ALASKA LEGISLATURE COMMITTEE FILES 2007-2008 SRES 12708

Administration Field Economics Estimates

Table below from Sept 4, 2007 Administration Presentation

Project Net Present Value of Cash Flows (10% Discount Rate)				
$40 Test Price ($ Millions)				
	Status Quo PPT	ACES Plan	16% Gross Tax *No Capital Credits*	19% Gross Tax *With Capital Credits*
Field/Project A	178	128	-35	27
Field/Project B	72	48	-22	9
Field/Project C	59	27	-53	-22
Field/Project D	-64	-90	-398	-282
Production Tax Revenues FY2008 @ $60 oil price	*$1.3B*	*$2.0B*	*$2.1B*	*$2.0B*

- Project Economics decrease by 33% to 54%
- What geologic & commercial risks were assigned?
- Where are dry holes & failed projects accounted for?

Summary

- Significant tax increases outweigh any potential benefits

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Save extract issues

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TESTIMONY OF THE

ALASKA OIL AND GAS ASSOCIATION

TO THE SENATE RESOURCES COMMITTEE

ON SENATE BILL 2001

October 23, 2007

Mr. Chairman and Members of the Committee. Thank you for the opportunity to testify before you today on Senate Bill 2001.

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, 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 members have taken this approval process to the highest level. AOGA positions on tax-related issues require 100% consensus of the AOGA Members. Let me be clear: my testimony today reflects the full consensus of the members of the AOGA Tax Committee, with no dissent.

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 at this early date in this Special Session to provide you with a complete analysis of the many components of SB 2001, we will describe for you but a few of the troubling aspects of this legislation. The AOGA Tax Committee is in the midst of a comprehensive review of the legislation and will be in a position at a future date to characterize those concerns.

Here we are in Juneau for the fourth time in the past two years to deliberate whether one of the State's taxes on oil and gas should be changed, and if so, what it should be changed to.

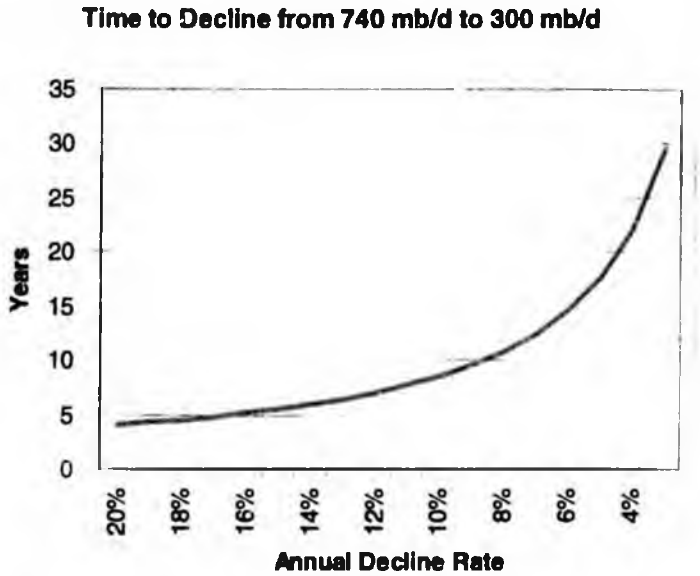
Last year the Legislature passed the Petroleum Production Tax, or PPT. Now, less than a year later, the Administration is telling you that the PPT is broken. They say it's too complicated to forecast, it isn't bringing in the revenue that was forecast last year, and they don't have enough capable auditors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

In discussing the merits of SB 2001 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 barrier is reached around FY 2022 or FY 2037. If you have a child in junior high school, this represents the difference between that child being able to grow up and have a career on the North Slope, and not having this opportunity.

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. That's why new investment is such a crucial question facing the State, both in the context of the proposed tax proposal and in other areas that affect the business climate here.

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 are 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, and there are three areas of investment that can be made to deal with it: exploration, heavy and viscous oil development, and slowing decline of existing fields. The first two are of greatest benefit for the long term, and the other one is of great benefit for the near term. We need all three kinds of investment and don't have the luxury of ignoring one or two of them. I have explained our collective situation in such detail so we can each see for ourselves why declining production is the great issue of the day for Alaska.

Turning now to the relative merits of SB 2001versus 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 20% 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.

noted - by Sen Stedman, CH

There is the question of whether the inability of explorers and almost-producers to sell their credit certificates near face value has been a material problem. As the Executive Director of AOGA, I can assure you there is no one among AOGA's membership who thinks any problem in selling the certificates has been serious enough to justify amending the PPT.

Now, moving on to SB 2001, 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. SB 2001 will not do so, either.

The second standard for evaluating SB 2001 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 SB 2001 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.

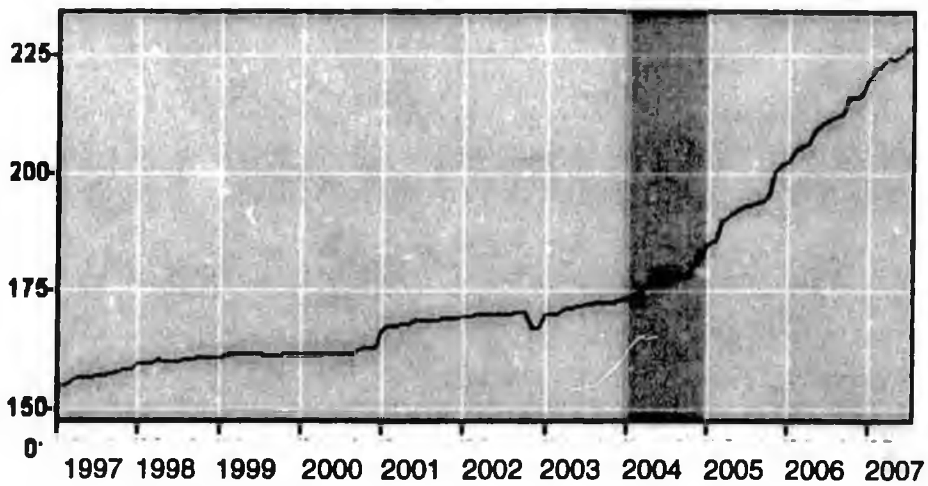
Let us consider this "dramatic difference" between the projected expenditures behind the fiscal note last year, and what those expenditures have actually been. When the DOR staff in the prior Administration sought information about expenditures, they chose not to rely on the representations about 2006 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

* Admin. uses 2004 data for data costs
CH brought up

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 SB 2001 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 SB 2001, 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 onto 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.

+ A very dismaying thing about SB 2001is that Section 64 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, while Section 71(b) would make that repeal retroactive to April 1, 2006.

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? ~~You could probably repeal AS 43.55.165(d) and keep subsection (c) on the books without taking much risk, because the text of (d) is very repetitive of that in (c). But repealing them both is taking a needless chance.~~ Delete per Marilyn - not correct

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]

CH ~~Paul~~ Tom discussed the repeal with the Administration?

repeal

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 SB 2001 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.

M.C. No - They have not had the opportunity

Before I close, there are a few confusing things in the SB 2001 I would like to address.

The first of these is Section 1, declaring that subsection (b) in the new production-tax statute of limitations being enacted is intended to "confirm by clarification the long-standing interpretation of AS 43.05.260 by the Department of Revenue relating to limitation of assessments for the production tax on oil and gas and conservation surcharges on oil." Does anyone here know why this is in the bill? AS 43.05.260 is the existing statute of limitations for auditing all state taxes under AS 43, and what is it about this present limitations statute that is being "confirm[ed]" by the new AS 43.55.075(b)?

They have tried to meet w/ DOR - schedule conflicts. She does not believe the AOGA is being "dissed"

If you read this new section 075(b) — which begins on page 35 line 30 and runs through line 15 on page 36 of the bill — you see there are two parts to the subsection. One part is the first two sentences, which address the effects for tax purposes of judicial or administrative decisions that retroactively change parameters for calculating the tax. The other part is the last sentence, including paragraphs (1) and (2), and requires producers to report such decisions to DOR within 60 days and to file amended returns within 120 days.

The curious thing is that the existing statute of limitations (AS 43.05.260) — the interpretation of which is to be "confirmed" — has nothing in it pertaining to either of these

Remind DOR to have those meeting with the AOGA.

subjects. Here is the text of AS 43.05.260 and you can see this for yourselves. Subsection (a)

> **Sec. 43.05.260. Limitation on assessment.** (a) Except as provided in (c) of this section and AS 43.20.200 (b), the amount of a tax imposed by this title must be assessed within three years after the return was filed, whether or not a return was filed on or after the date prescribed by law. If the tax is not assessed before the expiration of the three-year period, proceedings may not be instituted in court for the collection of the tax.
>
> (b) For purposes of this section, a return filed before the last day prescribed by law or regulation is considered as filed on the last day.
>
> (c) The following exceptions apply to the limitation period in (a) of this section:
>
> (1) in the case of a false or fraudulent return with the intent to evade tax, the tax may be assessed, or a proceeding in court for collection of the tax may be begun without assessment, at any time;
>
> (2) in the case of a failure to file a return, the tax may be assessed, or a proceeding in court for the collection of the tax may be begun without assessment, at any time;
>
> (3) if, before the expiration of the time prescribed in this section for the assessment of a tax imposed by this title, both the department and the taxpayer have consented in writing to the assessment after the expiration of the time, the tax may be assessed at any time before the expiration of the period agreed upon; however, the period agreed upon may be extended by a subsequent agreement in writing made before the expiration of the period previously agreed upon.

sets three years as the period for DOR to audit and assess any additional tax that may be due, and it bars suits to collect any additional tax if that tax is not assessed within the three-year period. Subsection (b) says that, if a taxpayer files its tax return early before it is due, the three-year period starts running from the due date instead of the actual filing date. Subsection (c) creates three exceptions to the rule under subsection (a), which appear as paragraphs (1) – (3) of subsection (c): namely, for false or fraudulent returns to evade tax, for a failure to file any return at all, and for extensions of the three-year period that are mutually agreed upon in writing by DOR and the taxpayer.

