SB 2001

(FILE 3)

WRITTEN PUBLIC COMMENTS

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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."

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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.

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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]

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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 seperate-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 tne 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.

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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

[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.

B. "TIE" Credits.

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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WHITE PAPER

PRUDENT USE OF OPERATORS' BILLINGS:
STATE'S EXISTING STATUTORY DISCRETION &
IMPLICATIONS FROM ITS REPEAL

October 29, 2007

For purposes of ensuring compliance by taxpayers and facilitating audits by the Department of Revenue ("DOR"), the issue here is the distinction between starting from a set of standards or practices for billing oil and gas costs to the participants, and starting from the concrete results from applying those standards and practices.

The Administration has testified in committee hearings on SB and HB 2001 that subsections (c) and (d) of AS 43.55.165 are "mandatory" in nature for DOR, and may require DOR to take actions that it may not want to take. To free DOR from these constraints, the Administration says, these subsections need to be repealed.

The Administration is mistaken about the "mandatory" nature of AS 43.55.165(c) and (d) now in effect, as is clear simply by reading them. Side by side, they say:

(c) Subject to (g) and (h) of this section, if the department finds that the pertinent provisions of a unit operating agreement or similar operating agreement are substantially consistent with the department's determinations and standards under (a) of this section concerning whether costs are lease expenditures.

the department may authorize or require a producer, subject to conditions prescribed under regulations adopted by the department, to treat as that portion of its lease expenditures for a calendar year applicable to oil and gas produced from a lease or property in the state only

(1) **the costs**, other than items listed in (e) of this section, **that are incurred by the operator during the calendar year and that**

(A) **are billable to the producer**

or property is subject:

(B) for a producer that is the operator, would be billable to the producer by the operator in accordance with the terms of the agreement to which that lease

(d) Subject to (g) and (h) of this section, if the department makes the finding described in (c) of this section with respect to a unit operating agreement or similar operating agreement and, in addition, finds that at least one working interest owner party to the agreement, other than the operator, with substantial incentive and ability to effectively audit billings under the agreement in fact is effectively auditing billings under the agreement, **the department may authorize or require** a producer, subject to conditions prescribed under regul[...]ns adopted by the department, to treat as that portion of its lease expenditures for a calendar year applicable to oil and gas produced from a lease or property in the state only

(1) **the costs**, other than items listed in (e) of this section, **that are incurred by the operator during the calendar year and that**

(A) **are billed to the producer**

either not disputed by a working interest owner party to the agreement or are finally determined to be properly billable as a result of dispute resolution; or

(B) for a producer that is the operator, would be billable to the producer by the operator in accordance with the terms of the agreement to which that lease

Looking first at subsection (c), it starts with a declaration that it is subject to the terms of subsections (g) and (h) of the statute. Section 165(h) requires DOR to "adopt regulations that provide for reasonable methods of allocating costs between oil and gas and between leases or properties in those circumstances" where such an allocation is necessary — for instance, between oil and gas production in the Cook Inlet basin in order to apply the separate tax caps on such oil and gas.[1] Subsection (i) similarly allows DOR to adopt regulations to apply concepts of § 482 of the Internal Revenue Code to deal with costs incurred in transactions between affiliated parties. Neither kind of regulation bears on the question of using operators' billings or not as the starting point for determining the amount of the lease expenditures for such production, and there is no reason to assume that DOR would write them in such a way as to fetter its authority under subsection (c).

Subsection (c) continues with a statement that DOR must first find that the "pertinent provisions" of a an agreement of a "joint-interest billings" are substantially consistent with [DOR's] determinations and standards under (a)" of the statute, before it may wield its authority under subsection (c). If it can make this threshold finding, then DOR "may authorize or require

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[1] *See* AS 43.55.011(j) and (k) (capping the tax for Cook Inlet gas and oil, respectively).

a producer" to use, as its lease expenditures for a lease or property, "(1) the costs ...[[2]] that are incurred by the operator during the calendar year and that (A) are billable to the producer by the operator in accordance with the terms of the agreement to which that lease or property is subject...."

This is the heart of subsection (c), and as it plainly says, it is not mandatory at all for DOR. DOR "may authorize or require" the use of what would have been "billable" to the producer (emphasis added). As used in the Alaska Statutes, the word "may" is permissive or implies a discretionary power or privilege, while the word "shall" — in contrast — is mandatory. [3]

Moreover, the exercise of this discretionary authority to "authorize or require" the use of "billable" costs is "subject to conditions prescribed under regulations adopted by the department[.]" In other words, even when the statutory conditions are met for DOR to "authorize or require" the use of "billable" costs, it may by regulation create further limitations or conditions on the use of those costs.

Structurally, subsection (d) is very similar to (c). It starts with the same provision that it is subject to subsections (g) and (h) of the statute. It requires DOR to "make[ ] the finding described in (c) of this section" about the joint-interest billing agreement under which the billings are made. In addition, it requires that DOR ascertain that there is "at least one working

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[2] The omitted language refers to the categories of costs disallowed under subsection (e) of the statute, and the effect of that reference is to require a taxpayer to remove from the "billable" or "billed" costs under a joint-interest billing agreement costs disallowed under subsection (e). We omit the language for the sake of clarity with respect to the issue we are discussing in this white paper, not to conceal the fact that all uch disallowed costs would have to be taken out the "billable" or "billed" costs.

[3] *See* State of Alaska, Legislative Affairs Agency, *Manual of Legislative Drafting* (2007), p. 62; available online at http://w3.legis.state.ak.us/docs/pdf/DraftingManual2007.pdf (accessed 27 October 2007):

> (g) "May, "shall," "must"
>
> Use the word "shall" to impose a duty upon someone. The Alaska Supreme Court has stated that the use of the world "shall" denotes a mandatory intent. Fowler v. Anchorage, 583 P.2d 817 (Alaska 1978).
>
> Use the word "must" when describing requirements related to objects such as forms or criteria. (Use "must" sparingly, however, because most sentences using it can probably be written more clearly to impose a duty on a person, in which case "shall" would be the proper word.) Use the word "may" to grant a privilege of discretionary power. Rutter v. State, Alaska Board of Fisheries, 963 P.2d 1007 (Alaska 1998), p. 5. Use the words "may not" to impose a prohibition upon someone. For a further discussion, see Martineau, Drafting Legislation and Rules in Plain Englilsh (1991), pp. 81 – 82. For example:
>
> The commissioner shall issue a license ...., i.e., it is the commissioner's duty to do so.
>
> The information on the form must include ...., i.e., the form is required to have something in particular on it.
>
> The commissioner may inspect records ...., i.e., the commissioner may if it is necessary or proper, but the commissioner is not obligated to do so.
>
> .... [underscoring in original]

interest owner party to the agreement, other than the operator, with substantial incentive and ability to effectively audit billings under the agreement" and that the owner or owners are "in fact ... effectively auditing" the operator's billings to them under the agreement. Once DOR makes both findings, it "may authorize or require a producer" to use, as its lease expenditures for a lease or property, "(1) the costs ... that are incurred by the operator during the calendar year and that (A) are billed to the producer by the operator under the agreement to which that lease or property is subject and are either not disputed by a working interest owner party to the agreement or are finally determined to be properly billable as a result of dispute resolution[.]"

The chief difference between (c) and (d) is that (c)(1)(A) pertains to costs that are "billable" by the operator, while (d)(1)(A) pertains to costs that are "billed" by the operator.[4] The same permissive "may" is used in the crucial phrase about "authoriz[ing] or requir[ing]" the use of "billed" costs, and again, the exercise of this discretion is "subject to conditions prescribed under regulations adopted by the department[.]"

It is thus clear that neither (c) nor (d) is "mandatory" on DOR in terms of allowing or requiring the use of "billed" or "billable" costs under a joint-interest billing agreement if that agreement meets the statutory tests for ensuring its reliability. DOR may allow or require their use, but it doesn't have to. Indeed, it may further condition or limit their use by adopting a regulation.

AOGA's concern is, what happens if this express discretion to allow or require the use of "billed" or "billable" costs is repealed? The natural conclusion is that, if the legislature allows an agency to do something and then repeals that authority, then the agency can no longer do it. We believe it is more likely than not that this will be the courts' conclusion if AS 43.55.165(c) and (d) are repealed. Even so, we concede for the sake of argument that there may be at least some chance that the courts might reach the opposite conclusion. But our point is — why take that chance?

There is nothing in the present law that requires DOR to exercise this discretion, and keeping it on the books still won't require DOR to exercise it. But if DOR may ever want to start with an operator's joint-interest billings (or "billable" amounts) in order to simplify its audits or to allow non-operators to have something to base their reported lease expenditures on, it makes no sense to repeal its explicit discretion and thereby risk that DOR could not do so.[5]

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[4] Section 165(c)(1)(B) – (D) similarly pertain to "billable" costs, and § 165(d)(1)(B) to "billed" costs.

[5] In some testimony DOR has suggested that the provisions being added to subsection 165(b) will still allow it to authorize or require the use of an operator's joint-interest billings. The language to be added to (b) is identical in substance to subsection 165(a), where it currently appears — its removal from (a) is not immediately apparent in the Bill because (a) is being repealed and reenacted. The problem with DOR's line of reasoning is that the language being relocated provides:

> (3) In determining whether costs are lease expenditures, the department shall consider, among other factors, the
>
> (A) typical industry practices and standards in the state that determine the costs ... that an operator is allowed to bill a producer that is not the operator, under unit operating agreements or similar

operating agreements that were in effect before December 2, 2005, and were subject to negotiation with at least one producer with substantial bargaining power, other than the operator; and

(B) 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 a lease issued under AS 38.05.180(f)(3)(B), (D), or (E).

