Alaska's Proposed Production Tax

"PPT 20/20%"

SB 305/HB 488

Issues for Discussion and Further Research

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Juneau, Alaska
6 March, 2006

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

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- **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:

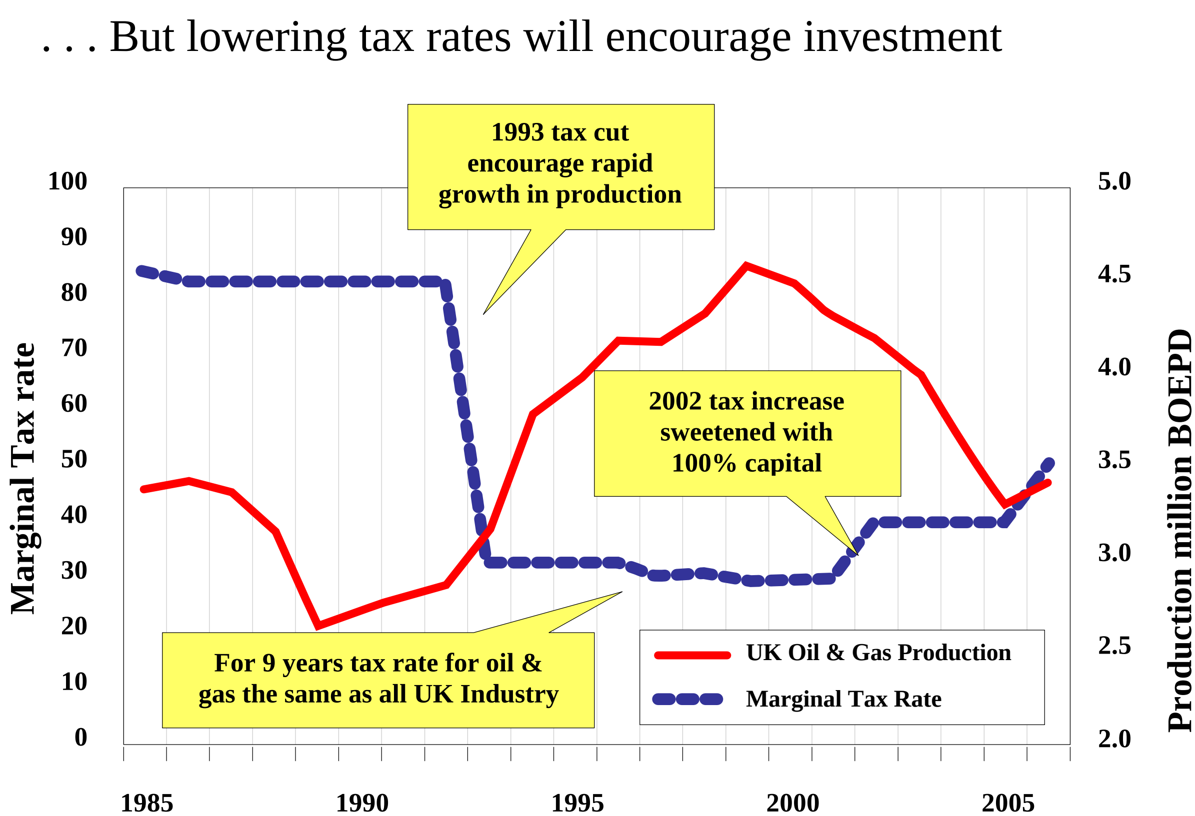
BP Graph of Production vs. Tax Rate

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

Year	Royalty	SPD	PRT	CT	Marginal Take Old Fields	Marginal Take New Fields	Brent Price $/BBL	Annual (£MM) Expenditures (1) Expl.	Annual (£MM) Expenditures (1) 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 economic 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**

Note: The "lookback" element is not included.

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

$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/BBLOpex)

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)

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%)
($21/377)

$356 Company pre-Fed Tax Cash Flow ($377-21)

$210 ¬ **- 146 41% Fed + AK Tax** ® **$146**
$210 Co. after-tax C/F

Oil Company		Alaska and Federal Gvt.
$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)]**

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	
Gvt. Take	Gvt. Take	"Windfall" Marginal Take	
¾ ¾ ¾	¾ ¾ ¾	¾ ¾ ¾	
$20.00	$60.00	$40.00	Gross Revenues
3.00	9.00	6.00	15% Royalty
¾ ¾ ¾	¾ ¾ ¾	¾ ¾ ¾	
17.00	51.00	34.00	Net (Revenues)
- 8.00	- 8.00	- 0.00	Operating + Capital Costs
¾ ¾ ¾	¾ ¾ ¾	¾ ¾ ¾	
9.00	43.00	34.00	Taxable Income
- 4.50	-21.50	17.00	Taxes 50%
¾ ¾ ¾	¾ ¾ ¾	¾ ¾ ¾	
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	
¾ ¾ ¾	¾ ¾ ¾	¾ ¾ ¾	
$40.00	$40.00	$40.00	Gross Revenues
- 6.00	- 6.00	- 6.00	15% Royalty
¾ ¾ ¾	¾ ¾ ¾	¾ ¾ ¾	
34.00	34.00	34.00	Net (Revenues)
- 8.00	- 8.00	- 0.00	Operating + Capital Costs
¾ ¾ ¾	¾ ¾ ¾	¾ ¾ ¾	
26.00	26.00	34.00	Taxable Income
- 13.00	- 13.00	- 13.00	Taxes 50%
¾ ¾ ¾	¾ ¾ ¾	¾ ¾ ¾	
13.00	13.00	21.00	Contractor Group Cash Flow
- .00	- 3.90	- 6.30	Government 30% Participation
¾ ¾ ¾	¾ ¾ ¾	¾ ¾ ¾	
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. <u>We have not, however, included any cash flow that would be derived by the government (or NOC) having an equity interest in a field.</u>
>
> 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.

