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**BP Presentation on PPT  
(CS HB 488 RES & CSSB 305 FIN)**

**Alaska State Legislature  
House Finance Committee  
27<sup>th</sup> April 2006**

For the record, my name is Angus Walker and I am the Commercial Vice President of BP Alaska.

I would like to start by thanking this Committee for the opportunity to again provide testimony on Committee Substitutes for House Bill 488 & Senate Bill 305.

I will not repeat our previous testimony, but would like to spend a few moments on the key issue for Alaska, production decline.

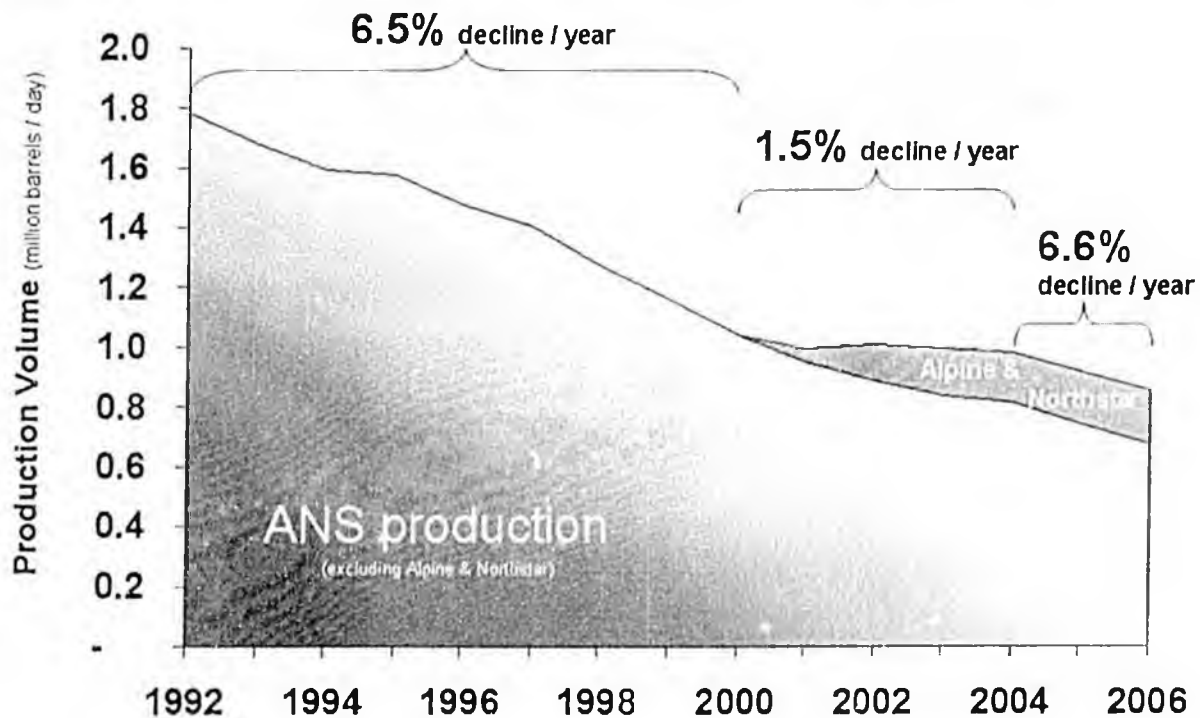
- **ANS production is declining rapidly, despite the current level of investment (circa 1 billion dollars per year).**
- **At the current rate of decline production will be about 450,000 barrels per day in 10 years.**
- **To achieve the DOR's latest production forecast, investment needs to be significantly higher than (at least twice) the current level of investment.**
- **The revenue projections provided to the Legislature by DOR & the consultants do not tell the whole story.**
  - **They rely upon production forecasts which require significantly more capital than is currently being invested.**
  - **They make no attempt to quantify the adverse impact that increased taxes will have on investment.**

Decline poses a serious risk to Alaska's future. And as such, it is essential that we carefully consider these factors. We believe that upon reflection you will agree a lower tax rate will reduce risk by attracting more investment and generate more production, more revenue, more jobs, more economic activity, more contributions to the Permanent Fund and more sustainable benefits for Alaskans. A lower tax rate will also mean a healthier oil business and stronger foundation on which to build the gas pipeline.

## Alaska North Slope Production Decline

Since 1999, both Industry and DOR have consistently overestimated production and have annually revised production forecasts down significantly. This is of great concern to us as it will be to you.

ANS production is declining rapidly, despite the current level of investment (approximately \$1 billion per year).

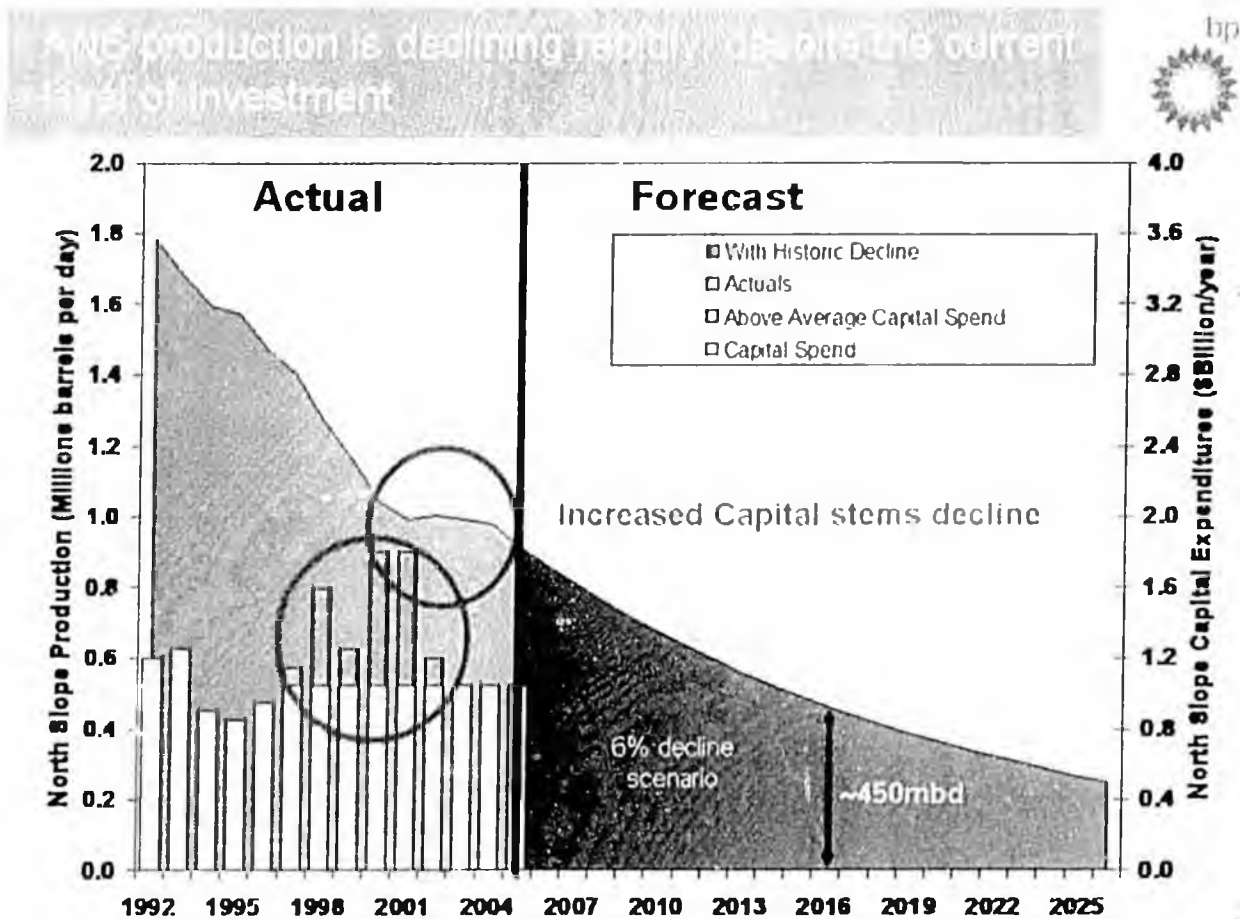


Many of you have heard us state that ANS production is declining at 6% per year. Why do we say that? For the eight years leading up to 2000, ANS production declined at a rate of about 6% per year. The development of Alpine, Northstar, and the Prudhoe Bay Satellites between 2000 and 2002 successfully stemmed North Slope decline for a number of years. However with NorthStar & Alpine on plateau or declining, 2005 saw a return to the 6% decline rate that has characterized this basin in the past. Unfortunately for all of us, there are no more fields of Alpine or Northstar's magnitude waiting to be developed.

## Investment leads to Production

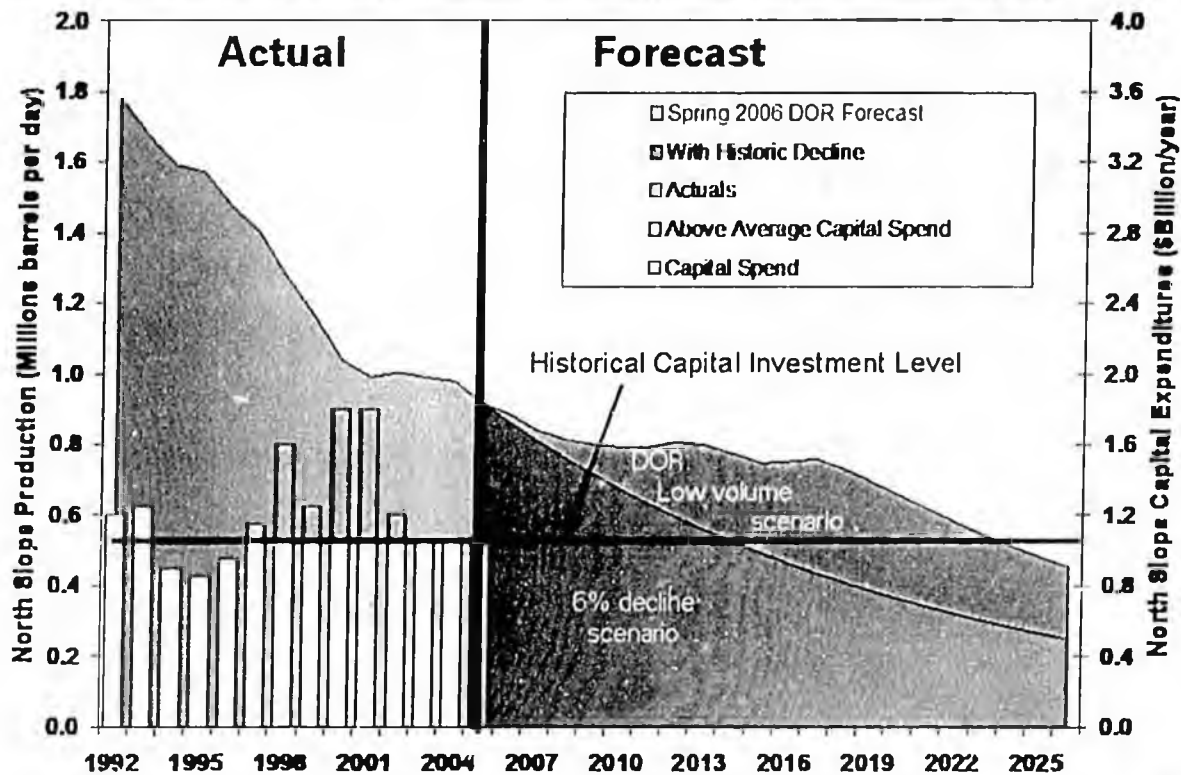
The decline abatement experienced about 2000 required investment levels above historical averages. This graph demonstrates the cause and effect relationship between investment and production.

This graph also extrapolates the 6% historical decline to demonstrate what will happen to production if investment remains at current levels. Within ten years ANS production will be approximately 450 mbd. This projection assumes investment stays at historic levels and is not adversely affected by increased taxation.



## Significant additional investment is required to offset decline

To achieve the DOR's latest production forecast, investment needs to be significantly higher than (at least twice) the current level.



The latest DOR 2006 spring forecast is the line above the blue wedge. The wedge represents the difference between the Spring forecast and expected decline at current investment.

This cause & effect (investment and production) demonstrated in the 1998 to 2004 timeframe provide a vivid illustration of why significant investment is required to meet the DOR Spring forecast. This future can only be realized if Alaska also realizes a significant investment increase. It is unrealistic to assume that the tax increase contemplated by the current version of SB305 will lead to a significant investment increase – like the one Alaska needs tomorrow. We need to ask ourselves what we want? Unless those investments are made, decline will continue at the current rate and the DOR will be revising its production forecast down yet again.

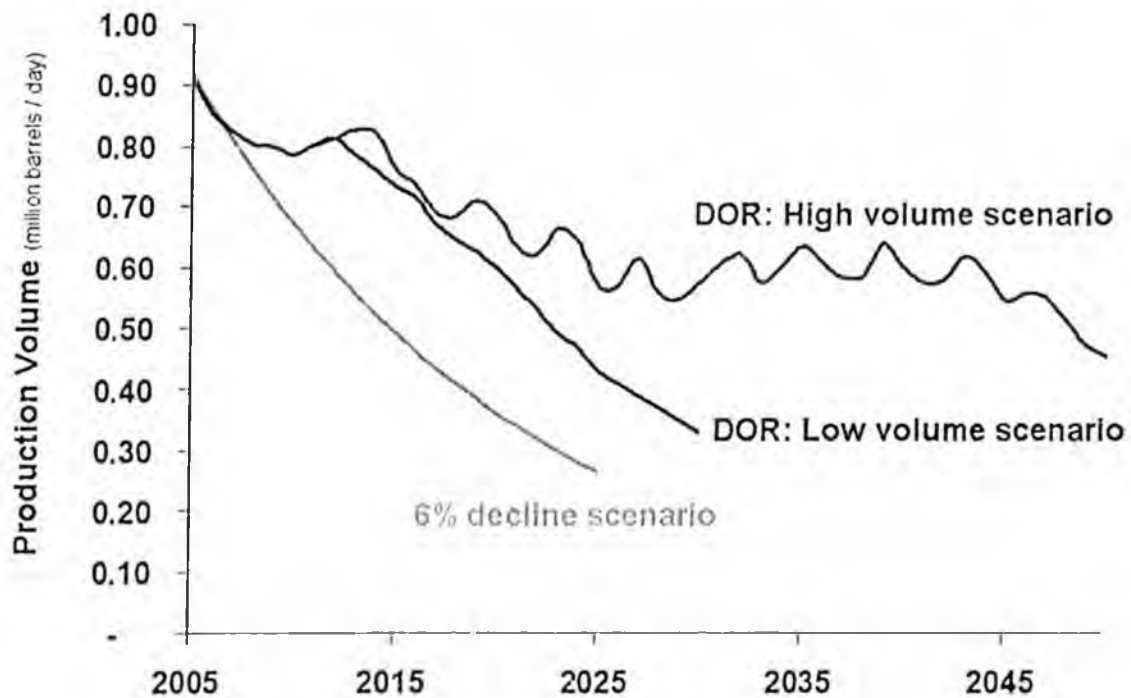
The blue wedge is 1.3 billion barrels of production over twenty years. At today's prices that represents tens of billions in state revenue lost because oil was left in the ground. This is before any consideration for the economic multiplier effect that the billions of investment would have created for the economy, for jobs, for Alaskans and for Alaskan businesses.

If the question is, "how do we maximize benefits for the people of Alaska?" We believe that the answer is not, "by increasing taxes on the oil industry."

## Production Profiles

It is important to recognize that there is a big difference between production forecasts that have been used to demonstrate the mechanics of the PPT tax and Alaska's current reality. You will recognize the forecasts below. The key point here is that the DOR "low volume" and "high volume" production scenarios would necessitate significantly more investment than Alaska is attracting today. The "low volume" forecast would require at least twice the current level of investment (c. \$1 bn per year) and the "high volume" scenario, much-much more. Given this fact, we believe it is unreasonable to assume that these scenarios represent the future profile in Alaska after a tax increase like the one contemplated today.

To achieve either the low or the high volume scenarios, investment levels would be significantly higher than current levels.



## Conclusion

- The decline of North Slope production is the most serious threat to Alaska's future.
- The tax regime you approve will directly impact how attractive Alaska is for investment and that will translate into a new investment and decline profile.
- The highest state revenue is derived from the greatest production not highest tax. And benefits are maximized when increased investment spurs economic activity, creates jobs, offsets decline and extends the life of Alaska's oil and gas businesses.

The 20 percent PPT tax would increase the marginal tax rate on our Alaska operations from 56% to about 61%. According to the DOR, this would generate an additional \$1 billion a year in state revenue at current oil prices and swell the state's substantial budget surplus.

BP agreed not to oppose this significant oil tax increase as a means of advancing the gas project. It was not an easy concession to make.

First, this increase in tax only makes sense if the future includes a gas pipeline. Without gas production, this tax increase – over time – will speed the decline and shorten the economic life of existing North Slope fields.

A lower tax rate will reduce risk by attracting more investment and generate more production, more revenue, more jobs, more economic activity, more contributions to the Permanent Fund and more sustainable benefits for Alaskans. A lower tax rate will also mean a healthier oil business and stronger foundation on which to build the gas pipeline.

On behalf of BP I would like to thank you for this opportunity to testify.

Angus Walker  
Commercial Vice President  
BP Exploration (Alaska) Inc.

*Note: BP has separately provided the committee written documentation summarizing the key issues relating to the proposed legislation and BP's specific recommendations and rationale for those recommendations for the committee's consideration. [Reference letter of April 27, 2006 from Angus Walker to House Finance Co-Chairs Chenault and Meyer]*



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April 27, 2006

The Honorable Mike Chenault  
Co-Chair, Committee on Finance  
The Alaska House of Representatives  
Alaska State Capitol, Room 505  
Juneau, AK 99801-1182

The Honorable Kevin Meyer  
Co-Chair, Committee on Finance  
The Alaska House of Representatives  
Alaska State Capitol, Room 501  
Juneau, AK 99801-1182

**Re: PPT Legislation: Corrections to Our Letter Earlier Today**

Dear Representatives Chenault and Meyer:

During the course of our testimony to the House Finance Committee today regarding the PPT, two errors were identified in the written letter that we submitted in conjunction with our testimony. We would like to take this opportunity to correct them for the record. First, on page 2 of that letter in the last paragraph under "Special Conditions on Using Capital Credits," the reference in bold font to "AS 43.55.160(j) and (k)" should have been to "AS 43.55.024(j) and (k)". Second, on the last page of that letter in the third-to-last paragraph, the reference in bold font to "subsections (j) and (k) in AS 43.55.160" should have been to "subparagraph (d)(2)(P) and subsection (i) in AS 43.55.160".

We apologize for not having caught these errors before submitting the letter, and we thank you for this opportunity to correct them.

Yours sincerely,

Angus J. Walker  
Commercial Vice President, BP Alaska



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**Re: PPT Legislation**

Dear Representatives Chenault and Meyer:

Thank you for the opportunity to comment on the proposed PPT legislation pending before the House Finance Committee. In my opinion, the greatest threat to Alaska's prosperity, jobs and economic well-being in the future is the ongoing decline of oil production. To counter this threat there must be a major increase – at least a doubling – of industry investment on the North Slope. The structure of the PPT has the potential to make Alaska more attractive to investors, but it will only serve Alaska well if the numbers are right and the mechanics are clear and workable. As drafted the bill threatens to frustrate this potential. Following is BP's view of the key provisions and recommendations for the committee's consideration:

**PPT Rate.**

- **Oil:** Significant additional investment is urgently required to stem North Slope production decline. More investment, more production, more jobs, and the resulting benefits to the state economy are better for Alaska than short term increases in revenue. And more investment promises greater total state revenue in the long run. We therefore urge the Legislature to **adopt an oil tax rate which is less than 20 percent.**
- **Gas:** An effective PPT tax rate of 1/3 that proposed for oil is appropriate for gas.

If there is a desire to tax gas or a particular category of oil at a different rate from the general one, the best way to do it is to exclude a portion of the value of that oil or gas from the PPT calculation instead of creating a separate PPT rate for it.

**Progressivity.** We remain firmly of the belief that **further progressivity above that provided by the PPT structure runs counter to Alaska's goal of maximizing benefits for its people.** We continue to hold that investment and economic growth provide more benefit and revenue than increased tax. Further, if one can justify, which we cannot, increasing the tax rate as the price of oil increases, then is it not equally justifiable to reduce it as the price of oil falls?

However, if the Legislature views progressivity as a necessary element of PPT, care should be taken to ensure the structure chosen is durable. Specifically we would contend:

- It's preferable to **base progressivity on the net "production tax value"** as the Senate Finance CS did. To do otherwise would introduce a deterrent to investment as costs of production increase and consume a larger portion of the value of the oil.
- The trigger point for progressivity must be **adjusted for inflation** or it will increasingly become unreflective of economic reality. It is worth recalling that the \$33 price for North Slope oil in 1980 is equivalent to more than \$71 today, solely because of inflation.

**Capital Credits.** Because of the design of PPT, a higher credit will increase reinvestment in Alaska and help meet Alaska's urgent need for significantly increased investment to counter North Slope production decline. **The proposed 25% credit for capital expenditures in the Senate's version is superior to the 20% credit in the House Resources CS.**

**Special Conditions on Using Capital Credits.** This change was added to the PPT by a floor amendment in the Senate. Superficially it sounds like a good idea: requiring the producers to pass on the benefits of their PPT credits to third parties who are using the producers' production facilities and pipelines. This would be logical if the PPT were part of the costs that producers include in the tariffs and fees charged for using their facilities, but PPT won't be part of those costs any more than state royalties on the producers' production would be. Tariffs and fees are based on the operating and capital costs for the facilities, not on the obligations that fall on the producer as a result of producing its own oil or gas, such as royalty, PPT or something else like income tax.

CSSB 305(FIN)AM further provides that if the PPT-credit benefit is not passed on to third parties through the tariffs and fees producers charge for using their facilities, DOR can disallow the credit retroactively for the periods when it is found not to have been passed on. This would throw the value of a credit completely up in the air until DOR can audit and confirm that the benefit from it was passed on. The effectiveness of the credit as an incentive for investment will be all but lost because of the uncertainty caused by the unnecessary and ill-advised provisions in **AS 43.55.160(j) and (k) of the Senate's version, which should be deleted as bad policy acting directly against the intent of the PPT bill and the need to attract investments to Alaska.**

**Transition (TIE) Credits.** It is appropriate and common practice to allow transitional relief for investments made under the ELF-based production tax. When Alaska switched from separate-accounting to its present income tax at the end of 1981, it provided transitional relief even though, as in the past five years, oil prices had risen significantly while separate-accounting was in effect.

CSSB 305(FIN)AM recognizes capital investments during the five years before PPT, but limits the use of the credit according to how much new investments are being made. While this limitation introduces a hurdle which a producer must overcome before it can get the benefit of the TIE credit, we recognize it is consistent with addressing the need for significant additional investment that is so urgently

required to stem North Slope production decline, and so we accept the Senate-passed version as a reasonable resolution of the transition issue.

**Effective Date.** Retroactivity is both unfair and problematic and could lead to delays, disputes and litigation, particularly when it involves the complete restructuring of a major tax like the proposed transformation of the ELF-based production tax into the PPT. April 1<sup>st</sup> as an effective date already involves a degree of retroactivity, which becomes greater and more unfair with each day. **July 1, 2006 would be an acceptable effective date, provided there is a transitional provision allowing taxpayers to report initially on the basis of the present ELF-based tax for a reasonable time until they can adapt their computer systems and software to the new PPT, and then they would pay the difference.**

**Use of Royalty Netbacks for PPT.** The House Resources CS, like the original Bill, would authorize, but not require, DOR to let producers determine the "gross value at the point of production" of their taxable oil and gas on the basis of three alternative approaches: the netback determined under their royalty settlement agreements with the State, the netback determined on a basis acceptable to DNR in the case of production from state lands (to the U.S. Interior Department when state land is not involved but federal land is), and "another formula" adopted by DOR for determining the value of oil or gas "at a specific geographic location."

The version passed by the Senate deletes reference to these three netback approaches altogether. The resulting silence on the matter in the Senate version would not bar DOR from using either or both of the royalty-based approaches, nor from using some other royalty-based approach. Since the door for using them remains open, we believe it is better for the Legislature to clarify their intention and provide specific guidance permitting DOR to use royalty-based netbacks as the House Resources CS does.

**Disallowance of "Abandonment" Costs.** This is a feature of the Senate-passed Bill that is not in the House Resources CS. We also believe these provisions are unnecessary because of the already-existing provisions in all versions of the Bill that require costs to be "ordinary and necessary" costs of producing oil or gas from that field in order to be deductible.

Worse, the Senate's provisions are ill-drafted and overly broad. Every time we cement an existing well, it might arguably constitute an "abandonment" of that well, even though we cement it in order to redrill it to a different bottom-hole location. Similarly, any time we replace a worn-out or out-dated piece of equipment or hardware, the removal of the old one might arguably constitute an "abandonment" of it. Applied in this fashion, the current version of SB 305 would open up normal field operations to almost innumerable "mini-abandonments" on an practically everyday basis. And for each "abandonment" its costs would be partially disallowed in proportion to the ratio of cumulative production as of the PPT effective date to the cumulative production as of the date when the "abandonment" occurs. This scenario would make PPT almost impossibly complex for producers to comply with and for DOR to administer and enforce. **For these reasons we believe the "abandonment" cost provisions in the Senate version should not be included in the House Finance Committee's CS.**

**90% vs. 95% "Safe Harbor".** Whether at 90% or 95%, the present provisions do not account for practical limitations in the real world and thus are unduly harsh and unfair. Producers cannot know in the early months of the year what that year's capital expenditures are going to be, both in terms of how much of the budget will be spent and in terms of how much whatever is spent will end up being properly classifiable as "capital" expenditure, which generates a tax credit. If capital spending comes in below budget for a year, the deduction and the tax credit for it will be less than planned earlier in the year, which in turn will make the PPT for those early months higher than planned at the time the payments for those months were made. Coming in under budget is a good thing that the State should encourage, but as the PPT is drafted now, it will likely trigger penalties and interest the further below budget the expenses are.

A 95% figure could be used for the "safe harbor" if it is based on the cumulative PPT for the current and prior production months in the year, using the information currently available at the end of each month of production. The 95% PPT payment could continue to be "due" at the end of the month after the one when the oil and gas are produced, which will allow interest to accrue starting then on an underpayment that falls outside this "safe harbor." **The AOGA letter of April 13<sup>th</sup> included a proposal to achieve this fair result, and we endorse it.**

**Definition of Deductible Costs.** In both the House Resources CS and the Bill passed by the Senate, deductible costs are defined in AS 43.55.160(c)(1) as "direct, ordinary, and necessary costs" of exploring for, developing and production oil and gas. "Direct costs" are defined in the new statute, and so is the phrase "ordinary and necessary." The intent is clear that, taken together, these two partial definitions define the combined term, "direct, ordinary, and necessary costs" – they are simply costs that are both "direct" and "ordinary and necessary." But any experienced lawyer will tell you that, legally, this is not necessarily the result because the terminology is not exactly the same. To ensure that the intent is carried out, all that is needed is to add language explicitly saying that the combined term does equal the sum of these two individually-defined parts. **In its April 13<sup>th</sup> letter to you the Alaska Oil & Gas Association offered specific language to do this, which we endorse.**

The present definition of deductible cost also speaks in terms of "costs incurred upstream of the point of production" for the oil or gas. Many costs that are clearly "upstream" in nature – such as the cost of helicoptering crews out to platforms in Cook Inlet – cannot be tied directly to any particular point along the route of the oil and gas as it moves from the reservoir to its eventual "point of production." While we believe the Legislature's intent here is clear, the present Bill language opens the door for arguing that such upstream costs are not "upstream" for purposes of being deductible for PPT. **In its April 13<sup>th</sup> letter to you the AOGA also offered specific language to clarify this, which we endorse.**

**Costs from Non-Arm's-Length Transactions.** In order for PPT to work, it is essential that its two central elements – the "gross value" of oil and gas and the "lease expenditures" to be deducted from that gross value – be done right. It would be a serious mistake to define lease expenditures in a way that involves special books, records and accounting methods that are unique to PPT, nor is it necessary to create a unique system like that. For this reason all versions of the PPT Bill wisely direct DOR, for purposes of determining deductibility, to follow industry practice about billable costs and authorize DOR to approve the use of costs billed by the operator to partners as the deductible lease expenditures for that field or exploration prospect.

Representatives Chenault & Meyer  
Re: PPT Legislation  
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Within this framework, the Senate has introduced special provisions invoking the "concepts" of sections 482 and 6662(e) of the Internal Revenue Code to deal with the matter of costs arising under transactions at less than arm's length. In terms of providing clarity and simplicity for PPT, it should be noted that these federal statutes, particularly section 482, are among the most difficult, cumbersome and fought-over provisions of the Internal Revenue Code. When the IRS invokes section 482 against a taxpayer, it often entails a sustained effort lasting a decade or longer.

These new special provisions are unnecessary where there is one or more partners in a field or exploration prospect with a sufficient stake in the costs to police the operator's billings effectively, and they create potential ambiguity and conflict with the other PPT provisions that already deal appropriately with less-than-arm's-length costs. First, the operator's partners themselves are going to be particularly concerned to make sure a billed cost is appropriate when it arises from a such a deal, and so there will already be a strong element of self-policing by the partners. Moreover, the requirement that lease expenditures be "ordinary and necessary" costs, as defined for IRS purposes, allows DOR to police the costs arising under less-than-arm's-length transactions even if the operator's partners somehow failed to police those costs. This makes the use of "concepts" from federal sections 482 and 6662(e) unnecessary. Second, introducing those federal "concepts" will create ambiguity to the extent they might be inapplicable to, inappropriate for, or inconsistent with the framework the Legislature is creating for PPT.

Where there is only one company involved or where the partners lack a sufficient stake in the costs to police the operator's billings effectively, the federal "concepts" are still unnecessary because of the "ordinary and necessary" requirement for expenditures to be deductible.

**For these reasons, we believe subsections (j) and (k) in AS 43.55.160 of the Senate-passed version of the Bill should be deleted.**

If, however, it is considered prudent or necessary to include specific language to deal with less-than-arm's-length costs in this situation, the Senate Finances CS did this by simply prescribing that such costs are limited to the "fair market value" of the goods or services involved. This effectively reached the desired outcome under the "concepts" of the two federal statutes, but without the enormous complexity, time, effort and controversy which those statutes entail.

I hope these comments are clear and helpful in your deliberations. We remain available if we can be of any further assistance to the committee.

Yours sincerely,



Angus J. Walker  
Commercial Vice President, BP Alaska

THE  
FOLLOWING  
DOCUMENT(S)  
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# Key PPT Issues and Recommended Solutions



ITEM	CSHB 488 (RES)	CSSB 305 (FIN)am	OTHER
PPT Rate	20%	22.5%	<20%
Progressivity	0.3% per \$ WTI spot > \$50	0.2% per \$ ANS West Coast spot > \$50	NONE
Credit	20%	25%	
Special Conditions on Credit	NONE	3 <sup>rd</sup> party	
Transition (TIE) Credits	1Q06 only	Last 5 years: 2-to-1 new investments to old	
Effective Date	1 April 2006	1 April 2006	1 July 2006
Use of Royalty Netback	Allowed	Silent	
"Abandonment" Costs	Already Addressed	Overkill	
Safe Harbor	90% each month: interest + special penalty + reg. penalty	95% each month: interest + regular penalty	95% due cumulatively during year, delinquent after 3/31 of next year
Deductible "lease expenditures"	Fragmented	Fragmented	Clarify definitions (AOGA proposal)
Non-Arm's Length Costs	Addressed	Overkill (IRC 482)	Fair Market Value (as in CSSB 305 (FIN))

TESTIMONY OF RICHARD OWEN

ON PROPOSED CSHB 488 TO THE HOUSE FINANCE COMMITTEE

March 30, 2006

Mr. Chairman, Members of the Committee:

Good afternoon. My name is Richard Owen and I am the Production Manager for ExxonMobil in Alaska and Vice President of ExxonMobil Alaska Production.

I am here today to discuss ExxonMobil's concerns with the Committee Substitute to HB 488. Before I go into our specific concerns I would like to take a few minutes to describe ExxonMobil's history in Alaska, how tax systems impact investments and our assessment of the remaining resource potential on Alaska's North Slope.

ExxonMobil has had a presence in Alaska for over a half century, investing more than 11 billion dollars in the State's economy. Currently, ExxonMobil has working interests in Prudhoe Bay, Kuparuk, Endicott and Granite Point. We are the operator of the Point Thomson Unit, and are the largest interest holder in the Prudhoe Bay field. Our current working interest oil production is approximately 180,000 B/D (*Note: EMWT 159,000 EMN*) and we are the largest owner of discovered gas resource. We are proud of the role our company has played in Alaska through exploration; initial field developments; construction of TAPS; development of new technology; and the promotion of efficient reservoir management practices. Today, our production from Alaska represents approximately 4% of ExxonMobil's worldwide oil and gas production. Our Alaskan

production is primarily from Prudhoe Bay and near-by satellite fields. Prudhoe Bay, along with Point Thomson, has significant remaining potential but it comes at higher cost and risk.

