

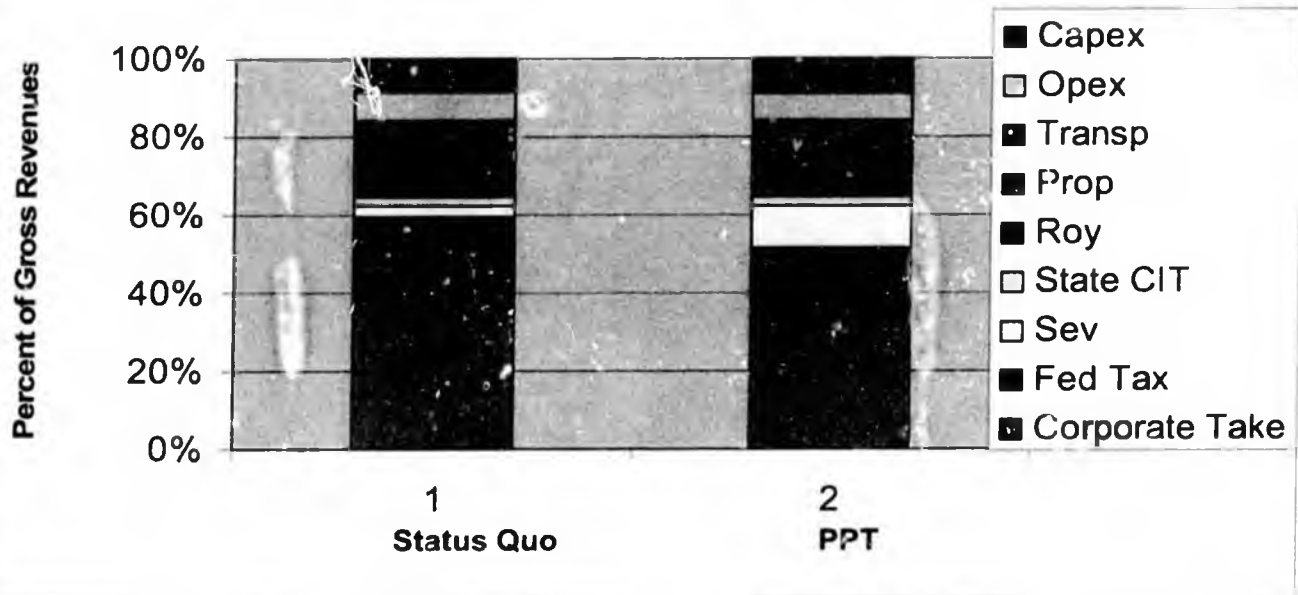
11592 HOUSE RESOURCES

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

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

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

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

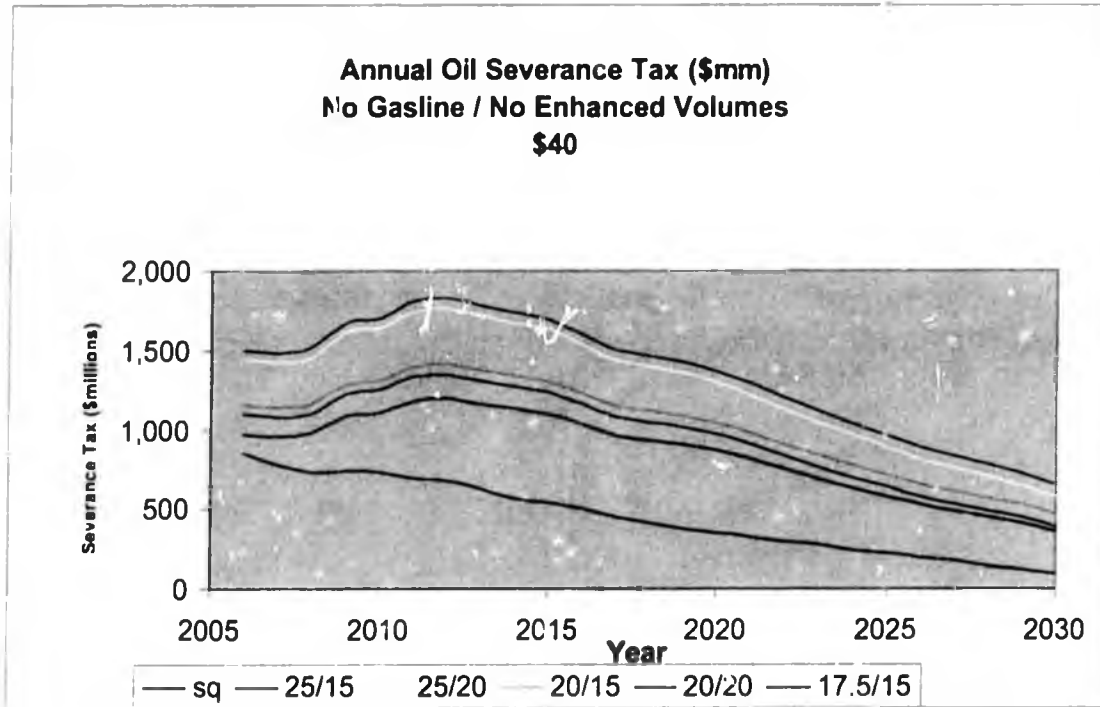


"Corporate take goes from 39% to 33% of gross revenues, or from 51% to 44% of the economic rent."

From: PPTAnalysis020106.ppt Roger Marks

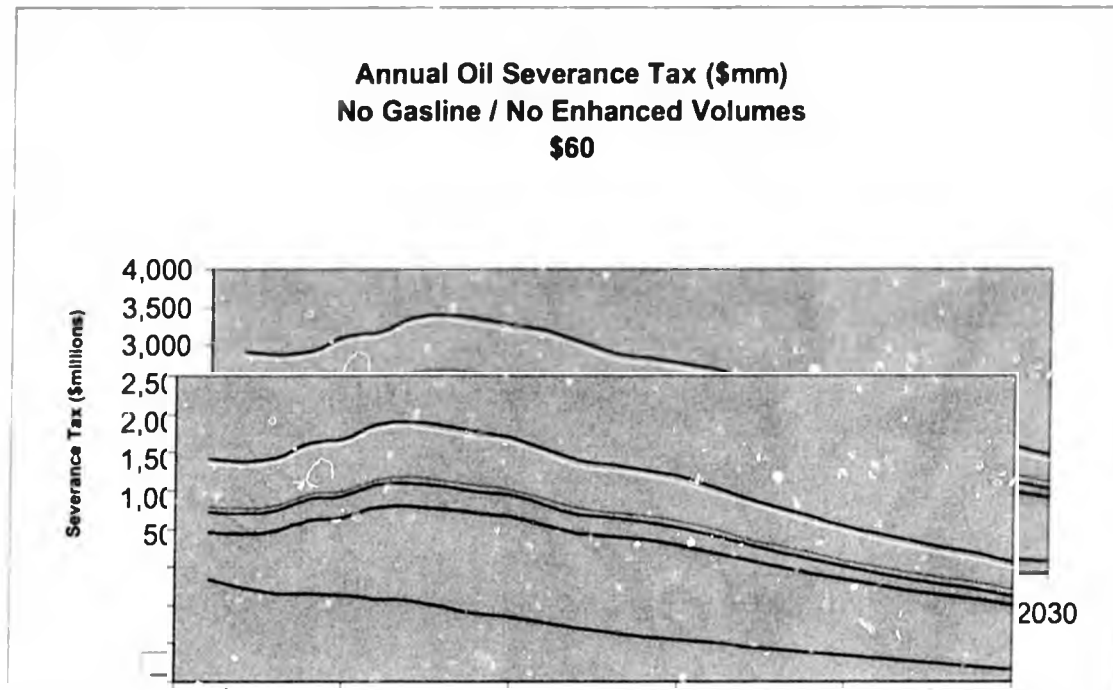
Note: Government Take goes from 49% to 56% an increase of 14%

Annual Oil Severance Tax - \$40 per BBL



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

Annual Oil Severance Tax - \$40 per BBL



| Estimated Near-term ALASKA ANNUAL REVENUES | | |
|--|---|---|
| | \$40/BBL | \$60/BBL |
| Status Quo | \$ 800 MM | \$1,200 MM |
| 25%/20% PPT as Proposed | \$ 1,500 MM | \$2,900 MM |
| Negotiated 20%/20% + Lookback | \$1,200 MM <u>- 167 MM</u> \$1,033 MM | \$2,300 MM <u>- 167 MM</u> \$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")
- Its 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) | 6.5% | 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)

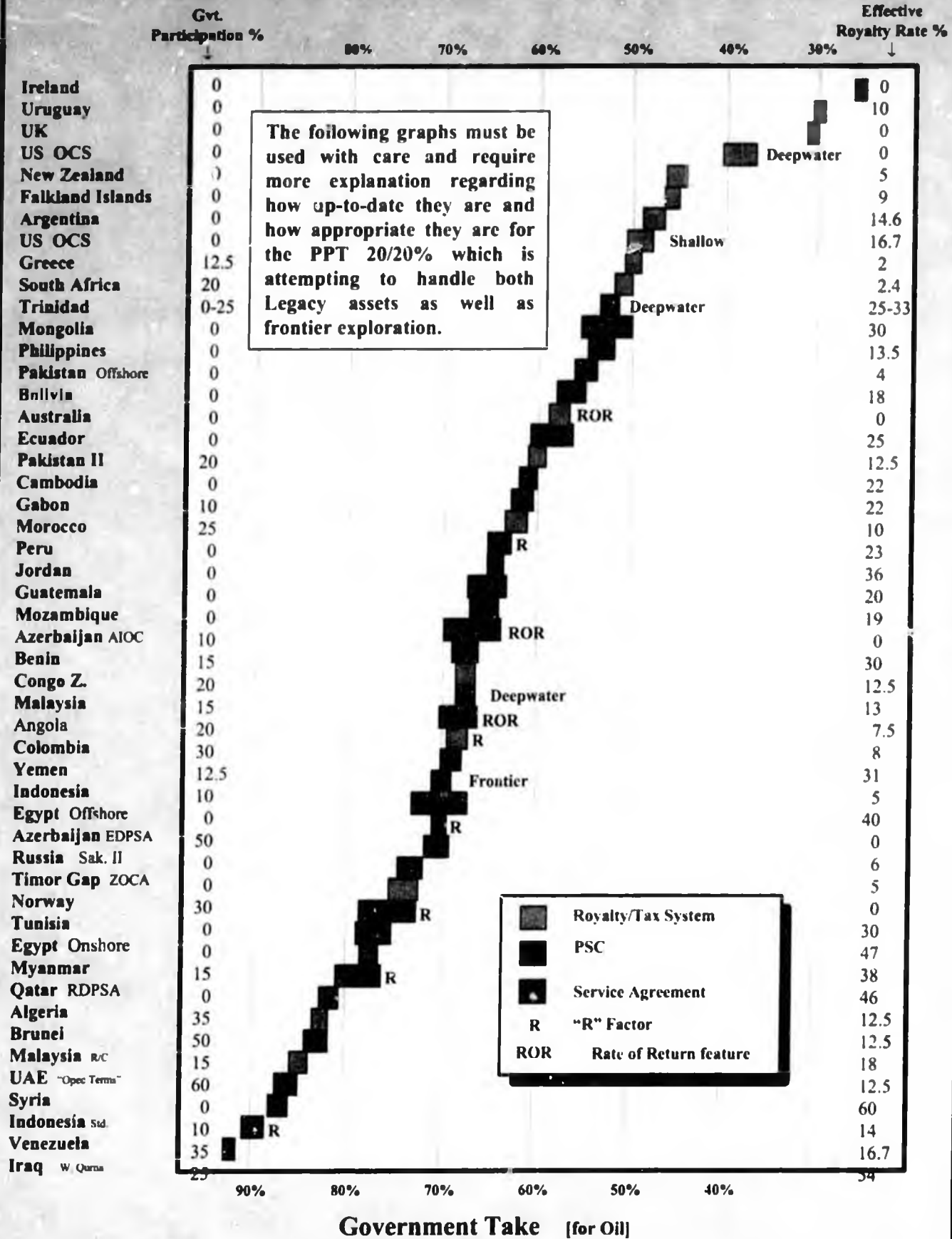
From: Graham Kellas - Petroconsultants

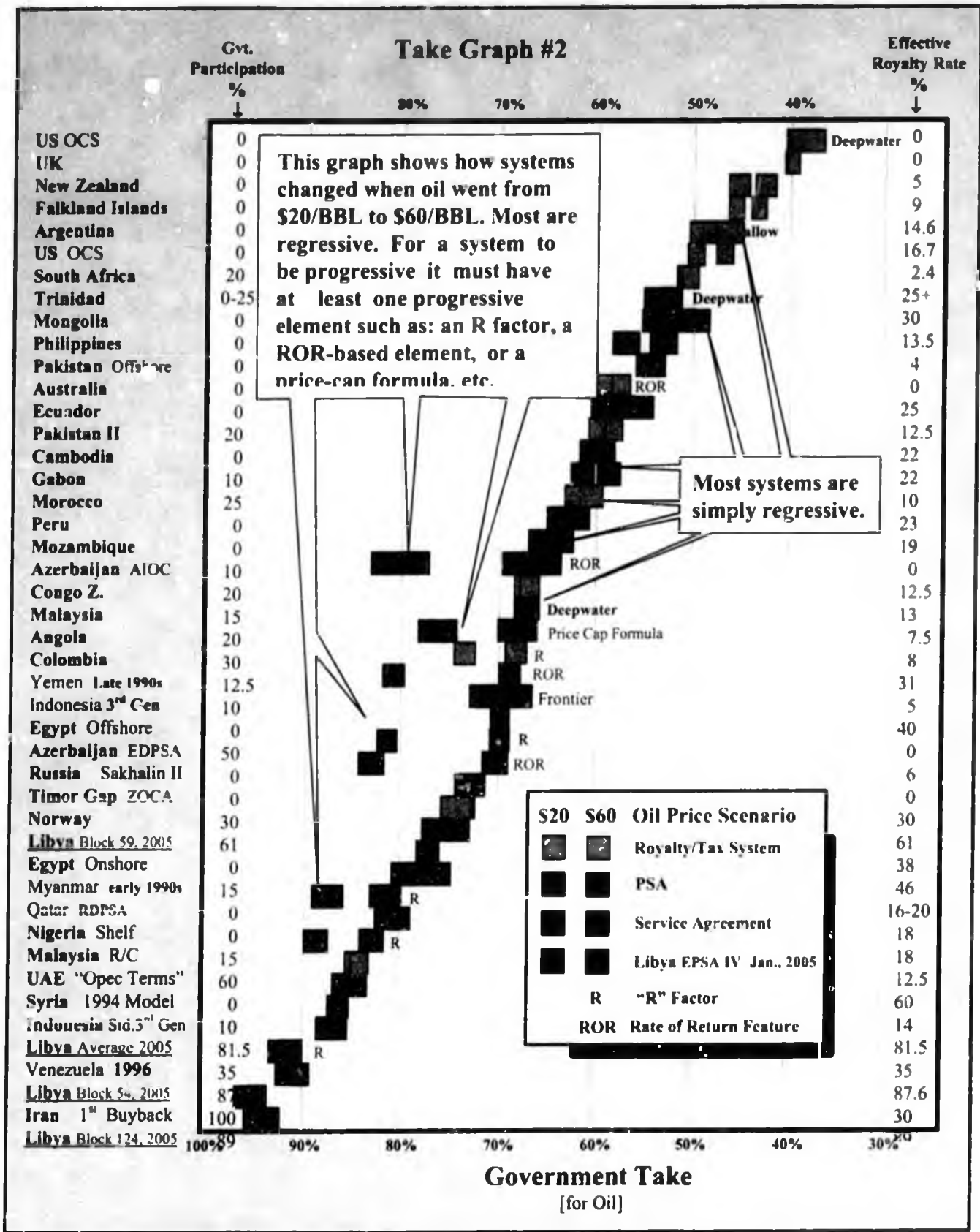
"New Fiscal Incentives encouraging Global Push Into Deepwater Plays"

The American Oil & Gas Reporter - Special Report; April, 1997 (pg 47-50)

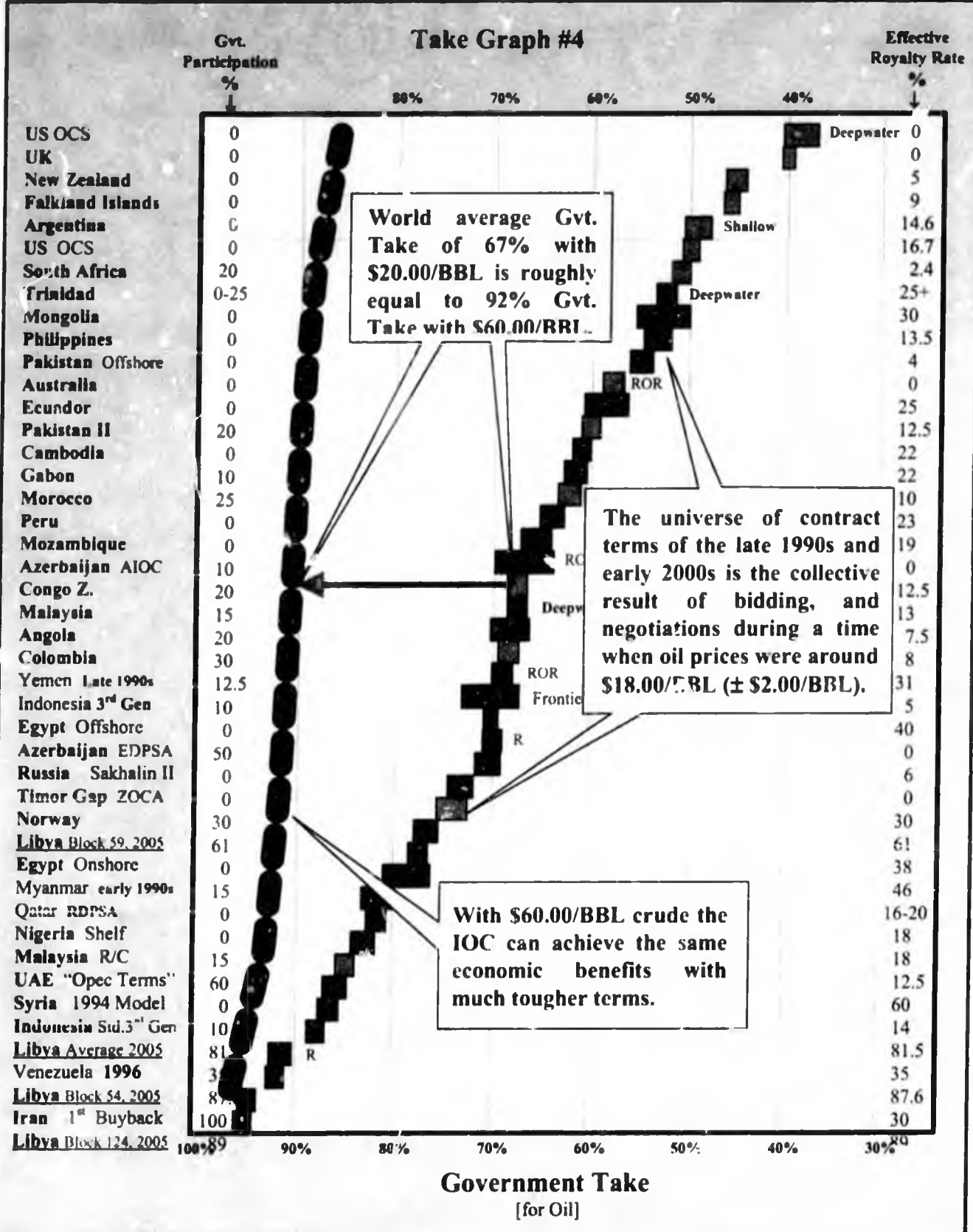
| | Marginal Fields | Economic Fields | Upside Fields |
|---|----------------------------|----------------------------|--------------------------|
| 20 Largest Producing Regimes | 80.0% | 74.6% | 72.7% |
| 30 Significant Producing Regimes | 73.4% | 66.7% | 67.7% |
| 66 Frontier Regimes | 65.3% | 60.5%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