Which of these provisions has anything to do with tax effects of retroactive decisions? Which has anything to do with having to report such decisions to DOR and filing amended tax returns? It is not immediately clear to us what either of these topics in the new statute of limitations has to do with interpreting any of the provisions in existing statute of limitations I've just reviewed with you. So what's going on with Bill Section 1?

We believe Section 1 is a stealthy attempt to legislate an outcome to matters that are already being litigated in the due course of administrative and judicial proceedings. In 1999 DOR amended one of its production tax regulations, 15 AAC 55.200, so that it reads remarkably like AS 43.55.075(b) being enacted in this bill. Here you have the regulation and the proposed

15 AAC 55.200. Retroactive adjustments. If retroactive adjustments in costs of transportation, sales price, prevailing value, or consideration for quality differentials relating to the commingling of oils or of oil and NGLs result from decisions of regulatory agencies, courts, or any other preemptive authority, those adjustments have a corresponding effect, either an increase or decrease as applicable, on the gross value at point of production as determined under this chapter, and the producer shall, on or before the third monthly payment due date specified in AS 43.55.020(a) after any adjustment, file amended returns covering the entire period of an adjustment unless the producer has obtained a stay on that filing or payment, regardless of the pendency of appeals of those decisions. [emphasis added]	(b) A decision of a regulatory agency, court, or other body with authority to resolve disputes that results in a retroactive change to a lease expenditure, to an adjustment to a lease expenditure, to costs of transportation, to sales price, to prevailing value, or to consideration of quality differentials relating to the commingling of oils has a corresponding effect, either an increase or decrease, as applicable, on the production tax value of oil or gas or the amount or availability of a tax credit as determined under this chapter. For purposes of this section, a change to a lease expenditure includes a change in the categorization of a lease expenditure as a qualified capital expenditure or as not a qualified capital expenditure. The producer shall (1) within 60 days after the change, notify the department in writing; and (2) within 120 after the change, file amended returns covering all periods affected by the Change, unless the department agrees otherwise or a stay is in place that affects the filing or payment, regardless of the pendency of appeals of the decision. [emphasis added]

new AS 43.55.075(b) side by side, with identical or parallel language in them being underlined. As you can see, the regulation deals with "decisions of regulatory agencies, courts, or any other preemptive authority" while the proposed new statute addresses any "decision of a regulatory agency, court, or other body with authority to resolve disputes[.]" The regulation deals with "retroactive adjustments in costs of transportation, sales price, prevailing value, or consideration for quality differentials relating to the commingling of oils or of oil and NGLs" while the proposed statute addresses "a retroactive change" to the very same things,[13] plus any change to "a lease expenditure[.]" Both state that retroactive changes in the parameters for calculating the taxable value have "a corresponding effect, either an increase or decrease,[[14]] as applicable on" that taxable value.

Now, the "interpretation" that comes into play here has to do with the question of when interest begins accruing on a tax increase or decrease that results from one of these retroactive decisions — does it begin to accrue as of the date of that decision? Or does it begin to accrue all the way back to the original payment due date? When DOR adopted the amendment to the regulation in 1999, the director of the Tax Division at that time told AOGA members that DOR was interpreting that amendment to mean interest would start to accrue as of the original payment due date for the tax, not as of the date of the retroactive decision.

We believe it is this "interpretation" of its own regulation, which is in the process of being appealed in due course, that the Administration intends to have "confirm[ed]" under Section 1 of SB 2001 as the proper interpretation of the pre-PPT statute of limitations. The question for you is, do you really want to confirm this?

Confirming it would set a destabilizing precedent, because it will mean that the laws can effectively be rewritten to deal with subjects that they did not originally deal with, and this can be done clandestinely by "confirming" some purported "interpretation" of it. For one thing, it would be an attempt by the Executive and Legislative branches to determine the outcome of matters that are already before or headed to the Judicial Branch in due course. Can the Legislature intervene in Judicial matters under the Separation of Powers Doctrine, and even if it can, should it attempt to do so here? Second, what does it say to potential investors in this state about our sense of justice, Due Process, and fair play?

Now, if the Administration appears before you or any other committee of this Legislature and disavows any and all intention to do such a thing, I would encourage you to ask them to clearly explain what they did intend to achieve with Section 1, so that it will be part of the legislative history of this bill. Then, if it becomes law, the legislative history will be there to establish that the "interpretation" which we fear is not the Legislature's intent, nor the Administration's.

A second confusing thing in SB 2001 relates to the new statute of limitations being proposed for production tax only. Why does the limitations period need be six years instead of three, when the three-year period can be extended and re-extended any number of times as appropriate? If the state auditors are anything like me and everyone I know, their work will expand to fill the time allowed — giving them six years to get their audits done will mean they'll take six years to audit even when they could otherwise be done more quickly. Unfortunately, the longer the audit runs, the greater the amount of interest there will be that accrues on any underpayment claimed in the audit. After three years, interest represents 38¢ for each dollar of additional tax claimed, assuming interest is not above its 11% APR floor rate. But after six years the accrued interest is 92¢ for each dollar of additional tax. By raising the stakes so substantially for each audit claim that is raised, the longer limitations period will make it easier to justify litigating claims.

The purpose of a statute of limitations is to bar claims when they start to become so old that the records, documents, and recollections of witnesses may well be lost or not readily available by the time those claims are finally raised. The present statute of limitations has worked for all the other taxes under Title 43, including the present worldwide corporate income

Sen Stevens -
Proposed lengthened period. How does
DOR: parties extend -

If DOR auditor & CO
making reasonable
progress they review the
and extend the time limit.
This happens very often
w/ BP & fairly common.

Sen. Wielechowski:
The state says they have to
negotiate is this true?

TOM WILLIAMS Jeopardy assessment - would disallow
everything.
audit
In taxpayer's interest to allow extension
in most cases.
Useful power the Dept. has.

What do taxpayers ask for?
The company has records, etc. they need to look for.

CH - ~~If the~~
What is the reason the Dept
wants the extension of statute of limitation
~~What could be~~ (Jerry B. not speaking to this - not approp. person
for DOR)

Interest due when tax is due.

(CH) How many times have the auditors come to them (DOR) to ask for extensions?

tax for oil and gas taxpayers, the domestic or "water's edge" income tax for other corporations, even the former separate-accounting income tax. It is worth noting that separate-accounting involved not only determining net income from all of a taxpayer's interests in oil and gas fields and prospects, but also its income from interests in oil or gas pipelines as well.[15] While PPT and SB 2001 are not simple taxes, separate-accounting was probably even more challenging to administer and audit. If Alaska didn't need a longer statute of limitations for separate-accounting, we don't see why one is needed now.

In conclusion, SB 2001 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. SB 2001 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. SB 2001 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. SB 2001 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 new production—production which will only come from investments yet to be made.

The most important policy question is whether SB 2001 provides a framework for encouraging this additional new investment. AOGA's 17 member companies unanimously agree that PPT does accomplish that goal, and as such, should not be changed at this time.

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:

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

[continued on next page]

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 (c) 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.

[13] The regulation addresses "quality differentials relating to the commingling of oils <u>or of oil and NGLs</u>" (emphasis added) while the proposed statute lacks the emphasized phrase. The PPT legislation last year changed the definitions of "oil" and "gas" so that "oil" includes "NGLs" and consequently emphasized language in the regulation is encompassed now by the phrase "commingling of oils" in the proposed statute.

[14] The regulation lacks the comma that appears here in the proposed statute.

[15] *See* former AS 43.21.020 (production income) and 43.21.030 (pipeline income).

They have a comprehensive review of bill going on! will ~~prepare~~ it when they have it. provide

Tom Williams - came up w/ idea for ELF. 2nd term Hammond Comm DOR.

Challenge - ~~production~~ reduction in production

Sen Wagoner - we heard from Steve Porter, in relation to tax rate. not as worried as tax rate as a double fiscal plan.

M.C. - Mr. Porter is 1/2 right. clearly the businesses concerned that there is no fiscal plan or plan ~~for~~ for spending.

Sen Wilken 6% Decline - Is there a model that shows decline under PPT or the ACES / ELF etc 6% decline moving

M.C. It is impossible to tell - not a direct comparison.

Revenue. how this compares -

6% decline was under the ELF

PPT incre. at the level of production. ; slow the decline

Investment is up - too early to see the barrels

Tuesday

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TESTMONY BY THE

ALASKA OIL AND GAS ASSOCIATION

TO THE SENATE JUDICIARY COMMITTEE

REGARDING SB 2001 & CSSB 2001(RES)

ON THE TOPIC OF "CORROSION"

October 30, 2007

Mr. Chairman and Members of the Committee:

For the record, my name is Thomas K. Williams, and I am Senior Royalty & Tax Counsel for BP Exploration (Alaska) Inc. I am appearing before you today to testify in my role as chair of the AOGA Tax Committee.

My present testimony pertains to the topic of "Corrosion" as scheduled for consideration today.

The Administration's proposed paragraph (19) to be added to AS 43.55.165(e) would, unless a situation is caused by a "super" *force majeure*, disallow any cost incurred for the repair, replacement or deferred maintenance undertaken in response to a failure, problem or event that results in an unscheduled interruption of or reduction in the oil or gas production or is undertaken in response to or is otherwise associated with an unpermitted release of a hazardous substance or gas. Not only is the language of this proposed revision ambiguous and likely to lead to additional audit exceptions and disputes, the entire provision is unnecessary.

The proposed provision states that otherwise ordinary and necessary, and thus deductible, costs would be disallowed if the Department of Revenue determines such costs were in response to a "failure, problem or event" that results in an unscheduled interruption of or reduction in production. What constitutes a "failure, problem or event" and under what standards would any of those be determined? Cost associated with any temporary, unforeseen shutdown or minor interruptions, regardless how minor, could now be disallowed by an auditor even when such an "event" arises despite otherwise prudent and necessary business operations.