One of ExxonMobil's objectives in both the gas pipeline fiscal contract negotiation and the discussion on oil taxes has been to reduce the risk associated with fiscal changes by working with the State of Alaska to establish a predictable and durable fiscal environment in which to make long term investment decisions. Changes in the fiscal regime for oil directly impact how we view the stability of the Alaskan fiscal environment, which in turn, impacts how we evaluate ongoing investment decisions. Tax systems need to be carefully designed to ensure the desired objective of resource development is achieved. To that end it is critical to take into account the quality of the remaining resource otherwise a change may result in unintended consequences, such as reduced investments and lower reserve recovery.

When I say quality of resource, I mean: the size and nature of the oil and gas reservoirs, the cost and technology required to develop those reservoirs, the distance to market, as well as the tax and royalty system that applies including the long-term stability of that system. Countries that are experiencing significant industry investment have achieved the proper balance in their fiscal regimes. ExxonMobil's assessment of the remaining oil resource suggests future growth opportunities will come from: complex enhanced oil recovery (EOR) projects, development of smaller, more marginal oil accumulations, and the innovative development of viscous and heavy oil resources. These opportunities will require the development and application of new technology, higher unit development

costs, and more complex operations to deliver a given production rate. These resources are much lower in quality as compared to Prudhoe Bay and Kuparuk, though they face the similar challenges associated with Arctic conditions and distance to market.

Therefore, we are concerned that the Administration's original proposal is weighted towards a higher tax which could prevent some of Alaska's challenged resources from being developed. The Committee Substitute contains even higher tax rates, which may prevent more of these challenged resources from being developed.

On February 28, I testified before the House Resources Committee about our key concerns with HB 488 as originally proposed. On March 18, I testified again before the House Resources Committee about how the proposed changes incorporated in the Committee Substitute bill exacerbate our concerns. I do not intend to cover all of my previous testimony but I will provide comments on two key areas: the addition of the progressive tax rate; and the elimination of the transition provisions.

HB 488, as originally proposed, represented a significant tax increase on the industry. And as I just outlined, we are concerned that the higher tax rate could prevent some of Alaska's remaining challenged resources from being developed. The committee substitute bill increases the tax rates as oil prices increase.

Too high a tax rate discourages investment. Companies are willing to accept the risks of long-term, capital intensive investments when there is a corresponding opportunity for upside potential through a variety of factors, such as increased production or higher

prices. When you limit or reduce the benefit that Companies can achieve from the upside factors, you reduce the attractiveness of those investment opportunities. The proposal to increase the already high base tax rate as oil prices increase, reduces or limits the upside potential which will result in Companies recalibrating investment decisions. Reduced investment will result in reduced resource recovery, diminished state revenues and fewer employment opportunities, with a resultant negative impact on the state's economy. Again, let me reemphasize this point. While higher taxes may bring in additional revenues in the short-term, any reduction in investment and subsequent production will significantly impact those revenues in the longer term. We think that the focus of the tax bill should be encouraging investment and growing production.

I would now like to discuss the Committee Substitute's elimination of the transition provisions. The benefits from a typical oil and gas investment take many years to be realized. Satellite and tertiary recovery investment decisions by our Company during the last five years were made under the ELF structure, anticipating a lower tax relative to that proposed under the PPT bill. The State appropriately provided this incentive so that these challenged and costly projects could be commercially viable. HB 488, as originally proposed, recognized that it is not appropriate to suddenly increase taxes on these investments without providing some form of consideration. The transition provisions in HB 488, as originally proposed, contained a five year transition period into the higher tax PPT system. This represented a reasonable transition by mitigating the increased tax treatment to which these projects will now be subjected. To avoid penalizing these recent investments, the transition provisions included in that bill are essential. The Committee Substitute bill eliminates these transition provisions and fails to adequately address the

significant increase in tax burden these past investments will now have to bear. Removal of the transition provisions would decrease investor confidence.

Despite our concerns with HB 488 as originally proposed, we are prepared to move forward under that system as originally proposed, since it sought to provide a balance of revenues to the state and producers across a range of oil prices, provided sufficient incentive for producers to undertake exploration and development risks, and included reasonable transition provisions for past investments. And, most importantly for ExxonMobil, oil fiscal contract terms consistent with the Administration's proposal would provide the predictability and durability necessary to advance the gas project to the next phase.

Let me reiterate that the quality of the resources, the risks undertaken by a producer, and the impact on the state's overall investment climate must be factored into the design of the tax system. While industry needs predictably and durability under which to gauge investment decisions, the attractiveness of that predictably and durability is lost if it comes at too high a cost.

As I mentioned earlier, the Committee's proposed substitute exacerbates our key concerns regarding both tax rates and transition provisions. We urge this Committee to support HB 488 as originally proposed.

Thank you again Mr. Chairman for the opportunity to testify today

# HB 488 (CS) Testimony

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ConocoPhillips Alaska  
March 30, 2006

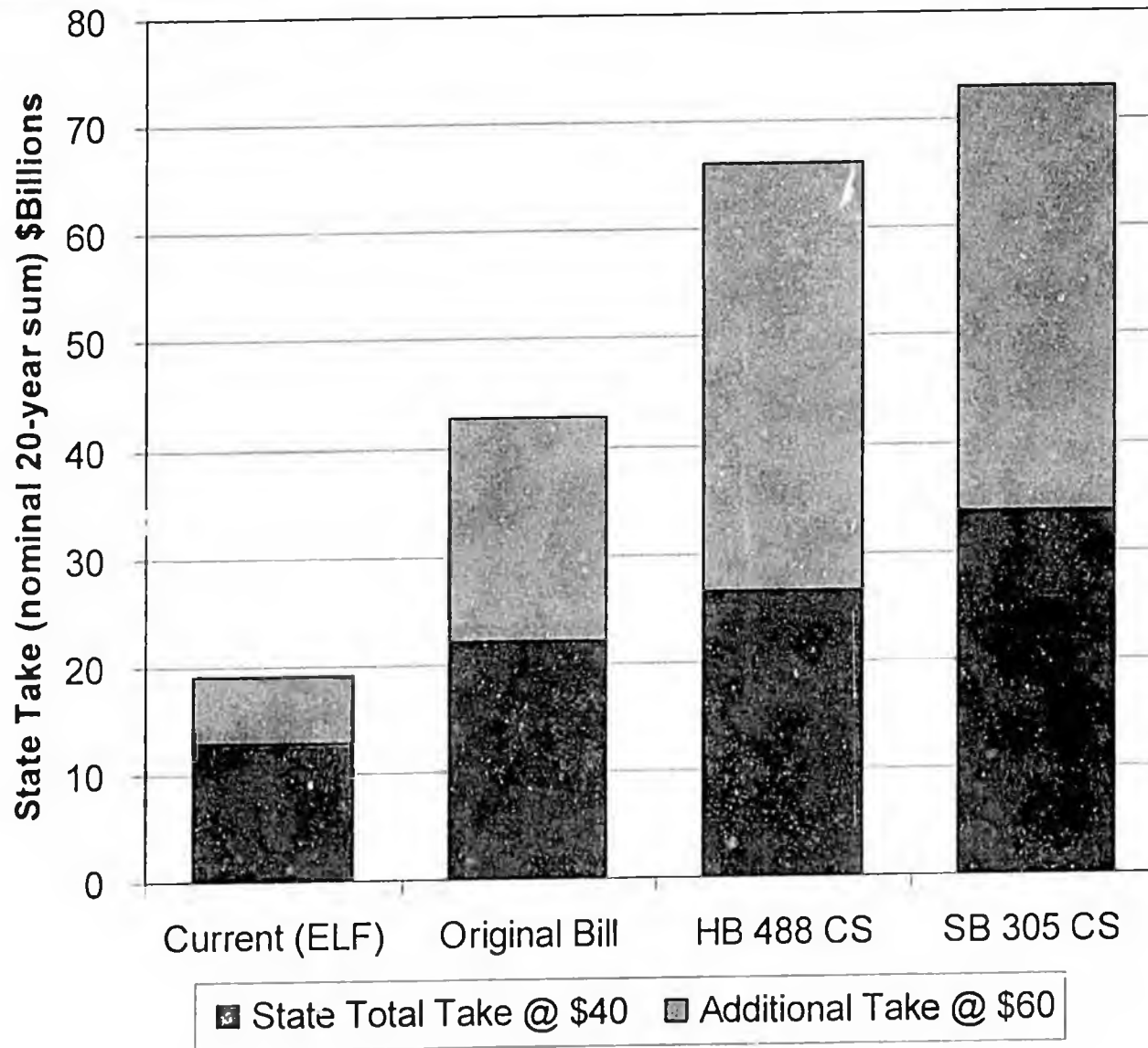
**Jim Bowles**  
**President**  
**ConocoPhillips Alaska**

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**Marianne Kah**  
**Chief Economist**  
**ConocoPhillips**

**CRA International**

# Projected Tax & Royalty Revenues



I, N, V, E, S, T, M, E, N, T,

BEATS

T, A, X

EVERY TIME

## WHEN YOU ADD IT ALL UP...

### TRIPLING TAXES ON ALASKA'S #1 ECONOMIC ENGINE IS NO WINNING MOVE.

In 1982, the Alaska Legislature passed the most aggressive tax increase in the history of the state.

One of the goals was to increase the corporate tax rate from 12% to 18% on a permanent basis. This was part of a broader tax increase package providing more revenue for Alaska's public safety, education and other state programs.

One of the goals was to increase the tax rate on oil and gas production from 12% to 18% on a permanent basis. This was part of a broader tax increase package providing more revenue for Alaska's public safety, education and other state programs.

What is the result? Higher taxes on oil and gas production. Instead of allowing the revenue to be used to increase state education, health care and other programs, the legislature is diverting it to other state programs.

Call your legislator today to demand a change.

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# ConocoPhillips Alaska

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**Alaska's No. 1 Gas Producer**

**Alaska's No. 1 Explorer**

**Largest Owner of State & Federal Leases**

**Largest Industry Community Supporter**

**Largest Royalty and Tax Payer**

**Key Employer**

**David Bramley**  
**CRA International**

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**CRA International**

**Review of Alaskan Fiscal Proposals**

**Presentation to Alaska House Finance Committee**



INTERNATIONAL

**David Bramley**

**March 30, 2006**

## Disclaimer



## Overview of CRA Approach

**Will the proposed changes to Alaska's fiscal system support new investment?**

**Comparable group  
of  
mature OECD  
producers**

**Economic potential**  
• Maturity /  
Prospectivity  
• Cost base

**Fiscal Terms:  
Total Government  
Take**

**Investor Capital Allocation Decisions**

*D.P.*



## Comparing Alaska's fiscal proposals to other mature OECD producing areas is the basis for a realistic appraisal of their impact on investment

### OECD<sup>1</sup> Oil & Gas Peer Group

- Alaska
- Australia NW Shelf
- Canada Oil Sands
- Norway
- UK North Sea
- US GoM Deep Water
- US GoM Shallow Water

### Common Investment Characteristics

#### Similar strategic roles in overall investment portfolios

- Large, established oil and gas producers
- Similar political and business risks

#### High level of comparability

- Remaining potential and costs are comparable from public data
- Similar fiscal structures

<sup>1</sup> Organization for Economic Cooperation and Development

## Alaska's production declined by 6% between 2000 and 2004: in the middle of the group

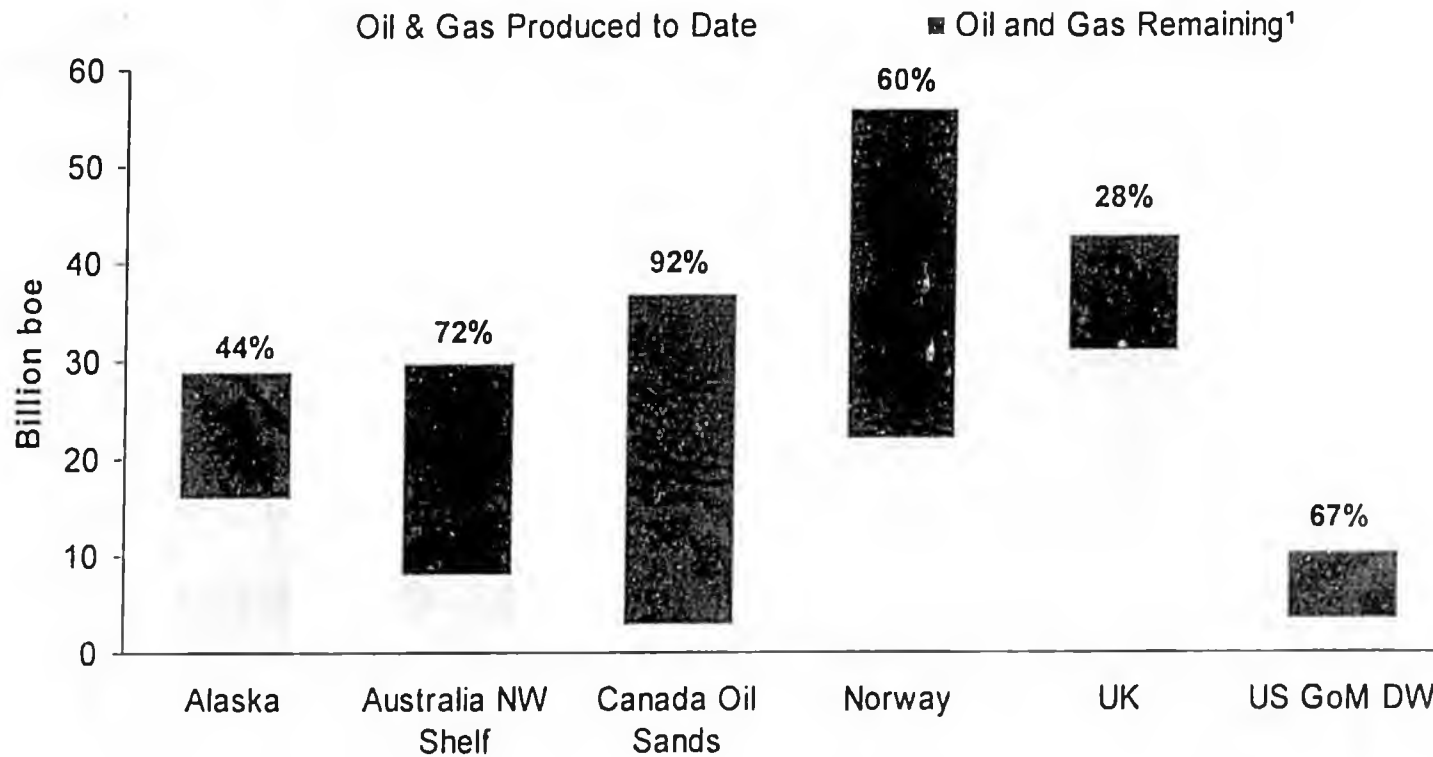
Total Hydrocarbon Production Change 2000-2004		
Region	2004 Production (mboe/day)	Growth/decline since 2000
US GoM SW	738	-27%
Australia NWS	403	-27%
UK	2,144	-19%
<b>Alaska</b>	946	-6%
Norway	3,180	8% <sup>1</sup>
US GoM DW	1,037	26%
Canada Oil Sands	997	64%

<sup>1</sup> Norway's production dropped by 10% between 2004 and 2005, the loss almost entirely through decline in oil production  
 Source: CRA Analysis of public sources of production history in each area



# Alaska has 44% of its known conventional oil and gas reserves remaining

## Total Hydrocarbons Produced/Remaining



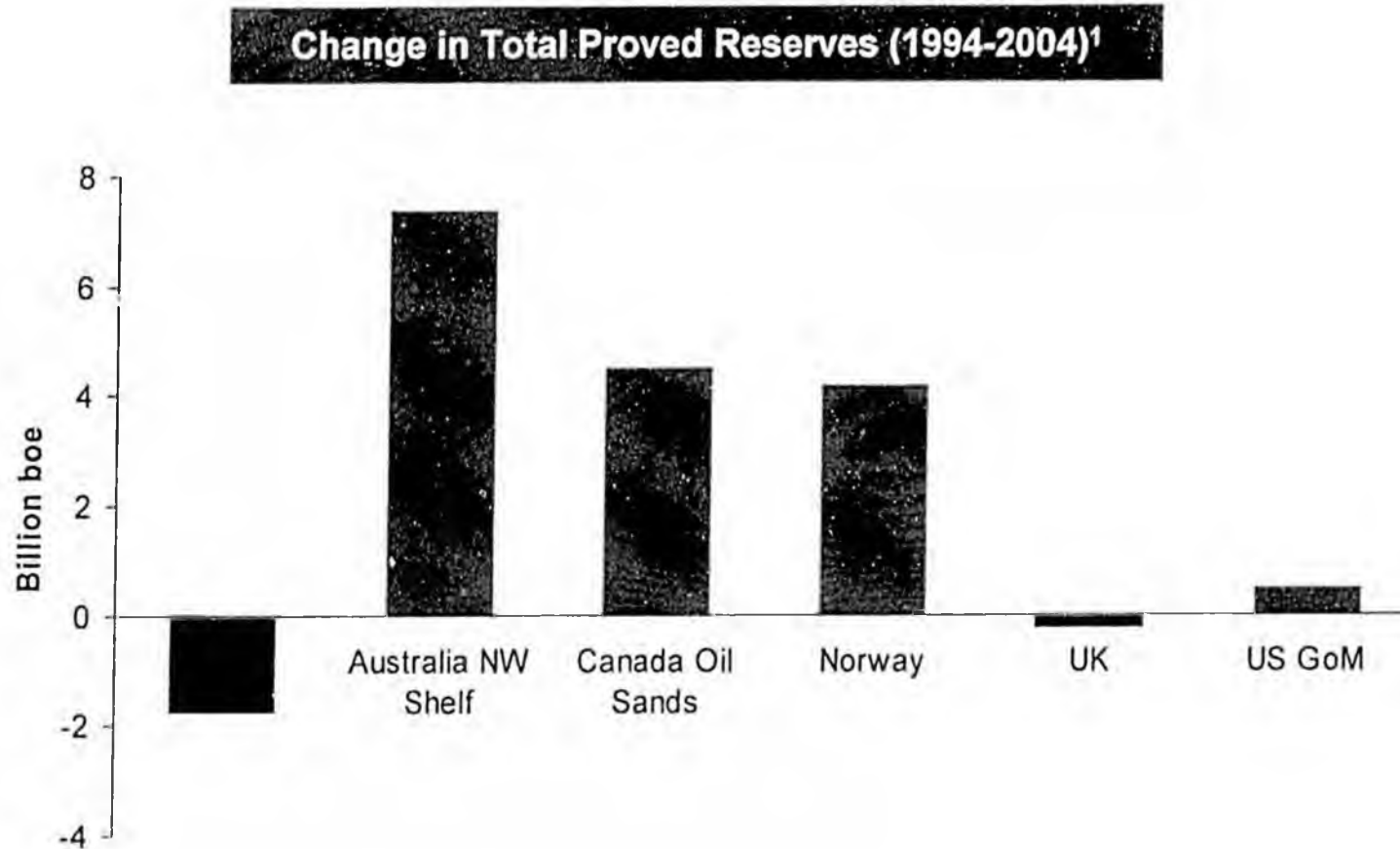
<sup>1</sup> Future estimates based on available data on '2P' or P50 basis: i.e. a central estimate of remaining potential

Numbers in red are percentage of total remaining

Sources: MMS, DOIR, Canadian Association of Petroleum Producers, NPD, DTI, DOE



## Alaska and the UK are the only regions within the OECD group to show a decline in proven oil and gas reserves over the last decade

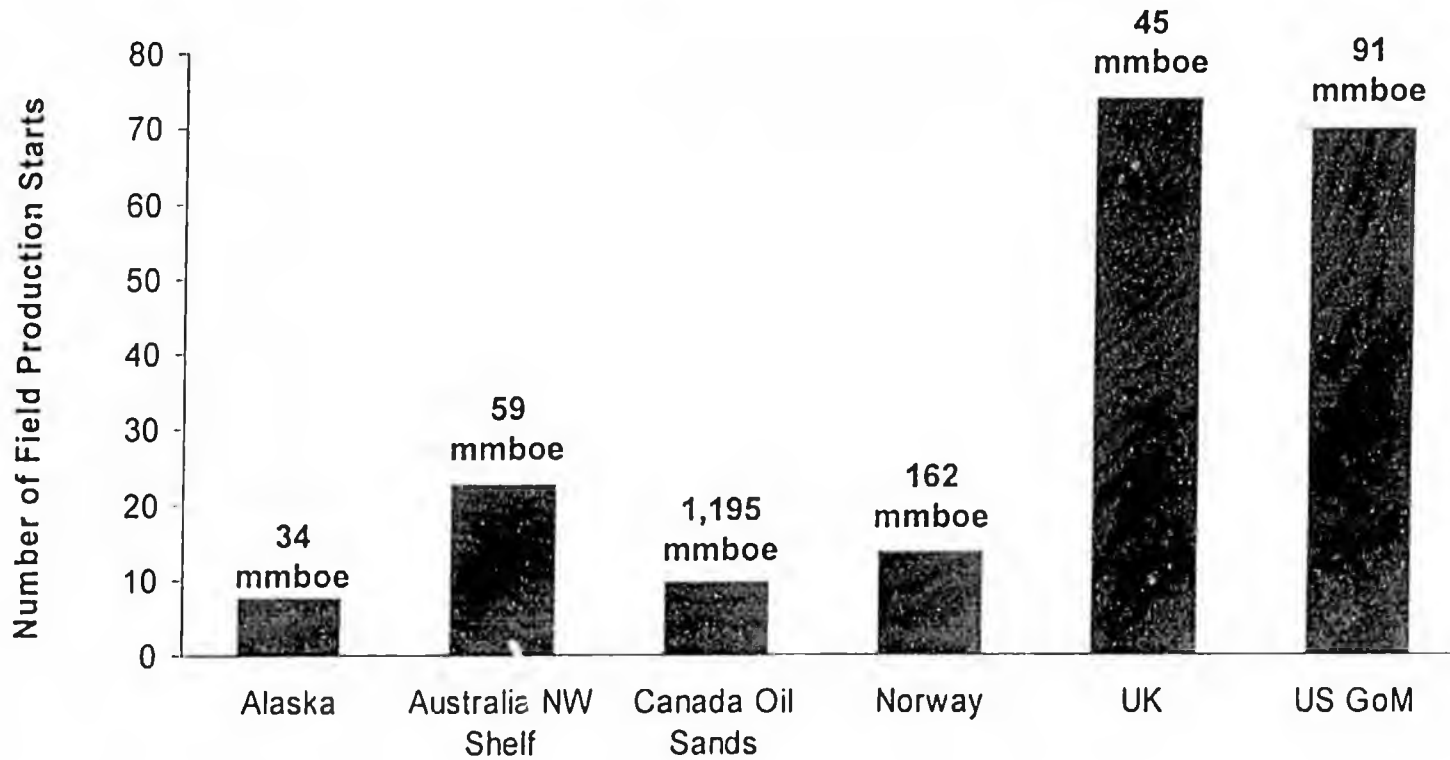


<sup>1</sup> – Figures based on proved (P1) reserves  
Sources: BP Statistical Review & EIA



# Alaska has had only eight new fields start production since 2001 and the average field size was the smallest of the group

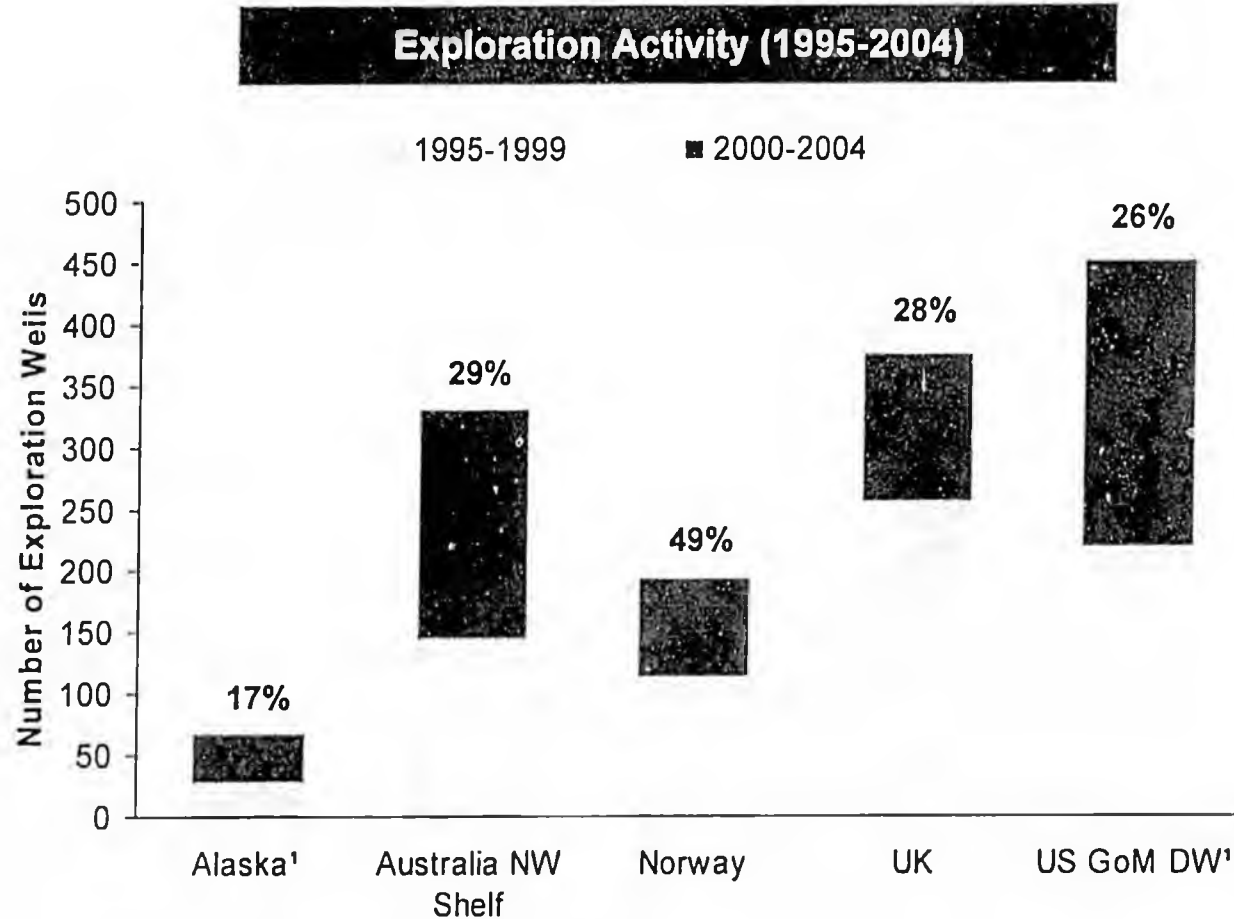
**Field Production Starts (2001-2005)**



Numbers in Red show average development size for new fields in each region over 2001-2005  
Sources: Alaskan DNR, WA Government, NPD, UK DTI and Offshore Magazine



## Alaska has the lowest exploration (wildcat) activity and success rate in the OECD comparison group



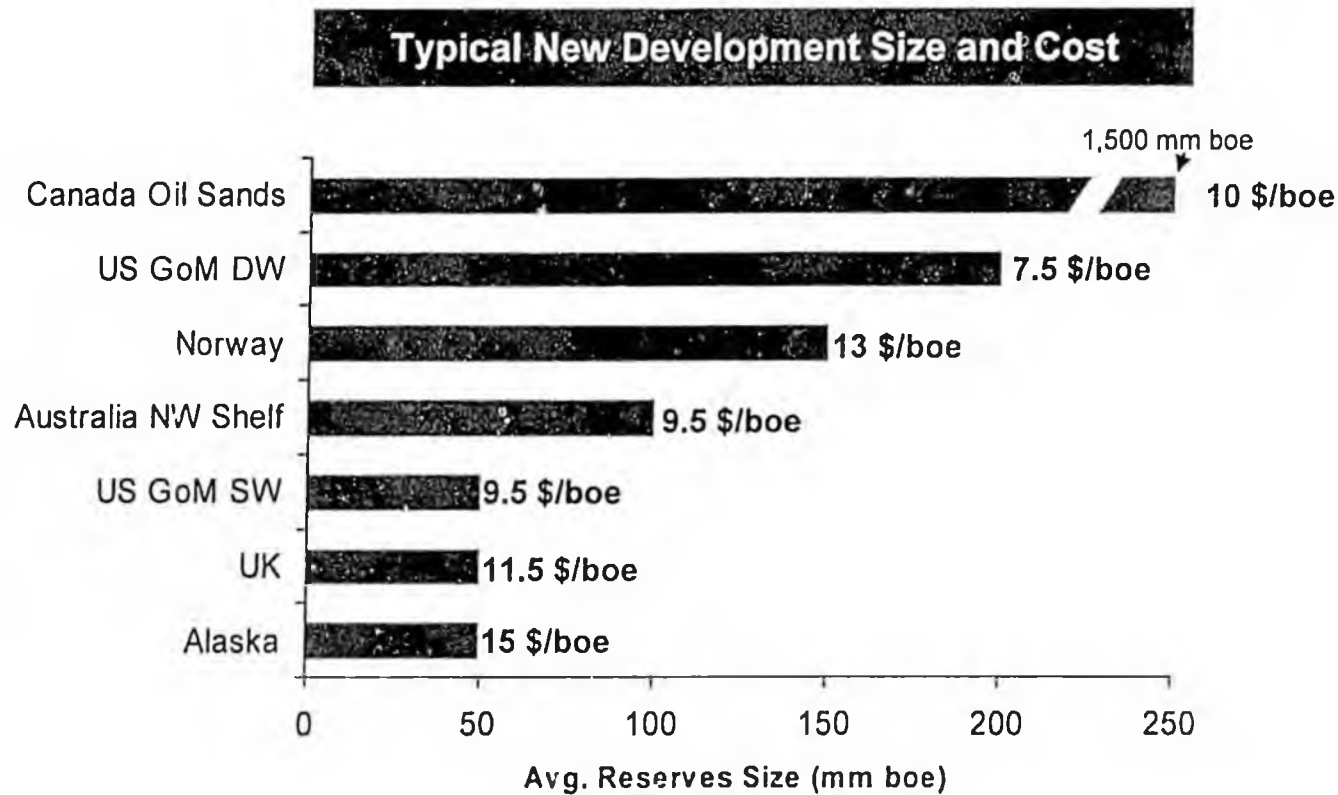
Numbers in red show exploration success per region in the period 2000-1H2004

<sup>1</sup> Alaskan and US GoM drilling numbers discounted by 50% from DNR / MMS figures for Exploration and Appraisal drilling

Sources: Alaskan DNR, Oil & Gas Resources of Australia, NPD and UK DTi, MMS



## Likely new developments in Alaska are relatively small and high cost



Figures in red show total technical costs: CRA estimates of capex and opex for a typical field.  
NB Alaskan total costs include an allowance for the incremental effects of TAPS, transportation and Jones Act shipping requirement costs.  
Source: CRA Analysis of public sources of field development activity in each area.



