12015 SENATE RESOURCES

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 al wing companies to sell (or trade) them and any Tax Loss Carry Forwards. This aspect shoul be particularly appealing to explorers. It reduces their risk. But by reducing exploration risk the ate takes on added risk. Consistent with basic economic theory and extremely common industry rhetoric there should be commensurate potential for reward or a greater share of th upside" for the State if it takes n 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)]

Note: The "lookback" element is not included.

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

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)

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 Gvt. Take	B Gvt. Take	C "Windfall" 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.

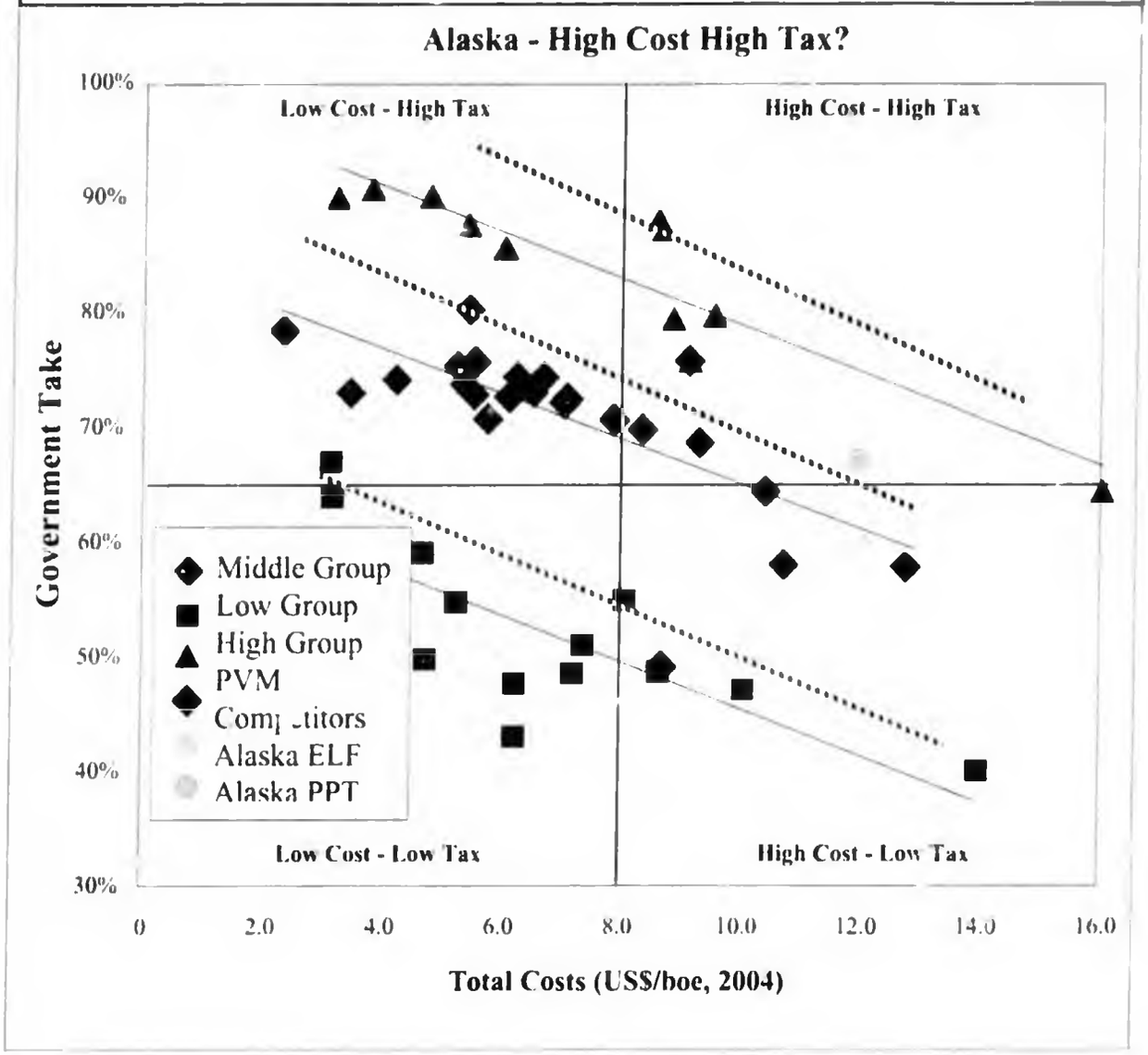
This is important because at $40.00/BBL oil price and $10.00/BBL costs with say 800,000 BOPD of production profits are $24 MM/day or $8.76 Billion per year. Just a 1% point difference in government take can represent around $87 MM per year. We must be extremely careful with our choice of a peer group,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

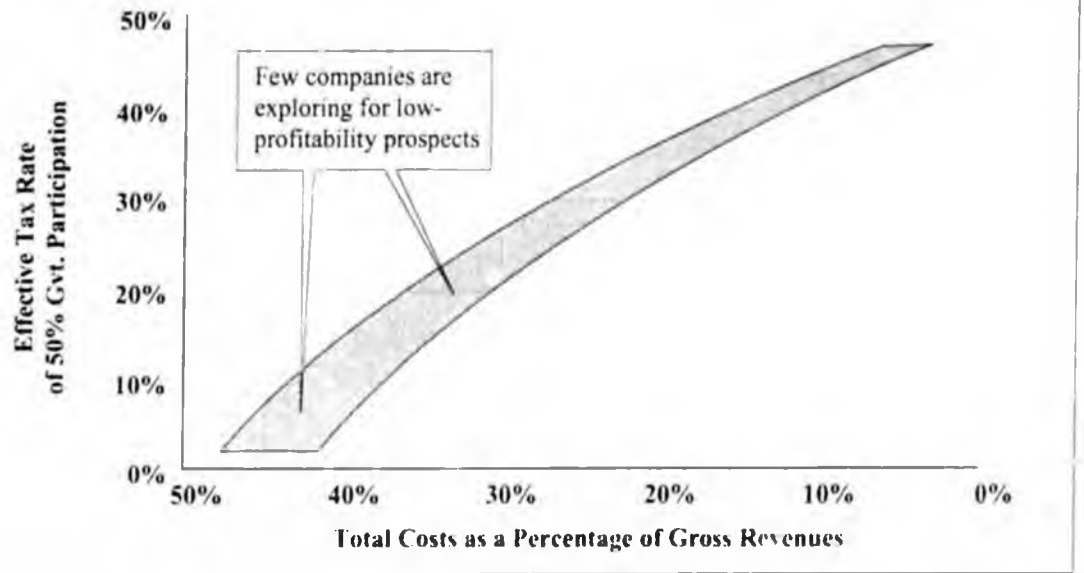
Following this logic, the government take calculation for the Libyan licenses would ignore much of the government production share – the 50% for which it pays its way on development and operating costs. This would yield a government take of only around 50% - very good terms indeed, but misleading.

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.

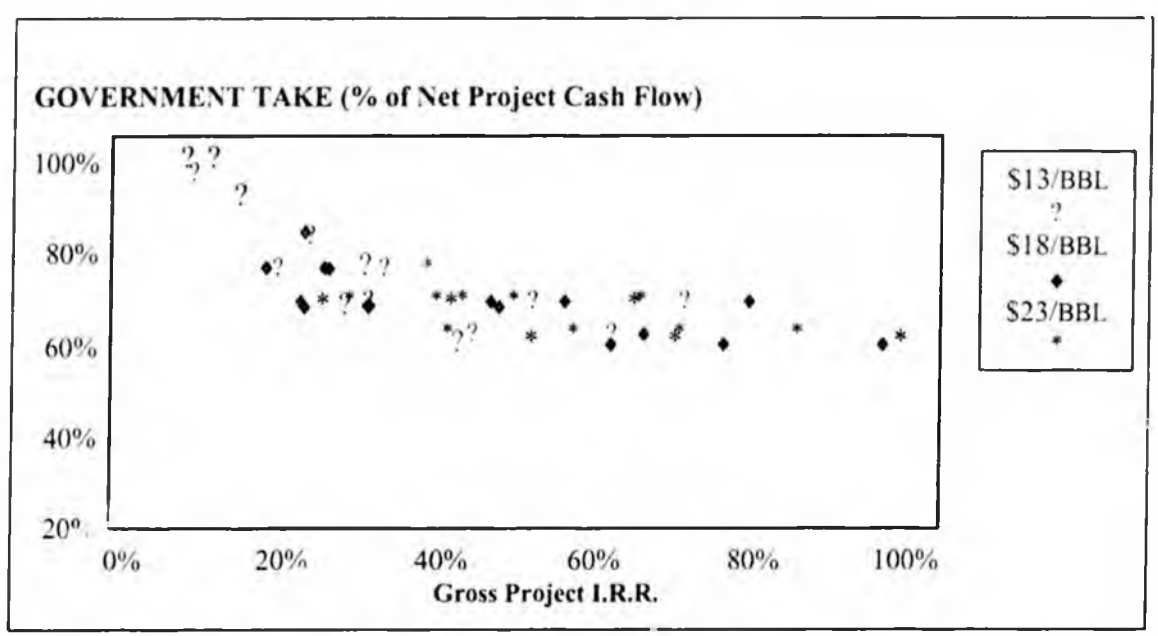
The guiding lights of fiscal system design are: Efficiency and Flexibility. These elements are not mutually exclusive.
Theoretically, an efficient, flexible contract is a more stable contract.

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**

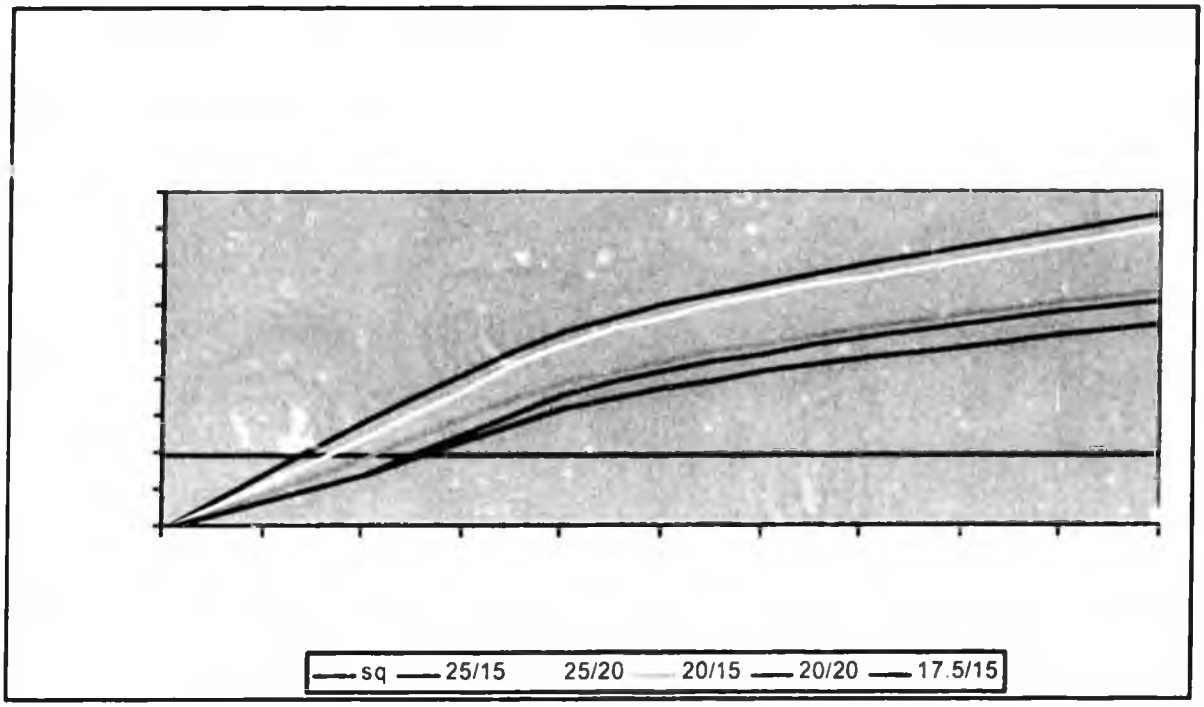
• **ROR Systems**
♦ **"R" factor**
+ **Price-based formulas**