Yet the issue of determining what portion of any maintenance costs should be disallowed, if related to improper maintenance or production interruption, was thoroughly debated when the Legislature was considering the PPT and again in recent legislative sessions. Each time amendments such as the one the Administration is now advocating failed because the difficulties with such subjective standards were immediately apparent. The State turned to Dr. Pedro van Meurs, an international gas consultant retained by the State, who recommended a flat 30¢ per barrel exclusion from what would otherwise be a producer's capital portion of its lease expenditures.

As Dr. van Meurs explained,

> it should be noted that in most oil and gas fields, assets will have to be replaced after the technical life of such assets has expired. Therefore, such replacements are reasonable lease expenditures and required to protect the health and safety of the workers and to protect the environment. The US $0.30 per BTU equivalent barrel is based on reasonable capital maintenance costs of fields for which I have (confidential) information.

van Meurs, "Enhancement of the Gross Character of the PPT Bill" (August 5, 2006). Dr. van Meurs further testified that

> maintenance is a reasonable deduction for PPT; but is sometimes hard to decide which expenditures fall into that classification. The simplest solution is to take some base expenditure that really will be replacement and over the next 20-30 years disallow a modest floor of the capital expenditures.

Senate Special Committee on Natural Gas Development, *Minutes* (August 9, 2006).

Dr. van Meurs' recommendation was adopted and become section 43.55.165(e)(18) of the PPT. The flat 30¢ per barrel exclusion sets a floor for maintenance cost and avoids the problems of case-by-case decisions as to whether maintenance (repair or replacement) is required because equipment or facilities have been improperly maintained or resulted in an unscheduled interruption. To adopt the Administration's proposed amendment while leaving the flat 30¢ per barrel exclusion in the law would result in a double disallowance of the same costs.

Dr. van Meurs' flat 30¢ exclusion also avoids all questions and disputes about which categories of costs were incurred due to a triggering event and are nondeductible as a result, and about how much was incurred in each cost category so disallowed.

Finally, the 30¢ per barrel exclusion applies every year, whether there is a triggering event or not. Over time the 30¢ figure may well prove to be a reasonably accurate approximation of the average amount of costs that would be disallowed by auditing and verifying exactly which cost categories are disallowed and how much cost is in each category. A flat rate disallowance greatly furthers the goals of clarity, certainty and efficiency in tax administration, enforcement and compliance. Paragraph (19), in contrast, would undercut each one.

Thank you for giving AOGA this opportunity to testify.

SJUD Oct 30, 07
Tuesday

Alaska Oil and Gas Association

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TESTMONY BY THE

ALASKA OIL AND GAS ASSOCIATION

TO THE SENATE JUDICIARY COMMITTEE

REGARDING SB 2001 & CSSB 2001(RES)

ON THE TOPIC OF "ACTUAL vs. REASONABLE COSTS"

October 30, 2007

Mr. Chairman and Members of the Committee:

For the record, my name is Thomas K. Williams. I am Senior Royalty & Tax Counsel for BP Exploration (Alaska) Inc. and a former tax administrator for the State of Alaska. I appear before you today to testify in my role as chair of the AOGA Tax Committee.

My present testimony pertains to the topic of "Actual vs. reasonable costs" as scheduled for consideration today.

Before I get to AOGA's concerns and questions about this topic, let me say that the issue of "actual vs. reasonable costs" was a very real one facing the Department of Revenue ("DOR") when I was Director of the former Petroleum Revenue Division (now the Tax Division) from 1975 to '79 and Commissioner of Revenue from '79 to '82. Back then this same issue arose in the context of the costs to transport ANS crude oil by marine tankers from Valdez to markets on the West Coast, Hawaii, St. Croix in the U.S. Virgin Islands, and – in the earliest years – the U.S. East and Gulf coasts.[1]

[1] The capacity of refineries on the West Coast and in Hawaii to refine ANS was about 900,000 barrels a day. Prudhoe Bay reached 1.2 million barrels a day in 1978, and once ANS production exceeded West Coast refiners' capacity to refine it, the excess had to be shipped to the more distant locations on the U.S. Gulf and East coasts because ANS could not be exported. At first this oil was delivered into a stationary VLCC (very large crude carrier) anchored at sea off the Pacific coast of Panama, and then the oil was pumped out the other side of that VLCC into ships small enough to go through the Panama Canal to the Gulf and East coasts. Later Panama built a trans-isthmus pipeline allowing large tankers from Valdez to unload directly into the pipeline, which could then carry the oil to the Atlantic coast of Panama where it was loaded directly into large tankers there. This eliminated the stationary VLCC and avoided the risk of accidents while loading and unloading oil into and from that VLCC in the open sea, and it reduced transportation costs because it allowed larger ships to be used on the Atlantic leg of the trip. Panama, of course, could calculate the savings in Atlantic ship costs with fair accuracy and set its pipeline tariff accordingly.

As for shipments to St. Croix, the Hess refinery there was exempt from the Jones Act requirement to use American-built, American-manned ships to transport oil there from another U.S. port. The cost differences between Jones Act ships and non-Jones Act ones was often large enough to allow a large foreign-flag VLCC to sail all the way around

The respective marine transportation costs had to be "netted out" or subtracted from the market value of the ANS delivered at each Outside market destination in order to determine the corresponding "netback" value of that oil at Valdez, and from the Valdez netback the pipeline transportation costs were further "netted out" to get the corresponding "netback" in the field, which was formally called the "gross value at the point of production" in the production tax statutes starting in mid-1977.

From a tax administrator's perspective, the advantage of using "reasonable" costs instead of "actual" costs is that you don't have to audit "reasonable" costs. You just find a publication or other recognized authority that tells you what the "reasonable" costs are in the current market conditions, and bingo! you're done. In fact, for international marine transportation there actually was such a publication or authority, the Average Freight Rate Assessment ("AFRA") published (by subscription) by the London Tanker Brokers' Panel. Those AFRA rates were particularly helpful for us in DOR to find the delivered cost to acquire a comparable foreign crude at a market destination where ANS was also going and competing against that foreign supply.

But AFRA didn't give us the "reasonable" cost or market value[2] of water-borne transportation in Jones Act ships. When we first heard about a new "USFRA" (for "United States freight rate assessment") in 1978, we were very inclined to consider using it to determine the "reasonable" costs for Jones Act tanker transportation from Valdez to the other U.S. ports where ANS was being shipped — very inclined, that is, until we discovered that the tanker fleet for ANS would dominate the rates quoted in this USFRA.

This illustrates one of the problems with using "reasonable" costs — finding an authoritative source you can trust and rely on. Oftentimes there simply isn't one, and sometimes a reliable source that you have found either goes out of business or becomes unreliable or inaccurate.

If you don't have a reliable, accurate and up-to-date source that allows you simply to look up the "reasonable" costs, the only other way to implement the "reasonable" cost approach is to examine and audit the costs for everyone involved in the activity in question. In a sense this is the worst of all possible worlds from a tax administrator's perspective, because you have to do all the auditing and other work that you would have to do in an "actual" cost system, and once you have that done you have the further challenges of proving to everyone that your "actual" cost figures are indeed accurate and representative of current market conditions. Given the constraints of tax confidentiality, how could you use cost information from other taxpayers to show any particular taxpayer how you came up with your "reasonable" cost figure?[3] Moreover, how could your "reasonable" cost figures be anything but badly out of date, given that the taxpayers'

South America to the Virgin Islands for less cost per barrel than shipping ANS there via Panama.

[2] AS 43.55.150(b) equates "reasonable" costs of transportation with the fair market value of that transportation: "If the department finds that the conditions in (a)(1), (2), and (3) of this section are present, the department shall determine the reasonable costs of transportation, using the fair market value of like transportation, the fair market value of equally efficient and available alternative modes of transportation, or other reasonable methods. ..."

[3] AS 43.55.040(1), as amended by § 21 ch 2 TSSLA 2006, finally creates a reasonable and workable solution to the problem of using tax information from one taxpayer in a proceeding against another taxpayer.

information from which your figures are derived would have to be audited first to ensure their reliability? What you would have is a tax that no taxpayer could comply with correctly when its tax comes due. It would be a tax that either requires almost numerous filings and refilings of amended returns by taxpayers as your "reasonable" cost data are published or updated on the basis of new audit results, or it would be a tax whose correct amount cannot be determined at all until all taxpayers are audited. The challenges for DOR in setting up and maintaining accurate records of each taxpayer's payments, corrections and final cost figures would be enormous. But relying on audits as the only way to determine the correct amount of "reasonable" costs would amount to "taxation by audit" instead of self-reporting and self-assessment, and it would be a particularly difficult and inefficient way to administer a tax that supposedly is self-reported and –assessed.

Rather than taking any of these unappealing alternatives, we opted in 1979 and 1980 to use "actual" transportation costs as much as we could[4] and save ourselves these troubles.[5]

From a taxpayer's point of view — and now I am putting my hat back on as chair of the AOGA Tax Committee — the "reasonable" cost approach suffers from three major problems. First, taxpayers only know about their own business and their own "actual" costs. Anything different from a taxpayer's own factual costs cannot be right, because the factual costs are what they are, and the facts cannot be different from what they are. It is a rare tax indeed that does not look at the actual performance or results of a taxpayer's business or business-related activities, and as long as a tax is taking such latter items into account, it is fundamentally unsound to ignore "actual" costs or similar "actual" results and to base the tax instead on some different cost or result, no matter how "reasonable" its derivation may be.

Second, unless there is some reliable, authoritative source about "reasonable" costs under the current conditions that is available to taxpayers before their tax returns and payments come due, it will be impossible for taxpayers to compute, report and pay the correct amount of tax on that due date. In the case of operating and capital costs to explore for, develop or produce oil or gas on the North Slope, there is no such reliable, authoritative source available at all, much less one that can be available on a timely basis.

