% or less as DOR assumes, then we would have 30 years or so before we hit the mechanical threshold.

Let me stress that this graph is not a prediction. It merely plots the results of the mathematical calculations[2] of how long it would take to get to 300,000 barrels a day from the level of 740,000 barrels a day in FY 2007, depending on what decline rate you choose. What it does show is how important the rate of production decline is for Alaska's future. The difference between a 6% decline rate and 3% doesn't sound like much, but as you can see from the graph, that difference determines whether the 300,000 threshold is reached around FY 2022 or FY 2037.

Investment in new production is the only way to slow the decline enough to give the children of this state a future with the North Slope similar to what we have enjoyed. There are three categories of investment that can slow the rate of decline on the North Slope, or at least keep it from getting any worse. These are, first, investment in exploration to discover new fields; second, investment in existing fields to prevent their decline from accelerating; and third, investment in innovation, technology, and new infrastructure to allow development of the vast but challenging resource of heavy and viscous oil that has already been discovered.

A great deal of the testimony to the Legislature, and a lot of the questions being asked, have focused on the fiscal terms of the "government take" for exploring in Alaska and the competitiveness of these terms relative to the terms in regimes elsewhere in the world. This kind of "who takes more" analysis is faulty for two fundamental reasons.

First, it assumes that the geologic prospects for making a commercial discovery in Alaska are comparable to those other regimes. This assumption is unsound. The North Slope has three major areas of significant oil and gas potential: the state lands in the central North Slope between the Colville and Canning rivers, the federal land in the National Petroleum Reserve – Alaska to the west of the state lands, and the coastal plain of ANWR to the east of the state lands. The exploration potential of the state lands is limited today primarily to the discovery of new satellite fields, as opposed to fields large enough to stand on their own economically. Exploration is still active in NPR-A and by no means over, but the courts have recently blocked federal leasing of the geologically promising lands around Teshekpuk Lake. And even if the Ninth Circuit decides to let that leasing go forward, the pro-leasing Bush Administration has less than 14 months left in office in which to hold the lease sale. Elsewhere in NPR-A, the relinquishment earlier this fall of some 300,000 acres of lands reflects disappointing results from leaseholder exploration efforts there. As for ANWR, despite Republican majorities in both houses of Congress and a pro-development president in the White House, the coastal plain is still closed.

And this brings me to the second reason why it is unwise to focus too much on investment in exploration as the solution to production decline. Exploration is a risky business, and there is no assurance that spending money to test a particular prospect will ever yield a dime of payback. Even when exploration succeeds in discovering a commercially viable field, it will take years from the time of its discovery until the time production from it begins. But the challenge of declining production confronts Alaska today — not eight, ten or a dozen years from now. By its nature, investing in exploration can make a significant contribution toward solving the challenge of declining production in the longer term, but not the shorter term when results are urgently needed.

Investment in heavy and viscous oil development is also a solution in the mid to long term. The first well ever drilled to test production from the Ugnu Formation was only drilled earlier this year in the Milne Point Unit, and it is still being tested and evaluated to gain a better understanding of the physical characteristics of the Ugnu oil. There are plans to use the results of these tests and evaluations to plan and develop a pilot project for producing Ugnu oil. Until then, West Sak will continue to be the only commercial heavy/viscous opportunity.

This gets us to investment in currently producing fields. Fortunately, there <u>are</u> investments that can be made, and are being made, in these fields to slow their decline. In the short term, this is in-fill drilling — that is, drilling new wells into the portions of a reservoir that are between the wells that have already been drilled. This accelerates the drainage of oil from the rock that currently lies in between existing wells. In-fill drilling last year contributed some 70,000 barrels a day to production from the Prudhoe Bay field. To put this into perspective, a 70,000 barrel per day field would be the 4th largest stand-alone field on the North Slope today.