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

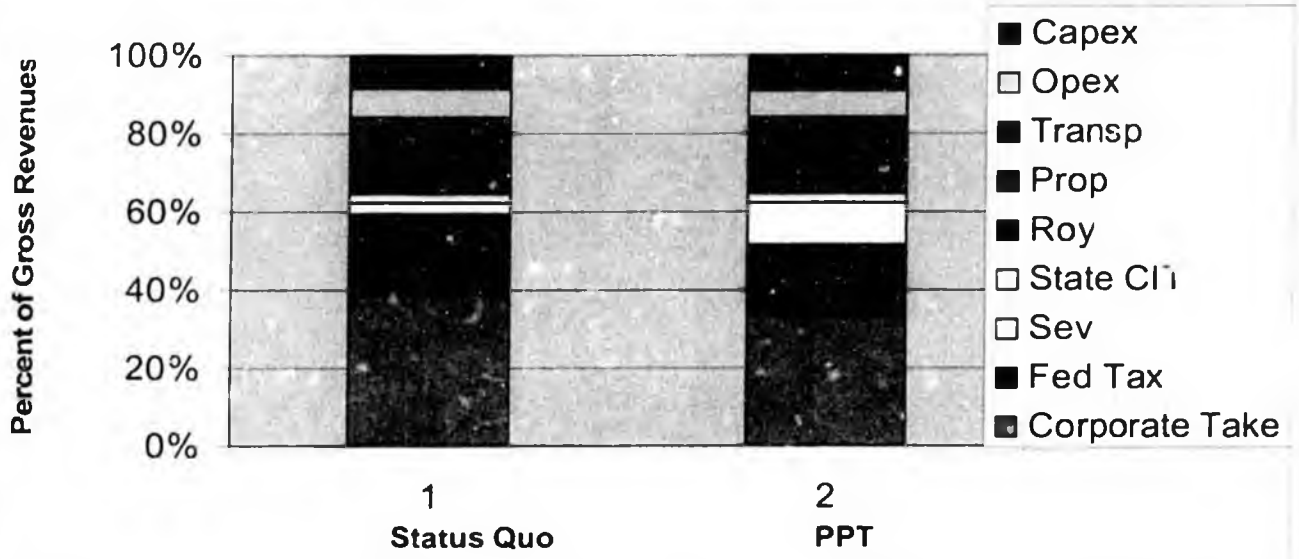
Estimated EFFECTIVE PPT RATES (from the graphs above)		
	$40/BBL	**$60/BBL**
Status Quo	**4%**	**4%**
25%/20% PPT as Proposed	**11.5%**	**15%**
Negotiated 20%/20% + Look-back	**< 8%**	**< 11%**
I assumed the "look-back" amounted to $1 Billion over 6 years = -$167 MM/year		

Government Take at $58 per BBL increases 14% with PPT 20/15%

I used this graph to illustrate that with this particular scenario i.e. 20/15% (like so many others) severance tax increase only results in an overall increase of Government Take of 14% (7 point increase from 49%). The Government Take statistic is the only reasonable barometer to use when discussing a change in terms. To say that the Severance tax increased by 100% or 200% is not fair or appropriate.

It brings to mind the famous "Panna-Mukta" dispute in India, which I will explain in my testimony.

Figure 12
Corporate Take at EIA Forecast Price ($58)
20% Tax/15% Credit
With Gasline & Enhanced Volumes

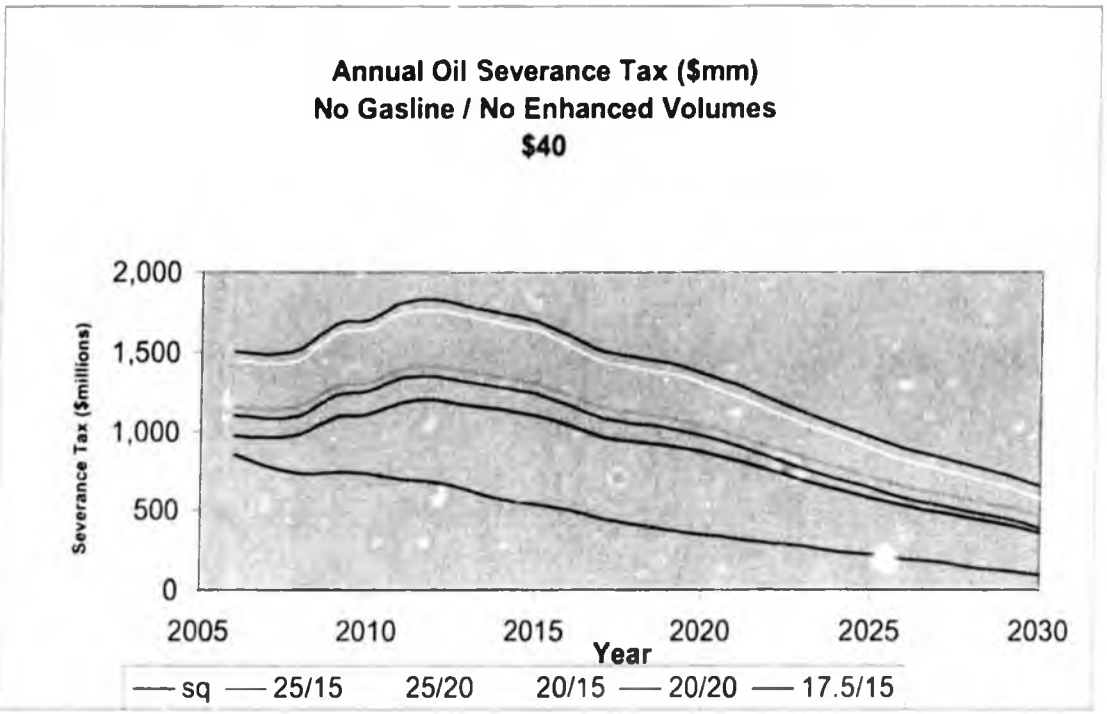


"Corporate take goes from 39% to 33% of gross revenues, or from 51% to 44% of the economic rent."

From: PPTAnalysis020106.ppt Roger Marks

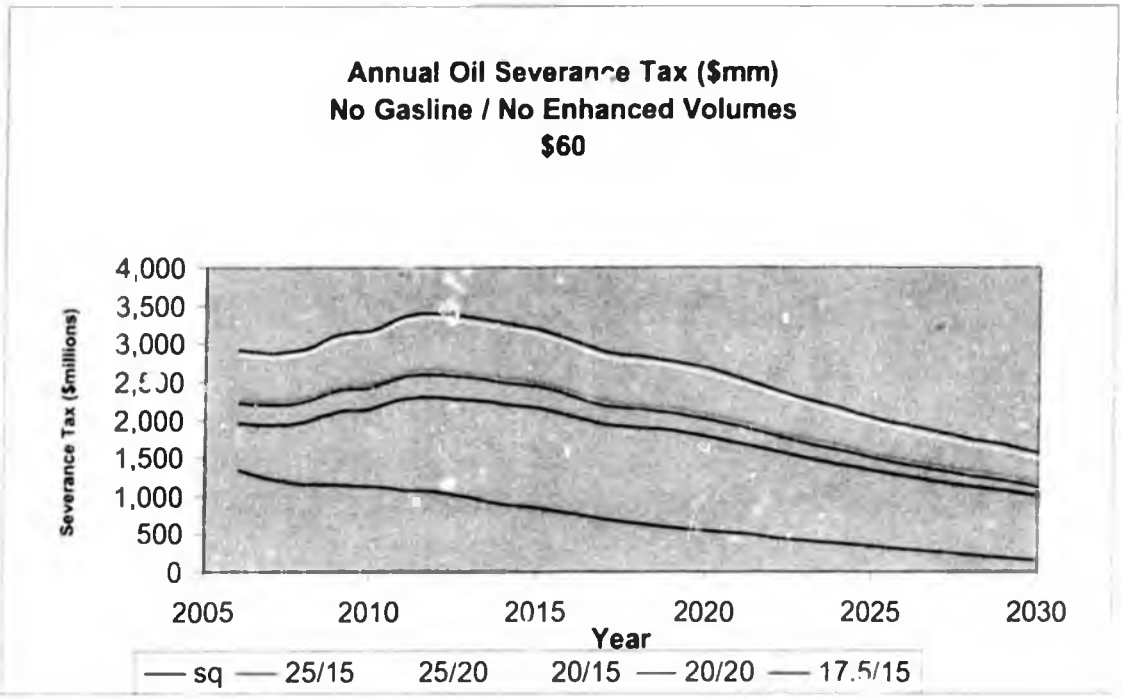
Note: Government Take goes from 49% to 56% an increase of 14%

Annual Oil Severance Tax - $40 per BBL



From: van Meurs 14 February, 2006 Report (pg 154-155)

Annual Oil Severance Tax - $40 per BBL



Estimated Near-term ALASKA ANNUAL REVENUES		
	$40/BBL	**$60/BBL**
Status Quo	**$ 800 MM**	**$1,200 MM**
25%/20% PPT as Proposed	**$ 1,500 MM**	**$2,900 MM**
Negotiated 25%/20% + Lookback	**$1,200 MM** **- 167 MM** **$1,033 MM**	**$2,300 MM** **- 167 MM** **$2,133 MM**
I assumed the "lookback" amounted to $1 Billion over 6 years = -$167 MM/year		

Industry Statistics - Handle with care!

When designing exploration terms the margin for error is not so critical i.e. plus or minus 5% or so depending on a variety of other factors such as the means by which a country allocates licenses or projects. However, with the Legacy Fields on the North Slope it is very different. There are millions of dollars per year represented by each percentage point of Government Take.

Important: The following statistics are "dated". We will discuss what has happened in the past few years. Also, most contract analysis in the past and now has focused on exploration projects not development type projects.

Database Table 7

World Petroleum Fiscal System Statistics

	PSCs	World Average	Royalty/Tax Systems
Number of Systems	72	136	64
Government Take	70%	65%	59%
Gvt. Participation			
Systems with Gvt. Participation (%)	36 (50%)	65 (48%)	29 (46%)
% Participation in those Systems with Gvt. Participation	25%	27%	30%
Royalty	5%	7%	8%
Effective Royalty Rate	23%	17%	8%
Ringfenced Systems	75%	55%	30%
Lifting Entitlement	63%	77%	92%
Savings Index	39¢	47¢	56¢
Cost Recovery Limit (PSCs only)	65%	N/A	N/A
Systems with ROR features or "R" factors	17%	21%	25%

From: "International Petroleum Fiscal Systems Database" PennWell Books (2002), Johnston

Weaknesses of Government Take

Before we press on, it is important to discuss the fact that Government Take is not a perfect statistic. We will have a difficult time ignoring it because it is an important metric but it can be more meaningful if we are aware of both the strengths and weaknesses.

Weaknesses of the Government take statistic:

- Does not adequately capture signature bonuses
  Unless analysis addresses both present value and risk — its an accuracy vs precision thing.
- Does not address "how" Government takes (such as front-end-loading)
  The companion statistic "ERR" helps here.
- Says nothing of timing and time value of money (unless "discounted")
- It's macroeconomic scope is too narrow.
  Does not measure all of the means by which Gvt. benefits i.e. **Gross Benefits**
  Such things as jobs.
- Says nothing of ringfencing (the ability to tax deduct costs incurred in one area against other license areas.
- Does not measure contract or system stability
- Reserve/lifting entitlements and "ownership" not accounted for
- Does not differentiate between diverse work program provisions
- By definition "Crypto taxes" don't get captured
- It is not relevant in some important situations Government take for exploration may not be the same statistic for development (the Gvt. participation thing)

From: "International Petroleum Fiscal Systems and Production Sharing Contracts" Course Workbook 2006, Johnston

More "dated" Industry Statistics - Handle with care!

Database Table 8 Fiscal System Statistics – for the more Prospective Countries 20th Percentile			
	PSCs	Average	Royalty/Tax Systems
Number of Systems	19	25	6
Government Take	78%	79%	80%
Gvt. Participation			
Systems with Gvt. Participation (%)	12 (63%)	17 (68%)	5 (83%)
% Participation in those Systems with Gvt. Participation	28%	32%	42%
Royalty	5%	6.8%	11%
Effective Royalty Rate	29%	24.5%	11%
Ringfenced Systems	90%	76%	33%
Lifting Entitlement	55%	63%	89%
Savings Index	30¢	31¢	37¢
Cost Recovery Limit (PSCs only)	62%	N/A	N/A
Systems with ROR features or "R" factors	26%	24%	16%

From: "International Petroleum Fiscal Systems Database" PennWell Books (2002), Johnston

More "Dated" Industry Statistics - Handle with care!

World Fiscal Terms – Regular and Special Situations			
	Government Take	**Effective Royalty Rate**	**Comment**
World Average for Oil (Includes all types of contracts: exploration, development, rehabilitation, EOR, heavy oil)	**65%**	**20%**	
World Average for Gas	**56%**	**15%**	Many contracts have a "gas clause"
Frontier Terms	**56-60%**	**15%**	
Heavy Oil Terms	**50%**	**10%**	These are still fairly rare
Deepwater Terms	**58%**	**13%**	

From: "International Petroleum Fiscal Systems and Production Sharing Contracts" (2006) Course Materials, Johnston

More "Dated" Industry Statistics - Handle with care!

Average State Take for Deepwater Projects

From: Petroconsultants "Review of Petroleum Fiscal Regimes (Oil) 1997."

