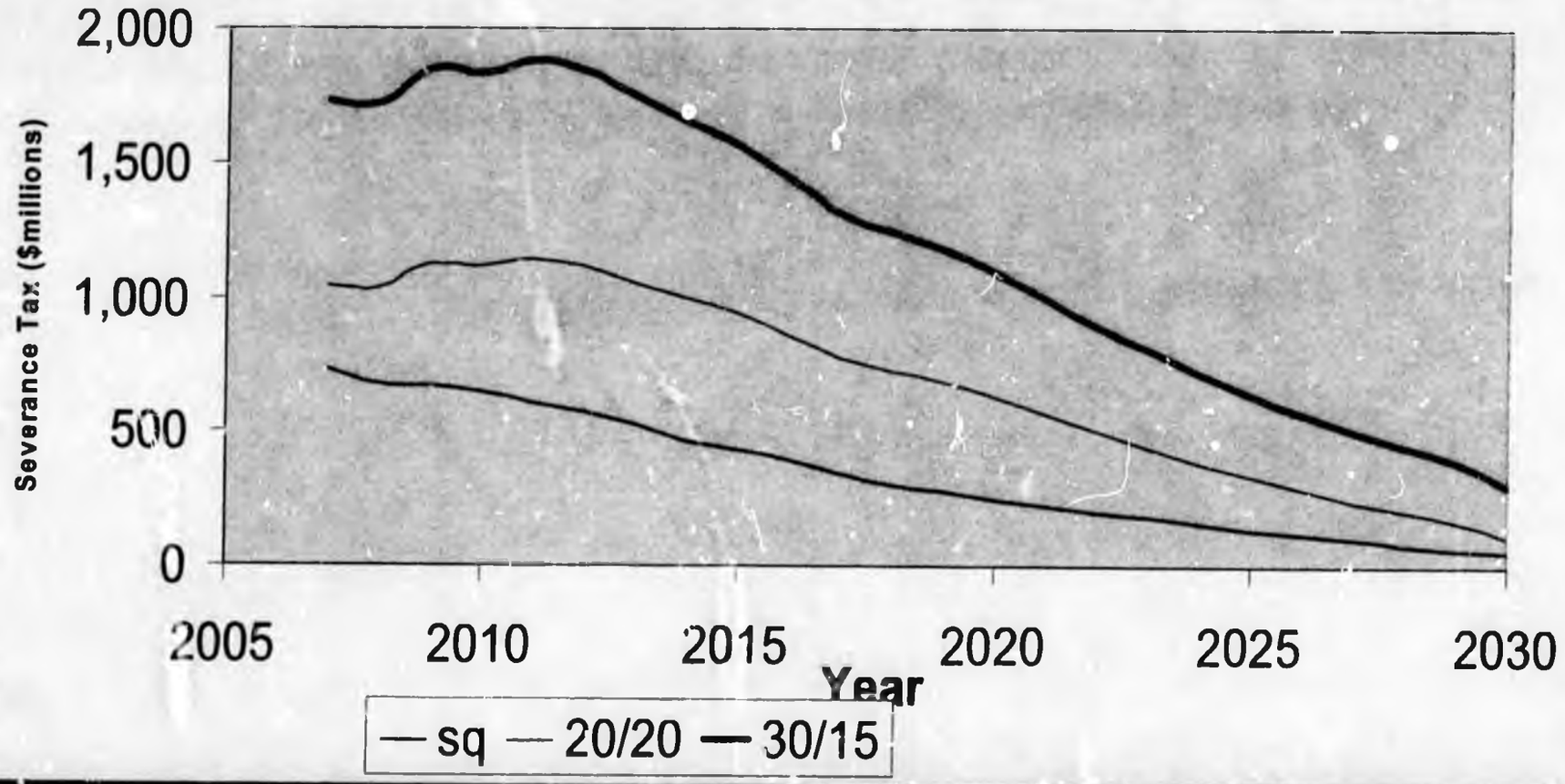
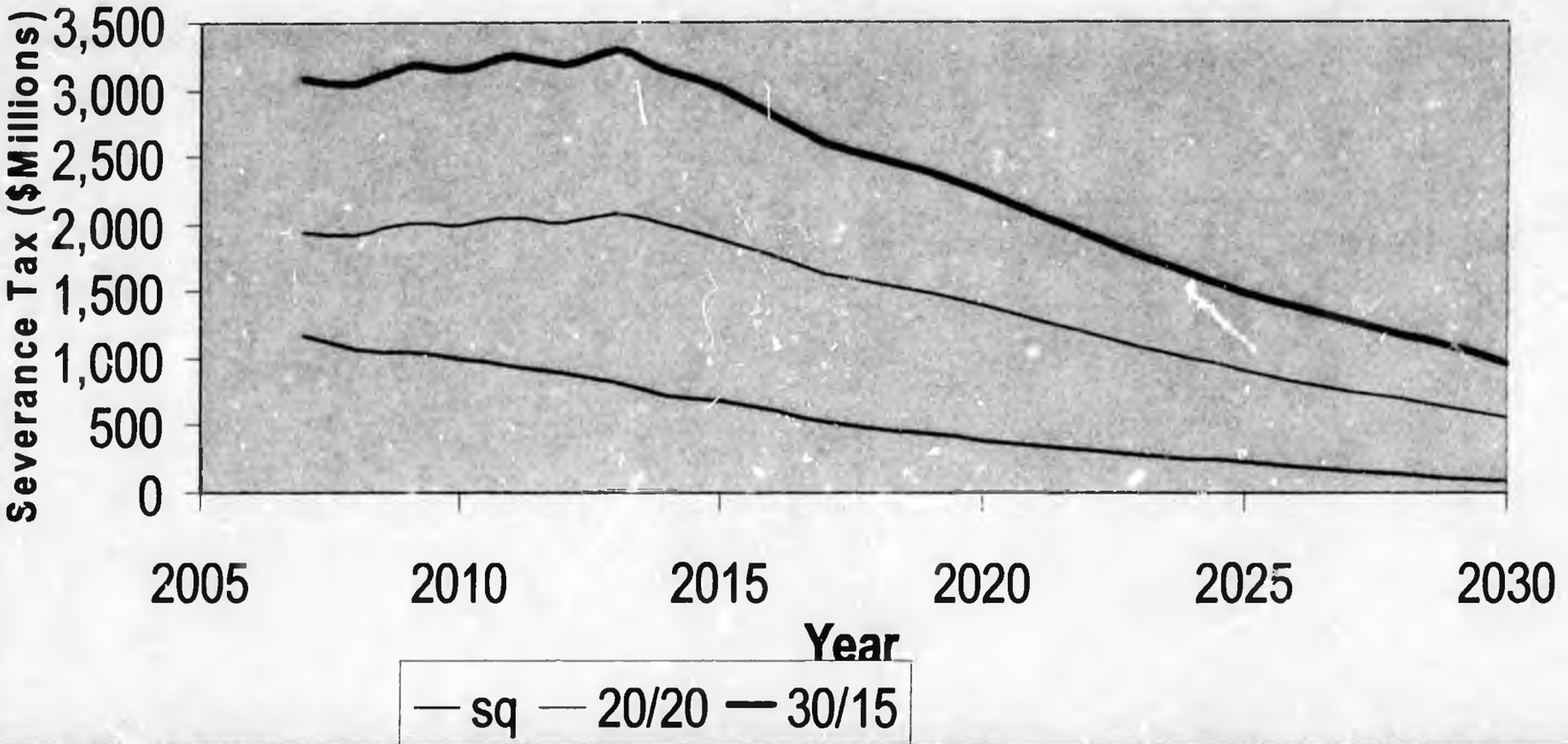
Figure 5c
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40



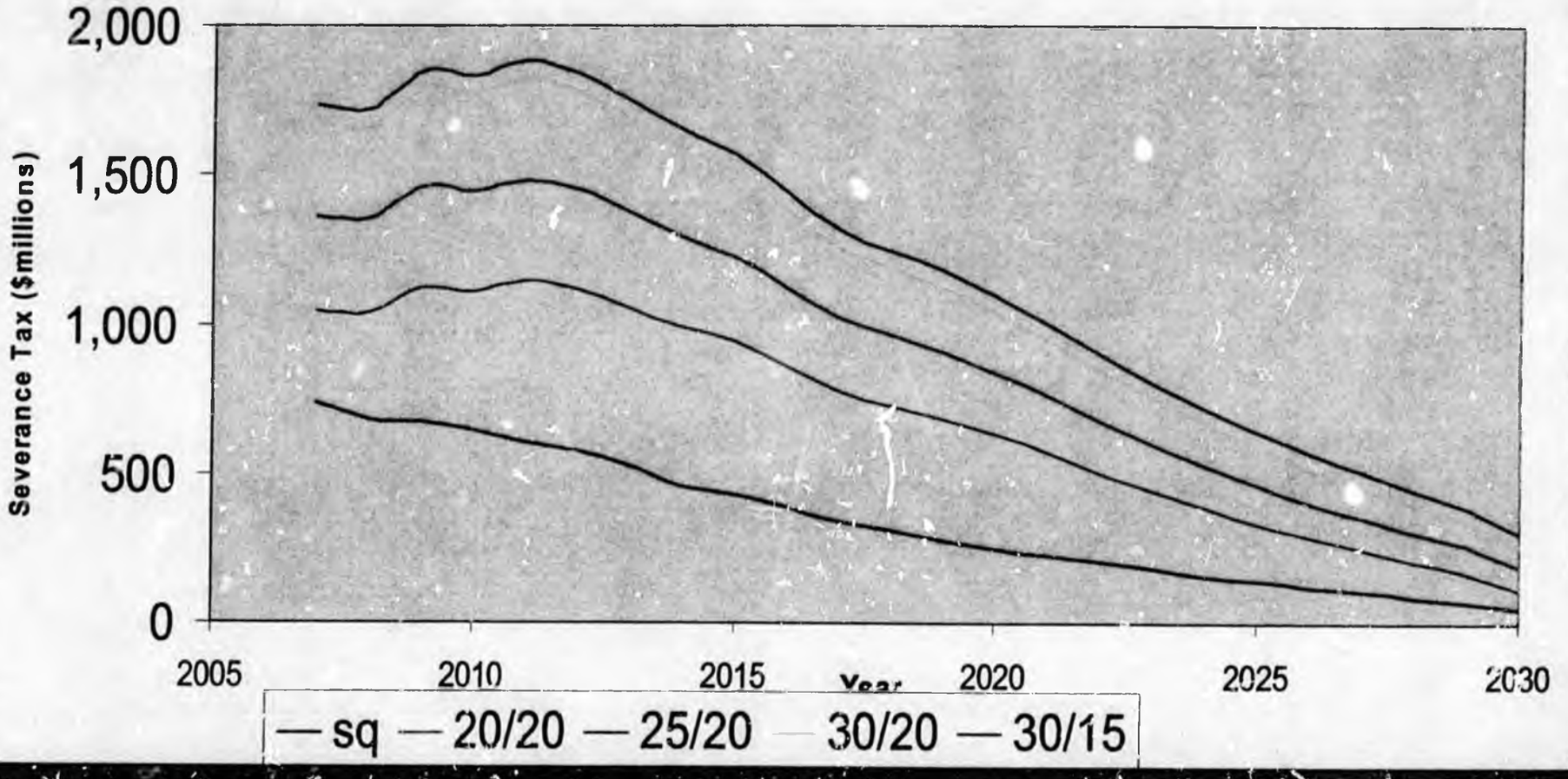
PPT 30/15 - Average annual revenues $840 million more than status quo and $500 million more than 20/20

Figure 6c
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60



PPT 30/15 - Average annual revenues $1,780 million more than status quo & $870 million more than 20/20

Figure 7
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40



STATE OF ALASKA
DEPARTMENT OF
REVENUE

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March 2, 2006

The House and Senate Resource Committees have conducted a number of hearings on HB 488 and SB 305, the Governor's bill repealing Alaska's current tax on oil and gas production and replacing it with a new petroleum profits tax, or "PPT." In the course of those hearings legislators have raised concerns about multiple issues, including certain terms appearing throughout the bill, which terms are defined in Sections 30-33 of the proposed legislation. Those terms and the potential for litigation and gaming they present are discussed in this memorandum.

Potential Ambiguities In Terms Used In The PPT and Consequent Opportunities for Disputes and Gaming

The PPT taxes the value of oil and gas at the "point of production." In calculating taxable value at the point of production, a producer is allowed to deduct capital and operating expenses incurred upstream of the point of production. Additionally, the very same expenses—to the extent they meet the PPT's rather broad definition of "qualified capital expenses"—garner a 20% tax credit, which may be either applied dollar-for-dollar against a producer's tax liability or sold for profit. And any net losses upstream of the point of production also earn a 20% tax credit that can be sold. Since both capital expense tax credits and loss tax credits attributable to operations upstream of the point of production can be liquidated at state expense, even in the absence of tax liability, both those that have a positive tax liability and those that do not have great interest in identifying the "point of production."

The "point of production" has been a subject of intense dispute between the State and its oil and gas lessees for many years. At various times the parties have argued that the point of production falls anywhere from the point at which oil and gas exits the wellbore to the point at which it is "in marketable condition," "of pipeline quality," and entering the Trans Alaska Pipeline System (TAPS) or other oil pipeline leaving the oil and gas unit of origin for market. These disputes have arisen with regard to both the State's royalty share of production (which compensates the State as landowner for its mineral interest) and the State's production tax on all oil and gas production occurring within its borders (whether on lands owned by the State or not).

Generally, oil and gas lessees have argued that the "point of production" is as far upstream as possible—preferably the wellbore. Conversely, the State has argued that the "point of production" is as far downstream as possible—where it leaves the Prudhoe Bay, Kuparuk River, or other unit of origin by pipeline for market. Producers have pushed the point upstream to minimize their royalty and production tax obligations while the State has pushed the point downstream to maximize the royalties and production taxes it collects and avoid issues about the allocation of costs accumulating between the wellbore and unit boundary.

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With the PPT one cannot assume that the producers always will be best served by pushing the point of production upstream and the State best served by pushing the point downstream. For example, an explorer or producer that incurs costs and earns tax credits in a year where it does not have taxable income would prefer that the point of production be moved downstream—at least for that year—to maximize its capital expense tax credits and loss tax credits. Additionally, if the "point of production" for the Pt. Thomson Unit is not at the wellbore but downstream at the unit boundary at the time that field is being developed, under the PPT the State will, effectively, "pay" for 40% of the surface facilities as those expenses are incurred, an outcome producers are certain to favor. However, a producer's financial interest in having the "point of production" pushed upstream or downstream may change for reasons currently unknown to legislators. For example, in a version of the PPT that predated its introduction as legislation, gasline-related capital expenditures incurred downstream of the point of production but upstream of a 2.0 bcfd (or larger) pipeline leaving the state were eligible for a 35% tax credit. While this credit has been removed from the PPT as introduced, we do not know whether it has been included in the gasline contract tentatively reached between the executive branch and producers BP, ConocoPhillips, and Exxon Mobil; if so, it may create an incentive for producers to push the point upstream for a 35% tax credit when they otherwise would have preferred to push it downstream for a 20% tax credit.

