

AK LEGISLATURE SPECIAL COMMITTEE FILES SCOMM 148 32248

FIELD DATA as of January 2007

Project: Abby
 Location: Block 5025/17
 License: Sole Concession
 Operator: Norsk Olie og Gas AS
 Discovered: 1971
 Year on stream: 1972

Producing wells: 56
 Water injection wells: 50

Water depth: 40 m
 Field definition: 123 km²
 Reservoir depth: 1,850 m
 Reservoir rock: Chalk
 Geological age: Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2007

Oil: 68.35 m. m³
 Gas: 21.06 bn. Nm³
 Water: 23.15 m. m³

**INJECTION**

Cum. injection at 1 January 2007

Water: 167.66 m. m³**RESERVES**

Oil: 53.8 m. m³
 Gas: 5.3 bn. Nm³

**REVIEW OF GEOLOGY**

The Dan Field is an anticlinal structure induced partly due to salt tectonics. A major fault divides the field into two reservoir blocks, which, in turn, are intersected by a number of minor faults. The chalk reservoir has high porosity, although low permeability. There is a gas cap in the field.

Recovery takes place from the central part of the Dan Field and from large sections of the flanks of the field. Particularly the western flank of the Dan Field, close to the Halfdan Field, has demonstrated good production properties.

PRODUCTION STRATEGY

Recovery from the field is based on the simultaneous production of oil and injection of water. Water injection was initiated in 1989, and later water injection was introduced in large sections of the field. The recovery of oil is optimized by flooding the reservoir with water to the extent possible.

PRODUCTION FACILITIES

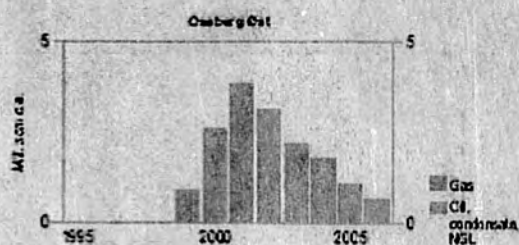
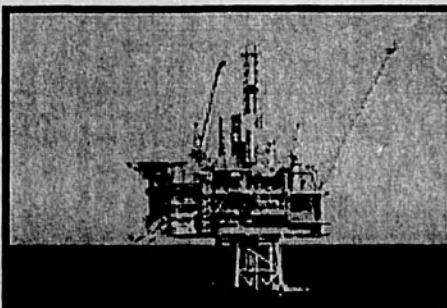
The Dan Field comprises six wellhead platforms, A, D, E, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FG, two processing and accommodation platforms, B and FC, and two gas flare stacks, C and FD.

At the Dan Field, there are facilities for receiving production from the adjacent Kraka and Ragnar satellite fields, as well as for receiving gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

After final processing, the oil is transported to shore via the riser platform, Gorm E. The gas is pre-processed and transported to Tyra East for final processing. Treated production water from Dan and its satellite fields is discharged into the sea.

The Dan Field has accommodation facilities for 97 persons on the FC platform. The B platform has accommodation facilities for five persons.





Oseberg Øst

Block and production licence	Block 95/5, production licence 051, awarded 1979
Discovered	1981
Development approval	11.10.1996 by the King in Council
On stream	08.05.1999
Operator	Norsk Hydro Produksjon AS
Licencees	Mobil Development Norway AS 4,70 % Norsk Hydro Produksjon AS 34,00 % Norsk ConocoPhillips AS 2,40 % Petoro AS 33,60 % Statoil ASA 15,30 % Total E&P Norge AS 10,00 %
Recoverable reserves	Original: 27,8 million scm oil 0,4 billion scm gas Remaining as of 31.12.2006 11,7 million scm oil 0,2 billion scm gas
Production	Estimated production in 2007: Oil 10 000 barrels/day Gas 0,62 billion scm
Investment	Total investment is expected to be NOK 19,2 billion (2007 values) NOK 8,8 billion have been invested as of 31.12.2006 (2007 values)
Operating organisation	Bergen
Main supply base	Mongstad

Development:

Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is 160 metres.

Reservoir:

The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oil-bearing layers of varying reservoir characteristics within the Middle Jurassic Brent group.

Recovery strategy:

The field is produced with pressure maintenance using both water injection and WAG (water alternating gas) injection.

Transport:

The oil is sent by pipeline to the Oseberg Field Centre for further processing and transport through the Oseberg Transport System (OTS) to the Shet terminal. The gas is mainly used for injection, gas lift and fuel.

Status:

Various measures for increased oil recovery are being evaluated in an ongoing process. A new drilling campaign is expected to yield increased production. The first well in the new drilling campaign is planned to be set on stream in February 2008.

Table 6.1 Sales Gas Forecast							
Year	P90		P50		P10		Mean
	(10 ⁶ m3/d)	(MMscfd)	(10 ⁶ m3/d)	(MMscfd)	(10 ⁶ m3/d)	(MMscfd)	
2010	3.7	202	2.7	201	2.7	202	201
2011	3.2	300	2.4	300	2.3	300	300
2012	3.0	240	2.2	260	2.1	300	291
2013	2.8	170	2.1	220	2.0	200	219
2014	2.7	110	2.0	150	1.9	150	151

Appendix V:

Nova Scotia Detail (from Deep Panuke Development Plan)

Estimates for the development phase include costs incurred by the firm as operator of the project from the fourth quarter 2006 to first gas production, scheduled to occur in the fourth quarter of 2010.

The costs shown in Table 6.2 are for the MEER option, and exclude any costs associated with the MOPL, which will be included in operating costs payable during the production life of the project.

The SOEP Subsea Option would see a reduction in the cost of the export pipeline during the Development Phase. However, there would be an increase in operating costs for liquids handled as a result of using the SOEP option. At this time, these costs were not defined.

Table 6.2 Development Phase Expenditures		(\$ Billions)
		2006
Total Cost to First Gas	Construction	700
	Subsistence	90
	Drilling and Completion	610
	Export Pipeline	100
	Subsea	200
	Initial Project Management & Engineering	135
		115

Table 6.1 Sales Gas Forecast

Year	P90		P50		P10		Mean	
	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)
2010	5.7	202	5.7	201	5.7	202	5.7	201
2011	8.5	300	8.4	300	8.5	300	8.5	300
2012	7.0	249	8.5	300	8.4	300	8.2	291
2013	4.5	159	6.4	228	8.4	300	6.2	219
2014	3.1	110	4.8	171	7.7	275	5.0	177

6.3.1 Development Phase Expenditures

Estimates for the development phase include costs incurred by EnCana, as operator of the Project, from the fourth quarter 2006 to first gas production, scheduled to occur in the fourth quarter of 2010.

The costs shown in Table 6.2 are for the M&NP option, and exclude any costs associated with the MOPU, which will be included as operating costs payable during the production life of the Project.

The SOEP Subsea Option would see a reduction in the cost of the export pipeline during the Development Phase. However, there would be an increase in operating costs for tariffs charged as a result of using the SOEP pipeline. At this time, these costs are not defined.

Table 6.2 Development Phase Expenditures	C\$ Millions 2006
EnCana Project Management & Engineering	115
Subsea	135
Export Pipeline	200
Drilling and Completions	160
<i>Subtotal:</i>	610
<i>Contingency</i>	90
Total Cost to First Gas	700

3.14 GUIDELINES FOR DEVELOPMENT PLAN (PART II)

Part II of the Development Plan should consist of the studies, analyses and evaluations, or other information and proposals, in support of Part I of the Plan. In accordance with the Act, proprietary information provided in Part II will not be disclosed without the proponent's consent.

The Act also requires that petrophysical, fluid, core and well testing data, analyses and evaluations, be provided to the Board for reasons other than as part of the Development Plan submission. The material should be referenced explicitly but need not be resubmitted. The material should be referenced explicitly but determined in accordance with the relevant provisions of the Act.

Appendix VI:**Newfoundland-Labrador Detail**

The following are to be provided where applicable and when available:

- geological studies;
- geophysical studies;
- petrophysical studies;
- reservoir engineering studies, including rock and fluid data and analyses, and reservoir simulation studies;
- original oil and gas-in-place and recoverable reserves studies;
- production engineering information and studies;
- field hydraulic studies;
- production and transportation systems studies;
- environmental studies and analyses;
- plans for waste treatment and disposal;
- development cost data and economic analyses of alternatives;
- information related to matters of conservation, safety of operations and pollution prevention; and
- any other studies that were used in support of the Development Plan.

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SCOMM

148:11



Official Business

ALASKA STATE LEGISLATURE

HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Representative Kurt Olson, Chair
State Capitol, Room 408
Juneau, AK 99801-1182
Phone 907-465-2693 Fax 907-465-3835

Saturday, October 20, 2007

Noon - 5 pm

Room 519

AGENDA

HB 2001

Oil and Gas Tax Amendments

Presentation by: Governor's Production Tax Team

"Alaska's Global Competitiveness under ACES"