These provisions merely allow DOR to adopt regulations establishing "standards" for what constitutes a lease expenditure. They say nothing about where a taxpayer is to look to find the amount of that lease expenditure for a particular unit or field. In contrast, subsections (c) and (d) say that, where DOR finds that a joint-interest billing agreement complies with DOR's standards about what constitutes a lease expenditure (this is the "finding described in (c) of this section" that (d) refers to), then it "may authorize or require" the use of "billable" costs or costs actually "billed" under that billing agreement. Repealing this latter authority will not affect DOR's authority to establish the "standards" but, as just explained in the main text, it may well preclude DOR from starting with joint-interest billings in determining the amount of the lease expenditures under those "standards."

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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 "PERSONNEL ISSUES: AUDITORS"

October 29, 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 "Personnel Issues: auditors" as scheduled for consideration today.

AOGA concurs with the State's goal of having a staff of highly capable, experienced, and professional auditors for oil and gas audits. Such an audit staff is essential for legislators, government officials and the public to have full confidence that Alaska's tax laws are being firmly, fairly and consistently enforced. Establishing this confidence will help provide stability in the state fiscal regime. It should also, we anticipate, lead to increasing transparency in the administration of the taxes that will enable our members to report and pay the correct amount of tax as it becomes due. In saying this, of course, I do not mean to disparage any auditor currently working for the State.

In this regard, we would point out that the Legislature, in changing the production tax, can make it fairly direct and straightforward for the state auditors to audit, or make it a nightmare for them that is almost as impossible to audit and enforce on a consistent principled basis as it will be for taxpayers to comply with it correctly. The difference lies in whether, in circumstances deemed appropriate by the Department of Revenue ("DOR"), producers and explorers may rely on an operator's joint-interest billings to them. If allowed by DOR, such billings would still be adjusted to remove expenditures in them that are specifically disallowed in AS 43.55.165(e) or to adjust those that are subject to allocation under AS 43.55.165(g) and (h).

AOGA is worried that repealing AS 43.55.165(c) and (d) could deprive DOR of this important tool, and we have prepared a "white paper" to explain our basis for this concern. Rather than take the Committee's time to discuss that paper, I could, with the Chairman's permission, distribute copies of it to the members of the Committee now, or I could hand them out during a break or at the conclusion of this hearing.

Turning now to the matter of the particular "Personnel Issues" involved in strengthening DOR's oil and gas audit capabilities, there are two basic approaches you could take. One is to engage outside auditors on a contract basis to supplement DOR's present audit team. The other is to hire new auditors as state employees. We see pluses and minuses for either approach, with no clear recommendation to offer you.

If you opt to hire the new auditors as state employees as the Administration proposes, there is the further question about whether to put them in the "exempt" category of state service. Although we might wish we could offer you useful advice, we do not believe we are qualified to speak on this matter, nor do we see it as an appropriate one for us to be commenting on.

Thank you for giving AOGA this opportunity to testify.

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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 "PENALTIES / *QUI TAM*"

October 29, 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 "Penalties / *Qui Tam*" as scheduled for consideration today.

PENALTIES

I would like to begin by discussing two new penalties that have been proposed, and compare them to the penalties provided by existing law.

- As introduced and in the Senate Resources Committee Substitute, SB 2001 would amend AS 43.55.020(d) to give the Department of Revenue ("DOR") authority to assess a penalty of up to $1,000 a day for each day that a "report" — that is, a tax return — under AS 43.55 is late. It is specifically provided that this new penalty is to be in addition to any penalty or penalties that DOR may levy under AS 43.05.220, and also in addition to any criminal penalty under AS 43.05.290.[1]
- The original Bill and the Senate Resources CS would both amend AS 43.55.040 to provide for a similar penalty of up to $1,000 a day for <u>each</u> "report, statement, or other document" that DOR "considers necessary to forecast state revenue under this chapter" and which is not given to DOR "at the time required[.]" Again, this new penalty is specifically in addition to those that may be levied by DOR under AS 43.05.220 or imposed under AS 43.05.290.[2]
- Both amendments provide for DOR to establish "standards adopted in regulation" for determining how large these penalties should be within the $1,000-a-day maximum.

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[1] *See* SB 2001, Sec. 47; CSSB 2001(RES), Sec. 15.

[2] *See* SB 2001, Sec. 49; CSSB 2001(RES), Sec. 17.

These penalties are unnecessary and threaten to be excessive out of all reasonable proportion to the nature of the infraction in most situations.

They are unnecessary because, first, there are already significant penalties on the books to ensure that taxpayers will provide tax returns and other information or documents to DOR, and second, because DOR has other, compulsory remedies available to obtain the production of documents it needs or wants. AS 43.05.220 already provides for four kinds of penalties:

1. a 5% penalty per month for each month that a taxpayer fails to file its tax return when due, with a maximum penalty of 25 percent; the penalty is on the amount of tax that is not paid when due;[3]
2. a similar 5% penalty per month, capped at 25%, for failing to pay the full amount of tax when due;[4]
3. a penalty of 5% for an underpayment due to "negligence or intentional disregard of law or regulation without intent to defraud,"[5] which, if levied, automatically triggers the levying of the 5%-a-month failure-to-pay penalty as well,[6] making a total penalty of 30% in almost all situations; and
4. a 50% penalty for an underpayment due to fraud.[7]

In addition, AS 43.05.130 already provides that a "person who, by conduct not described in AS 43.05.290, violates a provision of AS 43.05.010 – 43.05.130 or a regulation adopted under those provisions is subject to a civil penalty of not more than $1,000 for each violation."

In terms of DOR's ability to use other means of compelling the production of information or documents it needs, AS 43.05.010 provides, "The commissioner of revenue shall ... (7) hold ... investigations necessary for the administration of state tax and revenue laws; ... (9) issue subpoenas to require the attendance of witnesses and the production of necessary books, papers, documents, correspondence, and other things; (10) order the taking of depositions before a person competent to administer oaths; [and] (11) administer oaths and take acknowledgments[.]" AS 43.05.040 also authorizes DOR to issue subpoenas and specifically provides for judicial enforcement of such a subpoena.[8]

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[3] A 43.05.220(a).

[4] *Id.*

[5] AS 43.05.220(b).

[6] 15 AAC 05.210(g).

[7] AS 43.05.220(c). The minimum penalty under section 220(c) is $500.

[8] Specifically AS 43.05.040 provides:

> (a) The department may examine the books, papers, records, or memoranda of any person to ascertain the correctness of a return filed or to determine whether a tax is due, or in an investigation or inspection in connection with tax matters. The records and the premises where a business is conducted shall be open at all reasonable times for official inspection, and the department may subpoena any person to appear and produce books, records, papers, or memoranda bearing upon tax matters and to give testimony or answer interrogatories under oath respecting tax matters. The department may

The foregoing demonstrates that, if DOR wants or needs information, it can get it. With respect to information for forecasting purposes, DOR could just as easily write a regulation prescribing the kinds of information it wants for forecasting. The provisions of AS 43.05.010(7) — authorizing DOR to "hold ... investigations necessary for the administration of state tax and revenue laws" — provide in themselves a sufficient statutory basis for a regulation about providing information to DOR for forecasting purposes, and it has the further advantage of being open to revision or updating in the future as circumstances may change, without having to bother the Legislature in order to make such a change.

For these reasons, then, the proposed penalties of up to $1,000 a day are unnecessary. But, in addition — and this is a concern that this Committee, with so many attorneys among its members, will appreciate — a $1,000-a-day penalty for each "document" that is not produced "at the time required" can quickly reach levels out of all reasonable proportion to the nature or severity of the offense. You all know, for example, that in discovery it is all but standard practice to regard each copy of a document given to people on a distribution list as a separate document. So suppose a copy of such a distributed document is given to DOR on a timely basis, but the copies for the president, local CFO and field manager are furnished two weeks late. It is the information in the document that DOR needs on a timely basis, not the set of copies of it that were made. Is there any reason why the taxpayer should face $42,000 in penalties[9] for this?

We agree this is one of the situations that DOR could address in its regulation about when the penalty should be less than $1,000 a day. But let me just say in reply that I know of a real situation some time back involving the former $25-a-day late-filing penalty under AS 43.55.-030(d).[10] DOR issued an audit assessment for some $28 million in $25-a-day penalties even though the amount of tax being claimed was less than $4 million. Before it was issued, this assessment was reviewed by the auditor's supervisor and the director of the division known today as the Tax Division, and still the claim for this penalty was allowed to be made.

My point here is, DOR must already have some concepts and principles in mind about when $1,000 a day would be appropriate and when it should be less, and I trust they are not as

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administer oaths to persons who are so subpoenaed. A subpoena issued under this section may compel attendance of a witness or production of a document or thing, located either inside or outside the state, to the maximum extent permitted by law.

(b) A subpoena may be served by the commissioner of public safety or a peace officer designated by the commissioner of public safety, by a person designated by the Department of Revenue, or as otherwise provided by law. A subpoena may also be served by registered or certified mail for delivery restricted only to the person subpoenaed. The return delivery receipt must be addressed so that the receipt is returned to the department.

(c) If a person who is subpoenaed neglects or refuses to obey the subpoena issued as provided in this section, the department may report the fact to the superior court or the appropriate court of another jurisdiction, and may seek an order from the court compelling obedience to the subpoena. The court, to the maximum extent permitted by law, may compel obedience to the subpoena to the same extent as witnesses may be compelled to obey the subpoenas of the court.

9 Three late documents at $1,000 a day each would be $3,000 a day, times 14 days is $42,000.

10 AS 43.55.030(d) was revised last year to delete this penalty. *See* § 20 ch 2 TSSLA 2006.

draconian as what I described with the former $25-a-day penalty. But there is nothing in SB 2001 to indicate what those principles or standards might be. This is the Administration's bill, so DOR certainly could have indicated in the Bill what its thinking is about the standards should be for setting the amount of the penalty. We would ask that you get DOR's thoughts on the record about how the penalty should be scaled down from whatever its maximum may be$1,000 a day, and for what reasons or grounds. Even if the Legislature chooses not to prescribe standards for reducing the penalty in statute, at least DOR's current opinion on the matter will be on the record to guide us, and them, in developing that regulation, should this excessive penalty become law.