The PPT legislation could be amended in an effort to reduce the potential for disputes about the location of the point of production and the allocation of costs incurred upstream and downstream of the point of production. However, as HB 488 and SB 305 now stand, a lawyer working for an oil and gas lessee is given considerable leeway in arguing the point upstream or downstream, and an accountant working for an oil and gas lessee may divvy up costs in a way that a state auditor finds difficult to untangle. Using the Prudhoe Bay Unit as an example, and with regard to gas only, here is why:

Under the PPT there are four different categories of places that may qualify as a point of production for some portion of Prudhoe Bay gas. Factors that influence identification of the point of production for any given gas molecule include whether it is recovered by mechanical separation or gas processing and if it is metered between "gas processing" and "gas treatment." Under the PPT as proposed, the greatest potential for abuse appears to exist for gas run through an integrated "gas processing" and "gas treatment" facility, and the new Gas Treatment Plant planned for Prudhoe Bay may be just such a facility. "Gas processing" is defined to include processing of a gaseous mixture of hydrocarbons for the purpose of extracting and recovering liquid hydrocarbons, where upstream of any gas treatment. "Gas treatment" includes "conditioning gas" and removing non-hydrocarbon substances, as well as incidental removal of liquid hydrocarbons. Ambiguity arises for several reasons. First, "gas treatment" includes "conditioning gas," which is not defined, and one could argue that anything done to take gas from its condition in the reservoir to the conditions it must meet to be placed in a pipeline leaving the state constitutes "conditioning gas." Second, "gas treatment" also includes removing non-hydrocarbon substances from gas, but some non-hydrocarbon substances—like water and sediment—will be largely removed at the Flow Stations and Gathering Centers just downstream of Prudhoe's wellbores, while other non-hydrocarbon substances—such as carbon dioxide and hydrogen sulfide—will be removed in a new GTP, which will be downstream not only of the wellbores, but also the Flow Stations, Gathering Centers, Central Gas Facility (CGF), and most if not all other Prudhoe Bay Unit surface facilities.

Given these logistics and definitions, the Prudhoe Bay Unit operator, with the concurrence of other Prudhoe Bay producers, could attempt to game the system as follows. If the producers chose to push the point of production upstream, the unit operator court run all gas destine for the gas pipeline through the new GTP, making sure not to meter it at a point between the processing and treatment equipment located within the GTP, and claim that "gas treatment" begins, and hence the "point of production" is located, far upstream at the Flow Stations and Gathering Centers where water and sediment are removed. To push the point of production downstream under otherwise identical circumstances, the Prudhoe Bay Unit operator could simply install a meter between the "processing" and "treatment" equipment located within the GTP, and that meter would become the "point of production" under the definitions proposed in the PPT.

Moreover, Prudhoe Bay could become an auditing quagmire if gas recovered by mechanical separation as well as gas recovered without either mechanical separation or gas processing bypasses the processing equipment in the GTP, so that there is a multitude of "points of production" for bits and pieces of the gas originating from the Prudhoe Bay Unit. In that event, the costs of the Unit would be divvied up in accounting and audits necessary only for production tax purposes, and the State would not benefit from the adverse interests of individual lessees or joint interest accounting in the ways discussed by the executive branch when testifying in support of the PPT; it would be left on its own to defend its own interests, which would be adverse to those of the producers.

Arguably, there are other ambiguities in the definitions contained in the PPT. For example, if the point of production is pushed upstream at Prudhoe Bay to the Flow Stations and Gathering Centers and a hydrocarbon that was natural, associated, or casinghead gas is in gaseous phase at one of these facilities but is subsequently recovered in the CGF or new GTP as a liquid, one might argue that "gas" does not become "oil" for production tax purposes downstream of the point of incidence for the tax. This argument becomes more likely if gas is selling for less than oil on a barrel-equivalent basis, as is frequently the case.

The definitions of "point of production," "gas processing," and "gas treatment" are troubling for other reasons. Typically, one thinks of "gas processing" as occurring downstream of the "point of production," unless it is necessary to put gas in marketable condition, in which case it may occur upstream of the point of production, but, as to any governmental share, it is unlike other costs of production in that it is at the government's expense. Yet with the PPT it appears that the executive branch intends gas processing to occur upstream of the point of production, with room for a producer to argue the opposite. Also, frequently "gas treatment" is used in industry to refer to gas handling upstream of the point of production, but with the PPT my guess is that the executive branch intends it to most often or always occur downstream of the point of production. There is danger in using terms regularly used by industry in a manner atypical of industry usage—anyone that chooses to start a dispute has been provided by the PPT with ammunition to do so. Further, typical industry usage may be obscured by atypical application in the PPT, to the potential disadvantage of the State in collecting the royalties it is due based on value at the "point of production."

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Please be aware that with the memorandum I am not representing that the arguments advanced for alternative constructions of terms found in the PPT are the best or "winner" arguments. Rather, the point is that there is room for an interested party to argue that the proposed statutory language is ambiguous, and argue they will, if history is any indication. In fact, there may be too much money riding on one possible outcome for a producer to pass up the opportunity for argument, even if only to later settle somewhere between a better state position and a tenuous producer position.

Possible Approaches to Minimizing Ambiguities and Unintended Consequences

There are a number of possible approaches to mitigate the likelihood and unintended consequences of disputes over the location of the "point of production" and what is meant by "gas processing," "gas treatment," "oil," and "gas." Seven are set forth below:

1. At a minimum, the executive branch and the producers should be asked to go on record in writing in legislative proceedings on the PPT to specifically identify agreed-upon "points of production" for oil and for gas in each of the existing oil and gas units, both for facilities now in existence and for those planned for the future.

2. If the arguable ambiguities identified in this memorandum are brought to the attention of the executive branch, its personnel may come up with their own thoughts on how to "clean-up" the language or may be able to convince legislators that there is no room to argue ambiguity.

3. Legislators may want to ask the executive branch whether its proposed gasline contract will include tax credits for gasline-related capital expenditures, especially those that might influence a producer's desire to move the point of production upstream or downstream.

4. As long as the possibility for disputes over definitions remain, the State may want to retain the few advantages it has in multimillion dollar disagreements with some of the largest, most resourceful, and brightest companies in the world. Those advantages include the ability to set and change rules by regulation, the authority to decide disputes in the first instance by an agency hearing officer, and the jurisdiction of Alaska courts to hear those disputes on appeal, giving deference to agency decisions. If the executive branch is thinking of surrendering these advantages in a gasline contract and the legislature would prefer that the executive branch not, the legislature may want to include language to that effect in any PPT bill passed.

5. Legislators may want to consider a different point of production than that proposed by the executive branch. For example, the point of production could be as discussed by outside counsel for the executive branch in a memorandum dated January 5, 2005 and as found by Judge Compton in an April 1979 decision regarding the State's royalty share under state oil and gas leases. Both Judge Compton and the State's legal counsel have identified the point of production—at least for royalty purposes—as the point where oil is in "merchantable condition" and "metered ... for removal from the unit." More specifically, the point of production for oil could be at the entry of an oil pipeline leaving a unit and the point of production for gas could be at the entry of a gas pipeline leaving a unit, with a requirement in both instances that the oil or gas be in marketable condition and of pipeline quality, though fine-tuning would be needed to address situations where both oil and gas leave a unit in a single multi-phase pipeline, with

treatment that is normally considered part of the process of production occurring off-unit, as might be the case with offshore units or development at Pt. Thomson. Of course, use of the definitions discussed in this paragraph would require the executive branch, producers, and legislators to revisit the cost of the PPT's tax credits, which would increase if the point of production is moved downstream of where it would otherwise fall under the PPT's current definitions.

6. The legislature may want to include language in any legislation passed stating that the definitions used in the PPT are not "fair-game" for use in royalty disputes between the State and producers, at least if the final version of these definitions are in conflict with the principles discussed by Judge Compton in his April 1979 decision and the State's outside counsel in its January 2005 memorandum.

7 Legislators may want to address whether expenses related to experimental facilities for gas-to-liquids are eligible for the deductions and tax credits provided by the PPT. As the PPT now reads, a producer using Alaska as its site for a gas-to-liquids experimental plant may have the State "paying" for up to 40% of the experimental plant as long as one can argue that it is upstream of the "point of production," even if the producer intends to use gas-to-liquids technology in other parts of the world and not in Alaska, and there is little or no taxable production generated by the plant.

If legislators are interested in pursuing these or other ideas for minimizing the possibility of disputes and gaming as a result of terms defined in Sections 30-33 of HB 488 and SB 305, I would be happy to assist in that effort by drafting or reviewing language that could be proposed as an amendment to the PPT.

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March 2, 2006

Senator Tom Wagoner, Chair
Senate Resources Committee
State Capitol, Room 427
Juneau, AK 99801

Rep. Ralph Samuels, Co-Chair
House Resources Committee
State Capitol, Room 126
Juneau, AK 99801

Rep. Jay Ramras, Co-Chair
House Resources Committee
State Capitol, Room 104
Juneau, AK 99801

Re: Questions on PPT Legislation (SB 305, HB 488)

Dear Senator Wagoner and Representatives Samuels and Ramras,

Thank you for the opportunity to respond to questions posed during (and following) recent committee hearings.

Received 2/28/06, 12:00 p.m.

1. Identify values/amounts for the "look-back" or transitional section; per year according to the actual, by type (exploration, development, production), by company.

The Department of Revenue model uses $1 billion per year as capital costs, so for the transitional period, there would be about $5 billion. This annual costs are based on compilations of historical data. The attached excel files outlines public data regarding investments.

2. How are mob, demob, and platform abandonment costs treated—as tax credits or deductions?

Mobilization costs are capitalized for federal tax purposes, as Intangible Drilling Costs. As such, they are a capitalized expenditure for PPT purposes, and therefore are deductible and creditable. We understand that demobilization and abandonment expenditures are both expensed as incurred. This would mean that these costs are deductible, but would not generate a credit.

3. Is there a "rating" for political stability – or one that reflects instability?

We do not have any information on a quantification of the risk of political stability.

4. What loss of revenue is incurred by moving the effective date from Jan 1, 2006 to July 1, 2006 on both 20/20 and on 25/20?

Using a combination of our spring forecast and YTD actuals, the average ANS price between January 1, 2006 and July 1, 2006 was $58.62.

- The loss of revenue using the 20/20 system would be about $480 mm in additional tax.
- The loss of revenue using the 25/20 system would be about $770 mm in additional tax.

5. Section 9 – what amount is involved in this section?

A very small amount, probably no more than 1% of total state revenue from oil and gas. It is limited to three areas: [1] Alpine and its satellites; [2] the National Petroleum Reserve Alaska; and [3] Cook Inlet.

6. Was there consideration of phasing out the $73 million deduction over a certain period of time?

No, it was not considered.

7. Of the current 14 producers in Alaska, which would pay a severance tax after employing the proposed $73 million standard deduction?

With the merger of Chevron and Unocal, there are now 13 producers in Alaska. Of the 13 producers, BP, ConocoPhillips and ExxonMobil will pay severance tax at most price levels after employing the $73 million standard deduction. At high oil and gas prices, and given our cost assumptions, Anadarko and ChevronUnocal will also pay severance tax after deducting the $73 million dollar allowance, given the production volumes reported publicly by those companies.

8. Which other tax regimes – worldwide - have a progressivity structure?

TO BE PROVIDED

9. How many private royalty owners are there in Alaska – all areas, not just the North Slope (i.e., Nenana Basin, Kenai Peninsula, native corporation holdings, etc).

We do not have information on the number of private royalty owners in Alaska, which would include private oil and gas leases that are not in production. Homesteads staked under certain (but not all) federal homestead laws included oil and gas rights, and any of the owners of such parcels might enter into an oil and gas lease.

10. Provide a graph showing the status quo, the PPT, and the gas line contract terms.

This question appears to query the relationship between tax under the status quo, the PPT, and the gas line contract terms. At this time, gas line contract terms are not public information.

11. Provide information on the effect of previous incentives – the costs.

Claimed expenses under SB 185 (43.55.025) total $104. 8 million and claimed credits total $33. 6 million [see table below]. A claim was received by the Department of Revenue last week, thus the totals has been updated from the $95.5 million and $29.0 million figures previously provided.

12. What is the rational for offering the same amount of credits for non-state lease lands where the state receives no royalty tax benefit – was there discussion of a reduction in the credit to offset this?

The rationale is that the incentives have the potential to result in higher severance taxes; taxes that are assessed on any oil or gas production within Alaska's sovereign territory. Given the overall economic benefit of increased production of oil and gas (and particularly gas in the Cook Inlet where significant private lands occur), an incentive for exploration and development even in the event that a field would pay no taxes after incentives makes sense.

13. Why should Point Thomson be incentivised?

We believe the development of Pt. Thomson may be critical for the development of the gasline. Accordingly, incentivizing Pt. Thomson may well incentivize the gasline

Pt Thomson is particularly problematic for two reasons. First, it is a high cost field since it is a high pressure gas condensate reservoir and second we do need the gas reserves to underpin the gas pipeline economics. By providing incentives, the goal would be two fold. First any incentive to encourage Pt. Thomson improves the economics of the gas pipeline. Second, incentives may encourage early production of the liquids which requires expensive infrastructure to handle the high pressure production.

14. Can you provide better definitions for "point of production" and "oil" and "gas" and has the State litigated these terms?

We're not clear whether this question seeks more explanation of the definitions in the bill or is requesting that we consider modifying those definitions. Please clarify. Regarding past litigation, in general the point of production and the definitions of oil and gas have not been major subjects of litigation under the production tax statute. In contrast, there has been considerable litigation of related concepts, though not necessarily the phrase "point of production," in the royalty context.

In the tax context, there was at least one dispute decided at the internal DOR appeal stage relating to point of production, but most of the controversy in this area played out in the development of regulations defining "gas processing plant," rather than litigation. The use of the term "gas processing" in the bill is consistent with existing department regulations, but under current law gas processing generally is considered an activity occurring downstream of the point of production, while under the bill it is considered an activity occurring upstream of the point of production.

15. What steps must be taken to make the tax credits refundable rather than transferable?

This would require a language change to Section 12 at Sec. 43.55.024(d) and (e). We are available to work with drafters on the exact wording.

16. On Page 13, line 24 of the bill, what does "payment in lieu of" tie into for oil?

Section 21 (Sec. 43.55.160(d)(1)(B)) clarifies that payments in lieu of property taxes are deductible. Sec. 43.55.160(c) presents the general rule that lease expenditures are deductible. Lease expenditures would include property taxes. Sub-section (d) provides clarification for items that are not clear, such as "payments made in lieu of property taxes."

17. Does the limit on transferable tax credits in section 12 (subsection (e)) limit the amount of tax credits that a single taxpayer can take against their own production tax in a single year?

Section 12 (Sec. 43.55.024(e)) limits the amount of tax that can be reduced through purchased credits. There is no limit on credits utilized by a taxpayer that were generated by that same taxpayer.

18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues; have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the

legislation on the State's legal position in past agreements, current disputes, or future disputes?

Yes, such counsel(not all of them) have been consulted and such assessments have been discussed but have not generally been generated in formal written form.

19. Have you asked the Department of Law to review this legislation in light of the 6th Circuit Court of Appeals' decision in Cuno v DaimlerChrysler that is now pending before the United States Supreme Court?

The Department of Law has examined this question. As a Sixth Circuit decision, it has no direct precedence for Alaska. It is currently before the U.S. Supreme Court and many analysts believe that it will not be sustained in its current form.

20. Please provide information regarding the expenditures that will qualify for the transition credits—including the depreciation method chosen under the federal and state income tax systems.

It appears that this question relates to the transition provision in Section 21 (Sec. 43.55.160(g)) which allows a deduction for capital expenditures made over the last five years, deductible over the next six years. The capital expenditures that qualify for transitional treatment are the same type of expenditures that qualify for ongoing credits. These are defined in Section 12 (Sec. 43.55.024(h)). These expenditures include exploration expenses and those expenditures that are capitalized for federal tax purposes. Exploration expenses include geological and geophysical exploration. Expenditures capitalized for federal tax purposes include intangible drilling costs. The capitalized expenditures are subject to a variety of useful lives under federal and state income rules. See Question 60 below.