Marcia Davis, Deputy Commissioner, Dept. of Revenue

Bob George, Gaffney, Cline & Associates

Rich Ruggiero, Gaffney, Cline & Associates

Roger Marks – Economist, Dept. of Revenue

Torsten Wucherphennig – PFC Energy

Michael D. Williams – Economist, Dept. of Revenue

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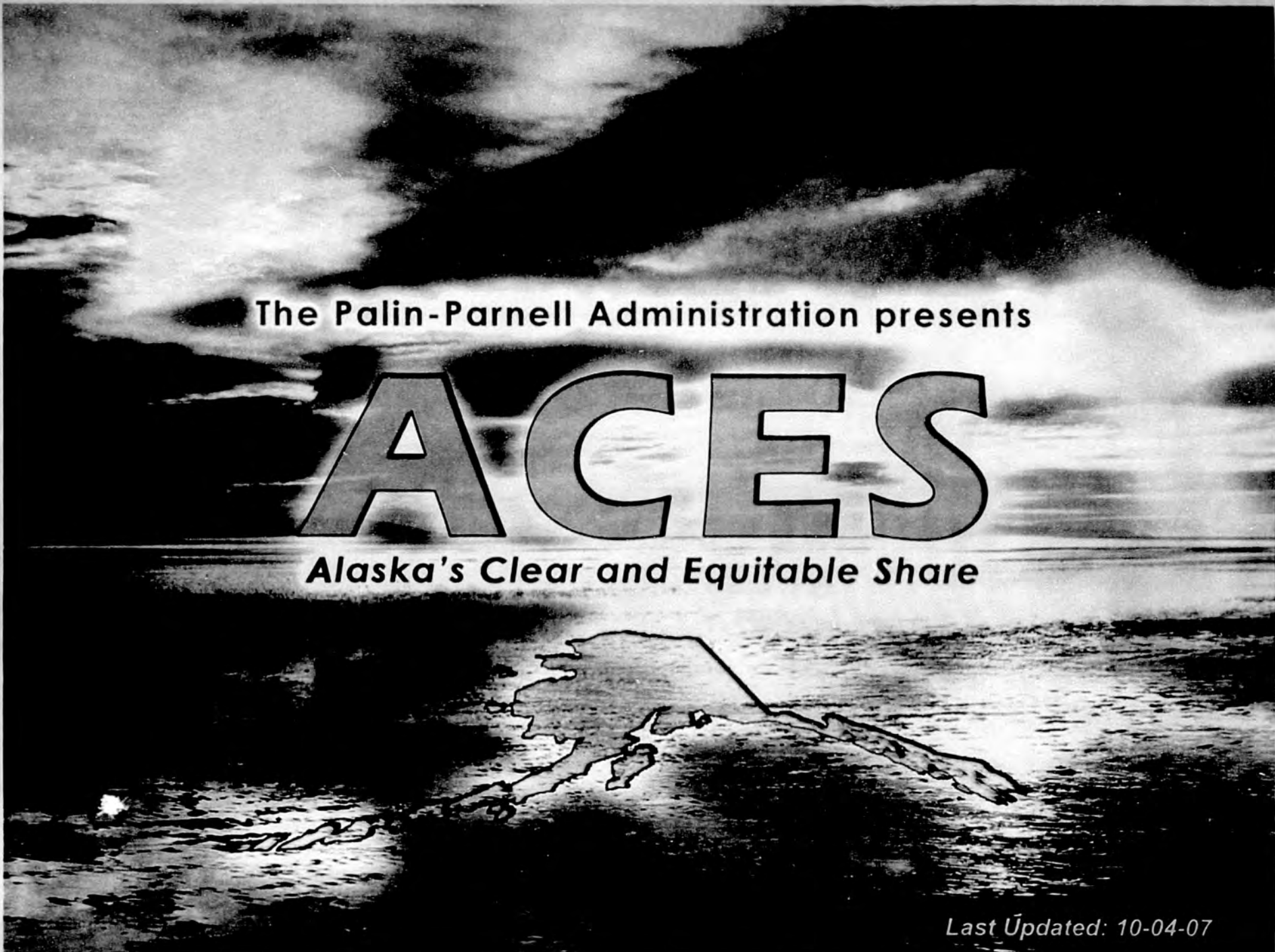
Representative Ralph Samuels
Representative Nancy Dahlstrom
Representative Scott Kawasaki

Representative Jay Ramras
Representative Mark Neuman
Representative Mike Doogan

HB 2001 Bill Packet Information October 20, 2007

Enclosed Documents:

- ACES - Power Point Presentation
- Gaffney, Cline & Assoc. - Memorandum dated October 16, 2007
- Government Take Comparison
Torsten Wucherpennig, Manager Asset Valuation, PFC Energy
- Government Competition for Oil & Gas Investment
Michael D. Williams, Chief Economist, Dept, of Revenue
- "Comparable Salaries..." Study - Requested by Chair Olson - 10/19/07
- Public Comments



The Palin-Parnell Administration presents

ACES

Alaska's Clear and Equitable Share

Last Updated: 10-04-07

ACES VS. PPT SCHEMATIC

ACES

Alaska's Clear and Equitable Share

ANS West Coast Price

- (minus Shipping/TAPS)

= Gross Value at the Point of Production

- (minus upstream capital costs [less 30 cents/bbl])

- (minus upstream operating costs)

= Net Income

	PPT	ACES	\$ DFNC
Base Tax Rate on Net Income	22.5%	25.0%	\$0.2 B
Plus Progressivity Surcharge:			
Per Barrel Net Income "Kicker"	\$40	\$30	\$0.2 B
Surcharge Rate applied to Net Income	0.25% / \$	0.20% / \$	
(Minus Credits)			
- (Capital (023a) [20%])	Yes	Yes	
- (NOL (023b))	Yes	Yes	
- (Transition [TIE] (023i))	Yes	No	\$0.2 B
- (Small Producer (024) [\$12mm])	Yes	Yes	
- (Exploration (025))	Yes	Yes	
= Tax Payment	\$1.4 B	\$2.0 B	\$0.60

FLOOR

ACES

Alaska's Clear and Equitable Share

PPT - HIGHER OF:

PPT Net Tax Payment

vs.

4% of Gross Income
(If ANS West Coast above \$25/bbl)

ACES

**FOR EACH UNIT WITH CUMULATIVE PRODUCTION OVER ONE BILLION BARRELS
AND DAILY PRODUCTION OVER 100,000 BARRELS PER DAY
PAYMENT IS HIGHER OF:**

ACES Net Tax Payment

vs.

10% of Gross



Alaska's Clear and Equitable Share

Measuring Government Fair Share: New Fields and Legacy Fields

Principles



- Fair share to government is an objective of fiscal systems (from the perspective of government)
- Based on international competitive opportunities commensurate with risk: make Alaska an attractive place to invest
- Needs to be an objective measurement of fair share that is systematically comparable
- The pattern of development is a) first comes investment, then b) returns are realized in subsequent years
- Measurement needs to recognize that investment decisions are based on forward-looking economics
- New fields are different from legacy fields

New Fields



- All costs are prospective
- Look at “take”
 - Take is a life-cycle concept
 - Percentage of economic rent going to government
 - Economic rent is gross revenues less costs (before taxes)
 - Discounting recognizes cost of capital – timing of take matters

- Many costs have already been incurred
- Measurements that look at cash flow in a single year can be deceptive as:
 - Large costs are often incurred in discreet time-frames (lumpiness)
 - Returns are realized after these investments
 - A single year cannot depict the economic picture
 - Systematic international comparisons for a particular year are meaningless

Legacy Fields: Marginal Tax Rate



- Look at share of the incremental dollar going to government (marginal tax rate [MTR])
 - Derived by looking at total per barrel government revenues at one price, and then increasing the price by one dollar
 - The difference in per barrel government revenues (from that at the lower price) is the marginal tax rate
 - Increasing the price by one dollar has no effect on costs
 - Cost issues are minimized
 - Limitations of annual “share” data

Alaska and its Competitors



Alaska's Clear and Equitable Share

- Governments use two major methods to take their fair share
- Royalty & Production Taxes
 - Developed nations
 - Stable democratic governments
 - Diverse economies
- Production Sharing Contracts (PSC)
 - Developing nations
 - Less stable governments – fiscal system administered by contract
 - Oil centered economies – better geology
- Alaska should be compared with tax/royalty jurisdictions
 - UK, Norway, Gulf of Mexico, Alberta, Canada
 - Under PPT & ACES, Alaska government take & MTR is between UK and Norway

Fundamental Changes from Past Efforts



- Data base
 - More exhaustive inventory of international jurisdictions (PFC effort)
 - Real projects (PFC effort)
 - Internal Schlumberger PEEP model with detailed fiscal systems – real projects analyzed
- Two fundamental changes to approach
 - Differences between legacy and new fields
 - Comparison to relevant competition

The Palin-Parnell Administration presents

ACES

Alaska's Clear and Equitable Share



Last Updated: 10-20-07

ACES VS. PPT SCHEMATIC

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Alaska's Clear and Equitable Share

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ACES

Alaska's Clear and Equitable Share

ACES Net Tax Payment

PAYMENT IS HIGHER OF:

Measuring Government Fair Share: New Fields and Legacy Fields

(If ANS West Coast above \$250M)

4% of Gross Income

VS

PPT Net Tax Payment

PPT - HIGHER OF:

LEGOS

Alaska's Clear and Equitable Share

ACES

Principles



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Principles

Alaska's Clear and Equitable Share

VCE2

Legacy Fields

ACES

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ACES

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- **Data base**

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- Real projects (PFC effort)

- Internal Schlumberger PEEP model with detailed fiscal systems – real projects analyzed

- **Two fundamental changes to approach**

- Differences between legacy and new fields

- Comparison to relevant competition



Gaffney, Cline & Associates Inc.

Technical and Management Advisers to the Petroleum Industry Internationally Since 1962

Principals
William B. Cline
Peter D. Gaffney

Four Oaks Place
1360 Post Oak Boulevard, Suite 2500
Houston, Texas 77056

Telephone: (713) 850-9955
Facsimile: (713) 850-9966
Email: gcah@gaffney-cline.com

RAR/jlm/C1492.00/gcah.300.07

October 16, 2007

MEMORANDUM

RE: Oil Company Capital Spending

Oil companies are by definition in business to make a profit. Their actions are aimed at removing or preventing any barriers to achieving increased profits. Taxes are a barrier to achieving profits and when raised serve to reduce profits and when lowered serve to increase profits. Thus, oil companies are naturally predisposed to oppose any increase in taxes. With all things being equal (which they rarely are), oil companies would preferentially invest in areas with the lowest taxes, however this is not the real world calculus.

When materiality and prospectivity are added to the investment decision criteria, oil companies quite often end up investing in countries with relatively high or above average tax rates. They do so because they believe (and often realize) that investments in those countries will provide access to new reserves and will generate significant profits. Similarly, countries that offer extraordinary potential (like Angola, Russia and Kazakhstan) are able to command a greater share of the total pie while, at the other extreme areas which have extremely favorable tax regimes (like Ireland and Morocco) still do not attract significant industry interest.

The oil companies are – rationally – resisting initiatives to increase their effective tax burdens and attempting to boil down the issue of fiscal policy and its impact on their capital investment decision making to a single factor: **the effective tax rate**. But the issue is not that simple. The oil companies must, if they are to remain in existence, do a good job at profitably replacing the reserves that they are currently producing. The number of locales in the world that offer the larger oil companies the needed level of materiality to do that are limited in number. ExxonMobil, BP, Chevron and ConocoPhillips for example, together produce over 12 million barrels of oil equivalent per day – to simply replace their production they need to find a Kuparuk size accumulation every 8 to 9 months!