Third, if DOR would be determining the amount of "reasonable" costs to explore for, develop or produce oil and gas on the North Slope on the basis of taxpayers' verified and audited "actual" costs for these activities, it would still be impossible for taxpayers to report and pay the correct amount of tax when it comes due. In addition, the problems of filing and refiling amended tax returns, or of having "taxation by audit," will be about as difficult and onerous for tax-

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[4] *See* 15 AAC 55.180; *cf.* AS 43.55.150(a) and (b).

[5] A further reason for going with a taxpayer's "actual" costs of transportation is that DOR's first netback-calculation regulations were adopted in 1979, and that was in the context of the former separate-accounting income tax, not the production tax. The first netback-calculation regulations for the production tax were adopted in 1980. If you are calculating a taxpayer's income, as you would be with an income tax (even separate-accounting), you really cannot use some artificial computation of the "reasonable" costs of the taxpayer's transportation if it has "actual" costs that you can audit and verify.

payers as they would be for tax administrators.

It is also worth remembering that, to the extent the "actual" lease expenditures can be based on joint-interest billings by the operator to the other participants in the operations, the total "actual" costs under those billings will be the same for each participant, with the only difference being the size of each one's share of that total. Even if DOR were not to rely on the audits by non-operating participants of the billings to ensure the accuracy and appropriateness of the amounts so billed, it would only have to do one audit of each set of billings by the operator,[6] instead of having to do completely independent audits for each participant's "actual" costs. So using "actual" costs could prove to be significantly less burdensome for DOR to administer, audit and enforce than one might first expect.

Thank you for giving AOGA this opportunity to testify.

6 On a related but different issue, see AOGA's "white paper" on the prudent use of joint-interest billings and the risk that DOR's present discretionary authority to allow or require the use of such billings may be lost if AS 43.-55.165(c) and (d) are repealed.

SJUD Tues Oct 30, '07
Thom Williams
CREDIT Buy Back Fund

Alaska Oil and Gas Association

AOGA

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TESTMONY BY THE

ALASKA OIL AND GAS ASSOCIATION

TO THE SENATE JUDICIARY COMMITTEE

REGARDING SB 2001 & CSSB 2001(RES)

ON THE TOPIC OF "CREDIT BUY-BACK FUND &

APPROPRIATION AUTHORITY"

October 30, 2007

Mr. Chairman and Members of the Committee:

For the record, my name is Thomas K. Williams. I am Senior Royalty & Tax Counsel for BP Exploration (Alaska) Inc. and a former tax administrator for the State of Alaska. I appear before you today to testify in my role as chair of the AOGA Tax Committee.

My present testimony pertains to the topic of "Credit buy-back fund & appropriation authority" as scheduled for consideration today.

As introduced, Section 45 of SB 2001 would enact a new statute, AS 43.55.028, establishing an "Oil and Gas Tax Credit Fund" to purchase tax credits from explorers and others trying to sell their tax credits issued under AS 43.55.023 or AS 43.55.025 and not being offered full face value for them, and authorizing DOR to use this fund to purchase such tax credits. At the same time, Section 63 of SB 2001 as introduced would repeal AS 43.55.023(f), which allows the Department of Revenue ("DOR") to acquire tax-credit certificates by making a cash refund to a person tendering such a certificate. This repeal would include paragraph (f)(4), limiting to $25 million a year the amount of such refunds that DOR may make to acquire tax-credit certificates. The repeal of this cap would be effective January 1, 2008 under Section 72 of the original Bill, as would the creation of the Fund.

The Fund would consist of money appropriated to it, plus "earnings on the fund." AS 43.55.028(b). The recommended annual appropriation to the Fund under § 028(c) would be 10% of the taxes collected by the state under AS 43.55.011 during a fiscal year if DOR's forecast for the average ANS West Coast spot price for that fiscal year is $60 a barrel or higher, and otherwise 15 percent of those taxes. But the actual appropriation, if any, for any given fiscal year would only be whatever the Legislature authorizes and the governor allows after making any reduction to the appropriation through the line-item veto power.

AOGA supports the concepts of the State buying back tax-credit certificates and of creating the Fund to do so. However, for this system to work, it will be essential that future Legislatures actually appropriate the necessary money into the Fund each year. Otherwise the Fund will turn into an empty promise for future investors.

Inasmuch as the topic currently under consideration includes "appropriation authority" for credit buy-backs, AOGA would draw the Committee's attention to a few potential issues relating to this portion of the topic:

1. Might the automatic inclusion of "earnings on the fund" as part of the Fund, without specific appropriations of those earnings back into the Fund each year, violate Alaska's constitutional prohibition against dedicated revenues?[1] If so, what might the legal effect be of AS 43.55.028(h), stating that "[n]othing in this section [*i.e.*, AS 43.55.028] creates a dedicated fund"?
2. Might the anti-lapse provision in AS 43.55.028(f) — which states that "[m]oney in the fund at the end of a fiscal year [including money appropriated to it] does not lapse and remains available for expenditure in successive fiscal years[,]"— belong more properly in a bill making an appropriation to the Fund, or a bill specifically reappropriating the remaining money back into the Fund, rather than the legislation establishing the Fund in the first place? If so, would AS 43.55.028(f) violate the Alaska Constitution's "one subject" rule for legislation?[2]

Although representatives of some members of the AOGA Tax Committee may be attorneys, the Tax Committee is not authorized or qualified to offer your Committee any legal advice or opinion about what the answers to these questions might or might not be. The most we feel we can properly do under the circumstances is to point these potential issues out to you, so you can get whatever professional legal advice may be necessary or appropriate to answer these questions and to revise, if necessary or prudent, these provisions of the Bill accordingly.

As I close, Mr. Chairman, I should mention that AOGA has prepared a "white paper" on aspects of tax credits under the proposed Bill that fall outside the specific scope of the present topic. In fact, that white paper covers the following topics; 50% limitation on credit taken in first year for capital investments, "TIE" credits, electric rate-payer benefits from selling tax credits, and conditioning exploration tax-credits on new requirements to share information. We believe that Committee Members might find some or all of those points to be of interest. With your permission, I could either pass copies of this "white paper" out to Members of the Committee now, or copies could be distributed to them at the next recess or at the end of today's hearing.

Thank you for giving AOGA this opportunity to testify.

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[1] Art. IX, § 7, Alaska Constitution states: "The proceeds of any state tax or license shall not be dedicated to any special purpose, except as provided in section 15 of this article [creating the Permanent Fund] or when required by the federal government for state participation in federal programs. This provision shall not prohibit the continuance of any dedication for special purposes existing upon the date of ratification of this section by the people of Alaska."

[2] Art. II, § 13, Alaska Constitution states in pertinent part: "Every bill shall be confined to one subject unless it is an appropriation bill or one codifying, revising, or rearranging existing laws. Bills for appropriations shall be confined to appropriations."

Submitted to Record @ SJUD Tuesday Oct 30, 2007

Alaska Oil and Gas Association

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WHITE PAPER

TAX CREDITS UNDER THE PETROLEUM PRODUCTION TAX

October 30, 2007

This paper addresses several questions about the proposed treatment of tax credits under SB 2001 and HB 2001 as introduced by the Administration, and about the underlying tax policies for that treatment. These are cutting in half the credit from capital expenditures that may be taken for the tax year when those expenditures are incurred, repealing the TIE credits after the end of 2007, preventing electric utility rate-payers in Anchorage from receiving benefits from the utility's sale of tax credits, and significant new information-reporting requirements in order to qualify for exploration credits.

A. 50% Limitation on Credit Taken in First Year for Capital Investments.[1]

As introduced, SB 2001 and HB 2001 would create a limit on the amount of tax credit under AS 43.55.023(a) for capital expenditures that a producer may apply against its tax liability for the year when the capital expenditures giving rise to that credit are incurred. Only half of the credit may be taken against the tax that first year, and the remainder carries forward to the next year or subsequent ones until it is used.

We cannot find a sound tax-policy reason for this limitation. The purpose of these credits is to provide an economic incentive for making new capital investments that will result in new production to slow the production decline on the North Slope. Because of the time-value of money for a producer or explorer, dividing this credit into two halves and deferring one of them to the second year would reduce the value of this incentive under the economic analysis for each new investment. This means the State would still end up allowing the same total amount of credit for a capital investment, but it stands to lose production to the extent this deferral impairs the value of the incentive from the credit and makes potential investments less attractive economically.

The only significant thing the State stands to gain from such a deferral is the one-time-only effect on its tax revenue for the 2008 tax year, which will see credits halved for capital expenditures during that year with no capital credits coming forward from 2007. But even this benefit, which is almost entirely of use for purposes of state spending, is diminished by the fact that the effects from the 2008 tax year show up on the State's books in two different fiscal years

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[1] This limitation does not appear in CSSB 2001(RES).

— namely, FY 2008 and 2009.[2]

Beginning in tax year 2009 and thereafter, the half-credit carried forward from the prior year plus the half-credit for the current year will add up to approximately a full-year credit being taken against the tax each year on that year's production, especially when a taxpayer's capital spending is not changing materially from one year to the next. This means that, after the one-time-only effects on state funds available for spending during FY08 and 09 ripple through, the only benefit the State will be getting from the credit deferral will be its own time-value of money.

It is unnecessary to digress here into the matter of what the State's time-value of money might be. The point is that the very system of incentives for investment under the production tax arises principally from the deduction of capital expenditures as they are incurred and from the tax credits — including the credits under § 023(a) for capital expenditures. For the State these incentives make sense solely because it is a "play" between the companies' time-value of money and the State's own, materially lower time-value of money. In other words, a dollar next year is more valuable to the State than the companies, and so by letting the companies have that dollar now and getting it back next year, the State makes the investment more valuable for them as well as for itself.