International Petroleum Exploration and Development Contracts #1





Difference between \$20/BBL and \$60/BBL



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

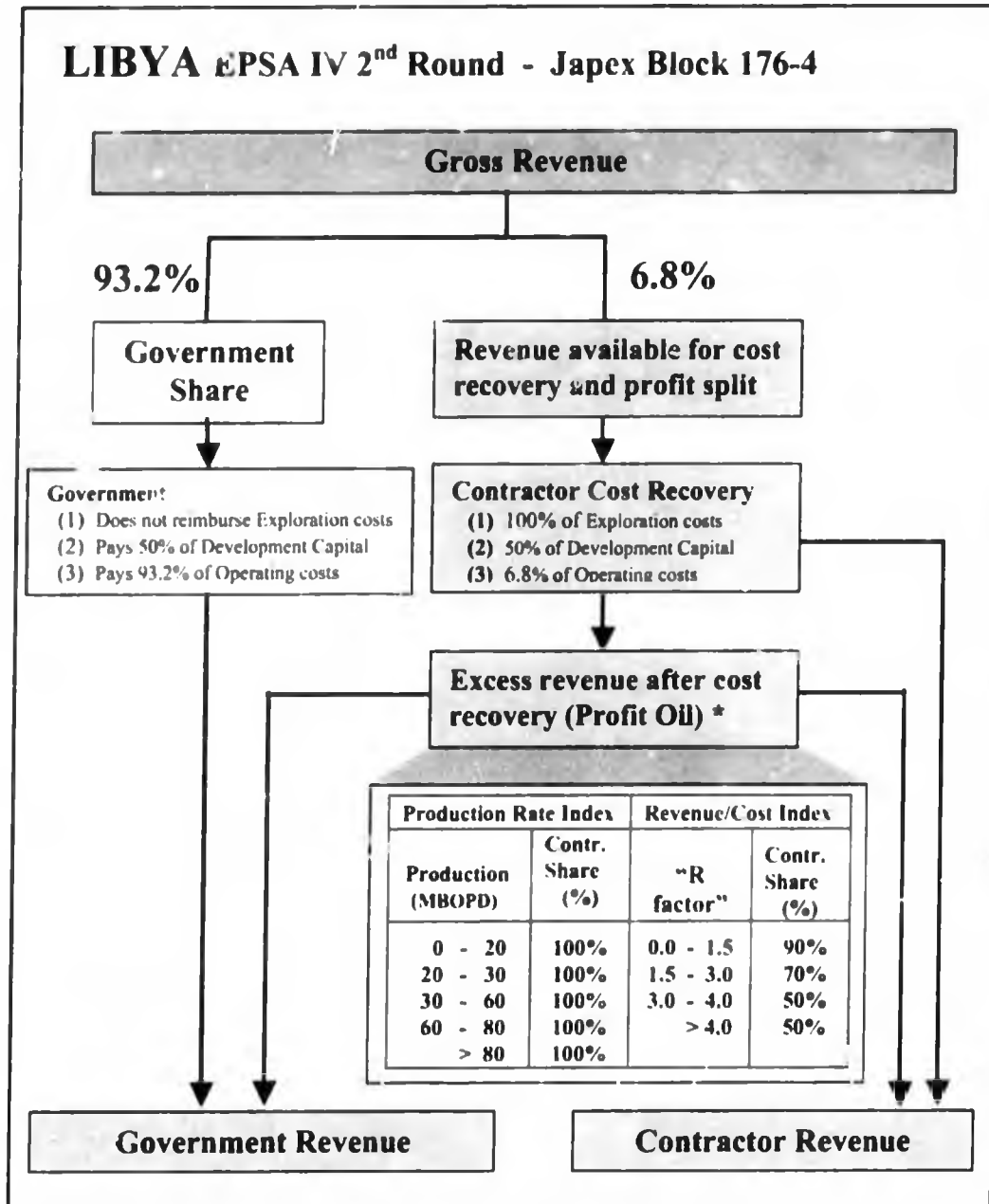
Contract Duration

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

| <u>Province/Block</u> | <u>Exploration Years</u> | <u>Production Years</u> |
|-----------------------|------------------------------|-----------------------------|
| 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 (Max 25) |
| Senegal | 3 + 2 + 2 | 25 + 10 |
| South Africa | 4 + 3 + 3 | as long as is profitable |
| Syria | 3 + 2 + 1 | 20 + 10 |
| Vietnam | 3 + 1 + 1 | 20 (total not to exceed 25) |
| Zambia | 8 | 25 |
| Average/Typical | 3 + 2.5 + 2 (7.5) | 25 |

Lybia's Latest License round - Mechanics



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

The Expected value (EV) formula

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

$$\text{Expected value} = \text{Reward} * \text{SP} - \text{Risk capital} * (1-\text{SP})$$

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.

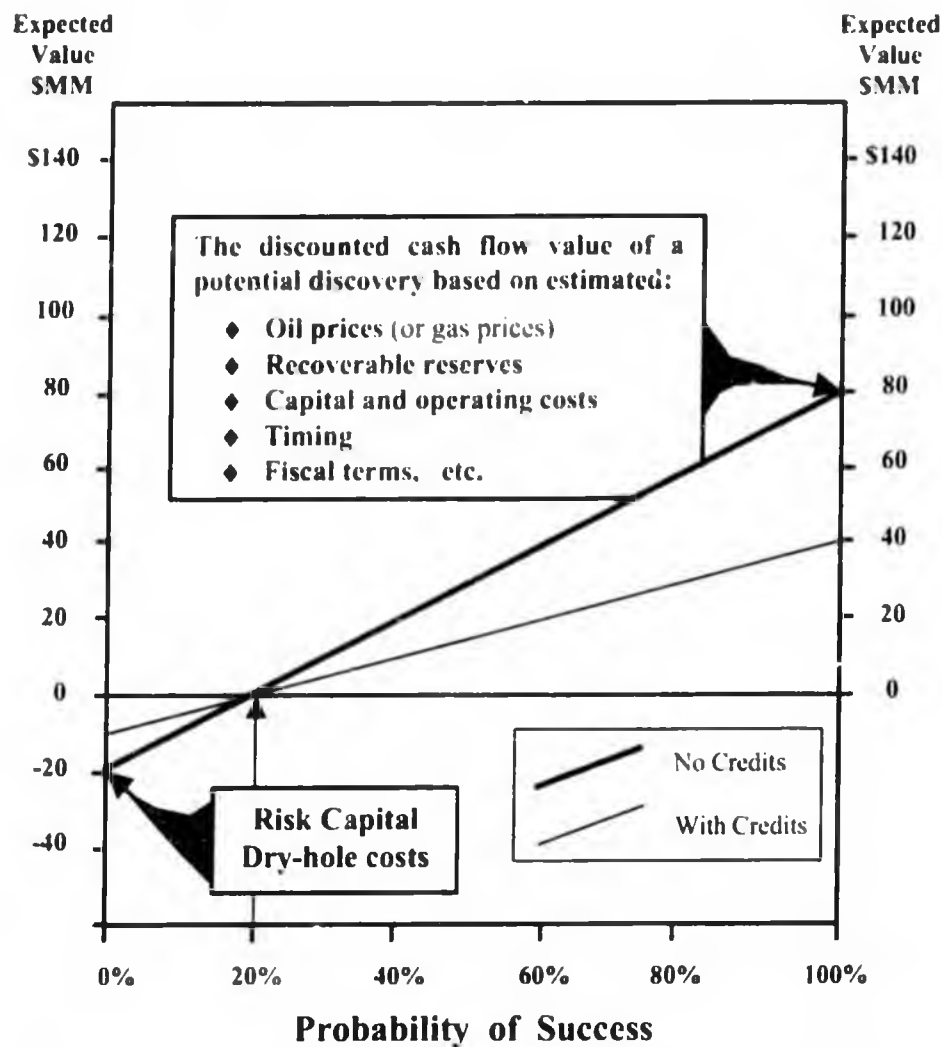
The expected value formula, whether it is used directly or indirectly (gut feel), provides the basis for billions of dollars of exploration investments. It is normally more complex with the common practice in the industry of using multiple outcomes (at least 3) on the "reward side" of the equation.

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)

| |
|---|
| <p>Contrast this with a common and typical “gas clause” found in many countries – in this case Angola.</p> |
|---|

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.

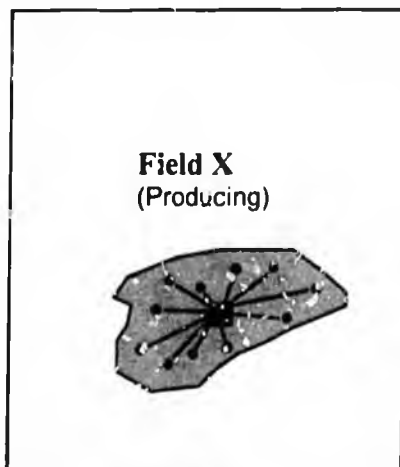
In the early 1980s exploration in the UK sector of the North Sea reached record levels (due to changes resulting from the 1983 budget). This is because the government allowed exploration costs to cross the ringfence as deductions against the 75% PRT tax on older fields. This created a huge exploration 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!

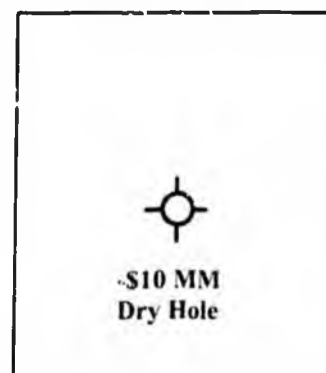
Most countries "ringfence" their acreage – that is, they do not allow consolidation.

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.

Block A – Company X



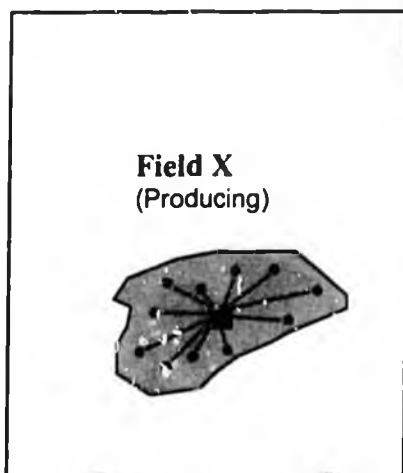
Block B – Company X



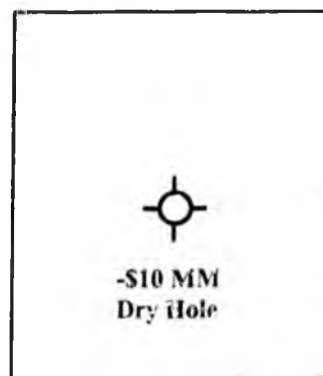
ALASKA PPT 20/20% Approach

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

Block A – Company B



Block B – Company X



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

Severance taxes are a function of field vintage

Severance tax rate on Oil

| | |
|--|------------|
| 1 st 5 years of production | 12.5% |
| After 5 years (for fields in production after 1981) | 15% |
| Fields in production prior to 1981 | 15% |
| There is a minimum tax of | \$0.80/bbl |

Severance tax on Gas

| | |
|------------------------------------|------------|
| Fields in production prior to 1981 | 10% |
| There is a minimum tax of | \$0.64/Mcf |

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

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

ELF Formula for Oil

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

Where PPW = avg production/well/day in a field

TP = avg daily production from a field

Note: ELF was born in 1977, the same year the 800 mile TAP was completed.

If average production/well/day in a field is < 300 bbls, ELF = zero, no severance taxes are due.

300 bbls/day was considered breakeven for a North Slope well at that time. And it appears that the breakeven calculation assumed considerable infrastructure costs associated with new fields and wells.

Voodoo Economics?

Psychologists wear thin on lawmakers

By Doug Robarchek

Knight-Ridder Newspapers

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

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

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

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

Unfortunately, the governor vetoed it.

Distributed by Knight-Ridder Tribune News Wire

Dallas Morning News — 27 January, 1997

Daniel Johnston

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

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

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

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

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

He is author of

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

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

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

March 14, 2005

Notes re: Substantive Changes to HB488 by the House Resources Committee

1. Make tax rate progressive-

Reasoning- The State should make more money at higher prices, and a larger percentage of the whole pie at extremely high prices. The Committee has increased the Governor's 20% tax rate to a progressive system. The 20% number will be in effect until the price of oil (West Texas Intermediate, WTI) reaches \$50/barrel. After \$50/barrel, the tax rate increases by .30% per \$1.00 increase in the oil price (WTI). The rate caps at 50% at about \$150.00/barrel, in case of a global oil shock. This makes the tax rate at \$60.00/barrel 23.5%, and \$70.00/barrel 26.5% and continues to escalate from there.

We feel that this keeps investment opportunity in Alaska very strong, but balances it out by taking advantage of windfalls in high spikes of oil prices.

2. Reduce Transitional Money as deductible allowance- The Governor allowed five years of past investments to be deducted as costs. The rationale behind the transition provision was that investments made for the previous five years directly led to the production of oil that is now being taxed at a higher rate. The Committee feels that this rationale is partly true, but that a full five years of looking back is not appropriate. The cost recovery of the five years of investments has already been enhanced by extremely high oil prices. The Committee has replaced the 100% cost recovery of the previous five years with a

greatly scaled back program. The CS will allow 75% of 2005 expenditures, 50% of 2004 expenditures, and 25% of 2003 expenditures to be deducted as costs. The payback period of six years that was in the original legislation has been increased to seven years. The same caveat of oil prices being at least \$40/barrel (ANS) before cost recovery is allowed remains the same. Additionally, the Committee has determined that the inflation indexing mechanism on the \$40 price shall be in statute, not left up to regulators. This change reduces the amount of deduction allowed by industry from 5 billion to 2 billion and reduces the amount of the credit from approximately \$1 billion to \$300 million. Therefore, instead of the State absorbing \$167 million annually in scheduled credits, the amount will be reduced to approximately \$43 million per year.

3. Exploration enhancement- The SB185 exploration tax credits of 40% will be extended 10 years. The Governor's credit rate of 20% remains intact. The Committee feels that this will significantly enhance explorers and independents. Department of Revenue has testified that exploration investment in new fields represents less than ten percent of all development and exploration investment dollars. The Committee wishes to emphasize exploration. As they do currently, the company will choose between which credit is most beneficial to them.
4. No credit for abandonment costs- The CS contains specific language that abandonment costs will not be eligible for tax credits.

5. Private Royalties- The CS sets private royalty oil severance tax rates at 5%.

6. AOGA technical changes- AOGA worked in conjunction with the Governor's office to suggest several technical changes and clarifications to the bill. Some of these changes are incorporated into the CS.

7. Contingency sur-charges- The CS will leave current statute in place, which makes a 5 cent/barrel sur-charge non-deductible and non-creditable. Currently, of the 5-cent/barrel charge, 2 cent/barrel is deposited into the Response Mitigation Account until the account reaches \$50 million. After this, the 2-cent/barrel charge is suspended. The CS lowers this amount to one cent/barrel. The remaining 3-cent/barrel charge is deposited into Prevention Mitigation Account. The CS increases this to 4 cents/barrel, while dropping the Mitigation money to 1 cent/barrel, leaving the total sur-charge at 5 cents/barrel.

8. Effective date- CS changes the effective date of the bill from 1 July to 1 April, the start of the second calendar quarter. This will result in an almost immediate effective date and will gain the State over 200 million dollars in the current fiscal year.

9. Issues surrounding the \$73 million allowance- The CS eliminates the 73 million annual dollar allowance, which resulted in a \$14.6 million credit. Instead, the Committee implemented an annual direct tax credit, dollar for dollar, for the first \$10 million worth of expenditures. The credit is annual, non-transferable, non salable and not eligible for carry forward. The credit can only be applied to the current year's severance tax. If there is no tax, the credit cannot be claimed. If a company has income but spends less than 10 million dollars, they can only claim credit up to amount that was spent.

10. Tax Credit Repurchase Program- To help protect explorers and new entrants to Alaska, the State will buy up to \$10 million per year per company for credits at 100% of face value. Companies must show that an equivalent amount to the credit is being reinvested for exploration or lease purchases in Alaska.

11. Penalties on underpayment of less than 90% of monthly tax liability- The CS puts in place a 5% penalty for underpayment of the monthly severance tax bill for any amount below the 90% threshold. In addition, interest will be charged on any payment shortfall less than the full liability.

PRESENTATION ON ALASKA PPT

to House Resources Committee
March 13, 2006

Analysis of PPT

Barry Pulliam
Dr. Tony Finizza

Suite 500
661 W 5th Street
Los Angeles, California 90071
213 624 8000

Suite 1172
1215 K Street
Sacramento, California 95814
916 440 2000

Suite 2825
Three Allen Center
333 Clay Street
Houston, Texas 77002
713 228 2700

Suite 21
106 E 6th Street
Austin, Texas 78701
512 478 3711



Econ One Research, Inc.

- An economic research and consulting firm with offices in California (Los Angeles and Sacramento) and Texas (Houston and Austin)
- We provide consulting services in various industries, including petroleum and natural gas, regulated utilities, electricity, telecommunications and computer software
- We have worked for:
 - A number of state governments on energy-related matters, including the States of Alaska, California, Hawaii, Louisiana, New Mexico, New York, and Texas
 - Federal government agencies, including the Department of Justice, the Federal Trade Commission, the Department of the Interior, and the President's Council of Economic Advisors
 - A number of foreign countries and international agencies, including the World Bank, Mexico, Nigeria, Turkey, and Tanzania on matters related to economic development and privatization of state-owned utilities
 - A number of companies in the petroleum and natural gas industries, including BP, Occidental Petroleum, ANR Pipeline, Koch Gateway Pipeline, Sempra Energy, KN Energy Corp., Lyondell-CITGO Refining, Total Petrochemicals U.S.A., Panhandle Eastern Corp., and ONEOK, Inc.



Barry Pulliam

- Senior Economist with Econ One Research, Inc.
- Masters Degree in Economics from the Claremont Graduate School, with 17 years of experience consulting in the petroleum and natural gas industries
- Has consulted with or served as an economic expert for the State of Alaska on a number of occasions, including:
 - Several severance tax matters involving the valuation of crude oil
 - Operation of the TAPS Quality Bank in proceedings before the FERC and Alaska PUC
 - Merger and antitrust investigations
 - Recent arbitration between State and ExxonMobil involving crude oil royalties
- Consulted with the States of California, New Mexico, Texas, and Louisiana on economic issues related to the petroleum industry
- Consulted with federal government agencies, including the Department of the Interior and the Federal Trade Commission
- Co-author of two recent studies prepared for the Alaska Department of Natural Resources related to natural gas markets and royalty valuation issues



Dr. Anthony Finizza

- Economist working in conjunction with Econ One Research, Inc.
- Ph.D. in Economics and Finance from the University of Chicago with over 30 years of experience working in the petroleum industry
- Chief Economist for ARCO from 1975 to 1998
- At ARCO, Dr. Finizza was in charge of petroleum price forecasting for the company's Long Range Planning Process and conducted scenario-planning exercises with senior management responsible for investment decisions
- Consulted with the California Energy Commission, the State of Hawaii, and the International Hydrogen Infrastructure Group (a consortium of private companies and the U.S. Department of Energy) on energy-related matters
- Currently teaches forecasting and modeling at the University of California, Irvine
- Published articles in *Business Economics*, *The Journal of Corporate Renewal*, and *The International Journal of Forecasting*
- Senior Fellow with the U.S. Association for Energy Economics
- Former President of the International Association for Energy Economics



Oil Price Issues

ENE

Conclusions/Observations Regarding Oil Price Forecasts

- Producers are using \$40 as a planning base case with \$30 as a stress price case. Majors may be using a slightly lower price range than independents, but are moving their views up.
 - This range may actually be lower than their best estimate, but is consistent with their “prudent” planning approach
 - This range is consistent with recent observed oil asset purchases
- This range is consistent with publicly available forecasts although the recent EIA AEO 2006 is above this range. (~\$54)
- What really matters is what forecasts are the “risk takers” using?
- Forecasters have been humbled (and will continue to be humbled) by their forecasts

ENE

Oil Price Outlook

- **Factors Suggesting Continued Higher Prices (short-term)**
 - Strong oil demand, especially in China and rest of Asia
 - Growing Gap Between Global Demand and Global Non-OPEC Supply
 - Non-OPEC oil supply cannot keep up with growing world demand permitting increase in OPEC's market power
- **Factors Opposing Higher Oil Prices (long-term)**
 - Conventional oil faces threat from alternative sources of liquids when prices are high
 - Tar Sands: economic at ~\$20-30 oil
 - Coal Liquids: economic above \$30/bbl
 - Shale Oil: economic above \$45-50/bbl
 - Penetration of Alternative Transportation Vehicles
 - Oil's key position in the transportation market will be eroded by Hybrid vehicles, Grid-Connected Hybrid vehicles, Fuel Cell Vehicles
 - A \$10/bbl difference in oil prices is an \$73B additional consumer costs per year