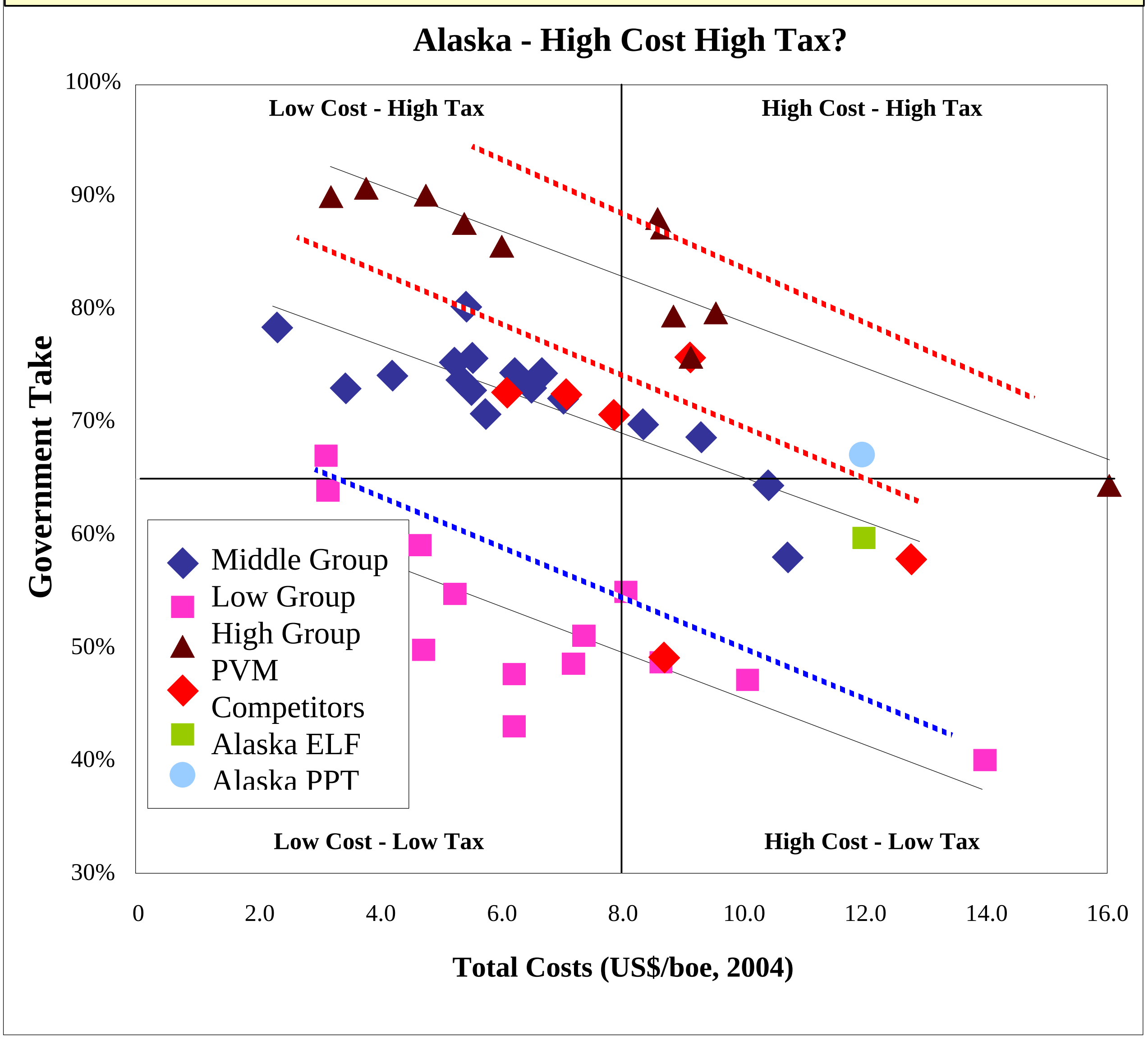
This is important because at $40.00/BBL oil price and $10.00/BBL costs with say 800,000 BOPD of production profits are $24 MM/day or $8.76 Billion per year. Just a 1% point difference in government take can represent around $87 MM per year. We must be extremely careful with our choice of a peer group, 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
¾ ¾ ¾	¾ ¾ ¾	
$40.00	**$40.00**	**Gross Revenues $/BBL**
- 2.80	**- 2.80**	**7% Royalty**
¾ ¾ ¾	¾ ¾ ¾	
37.20	**37.20**	**Net (Revenues)**
- 12.00	**- 12.00**	**Operating + Capital Costs** (30% of Gross Revenues)
¾ ¾ ¾	¾ ¾ ¾	
25.20	**25.20**	**Profits**
- 13.90	**- 13.90**	**Profits-based Levies 55%** (Taxes and Production Sharing)
¾ ¾ ¾	¾ ¾ ¾	
11.30	**11.30**	**Contractor Group Cash Flow**
- 1.53	**- 0**	**Government 13.5% Participation**
¾ ¾ ¾	¾ ¾ ¾	
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.**

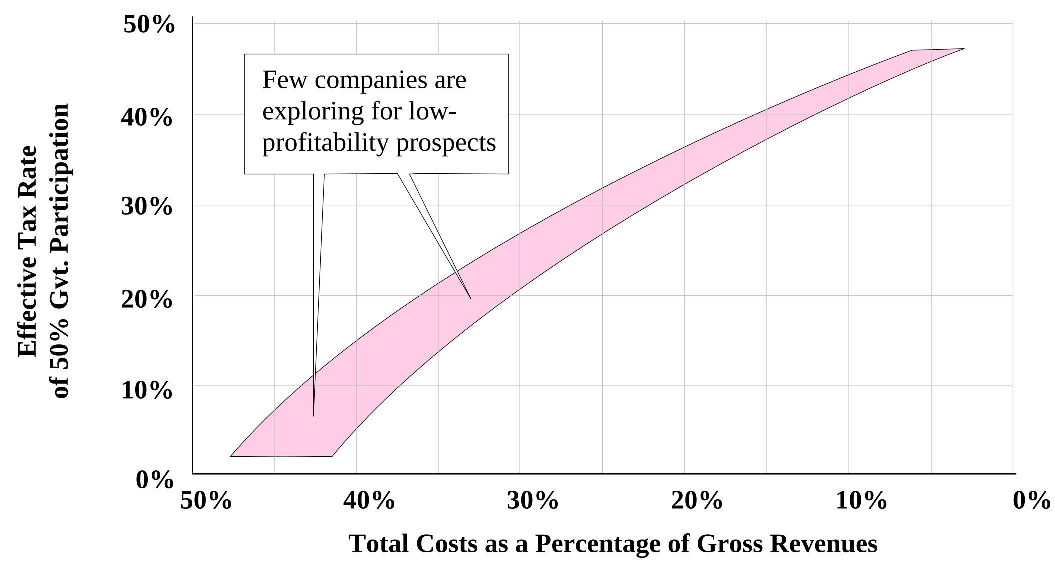
Following this logic, the government take calculation for the Libyan licenses would ignore much of the government production share – the 50% for which it pays its way on development and operating costs. This would yield a government take of only around 50% - very good terms indeed, but misleading.

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.