The limitation on the capital-investment credit so it is spread out over a minimum of two years is completely at odds with the mechanism by which the credit succeeds as an incentive for investment.

<u>B. "TIE" Credits.</u>

The "transitional investment expenditure" or "TIE" credits are a tax credit for capital expenditures incurred for production and exploration operations during the five years immediately preceding the April 1, 2006 effective date of the PPT.

Initially, they were proposed by the prior Administration as a way to soften the blow of the tax increase under PPT from the prior ELF-based tax for producers and explorers who had invested in good faith in this state in the expectation that the ELF-based tax, would continue to apply and allow their economic expectations for those investments to be fulfilled. Alaska itself has, as an expression of goodwill toward investors and those doing business here, provided similar transitional measures to soften the economic effects of a major transition from one kind

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2 The first installment payment to the State in FY 2008 is made in July 2007 for June production, the next is in August for July 2007 production, and so on. The State thus receives tax revenues in FY 2008 from oil and gas produced during the last seven months of calendar year 2007 plus the true-up on March 31, 2008. The only tax payments for tax year 2008 that will be received by the State in FY 2008 are the five installments for production in January – May 2008. The tax effect for the rest of calendar year 2008 from deferring half the 2008 capital-expenditure credit will show up in FY 2009 as the estimated payments and the March 31, 2009 true-up for calendar year 2008.

of tax to another.[3]

As Representative Ralph Samuels has stated during a hearing of the House Special Committee on Oil & Gas during this special session, the TIE credits were transformed by the House Resources Committee during the 2006 regular session into an incentive to invest sooner rather than later. This was done by modifying the TIE credit so that it takes $2 of current capital expenditure in order to get the TIE credit for $1 of pre-PPT capital expenditure. In conjunction with the expiration of TIE credits altogether after 2013,[4] the TIE credits provide an effective incentive to increase investment and to accelerate investments into the near term that might otherwise be made in the mid-to-long term.

The underlying premise of the TIE credits is that the royalty, property tax, state income tax and production tax revenues from the additional production expected to result from the increased level of investment will offset the cost to the state of the TIE credits. In the absence of any contrary indication, it seems premature to abolish the TIE credits after the end of this year.

C. Electric rate-payer benefits from selling tax credits.

SB 2001 and HB 2001 have two mysterious-seeming provisions that forbid "an entity that is exempt from taxation" from applying for a sellable tax-credit certificate under AS 43.55.-023 and from selling exploration tax-credit certificates under AS 43.55.025.[5] In testimony on these Bills, DOR representatives have been unwilling, on taxpayer-confidentiality grounds,[6] to identify who that tax-exempt entity or entities are that these provisions address.

Although we do not know which tax-exempt entity or entities DOR is concerned about, it is a matter of public record that the Municipality of Anchorage in 1996, through its operating division called Municipal Light & Power ("ML&P"), purchased Shell Oil's one-third working interest in the Beluga River gas field northwest across the Inlet from Anchorage. As a result of its working interest, ML&P should be incurring its share of the lease expenditures for the Beluga River Unit that the other working-interest owners there, both taxable, are incurring. This means ML&P should have tax credits from the capital portion of those expenditures, and since it has no

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[3] For instance, former AS 43.58 (temporary reserves tax), which allowed a dollar-for-dollar credit against the reserves tax for a given year for production taxes paid during the prior calendar year. Similarly the net reserves tax paid for a field gave rise to a dollar-for-dollar credit against future production taxes on production from that field. *See also* 15 AAC 21.650 and 21.660 for transitions from "ordinary" income tax to separate-accounting and back, respectively.

[4] For explorers and producers who did not have production in Alaska before April 1, 2006, the TIE credit expires at the end of the sixth calendar year after the year when they first apply a TIE credit against the tax under AS 43.55.-011(e) on their new production. *See* AS 43.55.023(i)(3)(A)(ii),

[5] *See* SB/HB 2001, Sec. 31 (enacting AS 43.55.023(*l*) to forbid a tax-exempt entity from applying for a tax-credit certificate) and Sec. 40 (enacting AS 43.55.025(g) to forbid a tax-exempt entity form transferring, conveying or selling a tax-credit certificate under § 025).

[6] If the entities DOR is concerned about are actually "exempt from taxation", it seems incongruous to assert that they are "taxpayers" protected by the tax-confidentiality statute.

tax liability to apply those credits, it would be eligible under current law to apply for a transferrable tax-credit certificate. In addition, if the Unit's working-interest owners undertake an exploratory program to extend the field or discover new gas reservoirs in the general vicinity, then ML&P could be eligible for tax credits under the exploration-credit program in AS 43.55.025.

ML&P would be forbidden from getting either kind of sellable tax-credit certificates under the Bills as introduced.

If ML&P could obtain and sell tax-credit certificates under AS 43.55, it would seem that the Regulatory Commission of Alaska would require ML&P to pass its resulting savings from selling such certificates on to its rate-payers.

AOGA takes no position about whether ML&P's rate-payers should get those benefits, or whether the State should get the tax revenue that it would lose if ML&P's tax-credit certificates are sold to a producer who applies them against its production taxes. However, this appeared to us to be a question that the Legislature might wish to answer for itself.

D. Conditioning exploration tax-credits on new requirements to share information.

Under SB 2001 and HB 2001 as introduced, an explorer would have to agree in writing to release proprietary well and seismic information and wellbore samples to the State, even for federal and private lands, in order to qualify for an exploration tax credit. AOGA is not aware of any other state where explorers are required to furnish such proprietary information.

Shooting seismic, taking wellbore cores, and analyzing such data are very costly. Yet undertaking such costs and risks is important to an explorer and can provide it with a competitive advantage in considering the resource potential of a particular area. Requiring an explorer to release such proprietary information to the State diminishes the value of these high-cost investments to the explorer and weakens their value to the potential operator of any area to be developed.

To the extent this proprietary and confidential information must be given directly to the Department of Natural Resources ("DNR"), we believe it would set an extraordinary precedent for a state to use its sovereign taxation powers in order to advance its interests as a mere property-owner.

The confidentiality provisions are also of serious concern. The proposal provides confidentiality protection for only ten years for most of the seismic data required to be produced, and for only two years on the rest. Seismic data typically has a shelf life in exploration areas (especially frontier areas) much longer than ten years. More troubling is that an operator is required, under the proposal, to provide a copy of check shot surveys or vertical seismic profiles. These surveys are expensive and are keys to seismic interpretations. This information generally has an indefinite shelf life and can be used to tie seismic of any vintage, new or old, to wells. Yet under the administration's proposal, such information would be classified as "well data" and afforded only a two-year period of confidentiality. At the very minimum all of the data required to be provided should be kept confidential for at least 10 – 20 years.

The Administration's proposal would also require an explorer to provide one-third of the wellbore core to the state. This requirement would not only be onerous and costly, but would be physically challenging and potentially damaging to the integrity of the entire core. Conventional cores are typically slabbed in half - one half for sampling/destructive analysis, the other half as a reference for geological core interpretation. Half core slabs are larger and more stable in storage and handling than 1/3 cores. Half core pieces also provide better core plugs. To require an explorer or operator to change its normal procedures to immediately provide one-third of the fresh core samples would be expensive and would limit the use of core material by the operator to evaluate and optimize development, which in turn would be both harmful to the producer and the State.

The Administration's proposed changes would be precedent-setting and create difficulties for explorers.

AOGA submits Alaska should reduce burdens on explorers, not increase them.

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TESTMONY BY THE

ALASKA OIL AND GAS ASSOCIATION

TO THE SENATE JUDICIARY COMMITTEE

REGARDING SB 2001 & CSSB 2001(RES)

ON THE TOPIC OF "GROSS vs. NET"

October 31, 2007

Mr. Chairman and Members of the Committee:

For the record, my name is Thomas K. Williams. I am Senior Royalty & Tax Counsel for BP Exploration (Alaska) Inc. and a former tax administrator in the Alaska Department of Revenue ("DOR"). I am appearing before you today to testify in my role as chair of the AOGA Tax Committee.

My present testimony pertains to the topic of "Gross vs. Net" as scheduled for consideration today.

Just to make sure AOGA understands the topic correctly, we take "gross" as referring to a production tax that is levied on the "gross value at the point of production" as defined in AS 43.55.900(12). The prior ELF-based tax was such a "gross" tax. We further understand "net" to refer to a production tax levied on the value that remains after subtracting the operating and capital costs for the oil and gas operation from the "gross value at the point of production." The present PPT is an example of a "net" tax, with "lease expenditures" as defined in AS 43.55.165 being the costs that are deducted from the "gross value" to get the taxable "production tax value." If you will, the "production tax value" under PPT is equivalent to a value at the rockface where the oil or gas flows into a well and is physically severed from the reservoir.

The fundamental question in the "Gross vs. Net" issue is not about which tax could generate more tax revenue for the State — if one tax will generate $*X* of tax revenues, it is always possible to find the rate for the other tax that also generates $*X* of tax revenues. Instead, the fundamental issue about a "gross" tax versus a "net" one should be how realistic you want your production tax to be in terms of its effects on the real world.

The universal reality about oil and gas is they are non-renewable. In other words, as we produce them, there is no new oil or gas being created to replace what we're taking out of the ground. As a consequence of this, the more oil and gas that we remove from a reservoir and produce, the more difficult and the more expensive it becomes to produce the next barrel of oil or cubic foot of gas from what remains in that reservoir.