21. Have any of the definitions in sections 30-33 been the subject of disputes with tax and/or royalty payers in the past? To the extent they have, please provide the definitions the state asserted in those disputes.

See question 18 above.

22. Please provide an identification of the point of production at each unit in the state under existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

23. Please provide an identification of 'gas treatment' and 'gas processing' facilities in the state under the existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

24. What standard will be used to determine whether oil or gas is of 'pipeline quality' under the definition of 'gross value at the point of production'?

This term only appears in the definition of "oil." It was not in the old definition, nor the new definition of "gas." The standard for "pipeline quality" has not changed under the bill. The standard is based on a series of court cases.

25. Provide a historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior.

TO BE PROVIDED

26. Will abandonment costs be eligible for deductions or credits under the legislation? If so, what estimates of the timing and costs of those activities does the Department project?

See Question 2 for deductibility of abandonment costs. With regard to costs, we are aware of no field having ever been abandoned in Alaska, and so we do not have any empirical data on costs.

27. How will AS 43.55.160(j) protect the State from a proliferation of corporate entities and/or companies claiming the tax free allowance?

TO BE PROVIDED

28. Provide the number of exploration and delineation wells estimated to be drilled over the first ten years of your economic models. Include the technical and economic success rates projected in the modeling.

Five [5] exploration wells per year are included in the model. The Department of Revenue assumes $100 million is spent on exploration per year. With average costs of $20 million dollars per well, this comes out to five [5] wells per year. Delineation wells are separate and included under development expenditures. The model assumes there are four [4] finds of large oil accumulations – reserves in place that would be on the order of 500 million barrels. There are four [4] relatively small fields that are characterized as being "heavy" oil. These fields would pay no production tax under the current system because their Economic Limit Factor [ELF] would be zero [0.0]. We did not include a "success rate" in our model.

29. Provide estimates for undiscovered resources in Alaska. Include the breakdown between technically recoverable and economically recoverable resources to the extent possible.

TO BE PROVIDED

30. Provide a historical analysis of the effective tax rate on each field in production on the North Slope over the past twenty years.

See Attachments A1 and A2. These tables contain effective tax rates since 1986 for all Alaskan fields on gross value at the point of production. The effective tax rate shown on these tables is the ELF x 12.25% for the first five years of production, and ELF x 15% thereafter. We note the effective rate varies between 15.0%, for Prudhoe Bay through 1987 (when the so-called "rounding rule" rounded the ELF up to 1), and 0.0% for a number of fields for a number of years.

31. How will Net Profit Share Leases be affected by this legislation? Will the gross costs of exploration and development go into the Development Account—or those costs net of the credits and deductions?

TO BE PROVIDED

Received 2/28/06, 2:30 p.m.

32. It's been reported that the gas line contract will propose the state take its gas production tax share in the form of gas. How does that work in this bill?

In the gasline contract the state has indeed proposed taking deliveries of gas in place of a production tax; this is not reflected in the PPT bill which will stand on its own, gasline or no. Under the PPT, if the producers sell gas, those revenues would be part of the net profit calculation. Under the gasline, they would not. Instead the state would receive a percentage of the gas, which it would monetize thought marketing. Note that the costs of developing (for example Pt Thomson) or running (for example Prudhoe Bay) a field that produces both oil and gas would go into calculating the oil profits for the PPT.

33. Of the pre-PPT credit provisions (or claw back), what is the cost to the state for legacy fields and what is the cost to the state for frontier regimes?

See question 20.

34. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

Sale of credits under SB185 do not effect the ability of the seller to claim those credits as Transitional Investment Expenditures (that is to qualify for the claw back.)

35. If we have a gas pipeline in 2015, what will the ELF tax "take" be on North Slope gas and what will the "take" be under the PPT? What will the "take" be under PPT if we take gas in lieu of the production tax (the take would, I assume be the day-to-day value of the gas less the state's cut in selling the gas on the marketplace)?

Without getting into price sensitive forecast, or the confidential draft gas contract, we can make the following observations about the comparison: The upstream costs are covered in the PPT, so the difference could be as simple as;

(a) under the PPT, a taxpayer would pay 20% of the gross value at the point of production, that is sales revenues less the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale would be paid to the state. (without taking into account the effect of the $73 million dollar allowance).

(b) Under the gas contract, the state will receive some percentage of the gas, and then pay the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale. If the state owns part of the pipeline, then the state will also receive that portion of the tariff which is profit accruing to the owner.

36. Is current production tax deductible from corporate tax? If no, is this impact in the models presented by the Administration?

Yes, current production is deductible from corporate tax.

37. Referring to Section five, what oil and gas is exempt from taxation—just what is discussed in Section 10?

The oil and gas royalty amounts paid to the state and federal government are exempt. (AS 43.55.900 (13) "ownership or right to which is exempt from taxation" means any ownership interest of the federal government or the state.")

Section 10 simplifies treatment of flared gas. Under current law there are three categories of gas – gas used in production operations which is exempt from tax, gas produced in excess of that needed for safety purposes which is taxable, and gas flared beyond the amount authorized for safety which is taxed and subject to a penalty. Currently there is no 'free use of oil' to produce more oil in statute. The bill

exempts from tax any oil or gas used in production operations, unless the Alaska Oil and Gas Conservation Commission determines that it was waste (instead of used to produce salable hydrocarbons), in which case it is taxed.

38. Referring to Section six, will there be any impact to current state taxes or municipality taxes from this change?

No, there should be no impact to current state or municipal taxes. This language change simply makes the description of Intangible Drilling Costs consistent with Internal Revenue Code language, which is how this item is interpreted currently.

39. Why was the payment for taxes and surcharges changed from the 20th day to the last day of the month? What is the economic impact of this change?

There is no economic impact and this just clears up current language. Under AS 43.55.020, payment for the tax is "due" on the 20th, however, the tax is not "delinquent" until the last day of the month. The significance of this is that according to AS 43.05.225 interest is assessed only when a tax "becomes delinquent." Thus this bill makes the due date the end of the month and in section 7 establishes that "an unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent."

40. Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

TO BE PROVIDED

41. What are the penalties for under-payment when sure-up is more than ten percent of the taxes owed?

If the taxpayer does not pay 90%, then interest will be due on the difference between the tax paid and the 90% amount.

42. Referring to Section 10, why does the AOGC [Alaska Oil and Gas Conservation Commission] role change from focusing on excess needed for safety reasons to whatever they determine to be waste? Does this provision provide more power to the AOGC on what is included/excluded for taxation?

Under current law, as applied by DOR regulation, the categories of flared gas recognized by DOR are different from (although related to) the categories recognized by AOGCC. The bill will simplify the categorization and harmonize it completely with AOGCC's. This simply creates one standard administered by AOGCC, in place of two standards administered by two agencies.

43. Why does it seem the credits and incentive [sic] are on production along with exploration if our focus is to provide incentives for exploration?

(The bill is based on the expectation that investment, both exploration and in existing fields, will increase production.

44. Can the carry-forward amount be used for a credit for more than the first year after the loss?

Yes, the credit carry-forwards can be used indefinitely. There is no time limit on the credit carryforwards.

45. Is it the case that any allowable expenses for the exploration, development, or production of gas can be deducted from oil revenues in determining net value? If so, could the expenses of a gas line be included in these deductible expenses?

Expenses are allowable only if they are "upstream" costs. A gas line is "downstream" and so would not be a deductible expense.

46. Why not use GAP [sic] accounting rules versus set up or our [sic] system of defining revenues and expenses?

GAAP (Generally Accepted Accounting Principles) are useful for determining whether an item of expenditure can be classified as an "expense." GAAP does not differentiate between expenses incurred specific to a lease and those expenses that are indirect to a lease. For example, GAAP does not distinguish between wages paid to a lease-based worker, and an employee in the home office.

47. Which credits can be applied to multiple years?

There is no time limit for credit carryforwards under the bill, nor for the optional credit codified in 43.55.025. However, any dollar of investment can only generate one credit, and that credit can only be used once.

48. Can a tax credit be sold in any year or just the year after it was accrued?

Once the credit has been turned into a Credit Certificate, it can be sold at any time. A person can apply for a Credit Certificate at any time, but the bill allows the Dept. of Revenue a period of time in which to issue the Credit Certificate. (See Section 12, Sec. 43.55.024(g))

49. What is the estimated economic impact to the state of the ability to sell tax credits?

TO BE PROVIDED

50. Referring to Section 16, what is current system and why do we need this change in confidentiality?

The bill codifies current practice embodied in regulations in our treatment of taxpayer information. The only change here is that the bill makes clear that any person receiving information released under current department practices, is subject to the same criminal penalties that apply to a state employee.

The current confidentiality law is very general in its exception language – information must be kept confidential "except in connection with official investigations or proceedings . . . ." The Department believes that current law does allow disclosure under the circumstances specified in the bill, but there has been some question about that, and it would be desirable to clarify the meaning of the law, as the bill does. In addition, there is the new provision on penalties, referred to above.

51. In what circumstances would oil and gas taxes go straight into the CBR.

Additions to the CBRF (Constitutional Budget Reserve Fund) are made for any oil and gas taxes collected in resolution of a dispute. That means that amounts collected because of an audit assessment, or subsequent settlement, are additions to the CBRF.

52. Referring to Section 18 and 19, why change from shall to is?

This change is made in accordance with the state style manual.

53. Why does the bill offer multiple methods to determine gross value? Who will choose a methodology?

The bill does not directly allow a taxpayer to elect alternative methods, it just allows the Department to authorize use of an alternative method. The election referred to would be an election between using an alternative method or just calculating gross value according to the usual rules – NOT an election among several different alternative methods. In implementing this provision, the Department will no doubt develop criteria for when a particular alternative method would be appropriate. I don't think we can predict now whether there might be circumstances under which more than one alternative method might be appropriate and under which the Department would authorize a taxpayer to elect among several alternative methods.

54. Section 21, page 1, line 8—why is this clause constrained y Dec. 1, 2005?

TO BE PROVIDED

55. Section 21, provision (h), which US CPI does the Administration plan on using?

This would be established by regulation. The Department has not evaluated the various CPI's at this time.

56. Are the current oil conservation surcharges deductible from any other taxation? If no, what is the policy reason to make them a credit in SB 305 and what is the economic impact?

Yes, current oil conservation surcharges are deductible from corporate income tax.

Other Questions

57. Do any other state taxes have a "standard deduction"?

a. Seafood Marketing Assessment (ASMI) tax is imposed only on processors/exporters that process or export fisheries resources with a value of $50,000 or more in a calendar year. AS 16.51.120(g).

b. Mining License Tax is not imposed when net income is less than $40,000 in a fiscal year. AS 43.65.010(c).

c. Gaming tax exempts gross receipts of less than $20,000 from paying the additional fee under AS 05.15.020(b).

d. Alaska's Estate Tax follows federal rules, but the most recent exemption (Fy05) included estates valued at under $1.5M.

58. How many NPSL's (Net Profit Share Leases) are in the state, and how much are they paying in royalties?

Out of 19 NPSL's, seven are paying royalties. These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was $81M. Total receipts from NPSL's from 2001—2005 were $254M.

Out of 19 NPSL's, seven are paying net profit share payments *(in addition to royalties and production taxes)*. These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was $81M. Total NPS receipts from NPSL's from 2001—2005 were $254M. Net profit share payments are not deductible for PPT purposes nor for the current production tax. Royalties and production taxes are deductible for NPS purposes.

Royalties, however, are paid on net profit share leases according to each individual lease contract. For example, one NPS lease in Duck Island Unit has a twenty percent (20%) royalty rate. Other NPS leases may have the standard royalty rate of 12.5% or another, negotiated royalty rate. Royalties and production taxes are due from a net profit share lease as long as there is production, even when there is no net profit share payment from the property.

Attached is an Xcel table of producing and non-producing NPS leases showing the lease number, the net profit share rate and the royalty rate for each lease. (See Attachment B)

59. What are the depreciable lives for O & G equipment for federal and state income tax purposes?

	Federal	Alaska
Equipment for exploration and production including drilling, gathering pipelines, pumping equipment, separation equipment, certain platforms	7	11
Offshore drilling	5	6
Pipelines, excluding gathering and transmission lines	15	17.5
Vessels, barges, other water transportation equipment	10	14.5

60. Please provide the tax calculation under the bill, with the following assumptions:

--Gross value	$60M
--Opex	15M
--Capex	10M

Gross value	$60M
Less: Opex	(15)
Capex	(0)
Tentative net profit Before standard deduction	$35M
Less: standard deduction*	(35)
Net Taxable income	$ 0

Tax	$ 0
Capital investment credit available for carryforward (20% of $10M)	$5M

* this calculation assumes that taxpayer has not reached $73M limit for the standard deduction.

61. Are net profit lease payments included as a direct cost under 43.55.160?

Net proft share payments under NPSL's (Net Profit Share Leases) would not be deductible lease expenditures because they are in the nature of lease acquisition costs. Lease acquisition costs are not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

62. Are lease bonus payments eligible for capital credit under 43.55.024 and/or are they included as a direct cost under 43.55.160?

Lease bonus payments are neither deductible nor eligible for capital credits. Lease bonus payments are in the nature of lease acquisition costs which are specifically not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

63. How are payments for "spec 3D" handled? Are they credit eligible under 43.55.024 or only allowed as deductions under 43.55.160?

We understand "spec 3D" to be certain seismic exploration costs. Exploration costs are allowed as deductions under Section 21 of the bill (Sec. 43.55.160(c)). Such costs are also eligible for credits under Section 12 (Sec. 43.55.024) by reference to definition of "qualified capital expenditure" at Sec. 43.55.024(h).

64. Please explain the taxation or exemption of royalties.

Public royalties (paid to federal or state jurisdictions) never enter into the base of gross value. This is so because AS 43.55.011(a) levies the tax on oil except oil the "ownership or right to which is exempt from taxation." This phrase is then defined in AS 43.55.900(13) as follows:

"any ownership interest of the federal government or the state."

These sections are not changed in the bill.

Because the bill changes the tax to a tax on net profits, it is necessary to specify deductions. Royalties are specifically disallowed as a deduction under Section 21

(Sec. 43.55.160(d)(2)(B)). Royalties paid to state and federal jurisdictions cannot be deducted because they are not included in the starting "gross value." Private royalties cannot be deducted because the related production is subject to tax.

65. Under Section 21 (Sec. 43.55.160(d)), "direct costs... include..." Does the word "include" serve to restrict the list of allowable expenses to only those items included below in (A)—(C)?

No, Sec. 43.55.160(d) provides additional clarification for the general rule stated at sub-section (c). Sub-section (c) provides the general rule that lease costs are deductible. Sub-section (d) addresses only those items that may have been questionable under the general rule. Additionally, we note that under AS 01.10.040(b):

"When the words 'includes' or 'including' are used in a law, they shall be construed as though followed by the phrase 'but not limited to.'"

Questions Received 3/1/06 12:00 a. m.

66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO_2 re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

TO BE PROVIDED

67. What happens if the "Big Three" sell off their assets to 20 smaller companies? Will the significant gax benefits ever be realized?

TO BE PROVIDED

68. How is it possible that any corporation gets triple the sale price for a commodity, having invested capital at the expected lower returns, and then maintains that they need a claw back provision? Why should we offer it?