There are also major investments being made, and yet to be made, in "renewal" of the surface facilities for existing fields. For instance, the gathering centers and flow stations for the

Prudhoe Bay field have been in service for over 30 years now. For them the situation is not all that different from what yours would be if you bought a minivan van years ago when your children were young, and now that the kids are all grown up and it's just you and your spouse who are driving it, it's time to replace that minivan with a new vehicle that suits your needs better. If Prudhoe Bay and the other producing fields are to continue producing in the decades to come, their original production facilities will need to be overhauled or replaced. Also, as increasing amounts of heavy and viscous oil come into production, even relatively new facilities that were designed for comparatively light "conventional" oil will probably need to be modified, refitted or replaced in order to minimize operating problems in handling that heavy/viscous oil. Regardless of the stimulus or purpose for making them, renewal investments in production infrastructure present a very similar cash-flow pattern as there is for investments in the original infrastructure to develop a field. And consequently, an incentive that is effective for the initial development infrastructure is equally effective for renewal as well.

So, this is the harsh reality in which we — government, industry, the present generation of Alaskans, and the next one — find ourselves. For all of us, decline is the great challenge that we must grapple with. It already threatens us now, and if unaddressed, will only get worse. Massive new investments for additional oil production are the only way to deal with this menace.

Turning now to the relative merits of CSHB 2001(O&G) versus PPT, AOGA submits there are several self-evident principles of taxation that should be used to test those merits. First, a tax must be "fit for purpose" — that is, it must do the things it is intended to do, and it should do them well. Second, the administration and enforcement of a tax should be as efficient as possible, consistent with ensuring compliance by taxpayers. Third, for a taxpayer who wants to calculate and pay the correct amount of tax when it comes due, it must be possible to do so.

Regarding the first test — achieving what the tax is supposed to achieve — most new taxes have as their primary or only purpose the new revenues that they will bring in for the government. In the case of PPT, however, things were not so simple. In part its purpose certainly was revenue-related, because most legislators viewed the prior ELF-based production tax as outdated and unduly generous to producers in terms of the reduction in tax rate that the ELF caused. But, as Pedro van Meurs explained repeatedly in his testimony last year and again at the beginning of this special session, the PPT was also designed to provide incentives for investing in production and in that way answering the threat of declining production.

With respect to the revenue side, no one disputes that PPT has brought the State more tax revenue since April last year than ELF would have. According to DOR, the increase was more than $800 million in the last nine months of 2006,[3] and at that rate it would have been over a billion dollars in additional production tax revenue for a full year. DOR also said at the time that the March 31st payments were about $137 million less than the $950 million that it had estimated, and in due course I'll come back to the questions of forecasting the PPT and higher-than-forecasted lease expenditures. For now, my point is that PPT has certainly outperformed the old ELF tax, which is just what it is supposed to do.

As a consequence of the fact that field costs are higher than DOR predicted last year, this Administration criticizes PPT for failing to generate all the tax revenues that the fiscal note for HB 3001 predicted. It has even been suggested that Alaskans were somehow promised that PPT would generate $800 million more this year than is now being projected, and that it is therefore necessary to raise the tax rate in order to make good on that promise.

That whole line of reasoning is flawed. First of all, DOR is complaining that they can't forecast PPT accurately because it has so many variables that affect the results. However, if they can't forecast it accurately, then why should so much reliance be placed on its current forecast that shows the prior forecast was off by $800 million? If the first forecast was poor, what has changed to make this latest one so good?

As I explained just a while ago, the purpose of PPT was more than just the tax revenues it would generate. It was to create incentives for attracting the massive new investments that will be needed in order to meet the threat posed by declining production. The system of tax credits under PPT provides significant incentives for investing in capital assets to explore for, develop, and produce more oil and gas.

- Current capital expenditures generate a 20% tax credit in addition to being immediately deductible as lease expenditures. For the kinds of economic analysis that reflect the time-value of money, these front-end benefits have the greatest possible positive effects on the results of the analysis.
- The incentive to invest sooner rather than later is materially increased by the fact that the "transitional investment expenditure" or "TIE" credit for pre-PPT capital investments can only be taken to the extent those prior expenditures are matched two for one by new capital expenditures, and taxpayers have only until the end of 2013 to use up their "TIE" credits.[4]
- The tax credit for a carried-forward annual loss particularly benefits explorers and those who are bringing new fields into production for the first time in Alaska and don't have production yet that they can deduct their costs against.
- The "section 024(c) credit" of up to $12 million a year for producers with less than 100,000 barrels a day of production is an incentive for independents and other smaller players to come to Alaska for oil and gas.
- The $6 million annual credit under AS 43.55.024(c) is an incentive for exploration and development in the areas of Alaska outside the North Slope and Cook Inlet basin.