The oil companies have compared Alaska's tax regime to mainly other lower 48 United States tax regimes; however, such a comparison would only be valid for a small portion of their overall investment capital spending. Lehman recently published a survey of 350 companies that showed estimated total worldwide capital spending in 2007 of just over US\$300 billion of which roughly one quarter or US\$77 billion would be in the United States (including Alaska). Overall, 2007 numbers represented over a 20% increase for international (i.e. non-US or Canada) spending with United States spending up slightly and Canadian spending down.

Looking at just the United States, expected 2007 spending represents an increase of 4.8% over 2006. A further breakdown of the numbers by Lehman shows that smaller

UNITED KINGDOM

UNITED STATES

SINGAPORE

AUSTRALIA

ARGENTINA

MOSCOW

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MEMORANDUM

October 16, 2007

Page 2

companies (those with annual spending under US\$1 billion) were estimating increasing their spending by some 10+% for 2007 while the large oil companies were only expecting spending in the United States to increase 1.2%.

The Lehman data seem to be corroborated by data in the oil companies' annual reports. Gaffney, Cline & Associates reviewed annual reports for BP, Chevron, ConocoPhillips and ExxonMobil for 2002 through 2006. Where available, capital spending data overall and in the United States for the upstream sector were used. Where such geographic breakdown was not provided data for corporate spending were used to arrive at the numbers below. The key piece of information is not the absolute value, but the trend of where the main players in Alaska are spending the bulk of their investment dollar. For upstream spending BP's investments outside the United States represented 50% to 75% of their overall total. Similar numbers for Chevron were 67% to 71%, ConocoPhillips 63% to 75% and ExxonMobil 77% to 85%.

		Capital Spending (\$millions)									
		2006		2005		2004		2003		2002	
BP:	US	\$6,592	50%	\$3,870	38%	\$3,913	36%	\$3,906	26%	\$3,100	32%
	International	\$6,526	50%	\$6,367	62%	\$7,095	64%	\$11,286	74%	\$6,559	68%
	TOTAL	\$13,118		\$10,237		\$11,008		\$15,192		\$9,659	
Exxon:	US	\$2,486	15%	\$2,142	15%	\$1,922	16%	\$2,125	18%	\$2,357	23%
	International	\$13,745	85%	\$12,328	85%	\$9,793	84%	\$9,863	82%	\$8,037	77%
	TOTAL	\$16,231		\$14,470		\$11,715		\$11,988		\$10,394	
Conoco:	Alaska	\$820	9%	\$746	11%	\$645	12%	\$570	13%	\$706	22%
	US (Continental)	\$2,008	21%	\$891	13%	\$669	12%	\$848	19%	\$499	15%
	International	\$6,685	70%	\$5,047	76%	\$3,935	75%	\$3,090	68%	\$2,071	63%
	TOTAL	\$9,513		\$6,684		\$5,249		\$4,508		\$3,276	
Chevron:	US	\$4,123	32%	\$2,450	29%	\$1,820	29%	\$1,641	29%	\$1,888	30%
	International	\$8,696	68%	\$5,939	71%	\$4,501	71%	\$4,034	71%	\$4,395	70%
	TOTAL	\$12,819		\$8,389		\$6,321		\$5,675		\$6,283	

Moreover, the review of the annual reports show investment by these four companies in significant projects in jurisdictions that have average and marginal tax rates above those in place or proposed in Alaska.

In deciding where to invest, tax policy is one of the factors considered but is demonstrably not, in and of itself, the controlling factor.



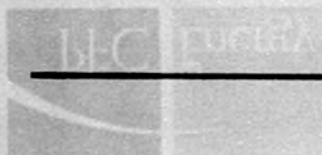
Strategic Advisors in Global Energy

Government Take Comparison

Prepared for the Department of Revenue, State of Alaska
Torsten Wucherpfennig, Manager Asset Valuation, PFC Energy

20 October 2007





30 October 2003

Government Take

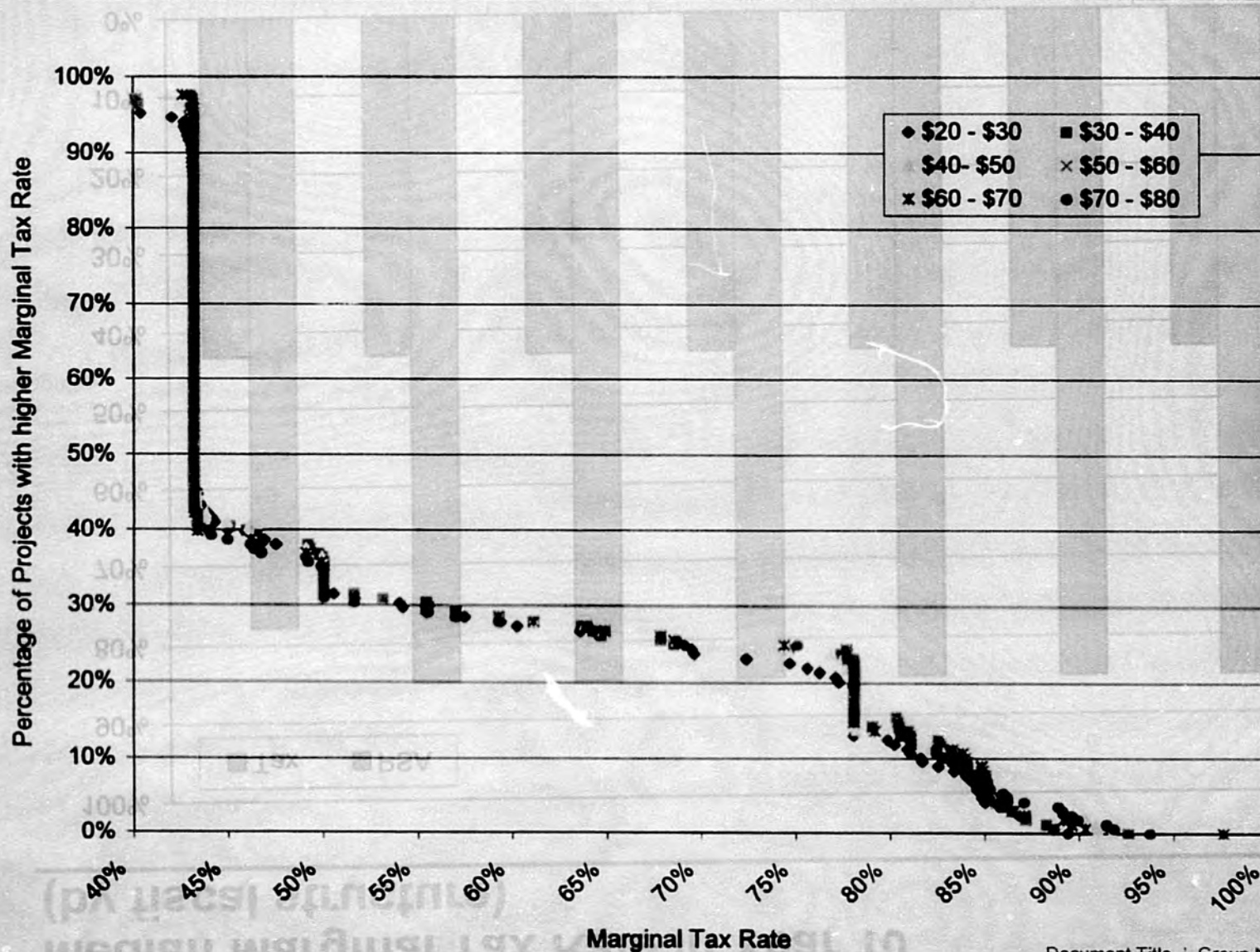
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Government Take Comparison

Strategic Advisors in Global Energy

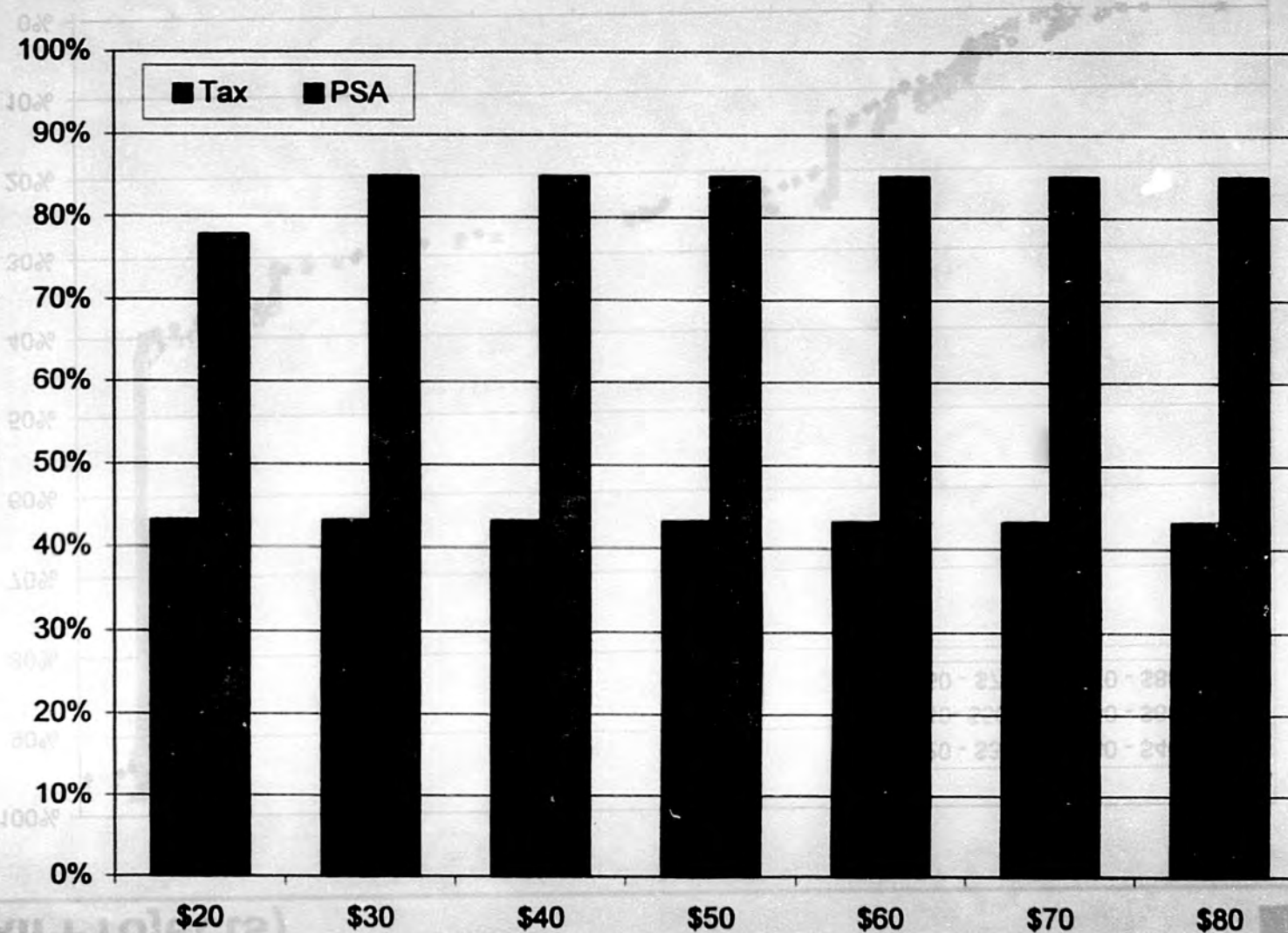
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Distribution Marginal Tax Rate of 190 fields (All Projects)