There is a further and related reality for the huge resources of viscous and heavy oil that are known to exist on the North Slope. Because of the physical characteristics of the oil itself and of the reservoirs wherein it is found, the oil is physically very difficult to produce, starting with the very first barrel. Viscous oil — by which we mean oil that flows much more slowly than conventional oil, but can still be pushed through the reservoir rock into the wells by injecting water to push it — is primarily found in the West Sak formation. The West Sak rock is crumbly, and a lot of fine particles of rock are entrained with the oil as it flows into the well bores, turning them into an oily sludge. This sludge has to be removed from the oil at the surface, and then it has to be disposed of. Remember that once the oily sludge is removed from the oil, it becomes "hazardous" material for purpose of health, safety and environmental laws, so it must be handled and disposed of with the greatest care. Heavy oil — that is, oil that is too thick to be pushed through the reservoir rock by water injection — is found in the Ugnu formation, which is not far below the deep permafrost. One promising technology for producing Ugnu oil would involve getting the reservoir rock to flow like a stream of sand into the well, carrying the oil with it, and then separating the oil from that sand-like rock at the surface. The same health, safety and environmental concerns for "hazardous" material would apply to the handling and disposal of the "sand" — which translates into high production costs even as production starts.

Suppose the State rejects the validity of these facts, or doesn't want to take them into consideration in designing its production tax. In that event, the State might levy a flat-rate tax of *X* cents per barrel or per thousand cubic feet. This would be the ultimate in simplicity to administer, with nothing to audit,[1] and taxpayers should be able to report and pay the tax with 100% accuracy when the tax returns and payments come due. Such a tax would also be much easier to forecast since it would depend on only one variable — namely, the volume being produced.

But we are not considering such a tax,[2] but ones imposed on the "gross" or "net" value. Below is a graph illustrating the production economics for a hypothetical field with a tax on "gross value" over the life of a "conventional" oil field. The five multi-colored vertical bars on this graph depict the economics of the field in five stages in its life. Each full bar represents the "gross value" of the oil being produced. The top (green) segment in each bar represents the State's one-eighth royalty on that oil production. The next segment down (red) represents a flat 15% "net" tax. The bottom segments (blue) in bars 1 – 4 and the second-to-bottom one in bar 5 represent the operating costs of the field. The black segment in each bar represents what's left for the producer — the net" operating margin.

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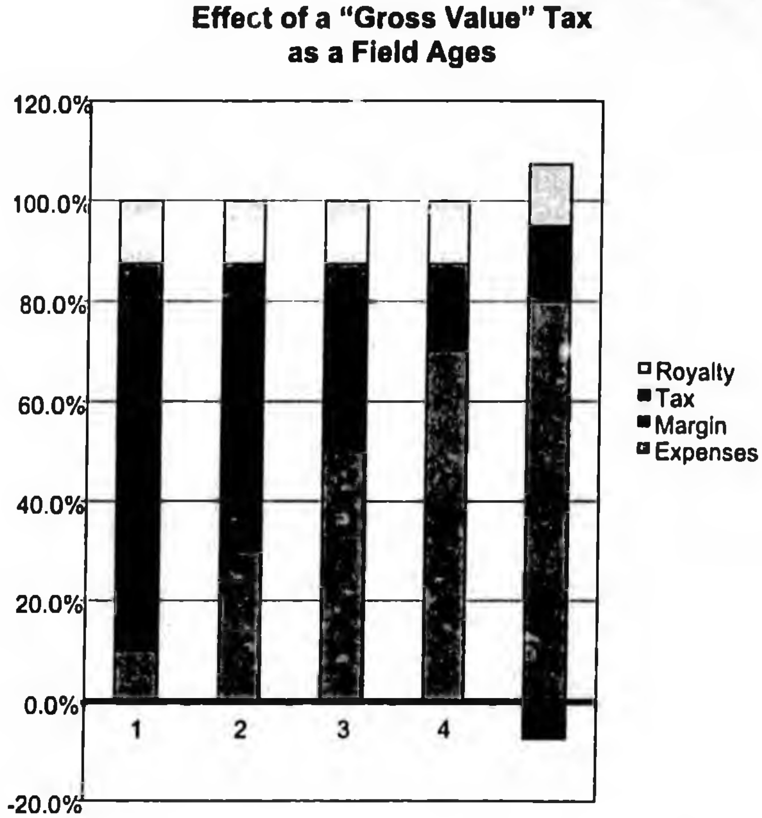
[1] The State would want to confirm that the meters to measure the volume of oil or gas being produced are accurate. The AOGCC already does this by witnessing proving-tests of the meters' accuracy. If DOR wanted to, it could send one of its own employees to witness these tests too, but this would not be an "audit" in any conventional sense of that term.

[2] The economic effects of a flat *X* cents-a-barrel tax would resemble those about to be shown for a "gross" tax.



This graph illustrates the increase in the production costs per barrel th t occurs as a field ages and its original reserves in place are increasingly depleted. Barring a catastrophic event that prematurely forces it to shut down permanently,[3] a field continues to produce until it starts losing money. The latter situation is illustrated in the graph by bar 5, where the producer's margin is depicted below the zero-percent line as a negative number.

Given the enormous challenge that Alaska faces from the decline in North Slope oil production, what is of greater concern is the effects on investment as a field's operating margin is increasingly squeezed by rising production costs per barrel. While the operating margin for the rest of the field is usually not a significant factor in the economic analysis of a new investment, the graph above can also be viewed as an illustration of the general deterioration in the quality of new investments available as a field ages. For example, drilling a hundred or so in-fill wells last year added about 70,000 barrels a day to North Slope production from what it otherwise would have been. But drilling a hundred such wells next year might only add 60,000 barrels a day, and the year after that only 50,000. As the margins for incremental investments become squeezed as the quality of available investments in a field gradually deteriorates, fewer and fewer investment opportunities will remain that are economically viable.

Thus, if all the North Slope investment opportunities in your portfolio resemble bar 1 in

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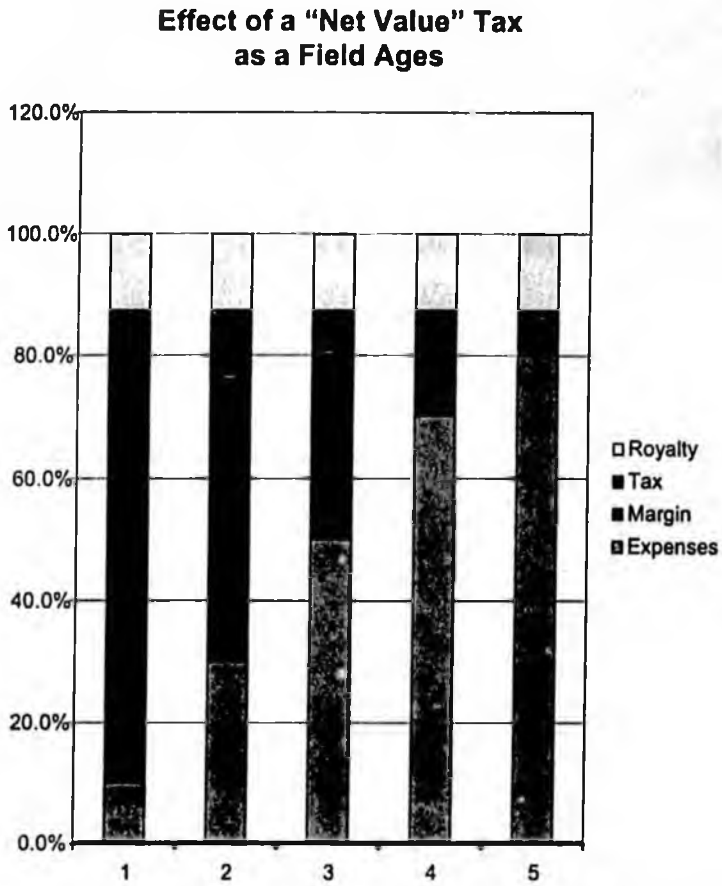
[3] This has happened in Alaska. The first commercially producing oil field here, the Katalla field near the town of the same name, shut down permanently after a fire burned down its nearby refinery on Christmas Eve of 1933.

the graph, you will probably go forward with practically all the investments that you can. Bar 1 illustrates a situation not unlike Prudhoe Bay's when it first came into production and ramped up to 1.5 million barrels a day. As the opportunities available to you look increasingly like bar 2, you would still take most of them, but probably not all. However, as your opportunity portfolio gradually starts to resemble bar 3, you would clearly start having fewer and fewer commercially viable opportunities. And if your opportunities generally look like bar 4, perhaps none of them will be made. Certainly you won't be investing if they all look like bar 5.

Contrast this situation under a "gross" tax with what happens under a tax on "net value" tax like PPT. Here is a graph showing the same hypothetical field as before, at the same five



stages of rising production costs during its life. The "net" tax, by design, starts out in bar 1 being equal to what the "gross tax" was in bar 1 of the earlier example. But, as the field ages and you move from left to right across this graph, each bar has a smaller tax segment (red) than the bar before. Even at bar 5 representing a very late stage in the field's life, there is still a positive operating margin, whereas the margin was a loss in bar 5 with the "gross" tax. This means that even at the bar-5 stage of its life, this hypothetical field is still operating economically. This shows that, if all other things are equal, a "net" tax allows production to continue longer than it would under a "gross" tax.