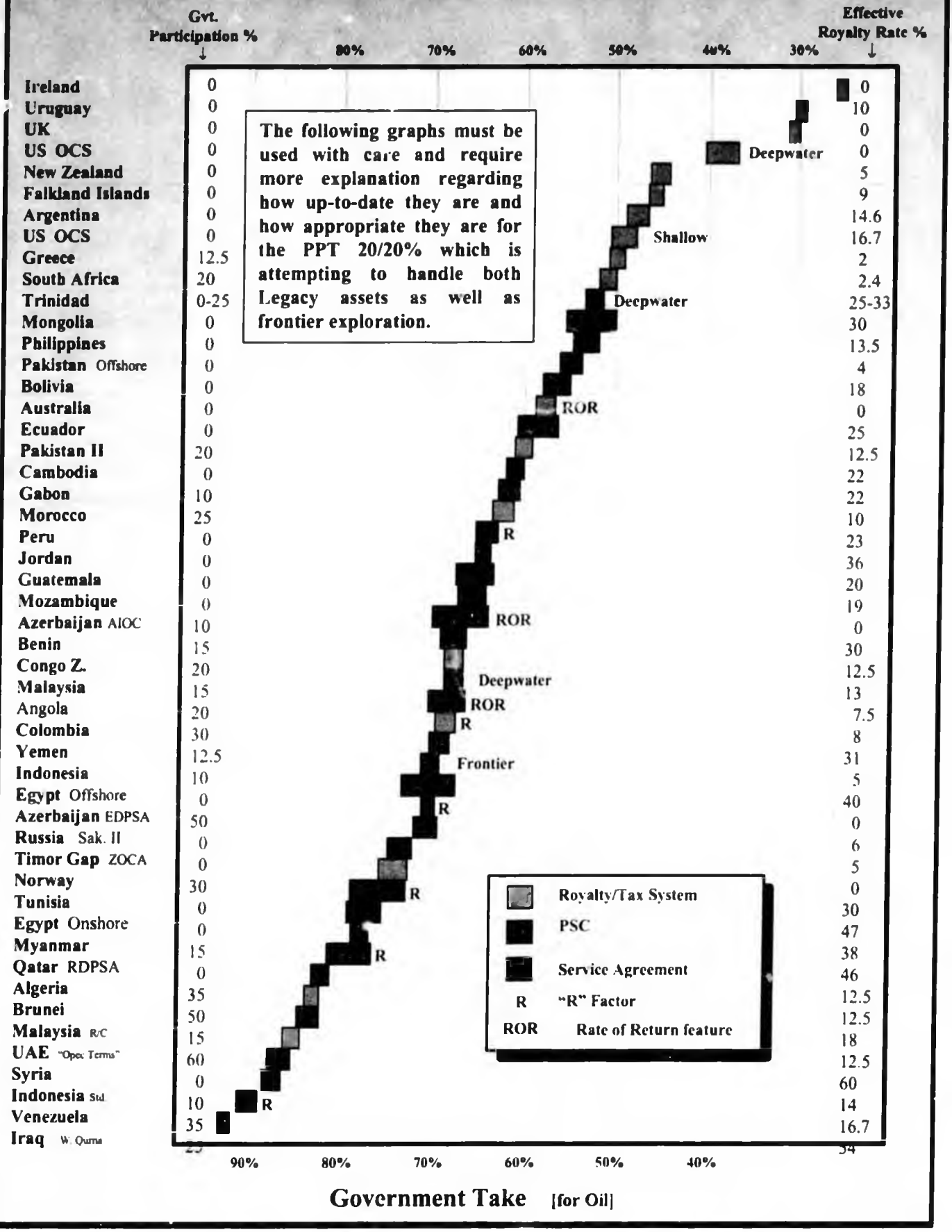
	Marginal Fields	Economic Fields	Upside Fields
UK	33.4%	33.0%	33.0%
USA (OCS)	46.1	41.4	37.1
Cote d' Ivoire	50.9	49.2	46.8
Nigeria	53.1	57.8	58.5
Thailand	53.3	54.7	50.5
Angola	56.2	52.6	64.8
Gabon	56.6	52.6	50.0
Congo	67.6	61.4	58.6
Indonesia	74.2	72.4	71.3
Malaysia	78.2	74.1	71.3
Average Deepwater	57.0	54.9	54.2
World Average (116 Fiscal Regimes)	69.9	65.1	63.9
Breakdown (From RFR 1995)			
72% Regressive	76.2	68.4	65.3
5% Neutral	56.5	55.8	55.7
23% Progressive	62.8	67.4	72.2

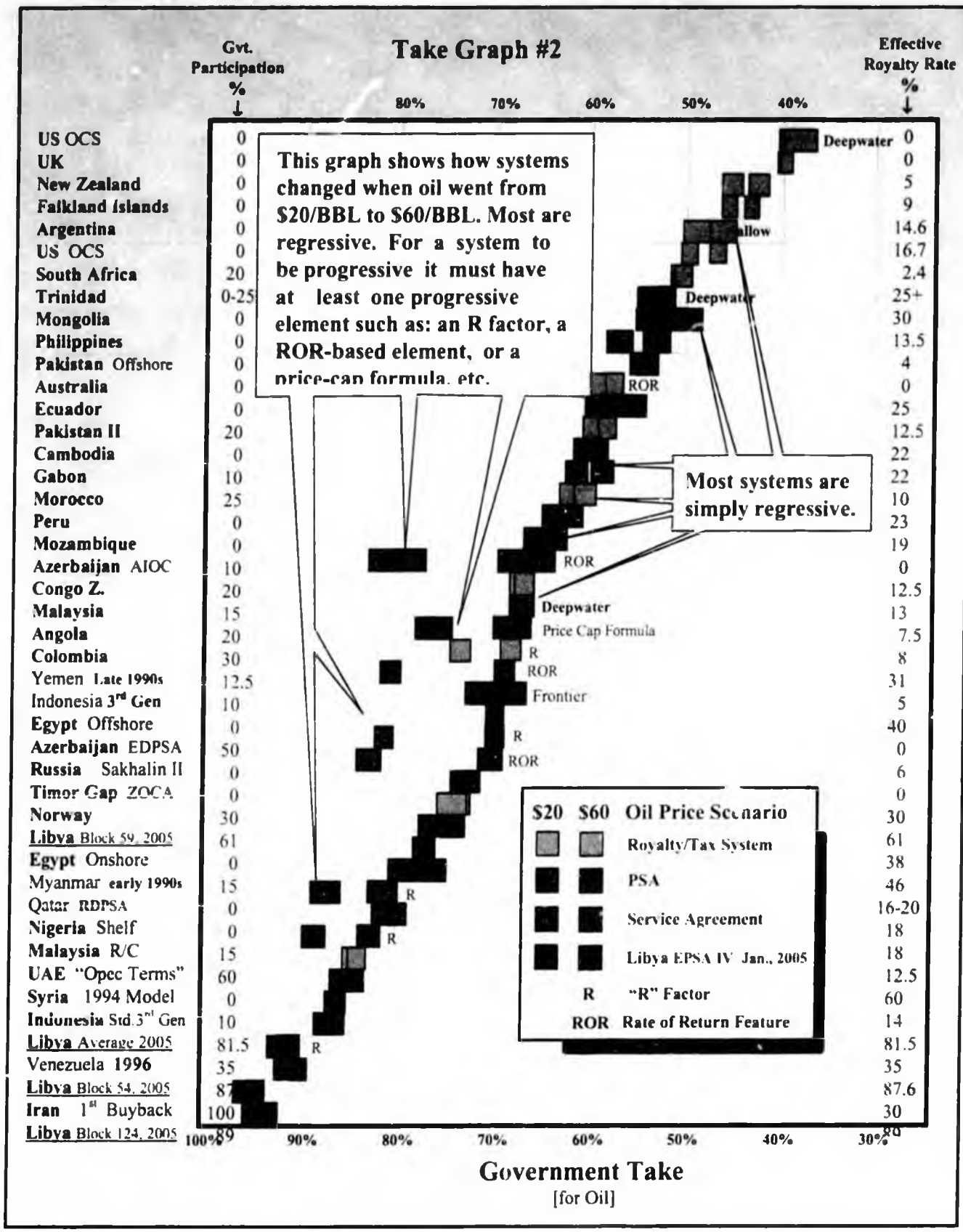
Average State Take (Peer Group Comparison)

From: Graham Kellas – Petroconsultants
"New Fiscal Incentives encouraging Global Push Into Deepwater Plays"
The American Oil & Gas Reporter – Special Report; April, 1997 (pg 47-50)

	Marginal Fields	Economic Fields	Upside Fields
20 Largest Producing Regimes	80.0%	74.6%	72.7%
30 Significant Producing Regimes	73.4%	66.7%	67.7%
66 Frontier Regimes	65.3%	60.5%	59.5%

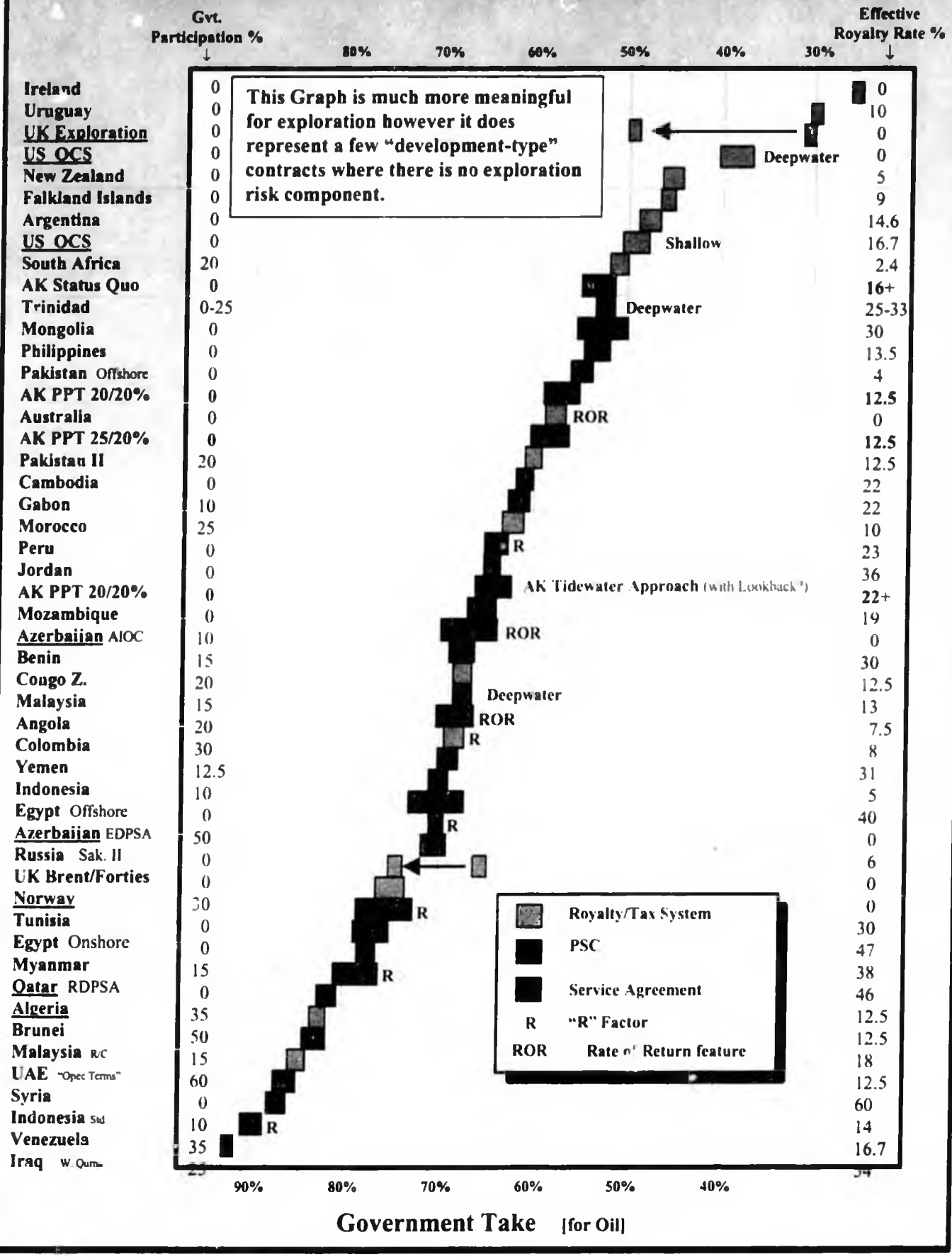
International Petroleum Exploration and Development Contracts #1