## Alaska emerges on a variety of measures as a relatively mature and high cost petroleum area

	Alaska	Australia NWS	Canada Oil Sands	Norway	UK	US GoM DW	US GoM SW
<b>Production Trend</b>	-6%		64%	8%		25%	
<b>Reserves Produced</b>		28%	8%	40%		33%	
<b>Proved Reserves Replacement</b>		Very Positive	Very Positive	Very Positive	Slightly Negative	(Positive)	
<b>New Field Starts/Field Size</b>		22 / 59 mm boe	10 / 1,195 mm boe	14 / 162 mm boe	70 / 45 mm boe	65 / 91 mm boe	
<b>Exploration Wells</b>		320	n/a	180	350	450	(Large)
<b>Exploration Success Rate</b>		29%	n/a	49%	28%	26%	(Mid-range)
<b>New Field Technical Cost (\$/boe)</b>		9.5	10		11.5	7.5	9.5

**Key to remaining prospectivity levels**

High



Mid-range



Low

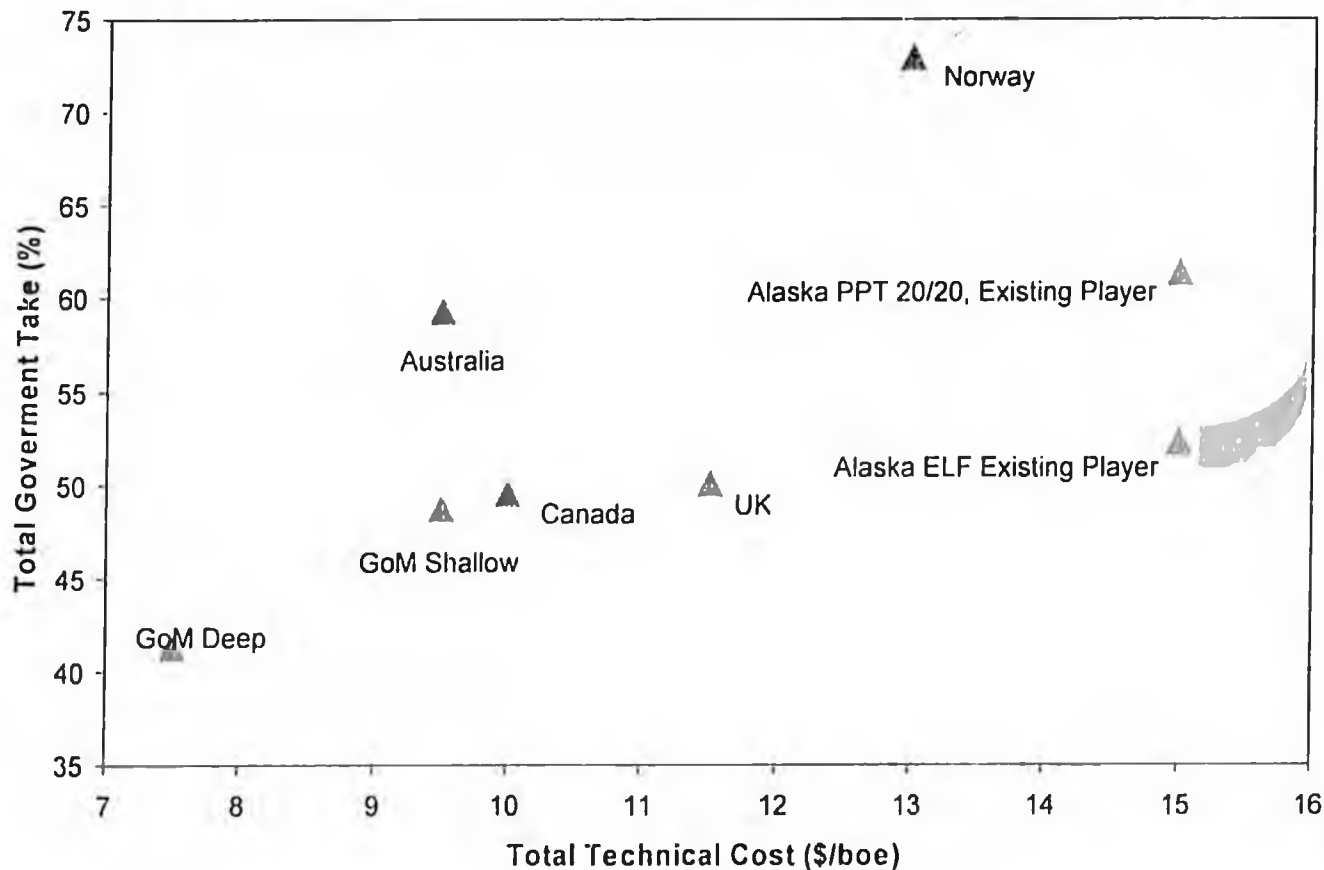


Source: CRA Analysis



The basic<sup>1</sup> PPT 20/20 proposal already gives Alaska the second highest level of total government take within the group

**Total Government Take versus Total Technical Costs**

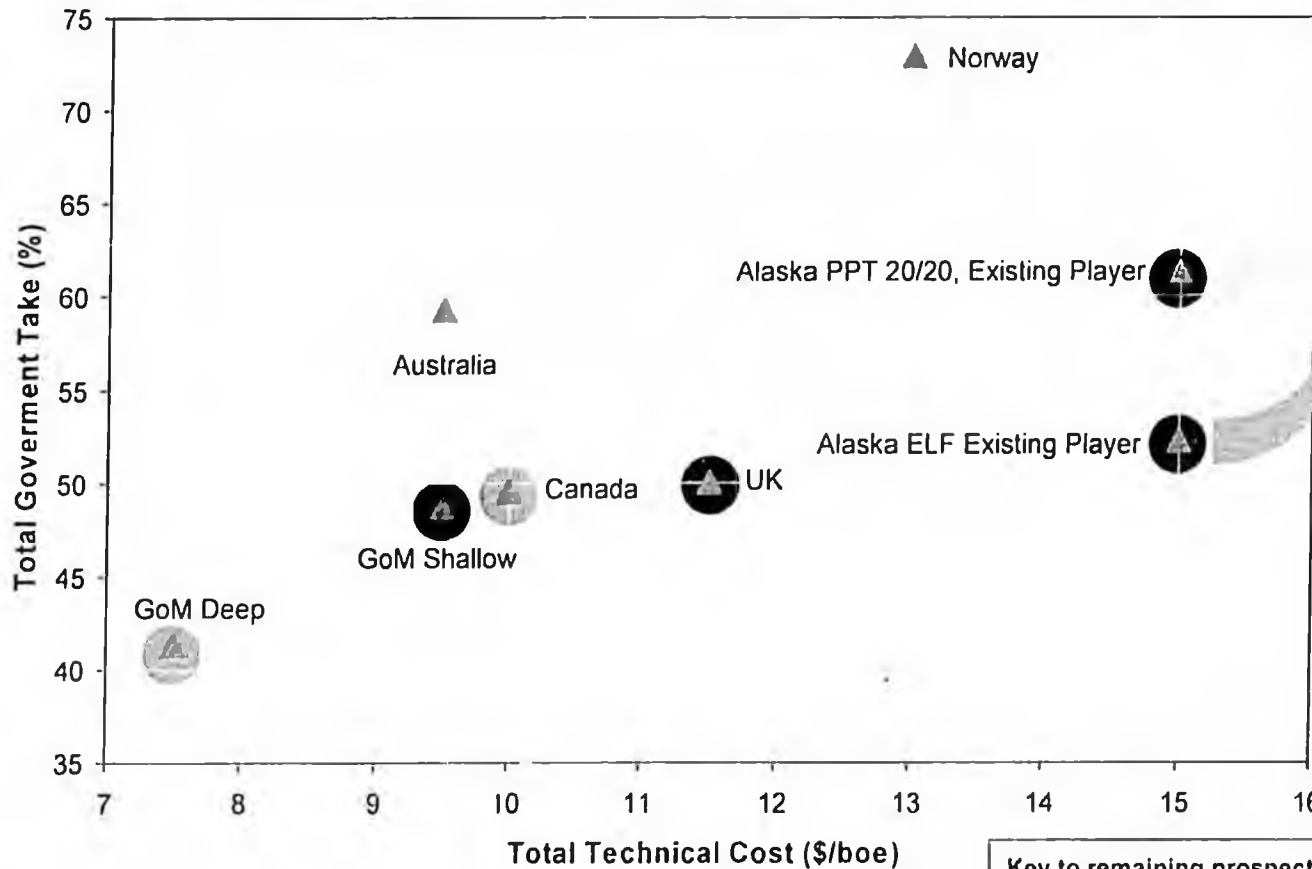


<sup>1</sup> i.e. the original HB 488 bill.  
Source: CRA Analysis



# High costs and lack of prospectivity compound the impact of Alaska's high overall government take

**Total Government Take versus Total Technical Costs**



Colors indicate CRA's assessment of prospectivity in each region.  
Source: CRA Analysis

Key to remaining prospectivity levels

High	●	Mid-range	●	Low	●
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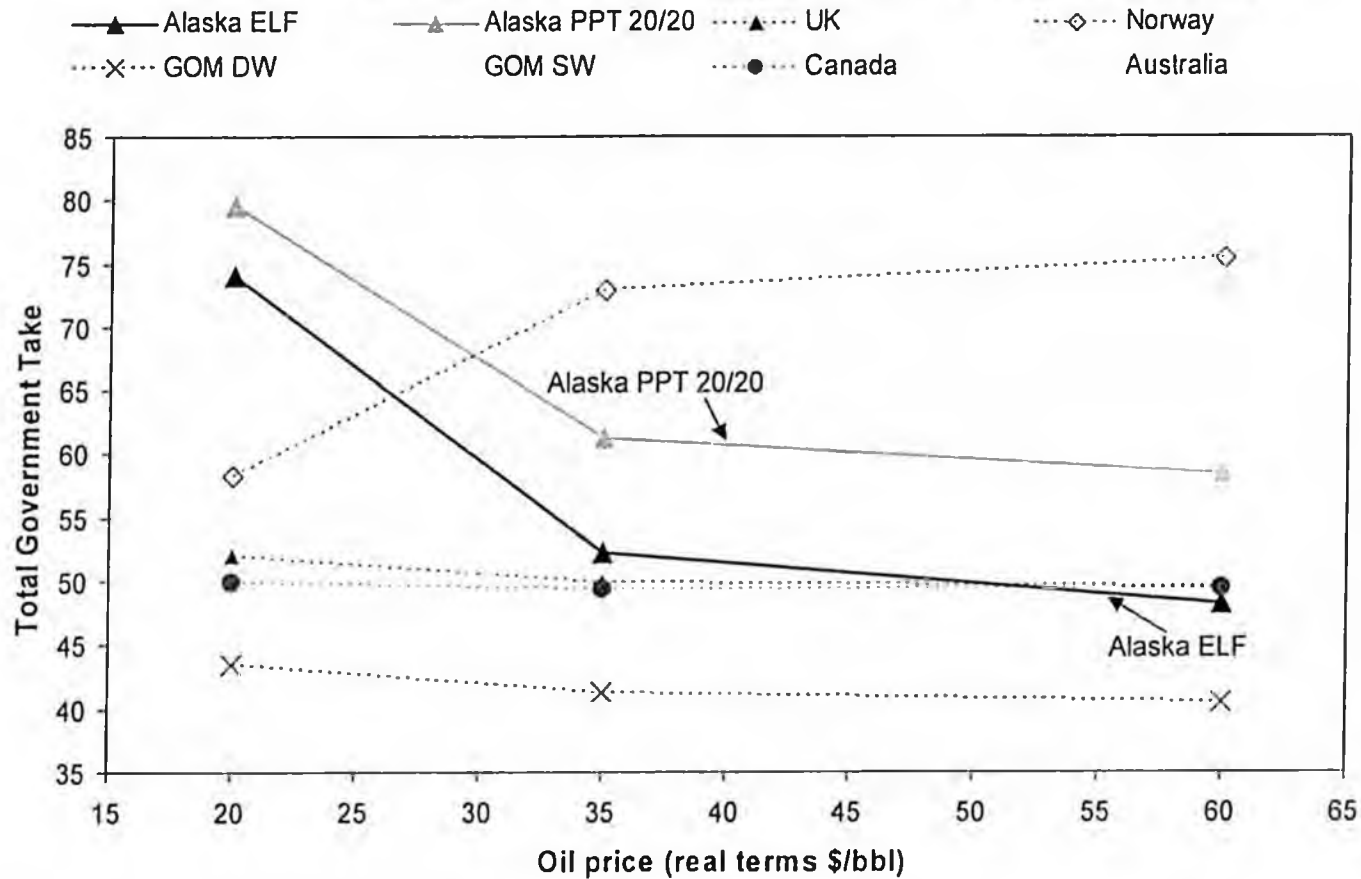


## **Norway's high tax rates are sustainable for an area with high prospectivity and other supporting factors**

- **Norway is significantly less mature than Alaska on all the basic quantitative measures (production growth, reserves, exploration success) and investment is further supported by industry perceptions of its prospectivity**
- **Norway's high tax rates also reflect a number of other structural and policy factors:**
  - Very generous tax relief on exploration investment
  - Presence of three leading players with high government ownership and for whom Norway is their 'core area'
  - Successive governments' policies of 'measured development' in the oil and gas sector as a whole

## Changing assumptions on oil price highlights the regressive nature of the Alaskan regime, especially at lower prices

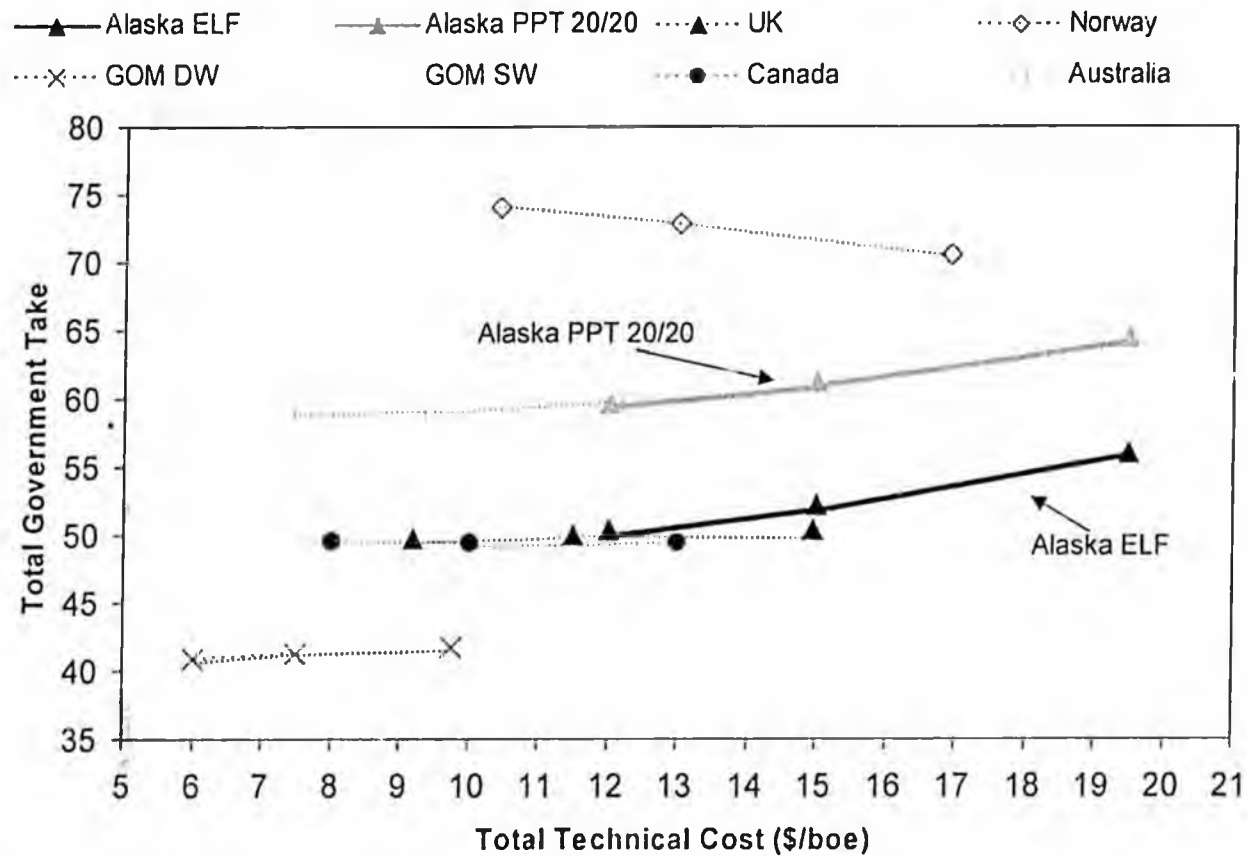
**Total Government Take for Different Oil Prices**



Source: CRA Analysis of Total Government Take for existing Alaskan participants

## Changing assumptions about cost of new field development also highlights a regressive aspect of Alaska's system – current and proposed

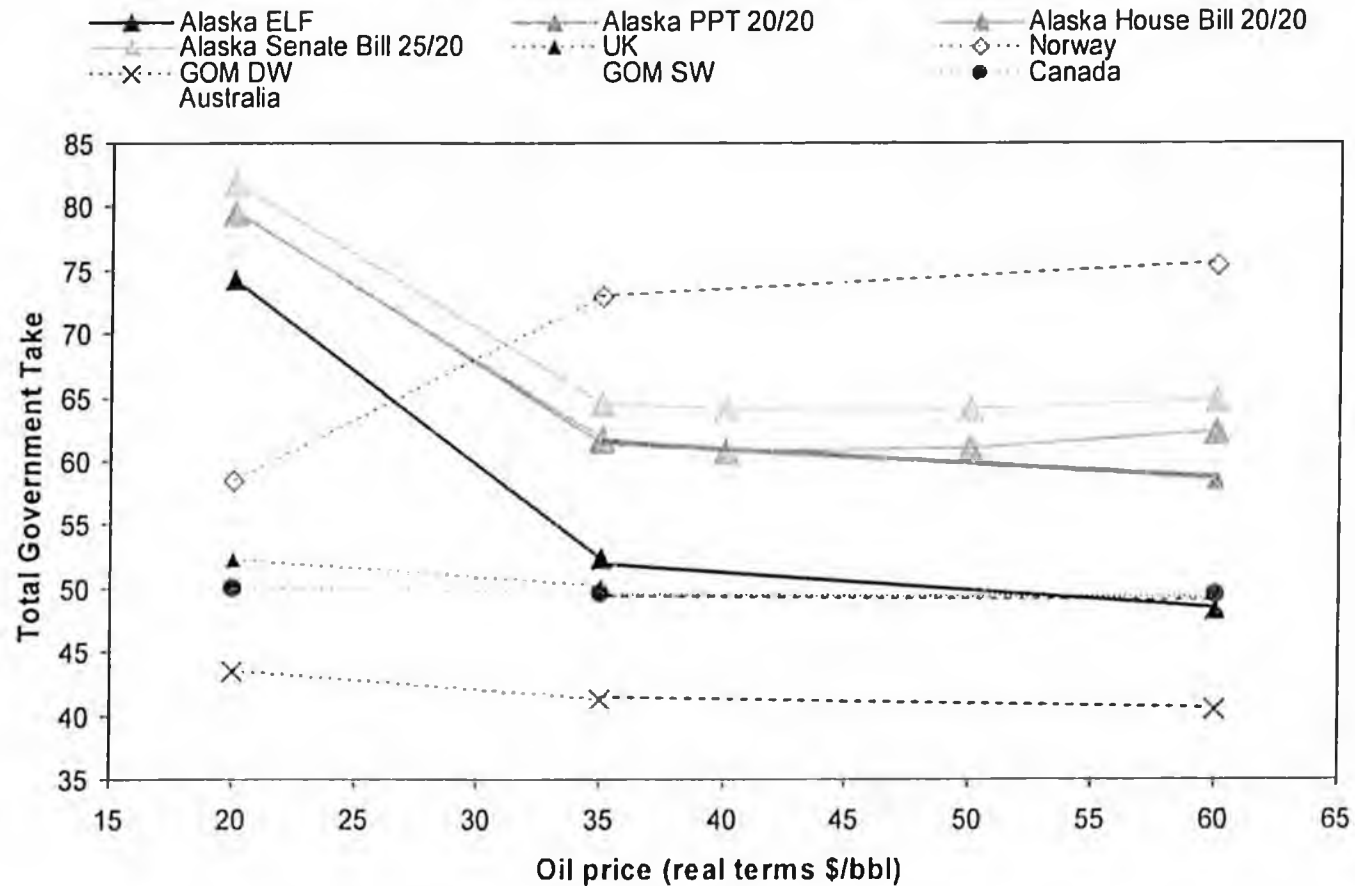
**Total Government Take for Different Cost Structures**



Source: CRA Analysis of Total Government Take for existing Alaskan participants

## The House and Senate proposals add to the levels of government take for the Alaskan field development

**Total Government Take for Different Oil Prices**



Source: CRA Analysis of Total Government Take for existing Alaskan participants

## Alaska's resource potential lies mostly in its existing assets, and in undeveloped gas and heavy oil reserves

Alaska's Resource Potential		
Resource Type	Comparative Size <sup>1</sup>	Incentivised by PPT 20/20 proposal?
Producing Fields / EOR	2-5 bn boe	No: higher tax take = direct disincentive
Known Undeveloped Resources: <i>Conventional Oil</i>	~0.5 bn boe	Only small new players have some incentive
Known Undeveloped Resources: <i>Conventional Gas</i>	6-8 bn boe	No: higher tax take = direct disincentive Gas pipeline approval could transform picture
Known Undeveloped Resources: <i>Heavy Oil</i>	5 bn bbl	Higher tax rates may cause serious delay to heavy oil development
Exploration Potential (YTF)	<1 bn bbl oil potential? Gas potential may be higher	Only small new players have some incentive

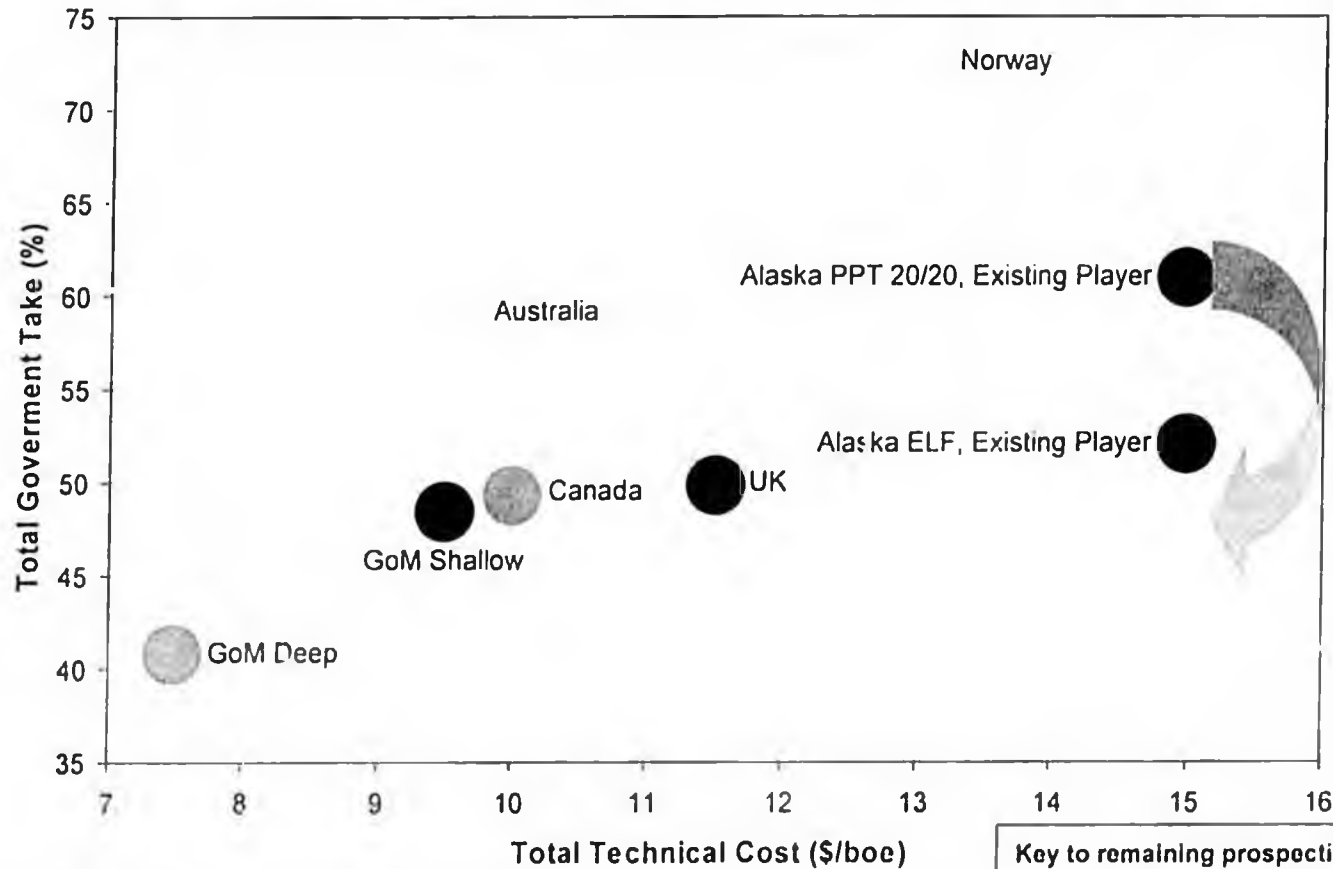
NB YTF = "Yet to Find"

Source: Alaska DNR, USGS, CRA estimates of incremental potential



# If Alaska wishes the new legislation to stimulate investment, a new system that reduces total tax take would be required

## Total Government Take versus Total Technical Costs



Colors indicate CRA's assessment of prospectivity in each region.  
Source: CRA Analysis

Key to remaining prospectivity levels


High	Mid-range	Low
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## **Increasing Alaska's oil and gas taxes will have a price**

- **We recognize the dilemma of balancing revenues and investment**
  
- **Alaska is mature, but has undeveloped potential**
  - Low prospectivity and new field size
  - High cost base
  - BUT huge known resources, heavy oil especially
  
- **Current fiscal proposals do not help competitiveness in OECD peer group**



CRA International  
Review of Alaskan Fiscal Proposals

Presentation to Alaska House Finance Committee

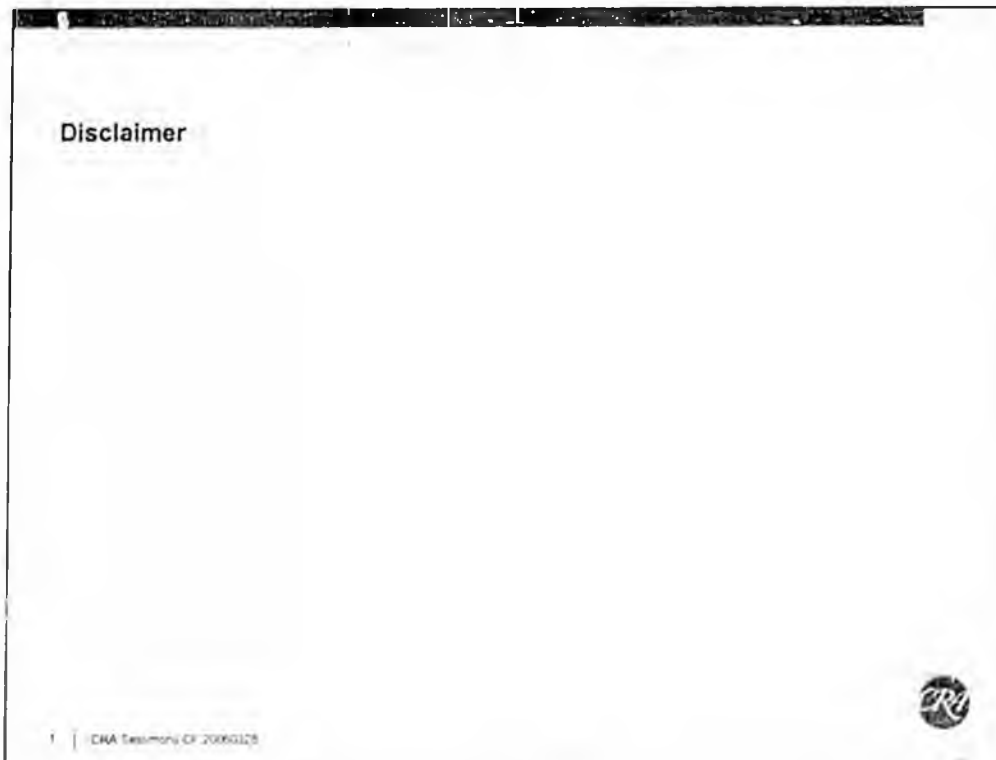
David Bramley  
March 30, 2006

Good afternoon. My name is David Bramley and I am a Vice President of CRA International; I am a business consultant specializing in the international oil and gas industry. CRA International is a global firm specializing in business consultancy and economics. In the oil and gas business we work for both private and national oil companies, and for governments. My own background is that I have worked in the international oil and gas business for 26 years, initially for Shell International in their E&P (Exploration and Production) division in a variety of technical roles, and as a petroleum economist and business planner, working in the Middle East, the Netherlands and the UK. I have been a consultant since 1989, and during that time I have worked on exploration and production business issues for major and independent oil companies, national oil companies and governments in more than 30 countries. Understanding the application of E&P fiscal systems and their business implications is fundamental to my work.

At the request of ConocoPhillips Alaska, we have carried out a piece of work analysing Alaska's proposals for fiscal change in comparison with the fiscal environment in other OECD regions that are also mature and significant oil and gas producers.

Let me say at the outset that we recognize there is a difficult trade-off for Alaska to make in balancing the imperatives of securing short term revenues with those of incentivizing investment to arrest future production decline. We have not approached this analysis with the view that lower taxes are an inherently good thing. Rather, we have identified a comparable group of international oil and gas producing areas and compared their fiscal systems in the context of their underlying economic potential and current levels of investment. Through these comparisons we have sought to illustrate how well Alaska's existing fiscal system is aligned to the economic realities of the region, and to infer what would be the consequences for investment of the proposed changes.

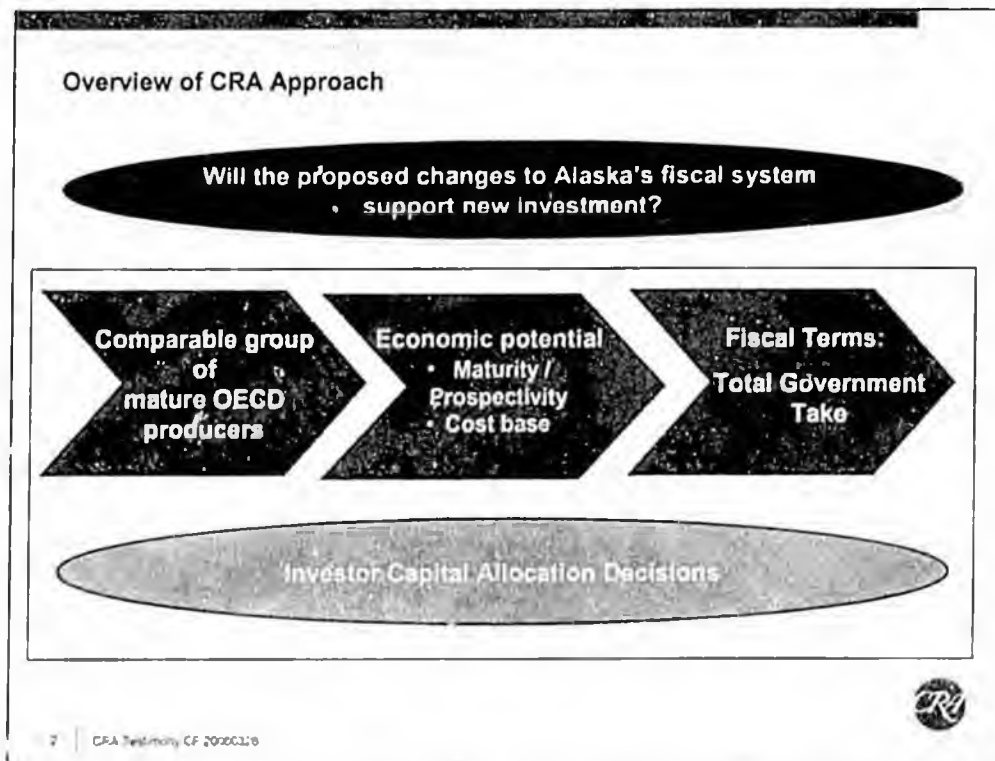
We have throughout used our independent professional judgement to generate working assumptions that we believe reflect the techno-economic realities in each of the comparison areas, and applied methodologies which we believe reflect the way investors will themselves assess the impact of fiscal terms in their investment decision making.



## DISCLAIMER

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CRA's work is performed on a best efforts basis consistent with that degree of skill and care normally exercised by consulting firms performing services of a similar nature. You hereby agree to release, indemnify, and hold us harmless from and against any costs or liability in excess thereof (including claims against us by third parties). Under no circumstances shall CRA be liable for consequential, punitive, incidental or special damages or claims in the nature of lost profits, lost revenue or lost opportunity costs.



I'd first like to explain in outline the question our analysis has addressed and the approach we have taken in answering it.

The question we have addressed is: 'Will the proposed changes to Alaska's fiscal system support new investment?' We have focused the main part of our work on the existing system and the original HB 488 bill proposal.

We have answered it by considering the impact of the fiscal changes on investor decision making. All of the potential investors in the Alaskan oil and gas business – large and small – make their decisions on capital allocation in the context of a larger portfolio of choices about where to invest, covering in principle a huge range of competing options in different parts of the world, different parts of the oil and gas value chain and even alternative energy businesses. Levels of capital mobility in the oil and gas business are very high, as they are in most sectors of the modern economy.

We have selected what we believe is an appropriate group on which to focus our analysis, and I will come back to why we selected the mature OECD producers for that purpose.

Even though the producing regions of the OECD group are highly comparable, each oil and gas region is unique, and we have characterized underlying economic potential by looking at relative maturity and remaining prospectivity, and the cost base for accessing available opportunities in each region.

Lastly we have analyzed the impact of fiscal systems in terms of overall government take of the net cash flows from investing in new opportunities in each area, the parameter we believe is the most fundamental factor in influencing attractiveness to investors. In doing this we have considered the full impact of all applicable taxes in Alaska, at both the state and federal level.


Drawing our analyses of all of these factors together has provided us with an effective high-level view of the impact on investment of current and proposed Alaskan fiscal terms.