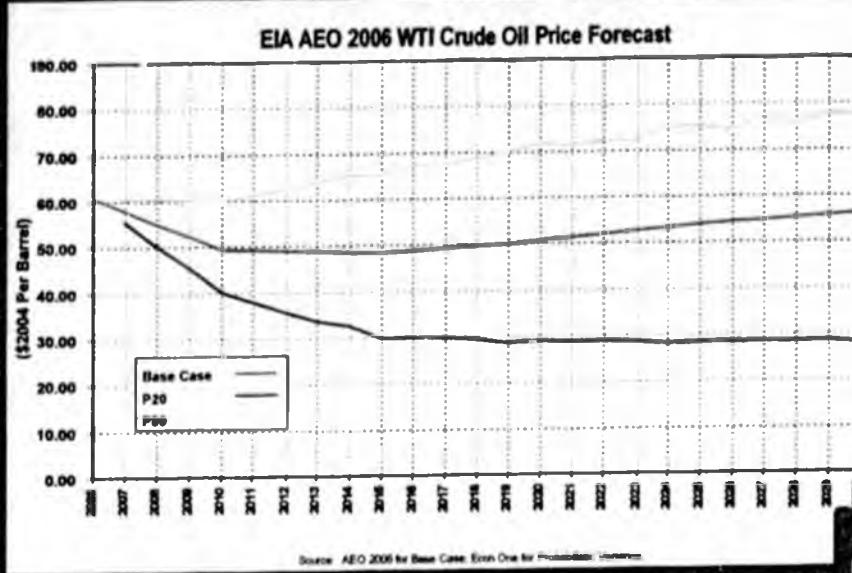
ONE

Oil Price Forecasts

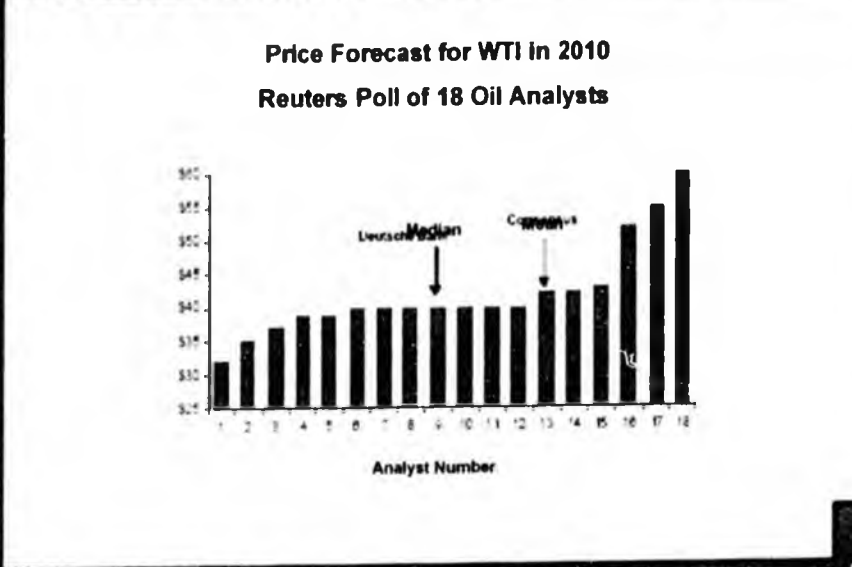
- **EIA's Annual Energy Outlook (AEO) – January 2006**
 - Forecast of oil prices (through 2030, converted to WTI by Econ One)
 - Include Alternative scenarios, probabilistic forecasts developed by Econ One
- **International Energy Agency (Paris) – 2005**
- **Reuters Poll of 18 Oil Analysts for WTI in 2010 (March 2006)**
- **NYMEX Futures market**
 - WTI oil contract traded since early 1980s

ONE

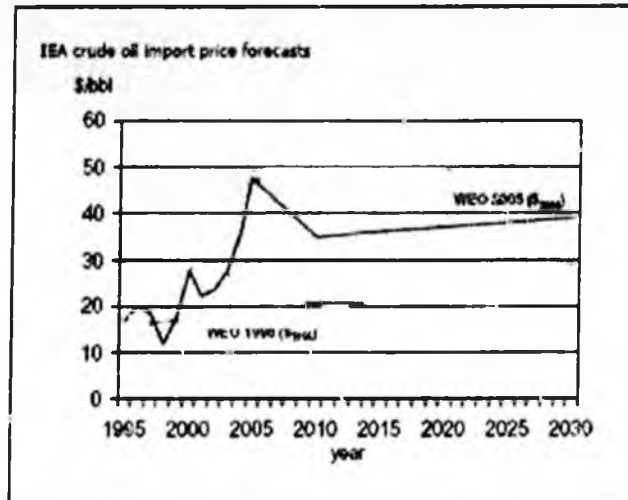
Oil Price Outlook – EIA Annual Energy Outlook 2006



Alternative Oil Price Forecasts – Reuters Poll (March 10, 2006)

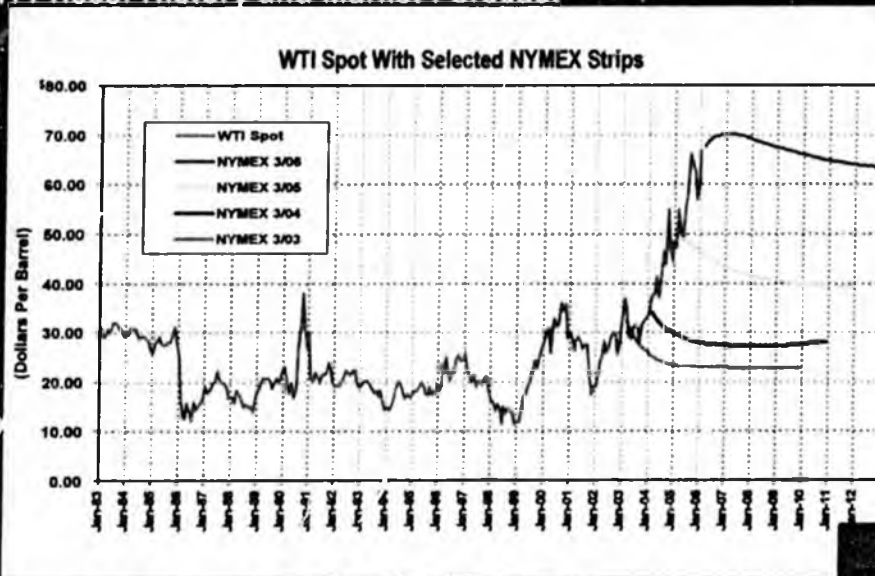


IEA (2005) Oil Price Forecasts



ONE

WTI Prices: History and Market Forecast



ONE

Producer View of Future Oil Prices

- Producers have been "burned" by forecasts of high oil prices in the past
- Producers will test their projects against a price path that is below their "Most Likely" view
 - They use the "official price view" as a speed limit to signal caution
 - By "high-grading," they will have a suite of projects resilient to price risk
 - Their price view lags the current market price by as much as 5-7 years as prices rise, and by 2 years as prices fall.
 - Current view might be: \$35-40/barrel
 - Producers will also "stress" test their projects at \$30/barrel
- The consequences of error are not symmetrical
 - If a producer underestimates the future path of prices, they will not undertake high risk projects and their returns will skyrocket (the current situation relative to a few years ago)
 - If a producer overestimates the future path of prices, they will be scorned by Wall Street and investors (their position in the late 1990s)
 - They will "miss" opportunities, but these misses will not be fully "penalized" by the market

Imputed Oil Company Price Views

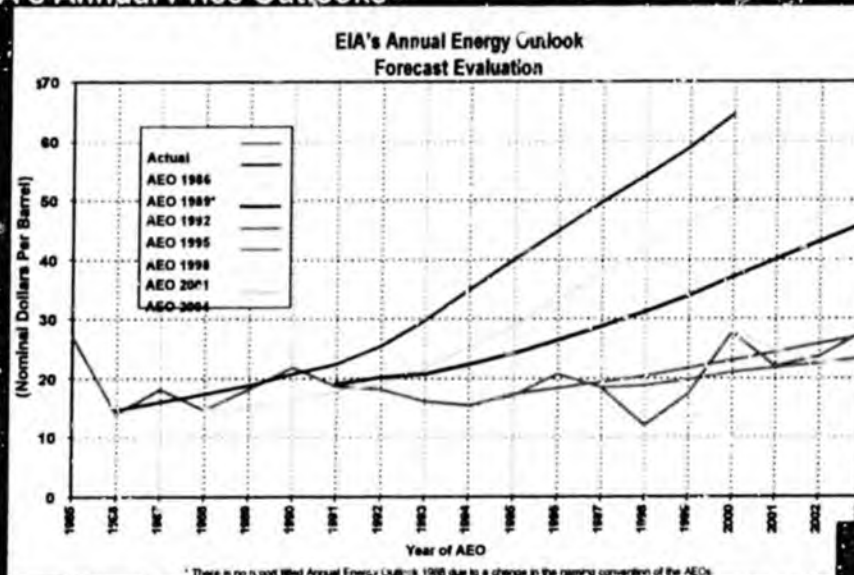
- Marubeni acquisition (2/23/06) of Pioneer GOM assets: ~ \$40
- Norsk Hydro acquisition (9/19/05) of Spinnaker Exploration: ~\$35
- Statoil acquisition (4/28/05) of EnCana's Deepwater GOM: ~ \$30

Some Examples of Humbling Oil Price Forecasting

- Energy Administration Administration (US DOE)
- A Private Oil Company
- Polls of "experts" – Society of Petroleum Evaluation Engineers

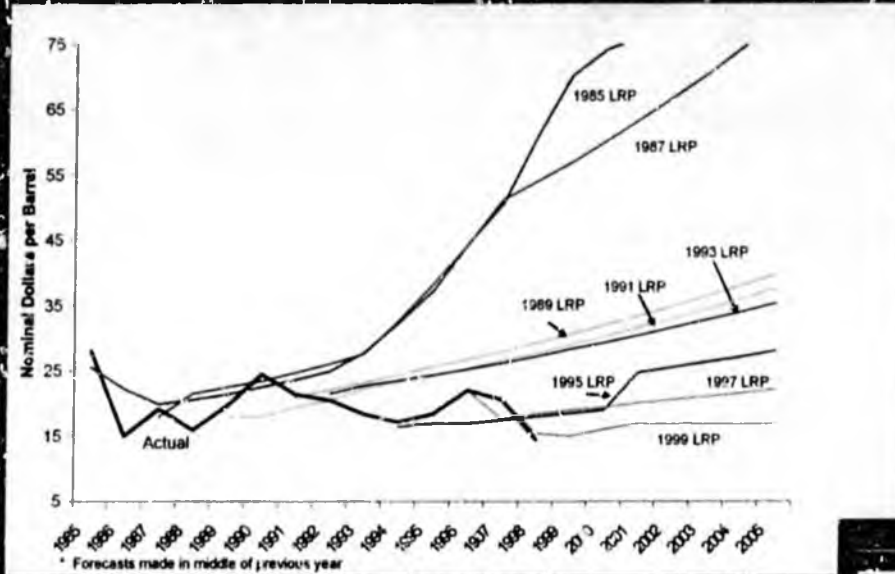
ENE

EIA's Annual Price Outlooks

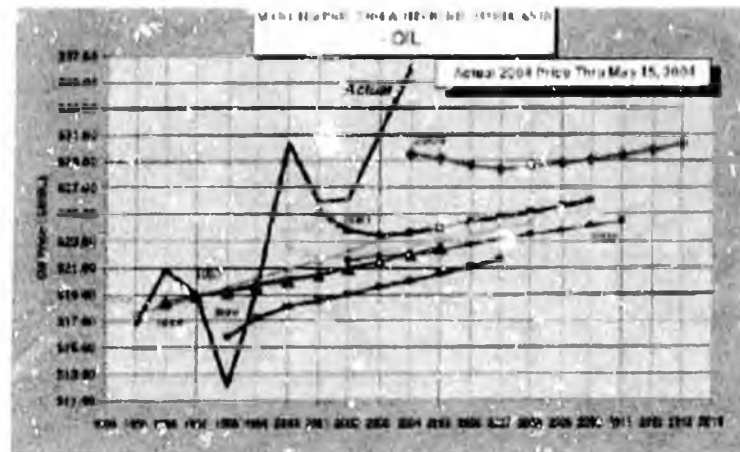


ENE

Outlooks From An Oil Company



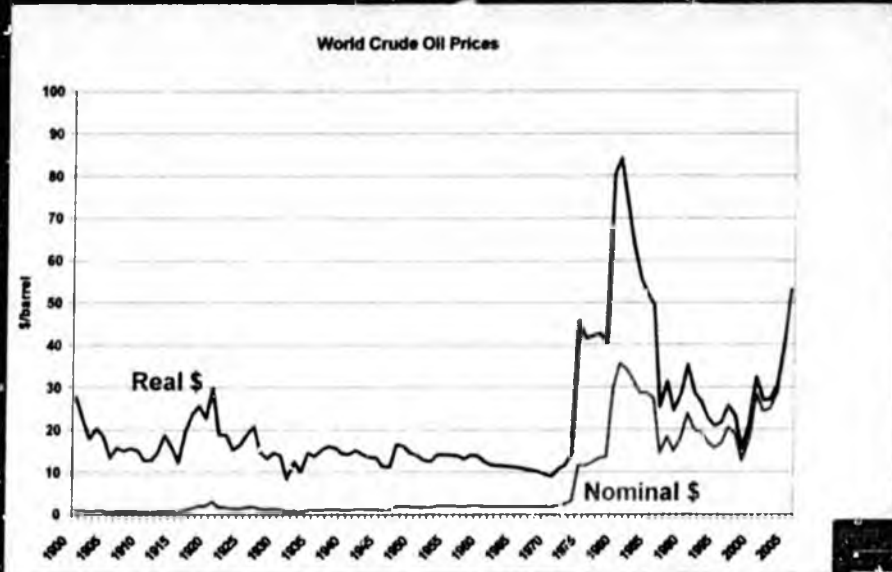
SPEE Annual Delphi Poll



Source: Society of Petroleum Evaluation Engineers (SPEE)



Historical Crude Oil Prices



Investment Decision-Making by Oil and Gas Companies

Financial Criteria
Net Present Value (NPV)

- Present value of future cash flows including capital investment
- A project with a positive NPV is a candidate for acceptance

ONE

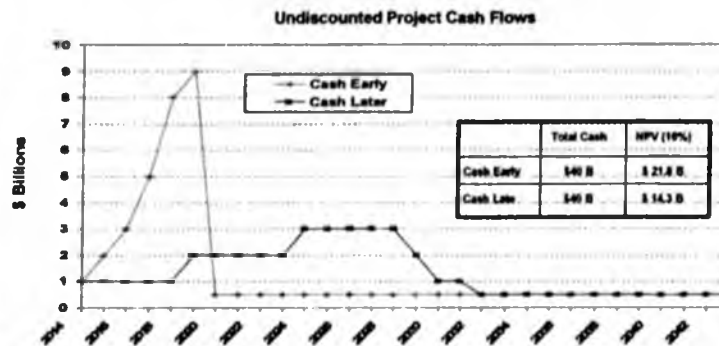
Financial Criteria
Internal Rate of Return (IRR)

- The discount rate at which the NPV of a project equals zero.
- All projects with an IRR greater than the risk-adjusted cost of capital should be accepted when there are no capital budget restraints. Choose higher IRR projects when there are capital budget restraints. Although the "market" would fund projects with IRR above cost of capital, project can be postponed.
- IRR of 12-15% currently indicates threshold rate of return without significant risk factors.

ONE

Financial Criteria Cash (Undiscounted)

- Not used as key investment metric
- Often used to view size of project in presentations to sovereign governments
- Antithetical to discounted cash flow analysis
 - Suffers from failure to reward cash early
 - E.g. Cash flows below are equivalent, but not in discounted terms



ONE

Economics of New Fields

ONE

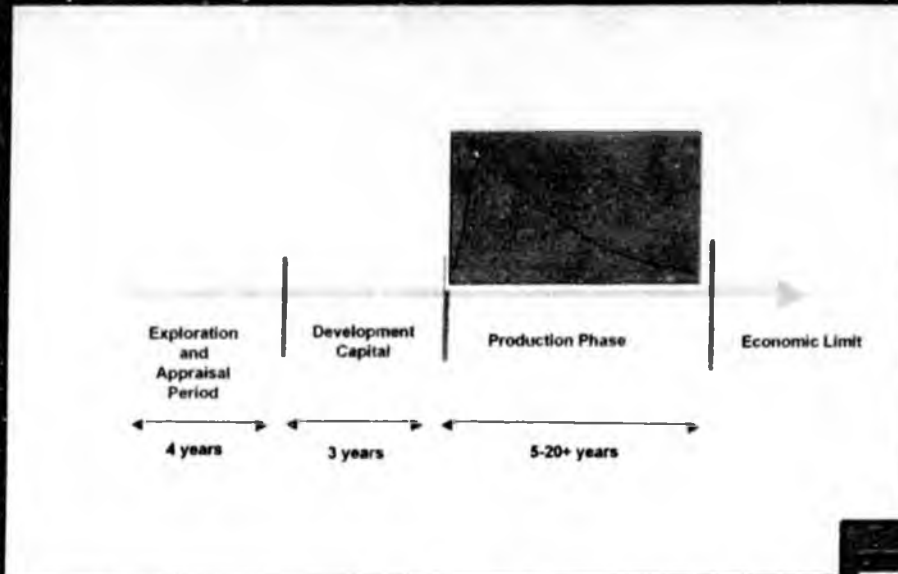
Prudhoe Bay Discovery Well - 1967



Conclusions/Observations Regarding Exploration Impacts

- Without ANWR opening, expectation of large oil discoveries are unlikely, due to the Field Size Distribution of remaining economic reserves
- At low prices, 25/20 helps explorer more than 20/20
- Incentives are required at low prices (say, \$73 M, although alternative approaches could work as well)
- At low prices, 20/20 and 25/20 preferred over SQ, in order to incent exploration
- Under either a 20/20 or 25/20 program, remaining reserves are economic, except for low prices (<\$30?)

Stylized Lifecycle of New Field



Comparison of Reserves – Central North Slope vs. ANWR

Undiscovered Technically Recoverable Oil Reserves

| | Central North Slope | ANWR |
|---|---------------------|------|
| Mean Estimate of Reserves (Billions of barrels) | 4.0 | 10.4 |
| Amount in Fields Over 1 B Barrels | 0% | 22% |
| Amount in Fields Over 500 M Barrels | 2% | 43% |
| Amount in Fields Smaller than 64 M Barrels | 51% | 1% |

Note: Not all these reserves are economic

Source: USGS

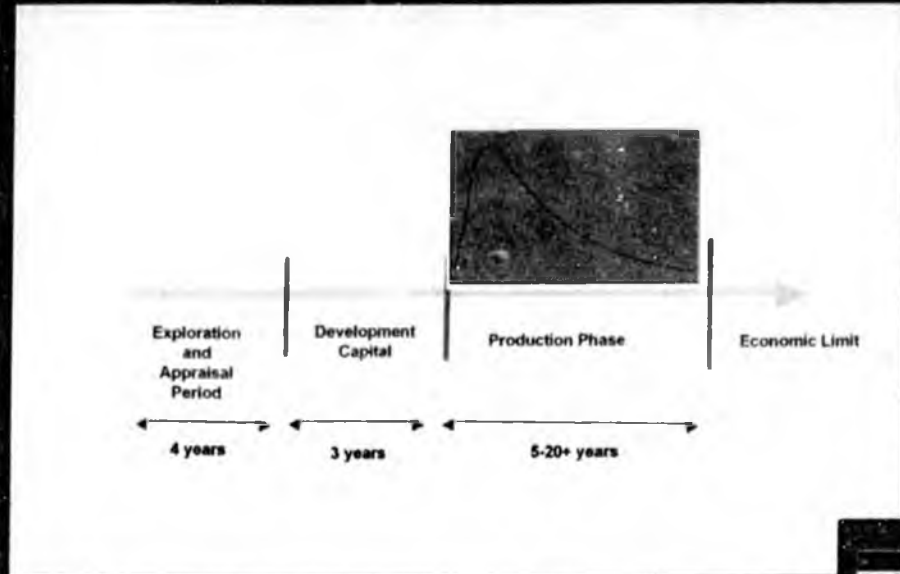
CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION



Central Microfilm Services
Department of Education & Early Development
State of Alaska

Stylized Lifecycle of New Field



Comparison of Reserves – Central North Slope vs. ANWR

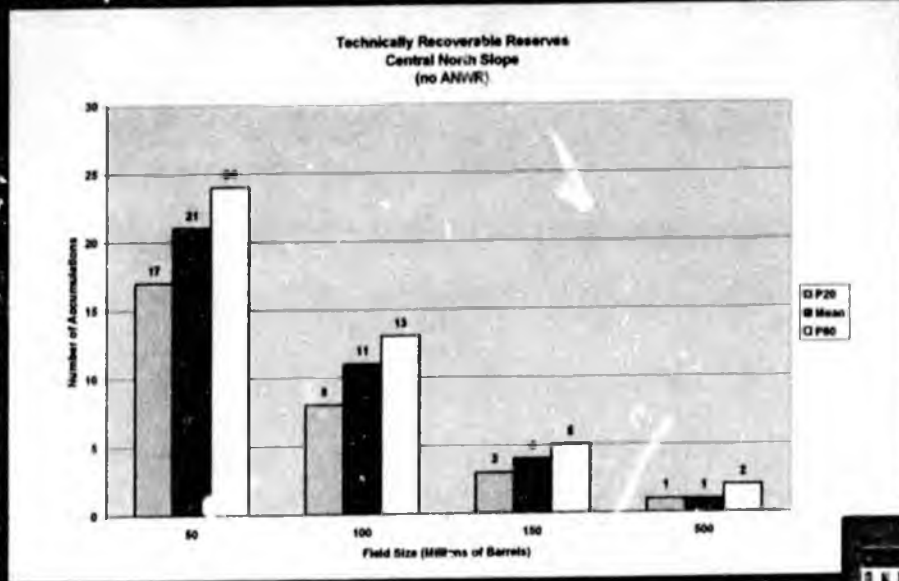
Undiscovered Technically Recoverable Oil Reserves

| | Central North Slope | ANWR |
|---|---------------------|------|
| Best Estimate of Reserves (Billions of barrels) | 4.0 | 10.4 |
| Amount in Fields Over 1 B Barrels | 0% | 22% |
| Amount in Fields Over 500 M Barrels | 2% | 43% |
| Amount in Fields Smaller than 64 M Barrels | 51% | 1% |