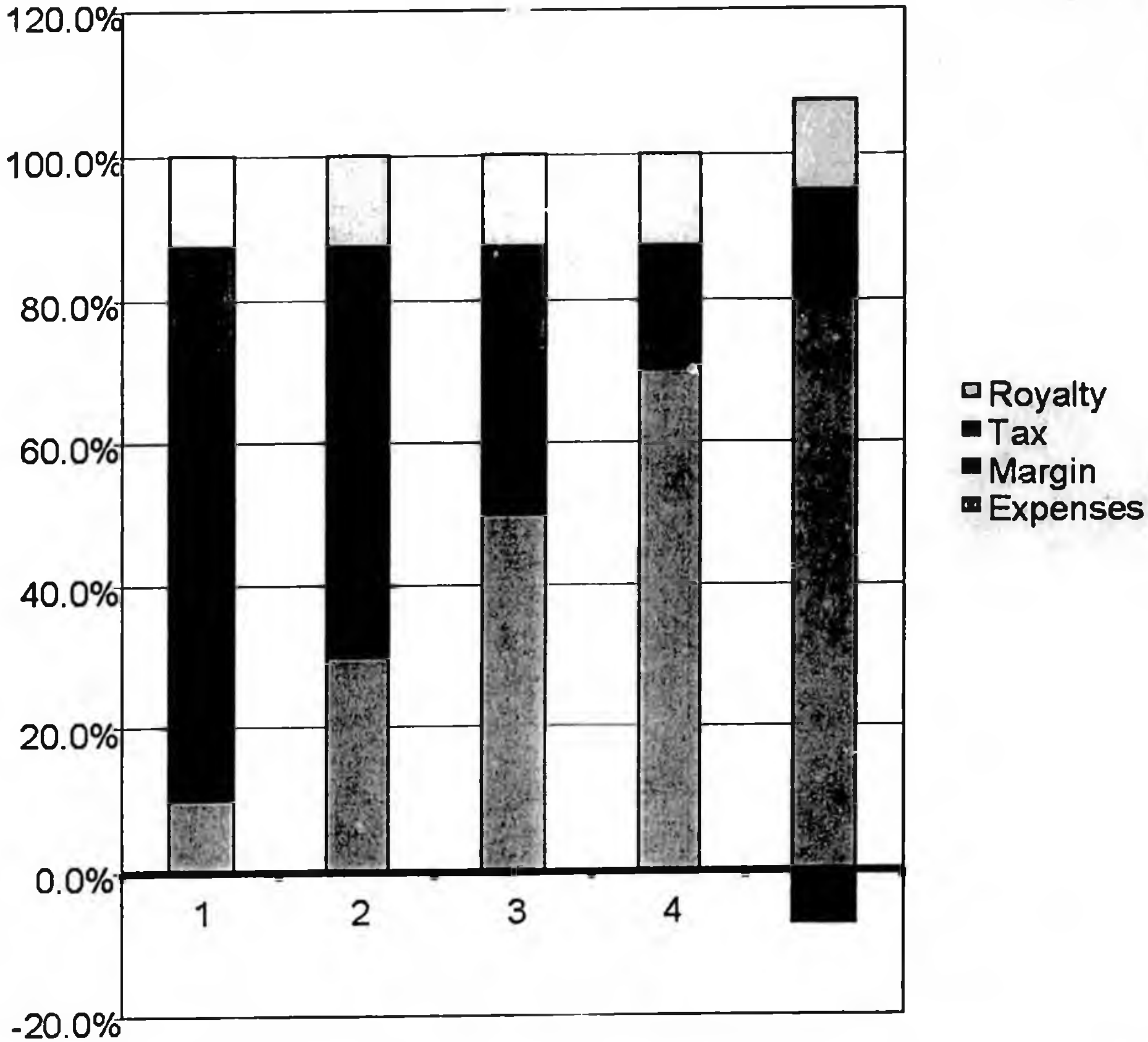
Further, if — as we did with the earlier graph — you view this one as illustrating the gradual deterioration of the portfolio of investment opportunities over a field's life, you can see that, once again, if your investment opportunities resemble bar 1, you will probably try to make as many investments as you can. But in each succeeding column to the right, the portfolio is better than it was for the same bar in the earlier graph because of the greater margins that you anticipate to get from your investments. And if you have a better portfolio of opportunities, you are likely to make more investments at each stage of the field's life than you would have made at the comparable stage under the "gross" tax.

The decline of North Slope is the greatest challenge facing our future and our children's future as Alaskans. The only way to slow the decline and soften its impacts on the future is to make investments to produce more oil. As we have just shown, a "net" tax will result in more investments to produce oil than a "gross" tax will. That is the reality Alaska faces.

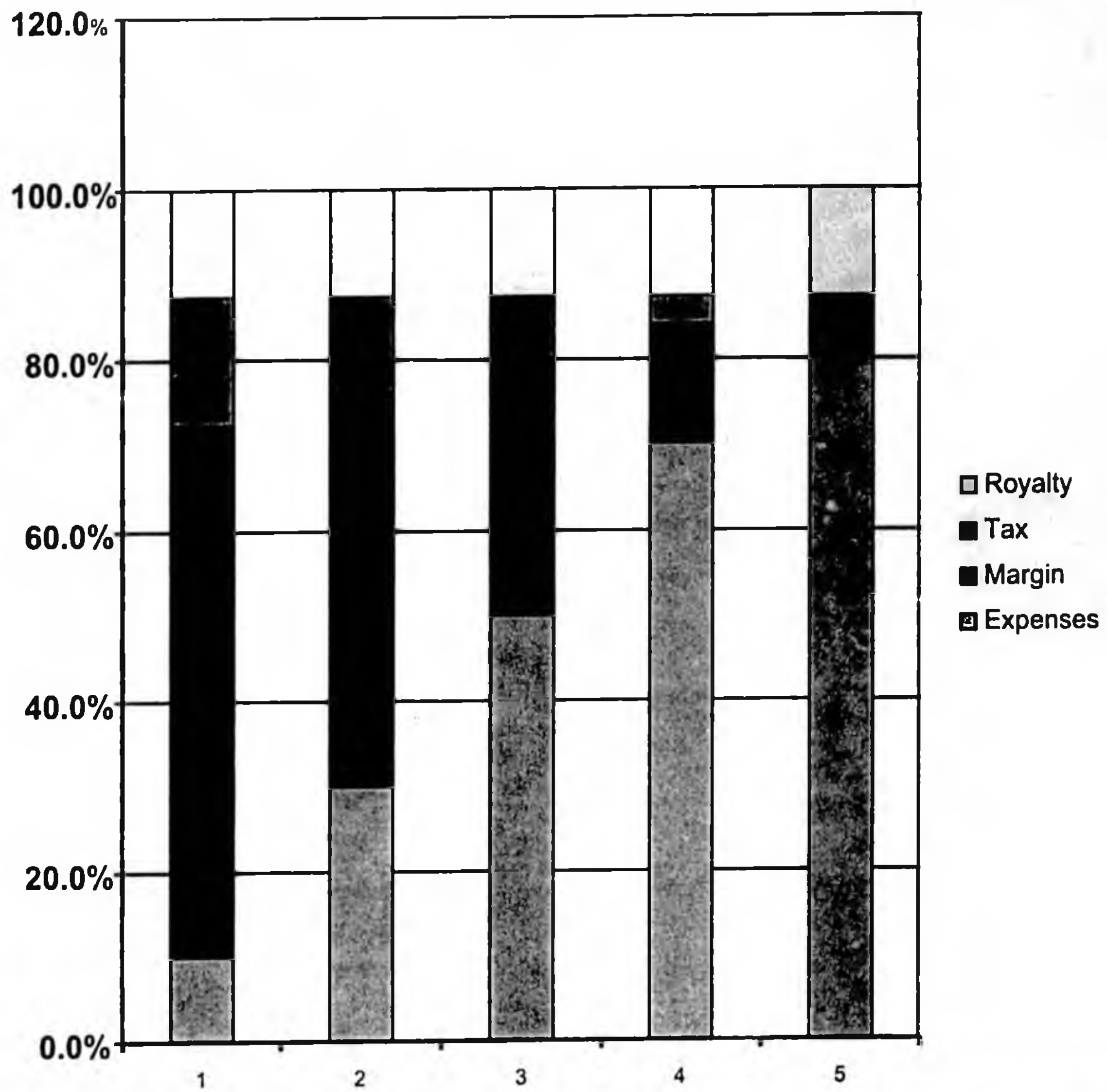
This is not the first Legislature to grapple with this reality, and you won't be the last. As an industry, all we can do in this process is to explain what this reality is and what the real-world effects promise to be from the taxes and policies Alaska may choose to adopt. That choice is yours. Whatever it is, we will comply with it, we will continue to do business here, and we will continue to strive to unlock the great potential that Alaska still has before it. But we know that one choice will allow our industry to do more than the other will. We hope it is the one to be chosen.

Thank you for giving AOGA this opportunity to testify.

Effect of a "Gross Value" Tax as a Field Ages



Effect of a "Net Value" Tax as a Field Ages



SB

2001

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BP Presentation on SB 2001
Senate Resource Committee