QUI TAM

Qui tam is a kind of lawsuit that arose in medieval England[11] and became most common in the United States as a suit by a private person — often a whistleblower — brought against someone under the federal False Claims Act[12] for alleged fraud against the federal government, usually by overcharging it for goods or services being provided. The federal Act was passed during the Civil War in response to widespread complaints by Union solders about being issued shoddy uniforms, cardboard-soled boots and spoiled food instead of the quality goods and merchandise that the Army was paying for. Under it the lawsuit is filed under seal, and the defendant is forbidden from disclosing anything to anyone about the case — not even the fact that it is being sued. The U.S. Attorney for the district where the suit is filed has a choice of appearing in the case and taking over the prosecution of the claims. If the U.S. Attorney declines to do so, the plaintiff (technically, the relator) may prosecute the case alone. If the relator wins, or if the government wins after taking over the case, he or she gets a percent of the government's recovery, plus the relator's attorney fees.

The whole concept of *qui tam* proceedings is inapplicable and inappropriate in the context of petroleum production taxes. Because of the confidentiality of tax information,[13] the only

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[11] "*Qui tam*" is Latin and comes from the first two words of the phrase "*qui tam pro domino rege quam pro se ipso in hoc parte sequitur*" meaning "he who sues herein as much for the lord King as for his own self."

[12] 31 U.S.C. § 3729 *et seq.*

[13] The confidentiality of whatever a person reports for tax purposes is the constitutional lynchpin for enforcing any self-reported and self-assessed tax. The most infamous example illustrating why the constitution requires tax confidentiality is that of Al Capone, the Chicago gangster who was convicted of federal income tax evasion in 1931 for failing to report and pay federal income tax on the money he got from racketeering. The Fifth Amendment protected even him against having to incriminate himself. Consequently, to prevent the Fifth Amendment from being a bar against punishing him for not having reported his income from criminal activities to the IRS, it was necessary that whatever he should have reported to the IRS would have to have been kept strictly confidential, so that it could not have been disclosed to anyone outside the IRS except to enforce the federal tax laws — and especially it could not be disclosed directly or indirectly to anyone enforcing the criminal racketeering laws. Oil companies are not like Al Capone, of course, but they are subject to strict antitrust and SEC restrictions about what they may disclose directly or indirectly to competitors or the public about future events and plans. If there were no confidentiality for what producers report to DOR on their tax returns or in response to a DOR forecasting-related request for producers' projections and plans for future periods, the mere act of giving that information to DOR might itself be a violation of law. The constitution does not allow government to force anyone to commit a criminal act any more than it allows government to force them to incriminate themselves for a criminal act they have committed without governmental

people who know the particulars of a company's production taxes are the folks in that company who are involved in preparing and filing those taxes, and the state employees, principally in DOR, who administer and enforce this tax. No one working for the company in preparing and filing the tax returns is a plausible candidate for becoming a *qui tam* relator because those tax returns are filed "under oath,"[14] and the penalties for perjury would be applicable if a false or erroneous return were knowingly filed. And it would be completely improper to allow state employees who review or audit the company's tax returns to be *qui tam* relators because it is already their job to find erroneous, false or fraudulent information in taxpayers' returns.

Thank you for giving AOGA this opportunity to testify.

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coercion. Moreover, the legal privilege here does not depend on whether a criminal act has actually been committed or would be, nor even on the person's belief or suspicion that criminal conduct might be involved. The Fifth Amendment privilege may be invoked even when the person doing so is confident that he or she has done absolutely nothing wrong, and for legal purposes nothing improper may be inferred from invoking it. Thus, to ensure that DOR can get the information it wants or needs to administer the production tax, there must be confidentiality for that information and this confidentiality must be strictly adhered to and enforced.

[14] *See* AS 43.55.030(d), providing in pertinent part: "The person paying the tax shall file with the department on March 31 of the year following the calendar year for which the tax was levied a statement, under oath, in a form prescribed by the department, giving, with other information required, the following [information]" (emphasis added).

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TESTMONY BY THE

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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.

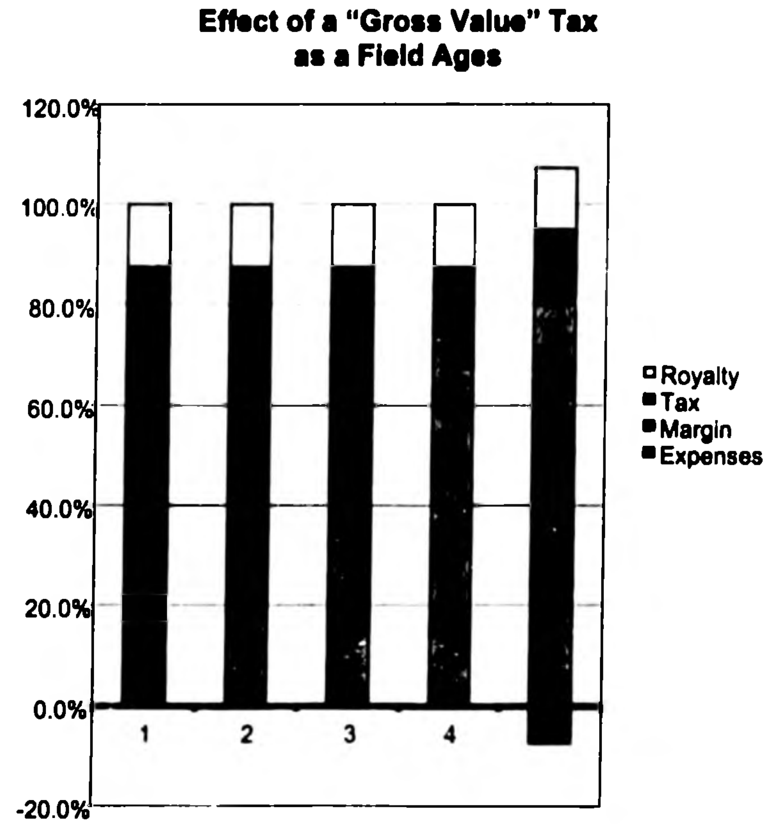
There is a further and related reality for the huge resources of viscous and heavy oil that are known to exist on the North Slope. Because of the physical characteristics of the oil itself and of the reservoirs wherein it is found, the oil is physically very difficult to produce, starting with the very 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.

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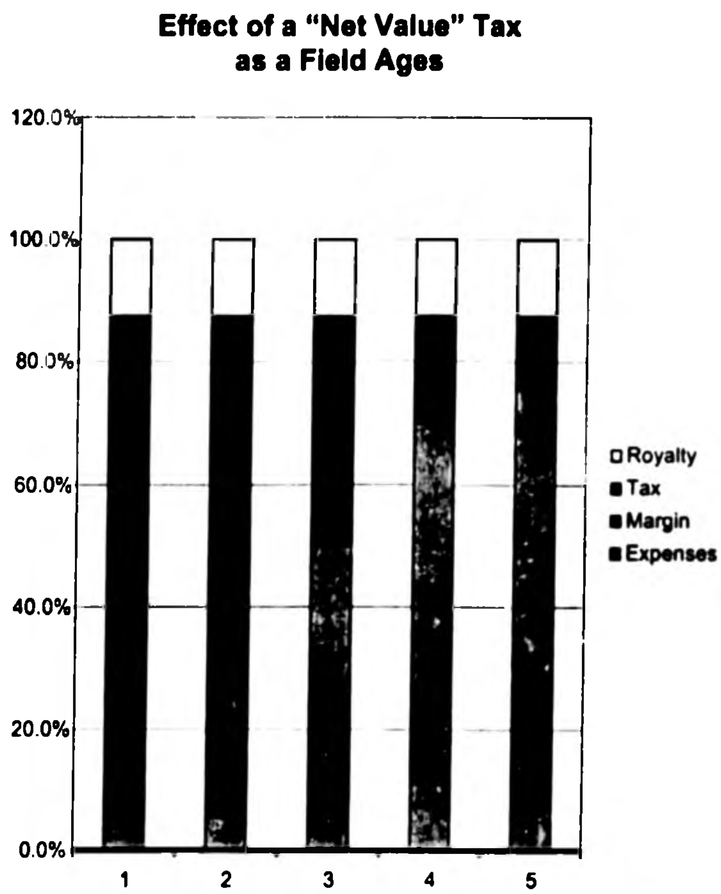
[3] This has happened in Alaska. The first commercially producing oil field here, the Katalla field near the town of the same name, shut down permanently after a fire burned down its nearby refinery on Christmas Eve of 1933

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.