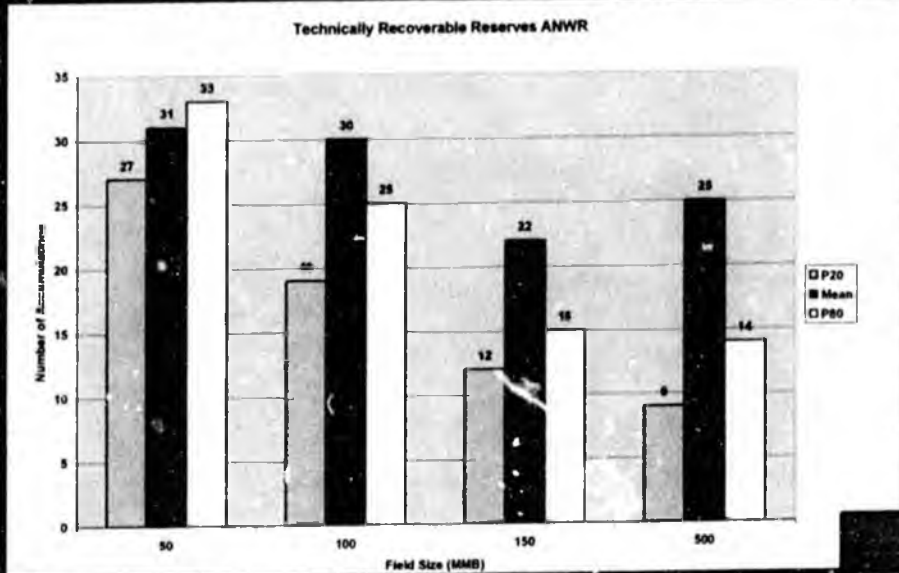
Note: Not all these reserves are economic

Source: USGS

Size Distribution of Undiscovered Fields in Central North Slope

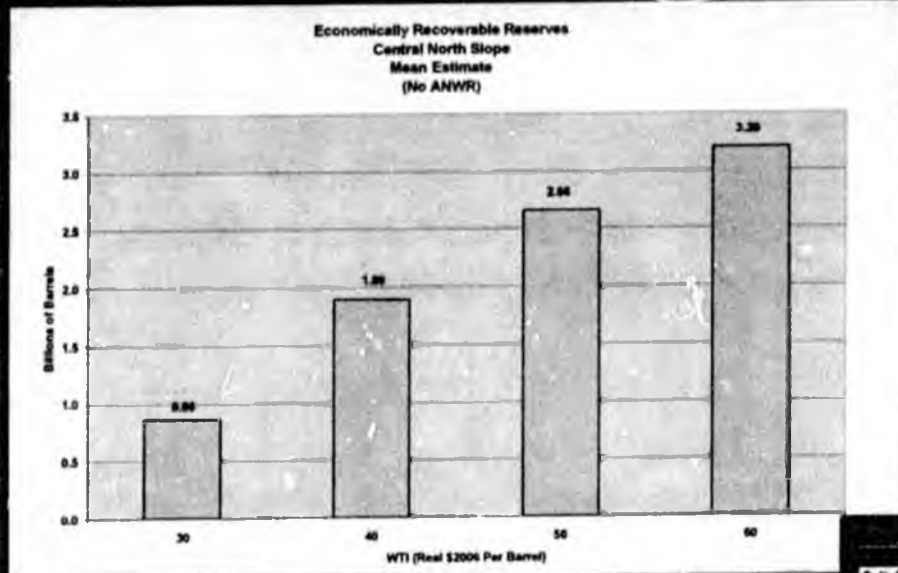


Size Distribution of Undiscovered Fields - ANWR

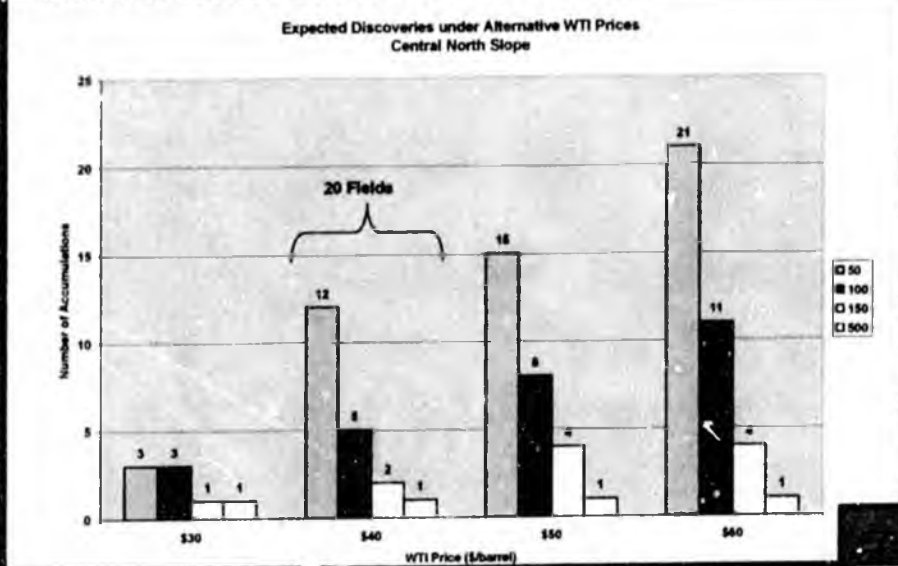


40 Billion Barrels of Technically Recoverable Oil Reserves in ANWR

Economic Oil Reserves in Central North Slope Alaska At Alternative Prices



Expected Discoveries Under Alternative Prices



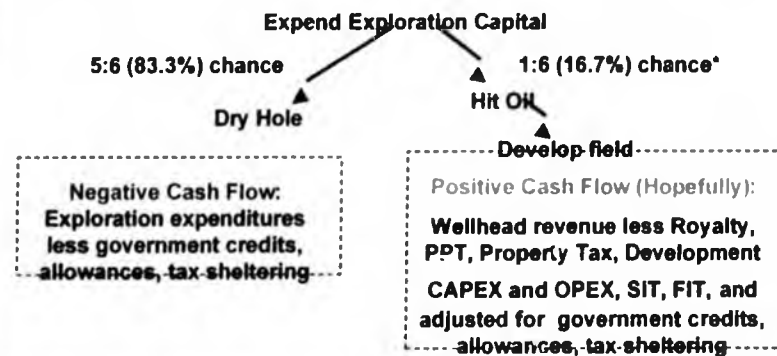
Likely Distribution of New Field Discoveries

| Size of Field | Percent |
|---------------|---------|
| 50 MMB | 60% |
| 100 MMB | 25% |
| 150 MMB | 10% |
| 500 MMB | 5% |

ONE

How An Explorer Will Look At The Exploration Proposition

- Calculate the Net Present Value of all outcomes, weighted by the expectation of the outcome
- $EMV = NPV(\text{a successful development project}) \times (\text{Chance of hitting oil}) - NPV(\text{cash flow from undertaking exploration})$



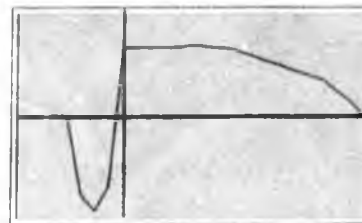
ONE

Schematic of Cash Flows For This Example

Cash Flow From
Exploration
100% of Time



Cash Flow From
Development
and Production
16.7% of Time



ONE

Avoiding Gambler's Ruin

- Say the chance of drilling a successful well is 1-in-6, or .167
- An explorer will want to mitigate the risk of failure by drilling more wells. (Possibly shared.)
- The chance of failure with one well is .833 (=1-.167). The chance of failure with a 6 well program is .334 (=0.833⁶)
- An explorer can drill six wells with an expected number of successful wells = 1.0

| No. of Successes | Chance | Expected Value |
|---------------------|--------|-------------------|
| 0 | .3341 | 0 |
| 1 | .4019 | .4019 |
| 2 | .2015 | .4030 |
| 3 | .0538 | .1614 |
| 4 | .0081 | .0324 |
| 5 | .0007 | .0033 |
| 6 | .0001 | .0078 |
| Total | | 1.000 |

ONE

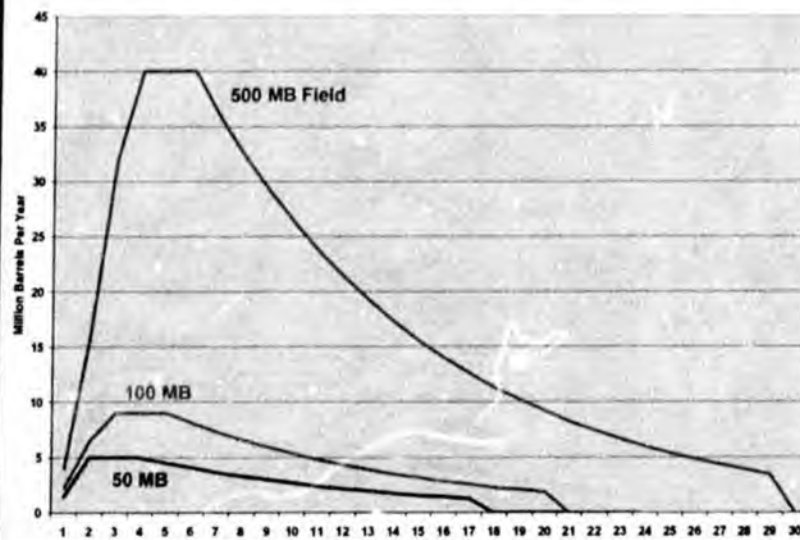
Illustration of A Failed Exploration Program - 1 Well

A One Well Dry Hole Program at \$20 Million

| | 20/20 | 25/20 | SQ |
|---------------------------------|--------------|--------------|--------------|
| Year | | | |
| 1 | -2.4 | -2.3 | -3.1 |
| 2 | -2.3 | -2.2 | -3.1 |
| 3 | -2.3 | -2.2 | -3.2 |
| 4 | -7.8 | -7.4 | -10.3 |
| Total Producer Cash Flow | -14.8 | -14.2 | -19.8 |
| Producer NCF NPV10 | -11.1 | -10.7 | -14.9 |

ONE

Oil Production Profiles



ONE

**Economics of an 6-Well Exploration Program
50 MM Field (High Cost, Low Productivity)**

Without \$73 M Allowance

| Price (Real \$2006) | Explorer NCF NPV10 | | |
|---------------------|----------------------------|-------|-------|
| | 20/20 | 25/20 | SQ |
| \$ 30 | -37.0 | -35.7 | -79.2 |
| \$ 40 | 44.9 | 41.1 | 23.1 |
| \$ 50 | 120.9 | 110.5 | 125.5 |
| | State Revenues (\$M) NPV10 | | |
| \$ 30 | 0.0 | -2.1 | 69.0 |
| \$ 40 | 64.8 | 71.1 | 100.4 |
| \$ 50 | 139.2 | 156.2 | 131.8 |



**Economics of an 6-Well Exploration Program
50 MM Field (High Cost, Low Productivity)**

With \$73 M Allowance

| Price (Real \$2006) | Explorer NCF NPV10 | | |
|---------------------|----------------------------|-------|-------|
| | 20/20 | 25/20 | SQ |
| \$ 30 | 43.2 | 4.0 | 79.2 |
| \$ 40 | 79.2 | 32.9 | 33.1 |
| \$ 50 | 159.9 | 157.0 | 125.5 |
| | State Revenues (\$M) NPV10 | | |
| \$ 30 | 39.2 | 39.6 | 69.0 |
| \$ 40 | 19.3 | 2.0 | 100.4 |
| \$ 50 | 77.2 | 79.9 | 131.8 |



Economics of an 6-Well Exploration Program

Without \$73 M Allowance

| Price (Real \$2006) | Explorer NCF NPV10 | | |
|---------------------|----------------------------|-------|-------|
| | 20/20 | 25/20 | SQ |
| \$ 30 | | | -34.9 |
| \$ 40 | | | 148.3 |
| \$ 50 | | | 331.6 |
| | Explorer IRR | | |
| \$ 30 | | | 9.9 |
| \$ 40 | | | 14.9 |
| \$ 50 | | | 21.1 |
| | State Revenues (\$M) NPV10 | | |
| \$ 30 | | | 139.2 |
| \$ 40 | | | 200.6 |
| \$ 50 | | | 281.9 |

ONE

Economics of an 6-Well Exploration Program

Without \$73 M Allowance

| Price (Real \$2006) | Explorer NCF NPV10 | | |
|---------------------|----------------------------|-------|-------|
| | 20/20 | 25/20 | SQ |
| \$ 30 | 5.4 | 3.3 | 34.9 |
| \$ 40 | 140.7 | 138.9 | 148.3 |
| \$ 50 | 284.1 | 261.7 | 331.6 |
| | Explorer IRR | | |
| \$ 30 | 10.3 | 10.2 | 9.9 |
| \$ 40 | 17.4 | 16.9 | 14.9 |
| \$ 50 | 22.8 | 22.5 | 21.1 |
| | State Revenues (\$M) NPV10 | | |
| \$ 30 | 54.2 | 54.1 | 139.2 |
| \$ 40 | 165.7 | 182.4 | 200.6 |
| \$ 50 | 286.9 | 277.5 | 281.9 |

ONE

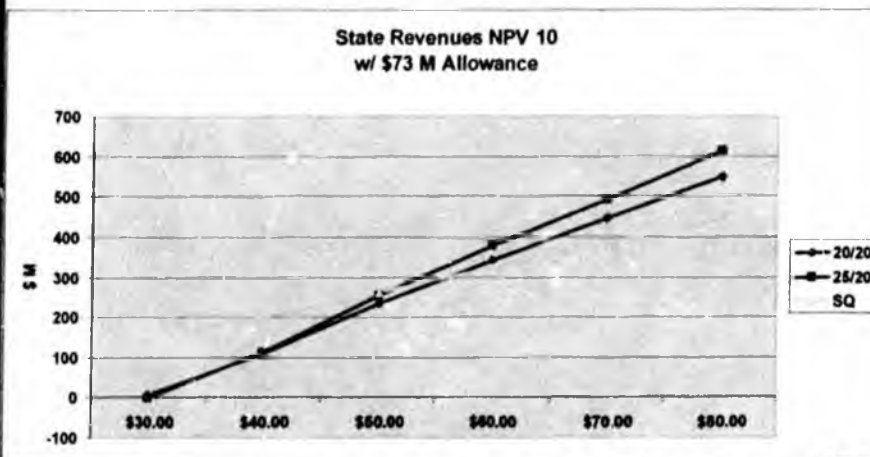
Economics of an 6-Well Exploration Program

With \$73 M Allowance

| Price (Real \$2006) | Explorer NCF NPV10 | | |
|---------------------|----------------------------|-------|-------|
| | 20/20 | 25/20 | SQ |
| \$ 30 | 32.6 | 37.7 | -34.9 |
| \$ 40 | 184.5 | 182.4 | 148.3 |
| \$ 50 | 323.5 | 311.0 | 331.6 |
| | Explorer IRR | | |
| \$ 30 | 11.7 | 12.0 | 9.9 |
| \$ 40 | 18.5 | 18.7 | 14.9 |
| \$ 50 | 23.9 | 24.0 | 21.1 |
| | State Revenues (\$M) NPV10 | | |
| \$ 30 | 6.2 | -2.2 | 139.2 |
| \$ 40 | 108.9 | 112.3 | 200.6 |
| \$ 50 | 232.6 | 253.0 | 261.9 |

INE

State Revenues (NPV10) From Example Exploration Program



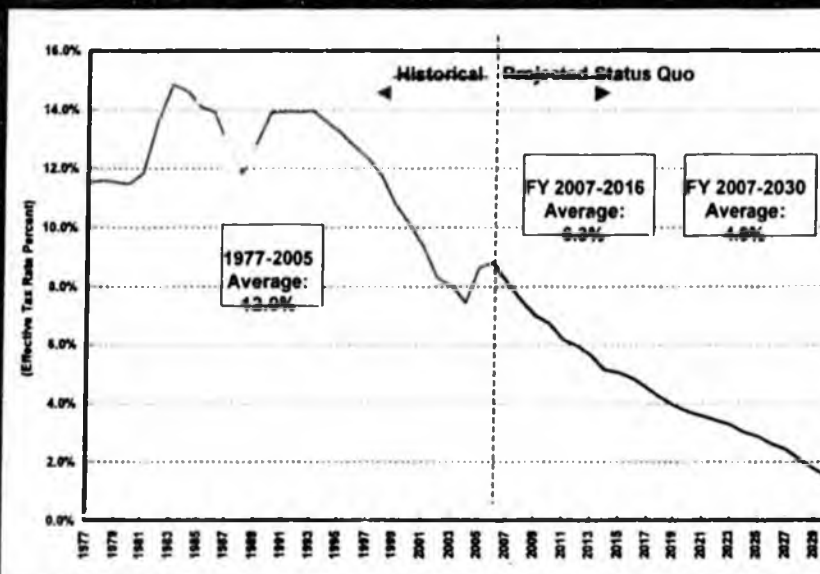
INE

Conclusions/Observations Regarding Exploration Impacts

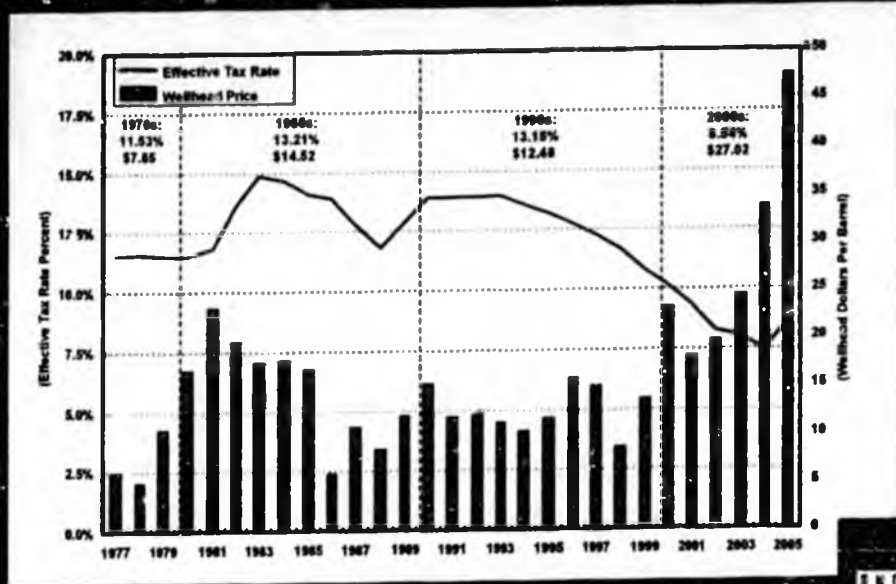
- Without ANWF opening, expectation of large oil discoveries are unlikely, due to the Field Size Distribution of remaining economic reserves
- At low prices, 25/20 helps explorer more than 20/20
- Incentives are required at low prices (say, \$73 M, although alternative approaches could work as well)
- At low prices, 20/20 and 25/20 preferred over SQ, in order to incent exploration
- Under either a 20/20 or 25/20 program, remaining reserves are economic, except for low prices (<\$30?)