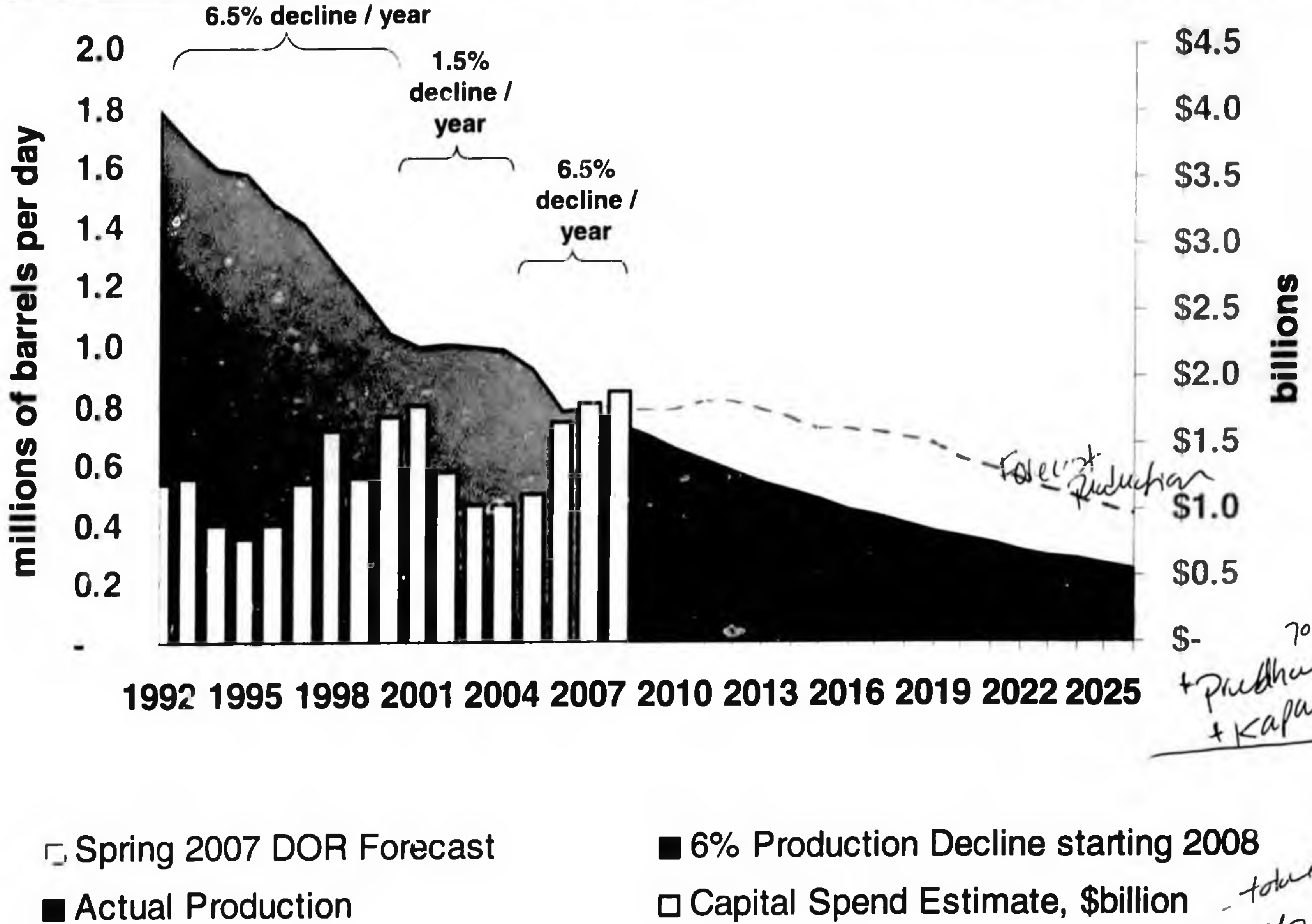
Claire Fitzpatrick and Mike Utsler
October 24, 2007

Key Messages

bp

- **Production**, not tax rate, is the major factor in determining state revenue for the future years
- Delivering the State's production forecast will require tens of billions of **investment**
- **Investment decisions** are made on the **combination** of strategy, resource prospects, technology, economics including **fiscal policy**, and risk.
- The proposed bill significantly **deteriorates economics on 70%** of investment options in the next 20 years
- Higher prices and developing technology could give the Alaska fields a new lease on life, but huge **investments are needed**

The State's production and revenue forecast counts on higher than historical investment



70% of oil will come from known resource ** + Prudhoe & + Kaparuk

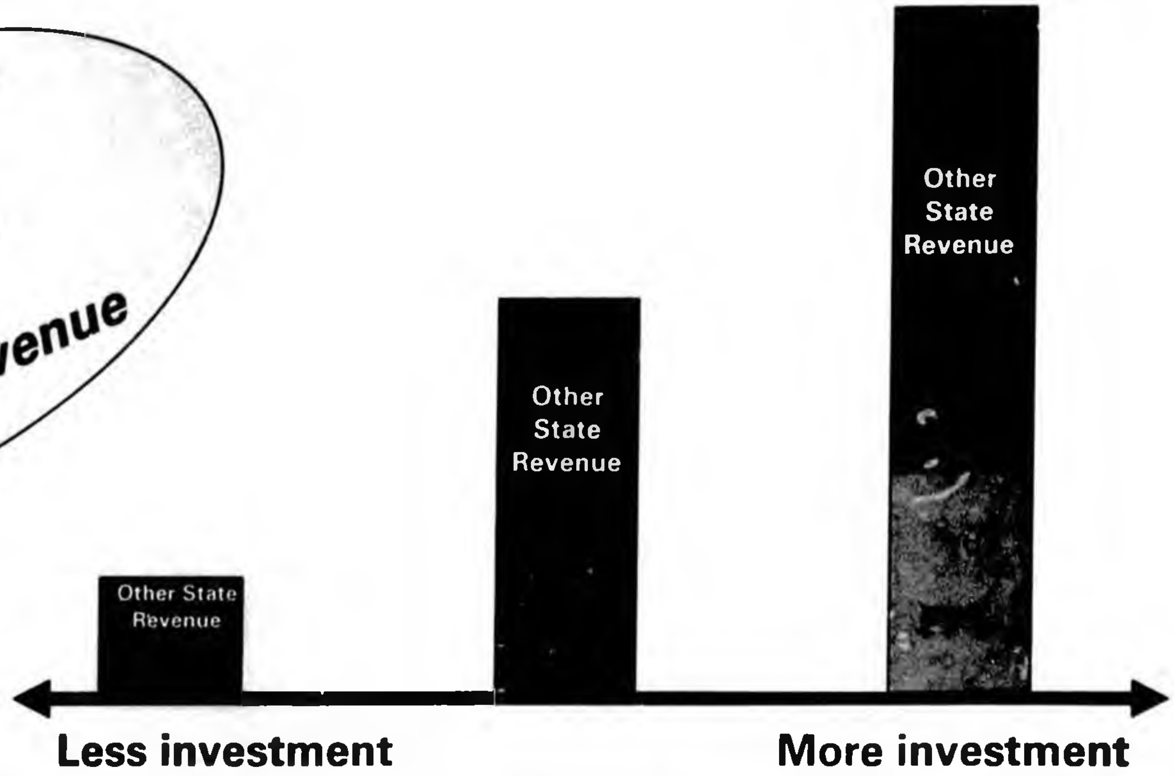
- total 800 wells drilled in last 10 yrs in Prudhoe..

Production Drives Revenue

bp

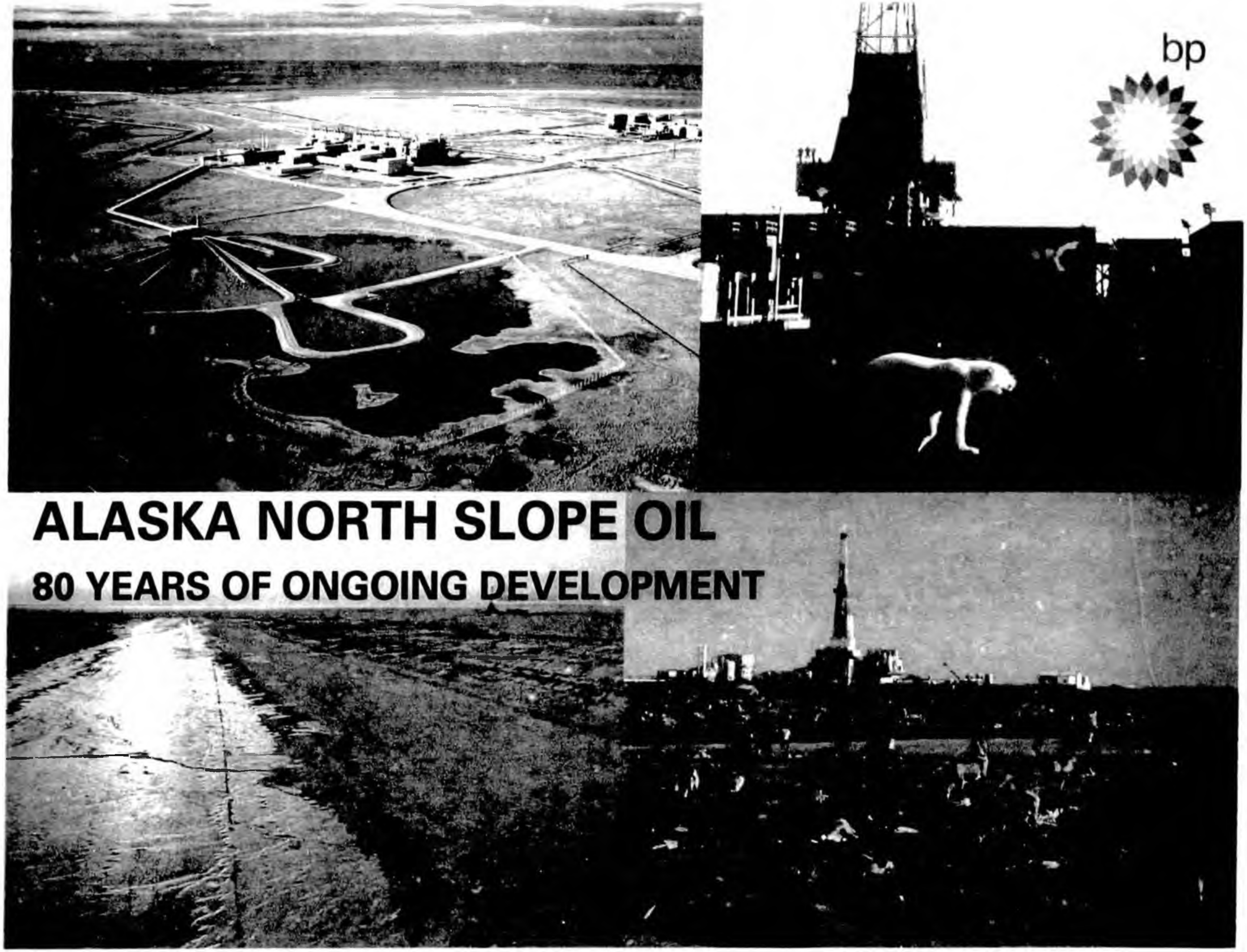
Decline Rate	15%	**6%**	3%
Produced Barrels	1.3 bn	3.9 bn	7.5 bn
Industry Investment	$5 bn	$25 bn	$70 bn
		Status quo	

Increase Investment
↓
Increase Barrels
↓
Increase State Revenue



ALASKA NORTH SLOPE OIL

80 YEARS OF ONGOING DEVELOPMENT



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