State of Alaska

Department of Revenue
Commissioner's Office

SARAH PALIN, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0405
Phone: (907) 465-2300
Fax: (907) 465-2394

The Honorable Mike Doogan
House District 25 Representative
716 West 4th Avenue
Anchorage, Alaska 99501
(907) 269-0216

October 17, 2007

Dear Representative Doogan,

Thank you for your questions and we look forward to working with you through the ACES process. Your original questions and the Department's answers are set forth below. Please let me know if you require any additional material.

1. *Deputy Commissioner Marcia Davis said at the outset that the administration wanted to fashion a tax plan that encouraged industry investment and enhanced stat revenue. Are these goals listed in priority order; that is, in instances that inevitable trade-offs arose between the two goals, were they decided in favor of investment over revenue?*

> The two goals are of equal value. The balance of the two goals leads to the ultimate objective to maximize the total value of oil and gas resources received by the state.

2. *Was the failure to predict income from the existing PPT all attributable to higher costs being claimed by the industry? If not, what other factors led to the spectacular chasm between what had been predicted for PPT and what was paid?*

> The difference between the PPT forecast and actual tax revenues was due primarily to the inaccurate nature of the cost information used in the forecast calculation. The fiscal notes provided during the 2006 PPT debate relied on a variety of sources, including reports of outside experts, public statements from the North Slope producers, and some 2002 – 2004 cost information provided by the producers. The current PPT law does not require industry to supply detailed information relating to past or future costs, making it difficult for the department to determine whether the increases were due primarily to increase prices on current investments (price per item), or from an increased level of investment activity (more items purchased). This is one of the primary reasons ACES seeks to make the companies/taxpayers report their costs to us in real time--and prospectively.

To some extent we know that costs increased as a result of increased prices. The department has verified a global price escalation that took place over the past two years due to both the global increase in material and labor costs due to increasing demand, and the North Slope specific renewal of many industry sub-contracts. The contracts negotiated by producers in late 2005 and 2006 were at substantially higher prices than their earlier contracts. The prior lower priced contracts were negotiated at a time when producers believed that oil prices would fall, and that belief suppressed the pricing of contractors who knew that work would only materialized if the oil and gas projects could be shown to be profitable at approximately $20 barrel oil. We anticipate costs to rise slightly more before leveling off after the coming fiscal year, as additional North Slope contracts are re-negotiated.

3. *Since there has been no auditing of costs claimed by the industry under PPT, what confidence can we have that the administration's revenue projections based on that data are accurate?*

For our projections we have used the costs filed by the producers in their tax returns. Until these returns are audited, the appropriateness and accuracy of the reported cost amounts remain open questions. It is unlikely that the industry has understated its costs

ACES contains provisions that will rectify the situation the administration currently faces. ACES will improve DOR projections through stricter reporting requirements that are not contingent solely upon tax returns. It will include the obligation to supply DOR with documentation that is currently supplied by the unit operators to the other unit working interest owners relating to budgetary matters. This information will contain the operators' forecasted costs for the next 12 to 18 months associated with the Unit's approved operations plan. While these plans can be changed by the working interest owners over time, the DOR will likewise be made aware of those changes real time.

In addition, current information will be made more readily and timely available to the DOR by the ACES provisions that (1) enhance the DOR's ability to hire a sufficient number of qualified oil and gas tax auditors to speed up our auditing process, (2) create a comprehensive, workable database where the data is derived via computer from standardized monthly and annual tax reporting forms, and (3) an extended statute-of-limitations to complete any assessments on filed returns, which will enable DOR to focus on high priority audits without concern that lower priority audits will be timed out.

4. *Insofar as the administration's plan is based on confidential information, how will the legislature be able to satisfy itself that such data is accurate and is being interpreted properly?*

The economic models created by DOR and DNR personnel that analyze various tax proposals were built using a substantial amount of confidential tax payer information, and confidential resource data, without which the models cannot be manipulated. We have been advised by the Department of Law that the legislature may only review this underlying confidential information when the legislature is in executive session and accompanied by signed confidentiality agreements. While this limits what we may allow legislator's to inspect prior to the start of the session, we are happy to share our methodology, including assumptions, so that legislators can understand the analytical underpinnings of the models as a first step to verifying the validity of their results.

5. *In what ways is the administration's tax plan "intended to drive new production?" What sort of research was performed to estimate the effect of the state's production tax policy on the industry's decisions to explore or develop? What other factors are involved? Where do state taxes rank in the hierarchy of industry decision-making?*

Investment decisions are influenced by a number of considerations including resource potential, tax structure, regulatory environment, infrastructure, political stability and many others. Although the resource itself is generally the most significant driver, each company must gage each of these elements according to its own strengths and investment objectives.