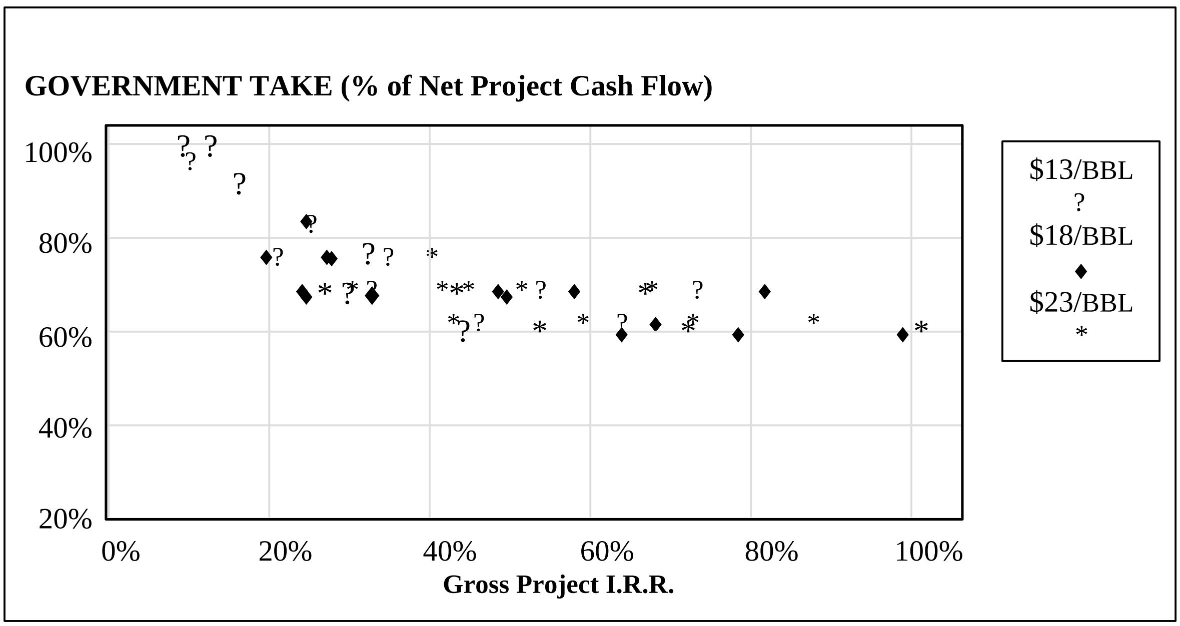
From: "International Petroleum Fiscal Systems and Production Sharing Contracts" Course Workbook, Johnston 2005, (pg 13)

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.

CONGO : FRONTIER
GOVERNMENT TAKE



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**

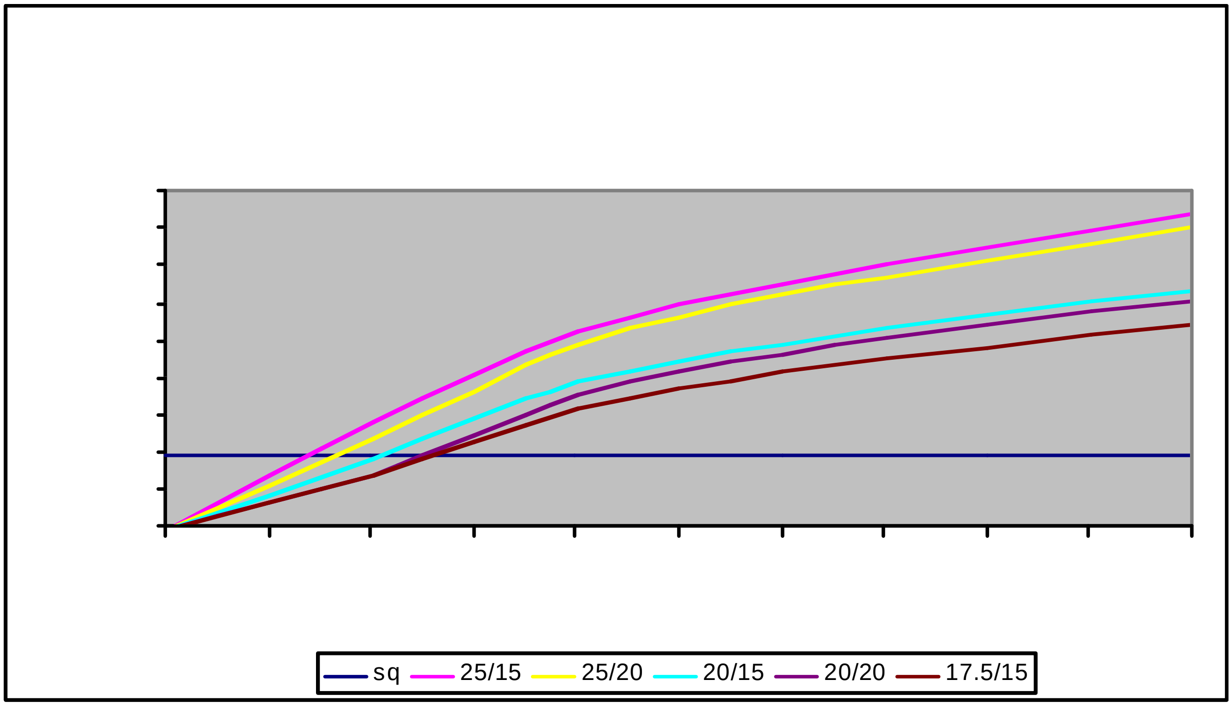
- **ROR Systems**
- ♦ **"R" factor**
- \+ **Price-based formulas**

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.