**Comparing Alaska's fiscal proposals to other mature OECD producing areas is the basis for a realistic appraisal of their impact on investment**

OECD <sup>1</sup> Oil & Gas Peer Group	Common Investment Characteristics
<ul style="list-style-type: none"> <li>• Alaska</li> <li>• Australia NW Shelf</li> <li>• Canada Oil Sands</li> <li>• Norway</li> <li>• UK North Sea</li> <li>• US GoM Deep Water</li> <li>• US GoM Shallow Water</li> </ul>	<p><b>Similar strategic roles in overall investment portfolios</b></p> <ul style="list-style-type: none"> <li>• Large, established oil and gas producers</li> <li>• Similar political and business risks</li> </ul> <p><b>High level of comparability</b></p> <ul style="list-style-type: none"> <li>• Remaining potential and costs are comparable from public data</li> <li>• Similar fiscal structures</li> </ul>

Organization for Economic Cooperation and Development

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Making meaningful comparisons of investment attractiveness over the whole of the diverse range of options available is complicated by differing corporate business strategies and greatly differing levels of business risk and rewards.

We have chosen instead to focus on comparisons between Alaska and a relatively small number OECD (Organization for Economic Cooperation and Development – the 'club' of developed economies) exploration and production areas for two reasons:

- Investments in this group tend to have similar strategic roles in overall investment portfolios, and in many ways offer substitutes for each other:
  - Large oil and gas provinces, of global significance
  - Production history from at least from the 1970s, but with significant remaining reserves and potential
  - Existing infrastructure and effective commercial and regulatory mechanisms to support its use
  - Free competitive access and absence of barriers to capital investment over a long period
  - OECD countries, with stable political, legal and commercial regimes
  - Similar overall ranges of risk and reward
- Situations that can be readily distinguished and compared with each other:
  - Similar fiscal structures, generally with royalty / tax systems, ring-fenced at the corporate level
  - Good availability of information from public sources

I should add that had we chosen a broader subset of opportunities for comparison, for example including higher prospectivity areas such as Angola or the Former Soviet Union, I do not believe the results of our work would be fundamentally different, although the comparisons would have been more complex and spanned wider ranges of risk & reward.

**Alaska's production declined by 6% between 2000 and 2004: in the middle of the group**

Total Hydrocarbon Production Change 2000-2004		
Region	2004 Production (mboe/day)	Growth/decline since 2000
US GoM SW	738	-27%
Australia NWS	403	-27%
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US GoM DW	1,037	26%
Canada Oil Sands	597	64%

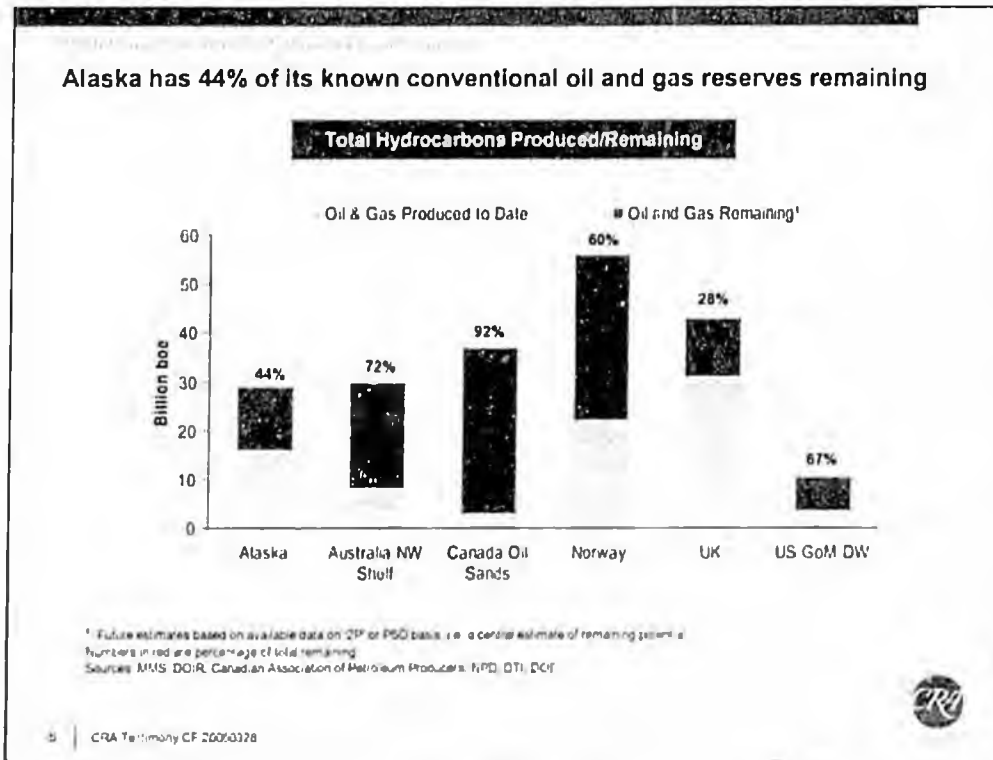
<sup>1</sup> Norway's production dropped by 10% between 2004 and 2005, the first annual decline through decline in production  
 Source: CRA Analysis of public sources of production history in each area.



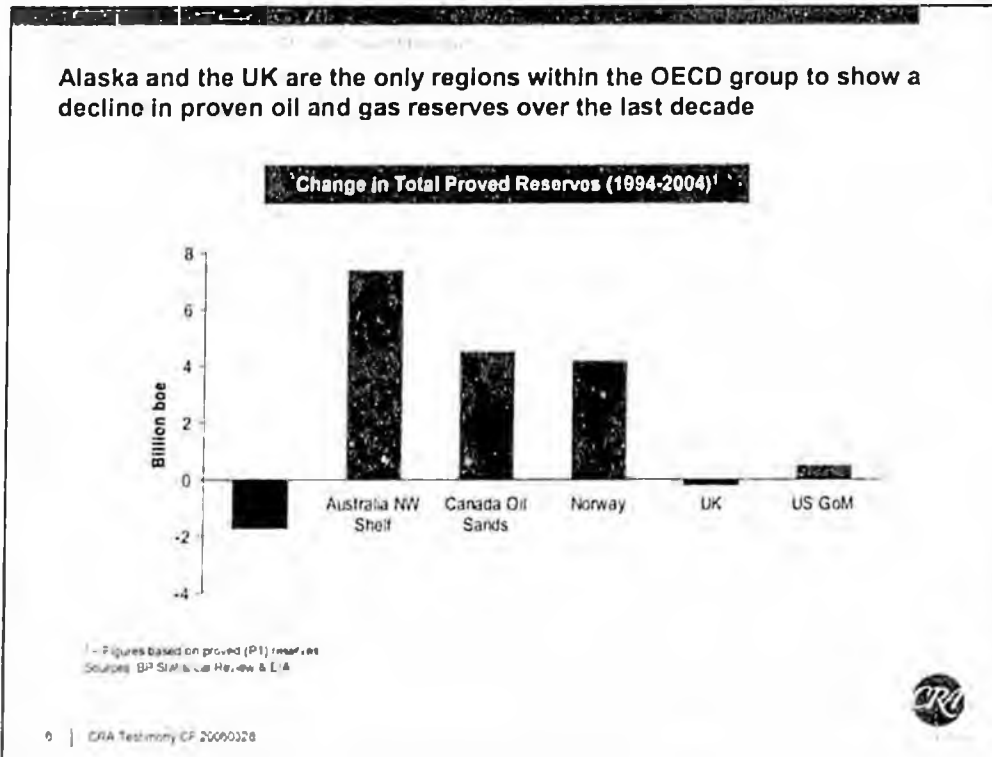
Petroleum is an extractive industry, and the overall economic potential of an area is a function of the nature of the hydrocarbon reserves present, and the technical and operational costs required to bring oil and gas to market. The concepts of maturity and remaining prospectivity of an area are useful ones, since in almost all cases the best hydrocarbon resources are discovered and developed early in its life: there is a natural pattern of 'diminishing returns' throughout the life-cycle of any particular area.

The relative level of maturity and remaining prospectivity of Alaska versus the other OECD areas is therefore an important factor in defining the context for comparisons of their fiscal regimes. Various parameters contribute to an area's maturity, and I would like to examine some of the most fundamental ones. Note that in this section we are going to consider only available conventional oil and gas resources. We have excluded any consideration of ANWR, and I will consider the currently largely uneconomic heavy oil resources later in the presentation.

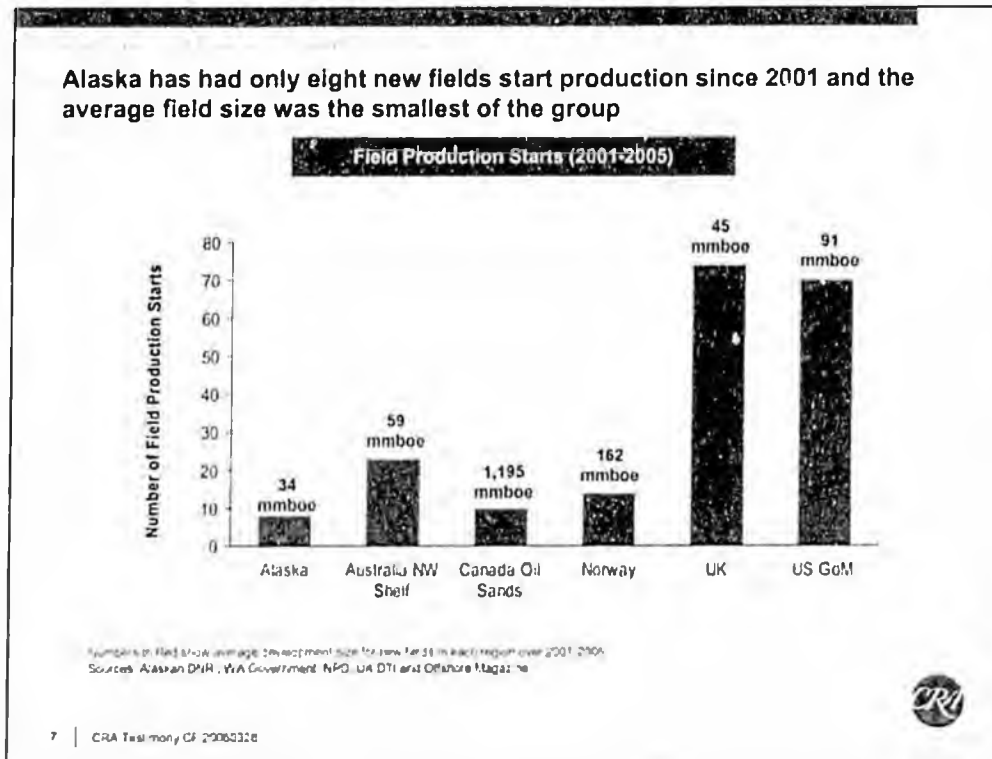
Overall production of oil and gas from an area tends, all other things being equal, to rise to a peak and then undergo a long steady decline. There are exceptions to this pattern – the UK is one. The table above shows that Alaskan production declined by a total of 6% between 2000 and 2004: in the middle of the comparative range. In fact the Alaska's longer term decline is significantly steeper than this recent rate: from the late 1980s until 2000 the average *annual* decline was around 6%.



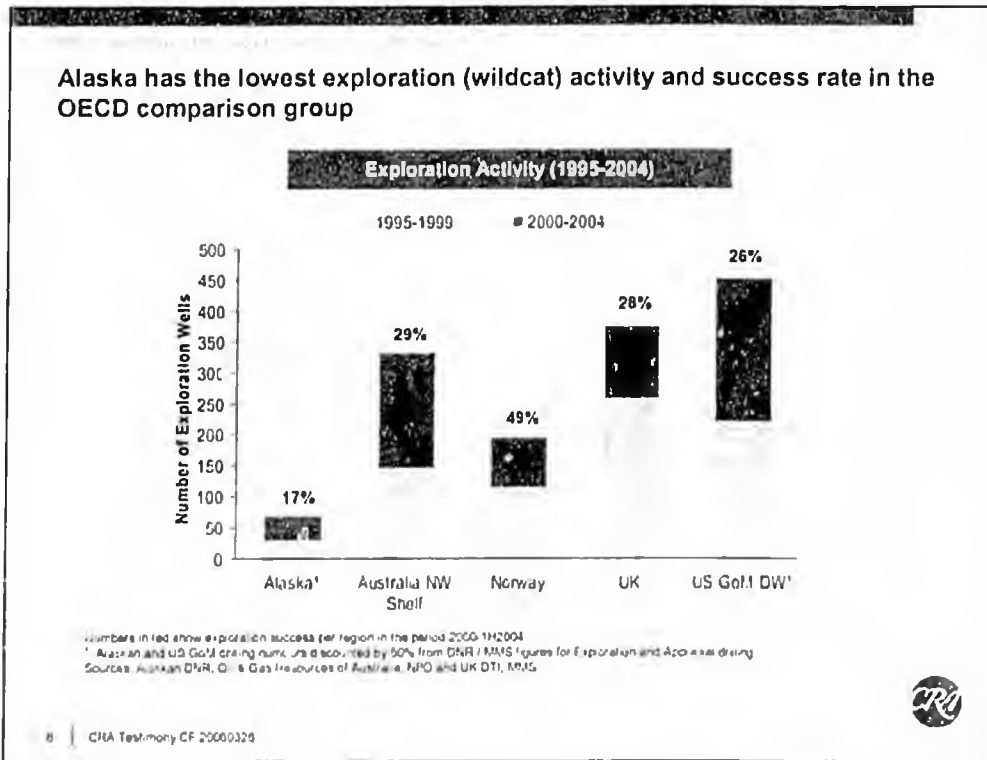
Remaining oil and gas reserves, and their size relative to past production from an area, are another fundamental measure of maturity. In a sense, these figures reflect 'gas in the tank', although any industry insider will acknowledge how elusive clearly-defined and verifiable reserves figures are for an individual field, yet alone a whole producing area. What we have shown on this bar chart is historic oil and gas production in green, and estimates of remaining reserves in blue. The future reserves are what is known as 'P50' – a central estimate of the known reserve potential. The figures on the top of each bar are the percentage of reserves already remaining out of the total figure. Alaska emerges with 44% remaining, second lowest to the UK (28%) within the group.



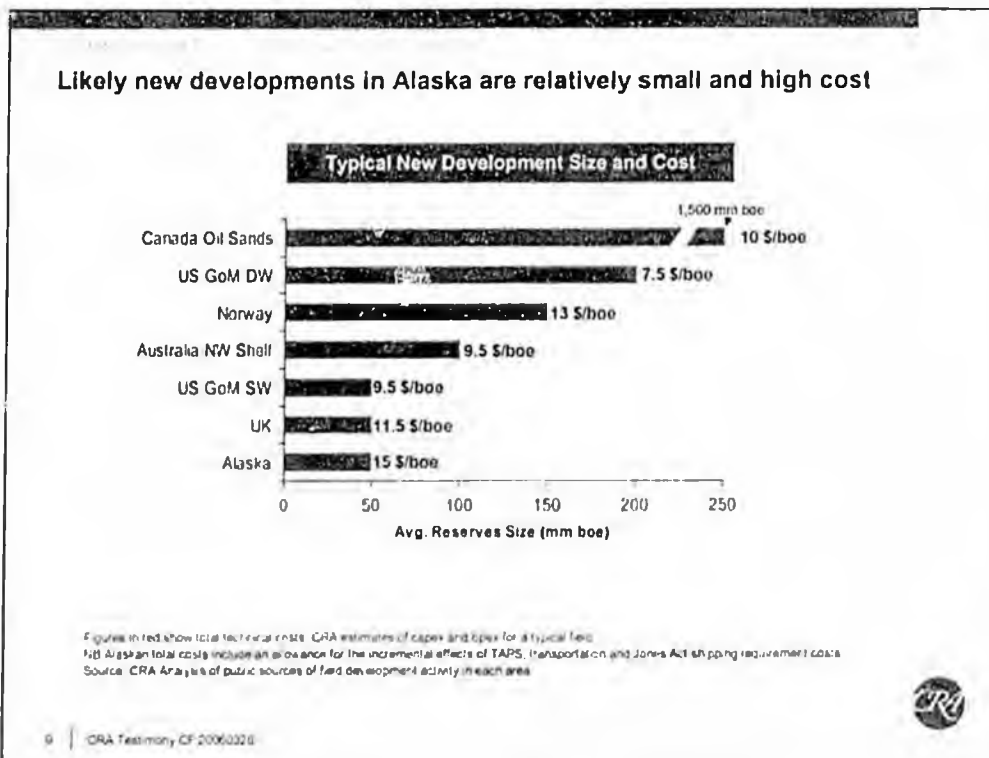
Another important measure associated with reserves reflects how successful an area is in replacing its year-by-year production with proved petroleum reserves. The chart above shows that amongst the comparison group, only Alaska – and by a small margin, the UK – have failed to replace production on a proved reserve basis over the past 10 years.



The pattern of new field developments in an area gives another measure of its potential to add to the producing base and arrest long term production decline. This chart shows the number of new fields brought on stream in each of the comparison areas and the average size of the new fields. Alaska has the lowest number of new producing fields with the smallest size amongst the whole group.



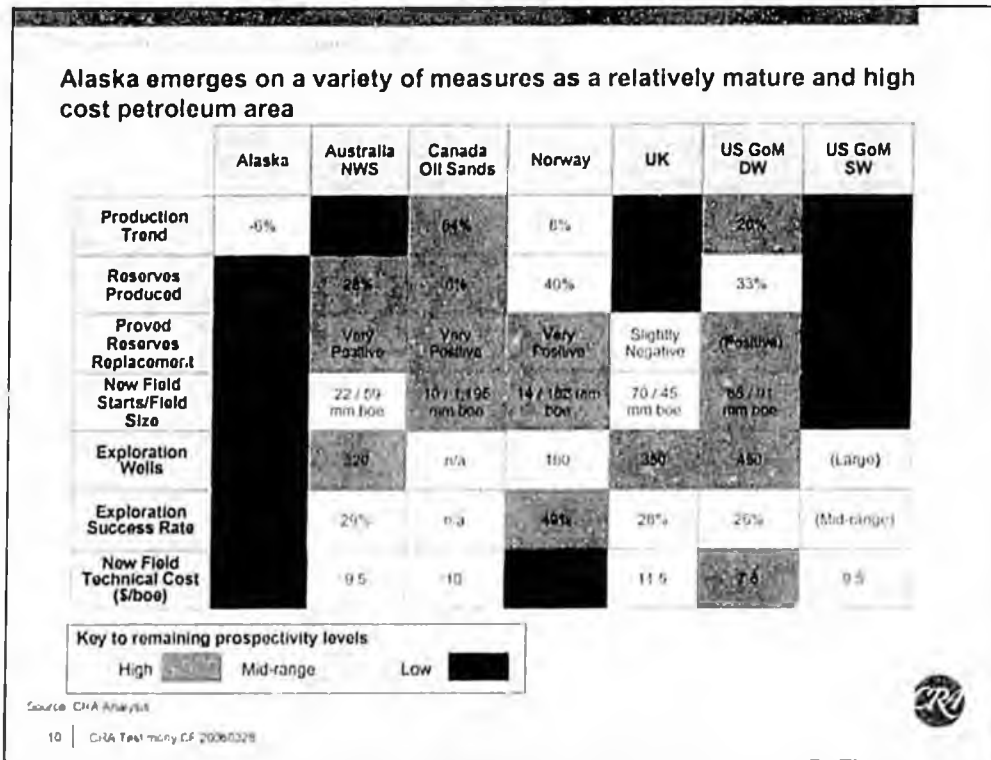
Looking at exploration activity, Alaska, clearly lags the other conventional oil and gas areas in the comparison group both in terms of number of exploration wells drilled and success rate. We have excluded the Canadian oil sands from this particular comparison, since exploration there makes little business sense with major resources already discovered, but undeveloped for economic reasons.



Based on recent development history and the available set of forthcoming opportunities, we have sought to develop a profile of a 'typical field' in each area. This is in our view both another helpful way of characterizing an area's economic potential and a good basis for our later calculations of government take in economic terms.

The results are shown in the table above.

Alaska's prospective developments emerge as a similar size – 50 mmboe – to those in the UK and the US GoM Shallow Water. The total technical cost per barrel of oil equivalent (in other words, capex and opex) to bring the Alaskan field on-stream is the highest in the group, at \$15/boe.

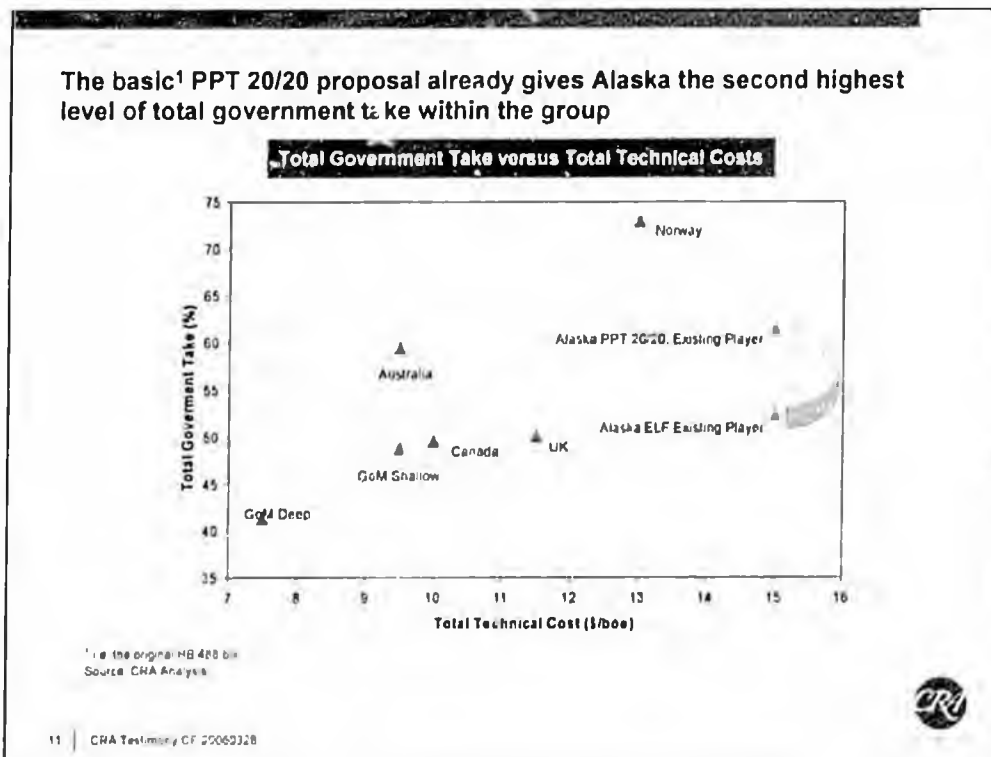


In the above chart we have drawn together all of these observations of maturity and indicated by colors the overall trends. Red indicates observations of low remaining prospectivity (or high maturity) and high unit cost; green indicates high remaining prospectivity, or low cost; and yellow signifies mid-range for those parameters.

As will be apparent by now, Alaska clearly emerges in the predominantly red category.

We need to be clear that this does not mean that Alaska has little remaining economic and resource potential: it does, as have all the areas under review. What it means is that in *relative terms*, all of them significant in some way to attractiveness for investment, Alaska ranks low in the group.

This maturity analysis also raises concerns about the impact of Alaska's existing fiscal terms. There is nothing here to suggest that Alaska's current regime is very competitive for new investment. Alaska ranks lowest of all in the group on measures of closely-related production replacement activity: exploration drilling numbers and new field starts. Even before looking at direct fiscal comparisons, that does not suggest a highly competitive climate for new investment.



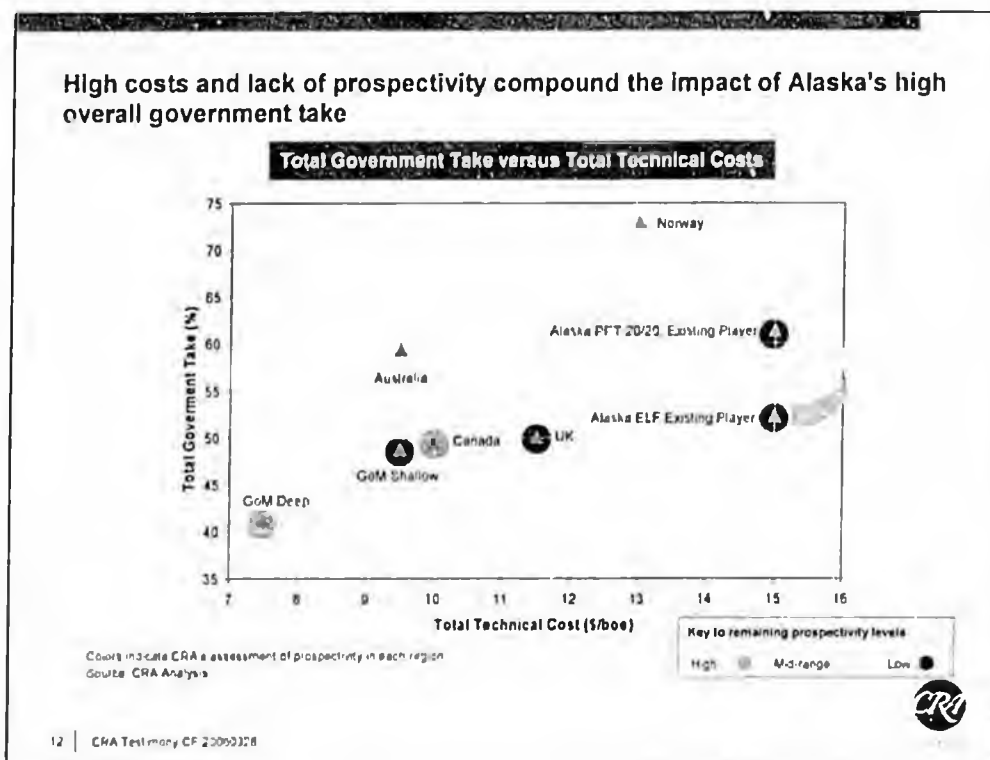
I would now like to move on to a direct comparison of total government take throughout field life for our representative fields for each area. Calculating this involves modelling the way in which the relevant fiscal system divides the available cash flow from a single additional new field between the government and the company investor. In the first instance, we have assumed an oil price of \$35/barrel in real terms, and I will come back to the way in which the results change under different price assumptions, typical of the range considered by investors. We have chosen \$35/barrel for our base price as we believe this is close to the central planning assumption that most investors currently use for decision making.

Overall government take is a good measure of the share of the total available economic value of a field that is captured by the fiscal system. It takes full account of the effects of tax rate, tax credits, and all of the mechanisms inherent in each system. In calculating this figure for a typical new field in each region we get something close to a 'like-for-like' comparison of the kind that will emerge in investor portfolios when they review opportunities across this group.

The chart above shows overall government take for each region, plotted against the unit technical cost for our representative fields.

The results show that under the current ELF / Severance Tax system Alaska's overall government take is third highest in the OECD group. Under the provisions of the original HB 488 (PPT 20/20) bill, Alaska's overall take becomes second highest in the group. This is a significant change.

The cross-plot also illustrates Alaska's high cost base. It might be expected that the overall relationship between technical cost and tax take would be an inverse correlation, with higher costs corresponding to lower levels of government take. All other things being equal, that would probably be the case. But in reality the relationship is more complex: prospectivity, field size and growth potential also play a strong role, and tax take also depends on choices by the government on the trade-off between short term revenue and investment.



Adding a color code to reflect relative levels of maturity suggests Alaska's positioning is a problematic one: a mature region, with a high unit cost base, but with relatively high government take. The fact that levels of re-investment in new exploration and development (illustrated in previous slides) are also fairly low adds to the concern of the potential impact of the new proposals.

Before moving on to look at the effects on government take of different price and cost assumptions, I would like to point out a feature of the original bill as it relates to new entrants.

In most of this analysis we have modelled the position of existing participants and therefore ongoing tax-payers in the State of Alaska. The application of the new proposals for new entrants to the state would be somewhat different, at least for their early investments. In the extreme case, a new field, entirely developed by a group of new entrants, would see almost no tax increase from the new proposals. The reasons for this are that the \$73 million allowance against tax in the original bill offsets the entire PPT liability on the new entrants' first field development. The \$12 million tax credit in the latest versions of the bill would have a similar effect. For subsequent investments, the new entrants' tax position would revert towards a similar one to that for existing players.

I will come back shortly to look at the significance of this fairly limited incentive for new entrants in the context of Alaska's likely available growth opportunities.

**Norway's high tax rates are sustainable for an area with high prospectivity and other supporting factors**

- **Norway is significantly less mature than Alaska on all the basic quantitative measures (production growth, reserves, exploration success) and investment is further supported by industry perceptions of its prospectivity**
- **Norway's high tax rates also reflect a number of other structural and policy factors:**
  - Very generous tax relief on exploration investment
  - Presence of three leading players with high government ownership and for whom Norway is their 'core area'
  - Successive governments' policies of 'measured development' in the oil and gas sector as a whole



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Since Norway is the only country in the comparison group with levels of government take higher than the Alaska proposals, and since Norway has been cited in previous testimony as an area with strong similarities to Alaska, I would like to make a number of points which I believe will be helpful in making sense of these comparisons.

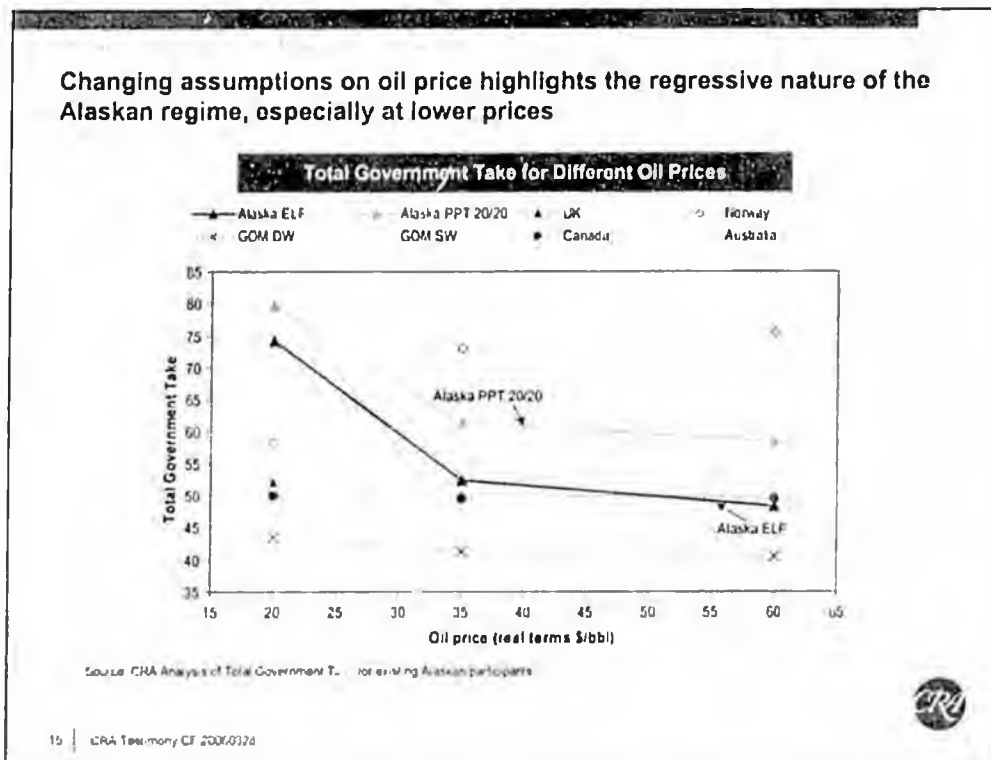
*Norway is significantly less mature than Alaska for conventional resources.* The results laid out earlier show clearly that on all important parameters – production maturity and decline, reserve replacement, new developments and exploration success rates – Norway has greater remaining growth potential than Alaska. Industry perceptions of exploration prospectivity in certain Norwegian areas – the deep water Haltenbanken and the Barents Sea in particular – are particularly strong.

Additionally there are a number of structural and policy factors that are relevant:

– *Norway has chosen to give incentives for exploration* in the form of generous tax relief on exploration investment, rather than loosening its fiscal terms. Norway's fiscal system effectively offers 78% tax relief to all explorers, even those not in a current tax-paying position.

– *Norway's upstream petroleum industry remains highly concentrated and led by largely government-owned companies.* Norway's three leading upstream companies are Statoil (72% government owned), Norsk Hydro (44%), and Petoro (100%). Together these three companies account for a very high portion of production, development and exploration spending. The undoubted strategic commitment of these three companies to Norway as the 'core area' of their overall E&P business, and their high levels of government ownership, have a bearing on the sustainability of high levels of government take. This is not to say that Norway is uninterested in attracting capital spending by international companies, but that it is less of a central issue for the Norwegians than it is, say, for the UK or Alaska.