From a state's perspective, it is important to understand the relative value of its resource, in addition to how its other features compare to those of competing areas. The state's ability to acquire the greatest possible value for its resources, however, depends largely on the state's ability to understand and respond to investment behavior. This means that regulatory and fiscal systems must be structured in a way that allow companies to meet investor expectations efficiently, but allow the state flexibility in capturing the greatest share of the resource's economic rent.

In structuring a tax system, the state has many tools at its disposal which affect companies in different ways at different periods in a project's economic life cycle. The most significant elements affecting an area's investment attractiveness allow a company to recoup its initial investment dollars as soon as possible. Value contributed by the state through capital credits reduce an investor's up-front costs and have a much greater positive effect on a project's net present value than does a reduction in tax rates. When an oil company invests, its future cash flow has uncertainties because of unexpected reservoir performance, and uncertainty relating to oil price. The sooner it recovers its initial capital investment, the more able the producer is able to weather the downside risks associated with production and oil price.

Both royalties and production taxes reduce the net cash flow that a company receives in the same way that operating and capital expenses do. These factors were taken into consideration in the Administration's modeling efforts, along with cost and sales price sensitivities.

The analysis done by the Administration was based on sampled range of real projects, currently posed for development in Alaska. We were able to model the impact of various tax structures on exploration and development of these projects within the context Alaska's cost environment. The analysis showed several interesting things.

One thing we found was that a straight gross tax rate, at anything like the rate that would be necessary to raise the kind of money that the state should expect to receive from its resource, resulted in quite unfavorable investment metrics across the development plays examined. We also examined a number of gross tax variations incorporating different exploration and development incentives, but were unable to find one that balanced our objectives as well as some of the net-based approaches.

6. *What is the history of industry investment in exploration and development in Alaska, in terms of dollars spent? Has Alaska's percentage of worldwide annual spending for exploration changed during the past 10 years?*

Please see attached documents.

7. *What happened to the "challenges of writing regulations for PPT" mentioned in the department's analysis of Aug. 3?*

The second round of regulations has been largely focused on describing lease expenditures and addressing joint interest auditing. The department anticipates that although challenges will remain, the ACES proposal will be more administrable and drafting regulations for ACES will be a simpler task.

ACES take a clearer approach to defining allowable lease expenditures by enabling the department to make determinations regarding what costs are included. The current PPT language requires the department make explicit exclusions, and to accept unit accounting conclusions regarding which costs qualify.

ACES also removes from consideration as leasehold expenses certain disputable classes of costs such as proportionate abandonment costs, crude oil topping plant costs, and replacement and repair costs associated with unscheduled reduced or shut in production, oil spills or gas releases. These clarifications greatly simplify the technical regulations relating to leasehold expenses.

8. *Is the administration considering contracting for auditors needed for any net profits tax?*

Yes. The department plans to use a contractor in the short-term, along with department auditors, for a compliance review focused on leasehold expenditures that is anticipated to begin immediately. The use of contractors, however, is not a sustainable solution for the state and are only planned to be used over the next 2-4 years. They will help to augment and fully develop the department's own upstream auditing ability and auditor training programs. Requirements for auditors will changes substantially during the first two years as our auditors are provided with the appropriate information.

9. *The original PPT was written as a method of getting a gas pipeline. Since that approach has failed, what will the administration be proposing for provisions that allowed producers to write gas line costs off against their oil taxes?*

The administration believes that a fair tax on oil should not impact the state's prospects for a gasline. ACES, as proposed, will not address the gasline directly but leave in place language from the existing PPT which disallows a gasline project from accruing certain credits (see below). The administration also believes that the most appropriate time to address any changes in the production tax as it applies to gas would be prior to the first open season, but at a time will more economic information is known about gas commercialization opportunities and gas projects are better defined.

AS 43.20.043 (f) of the existing PPT language states:
A taxpayer is not entitled to a credit under this section for expenditures that are made or incurred for the qualified capital investment or for qualified services made for exploration and development of gas that occur in the area of Alaska lying north of 68 degrees North latitude or that are made or incurred to transport gas from reserves located in the area of Alaska lying north of 68 degrees North latitude.

10. *What are the proposed credits for oil exploration and development credited against?*

The credits will offset liability for production taxes. To the extent a company's credits are larger than its production tax liability, the company may transfer credits to another taxpayer. In the case of qualified applicants that produce an average of 50,000 barrels per day or less, the applicant may seek a refund of the credits from the state.