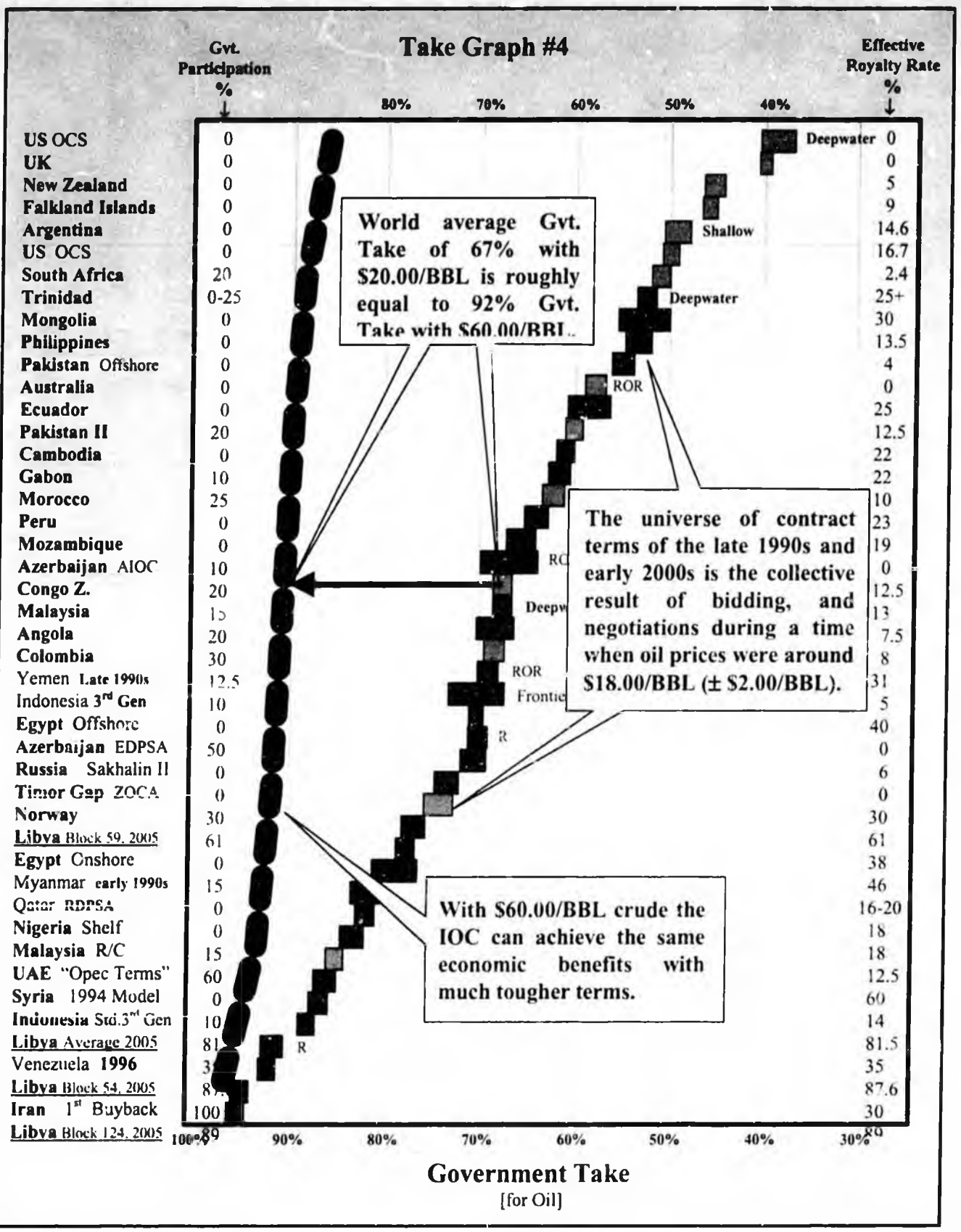


Difference between $20/BBL and $60/BBL

International Petroleum Exploration and Development Contracts #3



	Gvt. Participation %	Effective Royalty Rate %
Ireland	0	0
Uruguay	0	10
UK Exploration	0	0
US OCS	0	0
New Zealand	0	5
Falkland Islands	0	9
Argentina	0	14.6
US OCS	0	16.7
South Africa	20	2.4
AK Status Quo	0	16+
Trinidad	0-25	25-33
Mongolia	0	30
Philippines	0	13.5
Pakistan Offshore	0	4
AK PPT 20/20%	0	12.5
Australia	0	0
AK PPT 25/20%	0	12.5
Pakistan II	20	12.5
Cambodia	0	22
Gabon	10	22
Morocco	25	10
Peru	0	23
Jordan	0	36
AK PPT 20/20%	0	22+
Mozambique	0	19
Azerbaijan AIOC	10	0
Benin	15	30
Congo Z.	20	12.5
Malaysia	15	13
Angola	20	7.5
Colombia	30	8
Yemen	12.5	31
Indonesia	10	5
Egypt Offshore	0	40
Azerbaijan EDPSA	50	0
Russia Sak. II	0	6
UK Brent/Forties	0	0
Norway	30	0
Tunisia	0	30
Egypt Onshore	0	47
Myanmar	15	38
Qatar RDPSA	0	46
Algeria	35	12.5
Brunei	50	12.5
Malaysia R/C	15	18
UAE "Opec Terms"	60	12.5
Syria	0	60
Indonesia Std	10	14
Venezuela	35	16.7
Iraq W. Qurn.	25	34



What terms would yield the same economic benefit at $60/BBL?

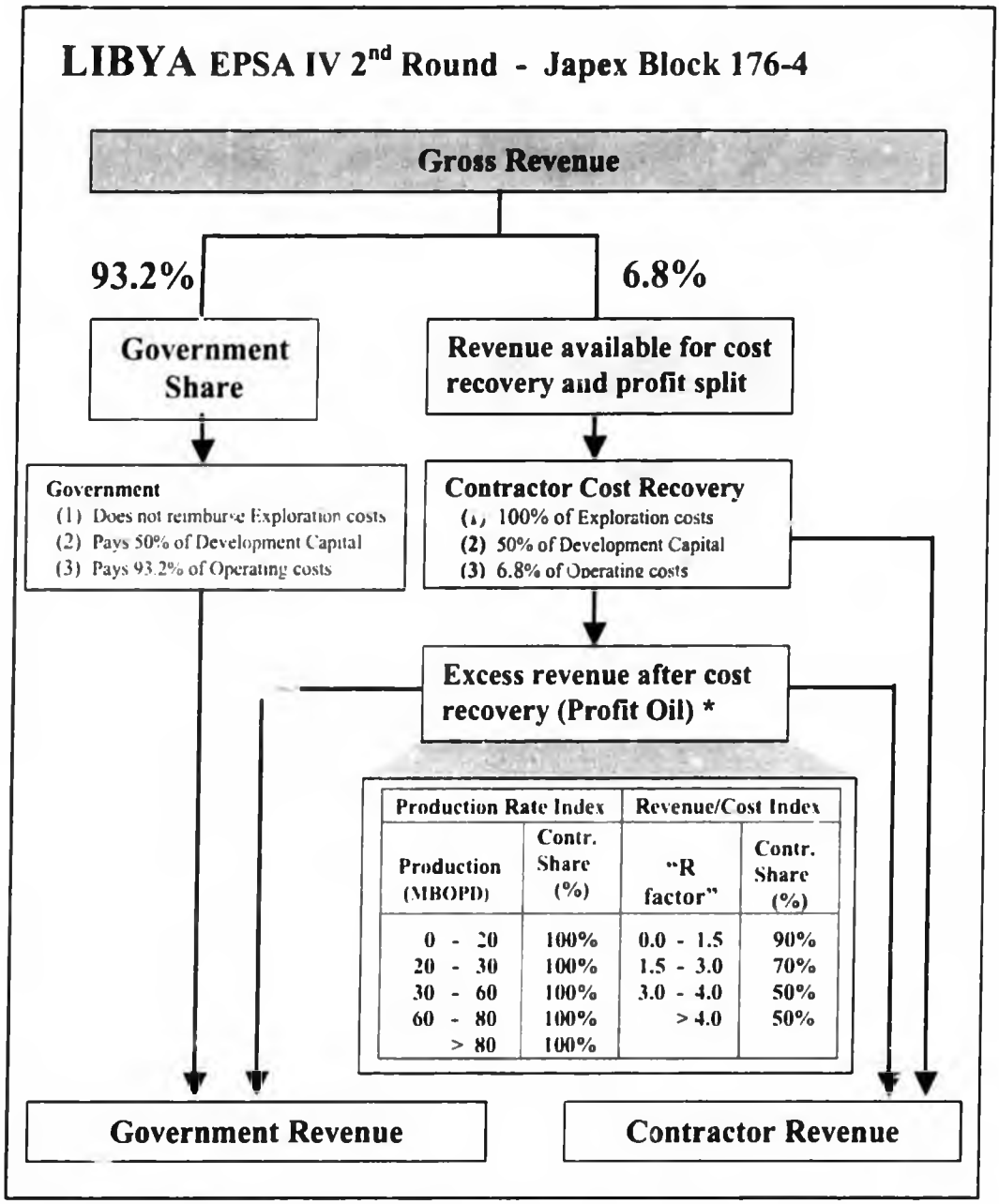
Contract Duration

This graph is provided in response to a statement made by one of the oil company representatives claiming that typical contract term, or duration, was 50-60 years. That is not consistent with my experience. The implications are heavy.

Examples of Contract Duration Worldwide

Province/Block	Exploration Years	Production Years
Abu Dhabi	3 + 2 + 2	33
Ajman	2 + 2 + 2	35
Albania	2 + 3 + 1.5	24
Algeria	5 + 2	15 - 30
Algeria	5 + 2	20 - 25
Australia	6 + 5	42
Beliz	8	25
Benin	2 + 2 + 2	25 + 10
Bolivia		30 Max
Brunei	8	38 + 30
Brunei Offshore	17	40 + 30
Cambodia	3 + 2 + 1	22
Congo Br.	4 + 3 + 3	30
Congo Br.	10	30
Cote d'Ivoire	2 + 2 + 2	25
Czech Rep.	4 + 4	20
Dubai	3 + 2 + 3	35
Ecuador	4 + 2	22
Egypt	8	20
France	5 + 5 + 5	5 + 5 + 5
Gabon Deepwater	5 + 3	10 + 5 + 5
Gabon	3 + 2 + 2	25
Ghana	7	18 (25 Total)
Guyana	4 + 3 + 3	25 + 5
Honduras	4 + 2	20 + 5
Hungary	2 + 2 + 1	25
India	3 + 2 + 2	25 + 5
Indonesia	3	20
Liberia	3 + 3	25 + 10
Madagascar	8	15 + 5
Malaysia	3 + 2 2 + 2 Dev	15
Malaysia R/C	5	29 Total
Netherlands	10	40
Nigeria	3 + 3 + 4	20
Oman	2 + 2 + 2	20 + 10
Peru	7	30
Poland	3 + 3	20 + 5 + 5
Rep. of Guinea	5	21 (Maz 25)
Senegal	3 + 2 + 2	25 + 10
South Africa	4 + 3 + 3	as long as is profitable
Syria	3 + 2 + 1	20 + 10
Vietnam	3 + 1 + 1	20 (total not to exceed 25)
Zambia	8	25
Average/Typical	3 + 2.5 + 2 (7.5)	25

Lybia's Latest License round - Mechanics



EPSA IV Terms – Flow Diagram * **Assumed P/O split** (not known yet)

The Expected value (EV) formula

This is the basic equation of modern day risk analysis. The rule is: If expected value is positive then the reward outweighs the risk. Companies try to choose investment opportunities that maximize expected value.

Expected value = Reward * SP - Risk capital * (1-SP)

Where:

Risk capital =	Costs associated with testing a prospect. Typically consists of dry hole costs , geological/geophysical costs, and possibly a signature bonus.
Reward =	Present value of possible successful exploration efforts based upon discounted cash flow analysis of a hypothetical discovery typically discounted at (or close to) corporate cost of capital. [see tables T 1.3 and T 1.4]
SP =	Probability of success (Likelihood of actually making a discovery – Estimated by geotechnical personnel.)
1 – SP =	Probability of failure (Likelihood of drilling a dry hole and losing the risk capital).

This formula provides the cornerstone of risk analysis. The rule is that if EV is positive, then the risk-weighted reward outweighs the risk-weighted cost of failure.