Have these incentives under PPT worked? The preliminary results so far say yes. DOR's August 3rd report on PPT states that capital investments for FY 2008 are 80% greater than previously estimated, despite the fact that operating expenditures are up by 101% over the prior projections.[5] Of course, it will take time before companies can fully respond to these incentives, and it will take even more time to tell whether the new investments to increase oil production succeed in actually getting more production. But so far things appear to be moving in the right direction.

Now, moving on to CSHB 2001(O&G), how well does it stack up under the standard of being fit for purpose? Certainly, it would generate even more tax revenue than the PPT will, at least in the short term. But it is premised on the totally mistaken notion that increasing what the government takes from the economic “pie” will encourage greater investment, or at least not decrease it from what it would be anyway. No one has ever taxed economic growth and development into existence. CSHB 2001(O&G) will not do so, either.

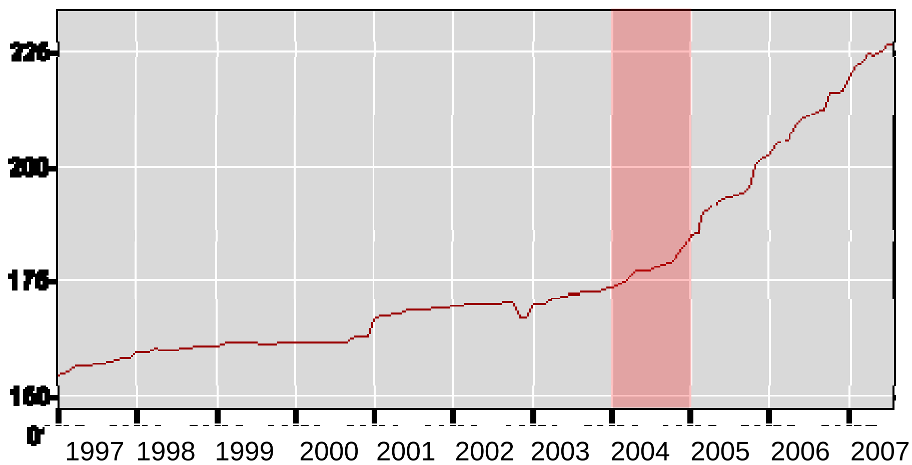
The second standard for evaluating CSHB 2001(O&G) versus PPT is that the administration and enforcement of the tax must be as efficient as possible, consistent with ensuring compliance by taxpayers. Here, the two chief objections to PPT have been, first, that it is all but impossible to forecast the revenues from it with the accuracy needed for state budget purposes, and second, that the audit challenges of PPT leave DOR’s auditors hopelessly outgunned.[6] So the questions that need to be answered are, how much merit do these criticisms have, and how would CSHB 2001(O&G) address these concerns?

Regarding forecasts for PPT, DOR cites two major concerns about the forecasts. One is that, “[w]hile costs would be expected to increase, the dramatic difference between what was predicted [in the prior Administration’s fiscal note for HB 3001] and what has actually been experienced brings into question whether the legislature made its decisions based upon appropriate information.”[7] The other is that DOR needs cost information about current and planned spending from the operators, producers and explorers, and this allegedly has not been forthcoming from them.

Let us consider this “dramatic difference” between the projected expenditures behind the fiscal note last year, and what those expenditures have actually been. When the DOR staff in the prior Administration sought information about expenditures, they chose not to rely on the representations about 2006 costs that individual companies gave the Legislature in public testimony at that time.[8] Instead, they looked at what they believed to be more reliable information contained in the most recent partnership tax returns that had been filed with the IRS for fields on the North Slope.