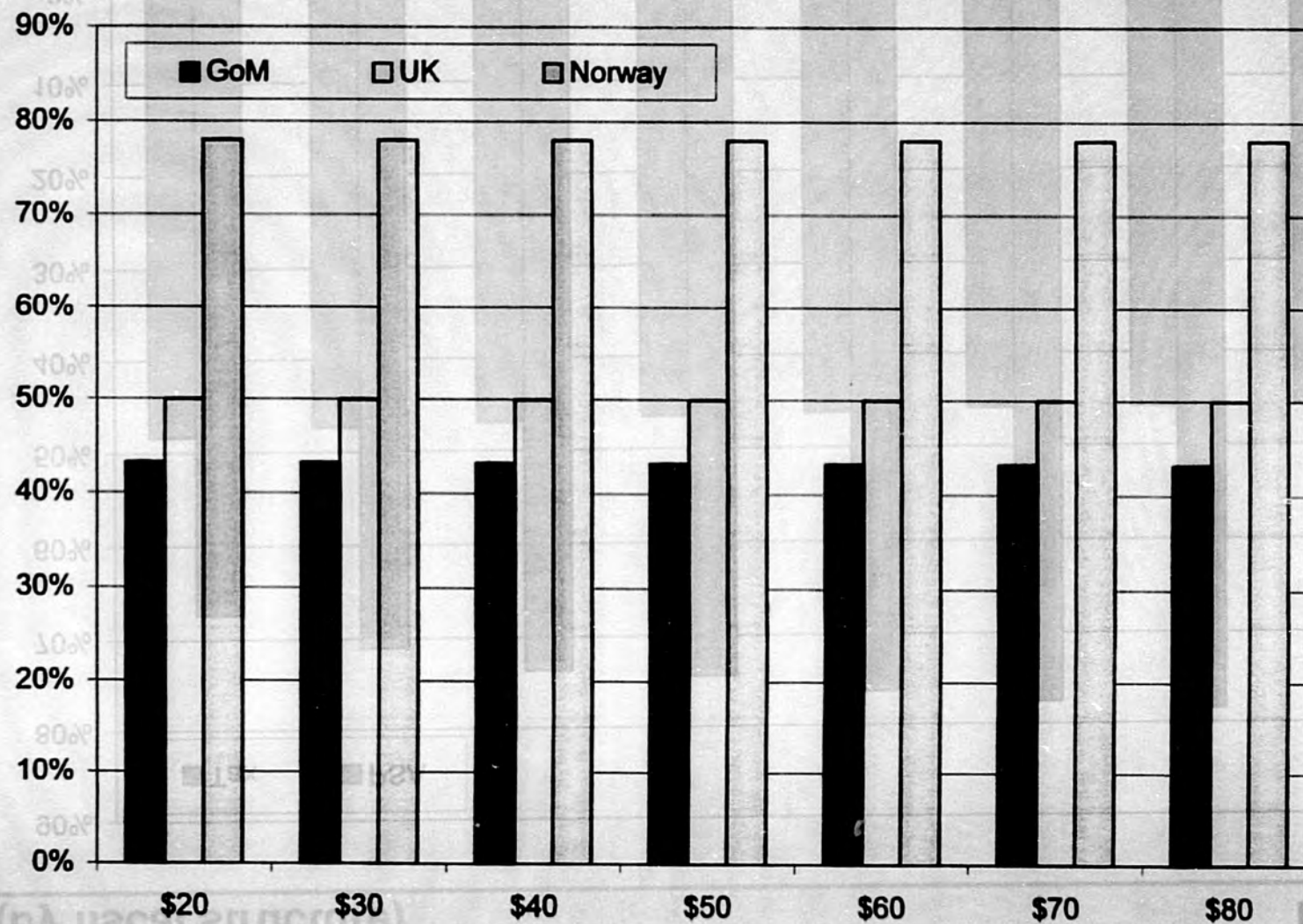


Median Marginal Tax Rate in Year 10 (by fiscal structure)

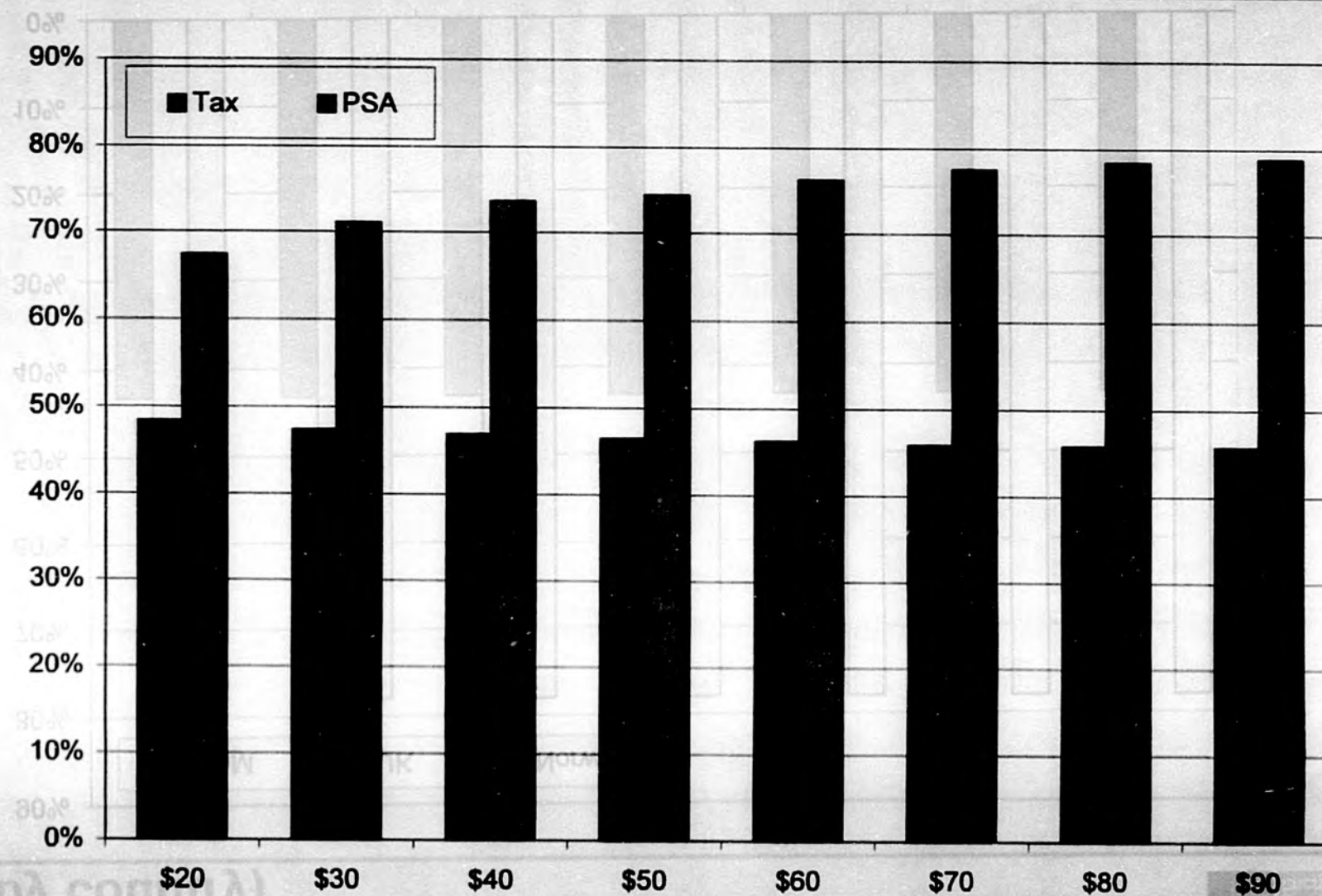
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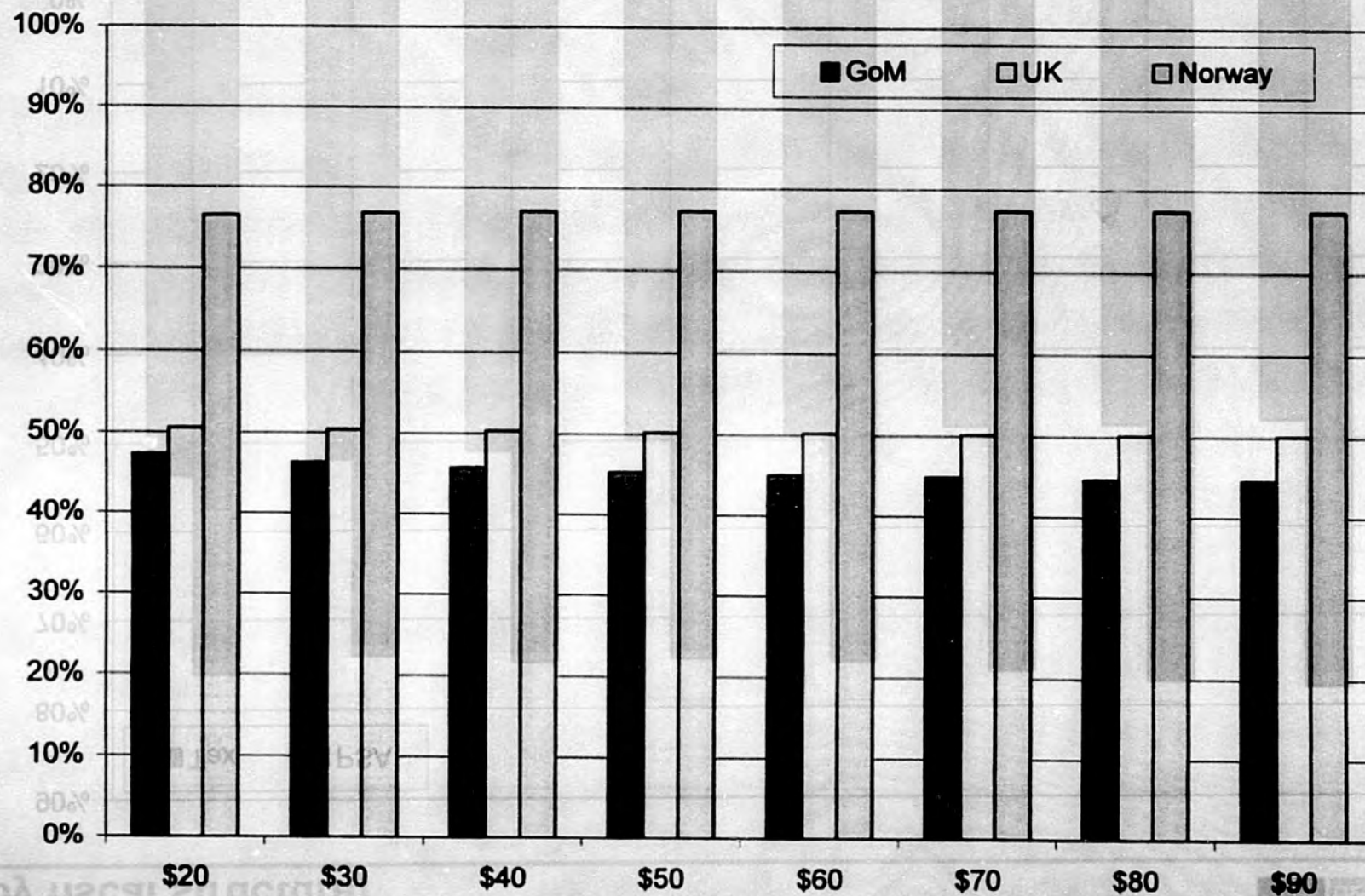
Median Marginal Tax Rate in Year 10 (by country)