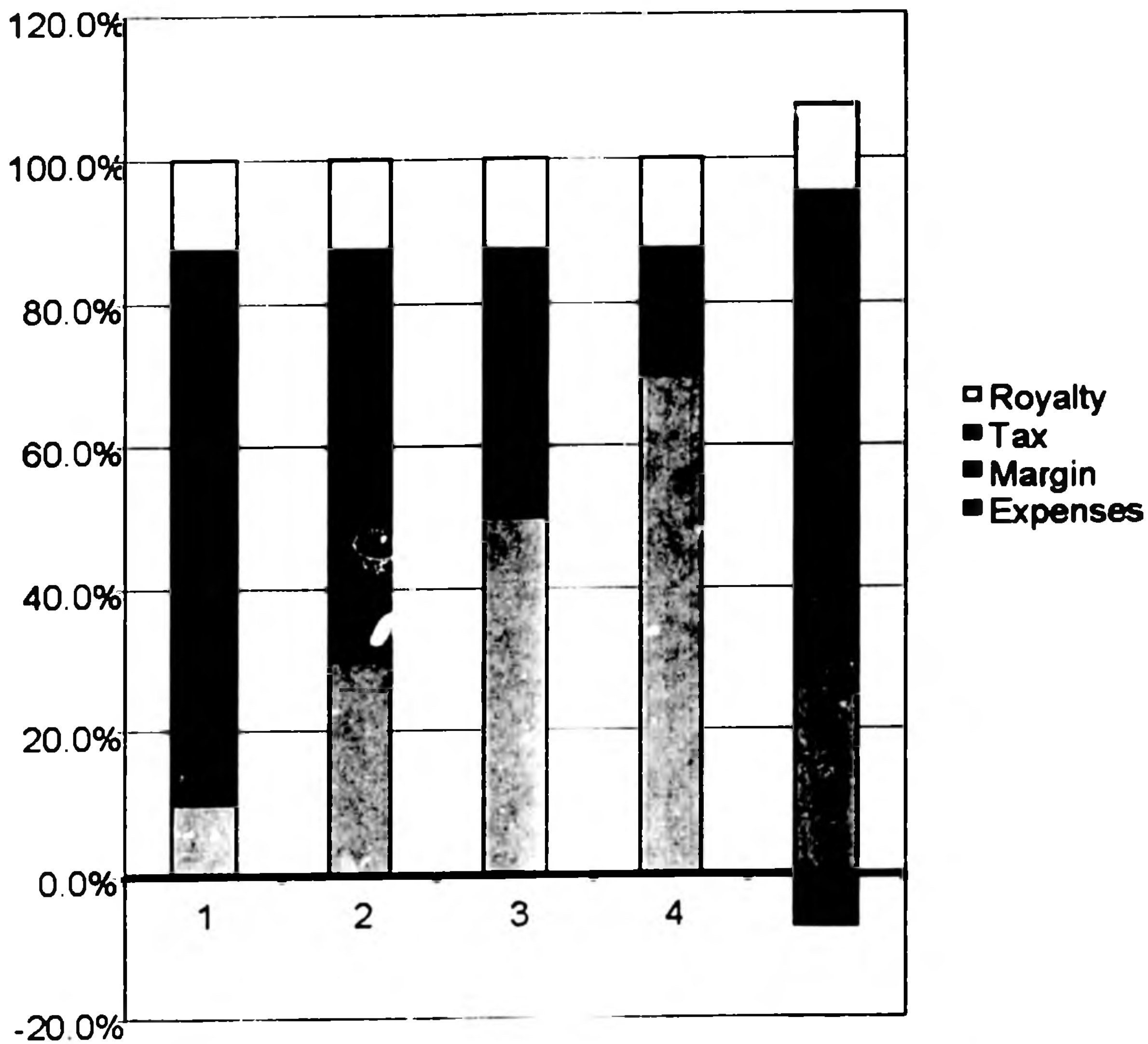
Further, if — as we did with the earlier graph — you view this one as illustrating the gradual deterioration of the portfolio of investment opportunities over a field's life, you can see that, once again, if your investment opportunities resemble bar 1, you will probably try to make as many investments 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



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SB2001 Oil Tax Issues (PPT)
Senate Judiciary Committee
Aves D. Thompson
November 1, 2007

Thank you. Mr. Chairman and members of the committee, I am Aves Thompson, Executive Director of the Alaska Trucking Association. The Alaska Trucking Association is a state wide organization representing trucking interests from Barrow to Ketchikan. In 2008, our association celebrates its 50th Anniversary of serving the interests of the trucking industry in Alaska. Our more than 200 member companies represent all of the diverse trucking operations in the state along with many associate members who provide goods and services to our industry. It is important to note that, in Alaska, trucking employs over 20,000 people - 1 out of 14 members of the Alaska workforce. Trucking payrolls total over $900 million annually. Trucking consists of several thousand family owned and corporate trucking businesses, most of which have fewer than 10 employees.

On behalf of ATA, I want to make several observations about PPT issues and SB 2001

It has been said many times that, in developing our natural resources, our constitution requires that we seek maximum return to the citizens of Alaska. While it seems that the emphasis has been on raising taxes to increase tax revenue to the state, we believe that the better way to maximize benefits to Alaskans is to provide good paying, long term jobs for this and future generations.

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The State needs to focus on how to slow the decline of production. To accomplish that objective, investments need to continue in existing fields, investments need to be made in heavy oil and investments need to be made to promote the development of new fields. Existing field development should be the first priority. Most of the new production, in recent years, has occurred in existing fields. Without this base production, heavy oil and other new field development will face major additional challenges.

The oil and gas business is capital intensive and it takes many years for return on investments to occur. Increases to taxes lengthen that recovery time and can negatively impact project economics and investment decisions.

We believe that it is important in setting tax policy to produce adequate revenues for the state but more importantly, encourage further investment in the development of our abundant resources.

We urge you keep the tax rate low and use incentives to encourage increased development investment. As stated earlier, we believe that the better way to maximize benefits to Alaskans is to provide good paying, long term jobs for this and future generations. Investment, not taxes, will provide the jobs we need to ensure our future.

Thank you for your attention. I will try to answer any questions.

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APEA/AFT

Written Testimony Before Joint Finance Committees
Exempting Auditors: Jeopardizing Alaska?
James Orr

First, thank you for your service to the State of Alaska and the large amount of time you are taking away from your family to understand the complexity of oil taxation measures. We are very appreciative of your willingness to listen.

We are here tonight to express concern with the sections of the bill to remove auditors and other personnel from the classified service into exempt status, in at-well positions. This important issue strikes the heart of the State Personnel Act: the disturbing trend of moving classified employees into exempt service.

The Constitution of the State of Alaska establishes the merit principle to govern employment (Section 12.6) while our statutes mandate that employment be:

- Free from political interference,
- Competitive in order to find the best qualified personnel
- With methods for evaluating performance.

Removing oil tax auditors and related positions from classified service tears at the very fabric of the merit system established by the Constitution. It is contrary to the establishment of a viable personnel system, which originally contained only a limited number of exempt positions.

We know from our members across the state, from every department, that there are severe problems filling key positions in public safety, health, and in most basic state services. The problem is systemic. The auditing positions are not unique and have had more success with recruitment than some. In one short recruitment period last month, they secured four applicants before closing the application period one day before the start of the Special Session.

We understand the need to hire additional auditors in order to adequately perform the work. **The Division of Personnel can resolve this particular problem without involving the legislature during a special session: the state has the statutory authority, found in AS 39.25.150, to establish a highly specialized job class to reflect the complex job duties. AS 39.25.150 charges the Director of the Division of Personnel with creating positions and establishing the pay within the classified service.**

APEA/AFT is happy to work with the division to accomplish our mutual goals of providing the best possible workforce through the merit system.

Aside from the constitutional issue of abiding by the merit system, **what compelling reason could justify removing auditing positions from classified service into the political arena where they could easily be subjected to the pressures of the times? The auditors face the oil industry every single day in their attempt to follow the statutes and regulations in the collection of billions of dollars of revenues. The political winds shift back and forth. It is imperative that these auditors be kept out of the direct line of fire.**

In conclusion, we ask that you support the merit system and that you retain the auditors in classified service and out of the political arena.

Thank you.

October 24, 2007

Senator Hollis French, Chair
Senate Judiciary Committee
State Capital Room 417
Juneau, AK 99801-1182

The Honorable Chair & Members of the Senate Judiciary Committee

The Alaska State Chamber of Commerce is concerned about the legislation, Alaska's Clear and Equitable Share (ACES) and the changes proposed to the tax structure of the recently enacted Petroleum Production Tax (PPT). The State Chamber believes changing the tax structure so quickly will have long-term negative impacts on the future of Alaska's economy. We believe that the consequences of adoption of ACES have not been fully considered with rega to all businesses in Alaska.

The Alaska State Chamber of Commerce is a business advocacy organization whose mission is to drive positive change for Alaska's business environment and to improve our member organizations by providing leadership, advocacy, connectivity and support. The policy debate on everyone's mind these days is the special session. During our most recent Board meeting, we noted the following observations.

<u>Renewing Public Faith in PPT</u>
State Chamber members have a strong commitment to ethical business conduct and understand your commitment to ethical conduct among elected and public officials. Because you have heard from Alaskans that their faith in the current petroleum production tax (PPT) is shaken, we understand the desire to see the production tax debated again but believe this comes with great risk. We urge caution in the rush to find a fix for something that may not be broken.

The concern is that while the Governor and the Legislature work to restore public faith, outcomes based more on emotion than economics will further chill the oil investment climate. A second concern is the stated goal of generating more revenue for the treasury. The chamber does not agree with that goal, and our members fear that Alaskans will confuse the outcome of higher tax revenue with the goal of fair share.

Our membership believes tax debate creates unwelcome risk and stalls investment planning and decisions. Taxes are a key consideration in all business investment decisions, so any time tax law is debated, investments can be delayed. The wrong tax rate can end all consideration of investment.

Certainly working to induce investment such that the pipe is full of oil at $80+/bbl would generate more revenue at the current tax rate than would a dwindling quantity of oil at a higher tax rate.

RAISING THE TAX RATE

Most of our members do not understand the finer details of petroleum exploration and production. However, they all understand two major trends in Alaska's oil patch:

- Taxes on the oil industry have increased at a rate no other business segment could survive; and,
- Despite billions of dollars invested by the oil industry on the North Slope and in Cook Inlet, production continues to decline at an alarming rate.

Many have repeatedly noted this decline. To propose a new increase to the production tax is a risky policy given the desire to encourage increased production. We have watched a decade-old production tax regime for Cook Inlet - essentially zero - encourage very limited investment. On the Slope, recent investments were committed under the significantly lower ELF tax and historically high oil prices, yet the exploration activity pales in comparison to that taking place in Canada and the Gulf of Mexico.

Raising production taxes in light of limited investment is counter intuitive. Instead of referring to fiscal notes and revenue projections, we urge you to set the policy outcomes you desire in the oil patch and then debate language to achieve those outcomes. We suggest the following statement can guide the debate:

- Adopt an oil tax regime that will generate reasonable revenue for state government, while encouraging maximum utilization of oil reserves.