Federal partnership returns are not due to be filed with the IRS until October of the following year, so even as late as August 2006 when the Legislature passed HB 3001, the most recent returns available were those for 2004. Here is a chart showing the Producer Price Index

Oil and Gas Field Machinery and Equipment PPI
Source: U.S. Department of Labor



for oil and gas field machinery and equipment during the last decade. The highlighted bar in the graph marks 2004, and you can see right away why a fiscal note based on the most recently filed federal tax returns, for 2004, would be way off the mark in predicting what the field costs would be in 2006 and ’07.

There was nothing sinister about what that Administration did. The companies said the 2006 costs were high, but the latest tax returns at that time indicated the costs were significantly less, with a fairly lengthy track record of gradual increases. DOR went with the reported information on the tax returns. I suspect the DOR staff in the present Administration would do the same in those circumstances. In any event, this is not a reason for casting PPT aside.

The other criticism that DOR makes of PPT is that producers and other taxpayers are not providing DOR with the information it needs in order to be able to forecast PPT revenues with sufficient accuracy. Obviously, AOGA is not privy to what these taxpayers are reporting to DOR as they make their monthly installment payments and their annual true-up payment on March 31st.

DOR’s second chief objection to the administrability and enforceability of PPT is that the audit challenges of PPT leave its auditors hopelessly outgunned. It is not for us to comment about the proposal to put auditors in the “exempt” service.

But there is a dimension to PPT audits, however, that we can and should address. This has to do with what the source or starting point for determining how much a producer’s deductible lease expenditures are. The PPT statutes currently allow DOR a choice between starting from the joint-interest billings and invoices that operators bill to the other participants in an oil and gas field or venture,[9] or starting from a comprehensive set of accounting rules and principles that DOR writes up.[10] Which choice DOR chooses will determine nothing less than the very success or failure of PPT as a tax — and for CSHB 2001(O&G) as well, if it is enacted. It is like having a tax based on your federal taxable income, and choosing between your federal tax return (as audited by IRS) as the starting point, or starting with the Internal Revenue Code and leaving it up to you and DOR's auditors alike to find what the right answer is under the Code. It is like having a tax based on your financial book income, and choosing between your audited financial statements filed with the SEC as the starting point, or starting with Generally Accepted Accounting Principles and leaving it up to you and DOR's auditors alike to find what the right answer is under GAAP.

From the taxpayer's perspective, this means a near certainty of continual assessments year after year for additional tax, interest, and perhaps penalties, and depending on how litigious a company may feel, it may mean a long series of lawsuits and appeals as well.

From the State's perspective, these same troubles for the taxpayer will mean that the incentives for investment under PPT, or CSHB 2001(O&G), will be seriously eroded. The greater the uncertainty about how much tax a company owes, the greater the likelihood that the incentives will turn out be less than their face value. A taxpayer's only recourse in this situation will be to discount the face-value of those incentives significantly, perhaps completely, in running the economic analysis about making an investment or not. As a consequence, the effectiveness of those incentives will be less than it should be, and Alaska will fail to realize the full amount of new production that it needs to meet the challenge of decline.

The other choice that DOR could make is to start with what an operator bills to the other participants in an oil and gas operation. Note that I said "start" with those billings — not "end." Anything in those billings that is nondeductible under AS 43.55.165(e) would have to be backed out. The central concept of lease expenditures in AS 43.55.165(a) is that they must be "direct" and "ordinary and necessary" costs of exploration, development, or production. It would be most surprising if there are anything in those billings that goes outside this standard.

How can Alaska be sure of this? Because the participants in an oil and gas operation do not give the operator a license to waste their money. I have heard a great deal of concern expressed during these hearings about how the companies might somehow try to "game the system" in order to reduce the tax they will pay the State. While so many are so worried about efforts by the companies not to overpay the State, why would most of these same people think the companies are somehow more willing to overpay the operator than the State? Clearly they don't want to overpay either one. If anything, since the operator usually is a direct competitor, they probably don't want to overpay it even more than they don't want to overpay the State. In other words, if an operator is exploring a geologic prospect, the non-operating participants don't want to pay any costs that are not for the exploration of that prospect. Similarly, if the operator is operating a producing field, they don't want to pay any costs that aren't for the operation of that field. It is reasonable to rely, in the first instance, on the non-operators' self-interests to police and limit what the operator can spend their money on, and they will do that policing by auditing the operator's invoices to them.