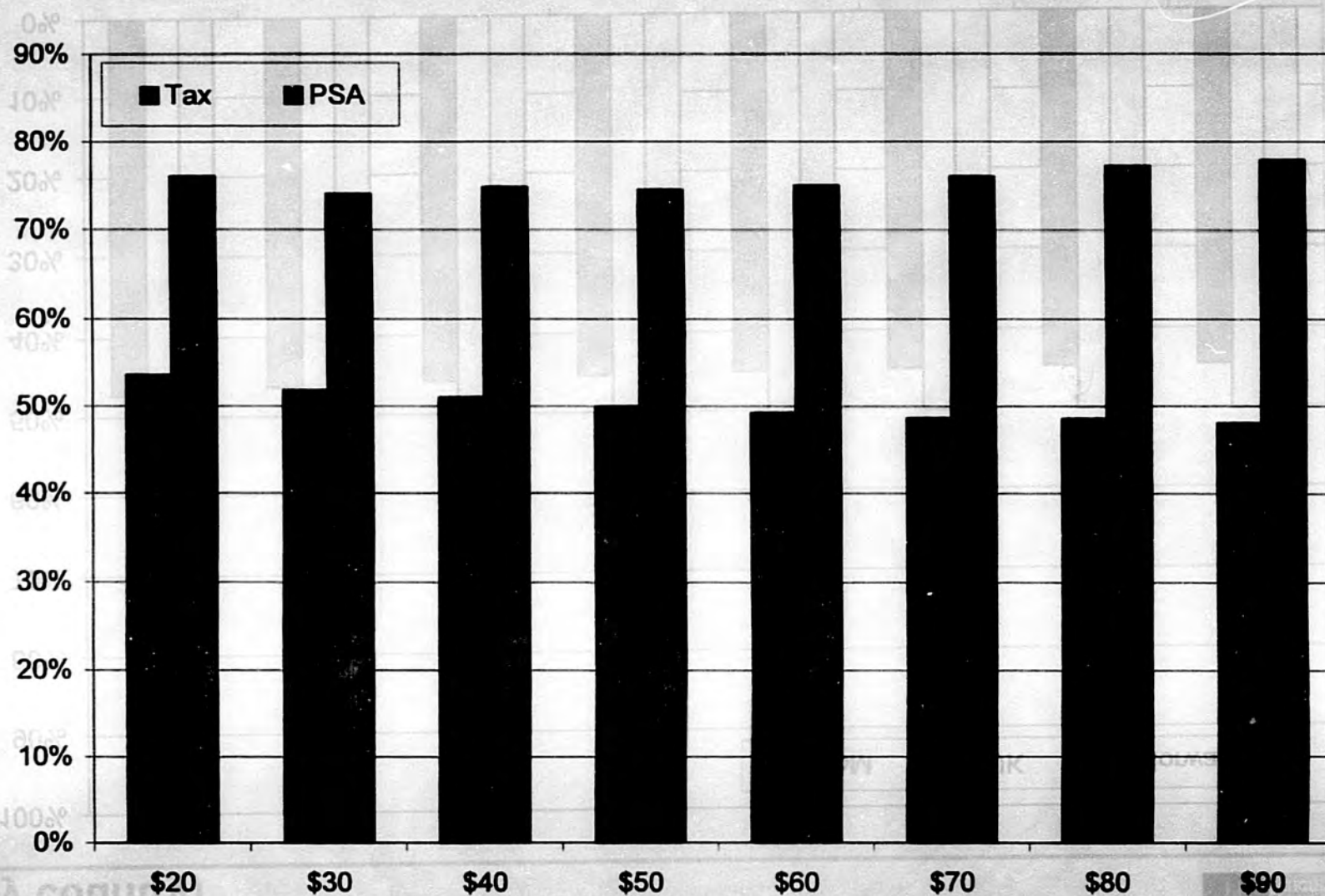
Median Undiscounted Government Take in Economic Rent (by fiscal structure)



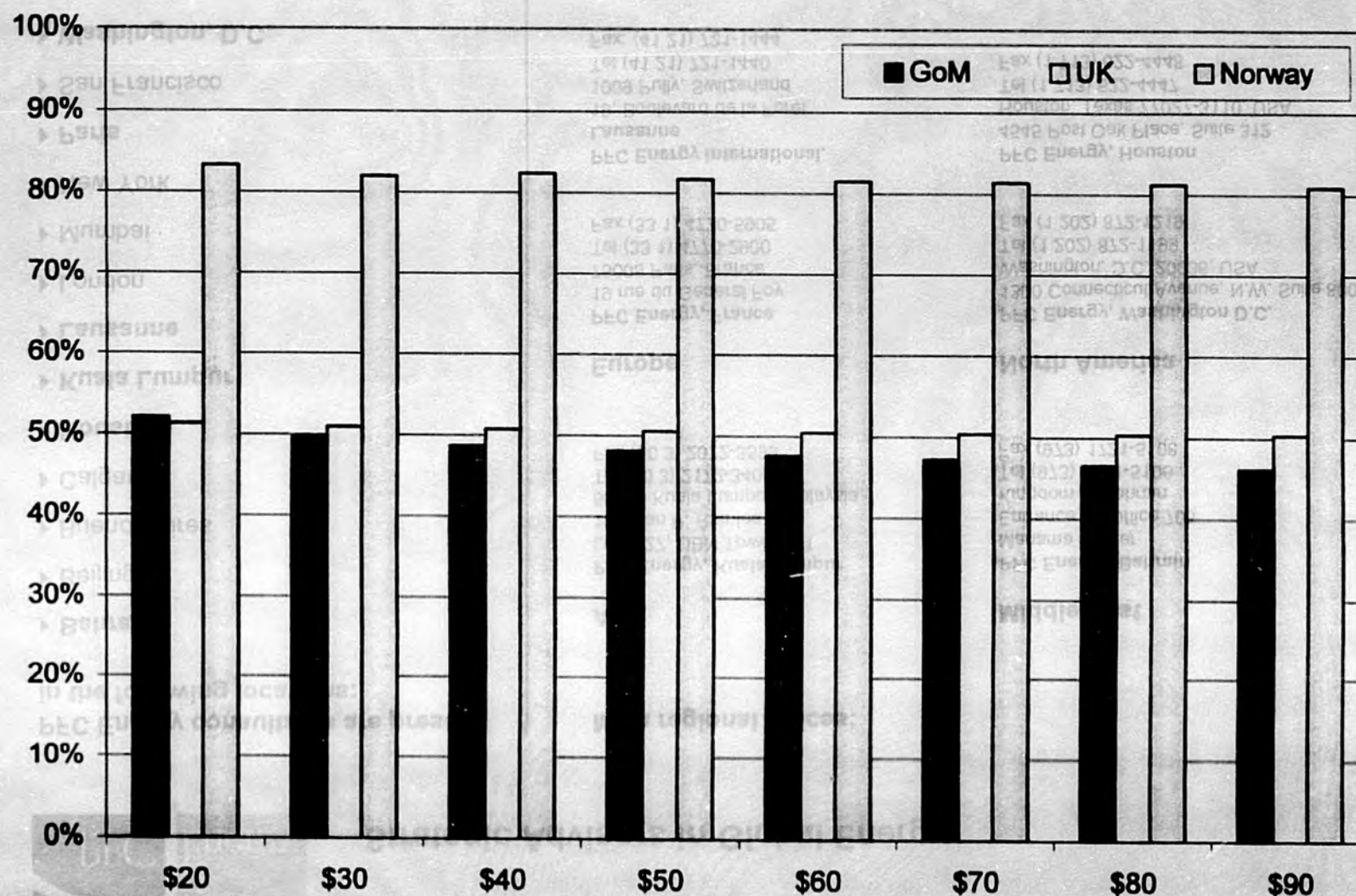
Median Undiscounted Government Take in Economic Rent (by country)



Median Discounted (10%) Government Take in Economic Rent (by fiscal structure)



Median Discounted (10%) Government Take in Economic Rent (by country)





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Main regional offices:

Asia

PFC Energy, Kuala Lumpur
Level 27, UBN Tower #21
10 Jalan P. Ramlee
50250 Kuala Lumpur, Malaysia
Tel (60 3) 2172-3400
Fax (60 3) 2072-3599