– *Norway has pursued a policy of 'measured development'.* In effect, this has meant there has never been a policy focus of maximizing levels of activity such as that in the UK during the 1990s. There are various reasons for this, including certain resistance to structural change and worries about potential inflationary pressures of large oil and gas revenues.

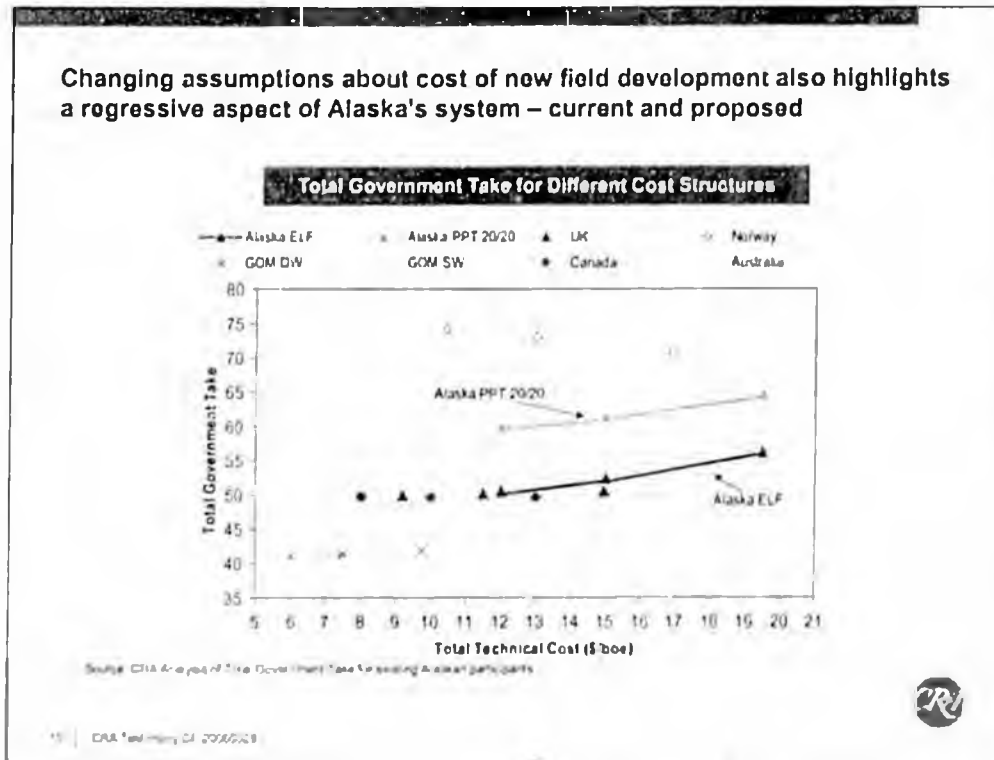


The fiscal response to changing oil price is also important to consider. Our base case considers an oil price of \$35/barrel. However, we must consider both higher and lower oil prices to reflect the way investors make decisions, and in order to capture the full range of possibilities that may affect future investment in Alaska. We have modelled these by considering a lower price of \$20/barrel and an upper price of \$60/barrel.

The chart above illustrates the regressive nature of both the current and proposed Alaskan fiscal systems. At low oil prices, when profitability is lowest, the government take is at its highest. In contrast, at high prices, when profitability is highest, the government take falls. The total government take on the new field development in Alaska in the \$20/barrel case is clearly significantly higher than any of the comparison group.

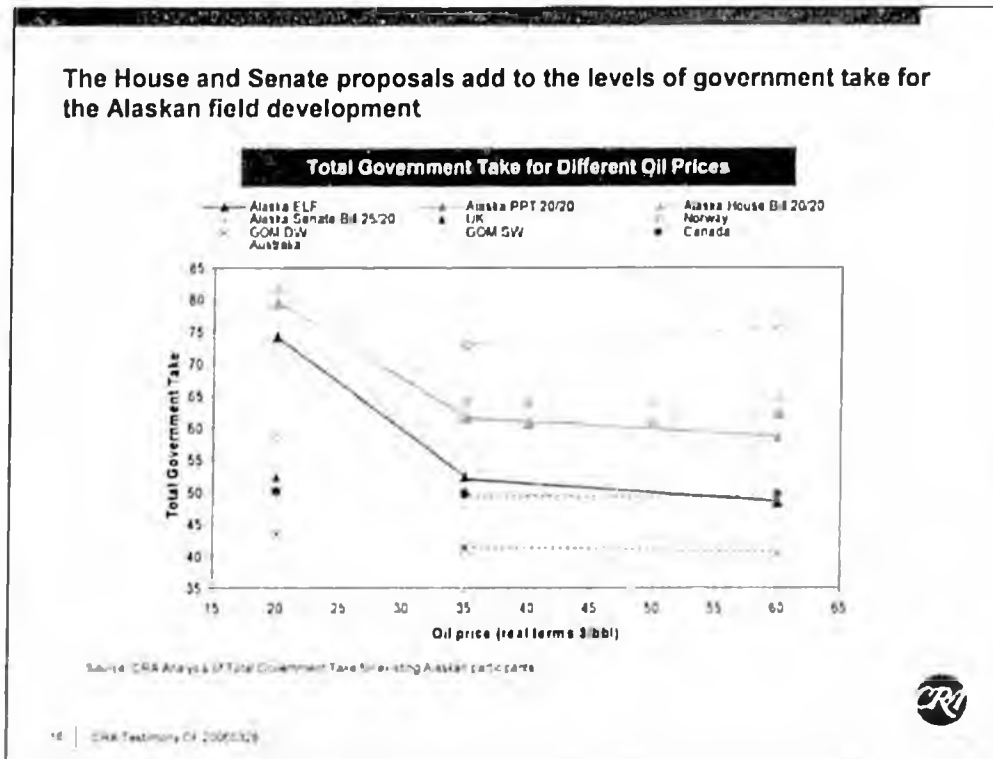
This 'regressive' feature of the Alaskan regime is not helpful in supporting positive investment decisions.

Changing assumptions about cost of new field development also highlights a regressive aspect of Alaska's system – current and proposed



The regressive nature of the Alaskan regime also manifests itself in the context of changing costs. In the chart above, we have examined the effect of higher and lower capital and operating costs on total government take.

For the Alaskan systems, as the project's costs increase, so the total government share also increases. Levels of government take under the proposed PPT system approach those of Norway for the higher levels of technical cost.




The above chart illustrates the additions to total government take that the current House and Senate proposals would give rise to, above and beyond the original bill. The House and Senate bills also exhibit a combination of progressivity on the upside and regressivity on the downside, which is highly unusual, in fact unique as far as I know. Clearly, this is not a helpful combination for supporting investment decision making.

**Alaska's resource potential lies mostly in its existing assets, and in undeveloped gas and heavy oil reserves**

Alaska's Resource Potential		
Resource Type	Comparative Size <sup>1</sup>	Incentivized by PPT 20/20 proposal?
Producing Fields / EOR	2-5 bn boe	No higher tax take = direct disincentive
Known Undeveloped Resources <i>Conventional Oil</i>	~0.5 bn boe	Only small new players have some incentive
Known Undeveloped Resources <i>Conventional Gas</i>	6-8 bn boe	No higher tax take = direct disincentive Gas pipeline approval could transform picture
Known Undeveloped Resources <i>Heavy Oil</i>	5 bn bbl	Higher tax rates may cause serious delay to heavy oil development
Exploration Potential (Y/F)	< 1 bn bbl oil potential? Gas potential may be higher	Only small new players have some incentive

1 bn Y/F = "Yield to Find"  
 Source: Alaska OPA, U.S. GSA estimates of resource potential

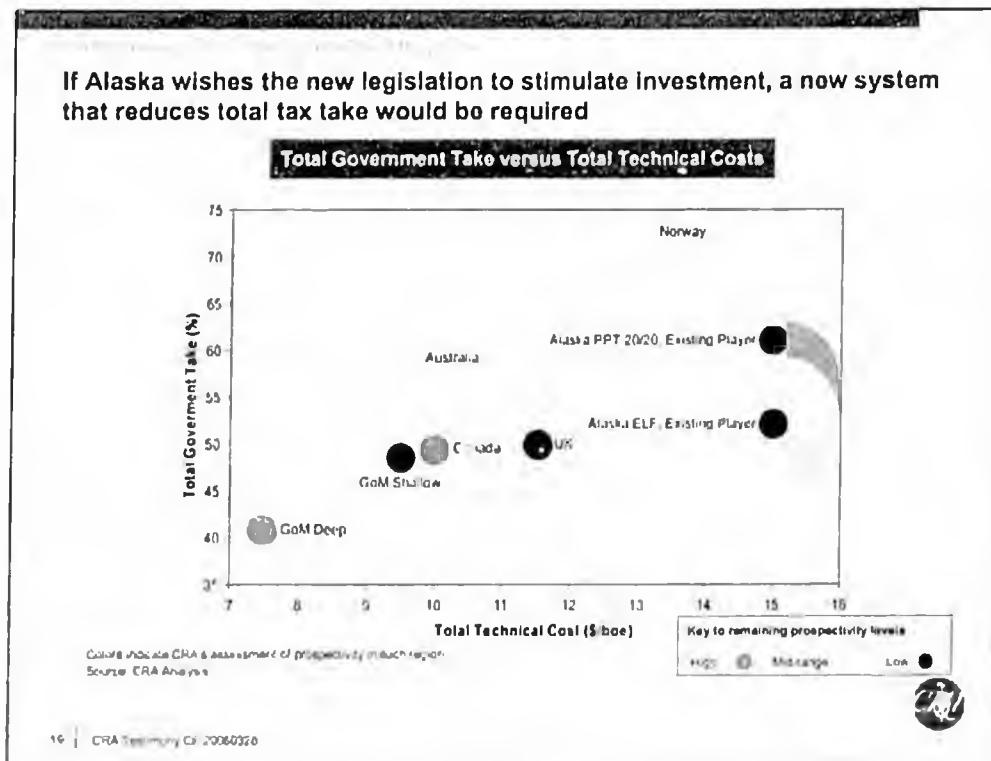


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In considering the impact of the new proposals on future investment, it is also helpful to consider where Alaska's future potential actually lies. As the above table shows, Alaska is in the somewhat unusual position of having the majority of its future resource potential in the form of known but undeveloped hydrocarbons: currently uneconomic heavy oil, and gas resources in particular. There is also major potential in incremental and improved recovery from producing fields. Each of these elements is significantly larger than the resources available through new exploration and undeveloped conventional oil.

The proposals for higher government take affect these large available resources directly. The mitigation of government take that is provided to new entrants for early developments is most likely to be helpful for new exploration and known conventional resources – not the areas where the largest parts of the potential actually lies.

In summary, our conclusions from this study of Alaska's investment attractiveness within the OECD group is that the new proposals will inevitably reduce future investment.



It is not in CRA's remit to suggest what the appropriate level of government take should be in Alaska. But based on the analysis I have outlined today we are led to an inescapable observation that the balance of the current proposals is slanted towards short term revenue collection over stimulation of new investment to stem future production decline. For us to have reached a different conclusion, I believe that a system that yielded total government take lower than the existing ELF regime would have to be in prospect.

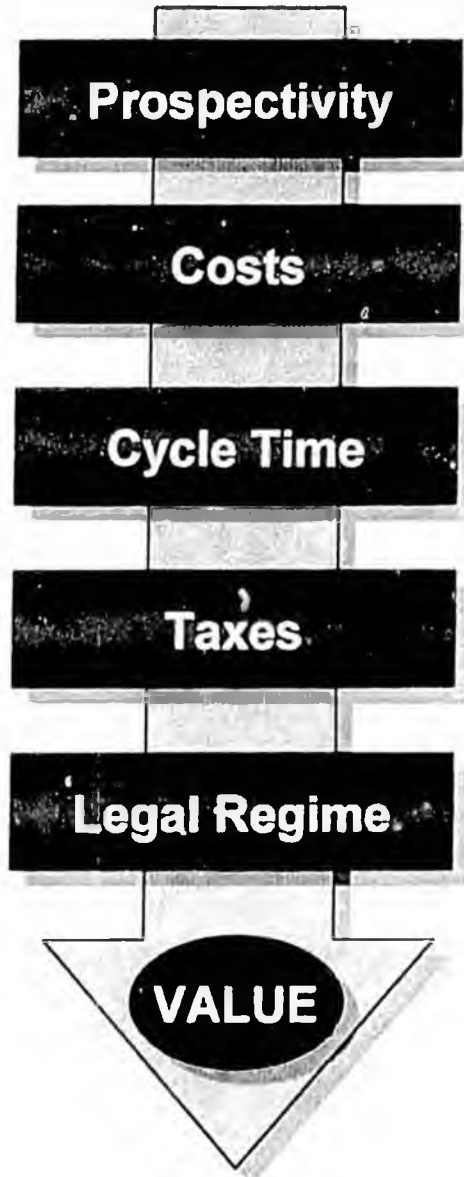
That is not a comfortable conclusion for me to put forward in this forum, but I hope that the reasoning behind it is by now clear.

**Marianne Kah**  
**ConocoPhillips Chief Economist**

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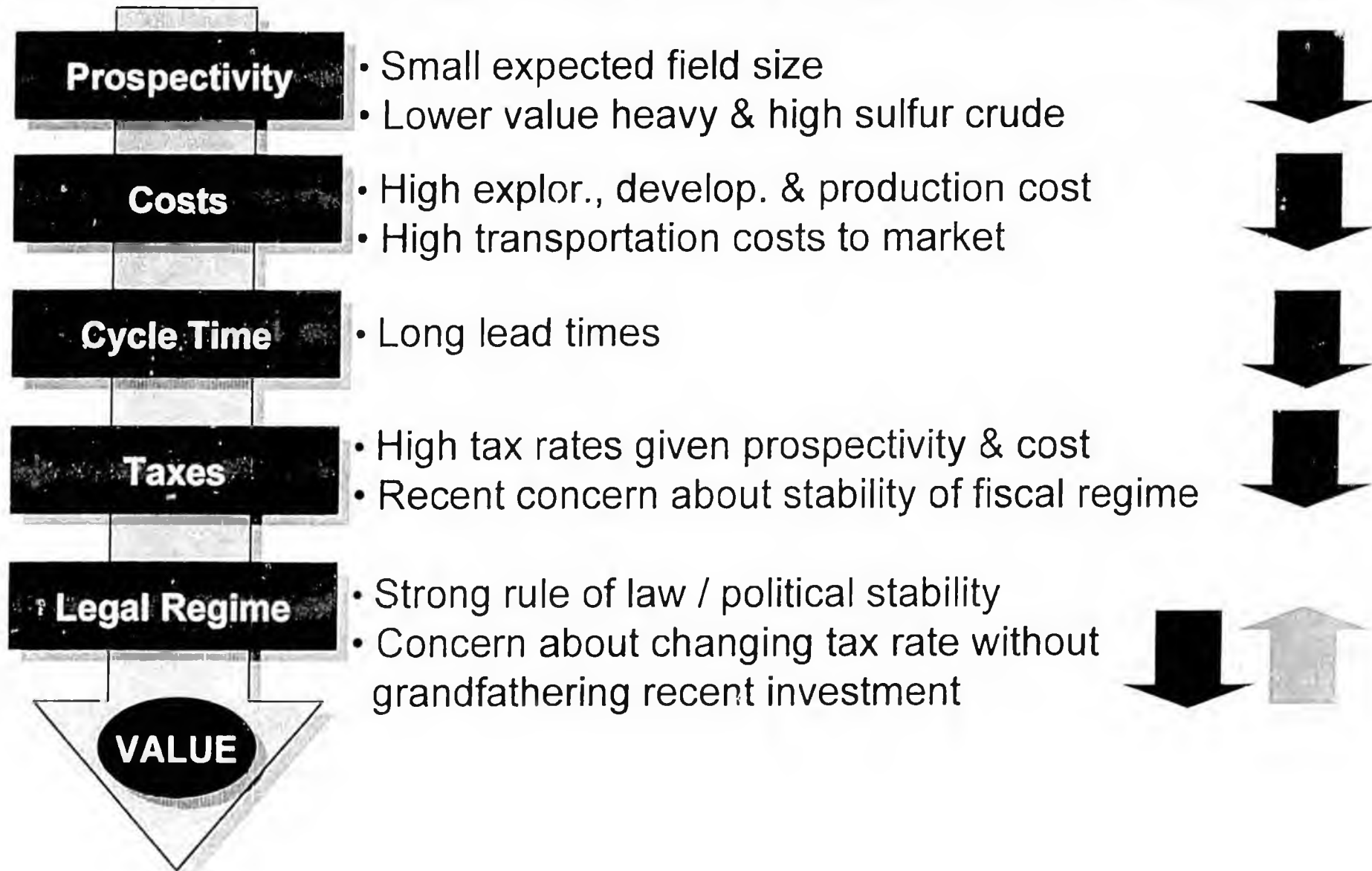
# Investment Criteria

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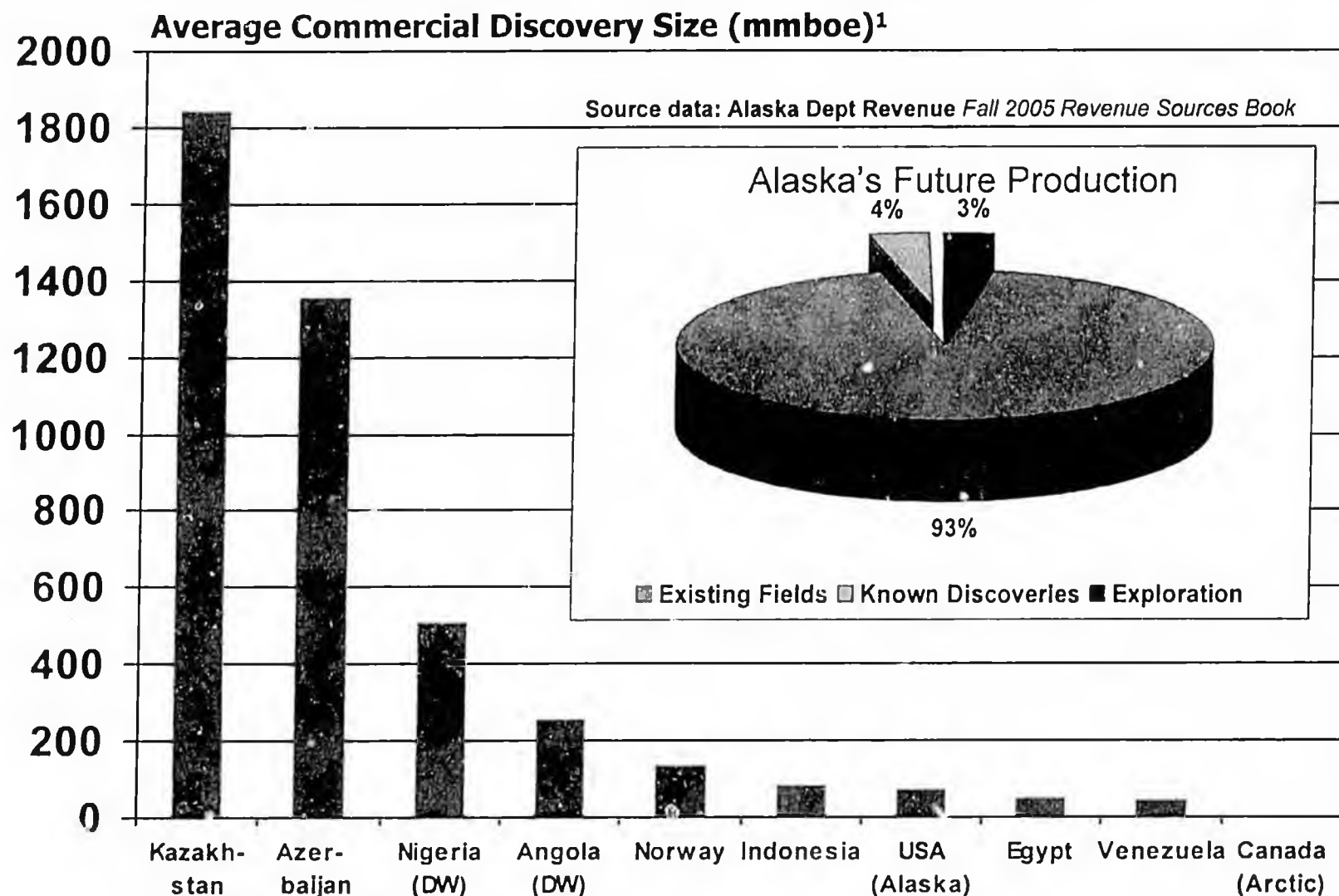
- Expected field size / maturity
- Crude quality
- Exploration, development & production cost
- Transportation costs to market
- Time to production
- Tax rates given prospectivity & cost
- Stability of fiscal regime
- Strong rule of law / political stability

# Investment Criteria - Alaska Rating



#3

# Global Average Commercial Discovery Size

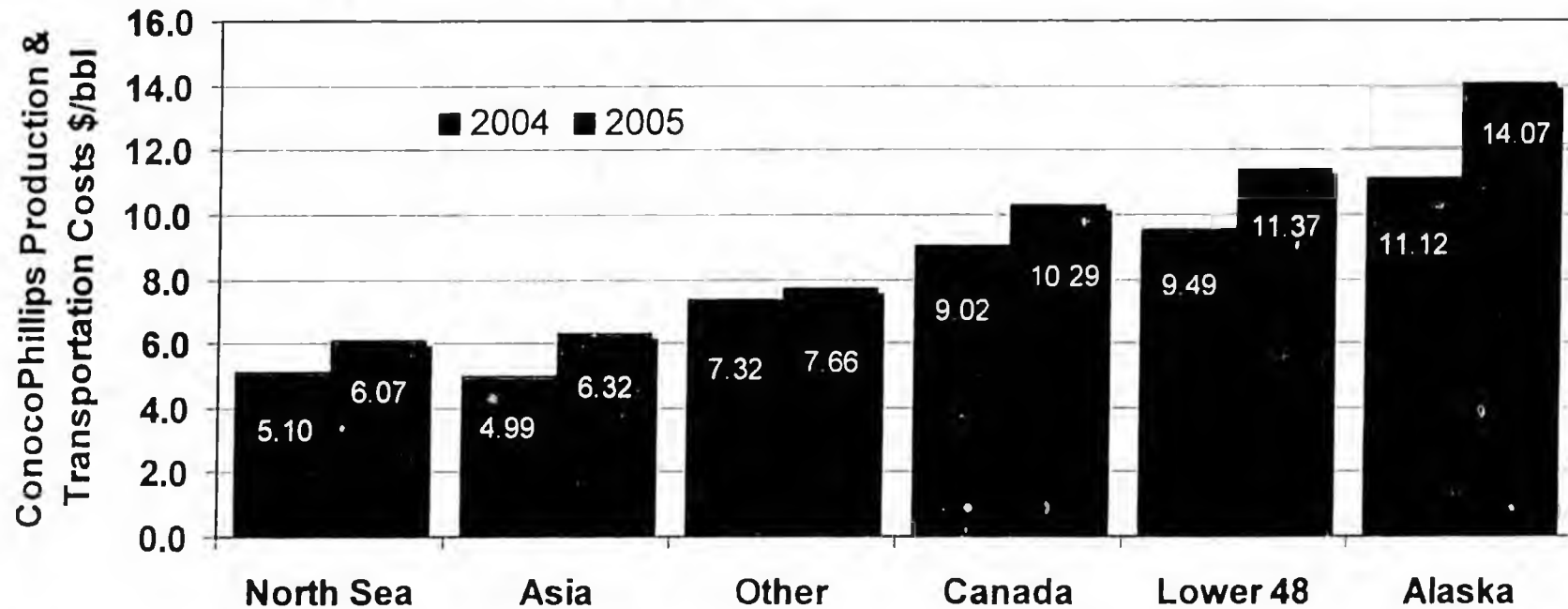


<sup>1</sup> Average commercial discovery size from 1994 to 2003.

<sup>2</sup> The average discovery size is calculated as: total commercial reserves discovered (1994-2003) / total commercial discoveries (1994-2003)

# Increasing Production Costs #4

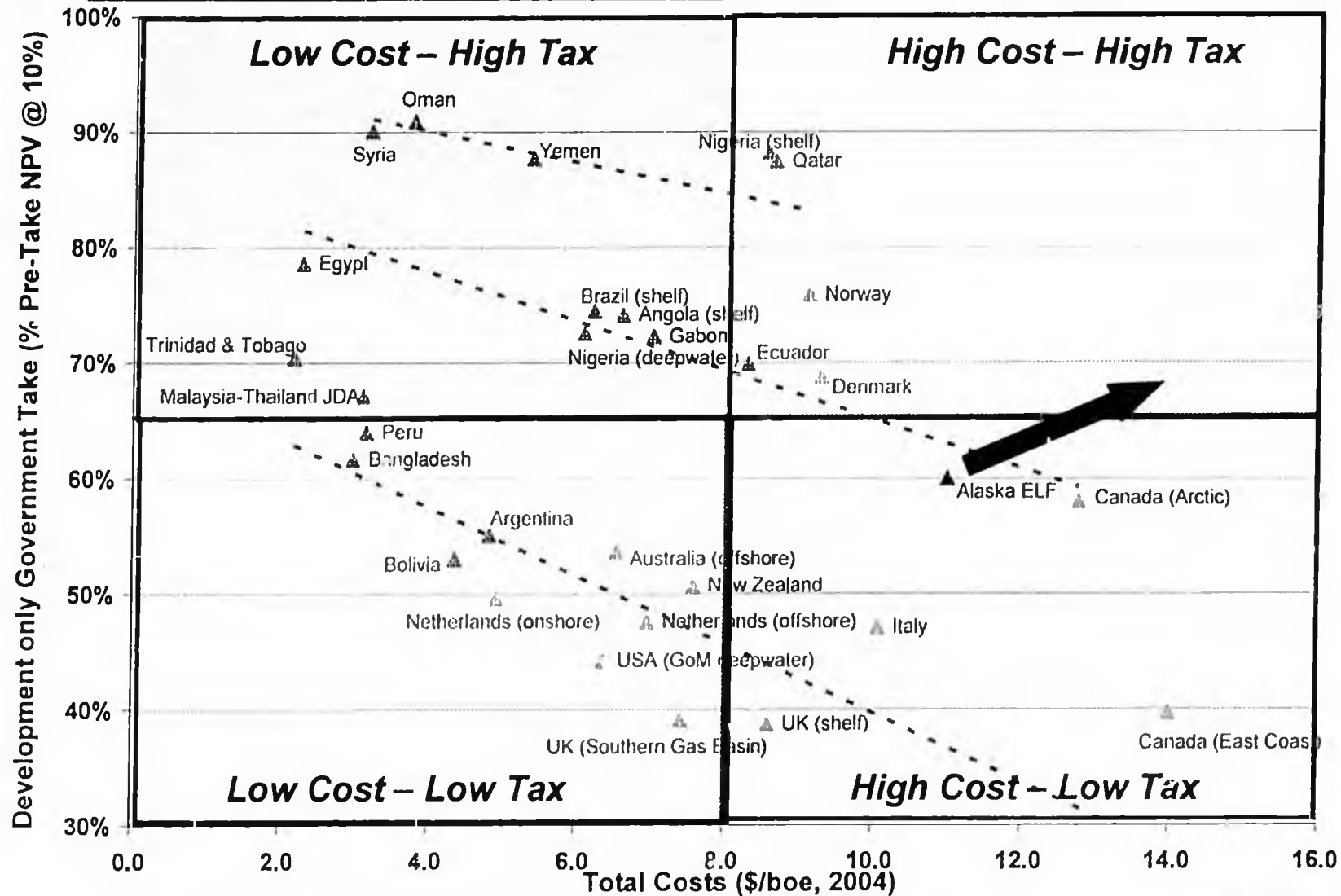
Source: ConocoPhillips 2004 Annual report and 2005 10-K



- Alaska has the highest cost structure in ConocoPhillips Portfolio
- Alaska costs are increasing at greater rate than other areas
  - Aging infrastructure concerns and increasing well work
  - Market Forces
  - Regulations
  - Smaller, more complex field developments

# Alaska – High Cost, High Tax? #5

Countries with no equity participation or not carried

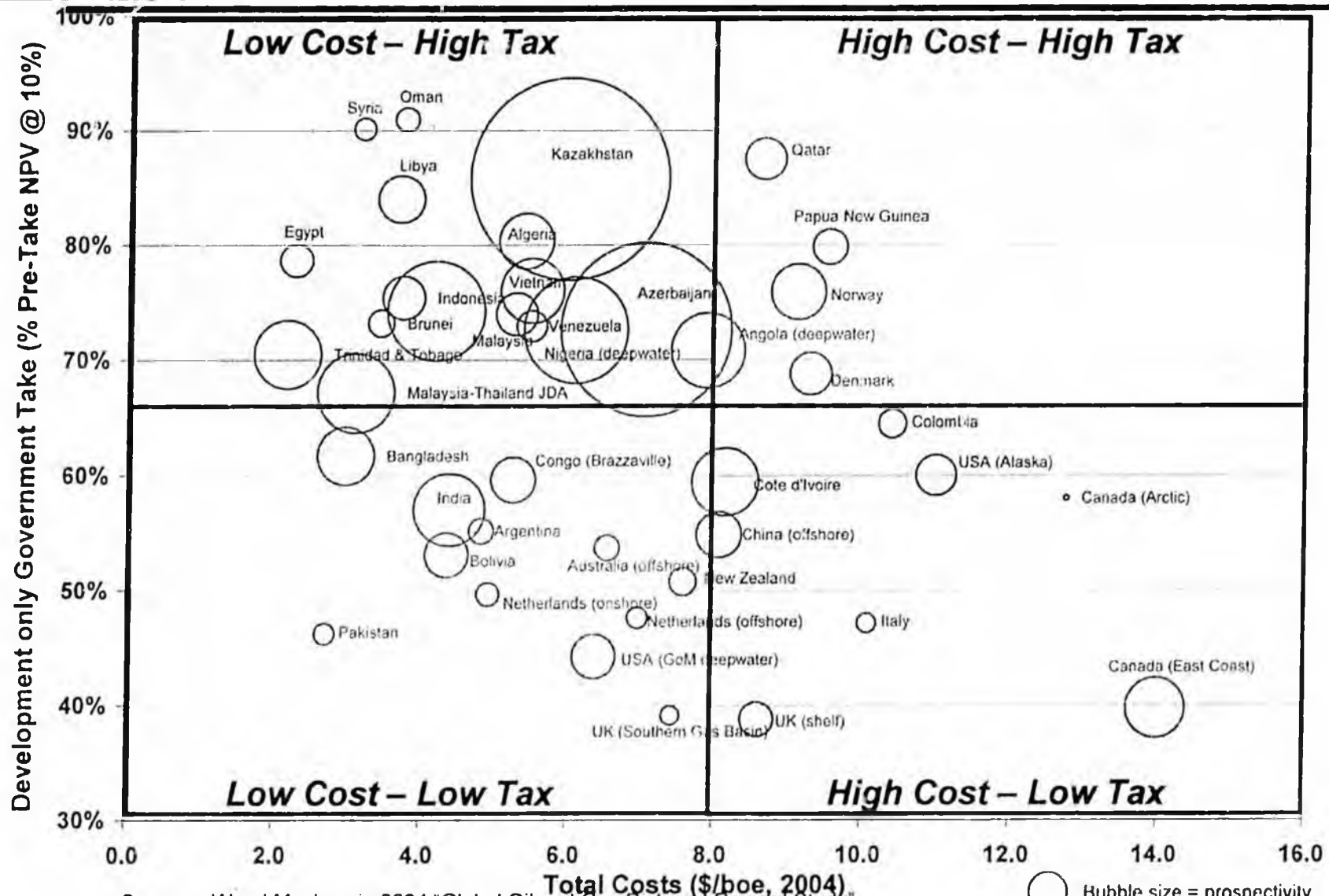


Source: Wood Mackenzie 2004 "Global Oil and Gas Risk and Reward Study".

▲ OECD Countries

Total cost includes capital and operating elements averaged over 10 year period (1994-2003). Economics were run at \$35/bbl long term real Brent price

# Alaska – High Cost, High Tax & Low Prospectivity



Source: Wood Mackenzie 2004 "Global Oil and Gas Risk and Reward Study".