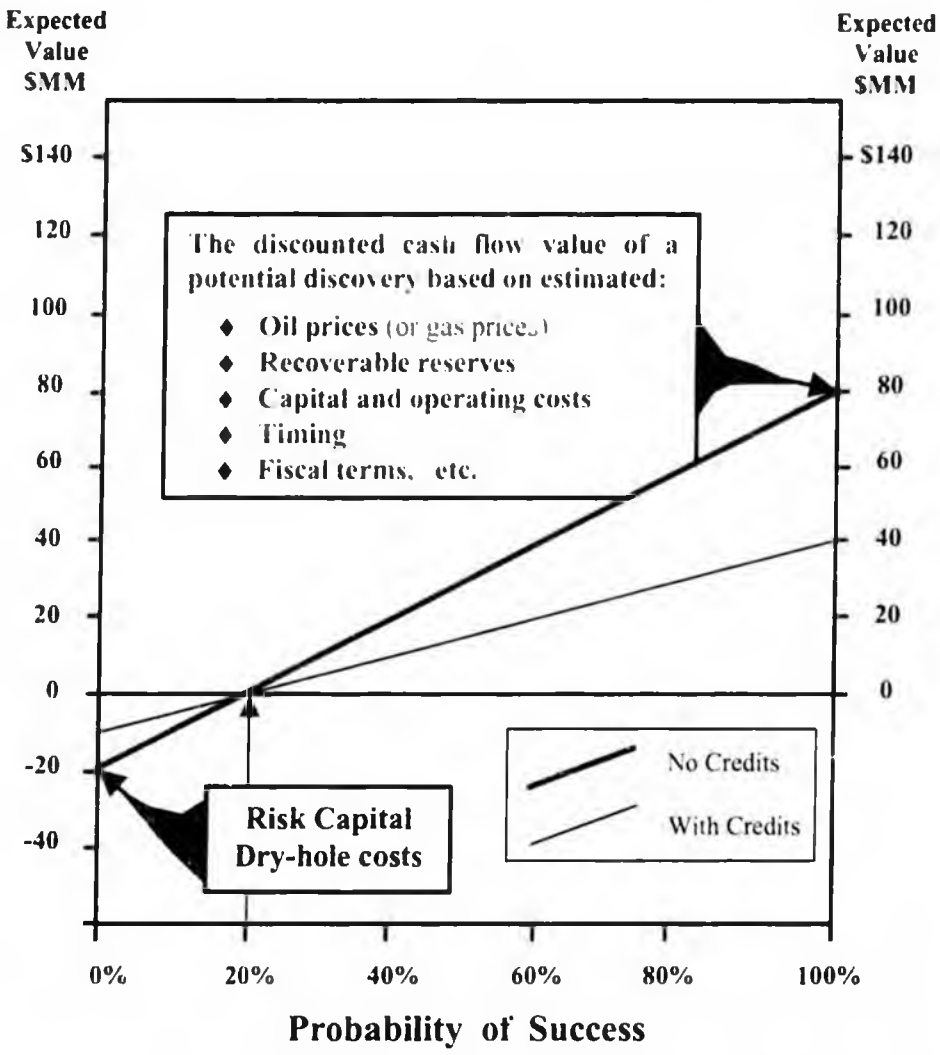
The expected value formula, whether it is used directly or indirectly (gut feel), provides the basis for billions of dollars of exploration investments. It is normally more complex with the common practice in the industry of using multiple outcomes (at least 3) on the "reward side" of the equation.

Expected Value

Assume: **(1) dry-hole cost (risk capital) is $20 MM**
(2) estimated probability of success is 20%
(3) a potential prospect would have to be worth $80 MM to the Company before they could even consider risking their capital drilling it.

This might correspond to say a 200 MMBBL prospect, i.e. "exploration threshold field size". Therefore prospects must be larger than 200 MM.

A credit arrangement like the one in-place now (not PPT 20/20%) reduces the "risk exposure" by 50%. Companies can justify smaller prospects (about half the size). The question is: With a credit system addressing the "risk side" of the equation what can be done on the "reward side" without destroying the incentive. The explorers in Alaska are close to the edge at even $40/BBL. Much to discuss.



BP Presentation on Proposed PPT (28 February, 2006)

"Because oil and gas co-exist in the same underground reservoirs, they are produced together through the same investments made in wells and facilities, they are also linked economically.

This inextricable physical and economic linkage is widely recognized by both governments and investors around the world.

North American royalty contracts cover both oil and gas. Internationally, production sharing contracts include terms for both oil and gas. General oil and gas tax laws across the U.S. and internationally always address both oil and gas.

Governments want to know how much money they will receive from oil and gas production. Similarly, investors need to know how much they will pay governments when oil and gas is produced and sold and make their investment decisions accordingly."

From: page 2 starting at paragraph 4 (emphasis added)

Contrast this with a common and typical "gas clause" found in many countries – in this case Angola.

Non-associated Gas: If non-associated natural gas is found, Sonangol and the contractor have 36 months, or such longer period as may be agreed upon, after the discovery date to agree terms under which it might be developed, whether for oil field operations, domestic consumption or export.

If no agreement is reached within that time, Sonangol may develop the discovery for its own account. Sonangol may agree for the contractor to opt back into the discovery, with reimbursement of Sonangol's expenses plus 1,000% of such expenses.

(This is like a "sole risk" provision)

Ringfencing

The issue of recovery or deductibility of costs is further defined by the revenue base from which costs can be deducted. Ordinarily all costs associated with a given block or license must be recovered from revenues generated within that block. The block is "ringfenced." This element of a system can have a huge impact on the recovery of costs of exploration and development. Indonesia requires each contract to be administered by a separate new company. This restricts *consolidation* or effectively erects a ringfence around each license area.

Some countries will allow certain classes of costs associated with a given field or license to be recovered from revenues from another field or license. India allows exploration costs from one area to be recovered out of revenues from another, but development costs must be recovered from the license in which those costs were incurred.

From the government perspective any consolidation or allowance for costs to cross a ringfence means that the government may in effect subsidize unsuccessful operations. This is not a popular direction for governments because of the risky nature of exploration. However, to allow exploration costs to *cross the fence* can be a strong financial incentive for the industry.

The importance of risk dollars has already been demonstrated. If a country with an effective tax burden of 50% allowed exploration costs to be deducted across license boundaries then the industry would be drilling with 50¢ dollars. It would cut the risk in half. From the perspective of the development engineer, it has little meaning unless development and operating costs are also allowed to cross. Dropping or loosening the ringfence can provide strong incentives, especially to companies that have existing production and are paying taxes.

In the early 1980s exploration in the UK sector of the North Sea reached record levels (due to changes resulting from the 1983 budget). This is because the government allowed exploration costs to cross the ringfence as deductions against the 75% PRT tax on older fields. This created a huge exploration incentive for any company paying PRT taxes. Some of the larger companies had substantial unused tax cover, and smaller companies did not have enough. The smaller companies purchased what came to be known as "Forties Units" to take advantage of the exploration relief provided by the hole in the ringfence. These "units" were a quarter of a 1% working interest in the British Petroleum operated Forties field which during that time was producing in excess of 160,000 BOPD. By late 1984 BP's Forties field had gained 22 new owners all with shares of less than 2%. A dozen companies owned only a 0.25% working interest "unit". The dynamics of ringfencing can be spectacular. The UK sector of the North Sea became the hottest offshore province in the world. By 1993 when the PRT was abolished, few fields were actually paying PRT. (Notice: This section comes straight from my course materials. Considering the intensity of the oil tax negotiations in Alaska I am researching this further as of 4 March, 2006 DJ).

- **Trinidad** decided to ringfence their deepwater license round in order to maintain a level playing field.

- This is also the kind of thing found in countries where there are different terms for oil vs gas. **Indonesia** does not allow costs from gas developments to be recovered from oil fields.

- **Colombia** is supposedly not ringfenced but unsuccessful exploration costs *within* a license area are not deductible unless they can be shown to have contributed in some way to the ultimate discovery.

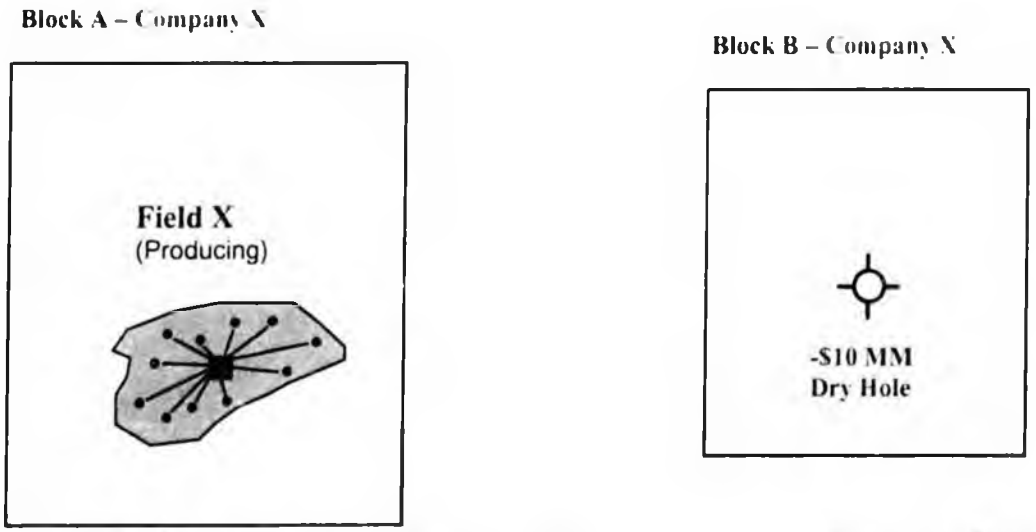
- **New Zealand** considered having the potential of a ringfence within a ringfence like that in Colombia (above). But decided it would be too hard to "sell".

- Lack of a ringfence = Government as silent partner in exploration.
  Some say "widows and orphans as silent partner".
  Some use the word "subsidize" in this context (See Norway below).

- **Norway** has no ring fence. But that is not all. If a company drills a dry exploration well **the government will reimburse** 78% of the costs just as if the company had production against which it could deduct the expenses. This is very unusual!

Most countries "ringfence" their acreage – that is, they do not allow consolidation.

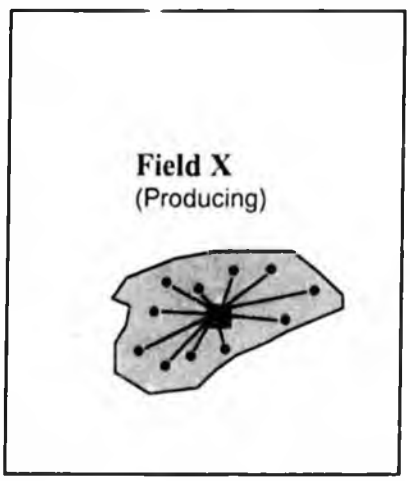
Assuming Company X drills a dry hole in Block B. With typical ringfencing the company would not be able to take the $10 MM loss and apply it to production/revenues in Block A for cost recovery purposes or as deductions for tax calculation purposes.



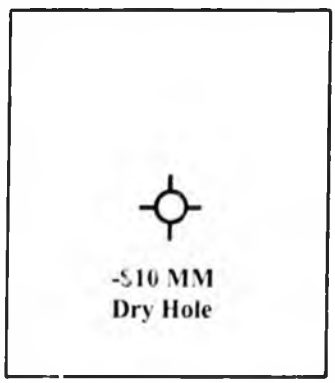
ALASKA PPT 20/20% Approach

Assume Company X drills a dry hole in Block B. With the PPT 20/20% system the Company X would be able to take the $10 MM loss and effectively apply it to production/revenues in Block A with Company B as deductions for (PPT) tax calculation purposes and it would be able to sell its 20% tax credit to Company B.

Block A – Company B



Block B – Company X



Alaska's Severance Taxes (also referred to as Production Taxes) **and The Economic Limit Factor (ELF)**

Severance taxes are a function of field vintage

Severance tax rate on Oil	
1st 5 years of production	12.5%
After 5 years	15%
(for fields in production after 1981)	
Fields in production prior to 1981	15%
There is a minimum tax of	$0.80/bbl
Severance tax on Gas	
Fields in production prior to 1981	10%
There is a minimum tax of	$0.64/Mcf

The Severance Tax was also a function of ELF, which was designed to differentiate the tax rate on the new super giant Prudhoe Bay oilfield and old declining fields in Cook Inlet.

Severance Tax paid = Severance Tax * ELF (even if severance tax is at minimum)
ELF Formula for Oil

$$ELF = (1-(300/PPW))^{((150{,}000/TP)^{1.5333})}$$

Where PPW = avg production/well/day in a field
TP = avg daily production from a field

Note: ELF was born in 1977, the same year the 800 mile TAP was completed.
If average production/well/day in a field is < 300 bbls, ELF = zero, no severance taxes are due.
300 bbls/day was considered breakeven for a North Slope well at that time. And it appears that the breakeven calculation assumed considerable infrastructure costs associated with new fields and wells.

Voodoo Economics?

Psychologists wear thin on lawmakers

By Doug Robarchek
Knight-Ridder Newspapers

Do you get the feeling that when psychologists testify in court as "expert witnesses," there's the odor of voodoo about them?

New Mexico State Sen. Duncan Scott thinks so. He proposed amending a bill so that psychologists would be required to wear cone shaped wizard hats with stars and lightning bolts on them when they testify, according to the Western Journalism Center in Fair Oaks, California.

The amendment also would have required psychologists to wear long beards and carry wands in court. The bailiff would have been ordered to dim the courtroom lights and strike a Chinese gong during testimony.