In the context of PPT, DOR should "audit the audits" to verify that the non-operators do indeed audit an operator's invoices on a regular basis, and that those audits are rigorous and at arm's length. But once these things have been confirmed by DOR in its verification of the non-operators' audits, there is little point for DOR to spend the time and effort to re-plow the field that the companies' audits have already plowed.

Daniel Johnston, a consultant hired during last year's debate on PPT, gave an informal presentation to members of the Legislature on Friday, Oct. 19, 2007. During that meeting, he praised the expertise of joint interest auditors and the ability for the state to utilize unit accounting. He went on to say that it would be "extremely insightful for the state to get unit accounting". Mr. Johnston observed that state auditors can be "vicious", but that joint interest auditors are "even more vicious".

Of course, for operations where there is only one participant or where there are no audits of the operator's invoices, this approach will be inapplicable. But there are still things DOR could do to build off the billing systems where there are such audits and extend them to these other fields. However, DOR has not yet adopted the "Phase II" regulations to implement and apply its existing statutory authority to authorize or require taxpayers to follow this approach.

Unfortunately, Section 37 of CSHB 2001(O&G) would repeal DOR's explicit statutory authority under AS 43.55.165(c) and (d) to require or authorize the use of operators' joint-interest billings as the starting point for computing the amount of a producer's deductible lease expenditures for that unit or field. We believe that this repeal will mean DOR cannot authorize or require a producer to start with an operator's joint-interest billings, even when DOR wants to allow or require their use. Since these repeals are in the proposed legislation that has been introduced, we expect that DOR, in response to us, will testify that somehow they will still be able to require or authorize the use operator billings even if these present statutory provisions are repealed. However, if you enact a law specifically saying DOR may do something and later on you repeal that law, doesn't that repeal mean DOR can't do it anymore? We think so. But even if you are persuaded by DOR that we're wrong on this point, why should you repeal those statutes and take the chance that the courts won't agree?

The reason I've spent so much time about the use of joint-interest billings as the starting point for determining a producer's lease expenditures is this: Consider the situation that a non-operating participant faces. All the information it has about what's being spent for the operation is what it gets from its billings from the operator, plus whatever it may learn by auditing those invoices. But if such a non-operator cannot start from those invoices, how can it figure out what to report as the lease expenditures for that operation? All the books and records of the expenditures are with the operator, and if the non-operator hasn't yet audited the operator, it will have no idea what those books and records show. It is infeasible for a non-operator to be auditing the operator month by month, yet the non-operator will somehow have to be reporting and paying installments month by month throughout the year. Even by the March 31 true-up the following year, it is unlikely that any audit of the operator's books and records will have been begun by that date, much less completed. The penalty for mis-estimating the installment payments is principally in the difference between the rate of interest on overpaid installments and underpaid ones. But the March 31 true-up is very serious business. Interest at an APR not less than 11% compounded quarterly begins to accrue, and penalties of up to 30% for negligence and failure-to-pay[11] can be assessed, on the amount of any underpayment continuing after that true-up date. If a non-operator cannot rely on its billings from the operator as the starting point for these purposes, what is it supposed to use?[12]

If, as we fear, the repeals of AS 43.55.165(c) and (d) under the proposed bill will indeed take away DOR's discretion to allow or require the use of operators' joint-interest billings, then CSHB 2001(O&G) will completely fail the third standard by which a tax is measured — that it must be possible for a taxpayer to get the tax right when it is due, when the taxpayer wants to do so. This will be impossible for non-operators under the proposed legislation. Even PPT will fail if the "Phase II" regulations do not reasonably implement DOR's present authority under AS 43.55.165(c) and (d) regarding the use of operator billings.