FISCAL PLAN

The State Chamber has advocated for decades for a state fiscal plan. We applaud the identification of the fiscal dilemma our state faces, and the willingness of many to check spending. A clear plan, however, is not guiding spending or revenue collection, or the question of how the state can invest new revenue in projects that will render a return on investment. Given today's oil prices, the Alaska's Clear and Equitable Share (ACES) legislation proposes to collect surplus revenue for a fiscal system that results in increased spending but lacks a strategic business plan for the state. This policy outcome does not warrant worsening the investment environment.

ALASKA'S BUSINESS IMAGE

As stated earlier, State Chamber members have a strong commitment to ethical business conduct. This includes our many members from the oil and gas industry. Given the daily headlines and investigations, our concern is that many Alaskans now view "business" negatively.

This impression is further fueled by the implications that the oil and gas industry has slighted the state through its accounting practices.

We encourage our policy leaders in Juneau to consider this dynamic and avoid making unfair accusations that further fuels this distrust of our Alaska businesses big and small. At the end of the day, differences of opinions exist and reasonable people can disagree.

TAX AUDIT EXPERTISE

We offer assistance in boosting the state's tax audit capabilities. We are confident that if industry can acquire talent to administer a wide range of complex tax regimes throughout the world, Alaska can recruit the best and brightest to administer our single regime. This expertise will be found in a combination of state employees and private contractors.

TAX ON PROFITS IS GOOD FOR BUSINESS

Although we are concerned with a proposed minimum tax on certain fields, we would like to thank you for recognizing the wisdom of a profits tax. So many today illogically condemn petroleum industry profits. Alaskans should cheer since those profits will allow the same companies to make the world-class investments Alaska needs to monetize our oil and gas.

Thank you again for taking time to address these critical issues for Alaska's future. I would be delighted to meet with you to discuss the points above in further detail.

Yours in economic prosperity,

Wayne A. Stevens
President/CEO

TOM LAKOSH P.O. BOX 100648 ANCHORAGE, AK 99510 Ph/Fax (907) 563-7380
November 1, 2007

TESTIMONY ON SB 2001, ACES

Would you please accept and fairly consider this written testimony, oral testimony and the additional testimony, documents and comments as attached and otherwise incorporated herein by reference:

1. My oral testimony before the House Resources Committee on 10/30/07 at the 19:14.48 time stamp, and my written testimony attached below.
2. The comments of Representative Guttenberg regarding lessee obligations proffered to the House Resources Committee on 11/1/07 beginning at 2:28.08 PM
3. The discussion of the House Resources Committee on 11/1/07 regarding the presentation of Pioneer Resources commencing at timestamp of 3:09:49 and continued until 4:25.
4. The standard ADNR form for a "Competitive Oil and Gas Lease", of which pages 1, 4, 5 and 6 are accurately copied below.

Although there are many issues I would request be fairly considered, my time before the committee is otherwise occupied by the need to address and correct material misrepresentations and material omissions publically disseminated by your legislative consultant and the ADOR. The offending misinformation presented yesterday is the representation that the PPT or amended ACES system of tax deductions and credits are necessary and/or the preferred mechanism to advance legacy oil field in-fill drilling designed to stem oil field production declines coupled with the material omission that the lease provisions for these fields already require lessee to "...drill those wells as a reasonable and prudent operator would drill, having due regard for the interest of the state...", standard lease at page 6. The consultants and DOR furthermore materially omitted that "...the commissioner will require amendments that the commissioner determines necessary to protect the state's interest", in consideration of lessee's plan of operations, (see page 4 of the standard lease and the exact same language in 11 AAC 83.158(e)).

A fair legislative investigation mandated by Article I Section 7 of the constitution of Alaska would necessarily require the following remedial actions:

1. A full apology by the offending parties on the committee floor and all Alaskan publications of record.
2. A full presentation by Gaffney, Cline and Associates depicting the necessary in-fill drilling and heavy oil extraction that is required of lessees pursuant to the diligence and prevention of waste provisions in section 13 of the leases in question. The modeling of this requirement must assume multiple standards of "reasonable profit" as garnered by all other Alaskan corporations and show utilization of all windfall profits above such reasonable rates of return already

garnered by lessees to date. The modeling must also incorporate existing ADOR oil price projections and any necessary extrapolations into the future to show a projection of lifetime field decline rates and projected revenues comparable to the offending presentation.

3. Call the Commissioner of ADNR and his knowledgeable ADO&G staff before the committee to fully explain: the various relevant leasing provisions; his administration of these leases both consistent and inconsistent with his constitutional, statutory, regulatory and contractual mandate to preserve the state's interest, and; in cooperation with Gaffney, Cline and Associates, fully explain what are the specific operational plans he will develop in administration of lessees duty to fully extract all hydrocarbons on their lease in conformance with with the applicable leases.

Sincerely, Tom Lakosh

TOM LAKOSH P.O. BOX 100648 ANCHORAGE, AK 99510 Ph/Fax (907) 563-7380
October 30, 2007

TESTIMONY ON HB 2001, ACES

My alternative to ACES is called **TRIPS**, Taxes, Royalties and Infrastructure for the Petroleum Sector. There are some, albeit few, sections of ACES that would be useful but the basic principles at work that require a wholesale reworking of the Bill are:

- Virtually all oil bearing structures on state lands have been explored so there's little reason to provide incentives to the industry to explore where they have already exploited everything they could. BP made this clear in their statement that 70% of their future investment would be in the greater Prudhoe area where they are obligated to wisely extract the hydrocarbons pursuant to the applicable leases and AOGCC guidelines. If producers don't provide full and efficient extraction in the operation plans submitted to the Division of Oil and Gas, leases may be subject to revocation and "there's always other fish in the sea". We should not give existing producers kickbacks where they're obligated to do the job properly and within technological feasibility and economic limits under their existing lease contracts and applicable law. With the price of oil above $80 there should be little left to recover in our legacy fields and we must demand that the ADOG conduct the mandated evaluations of the economic feasibility of heavy oil extraction now while we still have light oil to mix into TAPS shipments and the price is still high enough to warrant extraction without subsidy.
- Where extraction of heavy or viscous oils is necessarily tied to the availability of lighter oils, the ADNR and AOGCC must conduct the proper technology and economic analyses to insure the optimization of revenues from regulation of the rates heavy and light oils are extracted. The ADNR and AOGCC must thereafter issue the necessary directives to lessees to insure that lessees are producing each type of hydrocarbon on their leases in manner that optimizes the

total revenues to the state. There is no quantifiable correlation between the oil production rates or total state revenues and the tax rates so the proper oversight of our regulatory agencies, ADNR/ADOG must be conducted to insure that they regulate lessees to the optimal benefit of the state in conformance with Article VIII Section 2 and the applicable statute, regulations and lease provisions. Only then could the legislature determine if additional tax write-offs and credits would be necessary to ensure maximum benefit to the state and even then it would be preferable to provide ADNR/ADOG additional tools for incentivizing development because they could apply such incentives with surgical accuracy to specific leases and production units where taxes, no matter how specific, would tend to waste considerable revenue to produce the same hydrocarbon production/revenues.

- The fair legislative investigation of this tax matter mandated by Article I Section 7, necessitates that this committee call ADNR/ADOR to testify on its approval of unit and lease operation plans and explain: their best interest findings, the economic feasibility findings for hydrocarbon extraction required by lease provisions as associated with lease/unit plans of operation; and what their projections are for production at specific fields and for specific hydrocarbons in an effort to reach the maximal benefit to the state. Unless and until ADNR/ADOG produces findings that royalty relief is necessary to reach optimal production rates, any subsidy envisioned in tax write-offs and credits could only produce a negative fiscal note. Moreover, any fiscal note produced absent this detailed investigation would be arbitrary and capricious where there would be no basis for relating what production/revenue was already required of producers in comparison to what the tax legislation was predicted to create. The sad fact of the matter is that ADNR/ADOR has never performed any independent economic feasibility analyses of the operation plans proffered by producers to evaluate whether the state was receiving, or would receive in the future, maximum benefit from the producers' plans of operation. This administrative dereliction of duty must be rectified before the legislature can move forward with any additional incentives to industry beyond what is already provided for in AS 38.05.180. The producers have not utilized the current royalty reduction incentives and should not be allowed to "buffalo" an ill informed legislature into granting an "end run around" the ADNR/ADOR regulations that were specifically designed to prevent such relief without a thorough economic assessment that shows a clear justification for relief. The applicable statutes and regulations actually envision that operational plans required to generate optimal production over the life of the field may in fact demand that lessees operate at a net loss near the end of the field life. Where the legislature imposes write-offs and credits over this regulatory scheme, tax revenues could be eliminated and we might even have to pay producers 20% of costs where they generated no tax revenue at all due to write-offs. This situation would clearly require posting of a negative fiscal note that would violate the constitutional mandate to maximize public benefit. The legislature must first require ADNR/ADOG to exhaust their administrative duties and lessees must also first exhaust their administrative remedies before any additional incentives such as write-offs or credits are offered.
- If absolutely necessary, we can subsidize production of hydrocarbons that are difficult to develop by adjusting royalty rates instead of taxes. This would allow for lease by lease evaluation that is clearly more sensible than the broad subsidies to all operations. The royalty rates apply to gross production so the 19% range I've suggested has more than enough value available to provide incentive for development of heavy oils and remote gas should existing lessees submit, or new lessees sign on, to the new adjusted royalty rates that express the relative accessibility and marketability of specific lease types at specific distances from established infrastructure.