Effective Severance Tax Rates Over Time

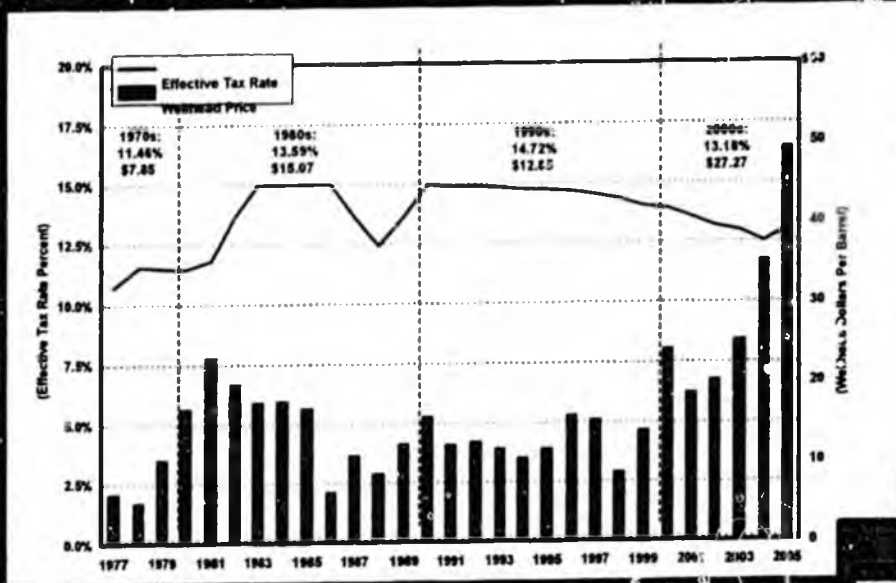


Effective Tax Rates and Wellhead Prices Over Time (All North Slope Fields)

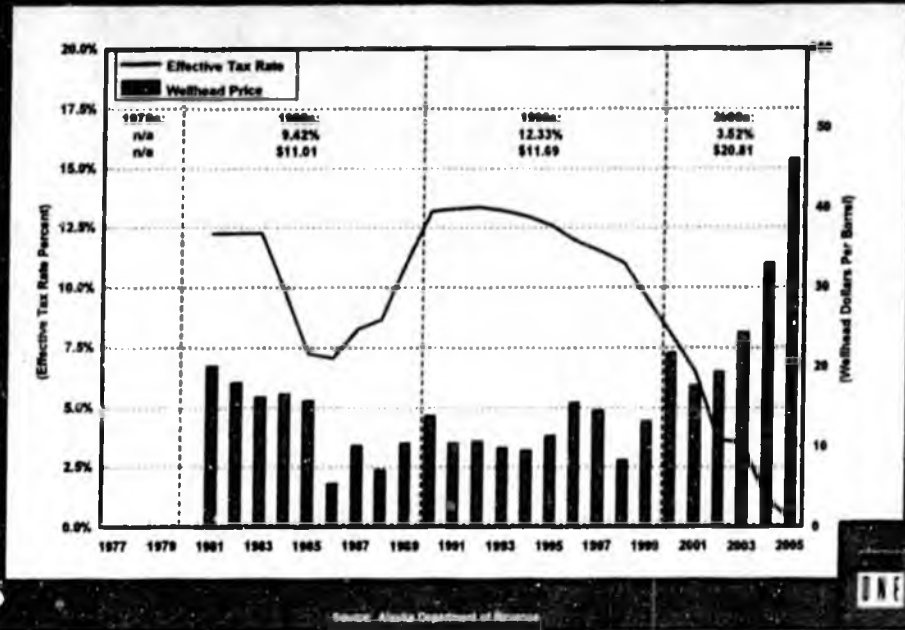


Source: Alaska Department of Revenue

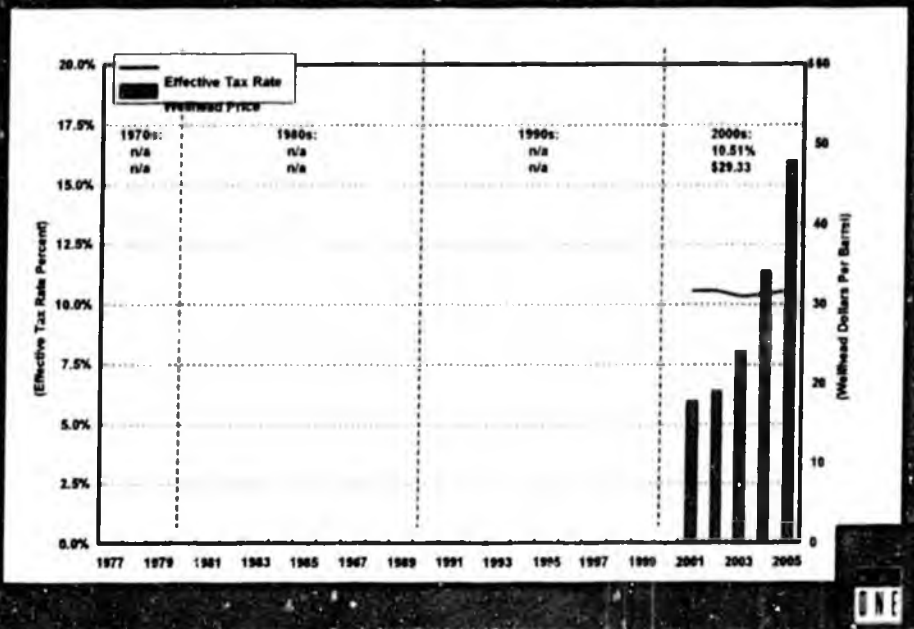
Effective Tax Rates and Wellhead Prices Over Time (Prudhoe Bay Field)



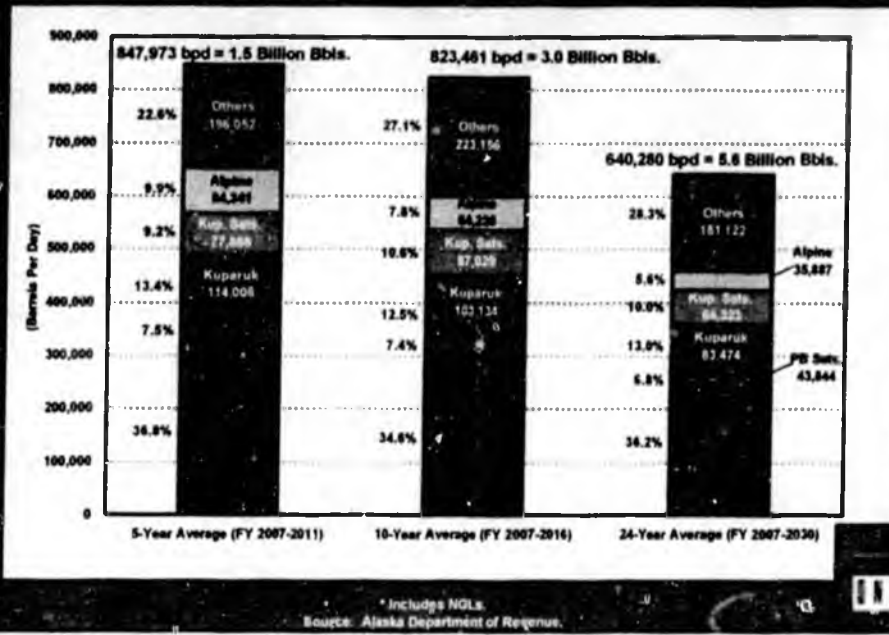
Effective Tax Rates and Wellhead Prices Over Time (Kuparuk Field)



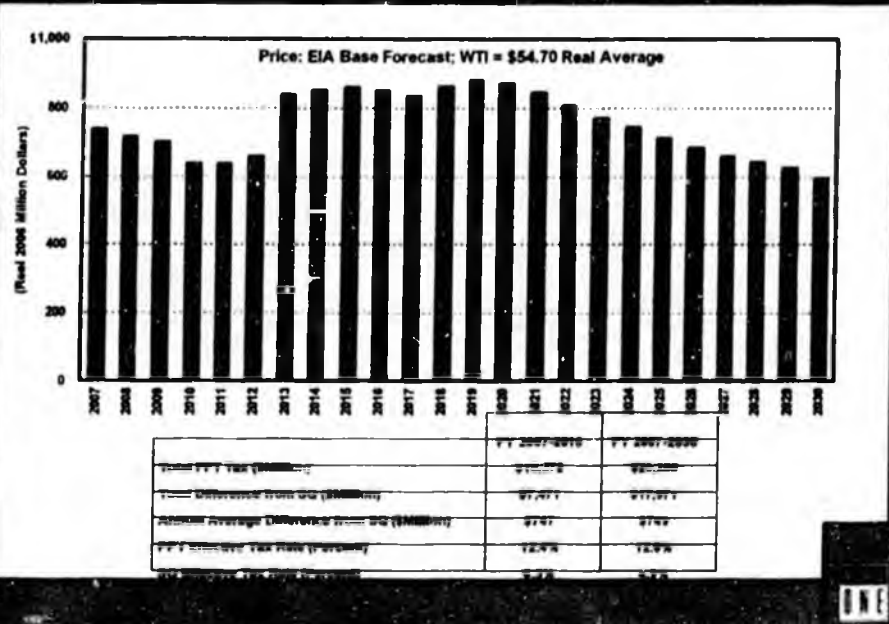
Effective Tax Rates and Wellhead Prices Over Time (Alpine Field)



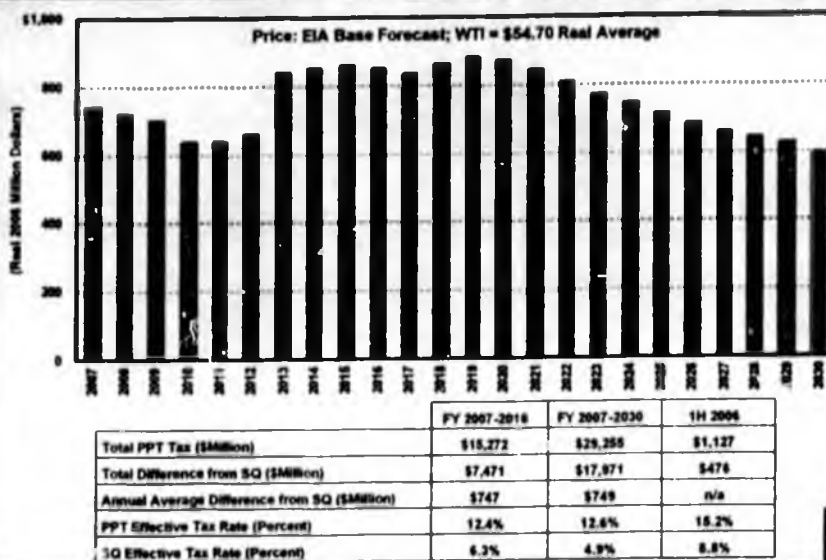
Projected North Slope Crude Oil* Production (FY 2007-2030)



Change in Projected Taxes Under a 20/20 Tax DOR Forecast Production (FY 2007-2030)*



Change in Projected Taxes Under a 20/20 Tax DOR Forecast Production (FY 2007-2030)*



* Calculated from July 2006. Includes 6-year transition and \$73 million exemption, volume per DOR Fall 2004 Forecast with Oilgrind projection.

Change in Projected Taxes Under a 20/20 Tax DOR Forecast Production (FY 2007-2030)*

| | EIA WTI Price Forecast | | | Fixed \$40 Price | FY2007-2016 Break-even | FY2007-2030 Break-even |
|--|------------------------|----------|----------|---------------------|---------------------------|---------------------------|
| | Base | Low | High | | | |
| Average WTI Price in Real 2008 Dollars | \$54.70 | \$33.80 | \$72.00 | \$40.00 | \$39.30 | \$26.00 |
| FY 2007-2016 | | | | | | |
| Total PPT Tax (Million 2008) | \$16,272 | \$6,788 | \$21,150 | \$8,888 | \$3,825 | - |
| Total Difference from Status Quo (Million 2008) | \$7,471 | \$3,614 | \$11,686 | \$3,434 | \$0 | - |
| Annual Average Difference from Status Quo (Million 2008) | \$747 | \$381 | \$1,188 | \$343 | \$0 | - |
| PPT Effective Tax Rate (Percent) | 12.4% | 10.3% | 15.0% | 10.2% | 6.9% | - |
| Status Quo Effective Tax Rate (Percent) | 6.3% | 6.5% | 6.2% | 6.2% | 6.2% | - |
| FY 2007-2030 | | | | | | |
| Total PPT Tax (Million 2008) | \$29,255 | \$12,705 | \$44,738 | \$16,230 | - | \$5,293 |
| Total Difference from Status Quo (Million 2008) | \$17,971 | \$4,824 | \$30,262 | \$8,317 | - | \$0 |
| Annual Average Difference from Status Quo (Million 2008) | \$749 | \$201 | \$1,281 | \$347 | - | \$0 |
| PPT Effective Tax Rate (Percent) | 12.6% | 6.7% | 14.5% | 10.0% | - | 5.0% |
| Status Quo Effective Tax Rate (Percent) | 4.9% | 5.4% | 4.7% | 4.9% | - | 5.0% |

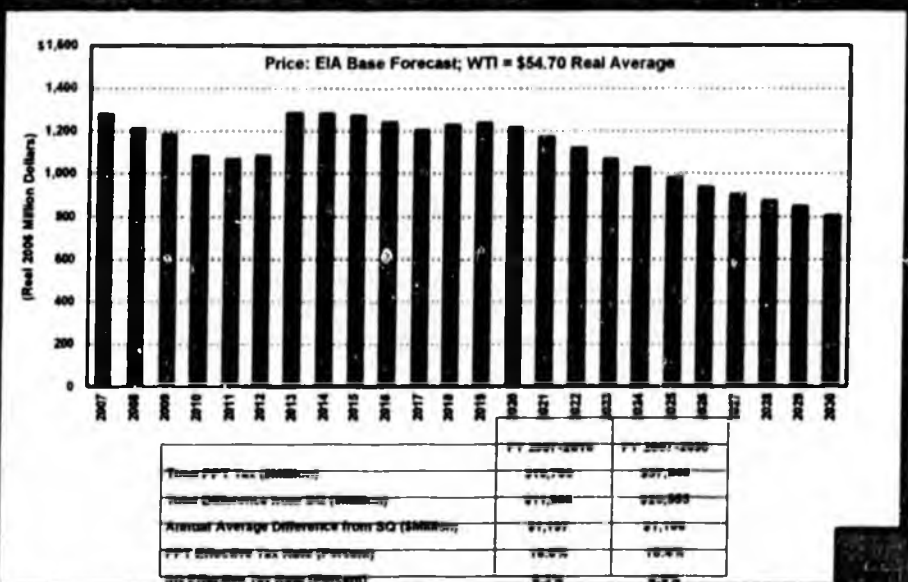
**Change in Projected Taxes Under a 20/20 Tax with
Costs Increased by 20%
DOR Forecast Production (FY 2007-2030)***

| | EIA WTI Price Forecast | | | Fixed \$40 Price | FY2007-2016 Breakdown | FY2007-2030 Breakdown |
|--|------------------------|----------|----------|---------------------|--------------------------|--------------------------|
| | Base | Low | High | | | |
| Average WTI Price in Real 2006 Dollars | \$54.70 | \$35.40 | \$72.00 | \$40.00 | \$34.80 | \$32.50 |
| FY 2007-2016 | | | | | | |
| Total PPT Tax (Million 2006\$) | \$12,000 | \$6,200 | \$16,000 | \$7,410 | \$4,570 | - |
| Total Difference from Status Quo (Million 2006\$) | \$6,000 | \$2,140 | \$10,210 | \$1,000 | \$0 | - |
| Annual Average Difference from Status Quo (Million 2006\$) | \$600 | \$214 | \$1,022 | \$100 | \$0 | - |
| PPT Effective Tax Rate (Percent) | 11.3% | 8.0% | 12.0% | 8.0% | 5.3% | - |
| Status Quo Effective Tax Rate (Percent) | 6.2% | 5.5% | 6.2% | 6.3% | 6.3% | - |
| FY 2007-2030 | | | | | | |
| Total PPT Tax (Million 2006\$) | \$26,000 | \$10,070 | \$41,000 | \$13,480 | - | \$6,150 |
| Total Difference from Status Quo (Million 2006\$) | \$16,320 | \$2,120 | \$27,010 | \$5,000 | - | \$0 |
| Annual Average Difference from Status Quo (Million 2006\$) | \$634 | \$66 | \$1,148 | \$222 | - | \$0 |
| PPT Effective Tax Rate (Percent) | 11.0% | 8.0% | 13.0% | 8.0% | - | 4.9% |
| Status Quo Effective Tax Rate (Percent) | 4.0% | 5.4% | 4.7% | 4.0% | - | 4.9% |

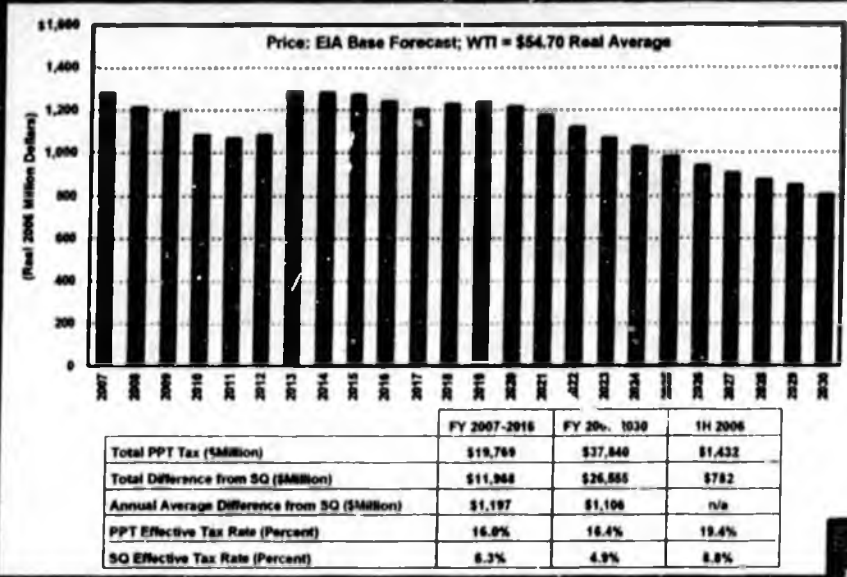
* Calculated from July 2006, includes 8-year transition and \$73 billion exemption, requires per DOE Fall 2002 Forecast with Ogoniuk projection.



**Change in Projected Taxes Under a 25/20 Tax
DOR Forecast Production (FY 2007-2030)***



**Change in Projected Taxes Under a 25/20 Tax
DOR Forecast Production (FY 2007-2030)***

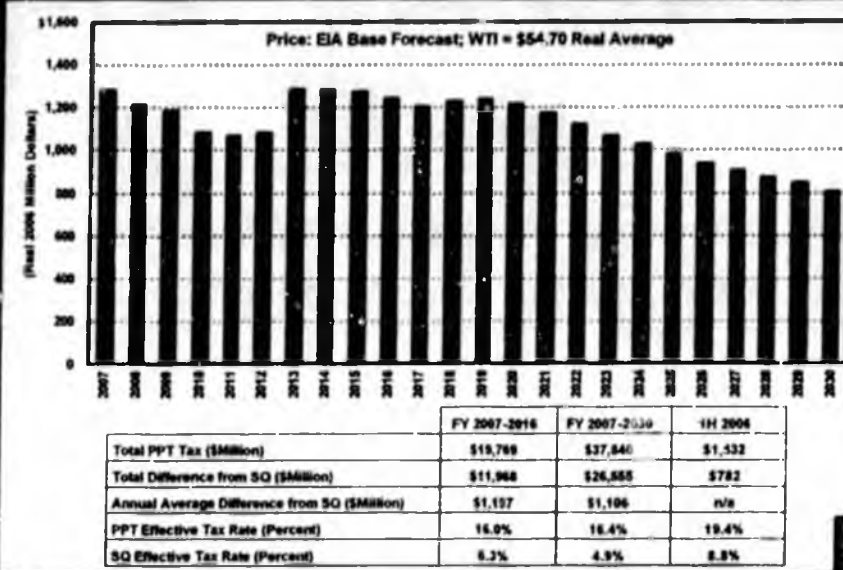


* Calculated from July 2006 historical 6-year transition and 272 million base price, volume per OIA Fall 2003 forecast with 100% completion

**Change in Projected Taxes Under a 25/20 Tax
DOR Forecast Production (FY 2007-2030)***

| | EIA WTI Price Forecast | | | Fixed \$40 Price | FY2007-2016 Breakover | FY2007-2030 Breakover |
|--|------------------------|----------|----------|------------------|-----------------------|-----------------------|
| | Base | Low | High | | | |
| Average WTI Price in Real 2006 Dollars | \$54.70 | \$35.40 | \$72.00 | \$40.00 | \$27.70 | \$26.10 |
| FY 2007-2016 | | | | | | |
| Total PPT Tax (Million 2006) | \$19,769 | \$12,915 | \$27,126 | \$11,780 | \$5,362 | - |
| Total Difference from Status Quo (Million 2006) | \$11,968 | \$0,740 | \$17,856 | \$6,330 | \$0 | - |
| Annual Average Difference from Status Quo (Million 2006) | \$1,197 | \$674 | \$1,706 | \$633 | \$0 | - |
| PPT Effective Tax Rate (Percent) | 16.0% | 13.0% | 17.7% | 13.0% | 6.3% | - |
| Status Quo Effective Tax Rate (Percent) | 8.3% | 6.5% | 8.2% | 6.3% | 6.3% | - |
| FY 2007-2030 | | | | | | |
| Total PPT Tax (Million 2006) | \$37,840 | \$17,228 | \$27,193 | \$21,508 | - | \$4,671 |
| Total Difference from Status Quo (Million 2006) | \$26,655 | \$6,266 | \$42,717 | \$13,645 | - | \$0 |
| Annual Average Difference from Status Quo (Million 2006) | \$1,106 | \$397 | \$1,780 | \$560 | - | \$0 |
| PPT Effective Tax Rate (Percent) | 16.4% | 11.7% | 18.0% | 13.3% | - | 5.0% |
| Status Quo Effective Tax Rate (Percent) | 4.9% | 5.4% | 4.7% | 4.9% | - | 5.0% |

Change in Projected Taxes Under a 25/20 Tax DOR Forecast Production (FY 2007-2030)*

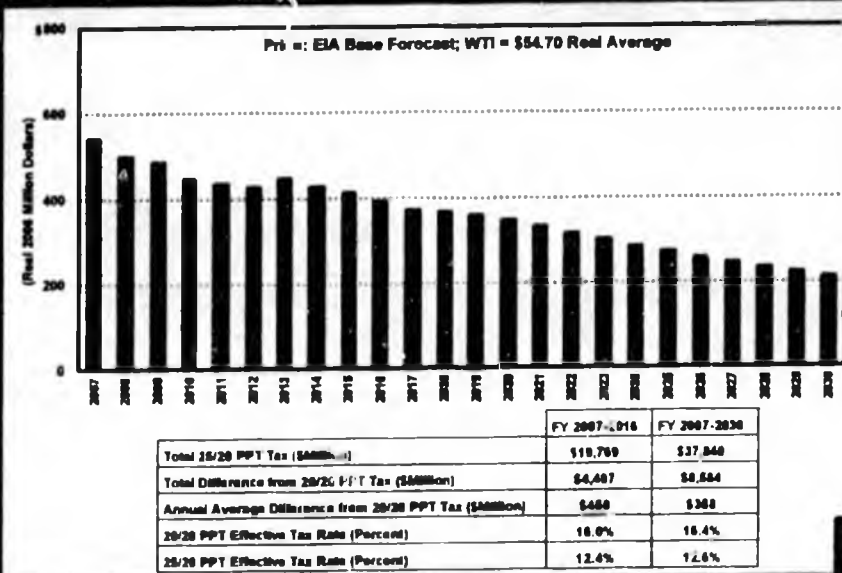


* Calculated from July 2008, includes 8-year transition and \$73 million transportation increase per DOR FY 2007 Forecast with Ongoing production.