This issue has been addressed by us and the Administration during hearings in previous committees over the past week or so. The Administration has stated that it is their intent to allow joint interest billings to be one of the tools they will utilize, and I would encourage this committee to reconfirm that intent with the Administration during your deliberations. In any event, if these are to be utilized, then there is no reason to repeal the specific authorization to do so. Section 37 should be eliminated from the bill.

We have prepared a white paper that describes in detail the issues related to the repeal of this important discretion and have attached it to our testimony for your further reference.

Before closing today we'd like to briefly discuss progressivity. Progressivity is a feature in the present production tax. It is levied under subsection (g) of AS 43.55.011, and is a separate tax from the basic PPT tax levied by subsection (e) of that statute. It is also in addition to the basic PPT tax. Like the basic PPT tax, the present progressivity tax is based on the "net value" of production. But, unlike the basic tax, progressivity is computed monthly instead of on an annual basis. The tax rate for progressivity is zero when the "net value" per BTU equivalent barrel is $40 or less, and it rises linearly at a 0.25 percentage points per dollar that the "net value" per BTU equivalent barrel rises above $40, up to a maximum rate of 25 percent. The 0.25 figure which sets the rate at which the tax rate rises is known as the "slope."

I should repeat that what I've just described is progressivity under the present law, not the Committee Substitute that is before you. Frankly, we are not entirely sure how progressivity under the CS is supposed to work.

The rationale for progressivity boils down to little more than "at these prices, the oil industry can afford to pay us more." If "affording to pay" is to be the rationale for setting taxes, then who was arguing, not even nine years ago, to give industry a break when the spot price for a barrel of ANS on the West Coast — after spending some $4.26 a barrel for transportation to get it there — crashed to $8.16 on December 23, 1998? No one.

It is this asymmetry that makes progressivity so objectionable to the industry. We have put up all the capital and taken all the risk in making that investment. Periods of high oil prices are not only an opportunity for industry to catch up after periods of low prices, but they are also the opportunity to make up for expensive investments that proved to be unsuccessful.

Take bonus bids for oil and gas leases as an example. The industry paid $1.013 billion in bonus bids for the Mukluk prospect in the Beaufort Sea in 1982, and then spent another $135.6 million to put in a gravel island and drill an exploration well — it was a dry hole. Even in the State's great $900 million lease sale in 1969, over $525 million of those bonuses was paid for acreage that turned out to be outside the main Prudhoe Bay field. And the acreage that was in the field represented less than 2% of its oil and just over a quarter of a percent of its gas.

AOGA opposed the inclusion of progressivity in the PPT legislation that passed last year, and we do not like it any more now.

In conclusion, CSHB 2001(O&G) fails two of the three standards for evaluating a tax, while PPT passes two of them and would pass the third one as well if DOR adopts the appropriate regulations. CSHB 2001(O&G) in the short term will generate more tax revenue for the State than PPT; however, it will achieve this at the cost of reducing the incentives for new investments, and worsening the overall tax climate for making them here. CSHB 2001(O&G) fails the test of being administrable as efficiently as possible, consistent with ensuring taxpayer compliance. This failure will primarily be due to repealing DOR's existing statutory discretion to allow, as appropriate, joint-interest partners do the auditing of the operator's billings to them. Instead DOR auditors could have to re-invent the wheel for themselves in each audit. CSHB 2001(O&G) also fails the test that a taxpayer who wants to pay the correct amount of tax when it comes due must be able to do so. This will be impossible for every company that owns an interest in a lease or property that it does not operate. This in turn will effectively destroy the value of the remaining tax incentives under this bill that potential investors will perceive. If they cannot tell what they owe, they surely cannot put a reliable figure to the value of the incentives under the tax.

All of this brings us back to the fundamental issue facing Alaska today…the decline of Alaska production. Today Alaska's production has fallen from its peak of 2.1 million barrels a day down to the 700,000 range. This means that the trans Alaska pipeline is 2/3 empty. I would remind you of my chart earlier that showed the purely mathematical results about how long we have before hitting the 300,000 barrel-a-day TAPS mechanical threshold, depending on what rate of decline you assume will turn out to come true.