TO BE PROVIDED

69. Please show us an international competitiveness rank and score for PPT under the following tax/credit scenarios, both overall and for new producers:

a. 30/15
b. 30/20
c. 25/20
d. 20/20

TO BE PROVIDED

70. Please present Mr. Marks' charts on pages 14-16 to show the difference between a PPT and status quo, annually under the following PPT plans at $20, $40, and $60/bbl:

a. 25/20
b. 30/20
c. 30/15

TO BE PROVIDED

71. Please show the corporate take chart on page 24 of Mr. Marks' presentation given the following tax/credit scenarios:

a. 25/20
b. 30/20
c. 30/15

TO BE PROVIDED

72. Please show the price point where DOR estimates corporate profit margins hit 15% and 20%.

TO BE PROVIDED

Attachment A1 (Question 30)

Effective Tax Rates, North Slope by Field, FY86 - FY05

	Prudhoe Bay	Midnight Sun	Polaris	Orion	Aurora	Borealis					
FY86	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.07%	0.00%	0.00%	0.00%	0.00%
FY87	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.47%	0.00%	0.00%	0.00%	0.00%
FY88	12.66%	0.00%	0.00%	0.00%	0.00%	0.00%	8.33%	0.00%	0.00%	0.00%	0.00%
FY89	12.33%	0.00%	0.00%	0.00%	0.00%	0.00%	8.71%	0.00%	0.00%	0.00%	0.00%
FY90	14.71%	0.00%	0.00%	0.00%	0.00%	0.00%	12.89%	0.00%	0.00%	0.00%	0.00%
FY91	14.91%	0.00%	0.00%	0.00%	0.00%	0.00%	13.19%	0.00%	0.00%	0.00%	0.00%
FY92	14.90%	0.00%	0.00%	0.00%	0.00%	0.00%	13.33%	0.00%	0.00%	0.00%	0.00%
FY93	14.85%	0.00%	0.00%	0.00%	0.00%	0.00%	13.34%	0.00%	0.00%	0.00%	0.00%
FY94	14.81%	0.00%	0.00%	0.00%	0.00%	0.00%	13.09%	0.00%	0.00%	0.00%	0.00%
FY95	14.76%	0.00%	0.00%	0.00%	0.00%	0.00%	12.85%	0.00%	0.00%	0.00%	0.00%
FY96	14.67%	0.00%	0.00%	0.00%	0.00%	0.00%	12.35%	0.00%	0.00%	0.00%	0.00%
FY97	14.59%	0.00%	0.00%	0.00%	0.00%	0.00%	11.72%	0.00%	0.00%	0.00%	0.00%
FY98	14.44%	0.00%	0.00%	0.00%	0.00%	0.00%	11.38%	0.00%	0.00%	0.00%	0.00%
FY99	14.23%	0.00%	0.00%	0.00%	0.00%	0.00%	10.53%	0.00%	0.00%	0.87%	0.00%
FY00	13.96%	0.00%	0.00%	0.00%	0.00%	0.00%	8.97%	0.00%	0.00%	0.58%	0.00%
FY01	13.76%	0.00%	0.00%	0.00%	0.00%	0.00%	7.40%	0.00%	0.00%	0.05%	0.00%
FY02	13.44%	0.13%	0.00%	0.00%	0.00%	0.96%	5.29%	0.00%	0.00%	0.52%	0.00%
FY03	13.05%	0.10%	0.00%	0.00%	0.00%	1.40%	3.44%	0.00%	0.00%	1.22%	0.00%
FY04	12.82%	0.00%	0.00%	0.00%	0.00%	1.03%	2.70%	0.00%	0.00%	0.84%	0.00%
FY05	12.65%	4.43%	4.43%	3.63%	3.62%	3.69%	0.76%	0.00%	0.00%	0.15%	0.00%

Note: The effective tax rate for Midnight Sun, Polaris, Orion, Aurora, Pt. McIntyre, and Borealis for FY 05 reflects 5 months' effect of the aggregation decision effective Feb. 1, 2005.

Attachment A2 (Question 30)

	Milne Point	[redacted]	[redacted]	Lisburne	Point Mcintyre	Niakuk	West Beach	NPRB	Alpine	Northstar
FY86	2.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY87	0.62%	0.00%	0.00%	4.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY88	0.00%	8.17%	0.00%	7.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY89	0.00%	12.25%	0.00%	6.25%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY90	0.00%	10.37%	0.00%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY91	0.00%	9.44%	0.00%	0.09%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY92	0.00%	9.51%	0.00%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY93	0.00%	11.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY94	0.00%	11.53%	0.00%	0.00%	7.28%	1.56%	0.00%	0.00%	0.00%	0.00%
FY95	0.00%	11.30%	0.00%	0.00%	11.30%	6.15%	0.00%	0.00%	0.00%	0.00%
FY96	0.00%	10.39%	0.00%	0.00%	11.60%	1.76%	0.00%	0.00%	0.00%	0.00%
FY97	0.29%	7.10%	0.00%	0.00%	11.63%	1.51%	0.00%	0.00%	0.00%	0.00%
FY98	0.46%	4.54%	0.00%	0.00%	11.29%	0.89%	0.00%	0.00%	0.00%	0.00%
FY99	0.64%	1.29%	0.00%	0.00%	11.75%	0.70%	0.00%	0.00%	0.00%	0.00%
FY00	0.38%	0.73%	0.00%	0.00%	9.45%	1.32%	0.00%	0.00%	0.00%	0.00%
FY01	0.16%	0.13%	0.00%	0.00%	6.47%	0.17%	0.00%	0.00%	4.24%	0.00%
FY02	0.02%	0.02%	0.00%	0.00%	3.10%	0.15%	0.00%	0.00%	10.76%	5.14%
FY03	0.00%	0.01%	0.00%	0.00%	2.40%	0.02%	0.00%	0.00%	10.50%	10.59%
FY04	0.00%	0.00%	0.00%	0.00%	1.63%	0.00%	0.00%	0.00%	10.33%	10.37%
FY05	0.00%	0.00%	0.00%	0.00%	4.78%	0.00%	0.00%	0.00%	10.17%	10.18%

Attachment B (Question 58)

By: G. Rogers, March 1, 2006, source DNR

NPS LEASES, NPS RATES & ROYALTY RATES & STATUS

	Unit - lease number	Royalty Rate	NPS Rate	NPS Status
	Duck Island			
1	312828	20%	79.5935%	in payout
2	312834	20%	48.8703%	in payout
	Milne Point			
3	355016	12.5%	40.0000%	in payout
4	355017	12.5%	40.0000%	in payout
5	355018	12.5%	30.0000%	in payout
6	355021	12.5%	30.0000%	in payout
7	388235	12.5%	30.0000%	in payout
	Kuparuk River			
8	355023	12.5%	30.0000%	not in payout
9	355024	12.5%	30.0000%	not in payout
10	355030	12.5%	30.0000%	not in payout
11	355032	12.5%	30.0000%	not in payout
	Colville River			
12	364470	12.5%	30.0%	non producing
13	364471	12.5%	30.0%	non producing
14	364472	12.5%	30.0%	non producing
15	364477	12.5%	30.0%	non producing
16	364478	12.5%	30.0%	non producing
	Point Thompson Unit			
17	312866	20%	52.352%	non producing
18	343109	12.5%	40%	non producing
19	343110	12.5%	40%	non producing
20	343111	12.5%	40%	non producing
21	343112	closed	closed	non producing

Average Effective Tax Rates, Low Volume Scenario, No Gasline

	$20/bbl	$40/bbl	$60/bbl
Status Quo	4.1	4.5	4.4
PPT 20/20	0.55	9.7	13.0
PPT 25/20	1.2	12.4	16.7
PPT 30/20	1.8	15.5	20.5
PPT 30/15	2.5	16.3	21.0

Cumulative Severance Tax Revenues, Low Volume Scenario, No Gasline

	$20/bbl	$40/bbl	$60/bbl
Status Quo	2,959	8,211	12,870
PPT 20/20	498	16,458	34,649
PPT 25/20	1,041	21,782	44,521
PPT 30/20	1,614	27,107	54,393
PPT 30/15	2,133	28,317	55,603

KEN THOMPSON
PRESENTATION 3-2-06

Comments On SB 305 and HB 488 Oil and Gas Production Tax
By Ken Thompson, Managing Director of AVCG/Brooks Range Petroleum

Personal Background

For the record, my name is Ken Thompson. I reside at 12031 Lilac Drive, Anchorage, Alaska. I am the Managing Director of Alaska Venture Capital Group, or AVCG LLC, an independent oil exploration company with a focus on the North Slope of Alaska. AVCG is a consortium of 15 independent oil and gas companies and individuals from Kansas and me as an owner/investor from Alaska. AVCG has a technical and operational services' subsidiary company called Brooks Range Petroleum, with offices in Anchorage.

AVCG LLC has been very active in the past six North Slope areawide lease sales and we have acquired over 160,000 acres of exploration leases in five exploration prospect areas, including new acreage we acquired earlier this morning in the NS lease sale. Our exploration strategy is to explore in the central part of the North Slope for fields in the 25-100+ million barrels range, fields that may be too small for the giant producers but fields that can be produced profitably by smaller companies like ours. We believe there are hundreds of millions if not billions of barrels of oil left on the North Slope in smaller fields of this size.

Our company is excited to report that the first exploration well AVCG will participate in with an ownership interest should have started drilling last night...the Cronus exploration well about 10 miles southwest of the Kuparuk Field, operated by Pioneer Natural Resources. We plan two exploration wells next winter and two the winter after that. With success, we will continue exploring and producing.

My comments today represent the perspectives of a small, independent exploration company. Having said this, many of you also know me as the past President of ARCO Alaska, Inc. I also served as Executive Vice-President for ARCO and head of global oil and gas exploration for ARCO. I do have exploration and production experience in over 20 countries throughout the world, so I'll also share my perspective in how I see the new production profits tax bill in the context of competitiveness in the world.

Introduction

- In my first week as President of ARCO Alaska in June, 1994, our ARCO staff reviewed state policies with me to educate me about the oil and gas industry in Alaska. One of the items they reviewed with me was the production tax and the complicated policy of ELF. Our government affairs personnel told me that ELF was in jeopardy...that the production property tax was going to be changed. That did produce uncertainty in our project economics forecast. Every year since then, production taxes and the ELF have been topics...and uncertainty remains. Sixteen years have passed since that meeting, and every year, I hear discussion about production taxes, ELF, and the imminent

threat of change. I welcome change and I say, "It's time to put the new system into effect and let's get on with it."

- Our company, AVCG, supports the proposed production tax changes provided the most important terms remain as written.
- Alaska has long been challenged to be competitive with fiscal regimes in other countries that offer competing projects; as an Alaskan, I'm excited to see the State ensure that our State's new oil tax regime is more like that in other countries...a progressive, profit sharing type structure versus a regressive, straight tax on gross revenues.
- The State will "share the gain" at high oil prices, but will likewise "share the pain" at lower oil prices...this helps small investors like AVCG/Brooks Range Petroleum limit our downside risk in the event of price collapse. And we think it is fair to share our upside profits with the State at a 20% tax rate; the State owns the land and the oil...we realize that we only lease it and we do have implied covenants to be fair with the State.
- At this point, I would like to answer three questions from my perspective: 1) Is this new production tax good or bad for industry; 2) what three things should not be changed; and 3) what three things should be changed?

Is This New Production Tax Proposal Good Or Bad For Industry?

- Both...for a small explorer startup company like AVCG LLC with about 160,000 acres under lease for oil exploration on the North Slope, the exploration economics with the proposal are favorable with an improvement in the rate of return. Near-term cash flow because of the investment tax credits is higher which improves the return on investment. But cash flow is lower a few years after new production startup as the State shares a higher share of the profits than what it currently does. We think the State taking 20% of the upside profits is fair, and we recommend the tax rate stay at 20%...the old 80/20 rule has proven to be a good one over time. Keep in mind the State will also still receive a 12.5-16.67% royalty share of all oil and gas revenues on State leases, oil and gas property taxes, corporate income taxes, and other revenues, in addition to the production profits tax.
- A key part of the bill is the investment tax credit, and AVCG plans to use that....our only area of exploration investment is Alaska and we do plan to return a large share of our future production cash flow back into exploration and development only in this state so we can grow to a sizeable company...the tax credit creates a clear incentive for us to do that rather than take the money outside.
- For a large major producer who is planning to make large capital investments on the oil side or in the gas pipeline, the bill could possibly be favorable for them as well when all is said and done.
- For any producer – large or small - who is not planning to make large capital investments but plans to send cash flow outside without a high re-investment plan in Alaska, this bill is likely not good for that type of company in Alaska.

What three things should not be changed?

- I "panicked" when I saw the profit tax reported at 25%...this takes too large a chunk of positive cash flow away from small companies - or really companies of any size - and our company sees this as cash flow that could be re-invested into new exploration prospects and new oil leases. I started warming up to the bill only when the tax rate was changed to 20%...then the AVCG economics started showing sufficient improvement in capital investment rates of return for us to attract new capital from partners or investors. When the tax rate changed from 25% to 20%, I crossed over from opposition to support of this proposal.
- It is essential to keep the 20% investment tax credit. This will help us in attracting new capital from AVCG partners or equity investors for new exploration and development. With a tax credit of 20% and re-deployment of the tax savings back into our exploration in the State, we can essentially drill an extra exploration well for each five exploration wells we currently have budgeted.
- It is essential to keep the $73,000,000/year operating cash flow "standard tax deduction" before production taxes are paid, at least for smaller producers. At a $40/bbl oil price, this equates as a production tax exemption for the first 5,000 net barrels per day to encourage new producers. As our company is risking a lot of money currently with no revenues whatsoever and with our first revenues to possibly occur only 3-4 years from now, I cannot emphasize how important having such an exemption is while we get our feet on the ground to eventual financial strength. Having said this, I do suggest, however, that this "pill might be easier swallowed" if the exemption were simply changed to read "there is an exemption for the first 5,000 net barrels of oil per day;" this certainly sounds better to the general public and is much easier to understand than saying, "there is an exemption for the first $73,000,000 of profits." This also implies that for larger companies, with say 300,000 barrels of oil production currently on the North Slope, they only get an exemption for the first 5,000 barrels per day...they still have to pay production profits tax on the other 295,000 barrels per day.

<u>What three things should be changed in the bill?</u>

- The bill allows for the investment tax credits to be sold to others in industry if a new explorer – like AVCG - does not yet have oil production revenues to use the credits. While this sounds good, in practical application these credits can only be sold to a few buyers...basically the major three oil producers who will literally set the market for these credits and the value they will receive when sold. With limited buyers, our company estimates the credits might be sold at only 70-75% on the dollar. This disadvantages new explorers...the majors get 100% of their credits while the new explorer must sell at 70-75% of value only to then see the major producers take 100% of the acquired tax credit against their production tax bill. It is suggested that the State consider establishing a pool of dollars from the production profits taxes taken in to buy the tax credits from small explorers. This makes sense...the State would not be giving up anything because the major producers would otherwise use the credits to reduce their tax bill and reduce revenue to the State....but using this approach,

the small explorer could turn around and re-invest the State-refunded credit into new leases, seismic or exploration drilling. In fact, the State might want to stipulate that if the State refunded the tax credits to a company, that company must use it for exploration or development. Our company would support such a concept. Explorers who don't want to do this option and re-invest in the State but just want the cash value of the credit could sell to the majors at 70-75% if they prefer that option.