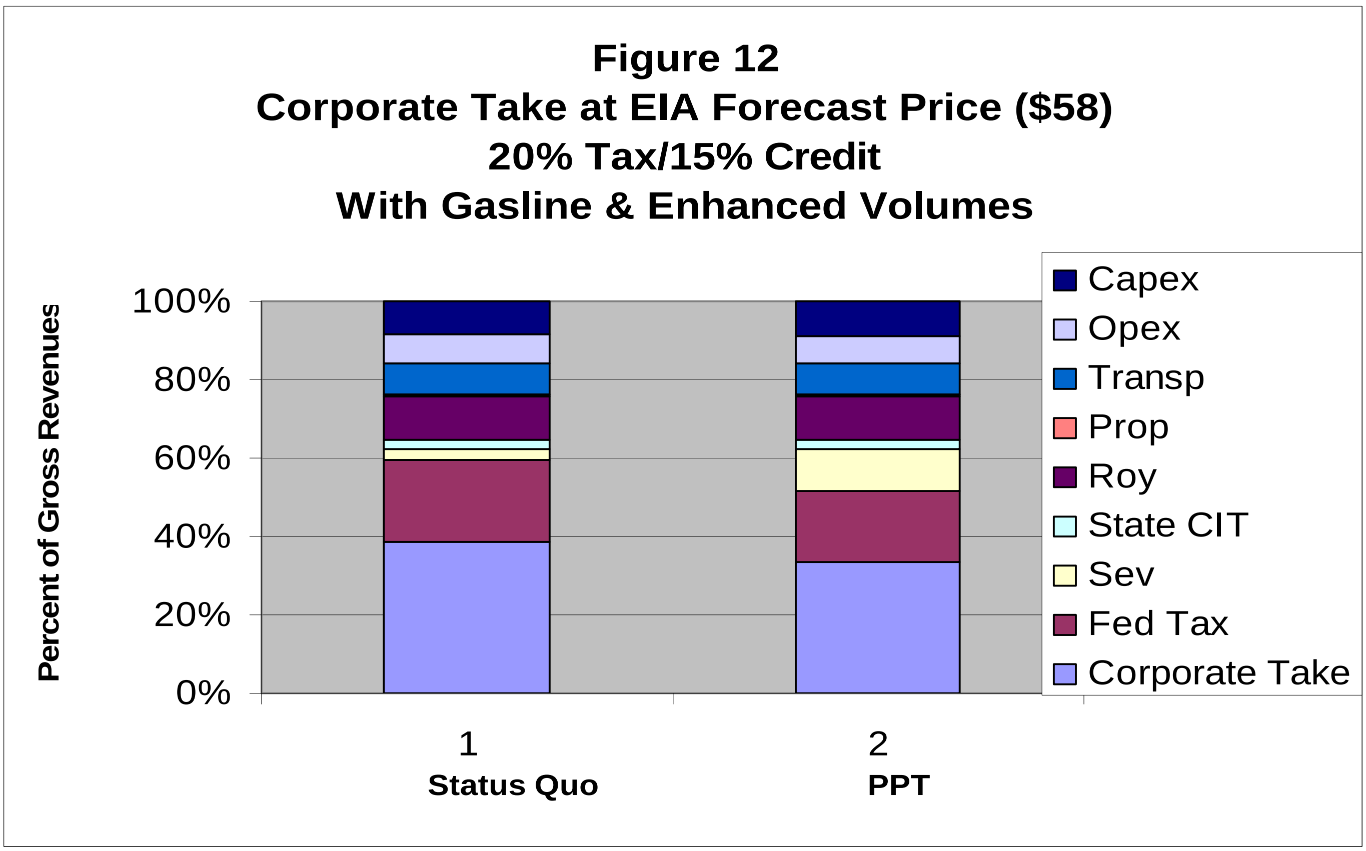
From: PPTAnalysis020106.ppt Roger Marks

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.

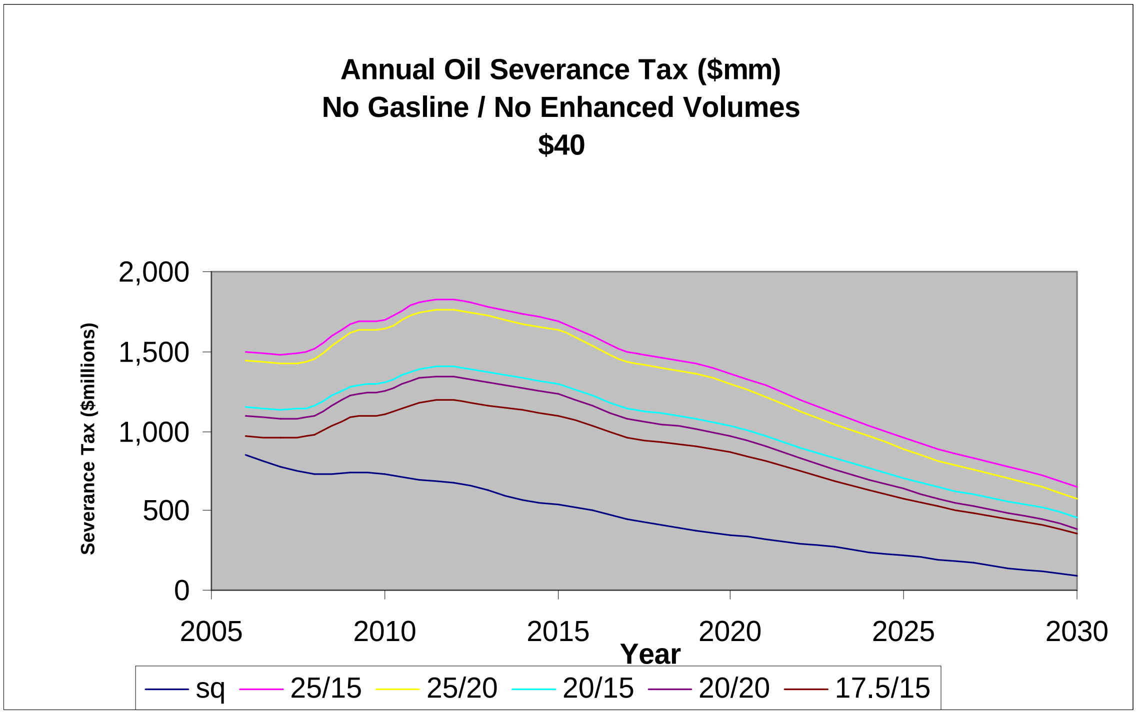


"Corporate take goes from 39% to 33% of gross revenues, or from 51% to 44% of the economic rent."

From: PPTAnalysis020106.ppt Roger Marks

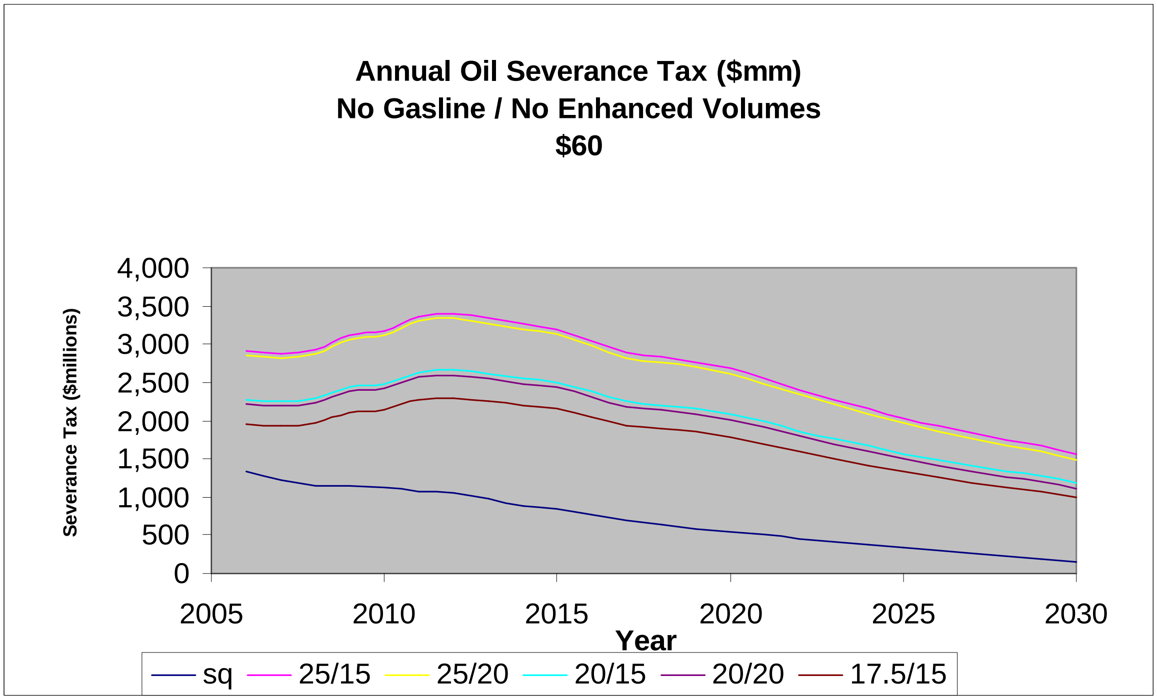
Note: Government Take goes from 49% to 56% an increase of 14%

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 20%/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.”