And it's important to remember that today's 6% decline rate would be on the order of 15-16% were it not for the substantial investments which continue to be made by operators in existing fields. Further, Alaska is fortunate to have on the nearby horizon Pioneer's Oooguruk project, scheduled to go into production in 2008.

The importance of future investment is further emphasized when one looks at the Department of Revenue's forecast of future production levels. In three short years, DOR projects that production will come from projects requiring significant new investment. Draw that timeline out to 2017—ten years from now—and you discover that half of Alaska's production will come from <u>new</u> production—production which will only come from investments yet to be made.

The most important policy question is whether CSHB 2001(O&G) provides a framework for encouraging this additional new investment. Committee Substitute for House Bill 2001(O&G) does not accomplish that goal.

Thank you for the opportunity to testify today.

ENDNOTES

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1 When production declines at X% a year, this means the production rate after one year (P_1) is ($1 - X\%$) of the initial production rate (P_0), or $P_1 = P_0 \times (1 - X\%)$. After the second year the production rate (P_2) is ($1 - X\%$) of the rate after one year of production, or $P_2 = P_1 \times (1 - X\%) = [P_0 \times (1 - X\%)] \times (1 - X\%)$, which can be simplified as $P_2 = P_0 \times (1 - X\%)^2$. After 10 years of decline, the rate P_{10} is $P_0 \times (1 - X\%)^{10}$. North Slope production was 1.404 million barrels a day in FY 1997 and 740 thousand barrels a day in FY 2007, while Cook Inlet produced 37 thousand barrels a day in '97 and 16 thousand barrels a day in '07. *See* DOR, *Revenue Sources Book Spring 2007*, pp. 97-98. So for North Slope production,

$$1{,}404{,}000 \times (1 - X\%)^{10} = 740{,}000.$$

Dividing both sides of this equation by 1,404,000 gives:

$$(1 - X\%)^{10} = 740{,}000/1{,}404{,}000 = 0.5271.$$

One can solve for ($1 - X\%$) by taking the 10th root of both sides of this latter equation:

$$\sqrt[10]{(1 - X\%)^{10}} = \sqrt[10]{0.5271}\text{, or}$$

$$(1 - X\%) = 0.9380.$$

In other words, on average the production rate each year was 93.80% of the rate for the prior year, which means the rate of decline averaged 6.20% a year. The same calculation for Cook Inlet, using 37,000 and 16,000 barrels a day instead of 1,404,000 and 740,000 respectively, yields an average annual decline rate of 8.0 percent.

2 Here is the math: From the analysis in Endnote 1 above, we know that for a given decline rate R, the volume of production after N years of decline is $P \times (1 - R)^N$. So for each decline rate in the table, you use that as the value of R in the formula, and then you solve for X as the value of N that gives 300,000 barrels a day as the rate. The equation for this is:

$$740{,}000 \times (1 - R)^X = 300{,}000.$$

When you take the logarithm of both sides of this equation, you get the following equation:

$$\log[740{,}000 \times (1 - R)^X] = \log[300{,}000].$$

The reason for using logarithms is that they have the property that the logarithm of two numbers being multiplied together equals the sum of the logarithms for each of them, while the logarithm of a number raised to an exponent X equals X times the logarithm of that number. Using this gives the following restatement of the prior equation:

$$\log[740{,}000] + X \times \log[(1 - R)] = \log[300{,}000].$$

Subtracting log[740,000] from both sides of the last equation yields the following:

$$X \times \log[(1 - R)] = \log[300{,}000] - \log[740{,}000].$$

Now you can solve for X by dividing both sides of the last equation by $\log[(1 - R)]$, which yields:

$$X = \frac{\log[300{,}000] - \log[740{,}000]}{\log[(1 - R)]}.$$

By plugging the decline rate of your choice into this last equation as the value of R, the value of X can be calculated by simple arithmetic. This straightforward calculation has been done for each of the decline rates shown in the graph.

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[3] DOR Press Release, "New Production Tax Nets Increased Revenues For Alaska" (April 3, 2007).