- The section in the bill on "determination of net value of oil and gas" listed direct costs that could be deducted from gross oil revenues to calculate a profit, or "net value of oil and gas" to then be taxed at the 20% tax rate. For a new explorer in Alaska, the startup costs in the State can be very substantial, particularly for smaller players. This can include high costs for bonding, participation in the oil spill consortium Alaska Clean Seas, indemnification insurance, etc. These types of costs should be clearly mentioned in the bill as deductible.
- Again, we hope the $73,000,000 "standard tax deduction" remains. But I certainly have seen that this item is a "hot button" to certain legislators. But I urge you that while you may be angry with certain large producers, please do not loose sight of how important this could be to a startup company like ours trying to establish a foothold in Alaska and someday contribute substantial oil revenues to the State. As an alternative, however, to the $73,000,000 profits exemption, we offer that the State might choose to use an approach that the State has already approved in the 1999 "Charter for Development of the Alaskan North Slope" between the State of Alaska, BP and ARCO. In that charter, there was a section entitled "Purchases From Qualified Producers" that guaranteed that BP and ARCO (now ConocoPhillips) would agree to offer to purchase any "qualified producer's" crude oil so that new entrants or small producers would not be disadvantaged in marketing their oil. In that section there was a clear definition of a protected "small producer"...actually, the Charter called such a company a "qualified producer." I quote from the Charter: a "qualified producer" means an entity with assets of less than $1 billion (worldwide) which produces not more than 10,000 barrels of gross working interest ANS liquid hydrocarbons per day." Again, we hope the deduction provision remains in the bill. If there is opposition in the end, AVCG does hope the small companies are protected in some way; perhaps an innovation such as using the Charter guidelines may help.

That concludes my remarks. I tried to share the perspective of an independent exploration company that only invests in Alaska. I have shared the three things our company would not change in this bill and the three things we would change. All in all, I am optimistic that this bill with some tweaking could help AVCG/Brooks Range Petroleum attract new partners and new capital to Alaska, increase our exploration budget, and establish us as an important oil producer someday.

Thank you for this opportunity to make comments.

Ken Thompson

ConocoPhillips

March 3, 2006

The Honorable Ralph Samuels
Alaska House of Representatives
Alaska State Capitol, Room 126
Juneau, AK 99801-1182

The Honorable Tom Wagoner
The Alaska Senate
Alaska State Capitol, 427
Juneau, AK 99801-1182

Dear Sirs:

I wanted to thank you again for the opportunity to express ConocoPhillips' views on HB 488/SB 305. During my testimony, there was some additional information requested by the committee members. This information is provided below:

House Resources Committee

1. (Rep. Berkowitz) What are your profit numbers for the last 10 years? How much of these are from your heavy oil investments?

   Listed below are the publicly reported earnings for ConocoPhillips' operations in Alaska for the years 2000-2005 as reported in our Annual Reports. Earnings from heavy oil investments are not reported publicly. Unfortunately, ARCO did not separate out Alaska earnings data in their annual reports, so the figures for the years prior to Phillips Petroleum's acquisition of ARCO Alaska may not be disclosed.

	ConocoPhillips Alaska Operations					
	9 Months					
	2000	**2001**	**2002**	**2003**	**2004**	**2005**
Exploration and Production Earnings $MM	$700	$677	$673	$1,079	$1,665	$2,410
Other Earnings $MM (TAPS/Polar/LNG)	$129	$189	$197	$366	$167	$142
Total COP Alaska Earnings $MM	$829	$866	$870	$1,445	$1,832	$2,552

2. (Rep. Gatto) What is your public rate of return on investments for recent years (past 2 annual filings)?

   Our Annual Report does include our corporate return on capital employed (ROCE) at a corporate level. The ConocoPhillips return on capital employed in 2004 was 15.2% and in 2003, the return on capital employed was 9.8% (GAAP

ROCE). The ConocoPhillips 2005 Annual Report has not been published as of this date.

3. **(Rep. Berkowitz) What would be the decline in effective tax rate as a result of removing the Oil Spill 470 fund (AS 43.55.201)?**

   The conservation surcharge on oil has not been removed from the statute and must be paid by a producer of oil. The proposed legislation will allow this surcharge to be applied as a credit against the producer's taxes due. At a surcharge of $0.03-$0.05/bbl. this credit amounted to approximately $3.4 MM for COP in 2005 and has essentially no impact on the effective tax rate at today's prices.

4. **(Rep. Ramras) What is the depreciation mix of the $700MM (this year's capital spend)? (e.g., 5-yr, 10-yr, etc.)**

   For 2005, ConocoPhillips Alaska's reported capital expenditures were $746.2MM. A large portion of the assets have not yet been placed in service so no depreciation has occurred. Once the equipment is placed in service, it will be depreciated at IRS depreciation schedules for federal taxation purposes. The $746.2MM can be broken down into these types of assets:

   Field Life 2% Leasehold Costs
   - *Costs which are depreciated on a per unit of production basis over the life of the fields*

   7-10 Years 62% Lease and Well Equipment (L&W)
   - *Are tangible costs such as tankers, casing, tubing, wellheads, separators and producing equipment necessary to serve the well (tanks, flowlines etc)*

   5 Years 11% Intangible Drilling Costs (IDC) - Capitalized
   - *Costs of drilling wells such as labor, location preparation costs, rig mobilization, drilling costs, completion costs, which generally have no salvage value*

   Immediate 25% Intangible Drilling Costs (IDC) - Expensed
   - *Costs of drilling wells such as labor, location preparation costs, rig mobilization, drilling costs, completion costs, which generally have no salvage value*

5. **(Rep. Kerttula) What would be the production tax on Fiord under the current ELF formula?**

   Fiord is expected to startup in the fourth quarter of 2006. In order to make the project economically viable, ConocoPhillips sought and obtained a letter from the Department of Revenue stating that Fiord would not be aggregated with Alpine for calculation of severance tax; hence, initial Fiord production would have an effective ELF severance rate of 0%. The ELF tax rate is currently expected to be

1.76% in 2007, and the total projected production would result in ELF production tax payments of just under $20MM over the next 10 years at today's prices. This figure, of course, does not include royalties, State corporate income taxes, state and local property taxes, the oil and gas conservation surcharge, or federal corporate income taxes attributable to the Fiord project.

6. (Rep. Samuels) What have been your abandonment expenses over the transition period?

   Abandonment expenditures are treated as expense rather than capital expenditures and thus do not result in tax credits under the proposed PPT production tax system. Our abandonment expenditures from 2001 to 2005 totaled $33.7 MM. However, none of these expenditures would be counted as capital or included in the *transitional investment expenditures* under the proposed PPT HB 488. On a go-forward basis, we do experience limited abandonment expenditures each year for activities such as plugging and abandoning old wells and some gravel removal and restoration (e.g., $12.6 MM in aggregate in 2005). However, these expenses, like our expenses for 2001 through 2005, are all anticipated to be operating costs that are not eligible for the capital credit. In addition, the bulk of the abandonment dollars would occur at the end of field life, when we expect limited, if any, production or revenue which will leave the production tax deductions associated with these expenditures with limited or no value.

Senate Resources Committee

1. (Sen. Stevens) Please break down the 2005 capital expenditures into exploration, development, and production expenditures?

   In 2005, ConocoPhillips reported capital expenditures of $746.2 MM. Approximately, 67% was associated with development activities, 13% on production maintenance activities and 2% on exploration. The remaining 18% was associated with marine, pipeline and acquisition expenditures.

If you have any questions regarding this information, you may contact me at 907-265-1650 or make arrangements through our Juneau office at 907-586-3680.

Sincerely,

Brian R. Wenzel
Vice President, Finance & Administration
ConocoPhillips Alaska

Alaska State Public Opinion Message System:

Rep Ralph Samuels's office

Filter applied is: All

Messages About

There are 14 messages about this subject

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Messages

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:39 about *Oil & Gas*

Message:

Taxes before gasline contract, weird! Most of you know that Pedro vanMeurs said for Governor Murkowski in Anchorage that just because the oil companies sign a gasline contract the contract is not going to obligate the oil companies to construct a gasline.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Go to Main Menu | Go to Search Page

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:43 about *Oil & Gas*

Message:

Why are you buying a pig in a poke when you are not allowed to even see the poke let alone the pig? What harm could it do to at least see the gasline contract?

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:46 about *Oil & Gas*

Message:

The gasline contract contains provisions that allow the oil companies to just quit in 3 or 4 years after signing the gasline contract. After that they have to offer a reason like they do not think the gasline is in their best interest.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:48 about *Oil & Gas*

Message:

Do you often buy pigs in pokes for your own business when you are not even allowed to see the poke? Then why are you conducting the States business in a manner that you would not tolerate in your own business.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mc utcheon
Po Box 101838
Anchorage 99510-1838

Fairbanks Daily News-Miner

Tax credit ruling could hurt gas line negotiations
By SAM BISHOP News-Miner Washington Bureau

Friday, March 03, 2006 - WASHINGTON--The U.S. Supreme Court may rule this year on the constitutionality of a tax credit similar to the one that Gov. Frank Murkowski wants to offer oil companies for in-state investments, according to a lawyer who analyzed Murkowski's proposal for the Alaska Legislature.

If the court rejects the tax credit, it could eliminate one plank of the package with which Murkowski hopes to lure oil companies into building a pipeline to bring Alaska North Slope natural gas to market, according to Marvin Kirsner, a tax lawyer with Greenberg Traurig in Boca Raton, Fla.

Oil company executives, testifying before legislators Tuesday in Juneau, declined to say whether any changes in that package might doom the gas line.

"It's too early to draw that conclusion," said Becky Hultberg, the governor's spokeswoman, on Thursday.

The Supreme Court on Wednesday heard oral arguments in the case on which the tax credit's future may hinge.

The case began when some Ohio residents sued over tax credits their state gave DaimlerChrysler Corp. for building a Jeep assembly plant. A district court rejected the citizens' argument, but an appeals court reversed the decision.

DaimlerChrysler appealed to the nation's high court, which agreed to hear the case.

The Ohio residents say their state's tax credit violates the U.S. Constitution. The constitution gives Congress the power to regulate interstate commerce, so courts have frequently prohibited states from taking actions that might limit such commerce, Kirsner said in an interview Wednesday.

The Ohio taxpayers argue that their state's tax credit improperly burdens interstate commerce because the credits are available only to companies that spend money in Ohio.

Murkowski's proposed tax credit is similar to the Ohio credit, Kirsner said.

At Wednesday's court hearing, Justices Antonin Scalia and David Souter offered comments indicating they didn't buy the constitutional argument.

Companies are free to invest elsewhere, Souter observed. "That's not discrimination, that's free choice," he said.

Scalia said fights over whether to offer such tax credits should be decided by politicians, not judges.

Members of Ohio's delegation in the U.S. Senate and House, who are nevertheless worried about the

court challenge, filed legislation last year to give states the authority to offer such tax credits.

Nothing in the constitution prohibits Congress from extending such authority; states are on less certain legal territory if they try it themselves, Kirsner said.

That legislation may get a boost if the Supreme Court rules in favor of the Ohio taxpayers, Kirsner said, because thousands of similar tax credits are offered across the country.

"I have the feeling that Congress will have no choice," he said, if the court rejects the tax credits.

In his analysis, Kirsner suggested the state put its shoulder behind the legislation in Congress.

Murkowski's proposed tax credit would let oil companies deduct up to 20 percent of the value of any in-state investment from their taxable income in Alaska. They would also get a $73 million standard deduction for any such investment.

Hultberg, Murkowski's spokeswoman, said the administration is considering Kirsner's analysis.

"It is one issue that one consultant has raised, so we're going to look into it," she said.

State Sen. Gene Therriault, R-North Pole, said he had discussed the issue with oil company representatives. They were aware of the Supreme Court case but did not express any serious concern about it, Therriault said Wednesday.

Washington, D.C., reporter Sam Bishop can be reached at (202) 662-8721 or sbishop@newsminer.com . The Associated Press contributed to this article.

Alaska's Proposed Production Tax

"PPT 20/20%"

SB 305/HB 488

Issues for Discussion and Further Research

Daniel Johnston

Juneau, Alaska
6 March, 2006

Daniel Johnston & Co., Inc.
www.danieljohnston.com
60 Shady Lane
Hancock, NH 03449

Daniel Johnston & Co., Inc. — Founded in 1985

Services include:

Consulting – (Similar to this work)
- **Economic and Financial Analysis and Modeling**
- **Risk analysis**
- **Economic modeling**
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Teaching
- **Public Courses** (each year: Singapore, Middle East, Houston, Europe)
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- **University of Dundee, Scotland**
- **University of North Texas**
  - **Institute of Petroleum Accounting**
  - **Petroleum Accounting and Financial Management Journal**

Expert Witness Work
- **Arbitration, Litigation, Mediation**
  - **High Court – New Delhi,**
  - **Supreme Court – India**
  - **International Court of Justice**
  - **High Court – Wellington, New Zealand**
  - **Brussels, London, USA, etc**

In the past 15 years my work has been fairly equally divided between oil companies and governments. Further information is provided at the end of this report.

Mineral resources are a gift from God

I dedicate this work to the current and future generations of Alaskans and to my family.

May God bless us all.

Daniel Johnston
6 March, 2006

PPT 20/20% Analysis and Discussion

My mandate:

Analysis, Research, Discussion, Recommendations

Help design a Fair System

Nobody Wants a Punitive Arrangement.

Future Generations will ask:

(1) Did we design the system right with the best information, tools, and resources available to us?

(2) Did we negotiate effectively and from a position of strength? If not did we do the best we could with what we had?

(3) Did we manage to strengthen or undermine the bargaining position for future generations?

Remember, the whole world is watching and we will continue to be observed and judged for years to come.

Warning:

Before we go further I must point out that I have had barely one month to address and/or prepare for many of these complex issues, the situation, the proposal, the SB 305/HB 488 Bills, and all that goes with it (travel, meetings, hearings, analysis and everything). I need more time.

I cannot claim to have exercised due diligence on a variety of matters in the little time I have had so far — there is too much at stake. More work must be done.

I do believe that even this preliminary assessment of the proposed tax regime (PPT 20/20%) can help facilitate discussion and foster an understanding of the key issues and concerns. This report is provided in conjunction with my testimony on 6 March, 2006. The appropriate context for any statements here must include my oral testimony.

I have never submitted a such a large and complex document to the kind of scrutiny I expect this one to undergo with so little time, under such pressure, and with so much at stake.

The testimony from various oil companies occupied an immense amount of time while I was preparing this report but I believe I was obligated to observe those hearings. Much of that testimony was helpful to me. Responding to some of the remarks I believe is mandatory and is included in this preliminary analysis.

I appreciate the assistance from personnel with the Legislature and the Administration particularly Dr. van Meurs and Dr. Roger Marks, and the Econ One consultants. I appreciate that no one has pressured me to lean one way or the other – this is important.

This report should be viewed as a preliminary indication of things I intend to address in detail when I have had sufficient time to finalize my research and review the results of economic modeling that is being performed as I write this report.

I reserve the right to correct, amend, change and/or add to this preliminary report.

Daniel Johnston
6 March, 2006

CONCLUSIONS

1. **Alaska has every right to change the system.**
   - a) Alaska is not the only region considering or making changes these days.
   - b) Alaska may have more justification to change than most:
     - (1) Because of the ordinary regressive effect of the royalty,
     - (2) the ordinary regressive effect of a severance tax,
     - (3) the inefficiencies of ELF's field production rate element
     - (4) the inefficiencies of ELF's daily well production rate element

2. **The new system should increase revenues to the State of Alaska <u>and</u> enhance exploration activity.**
   - a) These sound like mutually exclusive objectives. Not necessarily.
   - b) Increasing taxes on existing production is relatively inelastic.
   - c) Incentives like those proposed (credits) can work well for exploration.

3. **The new system should be a well designed <u>modern</u> system.**
   - a) PPT 20/20% would just bring Alaska up to the end of the last century.
   - b) The system should be flexible, progressive, simple, and transparent.

4. **Trying to craft one system to fit all situations here may be impossible.**
   - a) Like trying to design a saddle for your horse that must also fit your dog.
   - b) Exploration is extremely different than production from existing fields.
   - c) With the Legacy Fields like Prudhoe Bay there is little margin for error. Getting it wrong by even 1 or 2 percentage points of Government Take will be measured in the hundreds of millions of dollars.
   - d) Margin for error with exploration terms is not nearly as critical.