Total cost includes capital and operating elements averaged over 10 year period (1994-2003). Economics were run at \$35/bbl long term real Brent price

Prospectivity = Average commercial discovery size (1994-2003)

○ Bubble size = prospectivity

# Higher Taxes Will Reduce Investment

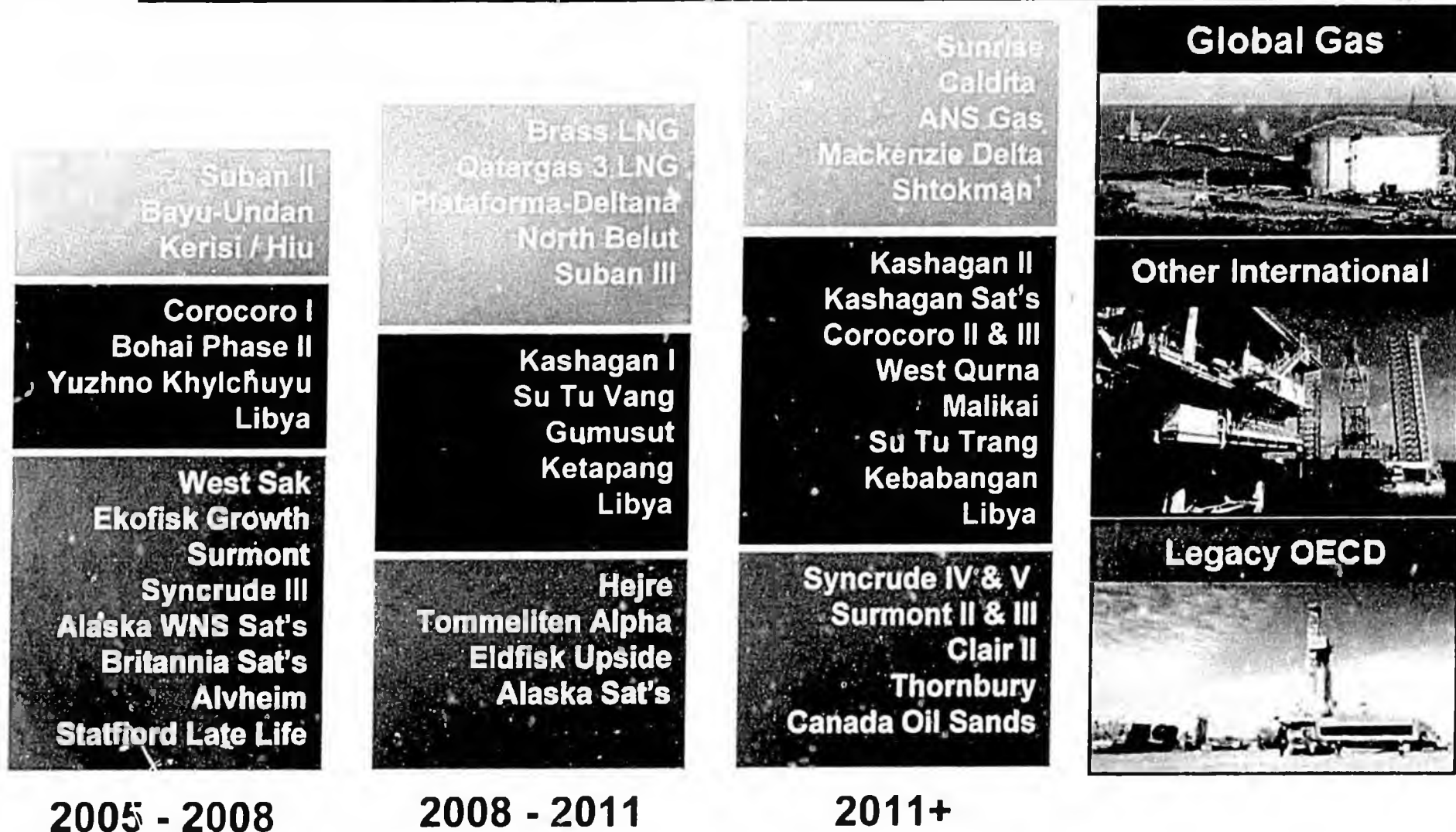
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- Reduces after-tax cash flow available for investment #7
- Adversely changes risk / reward balance
- Capital goes elsewhere to:
  - Other countries
  - Other energy sources
  - Other industries

**“If You Tax Something, You Will Get Less of It”**

# ConocoPhillips' Major Upstream Projects

#8



<sup>1</sup> Negotiations are under way.

# What's Wrong With Windfall Profits Taxes

#9

- 
- “What a windfall profits tax does is introduce a lot of distortion. It reduces investment, it increases a sense of political risk and it doesn’t achieve the goal that is intended ... it will really lead to decreased supply”.  
*Daniel Yergin interview, Capitalism Magazine, November 11, 2005*
  - “If it is again enacted, a windfall profits tax can be predicted to result in a diminution of domestic energy production... Sadly, the recent clamoring by some for new energy taxes indicates that the lessons of the 1970s were not learned.” *Open Letter to America’s Elected Officials, 250 economists, October 25, 2005*

Non-partisan Congressional Research Service assessment  
of 1980 Windfall Profits tax on domestic crude oil:

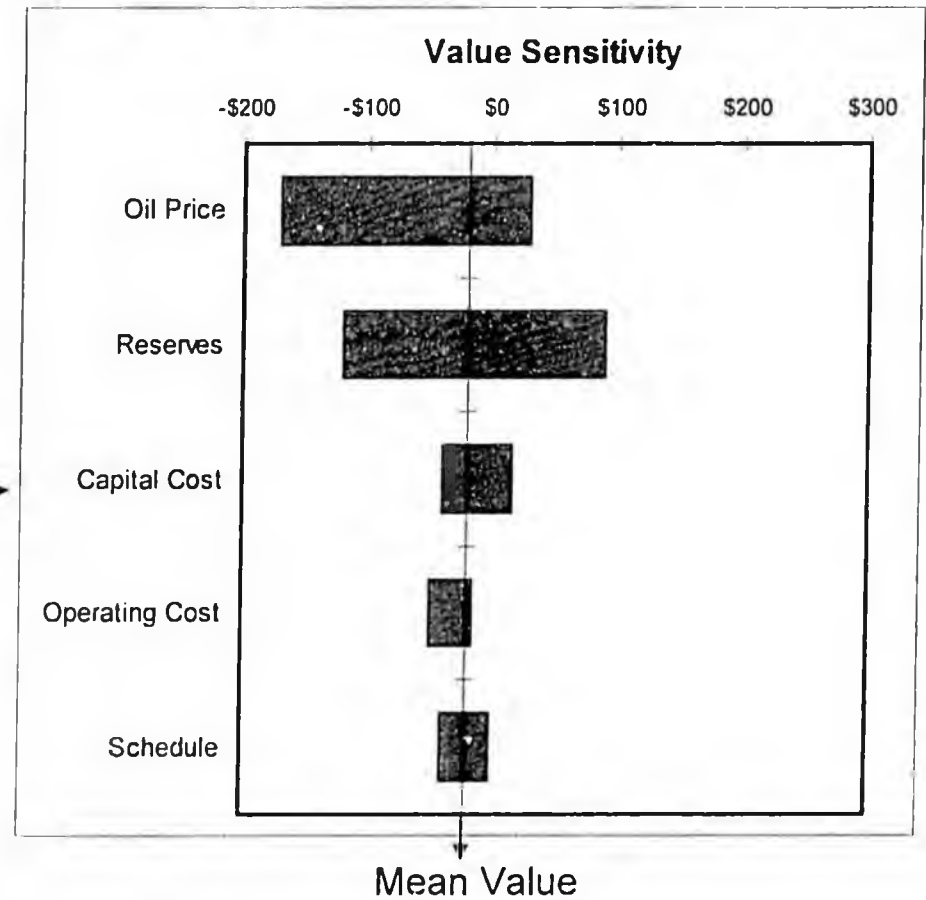
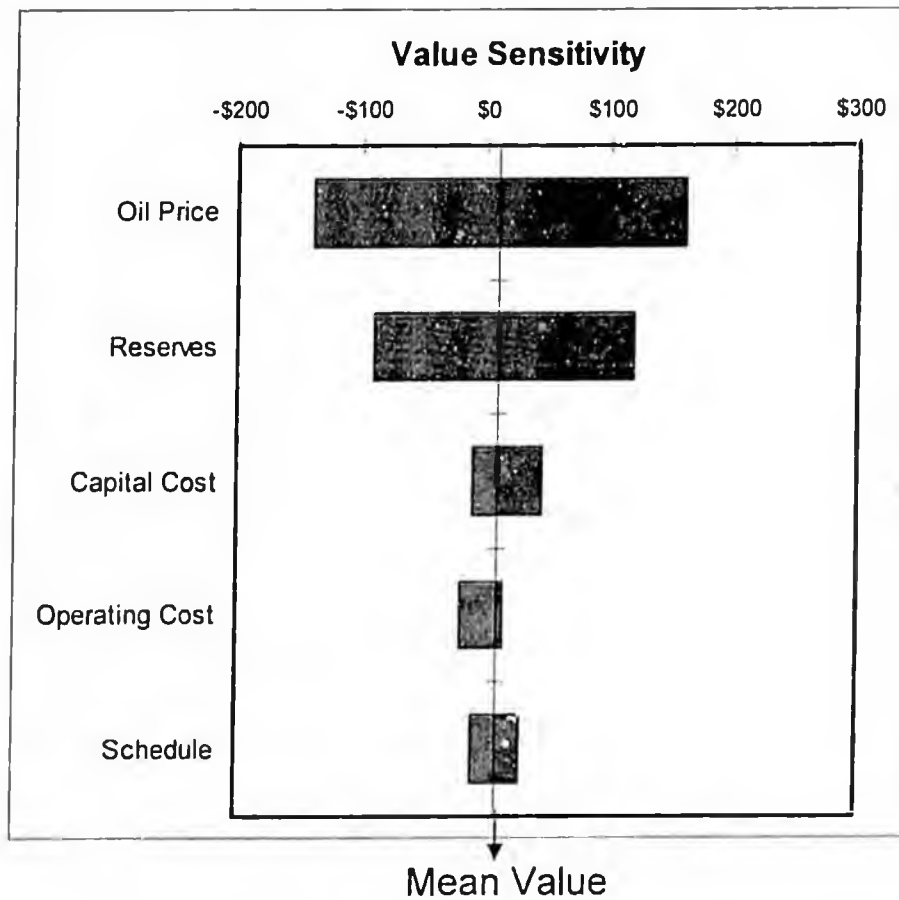
- Removed \$79 billion in gross revenues from industry that could otherwise have been invested
- Reduced domestic oil production by up to 1.6 billion barrels between 1980 - 1986
- Generated only 20% of expected gross revenues

# Impact of Progressivity on Risk/Reward Balance

#10

Positive Value –  
Project Accepted

Negative Value –  
Project Rejected



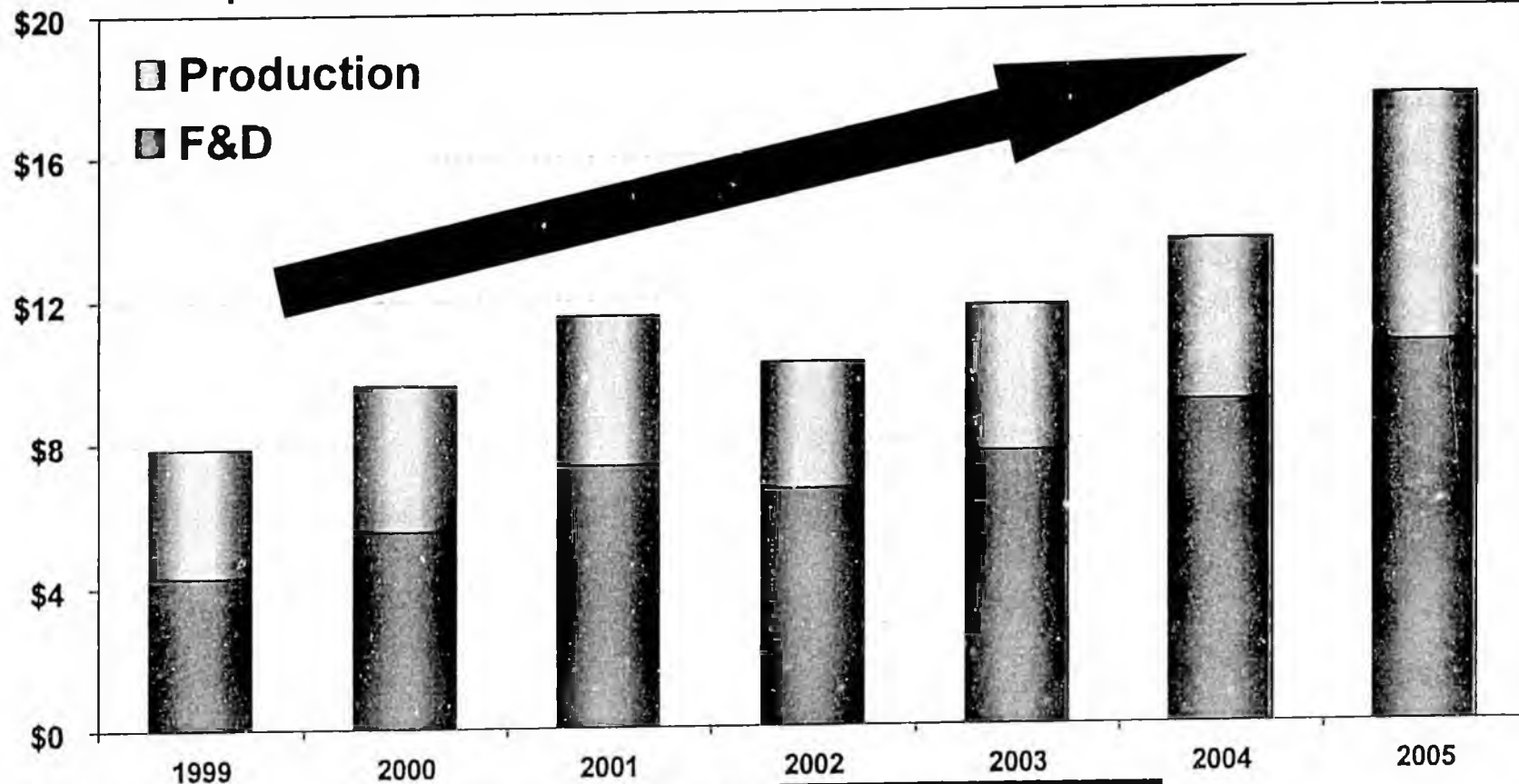
Project value is decreased when price upside is removed

# Finding, Development & Production Costs

# 11

## More than Doubled Since 1999

2006 Dollars per Barrel of Oil Equivalent



Excludes all government take (\$20-25/bbl),  
adjustment for the time value of money &  
a cost of capital return

Source: J.S. Herold

## Key Messages from Corporate Perspective

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#12

- Current tax rate already uncompetitive given cost & prospectivity
- Proposed tax increases will reduce investment & production in Alaska
- U.S. federal windfall profits taxes lowered production and failed to produce expected revenues

From TAPS Production Model

March 30, 2006

Dept. Revenue

Div. Tax

Share of Oil in Pipeline		Yesterday's Gross Revenue	
Exxon:	20.34%	\$	10,263,503.90
BP:	46.93%	\$	23,680,739.32
CP:	28.29%	\$	14,275,050.40
Chevron:	1.36%	\$	686,251.98
COCH:	3.08%	\$	1,554,158.90
	<u>100.00%</u>		

Yesterday's Production: 782,321 bbls

YTD Average: 854,740 bbls/day

Yesterdays' Price ANS: \$64.50 /bbl

# Summary

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- Higher taxes will reduce investments
  - 20% strikes the right balance
  - Windfall profits surcharge increases project risk
- Recognition of transition investments is fair
- Reasonable start date

## BP Presentation on CSHB 488 (PPT)

Alaska State Legislature  
House Finance Committee  
29<sup>th</sup> March 2006

For the record, I am Steve Marshall, President of BP Exploration Alaska. I appreciate the opportunity to provide my point of view regarding HB488.

I have watched the oil tax proceedings over the course of the last few weeks with great interest. As the discussion has evolved, I've become increasingly concerned. My concerns center on both the direction of changes and the focus of the discussion itself. I believe the current bill is moving in the wrong direction and will hurt Alaskans. And, while we have many common goals upon which to align our conversation, we have clearly not been successful so far.

It seems to me that while a lot of energy has been brought to bear, we are having the wrong conversation. So what is the right conversation?

We cannot afford an "us and them" conversation. We are all in the boat together. We all benefit from increased production and we all suffer from production decline. As our business faces its middle-age challenge, the day-to-day business is really about battling decline. I know that this doesn't have quite the same sizzle as a big project or new discovery, but this is our shared reality.

So the real issue before us is one of finding a suitable tax structure and rates that will encourage additional investment, stimulate development, get additional barrels in the pipeline; and yes, also give Alaskans a fair share of oil price upside when we all have such good fortune.

So the question is, what tax policy and plan will achieve this? This is the key point of discussion.

While the current high price is of great benefit, it has the tendency at the same time to mask the seriousness of the underlying production decline. We cannot afford to be distracted by the price environment. Instead, we need to recognize the underlying performance of the business, focus on our mutual goal of increasing production and avoid any outcome that creates undue burden across the whole of the business cycle. If we don't work together and get this right, decline will continue unabated and no tax rate will be high enough to generate the level of revenues Alaska needs to remain robust. We will all lose.

I wish I shared the confidence of your consultants that increasing taxes will not reduce investment. As an investor who has spent considerable effort to make Alaska more competitive so that we can successfully compete for increased investment, I have a different view. As I consider this bill, I recognize that my job is going to be much more difficult.

I feel a real personal stake in this today. To some degree, this is a result of my participation in the work over the last several years. An effort by the Alaska organization to develop a tangible plan that extends more than 50 years into the future. But, to a larger degree, it is because I am accountable to over 5,000 employees and contractors who have worked so diligently to develop the plans that underpin this future.

I'm privileged to have led this organization for the last five years. Through that time, the people of BP Alaska have faced many challenges and continued the progress to where we have now turned a corner and see new growth and opportunity. And their efforts and passion have had an impact on me. I have been affected by their commitment to this future, by their commitment to their local communities, by their dreams for their children and by their passion for the richness and unique qualities of living in Alaska.

With this in mind, I remain hopeful that we can return to a common dialog. In this discussion we will align behind the mutual goal of growing the pie and stand firm against the common enemy - production decline. I remain confident that this Committee will re-direct the conversation and the bill in such a way that we all end up with a tax policy that works for the people of Alaska and for investors like BP.

BP remains committed to this legislative process. We will continue to do our part in providing testimony and support with the goal of together creating a balanced structure that results in an infusion of capital, reduces decline, creates growth in state revenue, provides a better balance at high oil price and secures a healthy oil business that bridges us to gas and beyond.

You will hear Angus describe why:

- Production is declining
- Significant additional investment is vital to stem decline
- Production is paramount in maximizing State revenue and benefit to Alaskans
- The current bill is not in the best interest of Alaska.

Thank you for the opportunity to address the members of this committee.

Steve Marshall

## BP Presentation on CSHB 488 (PPT)

Alaska State Legislature  
House Finance Committee  
29<sup>th</sup> March 2006

For the record, my name is Angus Walker and I am the Commercial Vice President of BP Alaska.

I would like to start by thanking this Committee for the opportunity to provide testimony on Committee Substitute for House Bill 488.

I will summarize the key issues raised in previous testimony and provide our view of the substantive changes made by the House Resources Committee to HB 488.

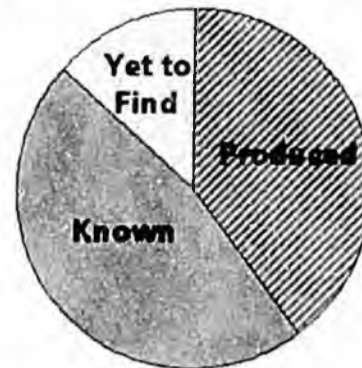
### Alaska has lots of Oil and Gas!

The good news for Alaska is that you have a huge known resource base, enough resources for the next 40 years and beyond.



		Billion barrels equivalent
	<b>Produced</b>	<b>15</b>
	<b>Known Remaining</b>	<b>17.5</b>
	Developed - Light	3.5
	- Viscous	0.3
	Undeveloped - Light	4
	- Viscous	0.7
	- Heavy	3
	- Gas	6
	<b>Yet to Find (Exploration)</b>	<b>5</b>

### Recoverable Resource



Source: DOR/USGS/BP

To date we have produced 15 billion barrels, but there are 17.5 billion barrels remaining that we already know about, 3.8 billion barrels of which have been developed to date.

Of the 13.7 billion barrels that are yet to be developed, there are:-

- 4 billion bbls of light oil remaining in the existing reservoirs
- 0.7 billion bbls of viscous oil, similar to that which we have started to produce
- 3 billion bbls of heavy oil lying in shallow formations below the permafrost
- 6 billion bbls of gas which we are working so hard to get to market

The scale of this known resource greatly exceeds that expected from future exploration. Future discoveries are expected to be of the order of 50-150 million barrels. It's not to say you should stop exploring, but you cannot rely on exploration to stem the decline of the North Slope.

While BP isn't exploring in the conventional sense, we are adding barrels. We're not only looking to develop our share of the 17.5 billion barrels, but we're looking to make it even bigger.

To put that in perspective, every time we increase the recovery efficiency by just 1% we access an additional 600 million barrels (400 mmbbls light oil and an additional 200 mmbbls heavy oil)..... Every 1% is equivalent to another Alpine!

It is for this reason we are investing in technology. We are exploring within our existing fields.

One example is that we're spending in excess of \$100 million implementing innovative technology to increase recovery at Endicott. If we are successful at Endicott it could add hundreds of millions of barrels of production across the North Slope. (Another Alpine?)

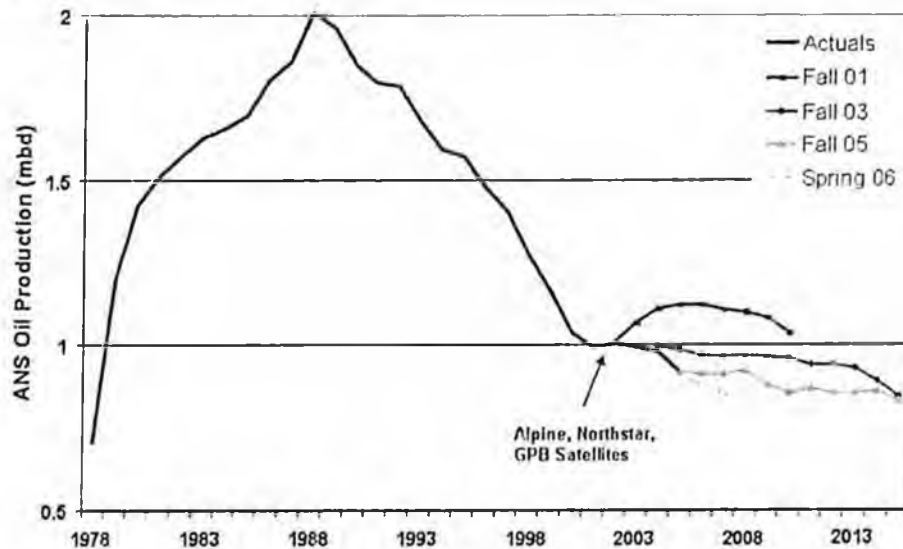
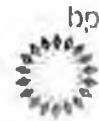
To develop the 14 billion barrels we know about would require well in excess of \$100 billion. And that kind of investment can only come from the Major oil companies of the world.

Encouraging new exploration is good but it is a fact, acknowledged by all who have testified, that the resources expected to be discovered through exploration will likely be significantly less than the resources we already know about. It is investment in the known resources that offers the greatest chance of stemming the decline of ANS production. As you look at incentives for exploration please do not overlook incentives for the investments in known fields, which are more likely to succeed.

## Production is declining:

Since 1999, both Industry and DOR have consistently overestimated production and have annually revised production forecasts down significantly. This is of great concern to us as it should be to you. A one hundred thousand barrel per day drop in production represents a drop in state revenue of around \$500 million per year at current prices.

### DOR Production Forecasts

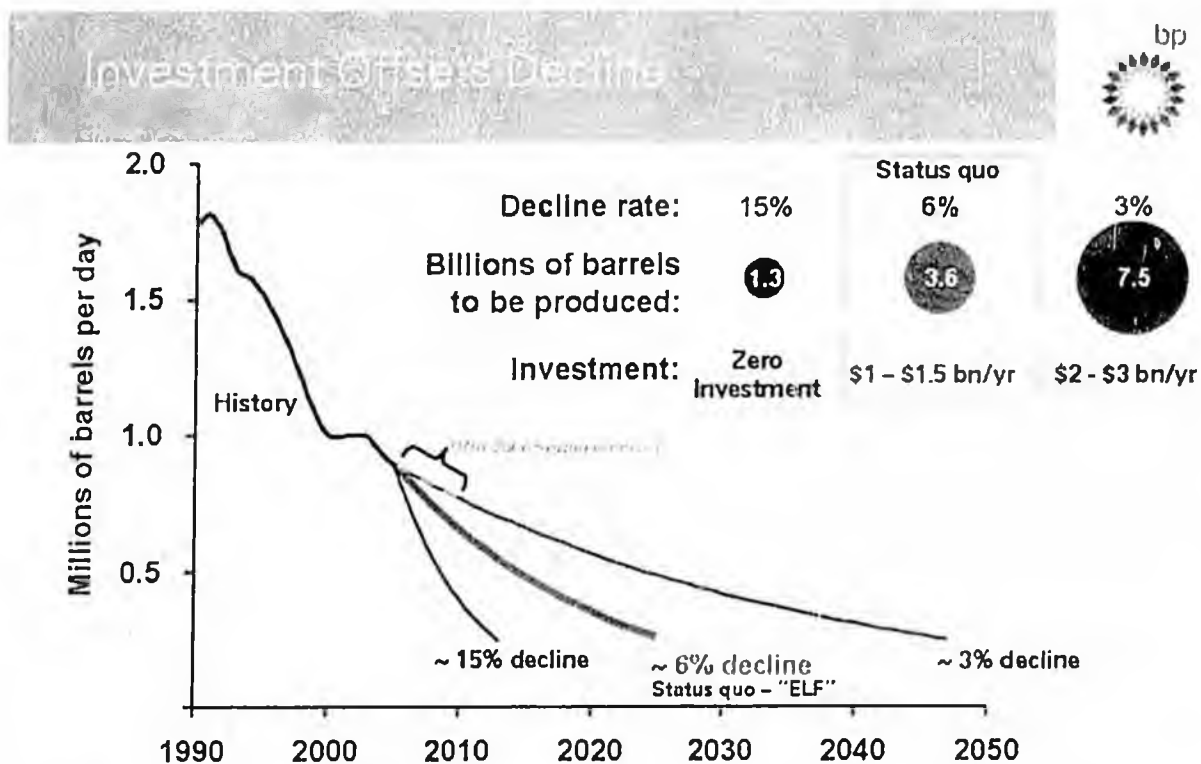


- Historical basin decline has been around 6%
- Flattening of production from 2002-2004 due to Alpine & Northstar
- Decline since 2004 has mirrored historical basin decline

This chart shows a subset of the DOR forecasts from 2001, 2003, 2005, along with the latest view of the Spring 2006 forecast, against actual production in red.

Whilst development of Alpine, Northstar, and the Prudhoe Bay Satellites between 2000 and 2002 successfully flattened North Slope production for a number of years, 2005 saw decline return to the 6% rate that has characterized this basin in the past. Unfortunately for all of us, there are no more fields of Alpine or Northstar's magnitude waiting to be developed.

**Significant additional investment is required to offset decline**



***DOR Spring Forecast cannot be met without significant additional investment  
The vast majority of that investment must be made in existing fields***

With no investment the natural decline of the fields would be the lower red line. At the current levels of investment (\$1-1.5 bn/year) that decline will be around six percent per year. The latest DOR 2006 Spring forecast translates into an approximate 3% decline which you can see is above the current status quo.

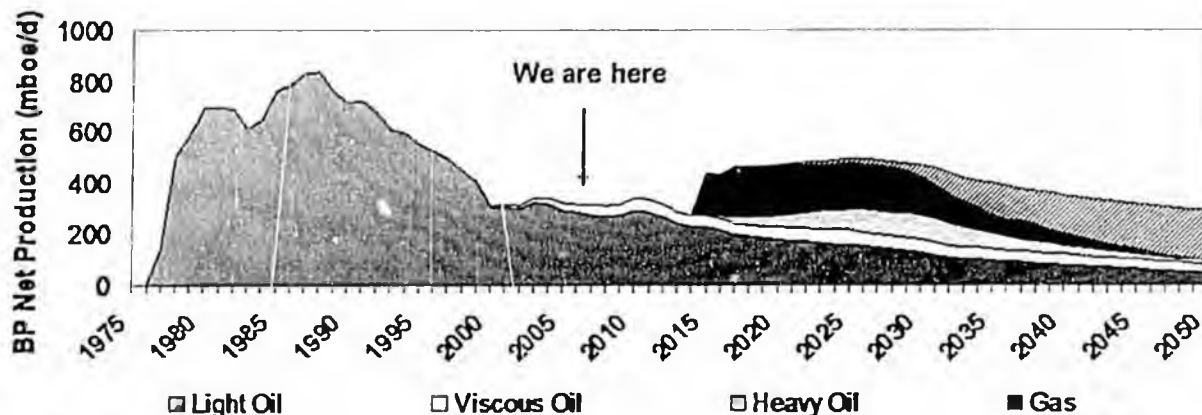
However, the 3% decline cannot be met without significant additional investment, in the order of 2 to 3 billion dollars per year. Unless those investments are made, history will repeat itself, decline will continue at the current rate, and the DOR will be revising its production forecast down yet again.

The real question for you to be asking industry and the consultants is 'what would it take to double investment in the Alaska North Slope?'

So what is BP doing to address the issue of decline?



## A 50 year vision



For several years now we have been pursuing our vision of a fifty year future for our business in Alaska. This future will be based on the development of the known resources on the North Slope (conventional light oil, viscous oil and gas).

Creating this future has many challenges and will not be easy to deliver, but we are already in action laying the foundations for the next 50 years.

We are pursuing technology to unlock the difficult oil.

We have been investing in infrastructure to get it ready for the decades to come (including \$1 bn by BP on four new tankers and \$400 million by the TAPS owners to update the pipeline). Each of these investments is designed to reduce costs and increase the wellhead value of Alaska's oil, to the benefit of the industry and the State.

We are hiring people, 200 people this year alone.

We have plans to invest \$14 billion over the next 10 years in our Alaska business.

We have great hopes for our Alaskan business, but are seriously concerned that without an appropriate fiscal policy that future will not transpire.



The size of the pie is the most important consideration. Maximizing the value of resources for Alaskans means maximizing state revenue by maximizing production. Resources left in the ground are simply a wasted opportunity.

This should be the focus of our deliberations. Alaska needs more investment, more jobs, more production, not higher taxes.

### Alaska will have the highest tax rates in the United States!

The good news for Alaska is that there is a huge known resource base on the North Slope.

The bad news is that it going to be technically difficult to extract that resource out of the ground. Every barrel gets more difficult.

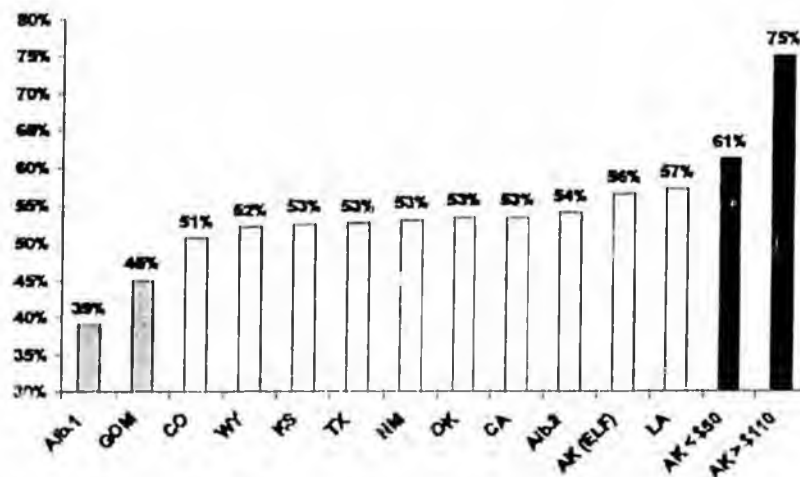
Alaska is already one of the most expensive places in the world to produce oil and gas.

Assuming the new 20/20 PPT is put in place, Alaska would also become the area with the highest marginal tax rate in the US. Needless to say this introduces one more barrier to attracting investment. The incorporation of yet higher tax rates at higher prices creates a bizarre fiscal regime, being regressive at low prices and progressive at high prices, thus reducing space for industry and creating yet more barriers to attracting investment.

The following graph shows how Alaska compares to other North American regimes both under 20/20 PPT and the scenario outlined in the House Resources CS.



Marginal Tax Rate North America: Tax Rate Comparison



➤ Alaska is already the highest cost region to operate

\*Alb: ALBERTA HEAVY OIL - pro and post-payout

BP data

### Alaska will have the highest marginal tax rate

To maximize the value of the resources in the ground, we should be focussed on maximizing North Slope production by attracting investment. The priority for the state of Alaska should be to encourage investments to help industry develop those known resources, not to make it more difficult and risky than it already is.