- The testimony clearly enforced the principle that "if you build it they will come". Angola got a $1 billion for its leases and rabid global competition because the oil co's knew there was oil to develop. If there's oil/gas to be found, the state should find it and define the field before it puts out leases so it can garner the highest bids among many competitors. The state would also be better able to predict development, classify fields to establish proper royalty rates and determine appropriate deadlines for relinquishment. The more we improve information on prospective fields and insure access, the less we need speculators that demand high rates of return. When we eliminate the discovery and access impediments we essentially only need contractors to build the production facilities and pump the oil as regulated by ADNR and AOGCC.
- If we have to subsidize the industry we should do it in a way that benefits other businesses and public interests. Taking money from royalties to improve transportation to the fields/pipelines floats everybody's boat. The heavy lift helicopters and low impact transport would also reduce tundra impacts, allow a longer exploration season and year round deliveries to isolated drilling/production pads. They would also be extremely effective tools for getting spill response equipment to remote sites and help repair global warming damage in remote areas that is directly caused by the oil we peddle.
- Our economic future through 40 - 60 years depends on our ability to market gas and the gas will not be marketable until the relative BTU value of gas approaches the price of oil BTUs, (PVM said it was at 40% of oil because Northern Tier coal companies successfully marketed their coal to power plants). The relative BTU value of gas can only be increased by de-valuing coal as a power plant fuel with a federal carbon tax. The carbon tax would also likely save us as much in damages to infrastructure from global warming as we would make on oil exports, billions and billions in prevented damage that we wouldn't have to otherwise spend our revenue on to mitigate. If we can't muster the ethics to pursue a carbon tax for its environmental benefit, we should at least pursue a state and federal carbon tax to increase the value of our gas in an effort to make the gas pipeline economical. The gas problem can only be rectified with a carbon tax and then all else will be controlled by the high, stable gas value generated by a proper valuation of this external cost of our hydrocarbon economy. More stringent particulate regulation would also likely help gas prices.
- Providing tax incentives to explore or produce on federal land will mostly provide returns for the federal gov't, leaving us with enormous development bills and not much revenue to show for it. Granting these tax write-offs without careful consideration of what will/should be required of producers under existing leases could well reduce revenues from taxes to zero and the additional payment of credits could even require the state to pay the producers for exporting the oil. The least negative impact to exploration from any tax increase can be accomplished by increasing the corporate income tax on hazardous operations because an increase in state corporate tax is used as a direct offset to federal income taxes so there' no net increase in taxes on the oil co's. The increased income tax will also allow Alaska to extract a fairer share of income from production of oil on federal lands and even more so from the federal outer continental shelf, (i.e. the 90/10 vs 50/50 royalty split, justice w/o a court). The progressive sales tax will also capture additional revenue from federal OCS leases that is otherwise escaping sufficient state capture.
- If we allow the oil co's to write off their Alaskan expenses it would tend to increase the price of our hydrocarbons and make them less competitive on the open market. Taxes do have an effect on corporate behavior and only taxing the gross at the point of export or in-state delivery will serve to keep a market check on expenditures in-state and therefore keep our hydrocarbons as cheap as possible in the market. We have recently discovered from RCA and FERC tariff

proceedings that the state and consumers have been overcharged for TAPS costs by as much as $3/bbl and a sales tax levied at the point of export must be imposed to insure the lowest overall transportation costs where a prior administration has illegitimately surrendered our right to challenge tariffs overcharges in the prior TAPS tariff settlement agreement. We would surely have a strong case for upholding the gross tax where it measures the oil value IN ALASKA. Both PPT and ACES are inviting fly by might wildcatters that will sell their credits and leave. The majors will be just as susceptible to the notion that spending controls are less of a priority given that they can sell the credits for marginal projects if they fail. Why not just take the money we'd spend on write-offs and credits and provide the needed oversight to exploration contractors we hire on a competitive bid? Existing lessees are already required to produce all hydrocarbons as is economically feasible and can apply for royalty relief if prices do not support optimal production rates.

- The discrepancies between projected revenues and collected revenues under PPT suggests that either the state is incapable of properly assessing tax provisions or that tax payers are withholding taxes. Both results suggest we must have a simple tax structure to avoid revenue shortfalls and costly litigation. Moreover, the complicated write-offs and credits would make it nearly impossible for ADNR/ADOG to properly assess appropriate plans for operation of leases/units if ADNR/ADOG was indeed inclined to properly implement their leases, statutes and regulations. Such an impairment of the lease contracts may well be interpreted as violating Article I Section 15 of the state constitution barring such impairment.
- The whole TRIPS scheme is designed to enhance certainty of development, (pre-defined leases and improved access), while alleviating risk due to low prices but eliminating any windfalls to industry, (the progressive sales tax spanning a $190 price range). Although I haven't done a precise analysis of the total government take, I strongly suspect that these rates would keep us below the Norwegian standard of 78% gross government take up to about $70/bbl and I would suggest lowering the base oil sales tax and/or raising the new class of corporate income tax until this parity was reached. I'm sure that the Norwegians never anticipated the blistering oil market we have today and so did not include progressivity. The gas problem can only be rectified with a carbon tax and then all else will be controlled by the high, stable gas value generated by a proper valuation of this external cost of our hydrocarbon economy. More stringent particulate regulation would also likely help gas prices.

Proposed Principles and Rates for Design of an Oil Tax Bill:
Production and Corporate Income Taxes, Royalty Rates and Lease Provisions with
State Commitments to Exploration, Infrastructure and Carbon Conservation

Raw Oil/Gas Sales Taxes: The gross tax on raw/unrefined hydrocarbons sold in/from Alaska shall be set at the value of the hydrocarbons at the Alaskan terminus of export or point of sale within Alaska in order to provide a market check on production costs and pipeline tariffs in furtherance of the relative competitiveness of Alaskan resources, (e.g. Valdez Marine Terminal for TAPS oil, Drift River or KPL Dock for Cook Inlet oil and gas, at the Canadian border in the case of gas transport by pipeline, at any in-state refinery or point of sale). This tax system would also encourage export of value added petrochemical and refined products. The suggested tax rates for crude oil are as follows:

1. There shall be a minimum sales tax of 15% of gross value for oil prices between $0 and $20/bbl;
2. At $21/bbl the sales tax increases to 15.5% and increases by a rate of 0.5% for each $1/bbl increase in price to $30 ;

3. At a price of $31/bbl the sales tax shall be raised to 20.2% of gross value and shall increase at a rate of 0.2% for each $1 in value per barrel until a price of $110/bbl at which point the tax will have accumulated increases to provide a rate of 36% of value;
4. At a price of $111/bbl the sales tax shall be assessed at 36.1% of value and shall increase at a rate of 0.1% for each $1 in value per barrel until a price of $210/bbl at which point the sales tax will have reached its maximum rate of 46% of value.

Corporate Income Tax: A distinct class of Alaskan corporations shall include those operations that handle substantial quantities of hydrocarbons and other hazardous materials, as classified by the ADEC, and be subject to a corporate income tax of 14%. The safety and security issues presented by these operations require significant oversight, security and public safety assets that warrant an enhanced level of corporate classification in such regard.

Royalty Rates: Lease bidders will proffer a signing bonus payment and a bid above an adjustable royalty floor/minimum established between 1% for the least marketable hydrocarbon, (e.g. inaccessible, undefined gas fields), to a maximum of 20% for the highest wellhead value hydrocarbon, (e.g. well defined, light and accessible liquids such as those at Point Thompson). Each new lessee shall consent to an adjustment of its royalty rate every 5 years after production startup that reflects any increase or decrease in the market valuation of the BTU content of the hydrocarbon(s) under development and/or by a substantial improvement in accessibility of leased properties as generated by state efforts. Lessees shall provide all necessary information needed to assess the accessibility of lease holdings and the relative BTU value of Alaskan hydrocarbons. The ADNR/ADOG shall provide a report to the legislature at the beginning of each general session all best interest findings relative to oil and gas development and suggest any additional statutory provisions necessary to advance the optimal development of the state's hydrocarbon resources from existing and proposed leases/lease sales.

Hydrocarbon Exploration, Production and Transport Lease Provisions: ADNR and AOGCC, shall in their administration of lessees operations, conduct the necessary analyses and issue appropriate directives to lessees to provide for the revenue optimizing extraction rates and use of technologies with respect to recovery of viscous and heavy oil recovery as such extraction may be tied to concurrent availability of lighter oils. All new leases shall have relinquishment provisions that reflect the realistic development timelines given the difficulty perfecting necessary permitting and development tasks. All lessees consent to regulation and assistance by the ADEC to effectively utilize and otherwise abate or sequester greenhouse gases released by exploration, production, transport, power generation and refinery operations associated with its leases. Lessees shall proportionately supply all necessary fuel for state aircraft, vessels and vehicles used to assist and administer lessees' operations.

Exploration Commitment: In order to exact the highest signing payments and royalty bids and to provide for a most efficient and predictable development of Alaska's hydrocarbon resources, the ADNR will commit to obtaining the services of exploration experts, whether contracted or employed, with the most advanced geologic mapping and analysis capability to define hydrocarbon resources to their greatest practicable extent prior to leasing of hydrocarbon fields to enhance "prospectivity".

Infrastructure Commitment: The ADOT in an MOU with DNR shall employ all due diligence in coordinating interested state and federal agencies to develop, subsidize or otherwise facilitate transportation of exploration and production materials to proposed leasing areas and for access of gas by Alaskan communities. A dedicated 4% portion of total royalty payments shall be set aside for this Safe Transport Development fund. The ADOT shall minimally provide heavy lift helicopters and other low impact vehicles to advance preservation of sensitive areas, enhance spill response, protect wildlife and maintain security in leasing areas as training for their primary public safety and security duties that shall include repair and prevention of Global Warming impacts across Alaska. The ADOT shall also advance planning and construction of ports, port services, rail systems and pipelines necessary to promote efficient materials transport along established Alaskan transport corridors and extensions along the AGIA certified ROW(s).

<u>**Carbon Conservation Commitment**</u>: The state shall employ all due diligence with appropriate funding of legislative and regulatory efforts to establish in state and federal law establishing a transferable carbon tax and to additionally advance CO_2 sequestration and secondary utilization, methane capture and abatement, and Arctic-appropriate carbon-neutral energy generation technologies using a dedicated 4% portion of total royalty payments. The ADEC shall develop regulations establishing a carbon tax, appropriate emissions standards and/or other carbon limiting constraints upon hydrocarbon lessees. The ADEC shall conduct the necessary analyses to establish abatement technology standards and pursue advancement of the best available technologies with a bi-annual $3 million grant funding that may accumulate beyond the $3 million level to ensure appropriate funding of appreciably superior and effective technologies.