Tax liability = [(Value - Costs) x tax rate] - credits.

Value = volume of oil x wellhead value*
Costs = allowable capital expenditures + operating expenditures
Rate = 25% + .2% for every dollar that net income** per barrel exceeds $30

*Wellhead value = ANS price – transportation costs (TAPS tariff)
* *Net income = Value - Costs

11. *What does allowing two years for claiming capital credits do to the state's revenue projections? How will the added uncertainty introduced into those projections by this provision be accounted for?*

We expect that allowing companies to claim capital credits for two years will actually improve the stability of the state's revenue projections. The effect of the 2 year spreading of costs is that a single high cost year gets spread over two years, muting its negative effect on state revenues. In addition, the state has an opportunity to anticipate and plan on the higher costs that will be experienced in the next ensuing year. Where costs are increasing steady state the state revenues experience no ill effect from the averaging across two years.

12. *What is a participating area?*

A participating area is a subset of an oil and gas unit that is considered reasonably proven to be capable of producing oil and gas in quantities that would enable the operator to earn a profit. By regulation, an Operator must form a participating area prior to production. The unit boundaries are surface boundaries. The participating area can be visualized as an underground water balloon, but with oil and/or gas as its contents, and the participating area's boundaries are the latex rubber balloon that encapsulates the oil and/or gas reservoir. Traditionally, most participating areas encapsulate the volume of oil and/or gas that is considered to be in communication and sharing the same reservoir pressure and other fluid and reservoir properties. Operators develop oil and gas fields within units on a participating area basis and the owners of leases that overlay any part of the participating area agree upon special Operating Agreement provisions to govern the operator's conduct of development of that Participating Area. The Operator submits and DNR approves a methodology for allocation of production and costs for the unitized leased acreage committed to the participating area.

13. *How much of the government take in the administration's charts is state take? What is included in state take, and how much is each of these segments worth?*

In our attempt to capture the state a fair share of Slope-wide revenues we have focused on the concept of the "share of the incremental dollar" or "marginal tax rate" ("MTR"), rather than "take."

The term "Government Take" refers to the percentage of economic rent going to government. This is the cumulative gross revenues less costs (before tax). It is a life-cycle concept involving all development costs, including a companies cost of capital. We use this concept in analyzing investment on new fields, where all (or most) of the costs will be incurred going forward.

'Take' does not work on legacy fields where most costs were incurred many years ago and have already been recovered. In addition, it does not work for examining a single year, for if a lot of costs are incurred one year, and you are looking at take the next year, the results can be deceptive.

The Marginal Tax Rate (MTR) is derived by looking at total per barrel government revenues at one price, and then increasing the costs by one dollar. The difference in per barrel government revenues is the marginal tax rate. The MTR is appropriate when costs have been recovered, and it can be looked at for individual years. It is what many economists use to compare government revenues internationally.

Total government revenues include royalties (state, federal, and private), state property tax, state production tax, state corporate income tax, and federal corporate income tax. The relative amounts of these vary depending on price.

Under ACES, with our 2008 cost assumptions, at a $60/bbl U.S. West Coast ANS price, the marginal tax rate is about 69%. In other words, as the price of oil moves up one dollar, government gets 69 cents of that dollar. About 50 cents of that goes to Alaska, or about $4.6 billion. This is broken out as follows:

Royalties	$1.9 B
Production tax (ACES)	$2.0 B
Property tax	$0.1 B
State corporate income tax	$0.6 B
	$4.6 B

14. *If the government take is a measure of the net value of a barrel of oil, what is that net value? What has been taken out to reach it?*

See question 13

15. *Under what scenario would the gross floor kick in? Specifically, what would have to happen to oil price and/or costs to bring the gross floor into play? Why is the gross floor lower than the ELF take from Prudhoe Bay?*

The floor would kick in when the combination of prices and costs yields net income such that the tax derived under ACES would be less than a tax derived at 10% of the gross revenue at the point of production. Given our assumptions for cost in FY 2008, we estimate the floor would kick in for the combined legacy fields at $40 West Coast oil price.

Under ELF, the gross tax rate would have been 15% X the field-specific ELF. The 10% gross floor would kick in for Prudhoe at an ELF of 0.67. Our forecast would be for this to trigger in 2017. Prior to that, the ELF for Prudhoe Bay would still be above the 10% floor.