Europe

PFC Energy, France
19 rue du Général Foy
75008 Paris, France
Tel (33 1) 4770-2900
Fax (33 1) 4770-5905

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19, Boulevard de la Forêt
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Fax: (41 21) 721-1444

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Manama Center
Entrance 4 - Office 705
Kingdom of Bahrain
Tel (973) 1721-5106
Fax (973) 1721-5108

North America

PFC Energy, Washington D.C.
1300 Connecticut Avenue, N.W. Suite 800
Washington, D.C. 20036, USA
Tel (1 202) 872-1199
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Case Studies: Government Competition for Oil & Gas Investment



Alaska Department of Revenue,
October 2007, Juneau, Alaska
Michael D. Williams, Chief Economist

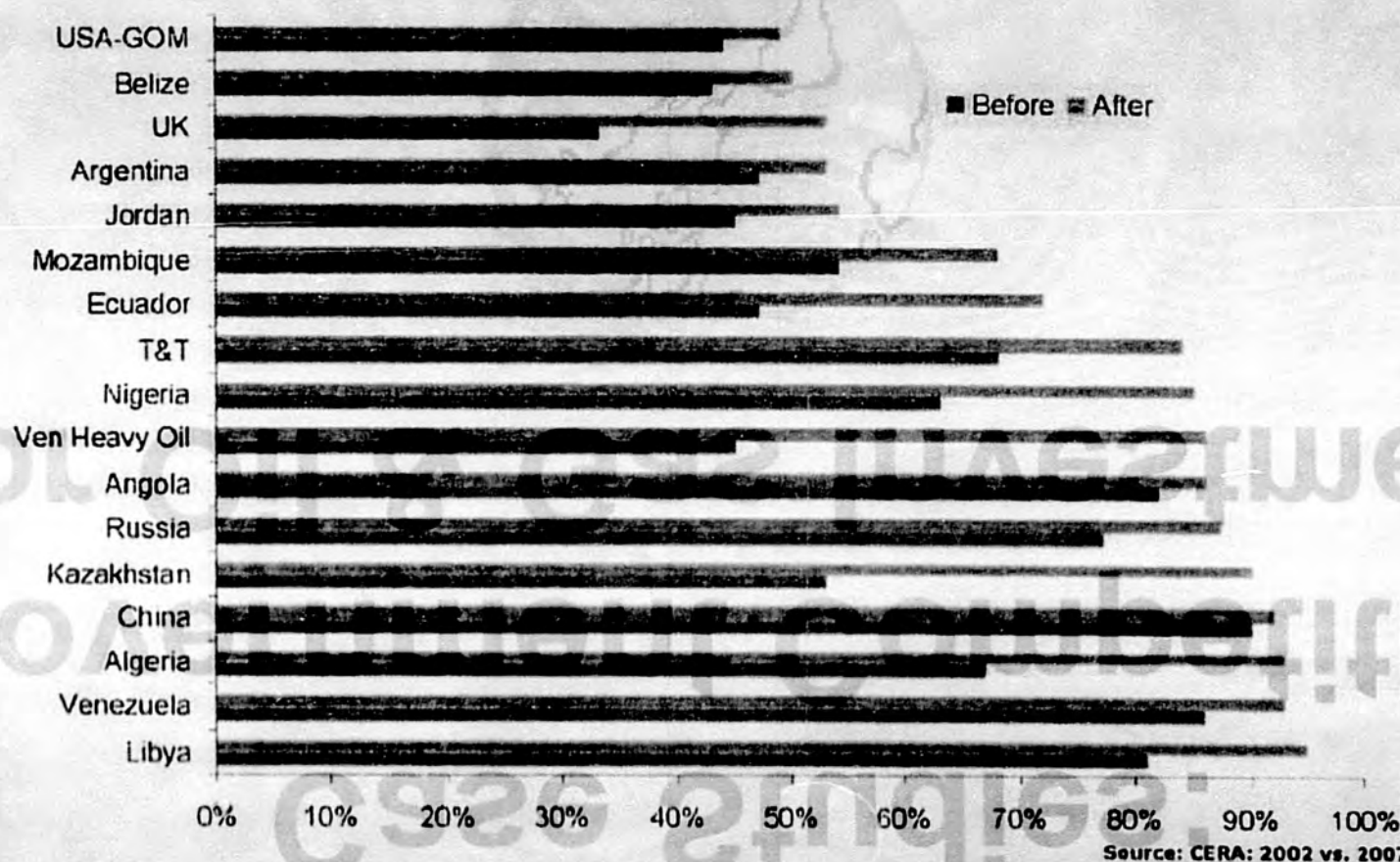


Capturing "Fair Share"

Assessment of Oil and Gas Jurisdictions
is Complex and Continuous



Changes in Government Take 2002 to 2006



Source: Report of the Alberta Royalty Review Panel, "Our Fair Share", page 29.

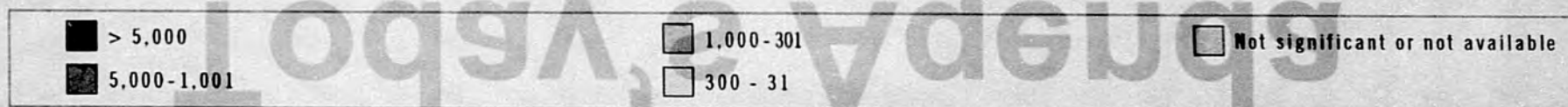
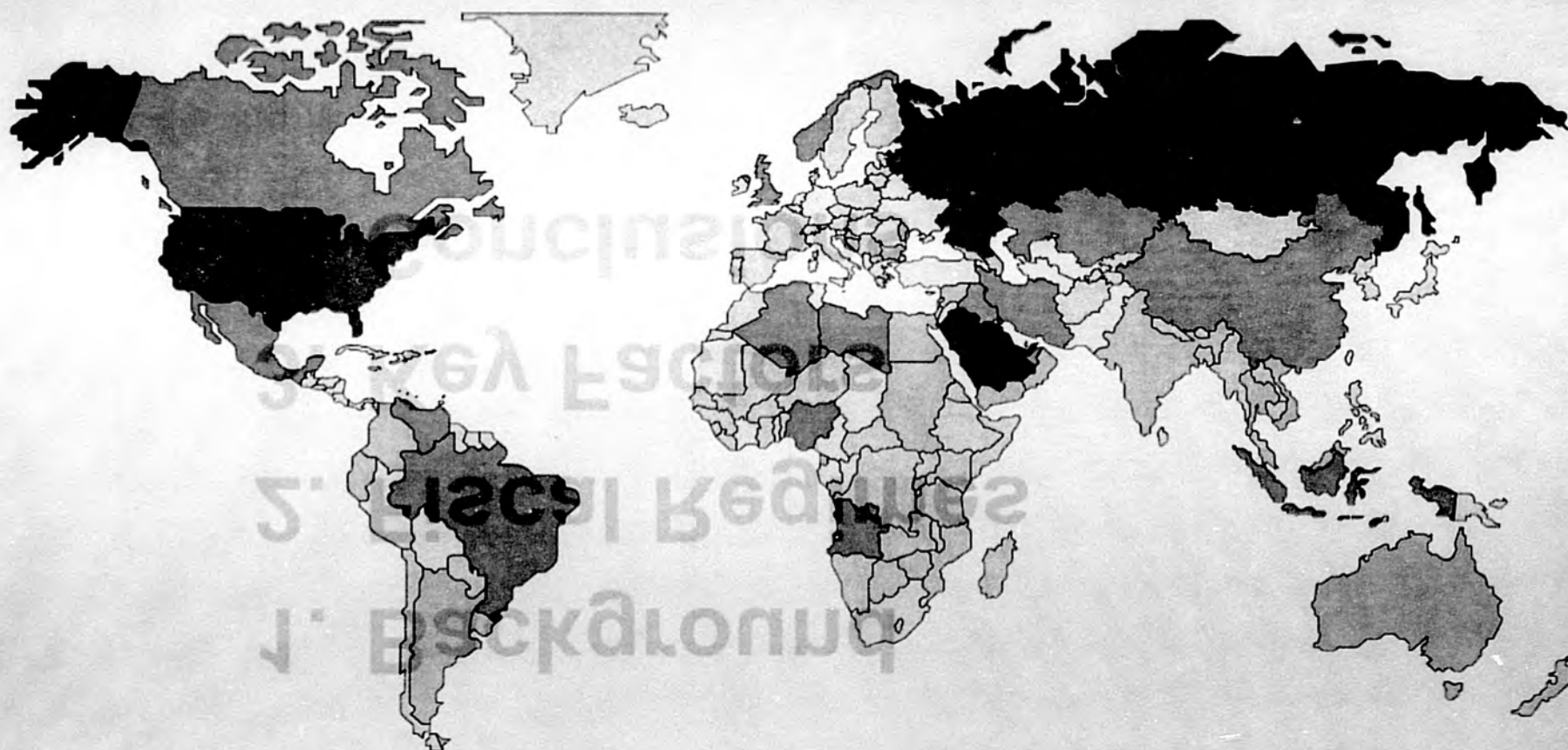


Today's Agenda

1. Background
2. Fiscal Regimes
3. Key Factors
4. Conclusions

Oil Producing Countries

Oil Producing Countries³



Source, ENI, *World Oil & Gas Review 2007*, for 2006, crude oil and NGL's in thousands of barrels per day, page 13.

Types of Legal Systems

- **Production Sharing** – Uses a Production Sharing Contract [PSC], the contractor receives a share of production for services rendered.
- **Tax / Royalty** – Government licenses right to extract and sell resources and imposes financial obligations on resource extraction:
 - Royalty
 - Tax: on income, production, property.

Tax / Royalty Governments Comparison

- **Alaska**
- **Alberta**
- **Norway**
- **United Kingdom**
- **US Gulf of Mexico [GOM]**

Alaska

- **Signature Bonus:** Yes
- **Royalty:** about 12.5%
- **Production Tax:** Petroleum Profits Tax, based on net income
- **Tax Credits & Uplift:** Yes
- **Property Tax:** Based on assessment
- **Corporate Income Tax:**
 - Alaska State = 9.4% of profit
 - US Federal* = 35% of profit

* Bonuses, Royalty, Production Tax, Property Tax, and State Corporate Income Tax are deduction from US Federal Income Tax.