What's more — we love this — the bill passed both houses of the New Mexico legislature.

Unfortunately, the governor vetoed it.

Distributed by Knight-Ridder Tribune News Wire

Dallas Morning News – 27 January, 1997

Daniel Johnston

Daniel Johnston lives and works out of his home in the New Hampshire countryside. He and his wife Jill have 6 children.

Daniel has 27 years experience in the petroleum industry. For 21 years he has been an independent financial consultant to the international petroleum industry. He has worked for 22 governments and most of the major and largest independent international oil companies. His consulting work focuses on the accounting, economic, and financial aspects of international petroleum exploration, contract negotiations, and petroleum fiscal system analysis and design.

He has testified as a financial expert witness in/and-or involving disputes in India, Australia, Russia, Turkmenistan, China, Yemen, California, Gabon, the Czech Republic, Equatorial Guinea, Indonesia, Kazakhstan, Myanmar, Texas, Timor Gap, Brussels, Wellington, Vienna, The Hague, and Vietnam.

He has a Bachelor of Science Degree in Geology from Northern Arizona University where he currently sits on the Advisory Council for the College of Arts and Sciences. He also has an M.B.A. (Finance) from the University of Texas at Austin.

He has published numerous articles and lectures worldwide on the subjects of: Economics and Risk Analysis; Petroleum Fiscal Systems; and Financial Analysis. Over 3,700 delegates from IOCs and NOCs from 60 countries have taken his courses.

He is author of

"Production Sharing Agreements" University of Dundee-Scotland (1994)
"Oil Company Financial Analysis in Nontechnical Language" PennWell (1992),
"International Petroleum Fiscal Systems and Production Sharing Contracts" (1994),
"International Oil Company Financial Management in Nontechnical Language" (1998)
"International Petroleum Fiscal Systems Analysis" Database (2001) PennWell
"Maximum Efficient Production Rate" (2002) University of Dundee (With David Johnston)
"Economic Modeling and Risk Analysis Handbook" (2002) U. of Dundee (With D. Johnston)
"International Exploration Economics, Risk and Contract Analysis" PennWell (2003)
"Introduction to Oil Company Financial Statement Analysis" PennWell (2005)

He is a column editor for the Petroleum Accounting and Financial Management Journal (PAFMJ) published by the Institute of Petroleum Accounting at the University of North Texas. He is also a charter member of the editorial board of Global Energy Outlook, published by Gordon Moody.

Daniel is an Honorary Lecturer at the University of Dundee, Scotland where he teaches public and industry courses and graduate seminars each May.

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(FILE 11)

Testimony Before the Senate Resources Committee

My name is Michael D. Williams and I am the Chief Economist for the Alaska Department of Revenue. I have lived in Alaska for a little over a year and I do not know all of you in this room. I have been in the oil gas business for over 20 years in various capacities including being an Economic Advisor to the Saudi Arabian Minister of Finance, a Principal Administrator with the international Energy Agency in Paris, and an Economist with Marathon Oil Company. I have operated my own consulting company at different times in my career and [as part of my work], conducted the empirical analysis for the Pulitzer Prize winning book "The Prize" by Daniel Yergin. My education includes a Ph D in economics and I wrote my Ph D dissertation on Alaskan natural gas.

The purpose of my talk today is to discuss future crude oil production volumes in Alaska, but before I do that I want to examine some of our earlier forecasts. An examination of our forecasts reveals that we usually over-estimate production volumes [see chart #1 & Explain]. There are two main reasons for this error and they are the following:

- **Maturity of the Prudhoe Bay field** – The field has been producing oil for close to 30 years and is subject to problems associated with an aging field. Thus, leaks in pipelines – such as what occurred on Thursday – and other events are more likely to occur. To reflect this reality, our production rate for future years has been decreased at Prudhoe Bay.
- **Difficulties Developing "Heavy Oil"** – dealing with the viscous oil on Alaska's North Slope requires new techniques and technologies. Because of the issues dealing with viscous oil, many of the viscous oil projects have been delayed as the oil companies attempt to figure out the best way to deal with this gooey substance. To reflect reality, the speed with which the production from heavy oil comes on-line in our forecast has also been delayed.

For the spring 2006 forecast, the Department of Revenue continues to make adjustments to our production expectations from the North Slope. In the near term, we have incorporated revised reservoir performance analysis on declining fields, reviewed the uncertainty associated with the pace and scope of developing satellite fields and re-evaluated unplanned downtime at all fields, especially Prudhoe Bay, resulting in a net reduction, on average, of

about 30,000 barrels per day over the next five years. Roughly half of this reduction is attributed to reservoir performance and facility related downtime and half is related to the pace of development of heavy oil, primarily at West Sak. We now forecast ANS production to average slightly above 800,000 barrels per day for FY 2007 through FY 2011.

North Slope crude oil production is characterized in three ways, each with discrete, albeit estimated confidence levels: (1) currently producing, (2) currently under development and (3) currently under evaluation. We do this so that you will have an understanding about the uncertainty associated with the production forecast. We continue to forecast production of only those reserves that have already been discovered and at minimum are being evaluated for development.

Oil production in Alaska is forecast to decline at a rate of about 6% in FY 2006 and about 1.5% per year thereafter [see chart #2 & Explain]. I will now describe the forecast categories in this chart.

- Production characterized as "currently **producing**" includes baseline production and presumes a continued level of expenditure sufficient to promote safe, environmentally sound operations. Such expenditures include the following: well diagnostic and remedial work, data acquisition and rate-enhancing expenditures such as perforating, acid stimulation, well work-overs, fracture treatments, artificial lift optimization and production profile optimization. This category of production also presumes continued gas and water injection for pressure support. Based on historical forecasting performance, we assign a 98% confidence level for the current fiscal year.
- Production characterized as "currently **under development**" is based on new projects currently funded and in the design/construction phase, as well as development drilling and enhanced oil recovery (miscible or immiscible injection) projects, currently funded or underway, but not included in the "currently producing" category. It also includes incremental oil expected from the long-term gas cap water injection project at Prudhoe Bay and the low salinity water-flood at Endicott. Examples of production "currently under development" include the Fiord and Nanuq satellites at Alpine, remaining J-Pad development at West Sak, development drilling at Schrader Bluff and certain satellite development at Prudhoe Bay. We have slowed the pace of development at all heavy oil fields to allow proper mitigation of

Testimony Before the Senate Resources Committee

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The purpose of my talk today is to discuss future crude oil production volumes in Alaska, but before I do that I want to examine some of our earlier forecasts. An examination of our forecasts reveals that we usually over-estimate production volumes [see chart #1 & Explain]. There are two main reasons for this error and they are the following:

- **Maturity of the Prudhoe Bay field** – The field has been producing oil for close to 30 years and is subject to problems associated with an aging field. Thus, leaks in pipelines – such as what occurred on Thursday – and other events are more likely to occur. To reflect this reality, our production rate for future years has been decreased at Prudhoe Bay.
- **Difficulties Developing "Heavy Oil"** – dealing with the viscous oil on Alaska's North Slope requires new techniques and technologies. Because of the issues dealing with viscous oil, many of the viscous oil projects have been delayed as the oil companies attempt to figure out the best way to deal with this gooey substance. To reflect reality, the speed with which the production from heavy oil comes on-line in our forecast has also been delayed.

For the spring 2006 forecast, the Department of Revenue continues to make adjustments to our production expectations from the North Slope. In the near term, we have incorporated revised reservoir performance analysis on declining fields, reviewed the uncertainty associated with the pace and scope of developing satellite fields and re-evaluated unplanned downtime at all fields, especially Prudhoe Bay, resulting in a net reduction, on average, of

about 30,000 barrels per day over the next five years. Roughly half of this reduction is attributed to reservoir performance and facility related downtime and half is related to the pace of development of heavy oil, primarily at West Sak. We now forecast ANS production to average slightly above 800,000 barrels per day for FY 2007 through FY 2011.

North Slope crude oil production is characterized in three ways, each with discrete, albeit estimated confidence levels: (1) currently producing, (2) currently under development and (3) currently under evaluation. We do this so that you will have an understanding about the uncertainty associated with the production forecast. We continue to forecast production of only those reserves that have already been discovered and at minimum are being evaluated for development.

Oil production in Alaska is forecast to decline at a rate of about 6% in FY 2006 and about 1.5% per year thereafter [see chart #2 & Explain]. I will now describe the forecast categories in this chart.

- Production characterized as "currently **producing**" includes baseline production and presumes a continued level of expenditure sufficient to promote safe, environmentally sound operations. Such expenditures include the following: well diagnostic and remedial work, data acquisition and rate-enhancing expenditures such as perforating, acid stimulation, well work-overs, fracture treatments, artificial lift optimization and production profile optimization. This category of production also presumes continued gas and water injection for pressure support. Based on historical forecasting performance, we assign a 98% confidence level for the current fiscal year.
- Production characterized as "currently **under development**" is based on new projects currently funded and in the design/construction phase, as well as development drilling and enhanced oil recovery (miscible or immiscible injection) projects, currently funded or underway, but not included in the "currently producing" category. It also includes incremental oil expected from the long-term gas cap water injection project at Prudhoe Bay and the low salinity water-flood at Endicott. Examples of production "currently under development" include the Fiord and Nanuq satellites at Alpine, remaining J-Pad development at West Sak, development drilling at Schrader Bluff and certain satellite development at Prudhoe Bay. We have slowed the pace of development at all heavy oil fields to allow proper mitigation of

challenging commercial and technical issues. Because of timing and scope uncertainty, our subjective confidence for this category of production is approximately 80-85%.

- Production characterized as "currently **under evaluation**" includes technically viable projects currently in the "pencil sharpening" stage where engineering, cost, risk and reward are all being actively evaluated. These projects are all currently unfunded by the operators but have a high chance of being brought to fruition. They include enhanced oil recovery at certain satellite fields, development drilling outside the core areas at West Sak and Schrader Bluff, expanded development at Prudhoe Bay satellites Orion, Polaris and Borealis and Alpine West development. Also included in this category is NPR-A development, Point Thomson, Liberty and development of other known onshore and offshore discoveries. Regarding NPR-A, we are forecasting production from four small 'puddles' in the vicinity of known discoveries currently named 'Lookout', 'Moose's Tooth', 'Spark' and 'Rendezvous'. Since these discoveries have been announced, there has been ongoing exploration outside the boundaries of these accumulations, and explorers continue to push further west in search of new development opportunities. Confidence levels vary for this category of production. Certain heavy oil development drilling for Schrader Bluff, Orion or West Sak in 2007 might have confidence levels approaching that of "production under development". Offshore developments such as Liberty, or potentially high cost, scope challenged developments such as Point Thomson probably deserve lower confidence, and our subjective assessment is in the 70%-75% range. All production from this category is subject to delays and scope changes that might impact reserves or production rates.

There are many details surrounding this forecast which are based on petroleum engineering knowledge – and I am not an engineer. In addition, I have only lived in Alaska for a year so I do not have the in-depth knowledge that he has. Our petroleum engineer prepared the forecast, and, for the more involved questions regarding geology and engineering, I will turn to our engineer for support.

Developing crude oil resources is capital intensive and will require significant investment in time and capital. The Governor's proposal tax system – the PPT – creates a fiscal framework that provides strong incentives for

exploration and reduces the risks and capital costs of development. Most importantly, it provides a long term revenue stream to the State by encouraging new participants and supporting new development.

This concludes my remarks and I will attempt to answer your questions.

Here are the Questions that remained to be answered by DOR (from March 2-3, 2006)

1. "look-back" – excel files to be provided.
8. progressivity structure for tax – not yet answered
11. claimed expenses under sb 185 – table to be provided
14. terms – they requested clarification from us
17. check on the order of credits to be applied
18. during discussion with outside law firms, did it change any of the bill provisions?
20. See #1
21. similar to question in #18.
22. define point of production - to be provided
23. gas treatment-processing facilities – to be provided.
24. get a list of the cases
25. historical analysis – to be provided
27. AS 43.55.160(j) -- to be provided
29. estimates of undiscovered resources – to be provided
31. Net Profit Share Leases – to be provided
37. to double check the sentence "Currently there is no "free use of oil" to produce more oil in statute.
40. other nations with profit system – to be provided
41. "true-up" issue – to provide more info on this.
49. estimated economic impact – to be provided
54. section 21, page 1, line 8 – to be provided.
57. clarify – some of the named had a tax when they exceeded the named value
58. language clean up – typo's sentence repeats.
66. oil field needs – to be provided

67, 68, 69, 70, 71 and 72 - to be provided

March 7, 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,

This letter contains our second interim series of questions and answers related to the above-reference legislative bills. We have listed below only those items for which we have provided answers, or provided additional information, since Friday, March 3, 2006.

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

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.