16. *Why does the gross floor provision require a less aggressive upside tax?*

There is the potential for significant new investment in both the Prudhoe Bay and Kuparuk River Units. A significant volume of known viscous and heavy oil is located within these two units, and its development will be costly. In addition, investments which slow the pace of decline by 1 or 2 percentage points can mean significant volumes of production at lower costs and thus result in significant revenue to the state. In balancing the lower costs associated with expanding existing developments in legacy fields with the importance of more costly new reservoir developments in these legacy fields, the administration struck a balance that more aggressively protected the state in a low oil price-high cost environment, and in return the administration left producers with a greater upside in the event of higher oil prices and lower costs. It is unreasonable to expect that the producers would proceed with high cost developments within legacy fields, having no protection on the downside, if there were not greater rewards received for taking the risks associated with costs and oil prices. Further, where enhancements to existing production in legacy fields have relatively lower costs compared to similar production volumes coming from new developments, this lower cost benefit is captured in the net tax structure, by lower costs being netted against gross revenues.

17. *The administration's world average figures use the mean "to kick out extreme numbers." If the extreme numbers are real, why would we kick them out?*

The purpose of looking at international "government take" numbers is to provide some guidance as to the fairness of the tax scheme, where "fairness" is measured against international norms. (Note that the notion of "government take" actually says very little about comparative investment attractiveness – which is also importantly a function of the size of the resource prize, and costs of exploration, development, and production.) The calculation of an "average" is indeed highly sensitive to data that falls in the extreme ends of the spectrum ("outliers") that is, an extreme value can significantly move the "average". However, an extreme value tells one little about "norms". The "median" statistic is not affected by outliers; accordingly, as a guide to fairness norms, the "median" provides more robust information.

18. *If, as we are told, North Slope oil production is declining by 6 percent a year, then next year we will be producing about 75,000 barrels a day less. If the administration's less aggressive upside tax leaves $1 a barrel on the table, what return in terms of exploration and development would make foregoing that $27,375,000 worthwhile?*

A: The administration's upside tax is not less aggressive than the current PPT structure. It proposes an increase in the net tax rate on legacy fields of 25% instead of the current 22.5%. In addition, ACES changes progressivity by having it begin at $30/bbl instead of PPT's current $40/bbl net income. While the rate of increase is slightly less aggressive (0.2% under ACES vs. 0.25% under PPT), the significance of the ACES' earlier start-up is that PPT progressivity would not provide greater revenue to the state that that provided by ACES until oil prices were over $120/bbl.

Sincerely,

Pat Galvin, *Commissioner*
Department of Revenue

Title:	**Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration**
Preparer:	Chuck Logsdon, Greg Bidwell, and Cherie Nienhuis, Economists, Department of Revenue
Date:	Updated 10/3/07
Purpose:	Provide information to legislature on capital spending on the North Slope
Data Source:	See sources on "Capex" sheet
Key Assumptions:	None
History:	Spreadsheet has been maintained and updated since the early 1990s.
Disclaimer:	The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration

Millions of nominal Dollars [dollars of the day]

All Companies

Year	Exploration	Development	Total
1975			3,827
1976			1,166
1977			890
1978	274	400	674
1979	174	1,282	1,456
1980	176	1,604	1,780
1981	419	3,104	3,523
1982	647	3,839	4,486
1983	818	1,100	1,918
1984	258	1,193	1,451
1985	514	1,547	2,061
1986	288	771	1,059
1987	288	1,020	1,308
1988	36	765	801
1989	132	748	880
1990	96	1,061	1,157
1991	120	1,178	1,298
1992	216	991	1,207
1993	192	1,148	1,220
1994	72	808	892
1995	84	748	856
1996	108	826	922
1997	96	1,070	1,142
1998	72	1,560	1,608
1999	48	1,179	1,239
2000	60	1,545	1,697
2001	152	1,636	1,788
2002	126	1,054	1,180
2003	90	970	1,060
2004	67	980	1,047
2005	30	1,268	1,301
2006	123	1,591	1,714
2007	194	1,787	1,981

Sources: 1975-1989: Data from the "International Oil Tax Comparison Study", April 1990.
Study did not provide a breakdown by company and no detail for the years 1975-1977.
1990-2000: BP and Arco annual reports; Communications with BP, Arco Alaska.
Various published sources. A breakdown by company provided, but no breakout of
exploration cost and development costs. Exploratory costs assumed to follow
$12 million dollar per well rule of thumb.
2001-2004: Communication with BP, ConocoPhillips 2002 & 2003 Annual Reports,
publications/extrapolations for others. Breakout of capex by company & type Capex spending.
2005-2007: Unaudited taxpayer submitted EIC and PPT credit information as of 10/3/07.
Exploration and development spending breakdown may contain inaccuracies, due to limited
information and to the fact that costs that do not qualify for exploration credits may qualify unde
the PPT as development capital credits.