Change in Projected Taxes Under a 25/20 Tax DOR Forecast Production (FY 2007-2030)*

| | EIA WTI Price Forecast | | | Fixed \$40 Price | FY2007-2016 Breakdown | FY2007-2030 Breakdown |
|--|------------------------|----------|----------|------------------|-----------------------|-----------------------|
| | Base | Low | High | | | |
| Average WTI Price in Real 2008 Dollars: | \$54.70 | \$35.40 | \$72.00 | \$40.00 | \$27.10 | \$26.10 |
| FY 2007-2016 | | | | | | |
| Total PPT Tax (Million 2008) | \$15,769 | \$12,915 | \$27,120 | \$11,700 | \$3,382 | - |
| Total Difference from Status Quo (Million 2008) | \$11,968 | \$6,740 | \$17,050 | \$6,535 | \$0 | - |
| Annual Average Difference from Status Quo (Million 2008) | \$1,197 | \$674 | \$1,706 | \$653 | \$0 | - |
| PPT Effective Tax Rate (Percent) | 16.0% | 13.6% | 17.7% | 13.0% | 6.3% | - |
| Status Quo Effective Tax Rate (Percent) | 6.3% | 6.5% | 6.2% | 6.3% | 6.3% | - |
| FY 2007-2030 | | | | | | |
| Total PPT Tax (Million 2008) | \$17,969 | \$17,226 | \$67,163 | \$21,508 | - | \$4,671 |
| Total Difference from Status Quo (Million 2008) | \$26,655 | \$9,200 | \$42,717 | \$13,645 | - | \$0 |
| Annual Average Difference from Status Quo (Million 2008) | \$1,966 | \$267 | \$1,700 | \$666 | - | \$0 |
| PPT Effective Tax Rate (Percent) | 16.0% | 11.7% | 18.5% | 13.3% | - | 5.0% |
| Status Quo Effective Tax Rate (Percent) | 4.9% | 5.4% | 4.7% | 4.9% | - | 5.0% |

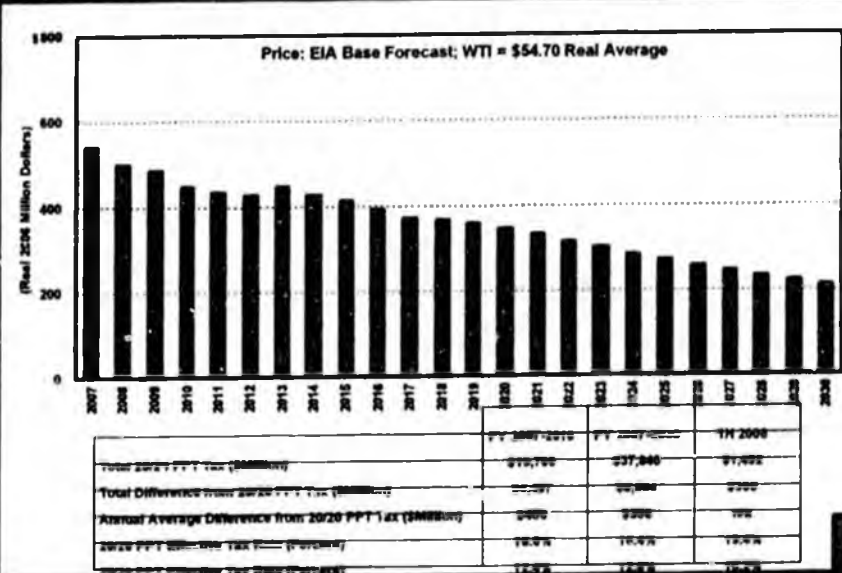
Difference in Projected Taxes Between a 25/20 and a 20/20 Tax DOR Forecast Production (FY 2007-2030)*



* Calculated from July 2008. Includes 5-year forecast and 271 million equivalent volumes per DOE Fall 2008 Forecast with Ongoing production.



Difference in Projected Taxes Between a 25/20 and a 20/20 Tax DOR Forecast Production (FY 2007-2030)*



Difference in Projected Taxes Between a 25/20 and a 20/20 Tax DOR Forecast Production (FY 2007-2030)*

| | EIA WTI Price Forecast | | | Fixed \$40 Price | FY2007-2016 Breakdown | FY2007-2030 Breakdown |
|---|------------------------|----------|----------|------------------|-----------------------|-----------------------|
| | Base | Low | High | | | |
| Average WTI Price in Real 2006 Dollars | \$54.70 | \$35.40 | \$72.00 | \$40.00 | - | - |
| FY 2007-2016 | | | | | | |
| Total 25/20 PPT Tax (Million 2006\$) | \$18,789 | \$12,815 | \$27,126 | \$11,769 | - | - |
| Total Difference from 20/20 PPT Tax (Million 2006\$) | \$4,487 | \$3,126 | \$5,898 | \$2,901 | - | - |
| Annual Average Difference from 20/20 PPT Tax (Million 2006\$) | \$460 | \$313 | \$587 | \$280 | - | - |
| 25/20 PPT Effective Tax Rate (Percent) | 16.6% | 13.6% | 17.7% | 13.6% | - | - |
| 20/20 PPT Effective Tax Rate (Percent) | 12.4% | 10.3% | 13.8% | 10.2% | - | - |
| FY 2007-2030 | | | | | | |
| Total 25/20 PPT Tax (Million 2006\$) | \$37,840 | \$17,226 | \$57,163 | \$21,558 | - | - |
| Total Difference from 20/20 PPT Tax (Million 2006\$) | \$8,964 | \$4,402 | \$12,455 | \$5,328 | - | - |
| Annual Average Difference from 20/20 PPT Tax (Million 2006\$) | \$268 | \$186 | \$319 | \$122 | - | - |
| 25/20 PPT Effective Tax Rate (Percent) | 16.4% | 11.7% | 18.5% | 13.3% | - | - |
| 20/20 PPT Effective Tax Rate (Percent) | 12.8% | 8.7% | 14.5% | 10.0% | - | - |

* Calculated from July 2006 includes Evers expansion and 223 million expansion, volume per DOR Est. 2003 Forecast with Ogonish production



Projected Government Takes DOR Forecast Production (FY 2007-2030)*

| | Total Government Take (Percent) | | | | Alaska Take (Percent) | | | |
|--|---------------------------------|---------|---------|------------------|------------------------|---------|---------|------------------|
| | EIA WTI Price Forecast | | | Fixed \$40 Price | EIA WTI Price Forecast | | | Fixed \$40 Price |
| | Base | Low | High | | Base | Low | High | |
| Average WTI Price in Real 2006 Dollars | \$54.70 | \$35.40 | \$72.00 | \$40.00 | \$54.70 | \$35.40 | \$72.00 | \$40.00 |
| FY 2007-2016 | | | | | | | | |
| Status Quo | 53.3% | 55.0% | 52.4% | 55.5% | 24.8% | 26.9% | 23.7% | 27.2% |
| 20/20 PPT | 57.2% | 57.6% | 57.1% | 58.2% | 30.8% | 30.9% | 31.0% | 31.5% |
| 25/20 PPT | 58.8% | 59.9% | 59.6% | 60.6% | 34.8% | 34.5% | 34.8% | 35.1% |
| FY 2007-2030 | | | | | | | | |
| Status Quo | 51.8% | 54.7% | 50.8% | 53.7% | 23.4% | 27.2% | 22.0% | 25.7% |
| 20/20 PPT | 56.9% | 57.1% | 56.9% | 57.3% | 31.2% | 30.9% | 31.3% | 31.3% |
| 25/20 PPT | 58.2% | 59.3% | 59.3% | 59.7% | 34.8% | 34.3% | 35.2% | 34.9% |



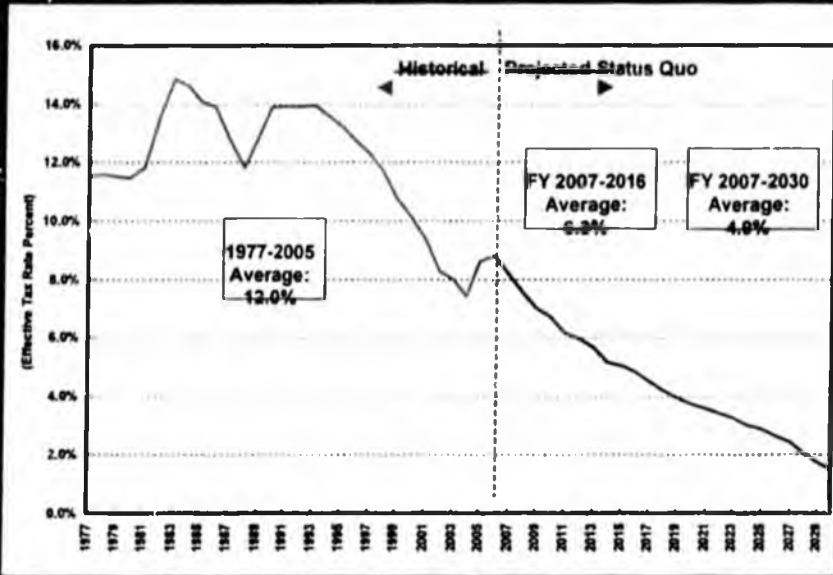
**Projected Annual Average Taxes at Various Tax Rates and Prices
DOR Forecast Production (FY 2007-2030)***

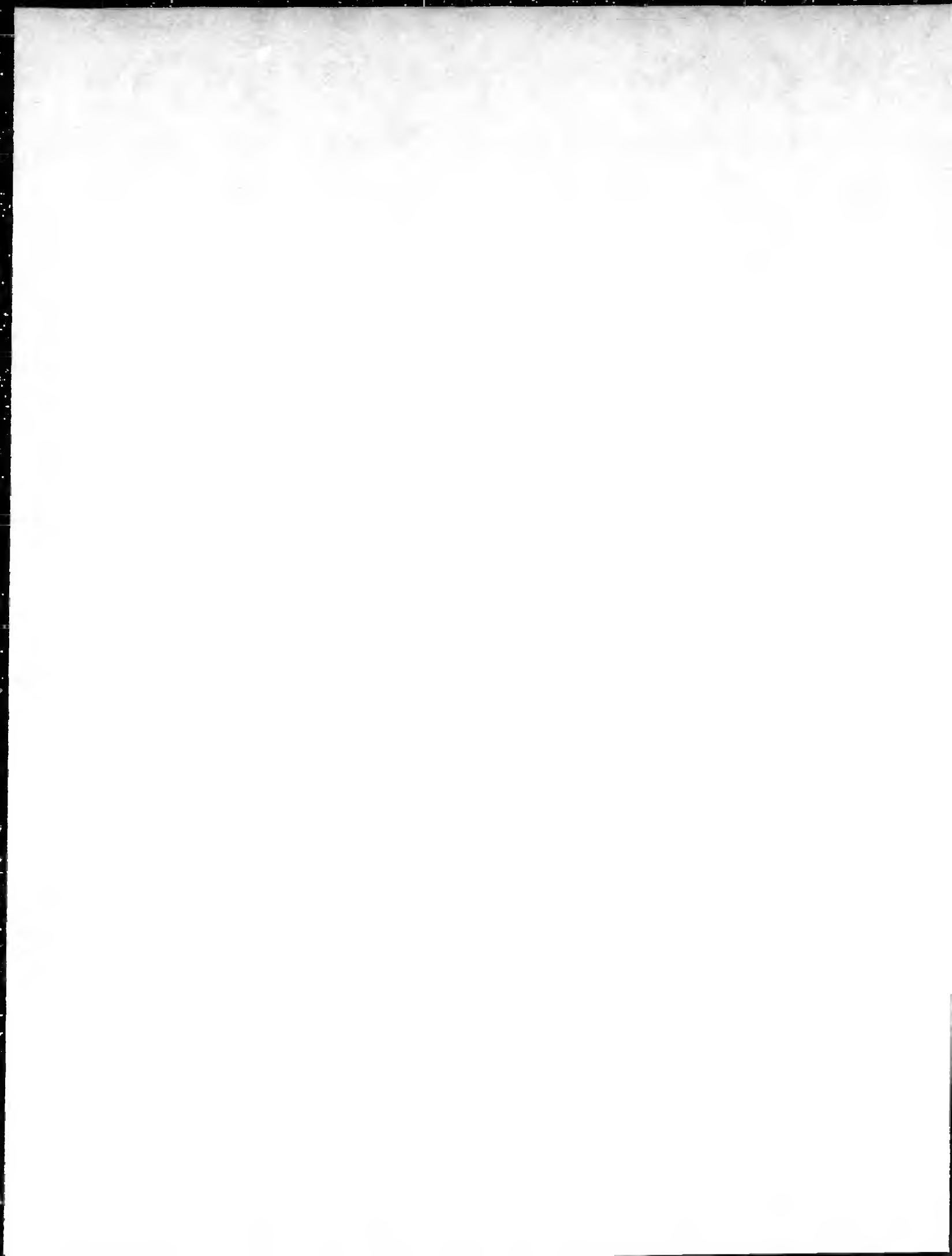
| WTI Price | 2020 | 2120 | 2220 | 2320 | 2420 | 2520 | Change Per % Increase in Tax Rate | Change Per % Increase in Credit Rate |
|---|-----------|-----------|-----------|-----------|-----------|-----------|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
| FY 2007-2016 | | | | | | | | |
| \$40 | \$995.8 | \$948.8 | \$1,034.8 | \$1,082.8 | \$1,130.8 | \$1,178.8 | \$58.0 | (\$13.8) |
| \$45 | \$1,148.5 | \$1,220.8 | \$1,291.6 | \$1,362.7 | \$1,433.7 | \$1,504.8 | \$71.1 | (\$13.8) |
| \$50 | \$1,492.2 | \$1,494.3 | \$1,578.4 | \$1,662.5 | \$1,746.6 | \$1,830.7 | \$84.1 | (\$13.8) |
| \$55 | \$1,871.0 | \$1,798.1 | \$1,885.2 | \$1,962.4 | \$2,039.5 | \$2,116.6 | \$87.1 | (\$13.8) |
| \$60 | \$1,811.7 | \$2,041.8 | \$2,112.1 | \$2,282.2 | \$2,372.4 | \$2,462.6 | \$118.2 | (\$13.8) |
| Change Per Dollar Increase in WTI Price | \$82.1 | \$54.8 | \$17.4 | \$80.0 | \$42.8 | \$55.2 | | |
| FY 2007-2030 | | | | | | | | |
| \$40 | \$678.3 | \$720.7 | \$765.1 | \$809.5 | \$853.9 | \$898.3 | \$44.4 | (\$10.8) |
| \$45 | \$878.9 | \$933.5 | \$988.0 | \$1,042.5 | \$1,097.1 | \$1,151.6 | \$54.8 | (\$10.8) |
| \$50 | \$1,081.6 | \$1,146.3 | \$1,211.0 | \$1,275.6 | \$1,340.3 | \$1,405.0 | \$64.7 | (\$10.8) |
| \$55 | \$1,284.3 | \$1,359.1 | \$1,433.9 | \$1,508.7 | \$1,583.5 | \$1,658.3 | \$74.8 | (\$10.8) |
| \$60 | \$1,487.0 | \$1,571.8 | \$1,656.6 | \$1,741.4 | \$1,826.2 | \$1,911.1 | \$84.9 | (\$10.8) |
| Change Per Dollar Increase in WTI Price | \$40.8 | \$42.0 | \$44.8 | \$46.0 | \$48.8 | \$50.7 | | |

* Calculated from July 2006, \$13 Million exemption; does not include transition volumes per DOR Fall 2006 forecast with Dugan's production

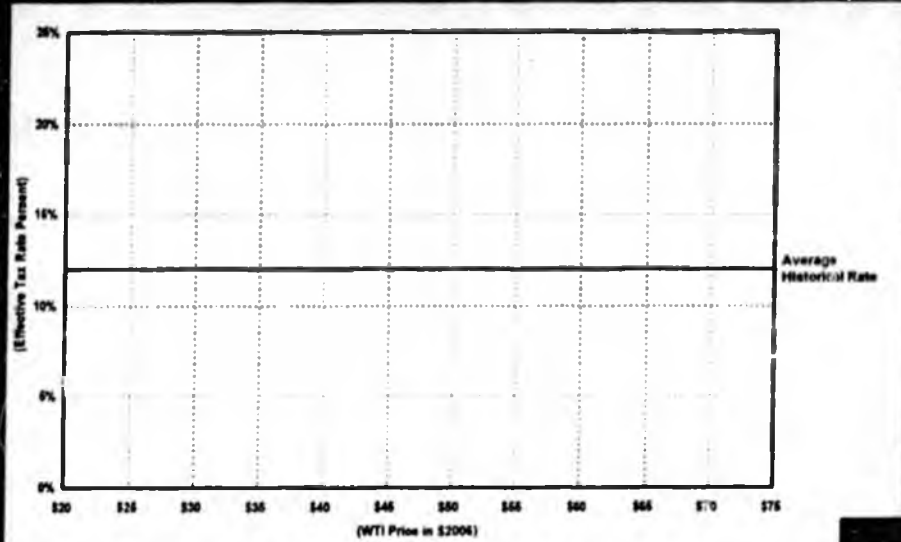


Effective Severance Tax Rates Over Time





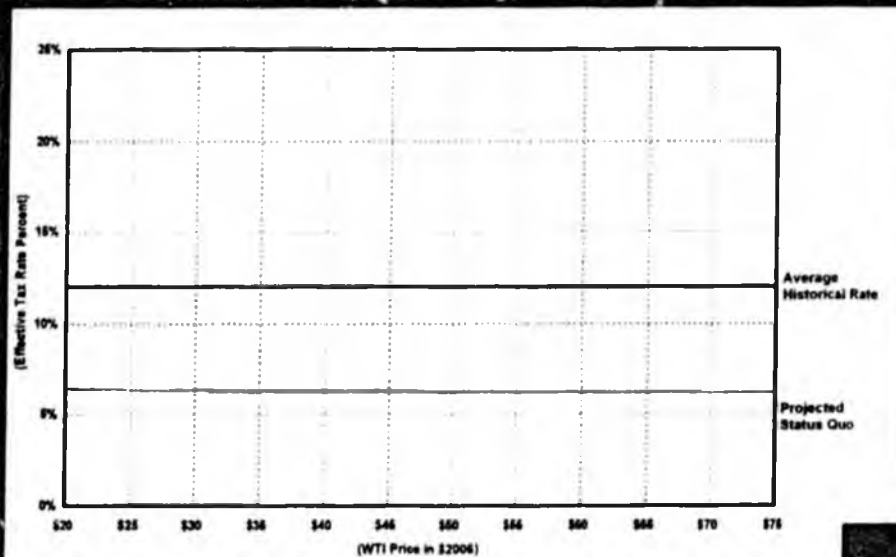
Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)



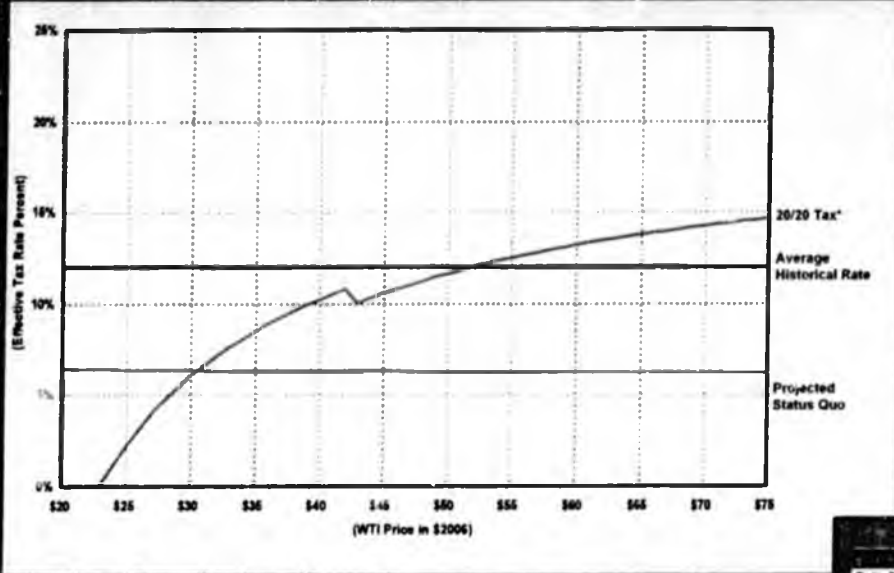
Source: Alaska Department of Revenue



Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)



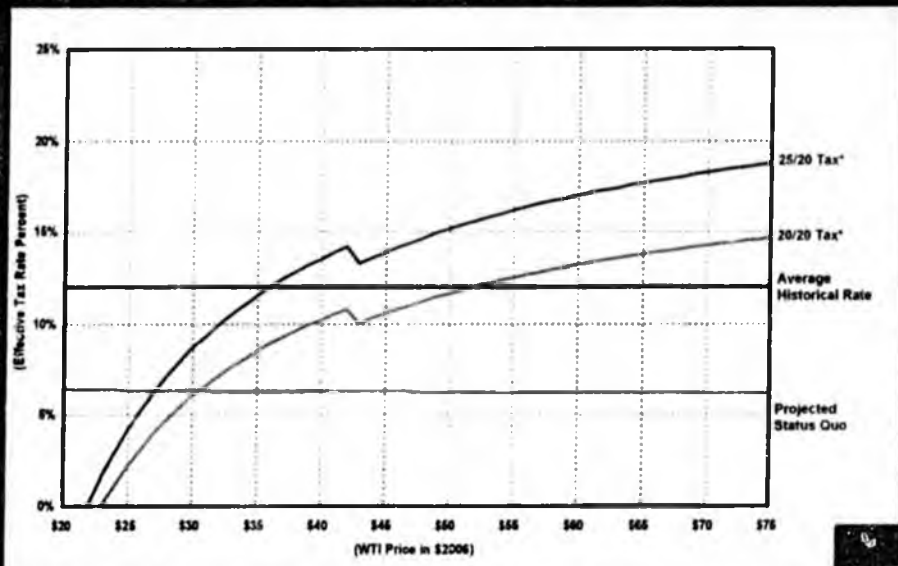
Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



* Calculated from July 2006, includes 9-year transition and \$73 billion exemption, volume per DOE Fall 2005 Forecast with Odegaruk projection. Source: @Globe24 - Alaska Department of Revenue.



Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



* Calculated from July 2006, includes 9-year transition and \$73 billion exemption, volume per DOE Fall 2005 Forecast with Odegaruk projection.



Example of Tax with Sliding Scale

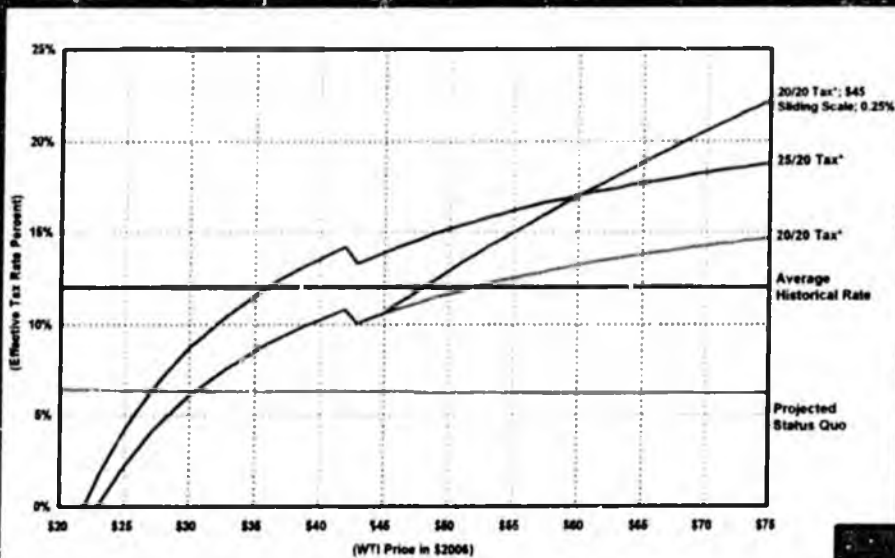
**Assumptions: 0.25% per dollar over \$45/barrel WTI (threshold);
\$55/barrel WTI price;
\$47/barrel ANS wellhead price;
20/20 PPT.**

- **Sliding Scale Tax in Addition to PPT, and Deductible Against PPT**
- **If WTI is <= Threshold price (e.g., \$45): No Additional Tax**
- **If WTI is > Threshold price: Additional Tax Equals 0.25% Per Dollar Over Threshold x Gross Wellhead Value**

$$\begin{aligned}
 \text{Additional Tax} &= (\text{WTI Price} - \text{Threshold}) \times \text{Increment Rate} \times \\
 &\quad \text{ANS Wellhead Price} \times (1 - \text{PPT Tax Rate}) \\
 &= (\$55 - \$45) \times 0.25\% \times \$47 \times (1 - 20\%) \\
 &= 2.5\% \times \$47 \times 80\% \\
 &= \$0.94
 \end{aligned}$$

ONE

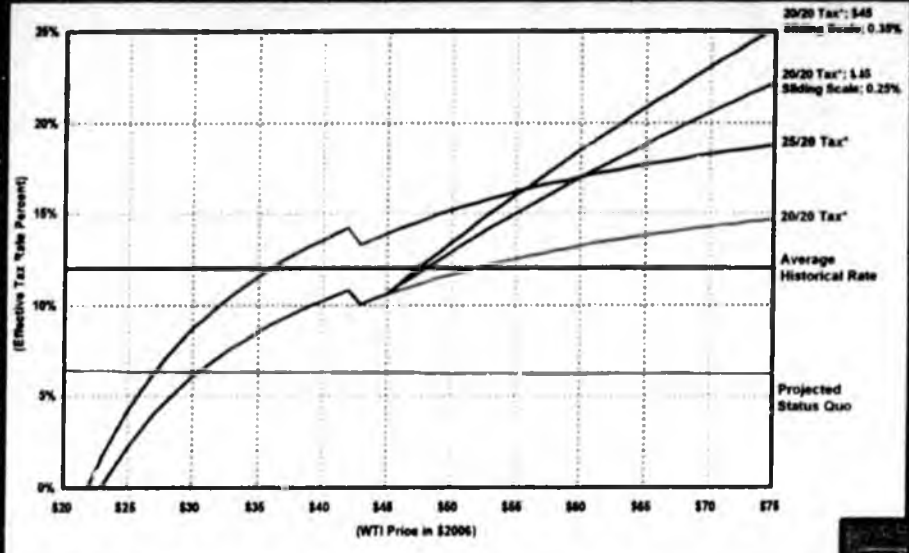
Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



* Calculated from July 2004 includes 6-year transition and \$13 billion exemption. Source: DOE, Fall 2004 forecast with regional projection.

ONE

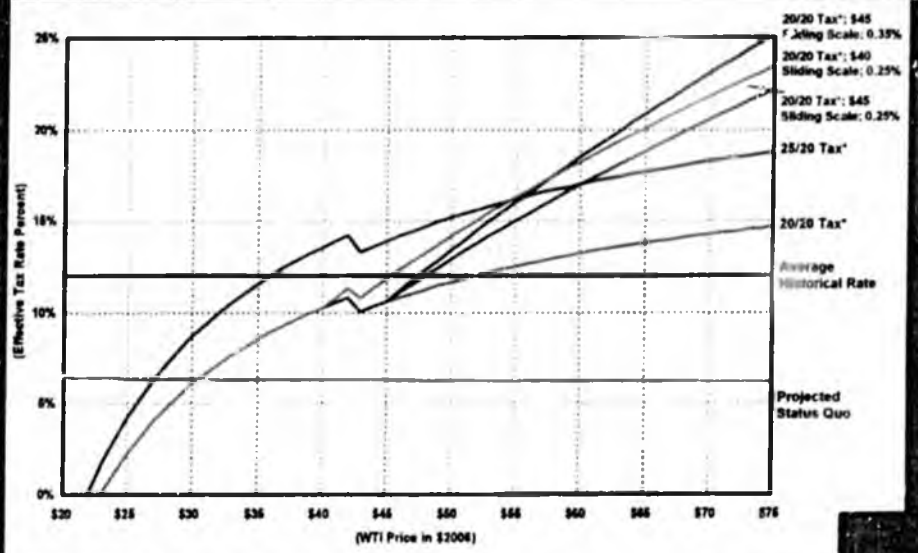
Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



* Calculated from July 2006. Includes 8-year transition and \$73 million exemption; volumes per DOR Fall 2005 Forecast with Ogeyrik projection.
Source: Minnesota - METS Department of Revenue.



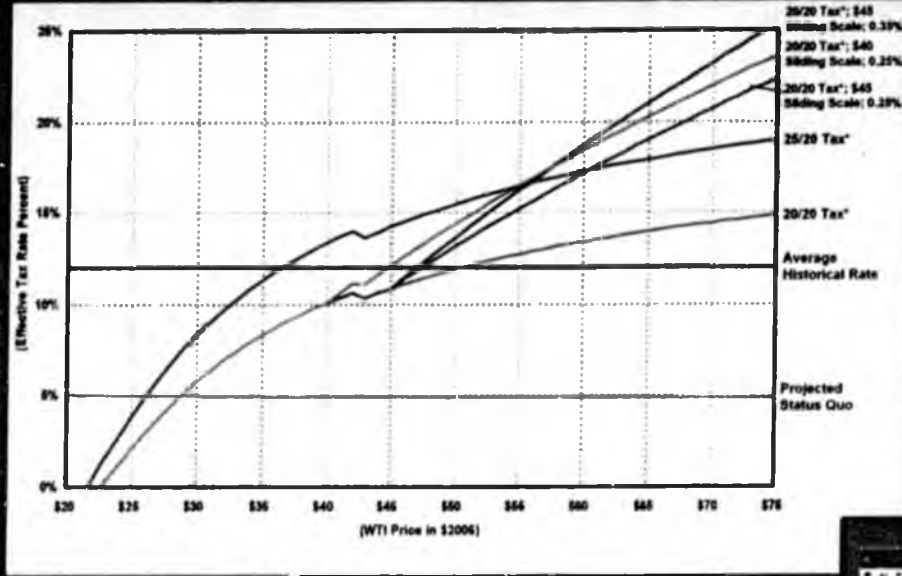
Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



* Calculated from July 2006. Includes 8-year transition and \$73 million exemption; volumes per DOR Fall 2005 Forecast with Ogeyrik projection.



Effective Average Tax Rates at Various Price Levels (FY 2007-2030)



* Calculated from July 2006. Includes 6 year production and 675 MBO production. Assumes an 2007-2030 forecast with constant reserves. Source: Reserves - Alaska Department of Revenue.



Projected Effective Tax Rates with Sliding Scale Tax DOR Forecast Production (FY 2007-2030)*

| WTI Price (\$ 2006) | Status Quo | 20/20 | 20/20 with 20/20 Sliding Tax | | | | | | | |
|------------------------|---------------|-------|------------------------------|--------------------|--------------------|--------------------|----------------------|--------------------|--------------------|--------------------|
| | | | \$35 Threshold Price | | | | \$40 Threshold Price | | | |
| | | | 0.20% Increment | 0.25% Increment | 0.30% Increment | 0.35% Increment | 0.20% Increment | 0.25% Increment | 0.30% Increment | 0.35% Increment |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | |
| \$30 | 4.0% | 5.8% | 5.9% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% |
| \$40 | 4.0% | 10.0% | 11.0% | 11.3% | 11.5% | 11.8% | 10.0% | 10.0% | 10.0% | 10.0% |
| \$50 | 4.0% | 11.8% | 14.0% | 15.7% | 16.4% | 17.2% | 13.9% | 14.4% | 14.9% | 15.4% |
| \$60 | 4.0% | 13.4% | 16.4% | 19.7% | 20.9% | 22.2% | 17.4% | 18.4% | 19.4% | 20.4% |
| \$70 | 4.0% | 14.9% | 21.5% | 23.2% | 25.0% | 26.7% | 20.5% | 22.0% | 23.5% | 25.0% |
| \$80 | 4.0% | 15.2% | 24.2% | 26.5% | 28.7% | 31.0% | 23.2% | 25.2% | 27.2% | 29.2% |

| WTI Price (\$ 2006) | 25/20 | 20/20 with 25/20 Sliding Tax | | | | | | | |
|------------------------|-------|------------------------------|--------------------|--------------------|--------------------|----------------------|--------------------|--------------------|--------------------|
| | | \$45 Threshold Price | | | | \$50 Threshold Price | | | |
| | | 0.20% Increment | 0.25% Increment | 0.30% Increment | 0.35% Increment | 0.20% Increment | 0.25% Increment | 0.30% Increment | 0.35% Increment |
| (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | |
| \$30 | 8.3% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% |
| \$40 | 13.3% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% |
| \$50 | 15.5% | 12.8% | 13.2% | 13.4% | 13.7% | 11.8% | 11.9% | 11.9% | 11.9% |
| \$60 | 17.8% | 16.4% | 17.2% | 17.9% | 18.7% | 15.4% | 15.9% | 16.4% | 16.9% |
| \$70 | 18.8% | 19.5% | 20.7% | 22.0% | 23.2% | 18.5% | 18.5% | 20.5% | 21.5% |
| \$80 | 18.4% | 22.2% | 24.0% | 25.7% | 27.5% | 21.2% | 22.7% | 24.2% | 25.7% |



**Projected Government Takes with Sliding Scale Tax
DOR Forecast Production (FY 2007-2030)***

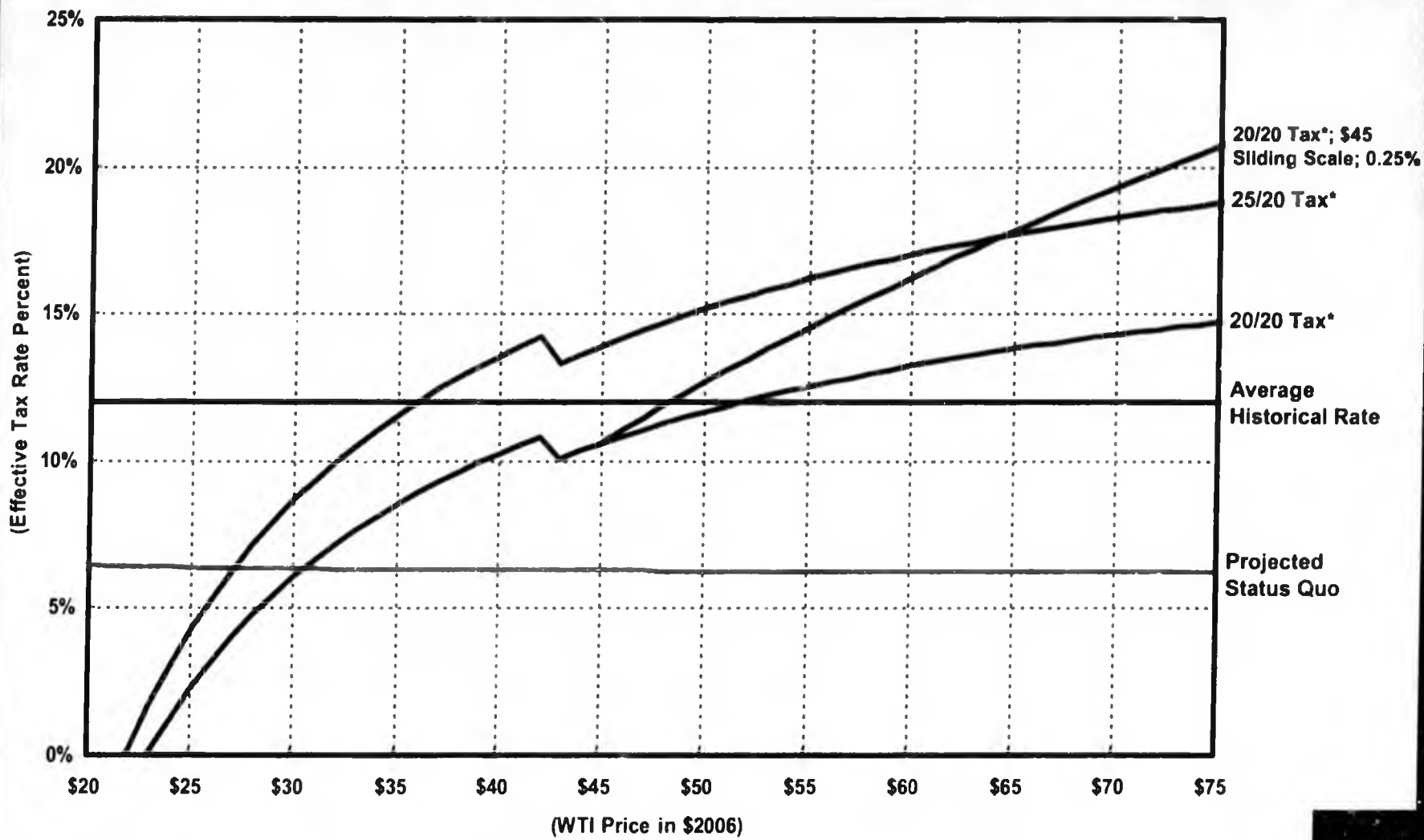
| WTI Price (\$ 2006) | Status Date | 2000 | 2000 with Sliding Scale Tax | | | | | | | |
|------------------------|----------------|-------|-----------------------------|--------------------|--------------------|--------------------|----------------------|--------------------|--------------------|--------------------|
| | | | \$30 Threshold Price | | | | \$40 Threshold Price | | | |
| | | | 0.20% Increment | 0.25% Increment | 0.30% Increment | 0.35% Increment | 0.20% Increment | 0.25% Increment | 0.30% Increment | 0.35% Increment |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | |
| | | | (Percent) | | | | | | | |
| \$30 | 57.0% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% |
| \$40 | 53.7% | 57.3% | 58.0% | 58.2% | 58.4% | 58.6% | 57.3% | 57.3% | 57.3% | 57.3% |
| \$50 | 52.3% | 55.9% | 58.9% | 59.4% | 59.9% | 60.4% | 58.2% | 58.5% | 58.9% | 59.2% |
| \$60 | 51.9% | 55.5% | 60.0% | 60.8% | 61.6% | 62.4% | 58.4% | 60.0% | 60.7% | 61.3% |
| \$70 | 50.9% | 55.5% | 61.2% | 62.5% | 63.3% | 64.4% | 60.6% | 61.9% | 62.4% | 63.3% |
| \$80 | 50.6% | 55.5% | 62.3% | 63.7% | 65.0% | 66.4% | 61.7% | 62.9% | 64.1% | 65.3% |

| WTI Price (\$ 2006) | 2500 | 2000 with Sliding Scale Tax | | | | | | | |
|------------------------|-------|-----------------------------|--------------------|--------------------|--------------------|----------------------|--------------------|--------------------|--------------------|
| | | \$40 Threshold Price | | | | \$50 Threshold Price | | | |
| | | 0.20% Increment | 0.25% Increment | 0.30% Increment | 0.35% Increment | 0.20% Increment | 0.25% Increment | 0.30% Increment | 0.35% Increment |
| (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | |
| | | (Percent) | | | | | | | |
| \$30 | 58.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% |
| \$40 | 58.7% | 57.3% | 57.3% | 57.3% | 57.3% | 57.3% | 57.3% | 57.3% | 57.3% |
| \$50 | 58.3% | 57.6% | 57.7% | 57.9% | 58.1% | 58.6% | 58.6% | 58.6% | 58.6% |
| \$60 | 58.3% | 58.8% | 59.3% | 59.7% | 60.2% | 58.1% | 58.5% | 58.8% | 59.1% |
| \$70 | 58.3% | 59.6% | 60.7% | 61.9% | 62.3% | 59.3% | 59.6% | 60.6% | 61.2% |
| \$80 | 58.4% | 61.1% | 62.1% | 63.2% | 64.3% | 60.5% | 61.4% | 62.3% | 63.2% |

* Calculated from July 2006. Increment is paid from 2007. \$30 Threshold Price: \$30. \$40 Threshold Price: \$40. \$50 Threshold Price: \$50. Forecast with Ontrack production.