Alberta

Conventional Oil

- **Signature Bonus:** Yes
- **Royalty*:** 14.78%
- **Production Tax:** None
- **Tax Credits & Uplift:** No
- **Property Tax:** None
- **Corporate Income Tax:**
 - Federal = 20% of profit
 - Provincial = 10% of profit

} Additive

* There are three tiers of royalty based upon the age of the well, those tiers are pre-1974, 1974-1992, and post-1992. The royalty rates are expressed in Canadian dollars per cubic meter and are sensitive to well productivity and market price. This analysis is for oil wells that went into production after 1992 and use the rate of \$130.09 per cubic meter, which is a royalty rate of about 15%. See "Technical Royalty Report OG#2: Alberta's Conventional Oil and Gas Industry", Alberta Department of Energy, 2007, page 14.

Norway

10

- **Corporate Income Tax:** 20% of profit
- **Signature Bonus:** No
- **Royalty:** Phased out
- **Production Tax*:** 50% of profit
- **Tax Credits & Uplift:** Yes
- **Property Tax:** None
- **Corporate Income Tax*:** 28% of profit

* Production Tax and Corporate Income Tax are additive.

United Kingdom

- **Signature Bonus:** No
- **Royalty:** Discontinued for new fields in 1982 & older fields in 2003
- **Production Tax*:** Fields developed before March 1993 pay 25%; there is no tax on fields with development approval after March 1993.
- **Tax Credits & Uplift:** No
- **Property Tax:** None
- **Corporate Income Tax:** 50% of profit

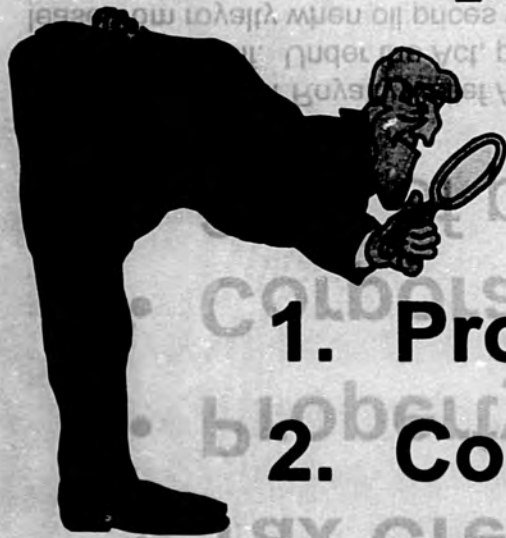
* For fields in operation prior to 1993, the Petroleum Revenue Tax is due and is a tax on net income with detailed specifications for such items as lease costs, acquisition costs, abandonment costs, tariffs, etc. The PRT has a tax rate of 25% and the tax paid is deductible from profits in computing Corporate Income Tax.

US GOM

- **Signature Bonus:** Yes
- **Royalty:** Royalty relief* for deep water
- **Production Tax:** None
- **Tax Credits & Uplift:** Yes
- **Property Tax:** None
- **Corporate Income Tax:** US Federal, 35% of profits

* The Deep Water Royalty Relief Act of 1995 expanded the Secretary's royalty relief authority in the GOM outer continental shelf. Under the Act, producers were able to exclude the first 87.5 million barrels of oil production from each lease from royalty when oil prices were under \$34 per barrel. When contracts were actually approved, the price "trigger" was not included in the agreement, thus, the contracts between the oil companies and US government do not specify a price at which the royalty payment is required. On January 9, 2007 the US government royalty rate was increased to 16.7% from 12.5% - but the 87.5 million barrel exclusion still applies, and there is still no price trigger in the contracts.

Key Factors



1. Prospectivity

2. Costs

3. Risk

- **Political**

- **Fiscal Stability**

4. Capital Depreciation Time Frame

5. Government Take

Attractiveness of Oil & Gas Resources

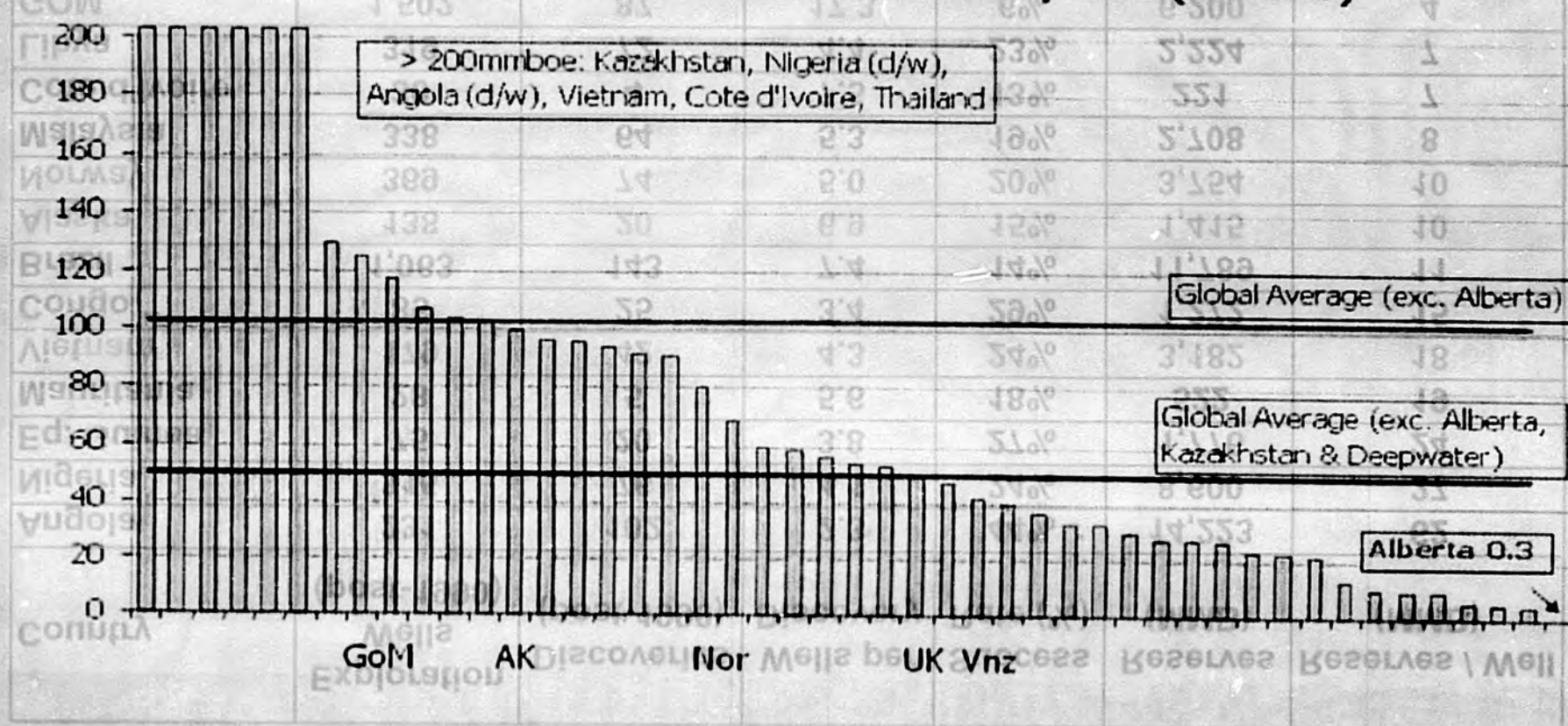
All Exploration & Discoveries Since 1990; Reserves are Reserves Added Since 1990

Country	Exploration Wells (post-1990)	Discoveries (post-1990)	Wells per Discovery	Success Rate (%)	Reserves (MMB)	Reserves / Well (MMB)
Angola	231	102	2.3	44%	14,223	62
Nigeria	315	76	4.1	24%	8,600	27
Eq. Guinea	75	20	3.8	27%	1,776	24
Mauritania	28	5	5.6	18%	522	19
Vietnam	179	42	4.3	24%	3,182	18
Congo	85	25	3.4	29%	1,272	15
Brazil	1,063	143	7.4	14%	11,789	11
Alaska	138	20	6.9	15%	1,415	10
Norway	369	74	5.0	20%	3,754	10
Malaysia	338	64	5.3	19%	2,708	8
Cote d'Ivoire	30	4	7.5	13%	221	7
Libya	319	72	4.4	23%	2,224	7
GOM	1,502	87	17.3	6%	6,200	4
UK	1,177	122	9.6	10%	3,826	3
Gabon	185	26	7.1	14%	472	3
Indonesia	1,200	193	6.2	16%	2,749	2
Argentina	1,110	230	4.8	21%	1,071	1
Australia	1,741	147	11.8	8%	1,600	1

Source: PFC Study September 2007, Alaska data from AOGCC and DNR

Conventional Oil Pool Size 1994 – 2003

Average Commercial Oil Discovery Size (mmboe)