(millions $)	Exploration	Development	Total
2001	152	1,636	1,788
2002	125	1,054	1,180
2003	90	970	1,060
2004	67	980	1,047

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

Progressive features are relatively common around the world. Following is a list of the main fiscal regimes with such features. "Old" features are defined as features that have been in existence for more than 20 years. "New" less than 20 years.

There is a wide variety of systems that are progressive with the level of well production or field production. These systems are not included in the list.

Country	Region/Type	Feature	Oil/Gas	Old/New
Canada	NWT	IRR based profit sharing royalty	Both	Old
	Newfoundland	IRR based profit sharing royalty	Oil	Old
	Nova Scotia	Payout based profit sharing royalty	Both	New
	Alberta	Production/Price sensitive royalty	Oil	Old
	Alberta	Price Sensitive royalty	Gas	Old
	Alberta oil sands	IRR based profit sharing royalty	Oil	Old
Colombia		Price sensitive windfall profits tax	Oil	New
Venezuela	Conventional Oil	IRR based profit share	Oil	New
Peru		R-factor royalty	Both	New
Bolivia		Profit sensitive Surcharge with uplifts	Both	New
Trinidad & Tobago	Conventional Oil	Supplemental Petroleum Tax, Price sensitive	Oil	New
	Deep water	Production/Price sensitive profit oil/gas shares	Both	New
Norway		Uplifts on Hydrocarbon Tax	Both	Old
UK	Old licenses	Uplifts and Oil Allowance on PRT	Both	Old
Denmark		Uplifts on Hydrocarbon Tax	Both	Old
The Netherlands		Uplifts on Special Profit share	Both	Old
Algeria		Cumulative Revenue sensitive PRT and uplifts	Both	New
Tunisia		Sliding scale taxation	Both	New
Libya		R-factor based profit oil splits	Oil	Old
Nigeria		Uplifts and tax credits	Oil	Old
Angola		IRR based profit oil shares	Oil	New
Qatar		R-factor based profit oil	Oil	New

		shares		
Saudi Arabia		IRR based corporate income tax rates	Gas	New
Iran		Buy Back contracts	Both	New
Pakistan	Offshore	Price Sensitive Windfall profits tax	Both	New
India		R-factor based profit oil shares	Both	New
Thailand		Profit sensitive SRB	Both	New
Malaysia		Price sensitive windfall profits tax	Both	Old
Indonesia		Uplifts	Both	Old
Australia	Offshore	IRR based PRRT	Both	Old
PNG		IRR based APT	Both	Old
Russia	Sakhalin	IRR based profit oil shares	Both	New
Kazakhstan	Tengi.	IRR based profit share	Oil	New
	General	New models with variety of progressive features	Oil	New
Azerbaijan	AIOC	IRR based profit oil share	Oil	New
	Other	R-factor based profit oil shares	Oil	New

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

Claimed expenses under SB 185 (43.55.025) totaled $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.

	No. of Projects	Claimed Expenses	Claimed Credits
Audited & Issued:	7		
N. Slope wells		$51,050,000	$13,308,000
Cook Inlet wells		$ 3,430,000	$ 392,000
Cook Inlet seismic		$ 3,178,000	$ 1,085,000
Audits In progress:	5		
N. Slope wells		$26,615,000	$10,646,000
N. Slope seismic		$ 7,957,000	$ 3,182,000
Other - seismic		$ 3,295,000	$ 1,318,000
Other - wells		$ 9,286,000	$ 3,714,000
Total	12	$104,811,000	$ 33,646,000

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.

Did such advice result in any changes to the legislation?

The bills reflect discussions with counsel that took place during the drafting process, so in that sense such advice did affect the legislation.

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'?

The current production tax statute taxes the "gross value at the point of production" of oil and gas. The quoted phrase was enacted in 1977 and replaced the previous statutory phrase "gross value at the well." This change was aimed at ensuring that costs of production operations downstream of the well would not be deductible in calculating the taxable value of oil or gas; rather, taxable value would be calculated at the point that production is complete.

In the case of oil, "gross value at the point of production" was defined as the value of oil where it is metered "in a condition of pipeline quality," and "pipeline quality"

was defined as "good and merchantable condition." This definition essentially adopts commercial standards of marketability for oil. HB 488 and SB 305 would simplify and shorten the definition of gross value at the point of production for oil but do not materially change it. In addition, the definition of "oil" is broadened to include liquid hydrocarbons recovered by gas processing in the case of leases or properties whose production is subject to gas processing. The bottom line is that the point of production under these bills would still be the point where oil is metered in a condition of pipeline quality, and "pipeline quality" would mean the same thing it has always meant under the production tax statute.

In the case of gas, neither the existing statute nor the new bills use the phrase "pipeline quality" or "good and merchantable condition" with respect to gross value at the point of production. Rather, the statutory definitions of "gross value at the point of production" for gas, as interpreted and clarified by the Department's regulations, 15 AAC 55.900(a)(6)(B) and (C), focus on where gas is accurately metered after separation from oil. The new bills retain this concept but, in effect, expand "separation" to include gas processing, so that in the case of leases or properties whose production is subject to gas processing, the point of production for gas recovered by gas processing is the point where it is metered downstream of the processing.

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.

While there is much that is parallel in the calculation of gross value at the wellhead between Royalty and Tax, many differences have developed. Both start with destination value in the market, and then subtract the tankering, pipeline and other costs to arrive at a well head value. The Department of Revenues valuation for Tax comes from statute and regulation. The Department of Natural resources valuation for royalty comes from lease contracts supplemented by Royalty Settlement Agreements (RSAs) which set forth different methods for each large North Slope producer. (Cook inlet valuation is not covered in this answer.)

Destination value, for the Department of Revenue is what the oil was sold for, or when the oil is not sold or is sold for a below market price, the so called prevailing value or spot price. Destination value for the Department of Natural Resources is a formula driven by the ANS or a basket of similar crudes.

From the destination value, each method subtracts marine transportation costs, TAPS costs (including tariffs, losses and quality bank changes from mid-point refineries), feeder line costs (including tariffs, losses and quality bank differences), and other miscellaneous costs. DOR deducts the costs specific to each taxpayer, while for royalty, some of the RSA have formulaic deductions and others use the royalty

payers' actual cost. In addition, DNR subtracts field costs for most DL-1 lease form leases on the North Slope whereas DOR does not.

The differences between wellhead values narrow across time. The average difference for the period FY00 through December 2005 is 3.9%. However, the average difference for the last 12 months is 6.1% while the average difference for FY00 through FY03 is 3.0%.

The critical point is that DOR uses actual proceeds, and only resorts to Prevailing Value when the conditions of 020 (f) are met, thereby taxing on the higher of proceeds or PV. For each of the three producers, DNR uses a single destination formula based on spot prices, not actual proceeds.

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?

a. Only 2 credits that have been issued have been sold to another party.

b. The Division will first obtain a waiver of confidentiality from the seller allowing the Division to confirm the credit amount to the prospective purchaser. Once sold, the Division makes the transfer and issues a new credit certificate to the purchaser upon receipt of documentation and confirmation of the transaction from the seller of the credit. The credit exists as an electronic entry in a Division database, therefore only the Division can make the actual transfer of the credit in that database. A new certificate is entered in the database to the purchaser and the old certificate is marked as transferred and its balance is zeroed out. The Division then notifies both the purchaser and the seller, in writing, of the completed transfer of the credit, at which time the purchaser may then apply the credit to its own production tax liability. When a credit is applied to a tax liability by a producer, the Division then verifies the holder and amount of the claimed credit against the credit certificates in the database.

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?

a. Net profits systems in the world typically work on the basis of three different concepts:

(a) monthly payments based on actual production, revenues and expenditures, without an annual true-up, as is the case in most production sharing agreements
(b) yearly payments based on a yearly return, filed within a few months after the year, without a need for monthly payments on account, as is the case for the Thai SRB, for instance. This means there is only a single annual payment.

(c) Yearly payments based on a yearly return, filed within a few months after a calendar year or a lease/contract year, with monthly payments on account. In this last case, the monthly payments could be based on:
   a. Estimates for each month, as for instance with the Nova Scotia profit sharing royalty. These estimates can be challenged by government and different estimates may be required.
   b. Payments based on a mixture of actual information from the previous month and estimates, such as in Algeria
   c. Corporate income tax style procedures, whereby payments are based on taxes paid in the prior year (Norway for the Hydrocarbon Tax).

The 90% rule proposed for Alaska is unique. The overall economic impact would depend on the taxpayers' cost estimates for each month. We expect that taxpayers will experience underpayments in some months, but will experience overpayments (because of estimates used) in other months. In addition, falling production amounts, or unforeseen costs will serve to likely create overpayments in later months. Overall, we do not expect any material net economic impact.

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?

At Prudhoe Bay about 8.5 billion cubic feet of gas a day is reinjected into the field for pressure maintenance. After stripping out certain hydrocarbon liquids, CO2 is reinjected along with the other hydrocarbons (and non-hydrocarbons). When an export line is built on the North Slope, the CO2 will be stripped (in "gas treatment"), and there is some question about what will happen with that CO2?

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

Assume 20 new companies suddenly showed up on the North Slope and each qualified for the 73 million dollar allowance. A total of 1.4 billion dollars in profits would be sheltered from taxes. If these companies had simply purchased their way in, then taxes would be lower by $280 million (20% of 1.4 billion) than they would be otherwise. At current prices, or say even at $40 oil, this could be a material portion (though not all) of the tax.

If that is the future of the North Slope and the sell off was for business purposes, the legislature may choose to act and make it less attractive to new firms coming in. If these were tax motivated sales, we hope the powers of the commissioner that are built into the bill would prevent the new entrants from using the $73 million allowance

73. Will the new confidentiality provisions extend to or have an effect on any other taxes besides the production tax.

The new confidentiality language added by secs. 4 and 16 of the bill applies only to information relating to the oil and gas production tax, not other taxes. This is because:

(1) AS 43.55.040(1) addresses information "necessary to compute the amount of the tax," and the phrase "the tax" is used throughout AS 43.55 as referring only to the production tax; and

(2) AS 43.55.040(1) deals only with information obtained from persons "engaged in production," or their agents, and with purchasers "of oil or gas," and with owners of a "royalty interest in oil or gas."

77. How much gas was flared so as to trigger taxes and/or penalties in recent years?

During FY 2005, 351,000 Mcf of gas was flared that was considered gross taxable production. Of that, only 120,000 Mcf was from fields with a positive ELF and subject to tax. During the same period 31,000 Mcf was flared and considered waste and subject to both tax and penalty.

80. When the 1989 ELF change was enacted, was it retroactive and were there transition provisions?

The 1989 ELF changes were made retroactive to January 1, 1989, and applied to oil produced after December 31, 1988. There was a transition provision to the effect that tax payable as a result of the retroactive changes would be due on the 20th day of the calendar month following the effective date of the Act. (The effective date of the Act was August 6, 1989.)

82. Under the new gas and oil definitions what will the net change to the spill fee be? In other words, looking at FY 2005, how much, if any (a) oil did we tax for its use in production operations and (b) how many ngls were put in TAPs?

During FY 2005 tax was collected on 1,222,400 barrels of crude oil used in production operations. During FY 2005 16,445,000 barrels of NGLs were put in TAPS.

83. For sales of credits by the smaller interests, estimate the price at which those credits will no longer have a market among the big three.

Credits may be used in the year of expenditure, carried forward to following years, or transferred (they are fungible). If transferred, the credit can not lower a severance tax rate below 80% of what it would otherwise be (AS 43.55.024(e)). These credits will have market value that would not exceed 20% of their face value ($1,000 in capital expenditures would save $200 in State severance taxes). A company generating them but unable to use them would face a choice – sell them or use them the following year (if they have taxable income).

Use the next year reduces the value of the credits due to discount rate. Oil companies typically try to use a 15% discount rate but will often settle for less, say 10%. This means, all other things equal, they would be willing to sell a $1,000 credit ($5,000 capital expenditures) for $900 (10% discount rate) or more. Conversely, another company would be willing to pay up to $999 for the credit to save $1,000 in State severance tax.

If we assume a billion in spend assume that 10% of that was for little companies that would want to sell their credits, so 200 million in credits are for sale. With our 20% limit, that implies that if the big three had a billion dollar in tax obligations, that market could absorb all the credits. As our fiscal note shows, if the price of oil is $40 or above, all of the credits would be usable in the immediate year. If oil falls below $40, then we expect that the credits would be fully utilized within two or three years. While the time-value of money means that those certificates would be discounted, we believe that the certificates would still be marketable.

84. If aggregation at Prudhoe Bay had been implemented on July 1, 2001 [the start of the claw back period], how much more would the State have received between then and the actual aggregation date?