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

Competitive Oil and Gas Lease ADL No.

THIS LEASE is entered into , between the State of Alaska, "the state," and

"the lessee," whether one or more, whose sole address for purposes of notification is under Paragraph 25.

In consideration of the cash payment made by the lessee to the state, which payment includes the first year's rental and any required cash bonus, and subject to the provisions of this lease, including applicable stipulation(s) and mitigating measures attached to this lease and by this reference incorporated in this lease, the state and the lessee agree as follows:

1. GRANT. (a) Subject to the provisions in this lease, the state grants and leases to the lessee, without warranty, the exclusive right to drill for, extract, remove, clean, process, and dispose of oil, gas, and associated substances in or under the following described tract of land:

containing approximately acres, more or less (referred to in this lease as the "leased area"); the nonexclusive right to conduct within the leased area geological and geophysical exploration for oil, gas, and associated substances; and the nonexclusive right to install pipelines and build structures on the leased area to find, produce, save, store, treat, process, transport, take care of, and market all oil, gas, and associated substances and to house and board employees in its operations on the leased area. The rights granted by this lease are to be exercised in a manner which will not unreasonably interfere with the rights of any permittee, lessee or grantee of the state consistent with the principle of reasonable concurrent uses as set out in Article VIII, Section 8 of the Alaska Constitution.

saltwater disposal, and preparing oil, gas, or associated substances for transportation off the unit area, and free of any lien for them.

8. PAYMENTS. All payments to the State of Alaska under this lease must be made payable to the state in the manner directed by the state, and unless otherwise specified must be tendered to the state at:

DEPARTMENT OF NATURAL RESOURCES
550 WEST 7TH AVENUE, SUITE 1410
ANCHORAGE, ALASKA 99501-3561
ATTENTION: FINANCIAL SERVICES SECTION

or in person at either of the Department's Public Information Centers located at

550 W. 7th Ave., Suite 1260 Anchorage, Alaska	3700 Airport Way Fairbanks, Alaska

or to any depository designated by the state with at least 60 days notice to the lessee.

9. PLAN OF OPERATIONS. (a) Except as provided in (b) of this section, a plan of operations for all or part of the leased area must be approved by the commissioner before any operations may be undertaken on or in the leased area.

(b) A plan of operations is not required for:

(1) activities that would not require a land use permit; or

(2) operations undertaken under an approved unit plan of operations.

(c) Before undertaking operations on or in the leased area, the lessee shall provide for full payment of all damages sustained by the owner of the surface estate as well as by the surface owner's lessees and permittees, by reason of entering the land.

(d) An application for approval of a plan of operations must contain sufficient information, based on data reasonably available at the time the plan is submitted for approval, for the commissioner to determine the surface use requirements and impacts directly associated with the proposed operations. An application must include statements and maps or drawings setting out the following:

(1) the sequence and schedule of the operations to be conducted on or in the leased area, including the date operations are proposed to begin and their proposed duration;

(2) projected use requirements directly associated with the proposed operations, including the location and design of well sites, material sites, water supplies, solid waste sites, buildings, roads, utilities, airstrips, and all other facilities and equipment necessary to conduct the proposed operations;

(3) plans for rehabilitation of the affected leased area after completion of operations or phases of those operations; and

(4) a description of operating procedures designed to prevent or minimize adverse effects on other natural resources and other uses of the leased area and adjacent areas, including fish and wildlife habitats, historic and archeological sites, and public use areas.

(e) In approving a lease plan of operations or an amendment of a plan, the commissioner will require amendments that the commissioner determines necessary to protect the state's interest. The commissioner will not require an amendment that would be inconsistent with the terms of sale under which the lease was obtained, or with the terms of the lease itself, or which would deprive the lessee of reasonable use of the leasehold interest.

(f) The lessee may, with the approval of the commissioner, amend an approved plan of operations.

(g) Upon completion of operations, the lessee shall inspect the area of operations and submit a report indicating the completion date of operations and stating any noncompliance of which the lessee knows, or should reasonably know, with requirements imposed as a condition of approval of the plan.

(h) In submitting a proposed plan of operations for approval, the lessee shall provide ten copies of the plan if activities proposed are within the coastal zone, and five copies if activities proposed are not within the coastal zone.

10. PLAN OF DEVELOPMENT. (a) Except as provided in subparagraph (d) below, within 12 months after completion of a well capable of producing oil, gas, or associated substances in paying quantities, the lessee shall file two copies of an application for approval by the state of an initial plan of development that must describe the lessee's plans

for developing the leased area. No development of the leased area may occur until a plan of development has been approved by the state.

(b) The plan of development must be revised, updated, and submitted to the state for approval annually before or on the anniversary date of the previously approved plan. If no changes from an approved plan are contemplated for the following year, a statement to that effect must be filed for approval in lieu of the required revision and update.

(c) The lessee may, with the approval of the state, subsequently modify an approved plan of development.

(d) If the leased area is included in an approved unit, the lessee will not be required to submit a separate lease plan of development for unit activities.

11. INFORMATION ACQUIRED FROM OPERATIONS. (a) The lessee shall submit to the state all geological, geophysical and engineering data and analyses obtained from the lease within 30 days following the completion of a well. The lessee shall submit to the state data and analyses acquired subsequent to well completion within 30 days following acquisition of that data. The state may waive receipt of operational data from some development, service or injection wells. The state will inform the operator of the waiver prior to well completion. The lessee shall submit the data and analyses to the Division of Oil and Gas, Department of Natural Resources, at the location specified in paragraph 25 of this lease. The data and analyses shall include the following:

(1) a copy of the completion report (AOGCC form 10-407) with an attached well summary, including daily drilling reports, formation tops encountered, a full synopsis of drillstem and formation testing data, an identification of zones of abnormal pressure, oil and gas shows and cored intervals;

(2) latitudinal and longitudinal coordinates for the completed surface and bottom hole locations;

(3) a copy of the permit to drill (AOGCC form 10-401 only, additional documentation not required) and the survey plat of the well location;

(4) a paper copy (no sepia copies) of all final 2-inch open hole and cased hole logs, including measured depth and true-vertical depth versions, specialty logs (such as Schlumberger's cyberlook, formation microscanners and dipmeter logs), composite mud or lithology log and report, measured-while-drilling (MWD) and logged-while-drilling (LWD) logs, velocity and directional surveys;

(5) a digital version of well logs in LAS, LIS or ASCII format on IBM format floppy disks, a digital version of velocity surveys in SEG Y format, a digital version of directional surveys in ASCII format (other formats may be acceptable upon agreement with the Division of Oil and Gas); and

(6) a paper copy of all available well analyses, including geochemical analyses, core analyses (porosity, permeability, capillary pressure, photos, and descriptions), paleontologic and palynologic analyses, thermal maturation analyses, pressure build up analyses, and fluid PVT analyses (an ASCII format digital version of the above information shall also be submitted, if available). The state may require the lessee to submit additional information in accordance with the applicable statutes and regulations in effect at the time of the completion date of the well.

(b) Any information submitted to the state by the lessee in connection with this lease will be available at all times for use by the state and its agents. The state will keep information confidential as provided in AS 38.05.035(a)(9) and its applicable regulations. In accordance with AS 38.05.035(a)(9)(C), in order for geological, geophysical and engineering information submitted under paragraph 11(a) of this lease to be held confidential, the lessee must request confidentiality at the time the information is submitted. The information must be marked **CONFIDENTIAL**.

12. DIRECTIONAL DRILLING. This lease may be maintained in effect by directional wells whose bottom hole location is on the leased area but that are drilled from locations on other lands not covered by this lease. In those circumstances, drilling will be considered to have commenced on the leased area when actual drilling is commenced on those other lands for the purpose of directionally drilling into the leased area. Production of oil or gas from the leased area through any directional well surfaced on those other lands, or drilling or reworking of that directional well, will be considered production or drilling or reworking operations on the leased area for all purposes of this lease. Nothing contained in this paragraph is intended or will be construed as granting to the lessee any interest, license, easement, or other right in or with respect to those lands in addition to any interest, license, easement, or other right that the lessee may have lawfully acquired from the state or from others.

13. DILIGENCE AND PREVENTION OF WASTE. (a) The lessee shall exercise reasonable diligence in drilling, producing, and operating wells on the leased area unless consent to suspend operations temporarily is granted by the state.

(b) Upon discovery of oil or gas on the leased area in quantities that would appear to a reasonable and prudent operator to be sufficient to recover ordinary costs of drilling, completing, and producing an additional well in the same geologic structure at another location with a reasonable profit to the operator, the lessee must drill those wells as a reasonable and prudent operator would drill, having due regard for the interest of the state as well as the interest of the lessee.

(c) The lessee shall perform all operations under this lease in a good and workmanlike manner in accordance with the methods and practices set out in the approved plan of operations and plan of development, with due regard for the prevention of waste of oil, gas, and associated substances and the entrance of water to the oil and gas-bearing sands or strata to the destruction or injury of those sands or strata, and to the preservation and conservation of the property for future productive operations. The lessee shall carry out at the lessee's expense all orders and requirements of the State of Alaska relative to the prevention of waste and to the preservation of the leased area. If the lessee fails to carry out these orders, the state will have the right, together with any other available legal recourse, to enter the leased area to repair damage or prevent waste at the lessee's expense.

(d) The lessee shall securely plug in an approved manner any well before abandoning it.

14. OFFSET WELLS. The lessee shall drill such wells as a reasonable and prudent operator would drill to protect the state from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas is produced in a well on other land not owned by the State of Alaska or on which the State of Alaska receives a lower rate of royalty than under this lease, and that well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and that well produces oil or gas for a period of 30 consecutive days in quantities that would appear to a reasonable and prudent operator to be sufficient to recover ordinary costs of drilling, completing, and producing an additional well in the same geological structure at an offset location with a reasonable profit to the operator, and if, after notice to the lessee and an opportunity to be heard, the state finds that production from that well is draining lands then subject to this lease, the lessee shall within 30 days after written demand by the state begin in good faith and diligently prosecute drilling operations for an offset well on the leased area. In lieu of drilling any well required by this paragraph, the lessee may, with the state's consent, compensate the state in full each month for the estimated loss of royalty through drainage in the amount determined by the state.