5. **The Producers want "fiscal certainty".**
   - a) For the pipeline I don't blame them and it may simply be required. But Alaska must be extremely careful - it is not a simple matter.
   - b) For the oil tax law I don't blame them – but it is not as critical. Companies operate regularly with much less certainty than is being demanded.
   - c) For everything to be "linked" — does Alaska want to be the pioneer on this risky and extremely unusual proposal? Its an issue of sovereignty.

6. **Much of the debate here regarding oil revolves around Government Take. With the gas pipeline project a Government Take statistic is much less meaningful. The time will come to address this issue and it is critical.**

7. **Crafting language to avoid "leakage" deserves appropriate terms on the front end — get the deal right.**

8. **There are several issues of critical importance that I have not had time yet to address in a way they deserve. These include:**

   a) **Relinquishment provisions. In Alaska companies have the right to hold acreage in ways that would astonish most other countries. It has placed Alaska in a difficult position—an issue of sovereignty.**
   b) **Abandonment provisions (site restoration, cleanup, dismantlement) need work. Big difference between existing and future facilities.**
   c) **The proposed "Linkage" with the gas pipeline deal is extremely disconcerting. The risks associated with this unique situation are immense.**

Other perspectives on ELF:

Alignment of Interests – not good. We know that.

First of all the tax is based on production not profits (i.e. regressive)

Reference:

The Indonesian Story: the DMO Holiday! Separate field status
(Definition of a Field)

The California Story: the Cunningham Field story
(Production per well)

The State lost in 2 ways: lower royalty AND lower taxes

If the system is going to be changed then: what criteria?

The system must be progressive

There must be a fair division of profits

There must be no unhealthy dis-incentives

Hopefully, the new system will be simple and transparent

One critical issue centers on whether or not raising (or lowering) taxes has an effect on investment activity in the petroleum sector.

Every Country is Unique — Is Alaska More Unique?

Boundary Conditions

- **Land-locked – High Transportation costs**
- **Arctic – high cost**
- **Field size distribution expectations relative to Arctic conditions**

Concerns

- **Need for fiscal certainty for Gas Pipeline (?)**
- **Issues of sovereignty**

Objectives

- **Fix Elf – Obtain a fair share of profits – Nothing punitive**
- **Craft a "modern" state-of-the-art system**
- **Magnify exploration activity**

Policy

- **Provide fiscal certainty?**
- **Take greater risk?**

Strategy

- **Reduce exploration risk exposure for oil companies**
- **Craft a progressive tax**

Tactics

- **Allocation mechanisms**

Fiscal System Analysis and Design – Things to Consider

This table is relatively self-explanatory but notice that Government Take has a broad context within which it fits as far as Contract Terms (using the term broadly) are concerned. When evaluating Alaska's position with respect to other elements it stacks up fairly well. This area/discussion deserves further examination.

The Balance Sheet

Prospectivity	Contract Terms
? Expected Field Size Distributions	? Type of System
? Petrophysical characteristics	PSC, Service Agreement, Royalty/Tax System
Porosity, Permeability, Saturations, etc	? Signature Bonus
Stratigraphy, Age, Depths, Thicknesses	? Work Program Seismic + Drilling
? Well Deliverability	$, Timing, Relinquishment, Guarantees
? Estimated Success Probability	? Royalty
Source, Seal, Reservoir, Migration, etc	? Cost Recovery Limit
? Oil vs Gas – Fluid Properties	? Effective Royalty Rate
API Gravity, Wax, H_2S etc	? Government Take
? Data Quality and Quantity	? Government Participation
? Exploration Drilling Costs	? Entitlement
? Post Discovery Costs	? Cost Savings Index
Development Drilling	? Ringfencing
Production Facilities	? "Crypto" Taxes
Transportation Costs	? Other (Lots of strange things)
Operating Costs	? Contract Stability
? Water Depth and Climate	? Allocation System
? Political Risk	

From: Johnston Course Materials.

Choosing the Appropriate Peer Group

Every mention of the UK in this debate mentions a Government Take of 50%.

Perhaps a better comparison for Prudhoe Bay would be the Brent or Forties Oil Fields. These fields pay a 50% Petroleum Revenue Tax (PRT) in addition to the 50% Corporate Tax, i.e. they have a Government Take or Effective Tax Rate of 75%.

Why has nobody mentioned the 75% Government Take in the UK?

As far as the choice of peer group is concerned, there is much work needed. Picking a peer group for Alaskan exploration (future) is one thing. Picking a peer group that fits both exploration and the Legacy Fields is quite another matter. I agonize over this.

The <u>problem</u> of "HOW" to calculate Government Take regardless of the peer group is quite another matter. And it is a huge issue.

Will increasing tax rates reduce investment in Alaska?

I believe there is strong evidence that producing activities are relatively unaffected by changes in tax rates unless they are dramatic.

The issue of industry response to changes in tax rate was addressed by BP (discussed in the following pages).

Do credits work?

I believe that "incentives" like the "credits" proposed can work quite well. I have experienced it.

In fact my inclination at this time is that we could enhance credits for exploration — still looking into that but supporting information is being generated and some follows.

The information that follows is preliminary. Gathering this information was prompted by remarks by the Producers and struck me as odd and inconsistent with my experience. I have had less than 5 very busy days to respond to this BUT it is critical. Alaskans don't want to lose jobs.

The producers say that a dramatic reduction in Government Take spurred investment activity in the UK in 1993. I disagree. There should be sufficient information to make an informed opinion even though my historical expenditure and drilling data comes from graphs (UKOOC) that had to be "reduced". Further work is required here. See below:

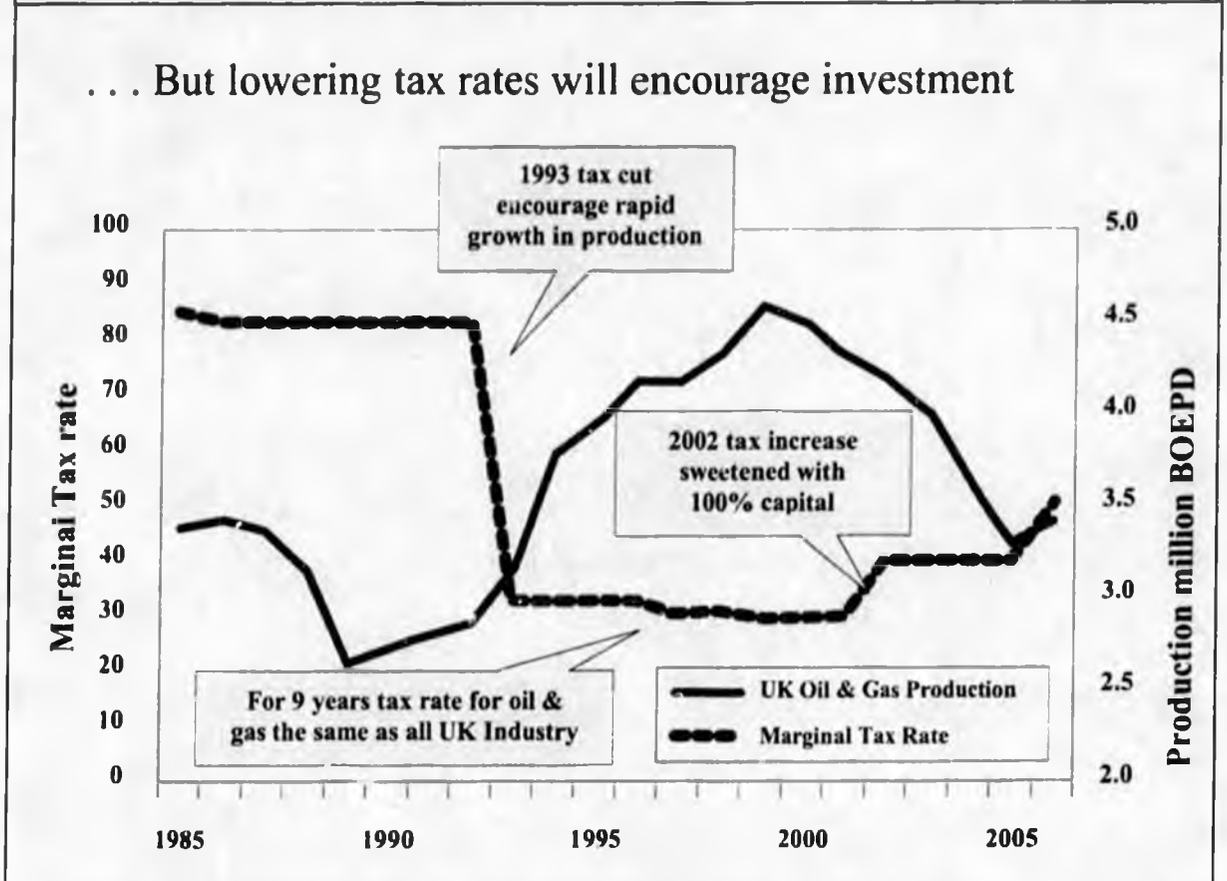
BP Graph of Production vs. Tax Rate

The graph below is not a fair representation of what the result of lowering the tax rate in 1993 was. In fact exploration expenditures went down significantly in 1994 and development expenditures did not go up (see following page). They went down but not as dramatically as exploration expenditures.

I think every Alaskan should consider this carefully and compare it to the data on the following page.

I experienced the "boom" in the mid-1980s in the UK sector of the North Sea that resulted from incentives provided that were very similar to the "credits" proposed here in Alaska. The increase in production was the result of exploration that occurred years before the 1993 reduction in taxes as one would expect. I do not see how it could be possible for industry to gear up and respond as quickly as this graph would suggest.

Please consider my work on the following page with caution. I had very little time to respond to this graph on such short notice with the busy schedule here in Juneau. With a bit more work we can verify — it is so important.



Source: BP presentation to Alaska Legislature 28 February, 2006 (page 8)

UK Petroleum Taxation History

					Marginal Take		Brent	Annual (£MM)	
					Old	New	Price	Expenditures (1)	
Year	Royalty	SPD	PRT	CT	Fields	Fields	$/BBL	Expl.	Dev.
1974	12.5%			52%	58%	58%		1,625	3,625
1975	12.5		45	52	76.9	76.9		1,750	6,813
1976	12.5		45	52	76.9	76.9		1,375	8,875
1977	12.5		45	52	76.9	76.9		1,500	7,750
1978	12.5		45	52	76.9	76.9		1,000	7,375
1979	12.5		60	52	83.2	83.2		750	6,750
1980	12.5		70	52	87.4	87.4		1,063	6,688
1981	12.5	20	70	52	90.3	90.3		1,375	6,875
1982	12.5	20	75	52	91.9	91.9		2,000	6,688
1983			75	50	87.5	87.5		2,125	6,250 Ring fence dropped in
1984			75	45	86.3	86.3		2,875	6,375 1980s for the PRT. When?
1985			75	40	85.0	85.0	28.43	2,813	5,500
1986			75	35	83.8	83.8	14.44	2,000	4,563 Price Crash
1987			75	35	83.8	83.8	18.42	1,438	3,688
1988			75	35	83.8	83.8	14.88	1,938	3,750 Piper Alpha Disaster (2)
1989			75	35	83.8	83.8	18.21	1,875	3,500
1990			75	35	83.8	83.8	23.79	2,375	4,125
1991			75	34	83.5	83.5	20.06	2,750	6,125
1992			75	33	83.3	83.3	19.31	2,000	6,250
1993			50*	33	66.5	33	17.04	1,625	5,063 Tax Rate Drops
1994			50*	33	66.5	33	15.87	1,188	4,750
1995			50*	33	66.5	33	17.00	1,375	5,500
1996			50*	33	66.5	33	20.61	1,313	5,313
1997			50*	33	66.5	33	19.19	1,438	5,063
1998			50*	33	66.5	33	12.84	875	5,938 Price Crash
1999			50*	31	65.5	31	17.83	500	5,563
2000			50*	31	65.5	31	28.55	375	3,125
2001			50*	30	65.0	30	24.43	438	3,875
2002			50*	40	70.0	40	24.86	375	3,875
2003			50*	40	70.0	40	28.79	313	3,563
2004			50*	40	70.0	40	38.30	344	3,188
2005			50*	50	75.0	50	53.73		

* New fields receiving development approval after 16 March 1993 exempt from PRT. Also, these take statistics ignore the effect of "uplifts" on the PRT.

SPD = Supplementary Petroleum Duty
PRT = Petroleum Revenue Tax
CT = Corporate Tax

(1) Derived from UKOOC graph – it was all I had at the moment. If anybody has the correct information I would appreciate it.

(2) Industry spent an extra £5 Billion for new safety equipment in the UK North Sea I have subtracted £1,000 Million per year for the 5 years following the disaster (my estimate)

The actual investment activity contradicts the theme that production after 1993 was strongly influenced by the tax reduction. Notice, there was a "boom" in the 1980s.

UK Drilling Activity History — Wells Drilled per year

This data was "reduced" from a graph from another UKOOC document and generated at 1:AM March 6, 2006. It begs verification and "real data" but I believe it confirms the fallacy of the claim that the reduction of Government take from around 85% to 33% enhanced investment activity in the UK in 1993.

More work needs to be done but it is clear to me that something is wrong with the conclusions drawn by BP regarding the 1993 fiscal event.

Year	Exploration	Appraisal	Development	Total
1974	67	33	19	119
1975	81	38	19	138
1976	58	28	52	138
1977	67	39	92	198
1978	38	25	92	155
1979	34	16	97	147
1980	31	22	117	170
1982	48	27	131	206
1983	69	44	111	223
1981	78	52	92	222
1984	108	78	102	288
1985	94	66	128	288
1986	73	41	81	195
1987	70	64	123	258
1988	94	86	159	339
1989	95	91	150	336
1990	163	66	122	350
1991	108	81	142	331
1992	75	58	161	294
1993	52	59	158	269
1994	63	38	197	297
1995	61	38	239	338
1996	72	41	256	369
1997	63	34	253	350
1998	47	33	272	352
1999	16	19	222	256
2000	27	33	213	272
2001	25	36	275	336
2002	16	31	258	305

Risk vs. Reward and the PPT Credit plan (Careful: more work needed here)

One critical aspect of the PPT is the fact that it was designed in part to encourage exploration by providing Credits and allowing companies to sell (or trade) them and any Tax Loss Carry Forwards. This aspect should be particularly appealing to explorers. It reduces their risk. But by reducing exploration risk the State takes on added risk. Consistent with basic onomic theory and extremely common industry rhetoric there should be commensurate potential for reward or a greater share of the "upside" for the State if it takes on added risk. As proposed the PPT places greater risk on the State without compensation on the reward side of the equation.

Examples of situations where countries exposed themselves on the "risk side" of the equation. Below I show for every dollar ($1.00) of exploration capital how much each party was exposed to:

	Company Exposure	Gvt. Exposure	Gvt. Take	
Indonesia Grass-roots oil **Exploration**	**$1.00**	**0¢**	**N/A**	Standard contract for
Indonesia Second-stage oil **Exploration**	**15¢**	**85¢**	**85%**	Standard contract for
Norway Grass-roots Exploration	**22¢**	**78¢**	**78%**	**Fairly new** (circa 2004)
UK (Circa mid-1980s) **Grass-roots** (1) **Exploration**	**25¢**	**?**	**85%**	Company exposure may have been less than 25¢ on the dollar
Canada	**20¢**	**?**	**?**	**PIP Grants** (2) (circa 1980±)
Alaska PPT 20/20% Without $73 MM Allowance	**39¢**	**AK & Fed**	**Depends**	

These things can work quite well. Another example might be the credits for coal-bed methane in the lower 48 in the mid 1990s (as I recall). Worth further examination.