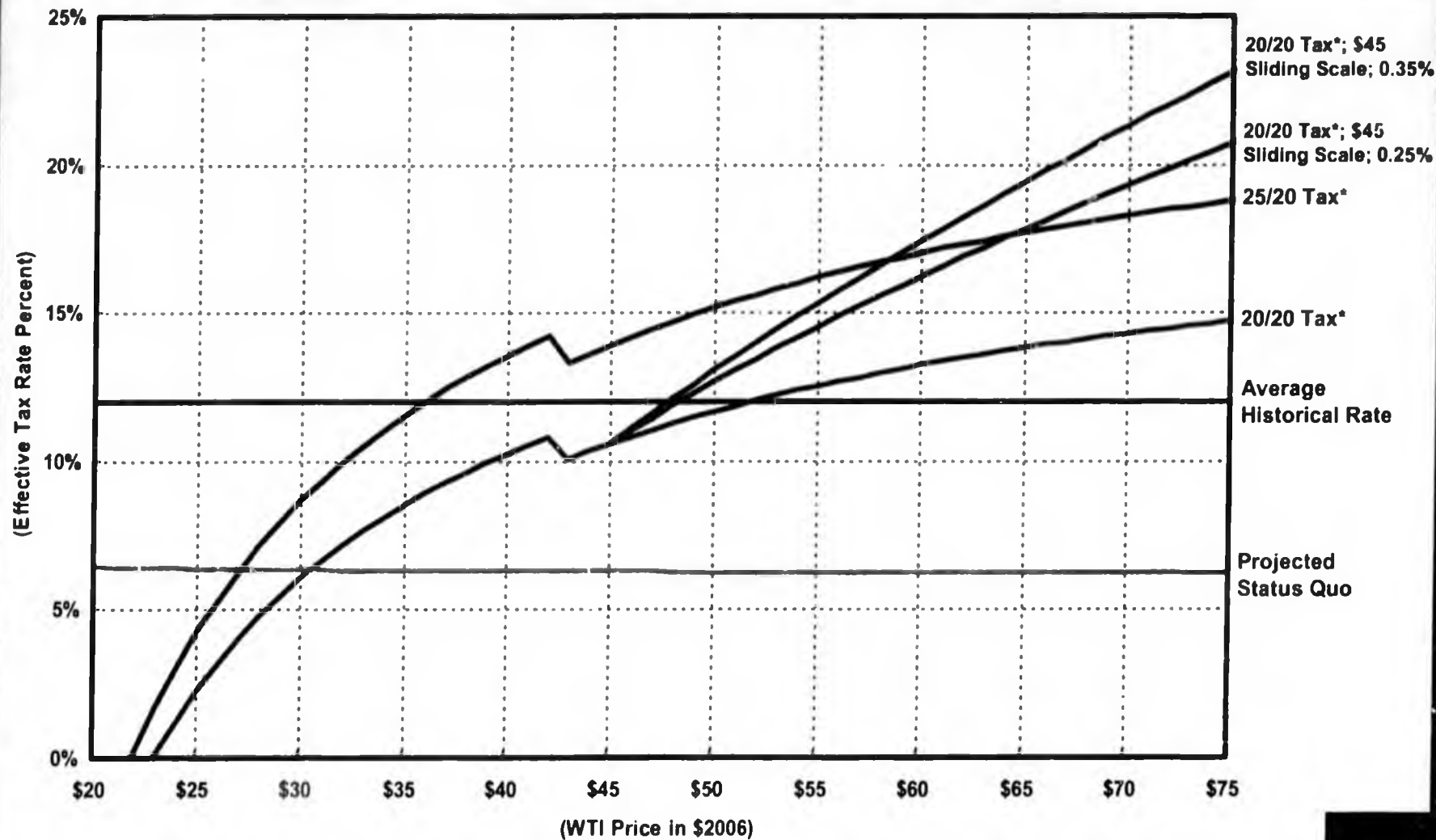
Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



* Calculated from July 2006; includes 6-year transition and \$73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.
Source: Historical: Alaska Department of Revenue.



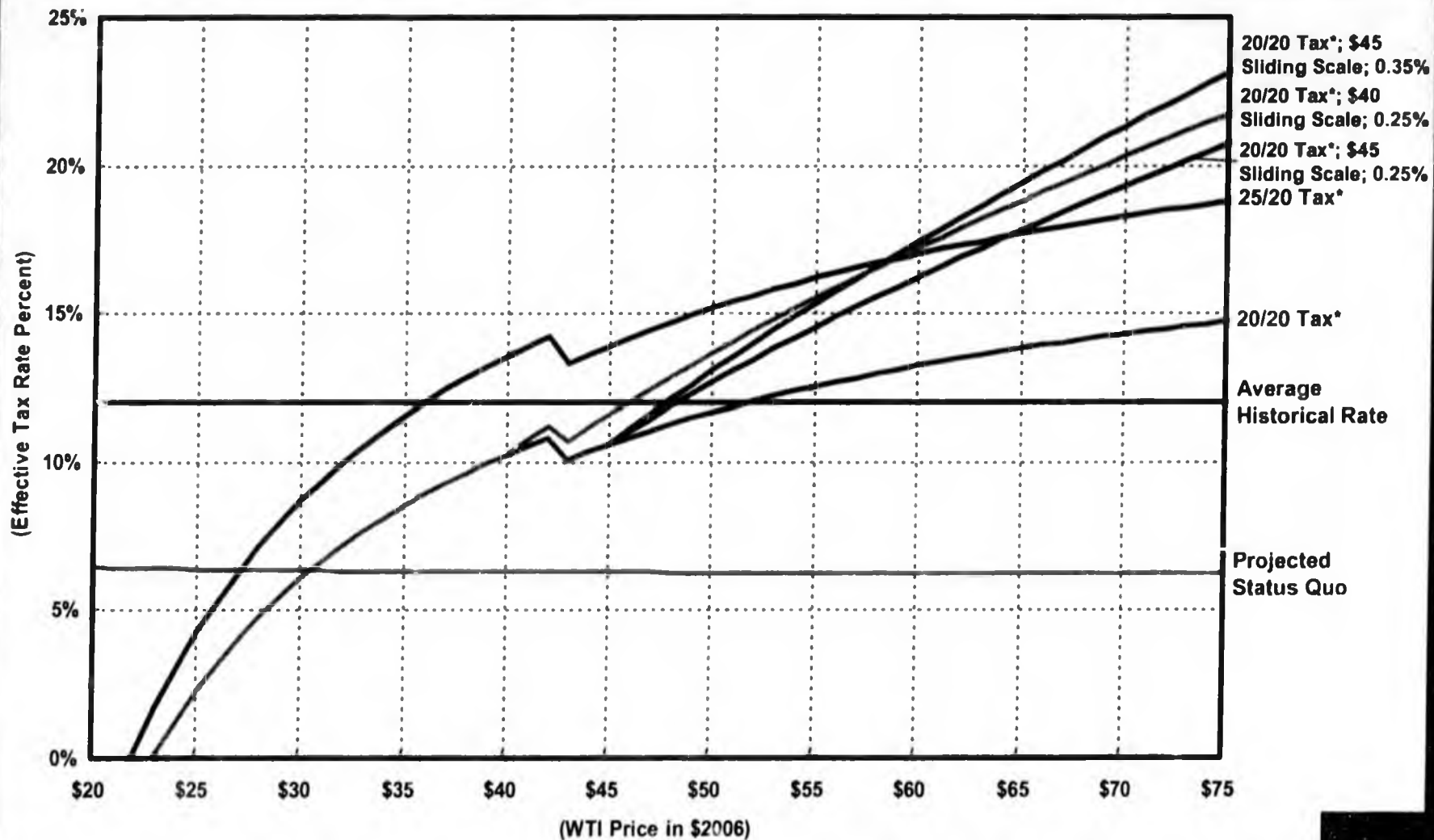
Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



Calculated from July 2006; includes 6-year transition and \$73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.
Source: Historical: Alaska Department of Revenue.

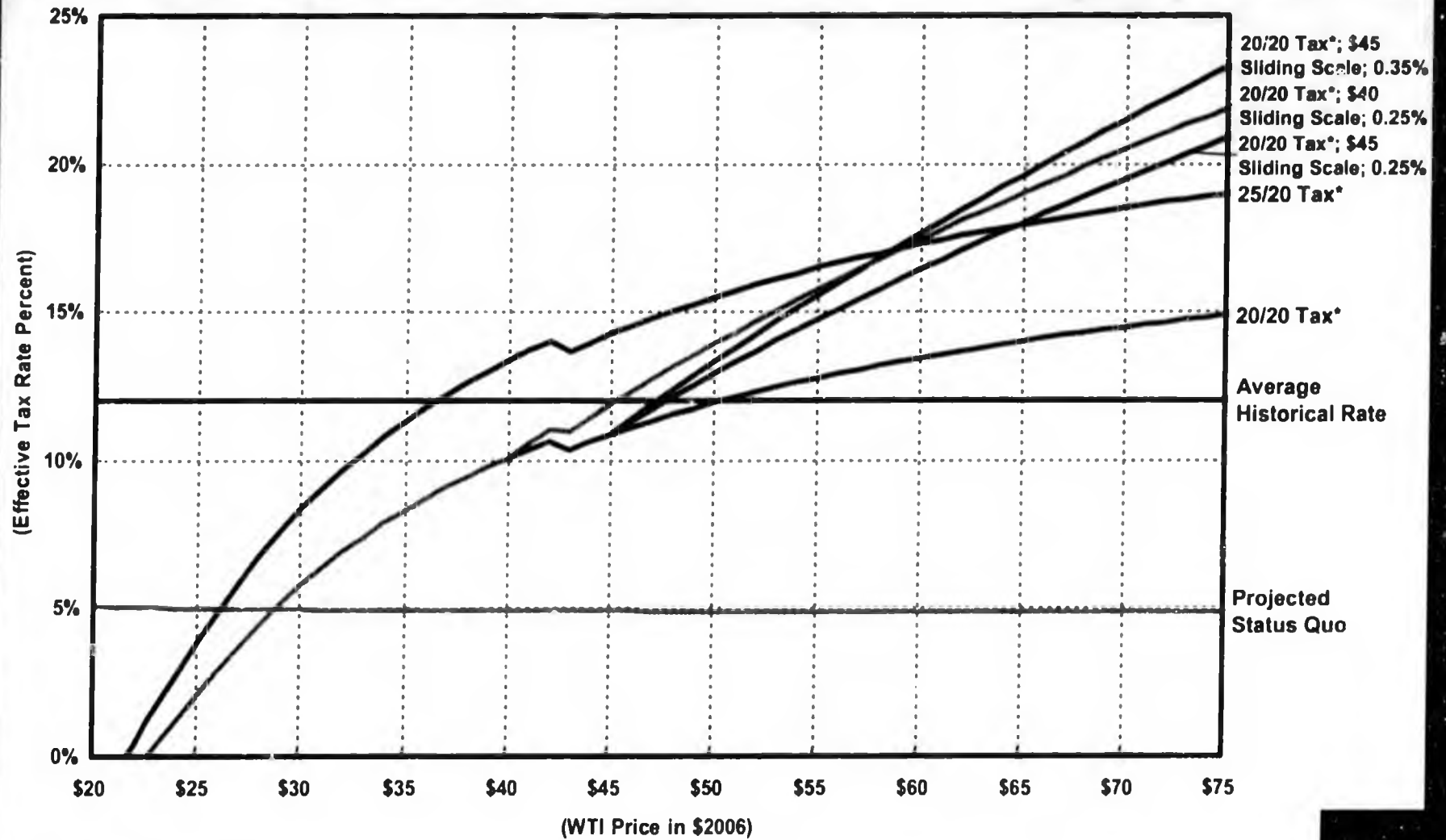


Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



* Calculated from July 2006; includes 6-year transition and \$73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.
Source: Historical: Alaska Department of Revenue.

Effective Average Tax Rates at Various Price Levels (FY 2007-2030)



* Calculated from July 2006; includes 6-year transition and \$73-Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.

Source: Historical: Alaska Department of Revenue.

Projected Government Takes with Sliding Scale Tax DOR Forecast Production (FY 2007-2030)*

| WTI Price (\$ 2006) | Status Quo | 20/20 with Sliding Scale Tax | | | | | | | | |
|------------------------|---------------|------------------------------|----------------------|-----------|-----------|-----------|----------------------|-----------|-----------|-----------|
| | | 20/20 | \$35 Threshold Price | | | | \$40 Threshold Price | | | |
| | | | 0.20% | 0.25% | 0.30% | 0.35% | 0.20% | 0.25% | 0.30% | 0.35% |
| | | | Increment | Increment | Increment | Increment | Increment | Increment | Increment | Increment |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | |
| \$30 | 57.0% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% |
| \$40 | 53.7% | 57.3% | 57.9% | 58.0% | 58.2% | 58.3% | 57.3% | 57.3% | 57.3% | 57.3% |
| \$50 | 52.3% | 56.9% | 58.5% | 58.9% | 59.3% | 59.7% | 58.0% | 58.2% | 58.5% | 58.7% |
| \$60 | 51.5% | 56.9% | 59.4% | 60.0% | 60.7% | 61.3% | 58.9% | 59.4% | 59.9% | 60.4% |
| \$70 | 50.9% | 56.9% | 60.3% | 61.2% | 62.0% | 62.9% | 59.8% | 60.6% | 61.3% | 62.0% |
| \$80 | 50.6% | 56.9% | 61.2% | 62.3% | 63.4% | 64.5% | 60.7% | 61.7% | 62.7% | 63.6% |

| WTI Price (\$ 2006) | 25/20 | 20/20 with Sliding Scale Tax | | | | | | | |
|------------------------|-------|------------------------------|-----------|-----------|-----------|----------------------|-----------|-----------|-----------|
| | | \$45 Threshold Price | | | | \$50 Threshold Price | | | |
| | | 0.20% | 0.25% | 0.30% | 0.35% | 0.20% | 0.25% | 0.30% | 0.35% |
| | | Increment | Increment | Increment | Increment | Increment | Increment | Increment | Increment |
| (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | |
| \$30 | 59.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% | 57.7% |
| \$40 | 59.7% | 57.3% | 57.3% | 57.3% | 57.3% | 57.3% | 57.3% | 57.3% | 57.3% |
| \$50 | 59.3% | 57.4% | 57.6% | 57.7% | 57.8% | 56.9% | 56.9% | 56.9% | 56.9% |
| \$60 | 59.3% | 58.4% | 58.8% | 59.2% | 59.5% | 57.9% | 58.1% | 58.4% | 58.7% |
| \$70 | 59.3% | 59.3% | 59.9% | 60.6% | 61.2% | 58.8% | 59.3% | 59.8% | 60.3% |
| \$80 | 59.4% | 60.2% | 61.1% | 61.9% | 62.8% | 59.8% | 60.5% | 61.2% | 61.9% |

* Calculated from July 2006; includes 6-year transition and \$73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.



Projected Effective Tax Rates with Sliding Scale Tax DOR Forecast Production (FY 2007-2030)*

| WTI Price (\$ 2006) | Status Quo | 20/20 with Sliding Scale Tax | | | | | | | | |
|------------------------|---------------|------------------------------|----------------------|-----------|-----------|-----------|----------------------|-----------|-----------|-----------|
| | | 20/20 | \$35 Threshold Price | | | | \$40 Threshold Price | | | |
| | | | 0.20% | 0.25% | 0.30% | 0.35% | 0.20% | 0.25% | 0.30% | 0.35% |
| | | | Increment | Increment | Increment | Increment | Increment | Increment | Increment | Increment |
| (Percent) | | | | | | | | | | |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | |
| \$30 | 4.9% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% |
| \$40 | 4.9% | 10.0% | 10.8% | 11.0% | 11.2% | 11.4% | 10.0% | 10.0% | 10.0% | 10.0% |
| \$50 | 4.9% | 11.9% | 14.3% | 14.9% | 15.5% | 16.1% | 13.5% | 13.9% | 14.3% | 14.7% |
| \$60 | 4.9% | 13.4% | 17.4% | 18.4% | 19.4% | 20.4% | 16.6% | 17.4% | 18.2% | 19.0% |
| \$70 | 4.8% | 14.5% | 20.1% | 21.5% | 22.9% | 24.3% | 19.3% | 20.5% | 21.7% | 22.9% |
| \$80 | 4.8% | 15.2% | 22.4% | 24.2% | 26.0% | 27.8% | 21.6% | 23.2% | 24.8% | 26.4% |

| WTI Price (\$ 2006) | 25/20 | 20/20 with Sliding Scale Tax | | | | | | | |
|------------------------|-------|------------------------------|-----------|-----------|-----------|----------------------|-----------|-----------|-----------|
| | | \$45 Threshold Price | | | | \$50 Threshold Price | | | |
| | | 0.20% | 0.25% | 0.30% | 0.35% | 0.20% | 0.25% | 0.30% | 0.35% |
| | | Increment | Increment | Increment | Increment | Increment | Increment | Increment | Increment |
| (Percent) | | | | | | | | | |
| (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | |
| \$30 | 8.3% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% | 5.8% |
| \$40 | 13.3% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% |
| \$50 | 15.5% | 12.7% | 12.9% | 13.1% | 13.3% | 11.9% | 11.9% | 11.9% | 11.9% |
| \$60 | 17.3% | 15.8% | 16.4% | 17.0% | 17.6% | 15.0% | 15.4% | 15.8% | 16.2% |
| \$70 | 18.5% | 18.5% | 19.5% | 20.5% | 21.5% | 17.7% | 18.5% | 19.3% | 20.1% |
| \$80 | 19.4% | 20.8% | 22.2% | 23.6% | 25.0% | 20.0% | 21.2% | 22.4% | 23.6% |

* Calculated from July 2006; includes 6-year transition and \$73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.



STATE OF ALASKA

DEPARTMENT OF REVENUE TAX DIVISION

FRANK MURKOWSKI, GOVERNOR

State Office Building
PO Box 110420
Juneau, AK 99811-0420
907.465.2320

550 W Seventh, Suite 500
Anchorage, AK 99501-3566
907.269.6620

www.tax.state.ak.us

March 13, 2006

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

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

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

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

Dear Senator Wagoner and Representatives Samuels and Ramras,

Thank you for the opportunity to respond to questions posed during (and following) recent committee hearings. This letter incorporates the answers presented during testimony which was based on our interim draft reports dated March 2 and March 7, 2006, and provides additional information not previously available. In addition, this letter expands some of the answers in response to followup questions posed during the hearings. We have included a substantial number of attachments which are indexed to the question number. Lastly, we have included an index, by topic, which should prove helpful.

DRAFT

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

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

| (millions) | Exploration | Dev. & Production* | Total |
|------------|-------------|--------------------|-------|
| 2001 | 152 | 1,636 | 1,788 |
| 2002 | 125 | 1,054 | 1,180 |
| 2003 | 90 | 970 | 1,060 |
| 2004 | 67 | 980 | 1,047 |

* We do not have information on the split between development and production expenditures.

Although we have not completed this work, we have some evidence about costs in 2005 and the first half of 2006 and it appears they will continue the downward trend seen in the four years presented.

DRAFT

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

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

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

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

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

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

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

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

A very small amount, probably no more than 1% of total state production of oil and gas. Currently it is limited to Alpine and its satellites and Cook Inlet, though production expected soon from the NPRA will also have private leasehold interest.

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

No, it was not considered.

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

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

DRAFT

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

Note: this question answers progressivity generally, but see definition at Question 91.

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

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

| Country | Region/Type | Feature | Oil/Gas | Old/New |
|---------|--------------|-------------------------------------|---------|---------|
| Canada | NWT | IRR based profit sharing royalty | Both | Old |
| | Newfoundland | IRR based profit sharing royalty | Oil | Old |
| | Nova Scotia | Payout based profit sharing royalty | Both | New |
| | Alberta | Production/Price | Oil | Old |

| | | | | |
|-------------------|-------------------|--|------|-----|
| | | sensitive royalty | | |
| | Alberta | Price Sensitive royalty | Gas | Old |
| | Alberta oil sands | IRR based profit sharing royalty | Oil | Old |
| Colombia | | Price sensitive windfall profits tax | Oil | New |
| Venezuela | Conventional Oil | IRR based profit share | Oil | New |
| Peru | | R-factor royalty | Both | New |
| Bolivia | | Profit sensitive Surcharge with uplifts | Both | New |
| Trinidad & Tobago | Conventional Oil | Supplemental Petroleum Tax, Price sensitive | Oil | New |
| | Deep water | Production/Price sensitive profit oil/gas shares | Both | New |
| Norway | | Uplifts on Hydrocarbon Tax | Both | Old |
| UK | Old licenses | Uplifts and Oil Allowance on PRT | Both | Old |
| Denmark | | Uplifts on Hydrocarbon Tax | Both | Old |
| The Netherlands | | Uplifts on Special Profit share | Both | Old |
| Algeria | | Cumulative Revenue sensitive PRT and uplifts | Both | New |
| Tunisia | | Sliding scale taxation | Both | New |
| Libya | | R-factor based profit oil splits | Oil | Old |
| Nigeria | | Uplifts and tax credits | Oil | Old |
| Angola | | IRR based profit oil shares | Oil | New |
| Qatar | | R-factor based profit oil shares | Oil | New |
| Saudi Arabia | | IRR based corporate income tax rates | Gas | New |
| Iran | | Buy Back contracts | Both | New |
| Pakistan | Offshore | Price Sensitive Windfall profits tax | Both | New |
| India | | R-factor based profit oil shares | Both | New |
| Thailand | | Profit sensitive SRB | Both | New |
| Malaysia | | Price sensitive windfall profits tax | Both | Old |

DRAFT