**Other countries have proven that reducing taxation increases investment:–**

UK – a role model for attracting investment



"Ordinary measures of Government take throughout the 1990's made the United Kingdom government appear rather crazy and irresponsible. . . . **The "gross benefits" to the UK Government go way beyond direct tax revenues and royalties received from the upstream sector of the petroleum industry. The economic impact of the industrial hyperactivity in the UK sector of the North Sea, a direct result of the "lenient" terms of the 1990's, is difficult to measure** Furthermore, the activity in the UK started in the late 1980's and early 1990's when the UK Government dropped the ring fence for the 75% PRT before Government take, as it is ordinarily measured, was drastically reduced **The UK offshore became the most active offshore province in the world. Reducing the Government take in the following years managed to sustain that boom. Activity and employment in the British petroleum sector is healthy and robust.**"

***Daniel Johnston***

*23 Oct 2002, Washington DC  
Petroleum Tax Design*

There was much discussion over recent weeks about the impacts of reducing taxes in the UK. The UKCS has been our backyard for many years and we couldn't agree more with Daniel Johnston that reducing taxes firstly created and subsequently sustained an economic boom. The UK's decision to reduce Government Take led to a significant increase in activity in the North Sea, more production, higher revenues for the Government and a ripple effect throughout the whole economy.

**The actions of the UK during the 1980's and 1990's provide an excellent role model for any Government hoping to attract investment.**

## Alberta Heavy oil



### Investment boom underway

- Capex increasing up to \$10 billion p.a
- Alaska flat circa \$1 billion p.a

### Enabling fiscal regime

- Key reform in 1995
  - 1% Royalty until project payout
  - 25% after payout
  - Federal and State tax of 39%

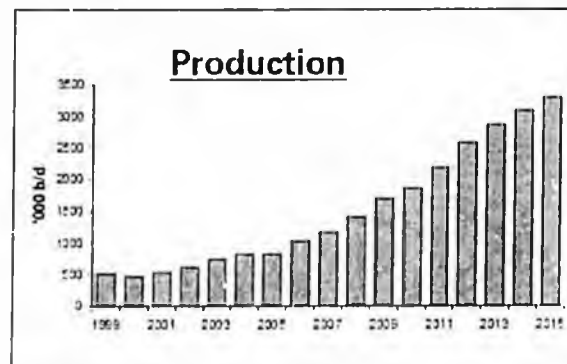
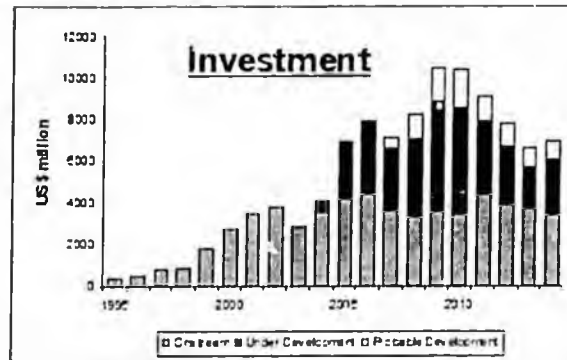
### Marginal tax rates

- 39% pre payout
- 54% post payout

Above rates will decline by 4% through 2007

- via phased reduction in Federal tax rates

Source: Wood MacKenzie



If we just take a relatively short trip across the border into Canada and look at what is happening in the heavy oil province of Alberta we find another great example of where cutting taxes has increased investment & state revenues.

**The current version of HB 488 is not good for Alaska and will not help stem decline of the North Slope and we encourage you to address the following key issues:**

1. The proposed progressivity in the tax rate combined with the significant base rate increase in moving from Elf to PPT (20/20) is inappropriate given Alaska's circumstances:
  - a. Challenged resource base
  - b. High cost environment
  - c. Distance to market
  - d. Regressive nature of the rest of the fiscal regime
  - e. Urgent need to attract very large amounts of capital to stem decline
  
2. Several of the newly introduced terms are unbalanced and will cause problems:
  - a. It contemplates only an increase in tax with no reduction in tax at medium and low prices
  - b. The tax rate is dictated by the price of WTI which is not representative of the realized value for ANS crude
  - c. There is no recognition of inflation and thus tax rates will effectively increase with time making the system unsustainable
  - d. The proposal contains a large step function in taxation at a single price point which could have bizarre consequences
  
3. Transition provisions demonstrate to investors that they do not have to bear the full risk of retroactive tax increases. Failure to provide for transition will harm the State's reputation with investors.
  
4. The change in the effective date to April 1 means this tax will be implemented before it is enacted by the Legislature. Retroactive application of taxation policy should be avoided.
  
5. Simplicity should be a key objective in setting fiscal policy and the current version of the Bill adds significant complexity to one of the most complex fiscal regimes in the world. This will be a further disincentive to investors.

At the highest level we do not believe this Bill as drafted achieves the mutual goal of increasing investment & stemming decline.

## Key Messages

I would like to leave you with the key messages from this testimony.

### Key Messages



- Alaska has lots of oil & gas but production is declining!  
Decline is our common enemy!
- Significant additional investment is required to stem decline
- Maximizing production will maximize State revenues and benefits to Alaska
- With a 20% tax rate Alaska will have the highest tax rate & the highest cost structure in the US
- The bill as drafted will not maximize benefits to Alaskans
- The UK and Alberta have successfully attracted significant investment and increased production by reducing taxes and are thus great role models

We believe that the changes made to HB 488, if enacted, would be a serious mistake for Alaska and we urge you not to adopt them but to return instead to a bill close in structure to the original Bill.

In order to maximize the value of Alaska's resources we believe you should be adopting tax rates lower than those proposed by the Governor. In so doing you would maximize investment, maximize production and maximize jobs for Alaskans. You would also take an important step towards creating a healthy oil business which will be the foundation for gas.

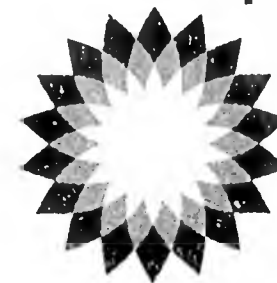
We recognize the burden on your shoulders in making these decisions. There are many people advising you to increase taxes, which will indeed increase state revenue, but for how long? One year? Two years? ....and at what cost to future production?

This is a matter of urgency. All Alaskans should be concerned. Short sighted increases in tax will jeopardize future oil investments, future oil production and the gas pipeline project itself.

We will continue to participate fully in the legislative process and will be available to assist this committee in whatever way we can.

On behalf of BP I would like to thank you for this opportunity to testify.

bp



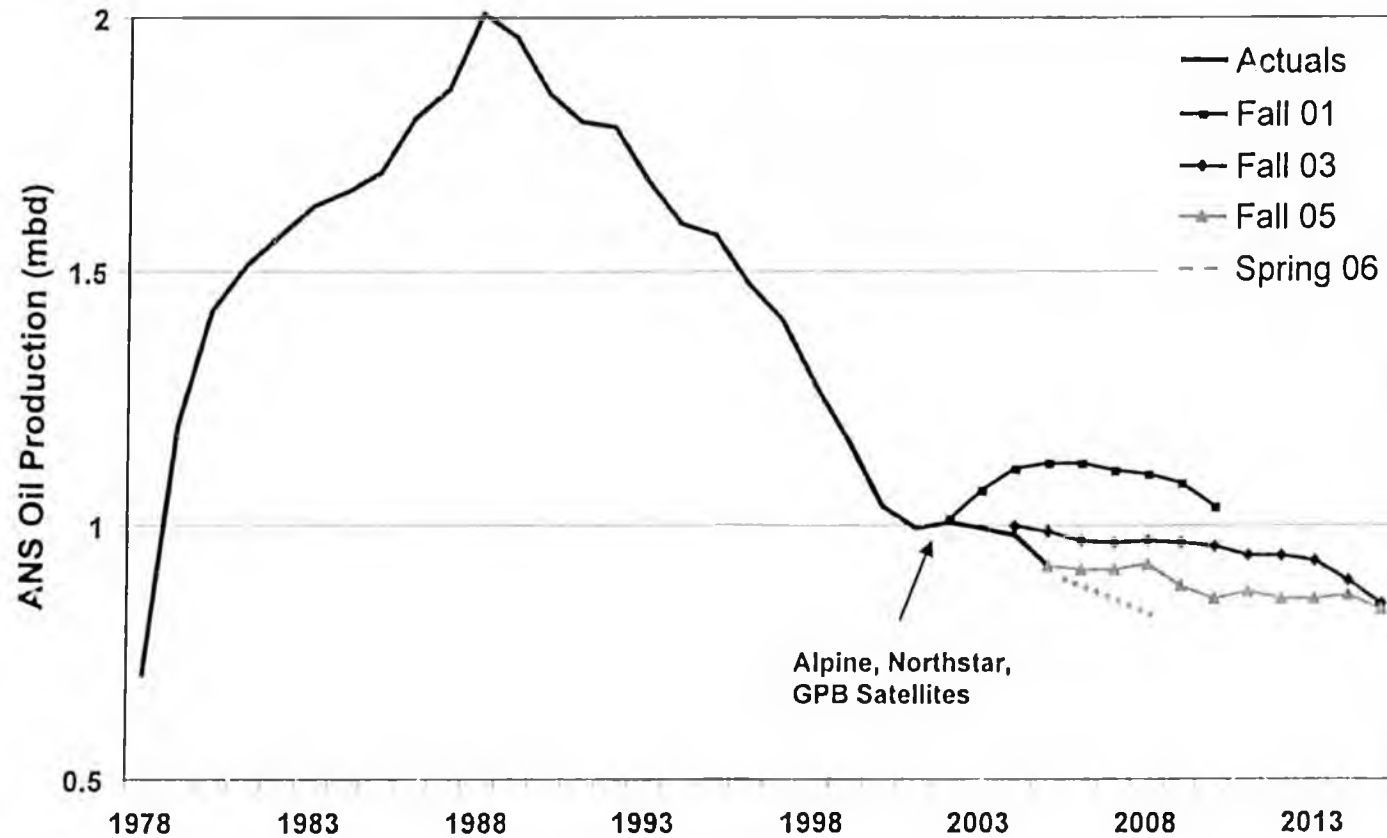
BP Presentation to the House Finance  
Committee  
REPTCS House Bill 3281

**Juneau**

**29 March 2006**

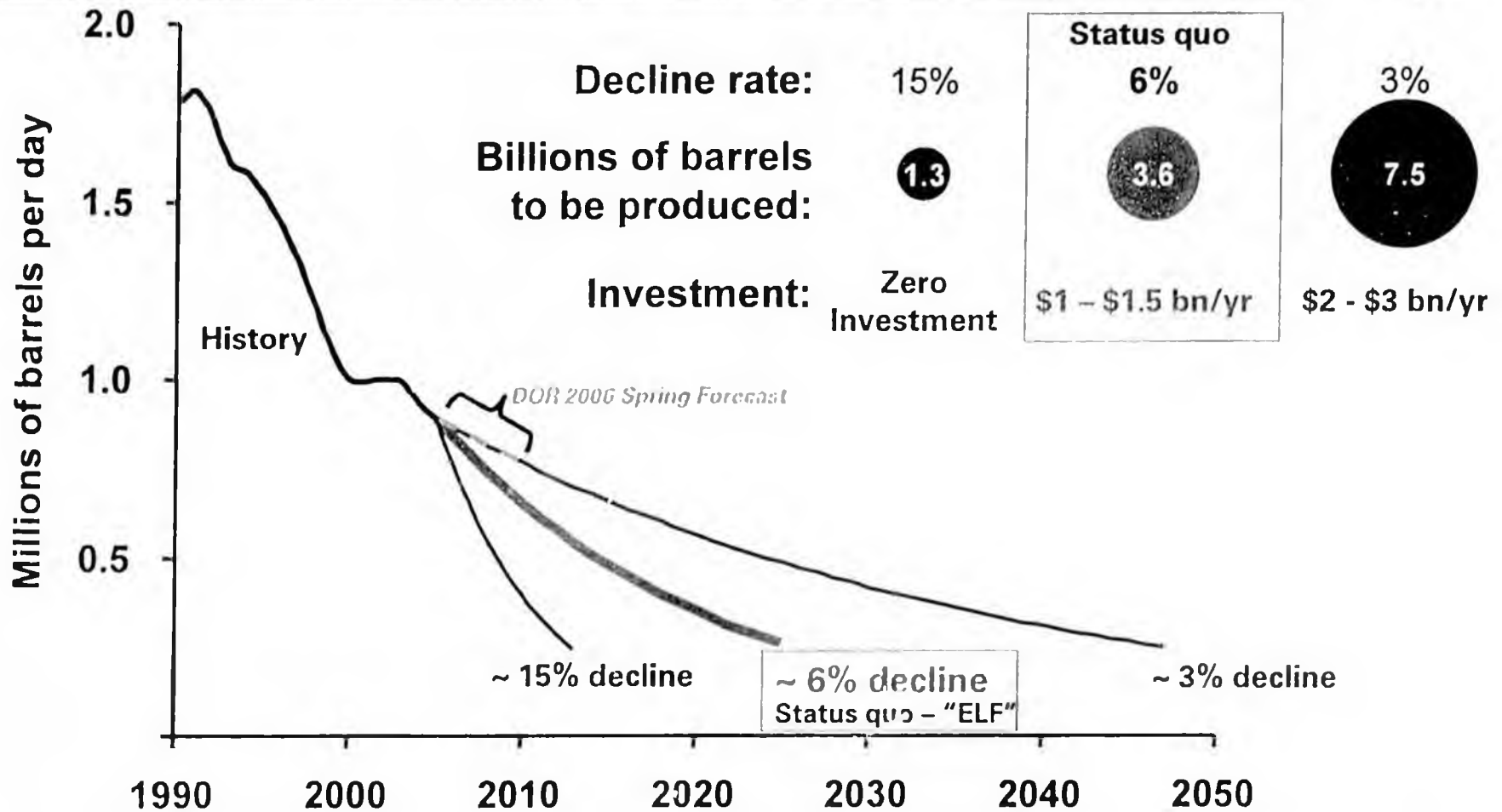
3-29-06

# DOR Production Forecasts



- Historical basin decline has been around 6%
- Flattening of production from 2002-2004 due to Alpine & Northstar
- Decline since 2004 has mirrored historical basin decline

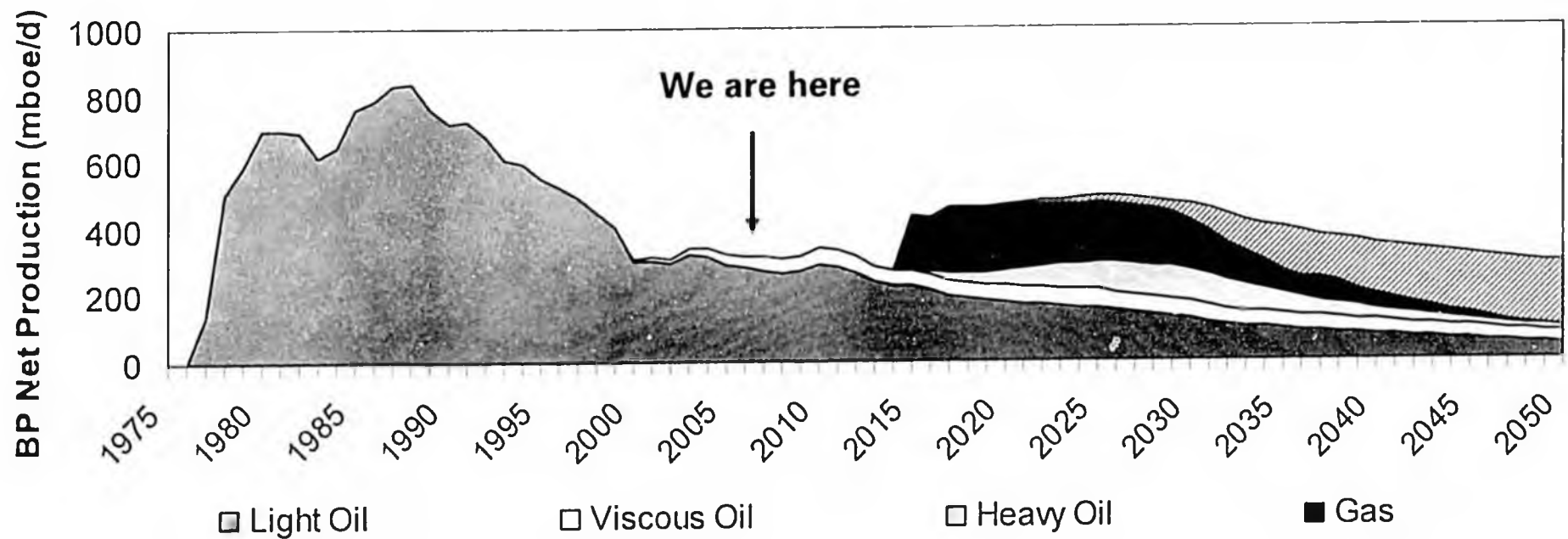
# Investment Offsets Decline



***DOR Spring Forecast cannot be met without significant additional investment  
The vast majority of that investment must be made in existing fields***



# A 50 year vision



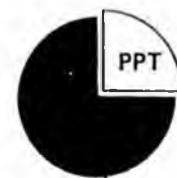
# Production Drives Revenue



Decline Rate	15%	<b>Status quo</b> <b>6%</b>	3%
Produced Barrels	1.3 bn	3.6 bn	7.5 bn
Operating Expenses	\$30 bn	\$50 bn	\$100 bn
Industry Investment	\$1 bn	\$20 bn	\$60 bn

**State Revenue**  
*(estimate)*

*Assuming  
20/20  
\$40 ANS*



All other non-PPT  
state revenue

**\$10 bn**



All other non-PPT  
state revenue

**\$30 bn**



All other non-PPT  
state revenue

**\$60 bn**

Less investment

More investment

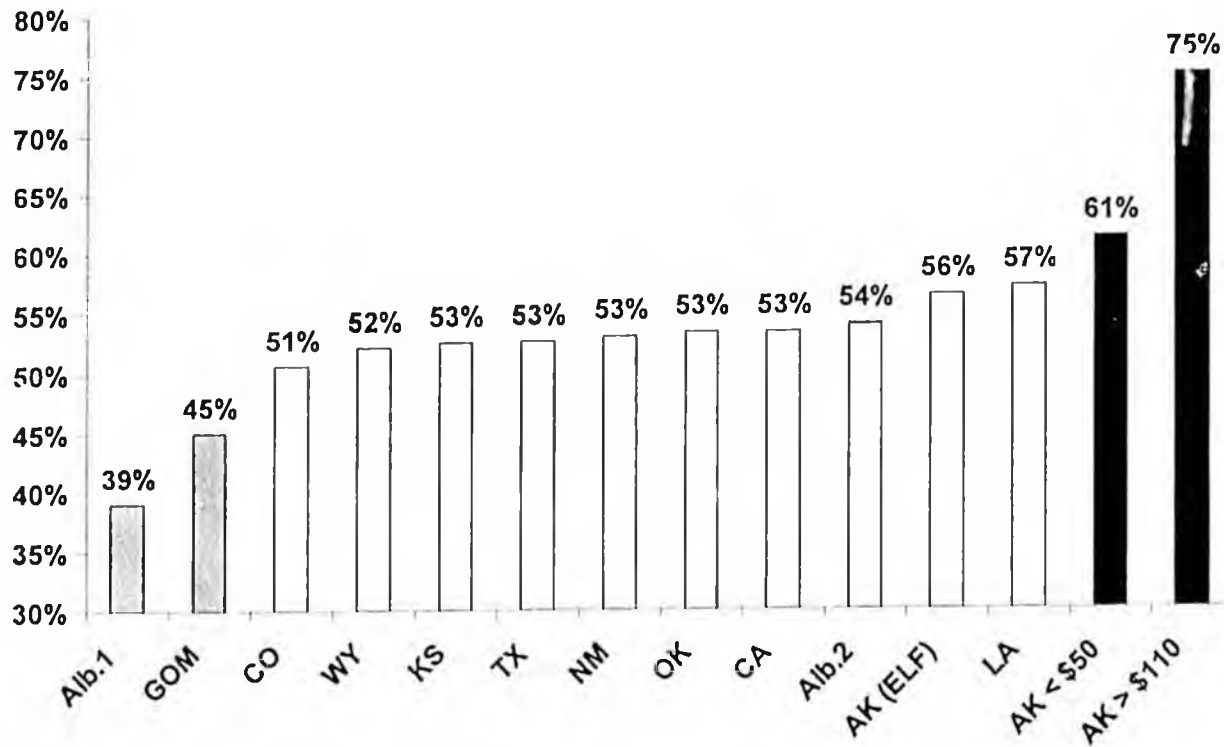
***Maximizing State Revenue means maximizing Production***

# US Marginal Tax Rates



Marginal Tax Rate

## North America: Tax Rate Comparison



➤ Alaska is already the highest cost region to operate

\*Alb: ALBERTA HEAVY OIL – pre and post-payout

BP data

## Alaska will have the highest marginal tax rate

## Key Messages



- Alaska has lots of oil & gas but production is declining!  
Decline is our common enemy!
- Significant additional investment is required to stem decline
- Maximizing production will maximize State revenues and benefits to Alaska
- With a 20% tax rate Alaska will have the highest tax rate & the highest cost structure in the US
- The bill as drafted will not maximize benefits to Alaskans
- The UK and Alberta have successfully attracted significant investment and increased production by reducing taxes and are thus great role models

**Chevron**



**Chevron - Alaska Area  
Testimony on HB 488  
Finance Committee**

**John P. Zager  
General Manager**

**March 29, 2006**

3-29-06



## Chevron's Alaska Presence

- Current Asset base is formed by combination of heritage Chevron and Unocal assets
  - Both companies have been active in Alaska for many years
- 4<sup>th</sup> largest producer in state
- 3<sup>rd</sup> largest operator
- 382 employees or full time contractors
  - 272 on the Kenai Peninsula
  - Payroll of >\$45 million
- Key customers: Tesoro, Enstar, Chugach Electric, Agrium, Aurora
- Chevron is the only producer in the state with a relative balance of assets in the Cook Inlet and on the North Slope
  - Both production streams are large enough to trigger PPT
- Chevron's Cook Inlet offshore assets are uniquely positioned to suffer from the proposed PPT



# Alaska North Slope Fields

Net Production  
16,000 BOEPD

Alpine

CVX (ORRI) 1%

Endicott

CVX 11%

Greater Kuparuk

CVX 5%

Greater Prudhoe Bay

CVX 1%

Pt. Thomson

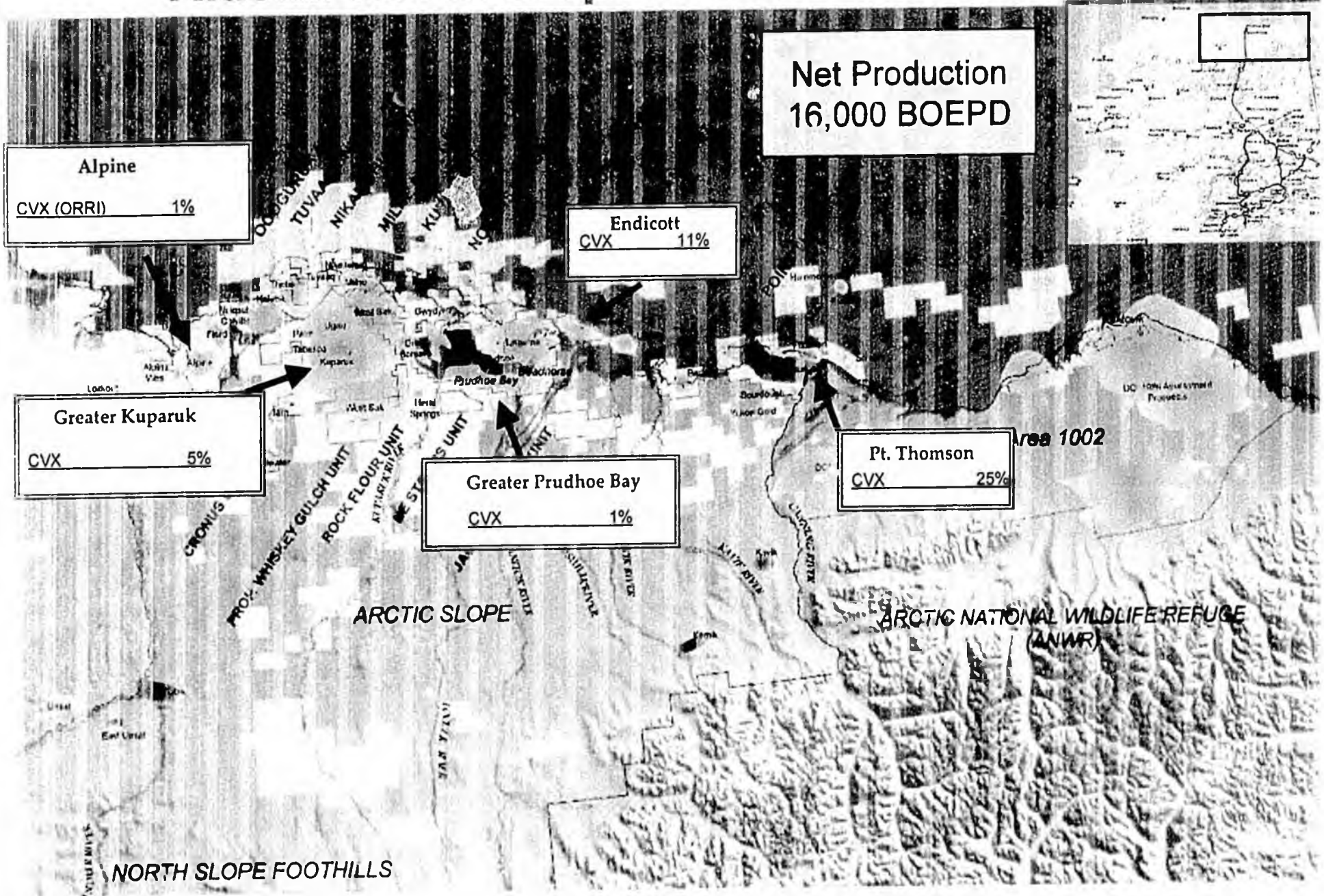
CVX 25%

Area 1002

ARCTIC SLOPE

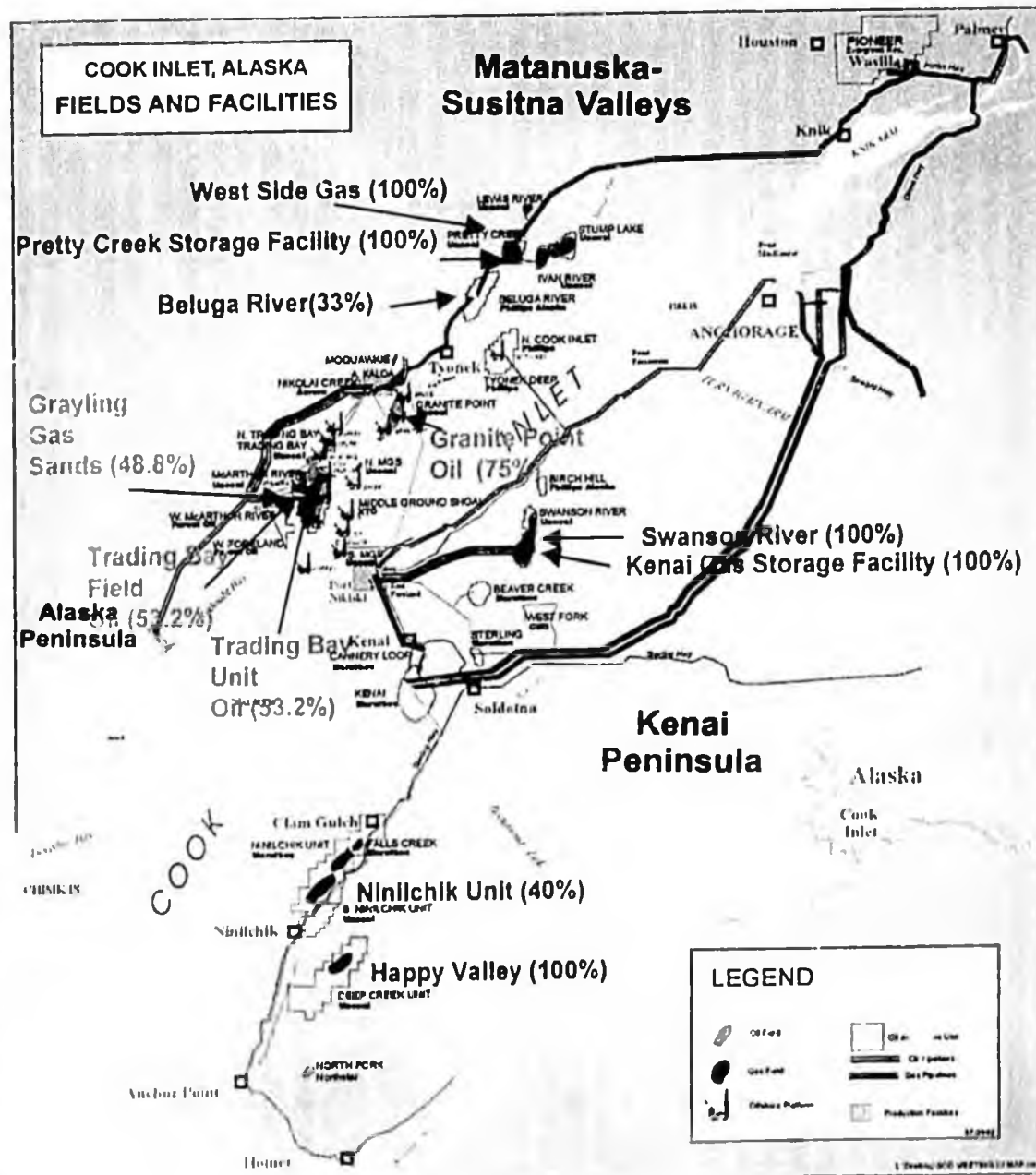
ARCTIC NATIONAL WILDLIFE REFUGE  
(ANWR)

NORTH SLOPE FOOTHILLS





# Cook Inlet - CVX Asset Description



## Cook Inlet Offshore :

- 3 fields ( all op. )
- 10 Platforms
- 145 wells
- 2 onshore plants
- 42 mile PL
- 10,900 BOEPD

## Cook Inlet Onshore :

- 8 fields ( 6 op. )
- 60 wells
- 2 gas storage fields
- WI% in 4 PLs
- 14,100 BOEPD