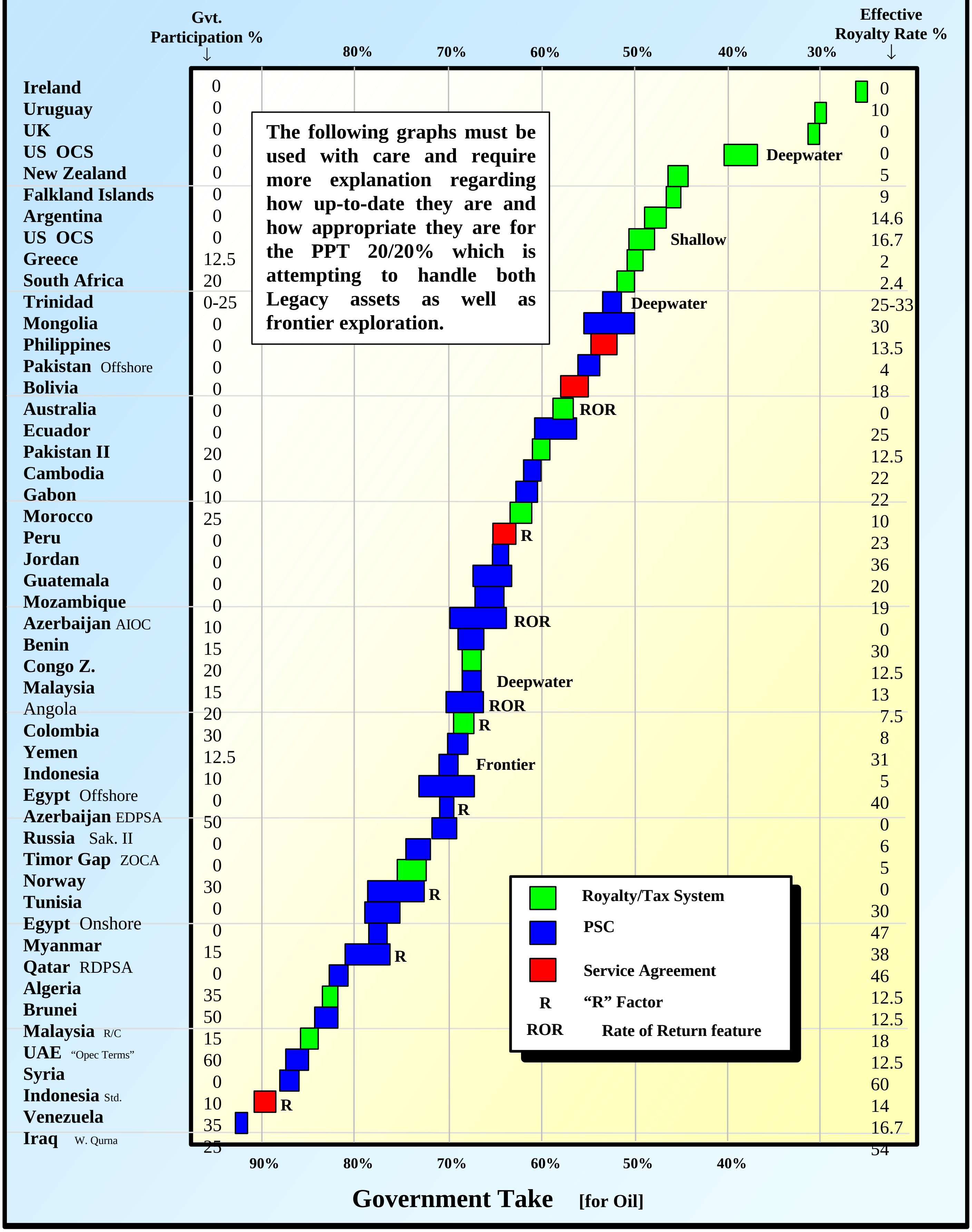
	Marginal Fields	Economic Fields	Upside Fields
UK	33.4%	33.0%	33.0%
USA (OCS)	46.1	41.4	37.1
Cote d’ Ivoire	50.9	49.2	46.8
Nigeria	53.1	57.8	58.5
Thailand	53.3	54.7	50.5
Angola	56.2	52.6	64.8
Gabon	56.6	52.6	50.0
Congo	67.6	61.4	58.6
Indonesia	74.2	72.4	71.3
Malaysia	78.2	74.1	71.3
Average Deepwater	57.0	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

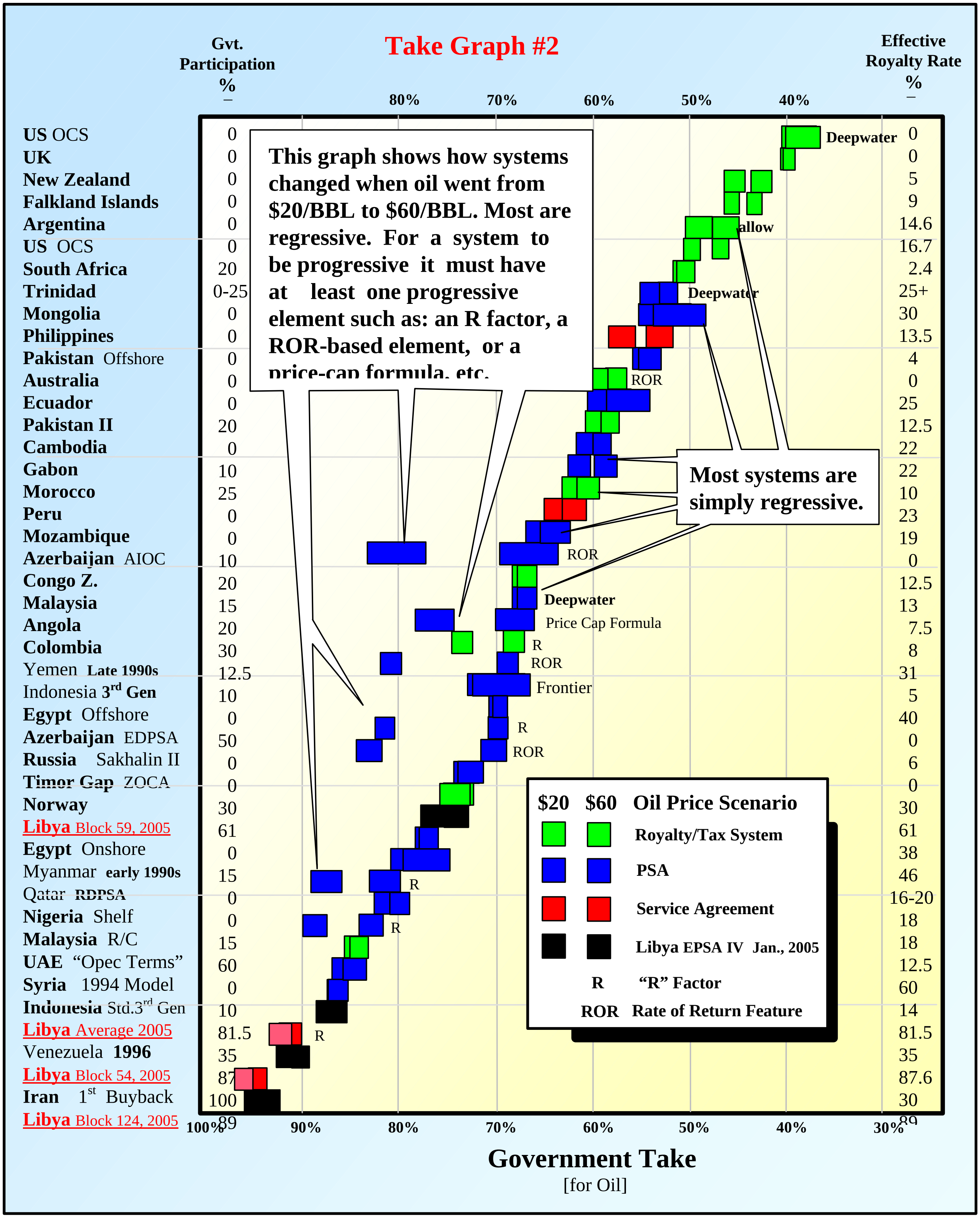
Average State Take (Peer Group Comparison)