Summary of Key Fiscal Elements of PPT 20/20%

The 5 Main Components of PPT (*Translated* from Robynn Wilson presentation 22 Feb., 2006)

(I am going to try and cast this in "my" words)

(1)	**PPT Rate**	**20%**
	PPT Base	**Company Cash Flow**
(2)	**Tax Credit Rate**	**20%**
	Tax Credit Base	**Capital Expenditures**
(3)	**TLCF or Net Operating Loss**	

"Negative Cash flow can also be converted in(to) a tax credit by taking the 20% tax value of these yearly losses." (PVM 26 Jan., 2006)

"A loss in any year can be converted in a tax credit by taking the 25% tax value. Therefore, in total, a credit of 45% can be obtained for new investments in Alaska." (PVM 14 Feb., 2006)

This language confused me a bit at first but if this thing wasn't "tradeable" it would behave just like a typical tax deduction – nothing cruel and unusual about it. If for example Alaska simply added a 20% tax without the credits, costs would be deductible and ultimately the State would pay for 20% because of the tax deductibility of the costs. It is called a "credit", I believe, because of the ability to "trade" it. It behaves though, like an ordinary deduction.

(4)	**Base Allowance Rate**	**$73 MM Deduction ("Standard Deduction")**
	Base Allowance Base	**Same as PPT base "deductible" for PPT calculation purposes**
(5)	**Transition Provision**	**Past Capital Expenditures from July 2001 to June 2006 to be amortized over 6 years (72 months)**

Summary of Key Fiscal Elements of PPT 20/20%

The proposed structure shifts some of the risk from the industry to the State of Alaska. Furthermore the "shift" is multi-dimensional:

(1) By shifting the tax base from "net production" to "profits"
(2) By providing a "liberal" definition of "profit" i.e. no depreciation
(3) By applying a 20% credit on capital expenditures (exploration AND development)
(4) By allowing credits to be traded
(5) By allowing TLCFs to be traded
(6) By providing the $73 MM "allowance"
(7) An added virtue of many of these elements is: There is no ringfence!

The question is: "If the State of Alaska is taking on more risk will it see more potential "upside" as is so common in the industry.

What do I think about the $73 MM Allowance?

(1) It is the most difficult and awkward of all.

(2) If Alaska simply MUST (for some legal or political reason) design a "one-size-fits-all" system then what are ya gonna do?

It is like designing one saddle that has to work on every farm animal on the farm.

Either this or something like it is required to distinguish legacy production at Prudhoe Bay and Kuparuk from frontier exploration.

What do I think about the "Lookback" provision?

(1) This provision is difficult for me but it does have some basis in economic logic.

(2) From a "fairness" point of view there is support.

However this same logic (fairness) provokes the question of whether or not a lookback should be provided to the Alaskans who have certainly lost because of ELF.

It is an important issue and deserves further consideration, more than I have given it so far.

This table illustrates the hierarchy of arithmetic one would expect in any given accounting period but is based on "full cycle" revenues and costs over the life of a field. It shows here that while the official PPT tax rate is 20% the actual rate is 7%. The "Tidewater Approach" treats transportation costs like a "tax" which places Alaska exploration on a more equal footing with other regions.

The "assumptions" used in this flow diagram are for illustration purposes only – not meant to be representative of my opinion about prices or costs.

PPT 20/20% System

20 MMBBLS of Oil at $50/BBL ANS West Coast Price

Oil Company Share		Alaska and Federal Gvt. Share
	$1,000 MM Gross Revenues	
	- 100 Taps $3/BBL + Shipping $2/BBL	
	$900 Gross Revenues at Wellhead	
	- 113 Royalty 12.5%	→ $113 Royalty
	$787	
$400 ← Assumed Costs ($10/BBL Capex + $10/BBL Opex)	Deductions	→ $10 AK Property Tax ($0.50/BBL)
	$377 Company Cash Flow	
	- 73 Allowance	
	$304 PPT Tax Base	
	- 61 20% PPT (before credit)	
	+ 40 Credit	
	- 21	→ $21 Net PPT (Note: effectively 7%)
	$356 Company pre-Fed Tax Cash Flow ($377-21)	($21/377)
$210 ←	- 146 41% Fed + AK Tax	→ $146
	$210 Co. after-tax C/F	
$610	Division of Gross Revenues	$290
42% [$210/(1,000 – 100 – 400)]	Take	58% [$290/(1,000 – 100 – 400)]
35% [$210/(1,000 – 400)]	Take "Tidewater Approach"	65% [($290 + 100)/(1,000 – 400)]

The credit system qualifies for a 20% credit on the capital expenditure. I assume $200 MM Capex out of the $400 MM.

(Credit = .20 * $200 = $40)

Note: The "lookback" element is not included.

Also: All $ figures are in Millions except per-barrel (BBL) figures.

Example Take Calculations — Regressiveness and Marginal Take

This exercise is used to illustrate two key points: First, why royalties are regressive, and second; the logic behind a "Marginal Take" statistic. "Marginal Take" or Marginal Government Take is typically not exactly the same as ordinary "Government Take". I believe the BP representatives use this statistic in this way. So we are not all exactly speaking the same language. We need to work on that.

A simple royalty/tax system with a 15% royalty and a 50% tax is used to illustrate this. Notice when oil prices increase from $20.00/BBL to $60.00/BBL (going from A to B) everybody makes more money BUT the government share of profits (Take) goes down. Example C examines separately what happens "at the margin" it focuses on just the "windfall" profits i.e. the difference between $20.00/BBL and $60.00/BBL.

Government Take

Example: Effect of Price Increase and "Windfall of $40/BBL"

A	B	C	
		"Windfall"	
Gvt. Take	Gvt. Take	Marginal Take	
$20.00	$60.00	$40.00	Gross Revenues
3.00	9.00	6.00	15% Royalty
17.00	51.00	34.00	Net (Revenues)
- 8.00	- 8.00	- 0.00	Operating + Capital Costs
9.00	43.00	34.00	Taxable Income
- 4.50	-21.50	17.00	Taxes 50%
4.50	21.50	17.00	Contractor Cash Flow
38%	41%	43%	Contractor Take
63%	59%	58%	Government Take

Variations on Government Take Calculation

This exercise is used to illustrate that there is added dimension to the problem mentioned in the previous graph i.e. there are more problems than just the difference between "Marginal Take" and ordinary "Government Take".

This time a royalty/tax system with a 15% royalty and a 50% tax is used but the system also has a 30% Government Participation element. The Wood Mackenzie report that ConocoPhillips referenced does not include the effects of Government Participation.

This is very important. The reason is because PPT 20/20% has many of the characteristics of Government Participation. In fact from an oil company point of view PPT 20/20% has many of the beneficial aspects of Government Participation without many of the painful aspects.

Government Takes

WoodMac ConocoPh Gvt. Take	Johnston Gvt. Take	BP Marginal Take	
$40.00	$40.00	$40.00	Gross Revenues
- 6.00	- 6.00	- 6.00	15% Royalty
34.00	34.00	34.00	Net (Revenues)
- 8.00	- 8.00	- 0.00	Operating + Capital Costs
26.00	26.00	34.00	Taxable Income
- 13.00	- 13.00	- 13.00	Taxes 50%
13.00	13.00	21.00	Contractor Group Cash Flow
- .00	- 3.90	- 6.30	Government 30% Participation
13.00	12.10	14.70	Taxable Income
40.6%	37.8%	36.75%	Contractor Take

Wood Mackenzie treatment of Government Participation

Global Oil & Gas Risks & Rewards — Wood Mackenzie – Nov. 2004

GOGRR Methodology Full Cycle Costs & Economics
(From page 9, "Tab" #9 "Methodology")

> In calculating the Government Take, we have included all elements of the fiscal regime, such as royalty, income tax, PSC profit shares and additional profits taxes. We have not, however, included any cash flow that would be derived by the government (or NOC) having an equity interest in a field.

Emphasis added. No explanation is given as to why this element is excluded.

PSC = Production Sharing Contract
NOC = National Oil Company

Administration and Dr. van Meurs treatment of Government Take

From the Administration's "Proposal for a Profit Based Production Tax for Alaska" February 14, 2006, Dr. Pedro van Meurs (page 103)

6.2.8 Azerbaijan

"The national oil company SOCAR participates for 20% in the venture, but this is almost on a "straight up" basis and therefore this participation is not included in the government take."

I agree with this approach because of the fact that SOCAR "pays its way" from day-one i.e. as Dr. van Meurs points out "straight up" (kind of like Norway) or sometimes we call it "heads up".

However, most of the time Government Participation is not "heads up" yet Wood Mackenzie excludes all forms of Government Participation.

If Government Participation were so painless as to ignore it in the Government Take calculations then why do oil companies hate it so?

The implications are huge.

Take Calculations With & Without Factoring-in Participation

Without factoring-in the Government Participation element the universe of fiscal terms is distorted by around 5 percentage points Government Take. Alaska looks "worse" than it should if this element is excluded.

The example below shows for a "world average" system with government participation of 13.5% (which should be close to World Average for all systems) how different the Take statistics look regarding this issue of Government Participation.

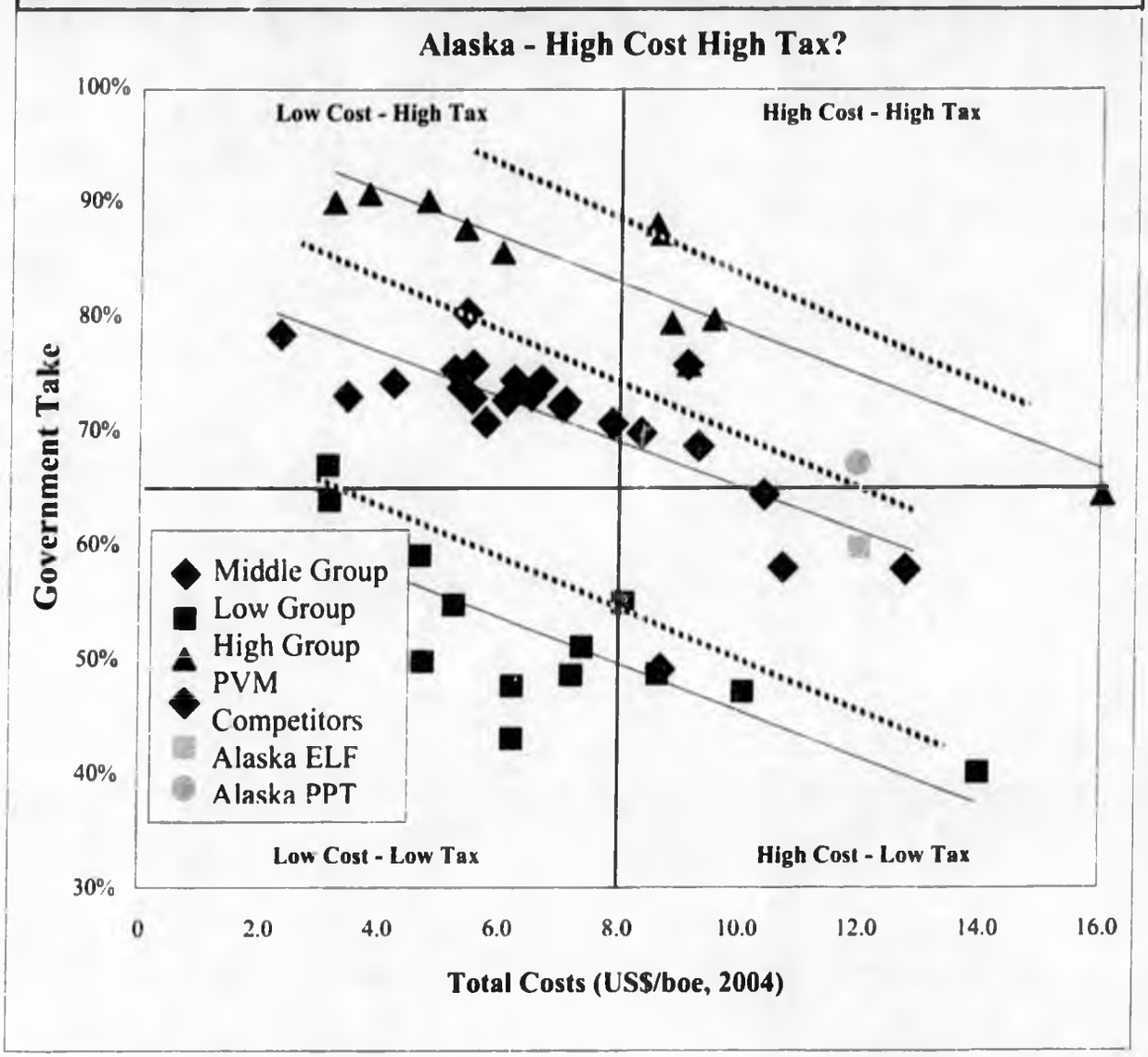
This is important because at $40.00/BBL oil price and $10.00/BBL costs with say 800,000 BOPD of production profits are $24 MM/day or $8.76 Billion per year. Just a 1% point difference in government take can represent around $87 MM per year. We must be extremely careful with our choice of a peer group, particularly for the legacy assets at Prudhoe Bay and Kuparuk.

World Average Government Takes
With and Without Government Participation

Gvt. Take With	Gvt. Take Without	With or Without factoring-in Gvt. Participation
$40.00	$40.00	Gross Revenues $/BBL
- 2.80	- 2.80	7% Royalty
37.20	37.20	Net (Revenues)
- 12.00	- 12.00	Operating + Capital Costs (30% of Gross Revenues)
25.20	25.20	Profits
- 13.90	- 13.90	Profits-based Levies 55% (Taxes and Production Sharing)
11.30	11.30	Contractor Group Cash Flow
- 1.53	- 0	Government 13.5% Participation
9.77	11.30	Cash Flow
35%	40%	Company Take

ConocoPhillips Government Take, Cost, and Tax Graph

I had a little difficulty re-creating the graph (from the ConocoPhilips presentation Feb 27, pg 19) based on the Wood Mackenzie 2004 "Global Oil and Gas Risk and Reward Study". It uses Government Take statistics that do not include "Government participation". The red dashed lines which I have added show (somewhat) how the "trend lines" might look if this element was included. This requires further consideration I am just trying to show what to expect. The real work has not been done yet. However factoring in Government Participation should make a difference of about 5 percentage points of Government take. Notice they are not parallel to the original lines in the report – much depends on costs and prices etc. And typically the governments with high take are more likely to have a participation option.



These lines represent what the picture might look like had the Wood Mackenzie report referenced by ConocoPhillips had included "Government Participation"

Government Participation (from my course materials)

Many systems provide an option for the national oil company to participate in development projects. Under most government participation arrangements, the contractor bears the cost and risk of exploration and if there is a discovery the government backs-in for a percentage. In other words the government is *carried through exploration*. This is fairly common and automatically assumed whenever some percentage of government participation is quoted.

Technically the government through the NOC is carried through "commerciality". Commerciality is usually downstream by a well or two from the actual discovery well. The contract clause that deals with the requirement for delineation/appraisal wells following a discovery is referred to as the "commerciality clause". The government agent usually the NOC must decide whether to exercise their right to "back-in" after the discovery has been appraised—the "commerciality point".

Over 40% of the counties have the option to back-in at the point of commerciality.

The key aspects of government participation are:

- What percentage participation? (Most range from 10% to 51%) (Average is around 30%)
- When does the government back in? (Usually at commerciality)
- How much participation in management? (Large range)
- What costs will the government bear? (Usually their pro rata share of costs)
- How does government fund its share of costs? (Often out of up to a certain % of Government's share of production)
- Does government reimburse its share of "Past Costs"? (Half do – half don't)

The financial effect of a government partner is similar to that of any working interest partner with a few *large* exceptions. First, the government is usually *carried* through the exploration phase and may or may not reimburse the contractor for past exploration costs. Second, the government contribution to capital and operating costs is normally paid out of production. Finally, the government is seldom a silent partner.