The State would have received $430.4M additional revenue. See estimates below:

ANS Oil Severance Tax
With and without aggregation of
PBU
FY2001 thru Jan 2005 Production

FY	No Agg	With Agg	Delta
2001	667.1	713.1	46.0
2002	444.5	501.2	56.7
2003	549.6	644.4	94.8
2004	594.5	720.4	125.9
2005	465.9	572.9	107.0
	2721.6	3152.0	430.4

Note: Estimate with Aggregation assumes all taxpayers are

paying under the aggregated Elf

85. Why are the status quo lines in the three graphs presented by Ms. Wilson flat once the forecast price effect is adjusted for? Wouldn't falling production and ELF move those down.

The status quo drops from $378 mm in 2009 to $291 mm in 2012. It looks flat because of the scale on the graph.

86. What will the actual cost to the investor be for these upstream investments, and what is the total government underwriting, state and federal, all tax types included. Is it different for large companies and small companies?

After state and federal tax, the investor would bear about 38% of the marginal capital. There is no reason to think it would differ appreciably between large and small investors.

87. Lord Browne famously said two years ago that any profits over $20 a barrel were being returned to shareholders as they weren't needed in BP's business. What tax rate, credit rate would be needed to have a cross over [unspecified period] at $20 [presumably Brent].

With a 20% credit it would take a tax rate of about 51% to affect a crossover at $20 Brent.

88. Please explain how the conservation surcharge is affected by oil price and what effect this bill has on the surcharge.

a. The conservation surcharge is a 3 cent per barrel charge on all oil produced less royalty barrels, so therefore it is not sensitive to price.

b. There will be changes in the quantity of oil subject to both production tax and conservation surcharges under the bill. One change will be positive, one negative. The positive change is that natural gas liquids extracted by gas processing and blended in the TAPS stream that are now taxed as gas, will be treated as oil under the bill. The negative change is that oil that is used in lease operations will not be taxed or subject to surcharge under the bill. Oil may be used to make fuel for lease operations and perhaps used for other production purposes. The overall result is an expected increase of the total surcharge amount of $444,000 per year, based on FY 2005 amounts. (See Question 82.)

The bill should not affect the assessment or collection of the surcharge, other than the quantity-of-oil effects described above. Any surcharge paid will be allowed to be

credited against production taxes, but that would only reduce the amount of tax collected, not the amount of surcharges collected.

89. Why are we including gas in the PPT calculation?

The bill includes gas in the PPT calculations because it is a stand-alone bill. The bill does not require implicitly or explicitly that a Stranded Gas Contract be subsequently concluded. Therefore, a PPT law would be entirely functional in case a Stranded Gas Contract is not presented to the Legislature or in case the Legislature rejects such a Contract.

The ELF system for gas is "broken". Just as the ELF is "broken" for oil, th gas ELF does not encourage reinvestment and it is not sensitive to price.

It should be noted that under high gas prices the Alaska State take for gas would increase significantly relative to the status quo. This would be beneficial in case significant gas reserves would be developed outside the scope of the Stranded Gas Development Act.

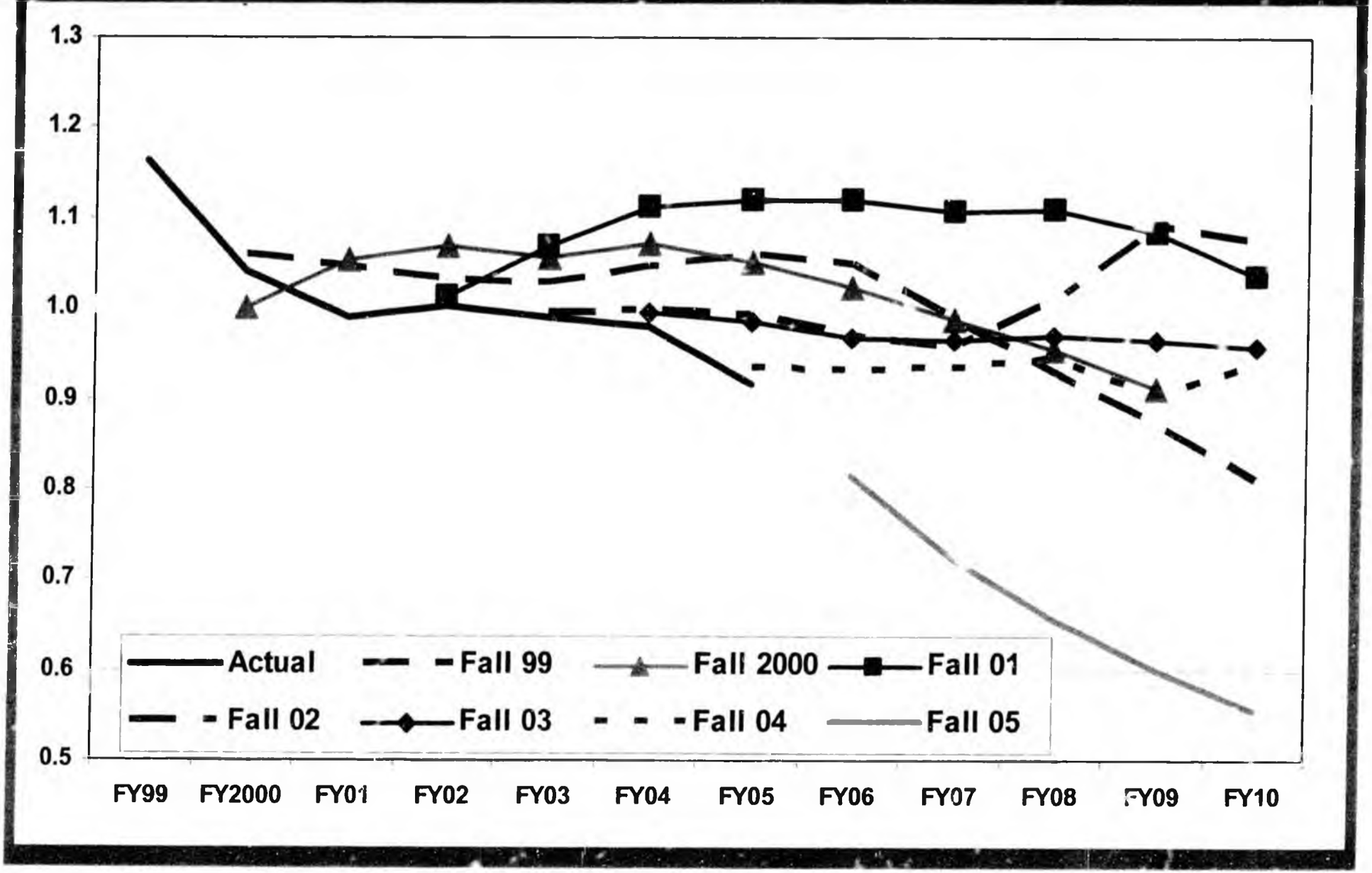
The inclusion of gas in the PPT is therefore a strong incentive for producers to conclude a Stranded Gas Contract that is in the interest of the State of Alaska. Including gas in the PPT enhances the bargaining position of the State for a good Stranded Gas Contract.

STATE OF ALASKA
DEPARTMENT OF
REVENUE

ANS Crude Oil Production Forecasts

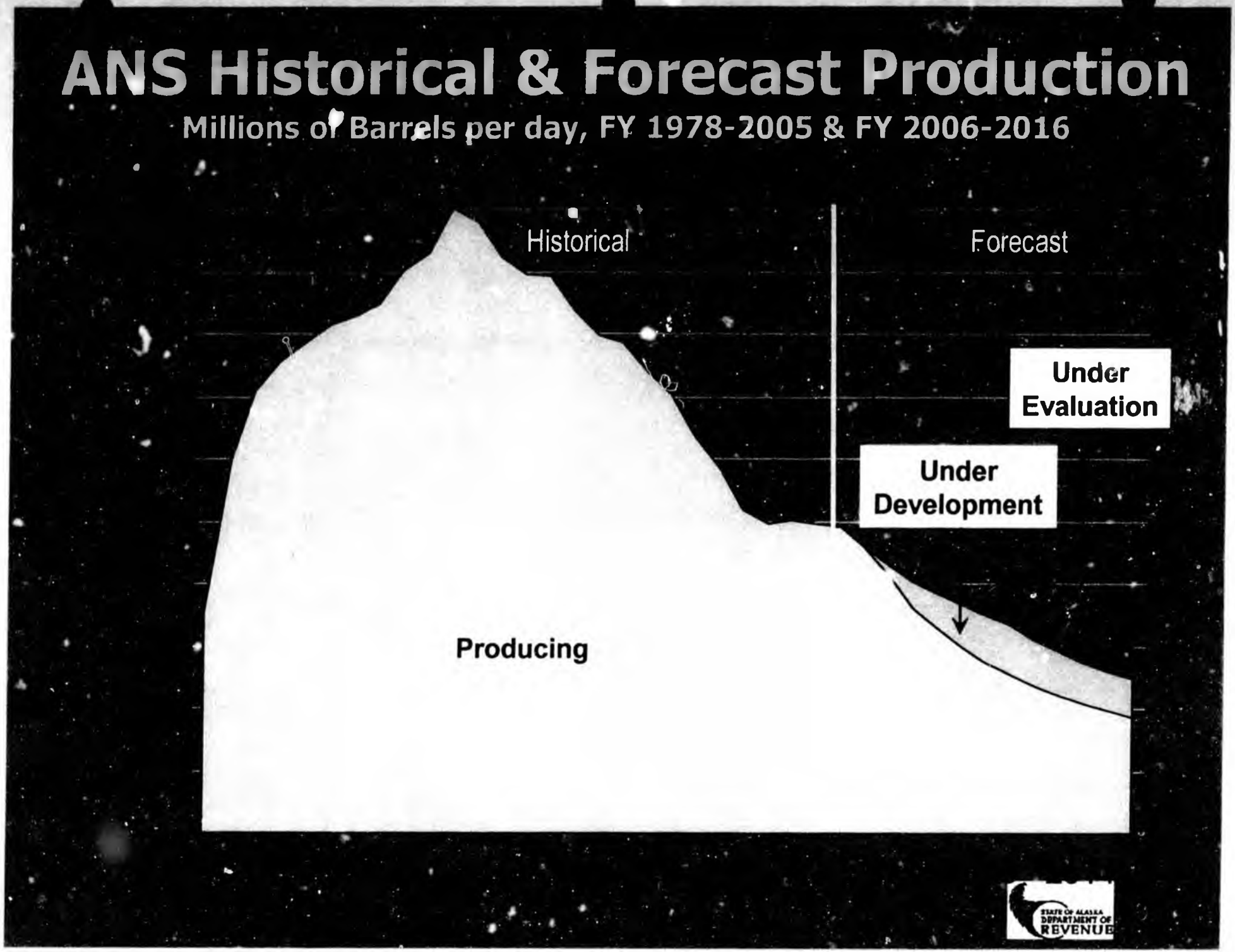
Fall Oil Production Forecasts

ANS, Millions of Barrels per Day



ANS Historical & Forecast Production

Millions of Barrels per day, FY 1978-2005 & FY 2006-2016



STATE OF ALASKA
DEPARTMENT OF
REVENUE

ANS Crude Oil Production Forecasts

Point of Production for Oil and Gas

Senate Resources Committee
House Resources Committee
March 7, 2006
Dan E. Dickinson, CPA

Oil or Gas – Why does it matter?

- Current rules
  - Gas taxed at 10% (times well based ELF) of gross
  - Oil taxed at 15% (times well & field based ELF) of gross
  - Free use of gas for production operations
  - (past production use of gas taxable)
  - Conservation surcharge on oil

Oil or Gas – Why does it matter?

- Proposed Rules
  - Gas and oil taxed at 20% of net
  - Free use of gas and oil for production purposes
  - (post production use of oil or gas remains taxable)
  - Conservation surcharge creditable

Oil or Gas – Why does it matter?

- Because the Point of Production is driven by the point of final separation

Point of Production – Why does it matter?

- Current rules
  - Costs incurred downstream of the point of production are deductible for calculating production tax.
  - Same effect for royalty except where defined field cost allowance

Point of Production – Why does it matter?

- If how costs were treated on either side of the point of production were identical it would not matter;
- But in switching from gross to net two different cost regimes.
  - Upstream outlays recaptured by 20% deduction and 20% credit for capital investment.
  - Downstream outlays recaptured through operating costs including depreciation.

Point of Production – Why does it matter?

- Yes – for a newcomer without heritage facilities, the cost difference is significant.

- May result in new facilities being built, or improve ability to access heritage facilities

Issues: combining production and post production facilities

- Current Rules
  - Central gas facility has post production activity (gas processing) & production activity (conditioning gas for pressure maintenance)
  - Had to allocate costs in plant because processing costs deductible

- Proposed Rules
  - Costs deductible (gas processing is production activity)

Gas or Oil?

- Oil
  - Must be in "condition of pipeline quality"
  - "Good and merchantable condition"
- Gas (in association with oil)

  first point accurately metered downstream from point of final separation

Why not a standard similar to oil?