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)

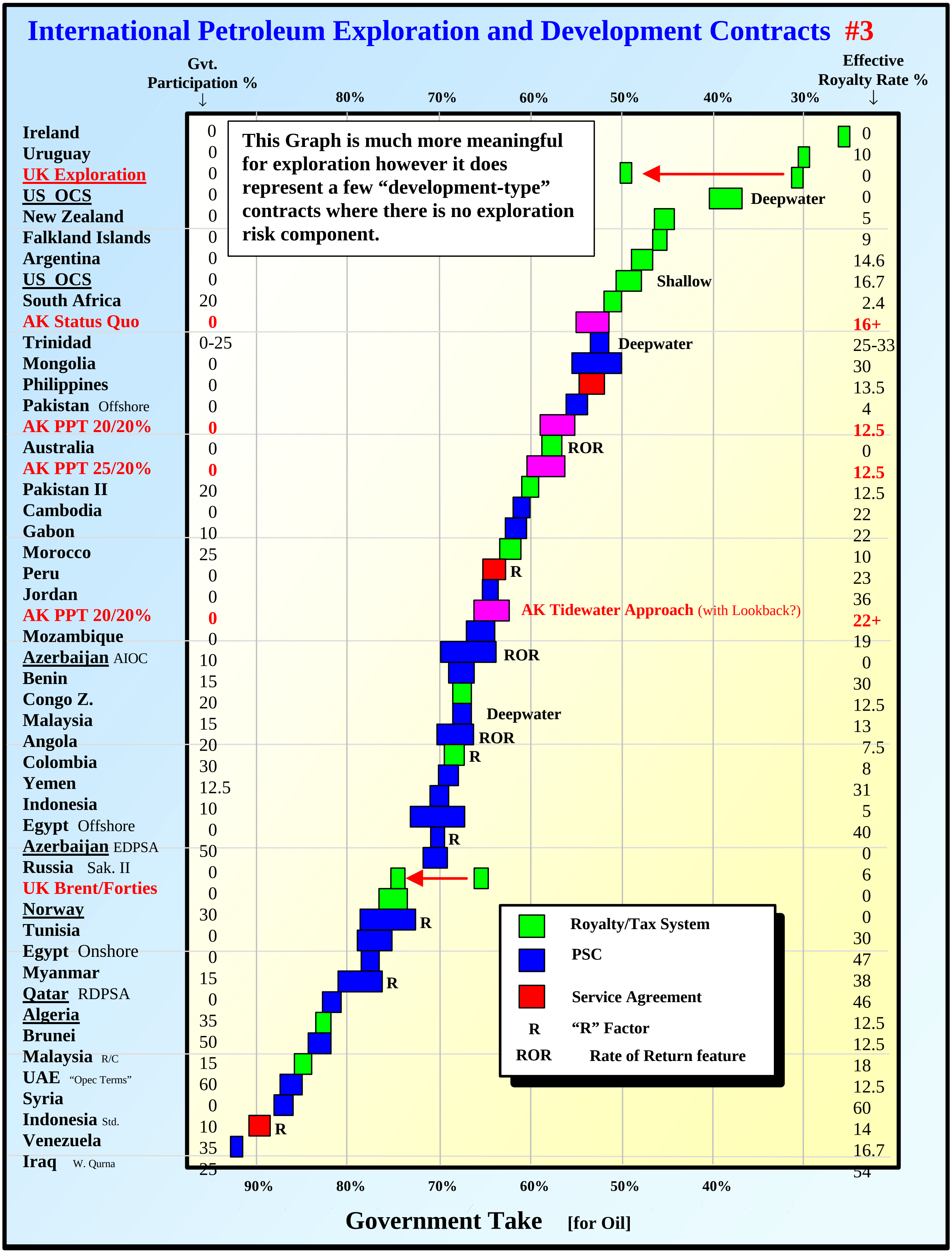
	Marginal Fields	Economic Fields	Upside Fields
20 Largest Producing Regimes	80.0%	74.6%	72.7%
30 Significant Producing Regimes	73.4%	66.7%	67.7%
66 Frontier Regimes	65.3%	60.5%	59.5%

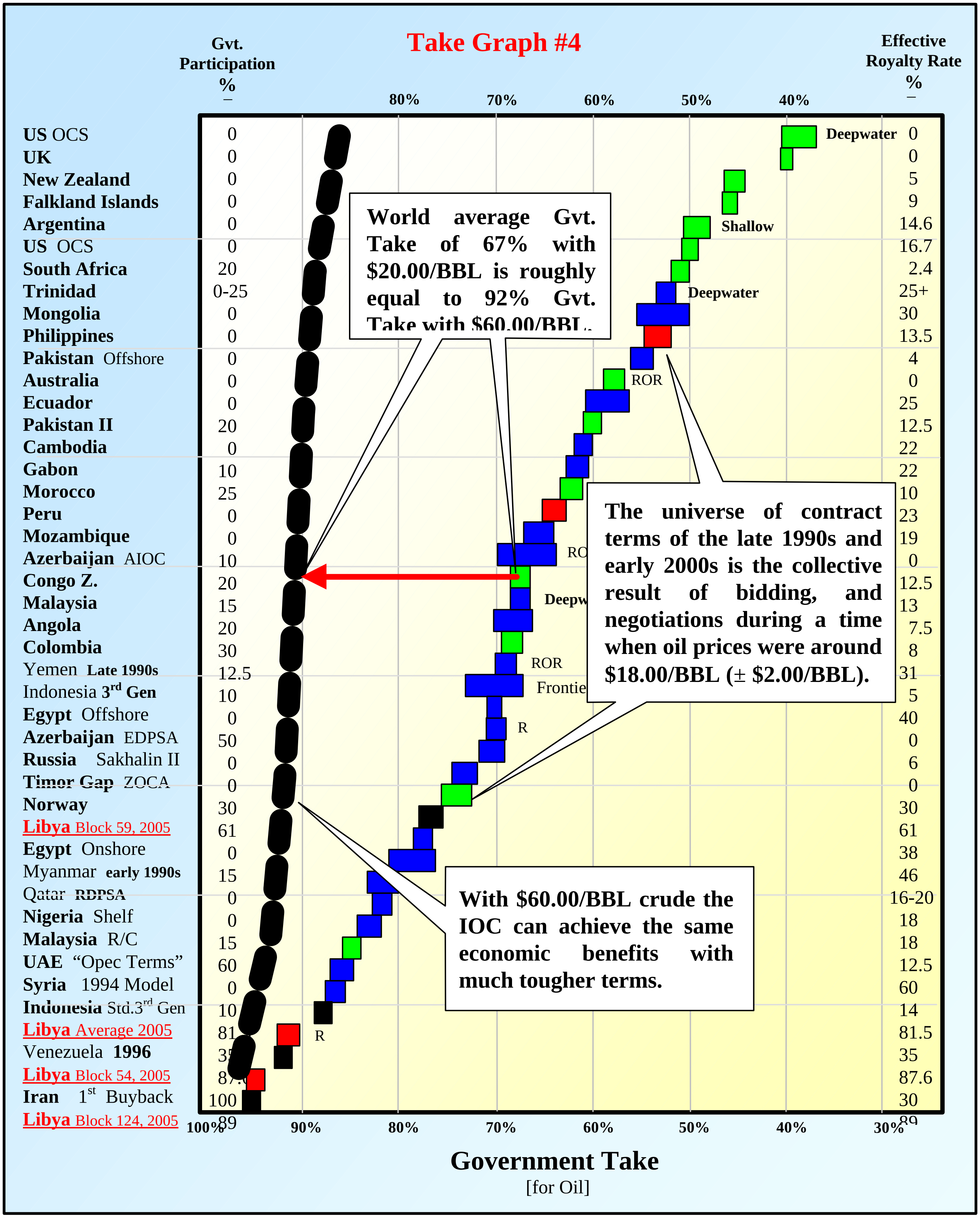
International Petroleum Exploration and Development Contracts #1