In Colombia the government has the right to take up to 50% working interest and will reimburse the contractor up to 50% of any *successful* exploratory wells. In China the government participation is 51%. This usually defines the upper limit of direct government involvement.

Contractors prefer no government participation. This is not totally selfish, but stems from a desire for efficiency as well as economy. Joint operations of any sort, especially between diverse cultures can have a negative impact on operational efficiency. This is particularly true when the interests of government and an oil company can be so polarized.

Government participation analysis controversy

One of the more controversial aspects of fiscal system analysis is the treatment of the government participation or the back-in option. Some analysts believe it is not appropriate to view this element of a system as a rent extraction mechanism. The argument goes like this:

> **Government take as a result of equity participation by government is really a government equity return, directly paid for by government, rather than a form of government take. Hence, comparing government take statistics by excluding government equity participation is probably a more accurate representation of levels of take.**

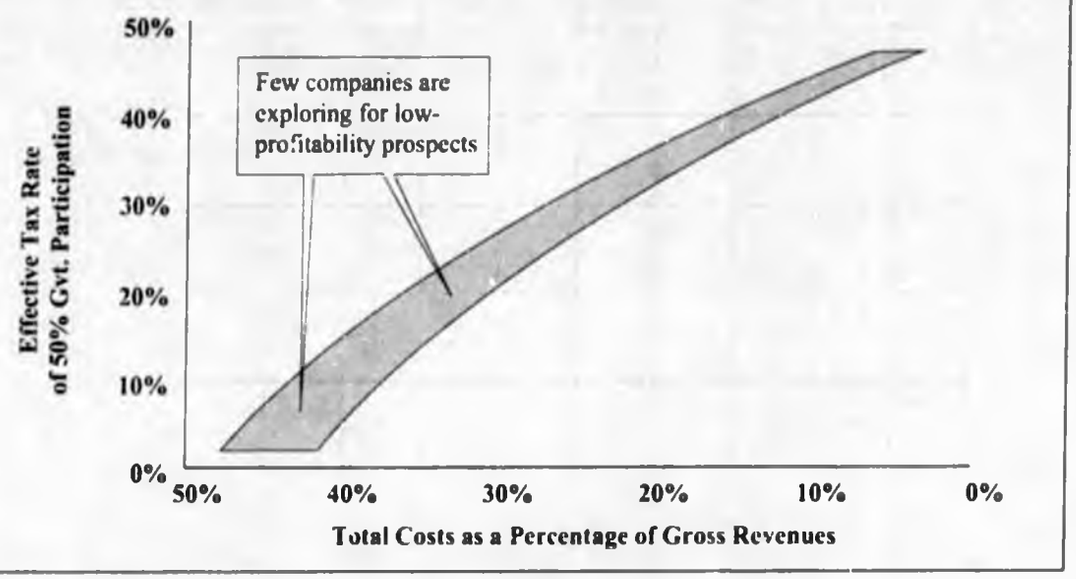
Following this logic, the government take calculation for the Libyan licenses would ignore much of the government production share – the 50% for which it pays its way on development and operating costs. This would yield a government take of only around 50% - very good terms indeed, but misleading.

Conceptually, there is certainly a difference between say a 50% profits-based tax and a government back-in option of 50%—both of which will guarantee the government an added 50% share of profits. An oil company would happily avoid both. From a purely financial point of view, companies will certainly prefer 50% government participation to a 50% tax because, with participation, after the NOC backs-in, it "pays its way". Just how different the financial impact is between a 50% tax and a 50% back-in depends on profitability. As profitability increases the back-in or participation element takes on more of the characteristics of a pure tax or a royalty depending on the point at which the government takes its share of production. While it is conceptually a bit abstract, as costs relative to gross revenues approach zero (the ultimate in profitability) the back-in begins to take on all of the characteristics of a tax, or in the case of EPSA IV, a royalty. Thus, the less profitable a venture is, the less painful the government participation element is. Either way though, both taxes and/or participation options cause the contractor financial pain to various degrees. Comparing two fiscal systems on the basis of government take alone then is not a perfect comparison if one system has participation and the other does not. This highlights one of the key weaknesses of government take statistics. However, to simply ignore the participation element would also be a misrepresentation. When comparing fiscal terms for exploration rights it is not appropriate to exclude or ignore the participation element as the argument above suggests.

From: "Impressive Libya licensing round contained tough terms, no surprises", Daniel Johnston, Oil & Gas Journal, April 18, 2005, pp. 29-37.

Government Participation "Painometer"

This graph shows that the relative financial pain caused by typical Government Participation (the "back-in") depends upon profitability [measured here in terms of Total Costs (Capex and Opex) divided by Gross Revenues]. For example when costs as a percentage of gross revenues are 20% a tax of 33% would have reduced contractor NPV (discounted 12.5%) by the same amount as a 50% Government Participation.



From: David Johnston speech, Libreville, Gabon January, 2006

Explanation of "Total Costs as a Percentage of Gross Revenues":

(1) Assume Oil prices are expected to average $50.00/BBL

(2) Capex and Opex are expected to average $4.00/BBL each = $8.00/BBL total

(3) Therefore total Costs as a Percentage of Gross Revenues = 16% ($8.00/$50.00)

This metric by-the-way, accommodates simultaneously both variations in price as well as cost.

Total Costs as a Percentage of Gross Revenues during the 1980s and 1990s average around 30 to 40% so from this perspective costs are about half what they were before.

Efficiency and Flexibility in Fiscal System Design

When I talk about a "Progressive System" I am talking about efficiency and flexibility. It goes to the heart of taxation theory and the issue of fairness.

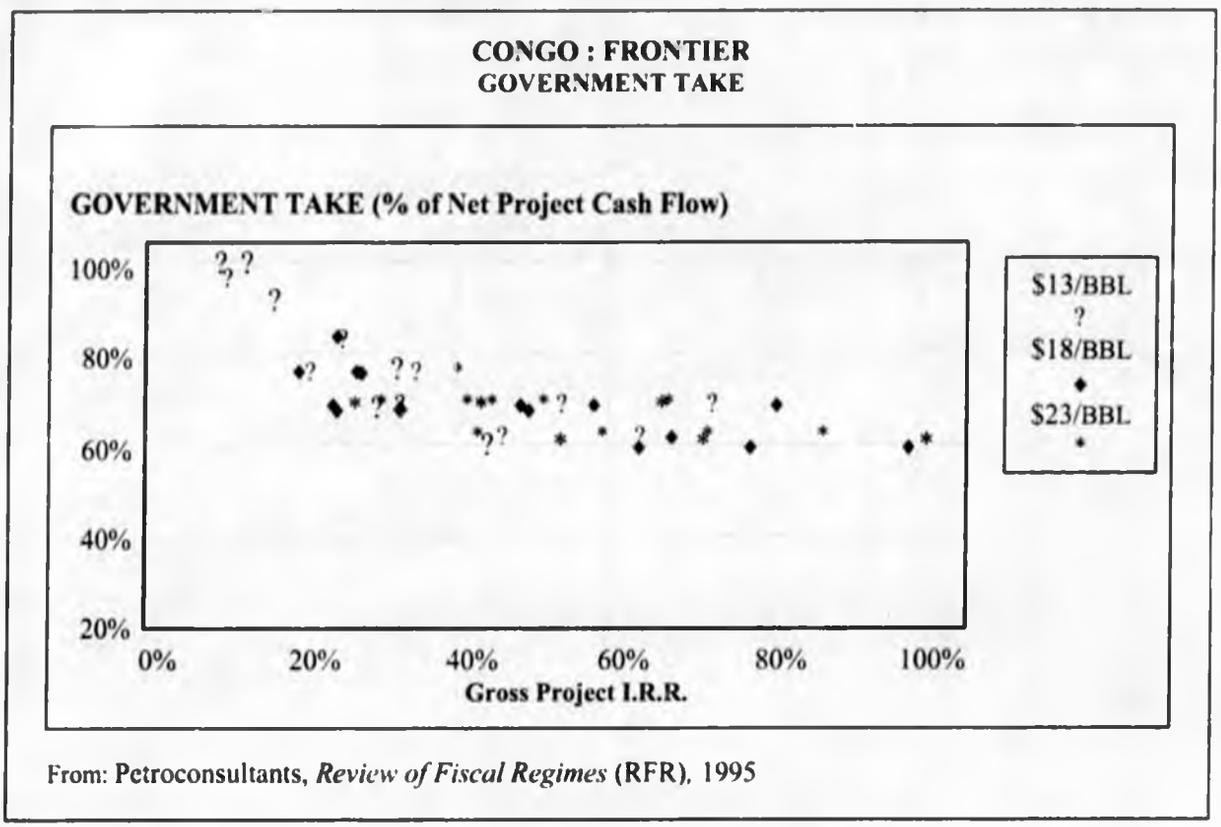
The guiding lights of fiscal system design are: Efficiency and Flexibility. These elements are not mutually exclusive.
Theoretically, an efficient, flexible contract is a more stable contract.

From: "International Petroleum Fiscal Systems and Production Sharing Contracts" Course Workbook, Johnston 2005, (pg 13)

Typical Regressive System & the Regressive Signature

This graph shows a typical "regressive signature" characteristic of most petroleum fiscal systems today. As profitability goes up, Government Take goes down. (However, most countries are re-thinking their position just like Alaska is.) The regressiveness is magnified when time-value-of-money is factored-in. Approximately 70% of the systems worldwide exhibit this kind and degree of aggressiveness. Today most countries like this one wish they had a progressive system. In the late 1990s around 65% of the countries were regressive.

Typically a company like Petroconsultants (below) would run economics (cash flow analysis) on 5 different field sizes, three different cost scenarios (high, average, low) and 3 different price scenarios (below). The resulting take statistics of these 45 permutations would be plotted on a graph like this.



From: Petroconsultants, *Review of Fiscal Regimes* (RFR), 1995

Regional Distribution of Petroleum Fiscal Systems

	Royalty/Tax Systems		Production Sharing Systems		Service Agreements
Africa **38**	C. Af. Rep. • Chad Congo (Z) Ghana • Madagascar Mali Morocco Namibia • Niger	Nigeria (Off) Senegal • Seychelles Sierra Leone Somalia S. Africa ♦ Tunisia (Old) ♦	Algeria ♦ Angola •+ Benin Cameroon ♦ Congo (Br.) Cote D'Ivoire Egypt Eq. Guinea • Ethiopia Gabon Gambia • Kenya	Liberia Libya ♦ Madagascar ♦ Mozambique Nigeria (DW) Sudan Tanzania • Togo Tunisia (New) ♦ Uganda • Zambia	Nigeria (JVs)
Europe **20**	Australia Bulgaria Czech Rep. Denmark France Greece • Hungary Ireland	Italy Netherlands Norway Poland ♦ Portugal Romania ♦ Spain UK	Albania ♦ Malta Poland Turkey		
Far East **23**	Australia • Brunei Korea S. Nepal New Zealand	Pakistan (On) PNG • Thailand + Timor Gap B	Bangladesh Cambodia China India ♦♦ Indonesia Laos Malaysia ♦ +	Mongolia MTJDA Myanmar Pakistan (Off) Timor Gap A Vietnam	Philippines
Former Soviet Union **7**	Russia +		Azerbaijan ♦♦ Georgia Kazakhstan • Kyrghyzstan	Russia • Turkmnistan ♦ Uzbekistan	
Latin America **23**	Argentina Bolivia Brazil Colombia ♦ +	Costa Rica Falkland Is. Paraguay Tr&To (On)	Belize Cuba Guatemala Guyana Jamaica	Nicaragua Panama ♦ Tr&To(Off) ♦+ Uruguay	Chile Honduras Ecuador Panama Haiti Peru ♦ Venezuela ♦♦
Middle East **18**	Abu Dhabi Ajman Dubai Fujairah	Neutral Zone Sharjah Turkey	Bahrain Iraq Jordan Libya	Oman Qatar ♦ Syria Yemen	Iran Kuwait (OSA) Saudi Arabia
North America **2**	Canada • United States				
Total 131	**58**		**63**		**11**

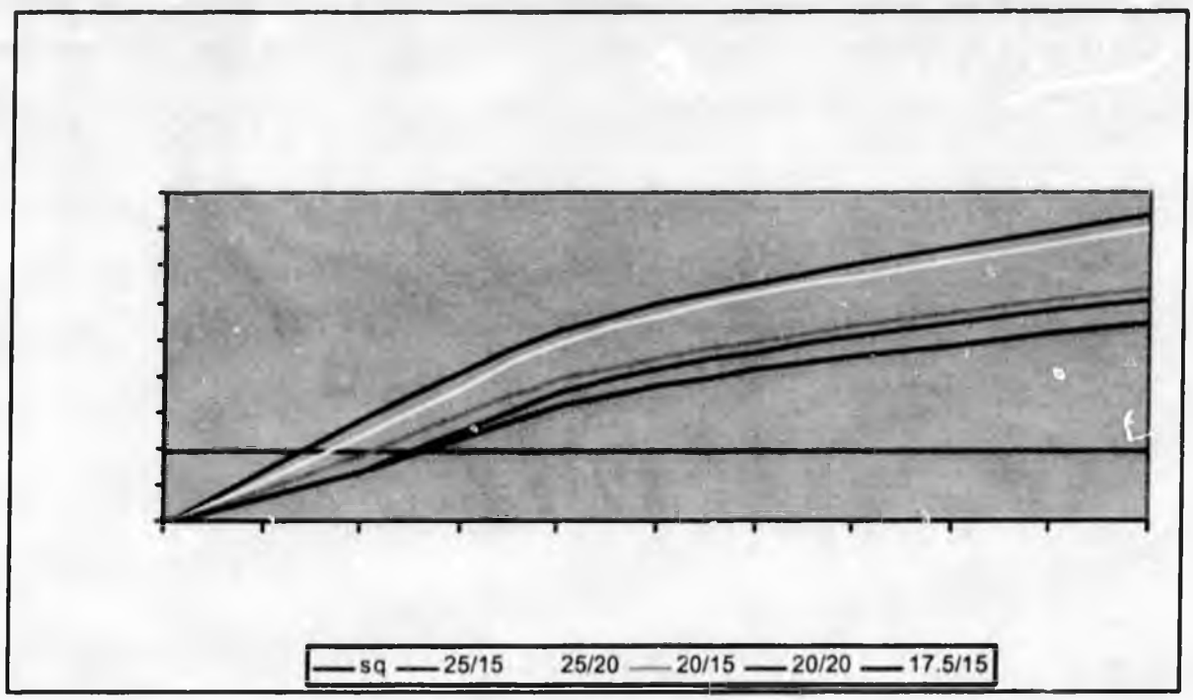
- **ROR Systems**
- ♦ **"R" factor**
- **+ Price-based formulas**

These are the systems that are most likely to be progressive.

Adapted from: Course Workbook, Johnston

Effective Oil Severance Tax Rate

The following graphs from Dr. van Meurs and Dr. Roger Marks are helpful and I find myself regularly referring back to them so I include them here for convenience. They may be out of date soon and I am still reviewing the assumptions and methodology.



From: PPTAnalysis020106.ppt Roger Marks

Estimated EFFECTIVE PPT RATES (from the graphs above)		
	$40/BBL	**$60/BBL**
Status Quo	**4%**	**4%**
25%/20% PPT as Proposed	**11.5%**	**15%**
Negotiated 20%/20% + Look-back	**< 8%**	**< 11%**
I assumed the "look-back" amounted to $1 Billion over 6 years = -$167 MM/year		