15. UNITIZATION. (a) The lessee may unite with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the exploration, development, or operation of the pool, field, or like area or part of the pool, field, or like area that includes or underlies the leased area or any part of the leased area whenever the state determines and certifies that the cooperative or unit agreement is in the public interest.

(b) The lessee agrees, within six months after demand by the state, to subscribe to a reasonable cooperative or unit agreement that will adequately protect all parties in interest including the state. The state reserves the right to prescribe such an agreement.

(c) With the consent of the lessee, and if the leased area is committed to a unit agreement approved by the state, the state may establish, alter, change, or revoke drilling, producing, and royalty requirements of this lease as the state determines necessary or proper to secure the proper protection of the public interest.

(d) Except as otherwise provided in this subparagraph, where only a portion of the leased area is committed to a unit agreement approved or prescribed by the state, that commitment constitutes a severance of this lease as to the unitized and nonunitized portions of the leased area. The portion of the leased area not committed to the unit will be treated as a separate and distinct lease having the same effective date and term as this lease and may be maintained only in accordance with the terms and conditions of this lease, statutes, and regulations. Any portion of the leased area not committed to the unit agreement will not be affected by the unitization or pooling of any other portion of the leased area, by operations in the unit, or by suspension approved or ordered for the unit. If the leased area has a well certified, under 11 AAC 83.361, as capable of production in paying quantities as defined in 11 AAC 83.395(4) on it before commitment to a unit agreement, this lease will not be severed. If any portion of this lease is included in a participating area formed under a unit agreement, the entire leased area will remain committed to the unit and this lease will not be severed.

16. INSPECTION. The lessee shall keep open at all reasonable times, for inspection by any duly authorized representative of the State of Alaska, the leased area, all wells, improvements, machinery, and fixtures on the leased area, and all reports and records relative to operations and surveys or investigations on or with regard to the leased area or under this lease. Upon request, the lessee shall furnish the State of Alaska with copies of and extracts from any such reports and records.

17. SUSPENSION. The state may from time to time direct or approve in writing suspension of production or other operations under this lease.

Testimony to State of Alaska Senate Judiciary Committee
Chairman Hollis French - Re: SB 2001
Date: November 1, 2007
From: Mary and Jim Odden, Glennallen, Alaska (Nelchina)

Senator French and other members of the Judiciary Committee, we thank you for this opportunity to express our thoughts on the important PPT legislation.

My husband and I have lived in Alaska since the mid-1970s and we have worked in both the public and private sectors. We currently own and operate a community newspaper which serves the Copper River Valley. Our business is very much tied to the local economy here, as well as to some of the intangible assets of life in Alaska.

We consider ourselves fiscal conservatives who also recognize that state government bears responsibility for maintaining public education, public safety, resource management, transportation infrastructure, and care for the weakest of our citizens.

We support the careful design of a fiscal plan for this state. We do not believe that major oil producers or the very slick, very expensive propaganda from their industry associations needs to tell us to do this, nor do we believe that the best long-term interests of the citizens of Alaska are necessarily those of the oil producers. We ask that our legislators make an open-eyed appraisal of where those interests diverge.

We support the governor's ACES plan which in our understanding is based on running hundreds of scenarios of different oil fields' productions and production costs at both low and high oil prices. If the legislature lowers the tax percentage from the ACES recommendation, then a tax progressivity should be made to balance the losses.

We believe that not only will the oil and gas industry NOT be hurt under the governor's plan, but that the plan promotes the much-desired stability.

Much has been heard on the tax percentage, but other provisions of ACES are equally important to our future as a state.

In particular, we ask that legislators preserve the price floor cost protections which ACES would institute on legacy fields such as Prudhoe.

And we ask that all the revenue and expense reporting requirements which ACES would place on industry in order to properly manage the PPT are preserved in the legislation. Transparency is critical. Give Alaska the tools.

Last, we ask you to adopt some form of the Senator Dyson amendment which asks that a future percentage of tax payments be dedicated to repaying the Constitutional Budget Reserves account.

Thank you for your time.

Subject - PPT

If the Oil companies are saying that they will leave under a higher tax structure, then the Alaska Legislature needs to ask "To Where?" ~~All the oil companies are continually claiming to leave~~

The Legislature has a ~~Fidu~~ fiduciary responsibility to put all the facts on the table during this important Debate

Mike Milligan
12056 Gara Dr.
Kodiak, Ak. 99615
487-4402

Alaska State Legislature

Please enter into the record my testimony to the Senate Judiciary
committee name

committee on PPT, dated 11-1-07.
bill/subject

PLEASE SEE TESTIMONY ATTACHED

Signed: Mike Milligan
Testifier

Representing (Optional)

12056 Gara Dr Kodiak 99615
Address

487-4402
Phone No.

The testimony of Jerry McCutcheon to Senate Judiciary 11/01/07

Mr. Chairman; Senators:

The use of ridiculous illustrative examples needs to stop; for they have bad habit of later being used as fact. Why do you think the oil companies are using DNR, DOR numbers rather than their own like Exxon's testimony today. Because some State dummy put out an illustrative example which proves the oil companies case better than the real oil company numbers do. Not one of you seems to have to have 'guts' to ask the oil companies to site exactly where they obtained the State numbers and obtain a copy of the document. Nor make the oil companies use their own numbers.

Gaffney Cline's use of wild "Blank" examples. For example: 250,000 barrels day as the oil pipeline minimum flow and shut down point is nuts! I do not care if it is only illustrative, it is stupid. Anybody want bet that it will not show up as real before the next election? And attributed to the State's experts! So it must be fact!

250,000 barrels at $80 /barrel is $7.3 billion a year. What lose wing nut is going shut down the oil line with $7.3 billion in oil flowing thru the oil line.

@40/barrel it is $3.65 billion ; @$20/ barrel it is $1.8 billion and @$10/ bl it is $900 million; not even $10 oil will not result in a shut down . 30 years ago van Poolen used 100,000 Bls/day not because that was the shut down point but because he needed some cut off for the computer. Oil companies did the same.

Lets use 100,000 barrels / day then @ $80/ bl oil is $ 8 million a day or that is $2.9 billion year; @40 / bl is $1.5 billion; @$20 is $750 million

Lets try just 50,000 barrels / day and $80 oil that is $1.5 billion; @$40 oil is $750 million/ year. @ $20 oil it is $375 million /year. Are you legislators so simple as to think the oil companies would shut down the oil line if thru put was only 50,000 barrels /day and oil was only $20 /barrel? Do you really think they would abandon the billions of dollars of infrastructure on the North Slope and then have pay for its removal. You have got a lose screw! Net, IRR's and stick them where they fit you the best. Get real ! Exxon just today told House Resources that there is another 53 billion barrels to be discovered in Alaska and that does not count the 30 billion barrels of viscous oil or the 30 billion barrels of heavy oil.

You have perfect example of no abandonment out there in Cook Inlet; they are called platforms and there is not a damn one of them that makes any economic sense the way you have been calculating things. Simply put, it costs more remove the platforms than to keep them. That is why they are still there.

There is a 1978 legislative report that calls for the construction of a new small oil line, when the oil flow thru the line gets too low, to take the remaining oil off the North Slope, then the conversion of the current oil line to a gasline.

But the fact that Prudhoe Bay has already produced 6.1 billion barrels more oil than would have been produced if a gasline were constructed back in the 1980' with more addition oil to come brought to an end to that idea for there is at least 9 billion or more barrels remaining in Prudhoe Bay to be produced. And you thought BP's 50 more years was just more hype, it is, but it is also true, probably the only time they told the truth.

It is a very good time to discuss the Cook Inlet platforms for those of you who persist at demanding a gasline at the expense oil recovery. There is more once recoverable oil that is now unrecoverable oil under the platform than they recovered, a [illegible]llion plus barrels worth at least $80 billion dollars at today's prices. Why? Because they because they sold off the gas as it came up with the oil. You do not get 15 percent decline rates when the gas is recycled for oil production. You can forget that AGRIUM $C0_2$ hocus pocus, it is not for real. If AGRIUM's ploy was for real they would be saying thing differently. It is not that it cannot be done but not the way they are going about it.

Some of you just don't want to get it. Like Senator Huggins who wants to storm a round and do something about getting a gasline ever since van Meurs. Do you really think Huggins is that stupid or does Huggins think you legislators are that gullible? Here is what Senator Huggins told the Resource Development Council before he introduced Representative Samuels: "regardless of what else is said here today, remember the gas is not going to flow before 2020, if at all".

Swanson River oil reservoir, Chevron / ARCO, leased gas from the Kenai gas field, Union /Marathon, for $0.10/ mcf and injected the gas into Swanson River to rebuild the gas pressure. The supplemental gas injection preformed so well, that Swanson River was one of the subjects at an SPE convention in Denver in 1977. The percent of oil recovery for Swanson was three times that of the platforms. Union / Marathon bought Swanson River reservoir to get their gas back when ARCO was sold.

Point Thomson's gas will not be available for twenty years after the litigation is settled. The highest and best use of Point Thomson's gas is to be injected into Prudhoe Bay to increase the gas pressure and therefore the oil recovery similar to Swanson River. Prudhoe Bay can take two Point Thomsons and have room for more. Since Alaska will own point Thomson, if Governor Palin does not sell Alaska out, Alaska should sue the Prudhoe Bay owners for a realignment of interests in Prudhoe with Point Thomson like the Prudhoe Bay owners sued one another several times to sort out Prudhoe Bay ownership the last time about a decade ago. The injection of Point Thomson's gas into Prudhoe Bay would make the State of Alaska the largest share holder in Prudhoe Bay.

Jerry McCutcheon susitnahydronow@yahoo.com