Difference between $20/BBL and $60/BBL


International Petroleum Exploration and Development Contracts #3
Gvt. Participation %
Effective Royalty Rate %
80% 70% 60% 50% 40% 30%
This Graph is much more meaningful for exploration however it does represent a few "development-type" contracts where there is no exploration risk component.
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. Qurna 25 54
Deepwater
Shallow
Deepwater
ROR
R
AK Tidewater Approach (with Lookback?)
ROR
Deepwater
ROR
R
R
R
R
R
Royalty/Tax System
PSC
Service Agreement
R "R" Factor
ROR Rate of Return feature
90% 80% 70% 60% 50% 40%
Government Take [for Oil]



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

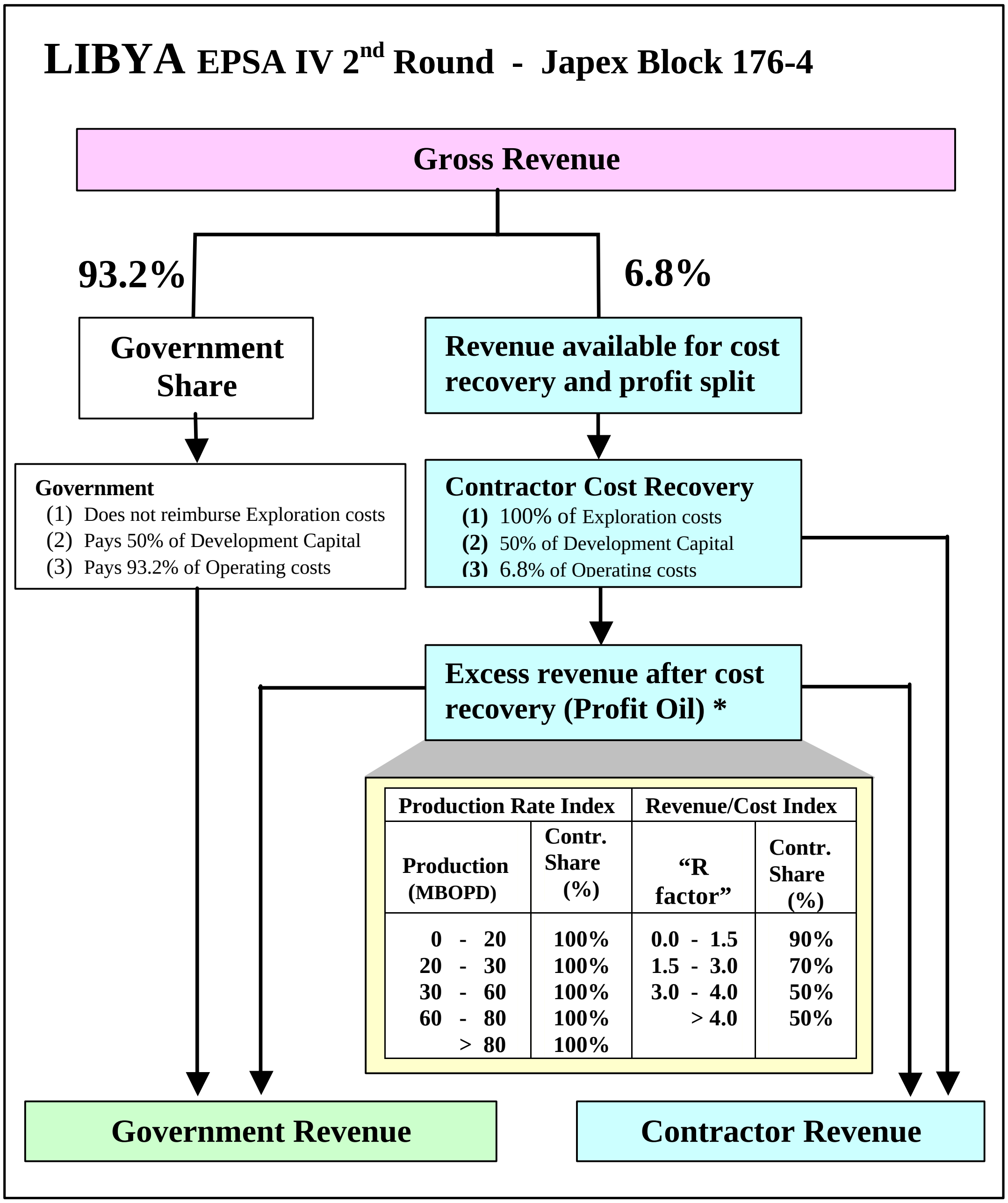
Contract Duration

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



Production Rate Index		Revenue/Cost Index	
Production (MBOPD)	Contr. Share (%)	"R factor"	Contr. Share (%)
0 - 20	100%	0.0 - 1.5	90%
20 - 30	100%	1.5 - 3.0	70%
30 - 60	100%	3.0 - 4.0	50%
60 - 80	100%	> 4.0	50%
> 80	100%		

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.