[4] For producers who begin producing in Alaska on or after April 1, 2006, they have six years from the year of that first production in which to use up their "TIE" credits. The rule still applies during those six years that it takes $2 of new capital investment in order to get a credit for $1 of the "TIE" investment from the years before their production begins.

[5] *See* DOR, *Petroleum Profits [*sic*] Tax (PPT) Implementation Status Report* (August 3, 2007), p. 3.

[6] *See* DOR, *Petroleum Profits [*sic*] Tax (PPT) Implementation Status Report* (August 3, 2007): "The Department has been severely hampered in its ability to provide the administration and the legislature with accurate revenue forecasts ...." *Id*., p. 4. "The complexity of auditing production tax has increased several fold under the PPT, and the PPT increased the number of determinations an auditor must make." *Id*., p. 5.

[7] *Id*., p. 5.

[8] *See, e.g.*, Alaska State Legislature, House Finance Committee, *Minutes* (March 29, 2006), p. 15:

> Representative Holm ... asked about the rate of return at $60 per barrel. Mr. [Angus] Walker [Commercial Vice President of BP Exploration (Alaska) Inc.] said BP is excited about current prices. BP does not make a profit until oil is above $22.50 a barrel.

At a $22.50 West Coast price, BP's implicit upstream field expenditures were about $11.95 a barrel, as opposed to the $7.27 per barrel in the fiscal note for HB 3001.

$22.50	ANS price on West Coast
1.76	Marine transportation to West Coast
4.38	TAPS
0.67	North Slope pipelines, quality bank, etc.
$15.69	Average North Slope wellhead value
1.96	State royalty (1/8)
$13.73	Taxable value
1.09	Production tax (15% base rate × ELF of 0.529)
0.69	Property tax ($/bbl average)
$11.95	Implicit expenditures/bbl.

SOURCE: DOR, *Revenue Sources Book Fall 2006*, p. 33 Fig. 4-6 (average ANS ELF); p. 39 Fig. 4-9 (marine, TAPS, and Slope pipelines/quality bank); p. 40 Fig 4-11 (ANS production); p. 42 Fig. 4-12 (property tax; $60 million for tax on TAPS is deducted from total for North Slope Borough, Fairbanks, Valdez and Unorganized Borough). All data are for FY 2006.

[9] The authority for DOR to take this approach is in AS 43.55.165(c) and (d). Subsection (c) states in pertinent part: "if the department finds that the pertinent provisions of a unit operating agreement or similar operating agreement are substantially consistent with the department's ... standards under (a) of this section concerning whether costs are lease expenditures, the department may authorize or require a producer ... to treat as ... lease expenditures ... the costs, other than items listed in (e) of this section, that are incurred by the operator ... and ... billable to the producer by the operator in accordance with the terms of the [operating] agreement[.]" Subsection (d) has very similar language.

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[10] The authority for DOR to take this approach is in AS 43.55.165(a), which states in pertinent part: "In determining whether costs are lease expenditures, the department shall consider, among other factors, (1) the typical industry practices and standards in the state that determine the costs, other than items listed in (e) of this section, that an operator is allowed to bill a working interest owner that is not the operator, under unit operating agreements or similar operating agreements ... and (2) the standards adopted by the Department of Natural Resources that determine the costs, other than items listed in (e) of this section, that a lessee is allowed to deduct from revenue in calculating net profits under [net profit share] lease[.]"

[11] The penalty for an underpayment due to negligence is 5% of the amount of the underpayment. AS 43.05.220(b). The failure-to-pay penalty for an underpayment is 5% of the underpayment for each month or partial month that the underpayment continues after payment was due, up to a maximum of 25 percent. AS 43.05.220(a). By regulation, DOR has adopted the policy that the imposition of a negligence penalty automatically triggers the imposition of a failure-to-pay penalty as well. 15 AAC 05.210(g).

[12] It follows that, if a non-operator can rely on the operator's joint-interest billings as the starting point for the non-operator's own lease expenditures for that operation, then the operator should similarly be able to use its proportionate share of the same total billable costs as the starting point for its lease expenditures for that operation. There is no reason to discriminate between them.