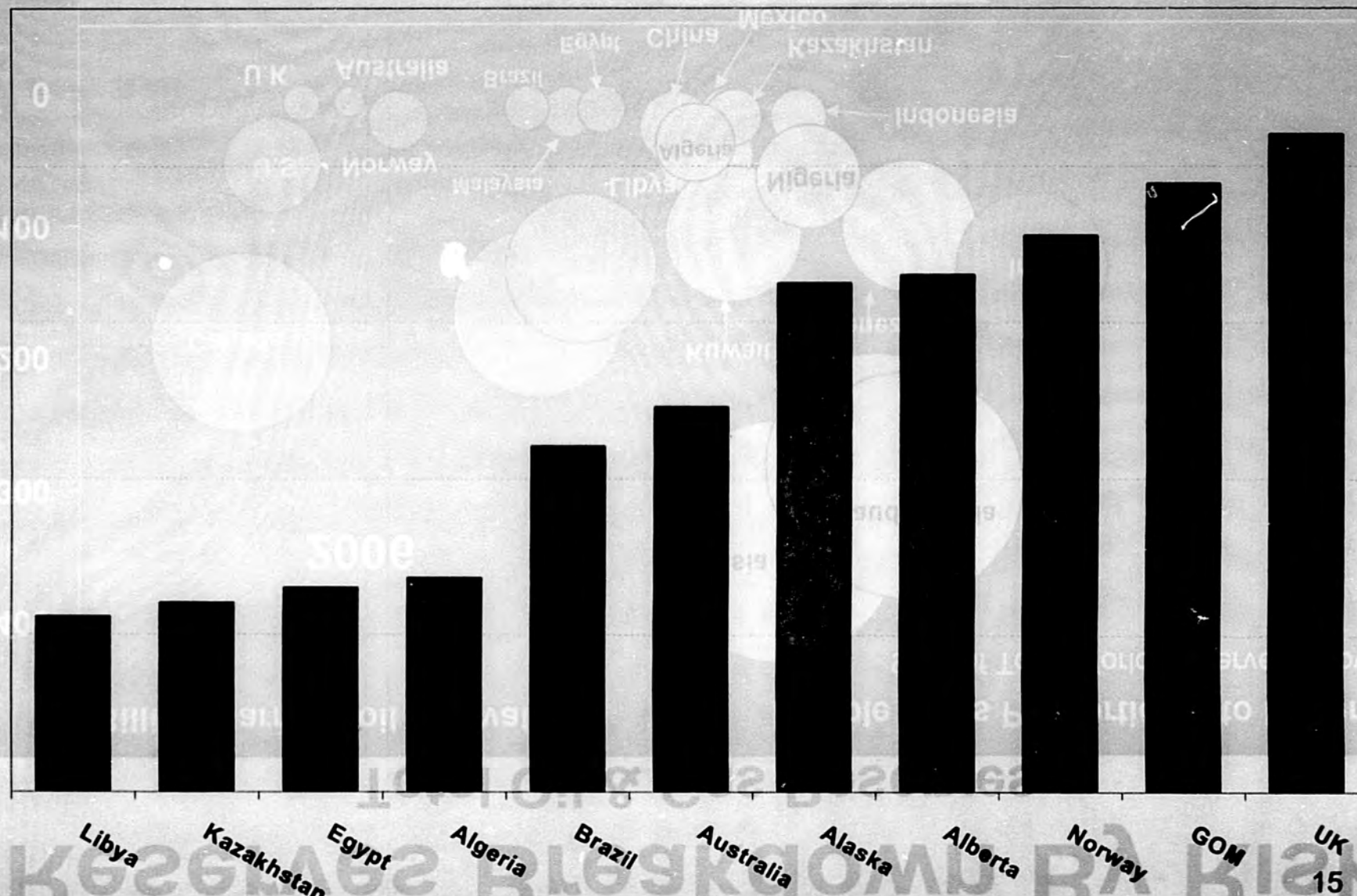


All Exploration & Discoveries since 1990: Reserves are Reserves Added since 1990

Attractiveness of Oil & Gas Reserves

Source: Report of the Alberta Royalty Review Panel, "Our Fair Share", page 50.

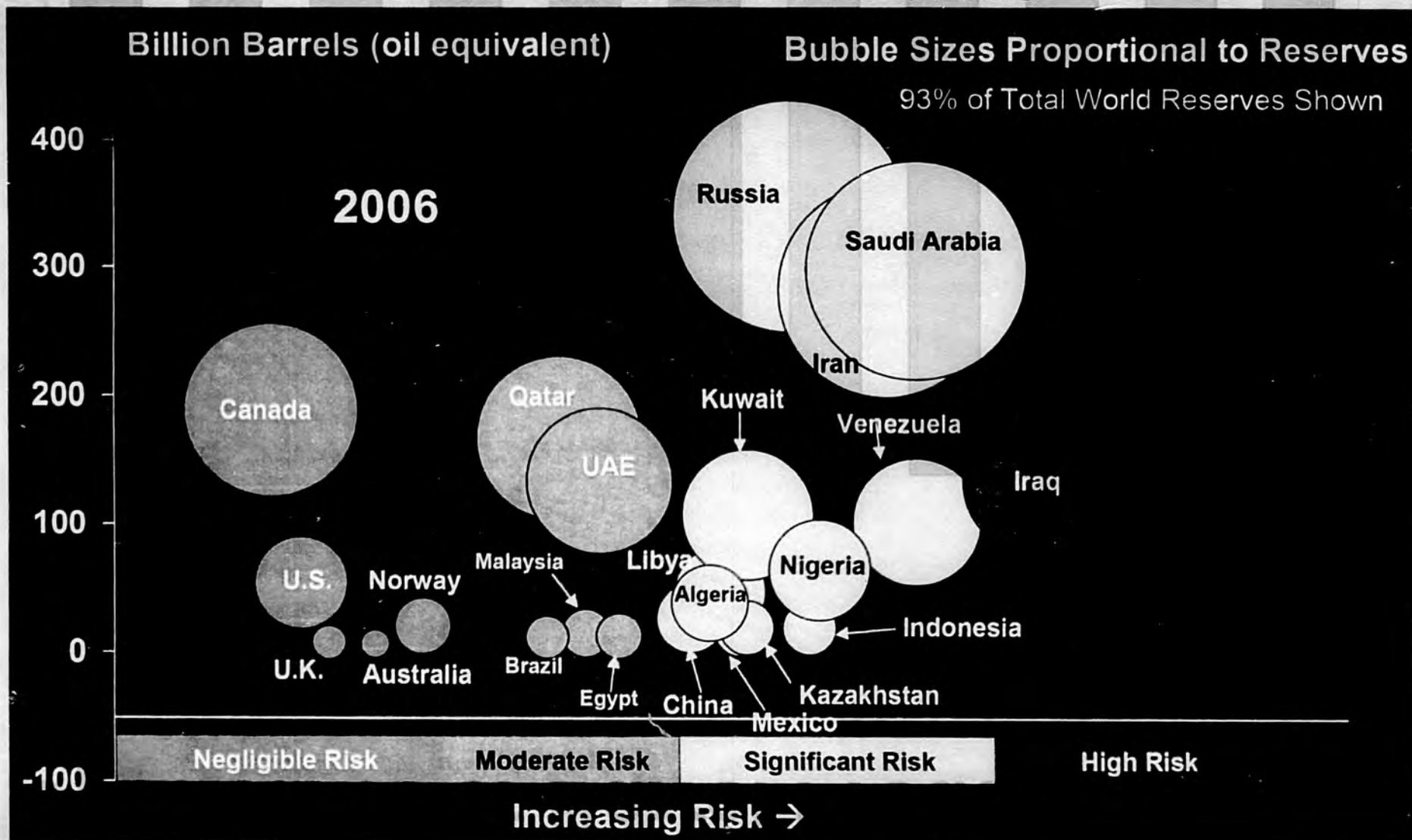
Upstream Per Barrel Production Cost



Dollars per barrel, includes capital and operating expense, most data from public sources.

Reserves Breakdown By Risk

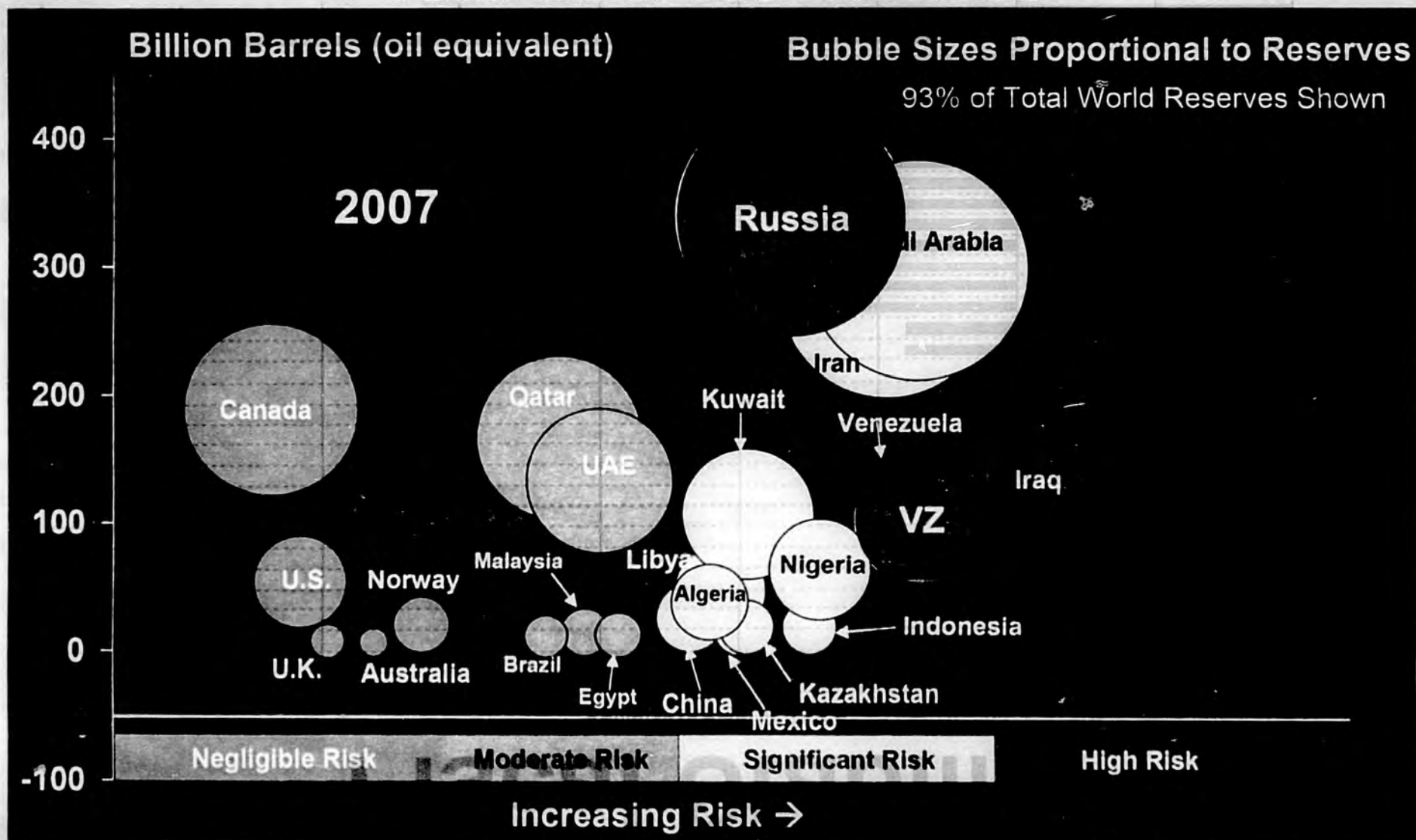
Total Oil & Gas Reserves



Source: ConocoPhillips, Petroleum Equipment Suppliers Association, April 20, 2006

Reserves Breakdown By Risk

Total Oil & Gas Reserves



Source: Initial chart from ConocoPhillips, Petroleum Equipment Suppliers Association, April 20, 2006, adjusted by DOR to reflect 2007 events.