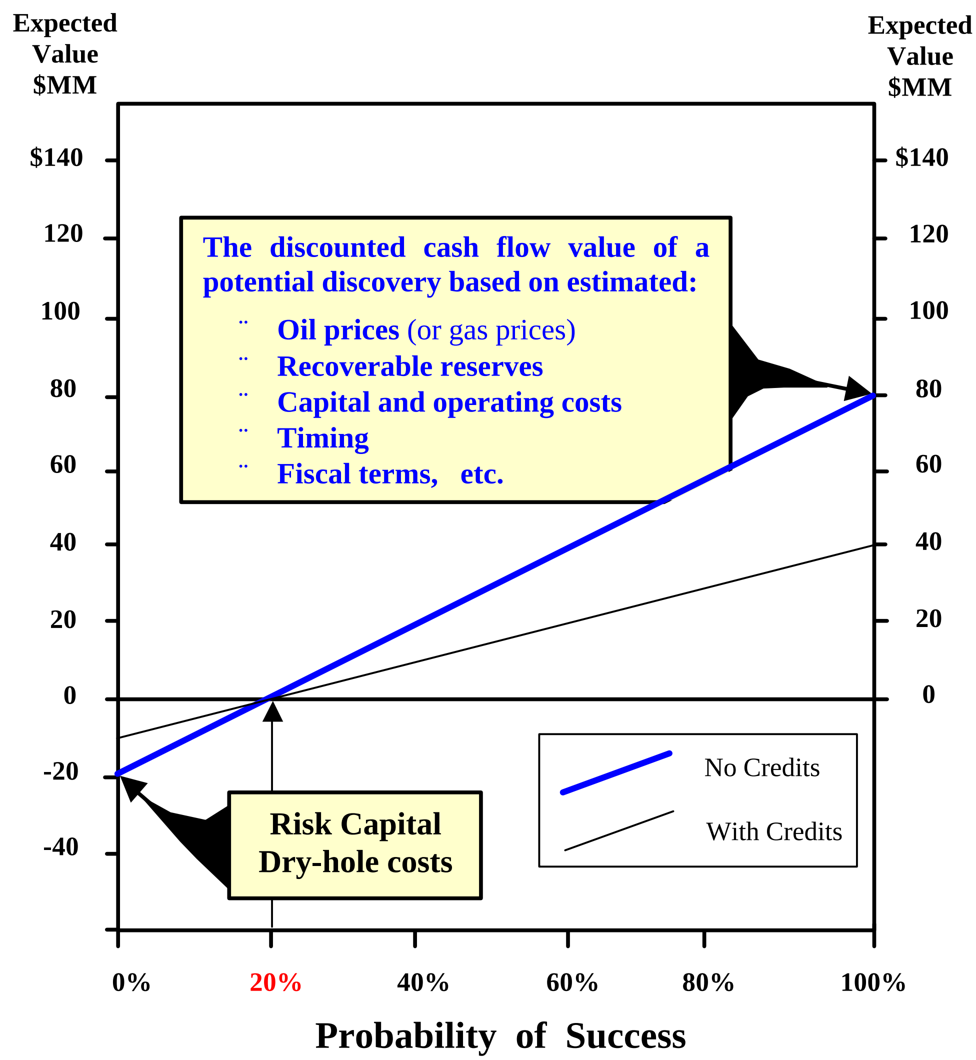
The expected value formula, whether it is used directly or indirectly (gut feel), provides the basis for billions of dollars of exploration investments. It is normally more complex with the common practice in the industry of using multiple outcomes (at least 3) on the “reward side” of the equation.

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.

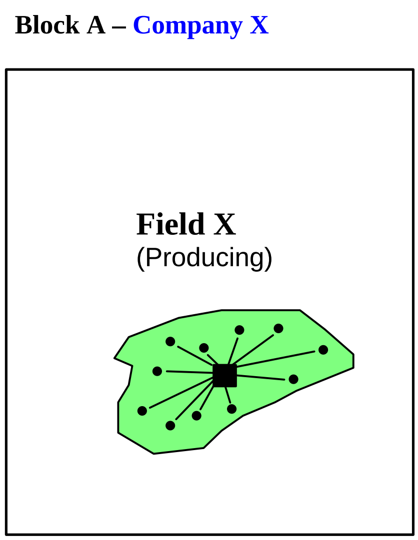
- **New Zealand** considered having the potential of a ringfence within a ringfence like that in Colombia (above). But decided it would be too hard to "sell".

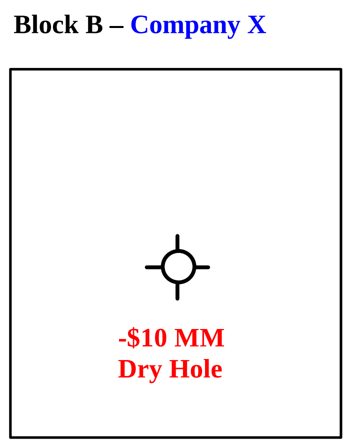
- Lack of a ringfence = Government as silent partner in exploration.
  Some say "widows and orphans as silent partner".
  Some use the word "subsidize" in this context (See Norway below).

- **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.

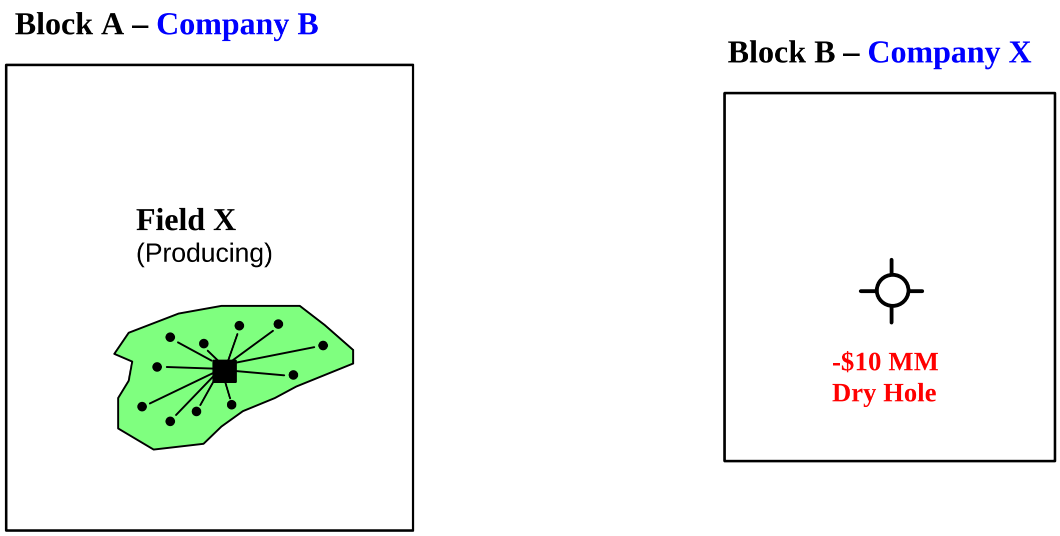
Assuming Company X drills a dry hole in Block B. With typical ringfencing the company would not be able to take the $10 MM loss and apply it to production/revenues in Block A for cost recovery purposes or as deductions for tax calculation purposes.





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.



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.

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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.

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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.