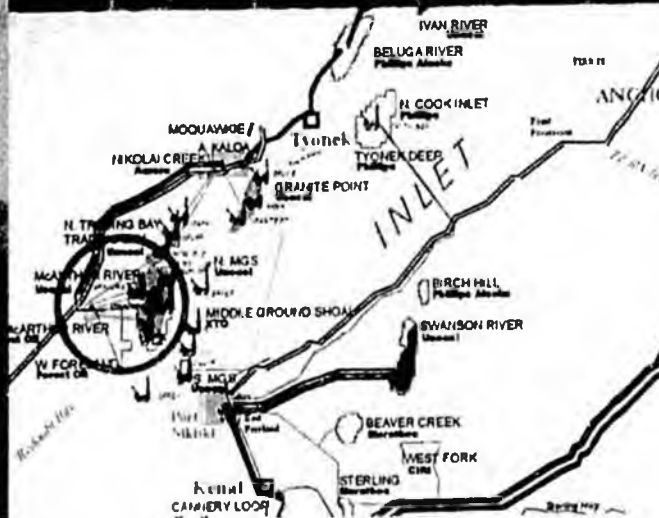
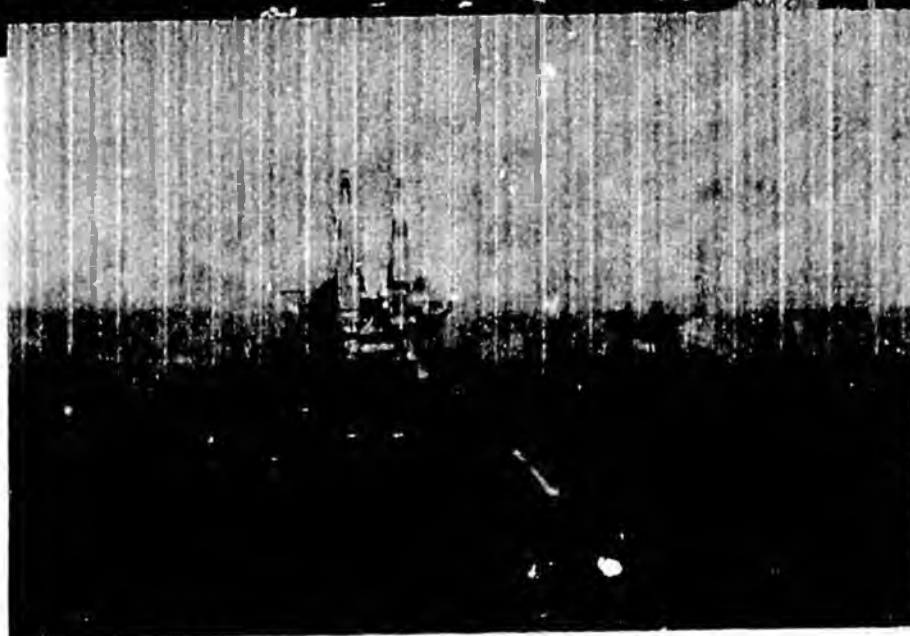
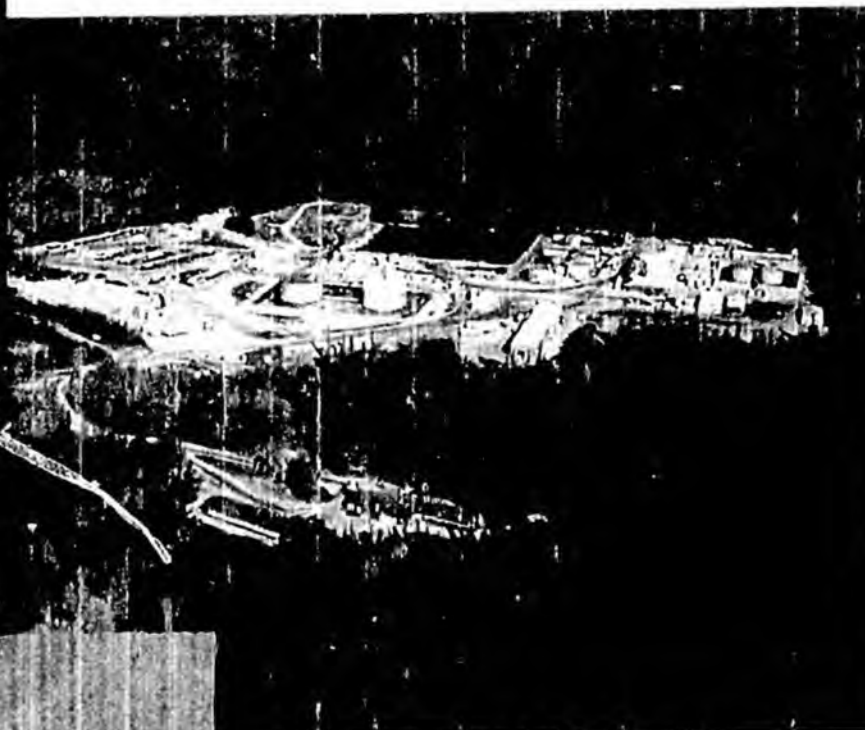
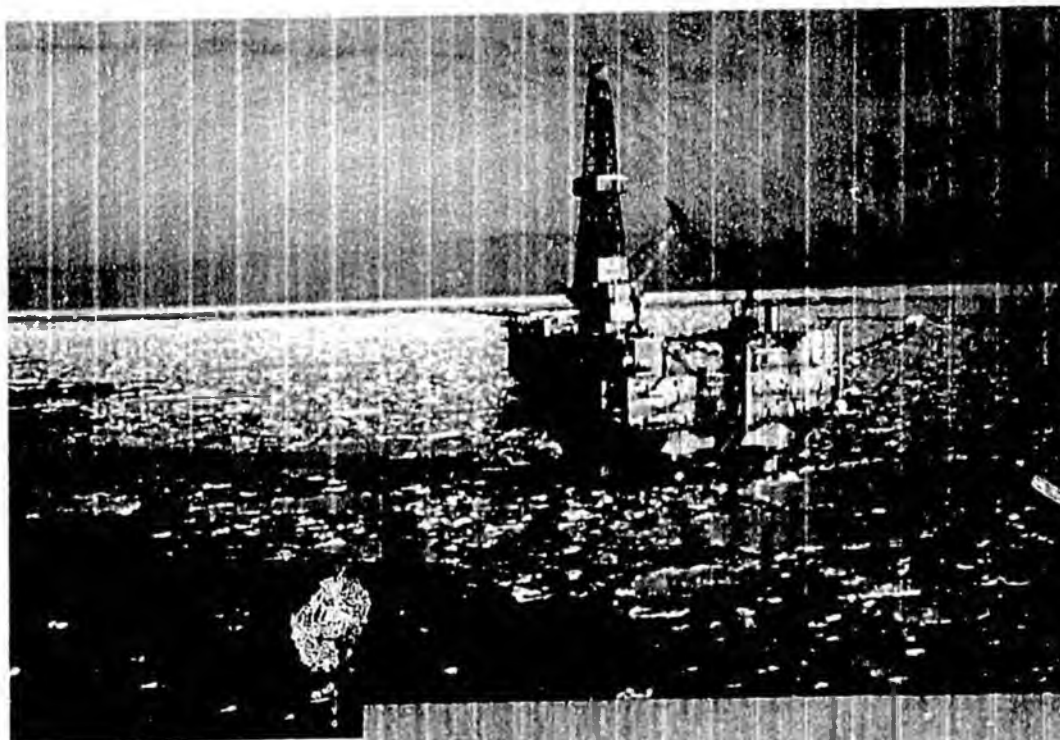
## Net Production

**Offshore Oil**  
**6,300 BOPD**

**Gas**  
**112 MMCFPD**

**25,000 BOEPD**

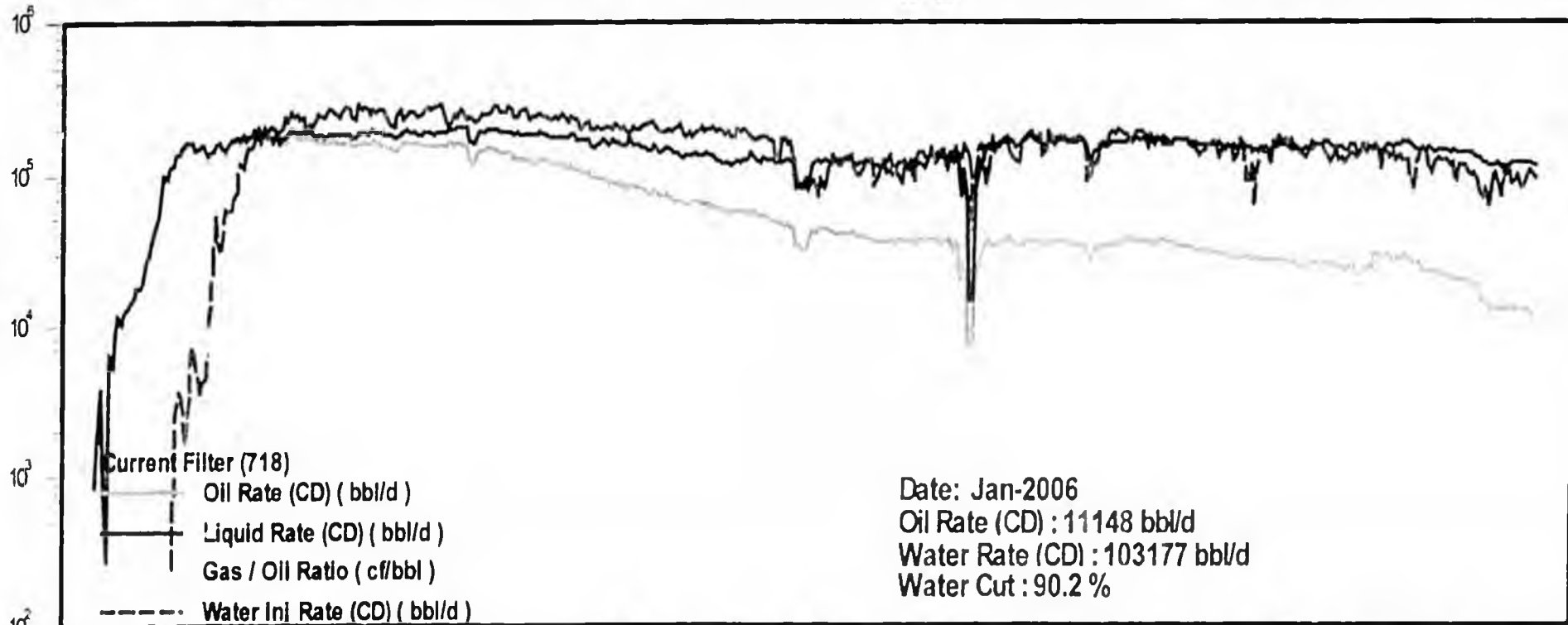
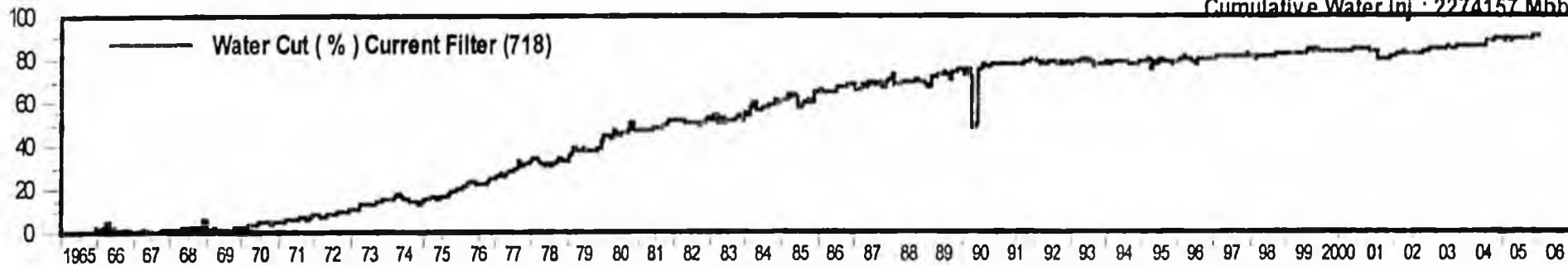
# Trading Bay Unit



# Cook Inlet Offshore



Cumulative Oil Prod : 1030570 Mbbbl  
 Cumulative Gas Prod : 1587463 MMcf  
 Cumulative Water Prod : 1117781 Mbbbl  
 Cumulative Water Inj : 2274157 Mbbbl



Date: Jan-2006  
 Oil Rate (CD) : 11148 bbl/d  
 Water Rate (CD) : 103177 bbl/d  
 Water Cut : 90.2 %

1965 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 2000 01 02 03 04 05 06

1-Prod and Wtr Out.grf

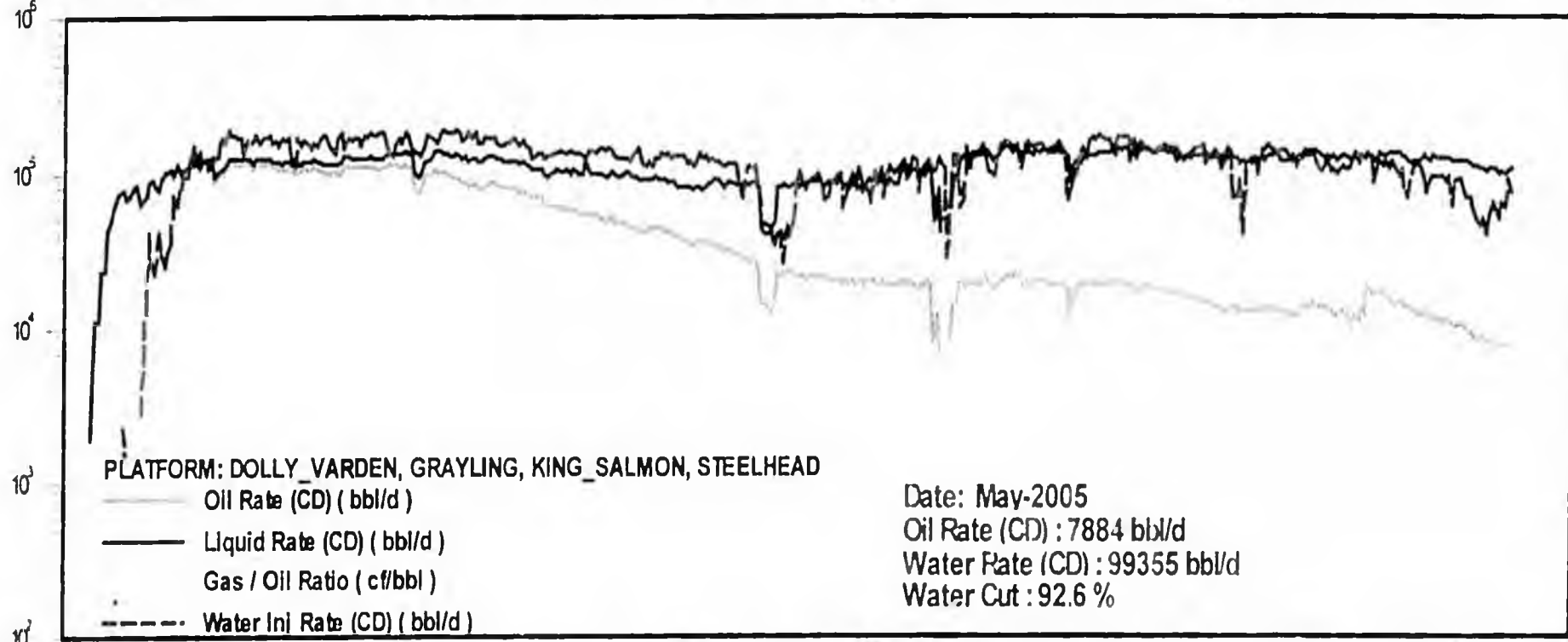
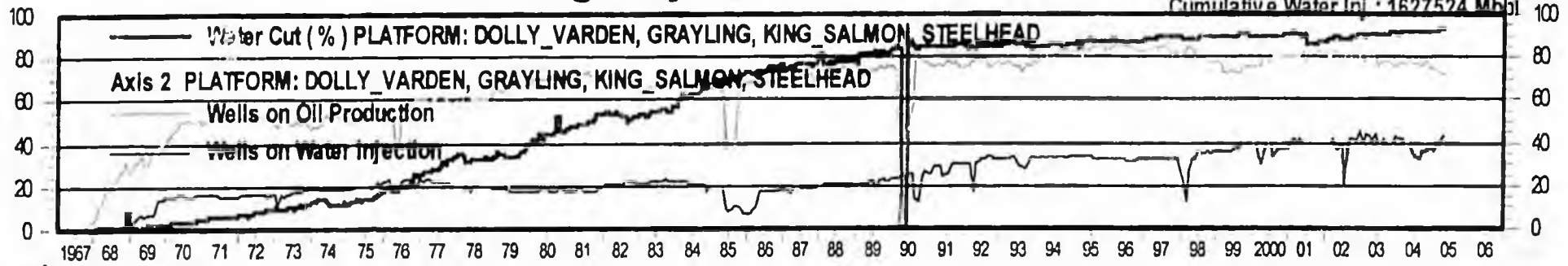
Date

02/24/2006 06:21:15



# Trading Bay Unit

Cumulative Oil Prod : 618928 Mbbbl  
Cumulative Gas Prod : 1266687 MMcf  
Cumulative Water Prod : 897435 Mbbbl  
Cumulative Water Inj : 1627524 Mbbbl



PLATFORM: DOLLY\_VARDEN, GRAYLING, KING\_SALMON, STEELHEAD

- Oil Rate (CD) ( bbl/d )
- Liquid Rate (CD) ( bbl/d )
- Gas / Oil Ratio ( c//bbl )
- Water Inj Rate (CD) ( bbl/d )

Date: May-2005  
Oil Rate (CD) : 7884 bbl/d  
Water Rate (CD) : 99355 bbl/d  
Water Cut : 92.6 %

1967 68 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 2000 01 02 03 04 05 06

Date

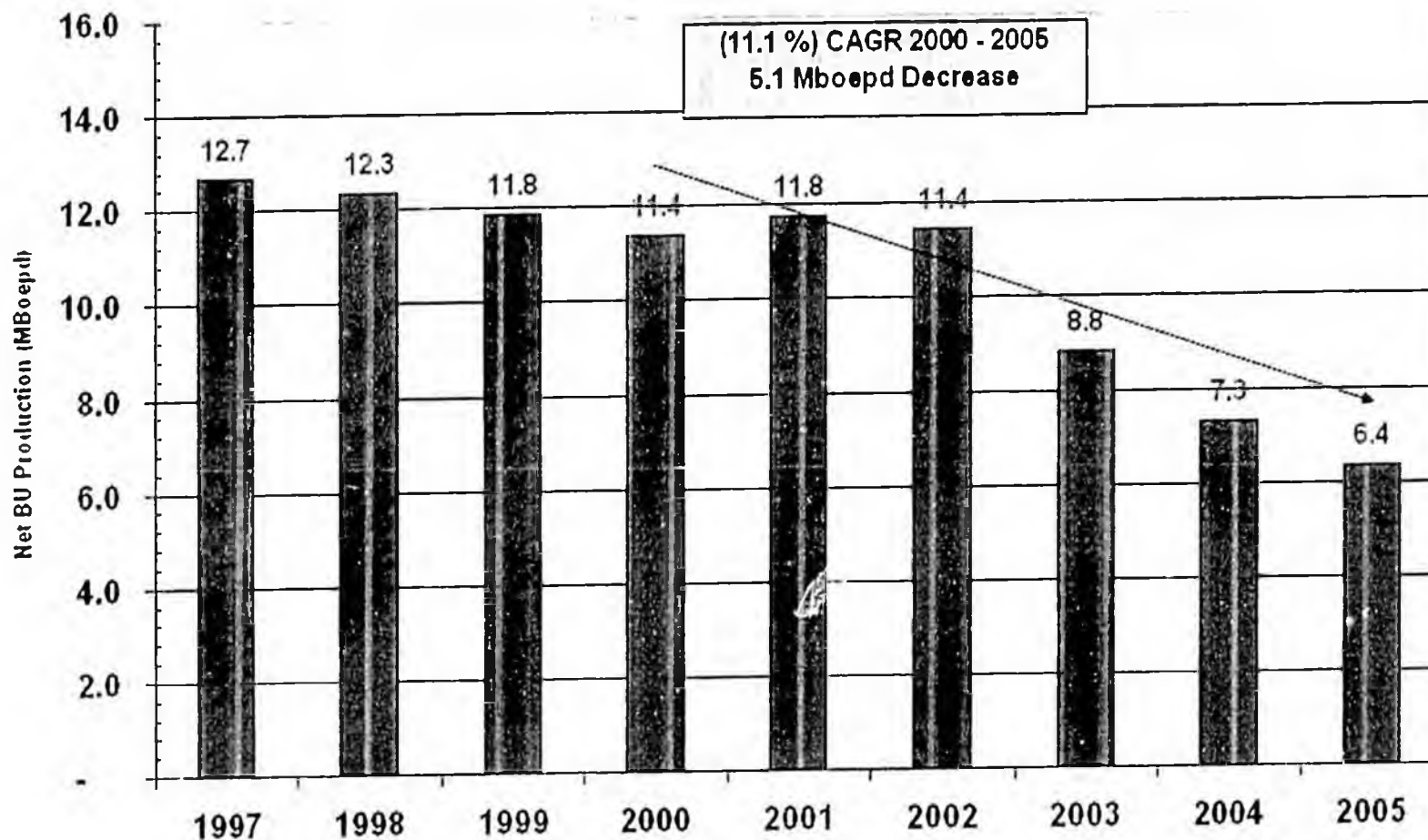
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7



# Cook Inlet Oil Production History

Cook Inlet Oil Business Segment Production History  
(Avg Annual Net MBoepd)





## Cook Inlet Offshore Oil

- Cook Inlet Oil is very high cost
  - Direct lift cost \$20 - \$25 per BOE
  - Currently breakeven on Cash Flow @ ~ \$30/BOE
  - Currently breakeven on Earnings @ ~ \$40 - \$45/BOE
  - Further production declines will raise breakeven prices
- Significant operational risks
  - Two platforms are currently shut-in
  - Must maintain critical mass of operations
- Cook Inlet Offshore cannot afford an additional tax burden



## Chevron Cook Inlet Strategic Study

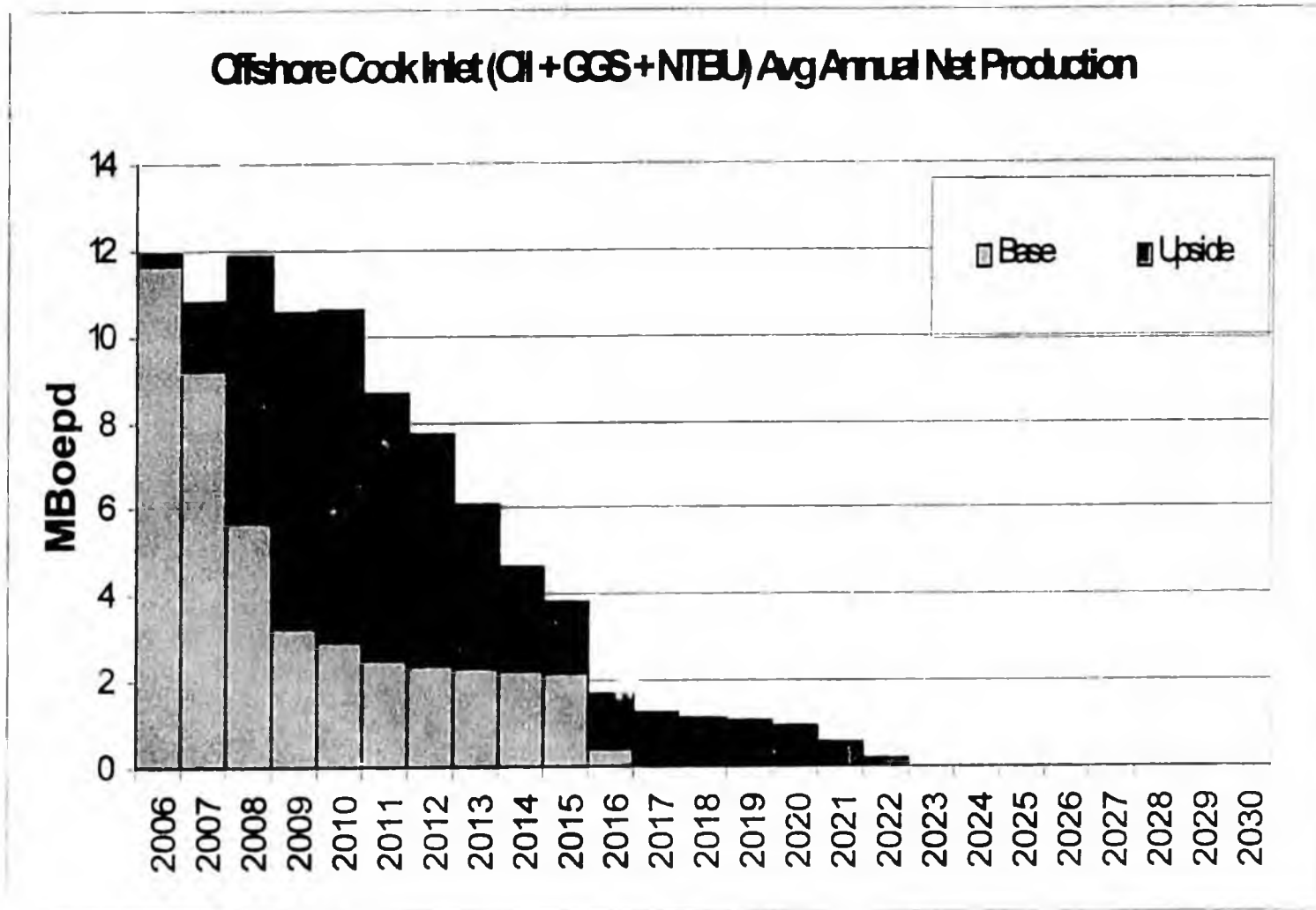
- August 10, 2005 Chevron acquires Unocal
  - Much speculation about Cook Inlet asset fit in Chevron Portfolio
- October 2005 – January 2006 – Strategy work completed
  - Determined that there are incremental investment opportunities in the Cook Inlet although they are in the lowest quartile of Chevron's investment portfolio, many projects did not make the cut
- February 2006 – Great news - announce decision that Chevron will retain all Cook Inlet assets with the intent to begin a multiyear investment program
  - Chevron will retain the current office locations



## Great news, so what's the problem?

- The Cook Inlet reinvestment program was evaluated using the current severance tax assumptions (zero severance tax)
- When modeled under the proposed 20/20 PPT the economics on some projects are degraded, some projects are improved, overall poorer economics for the program
  - Oil production taxes will go up dramatically
  - Will cause investment decision to be reconsidered
  - Higher taxes will cause less capital to be spent
  - Enhanced PPT terms could significantly expand the list of economic projects in the investment program and significantly extend the life of offshore oil production

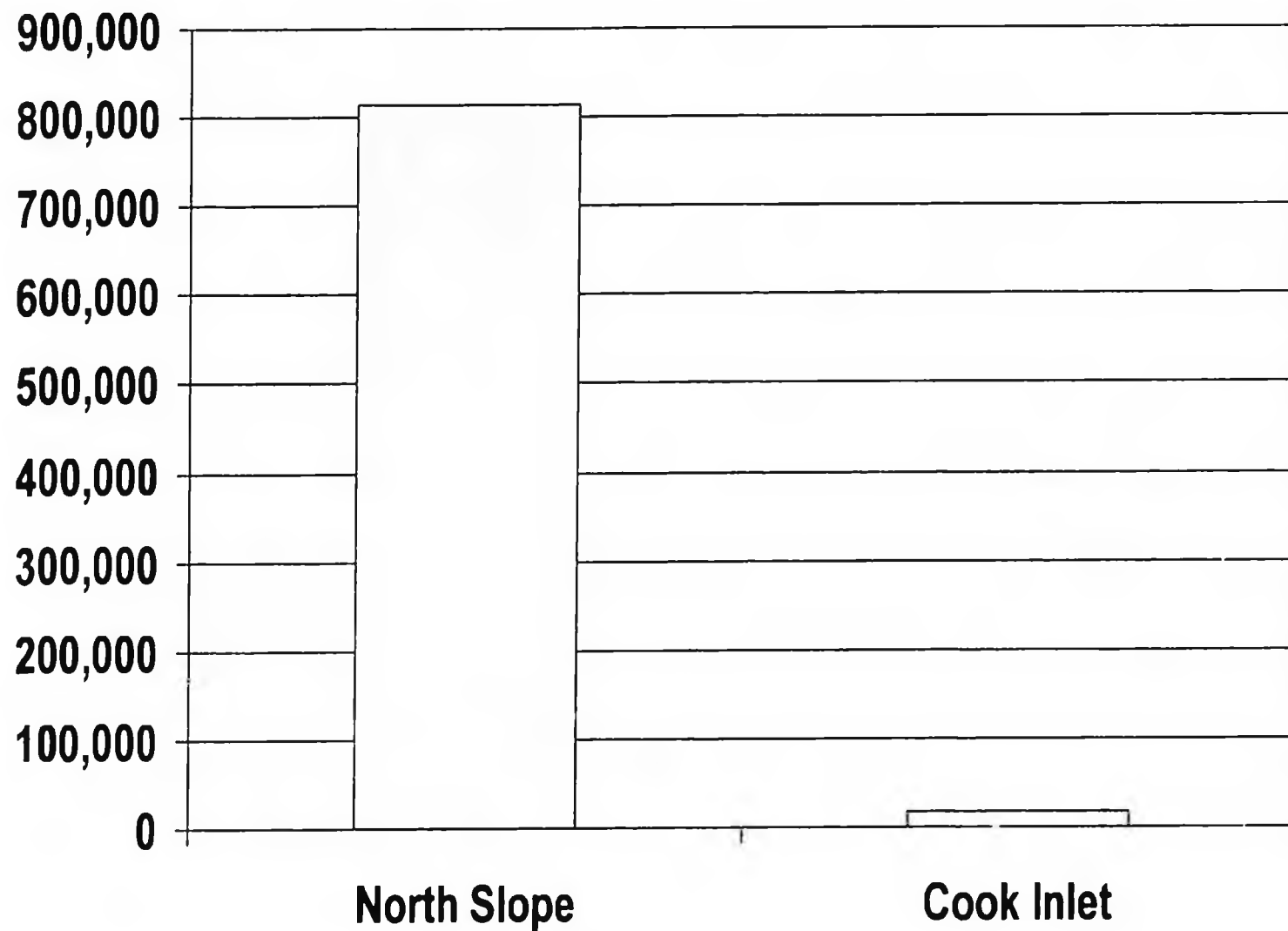
# Cook Inlet Production Forecast with Four Year Capital Plan



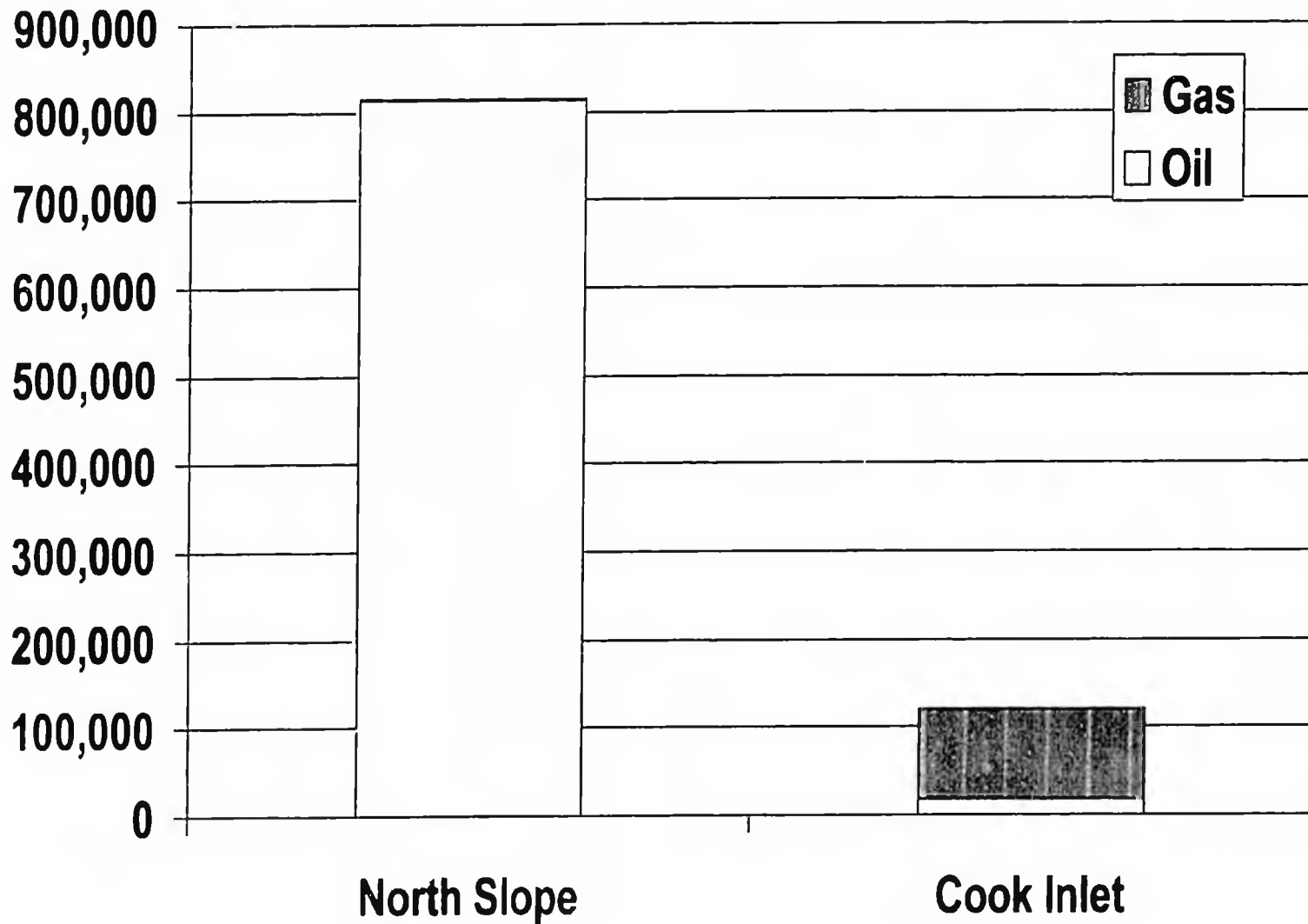
12



# Alaska Oil Production January 2006 BOPD



# Alaska Oil Production January 2006 BOEPD



14



## Reasons to Lower Taxes and Provide Incentives for Additional Cook Inlet Investment

- Gas is running out
  - Home heating, electrical generation, industrial consumption
  - Additional gas supply is critical to state's economy
  - Other options are much more expensive
  
- Currently a lack of significant exploration
  - Last Cook Inlet lease sale was poorly attended
  - New exploration efforts could add new fields
  
- Production tax is a pass through on most utility contracts
  - Tax increase represents increase in gas price to consumers
  
- Oil redevelopment will maintain and add new jobs and will extend field life
  
- Cook Inlet competes for capital with other areas in North America, does not compete for global capital
  - Under PPT Alaska will have the worst fiscal terms in the U.S.

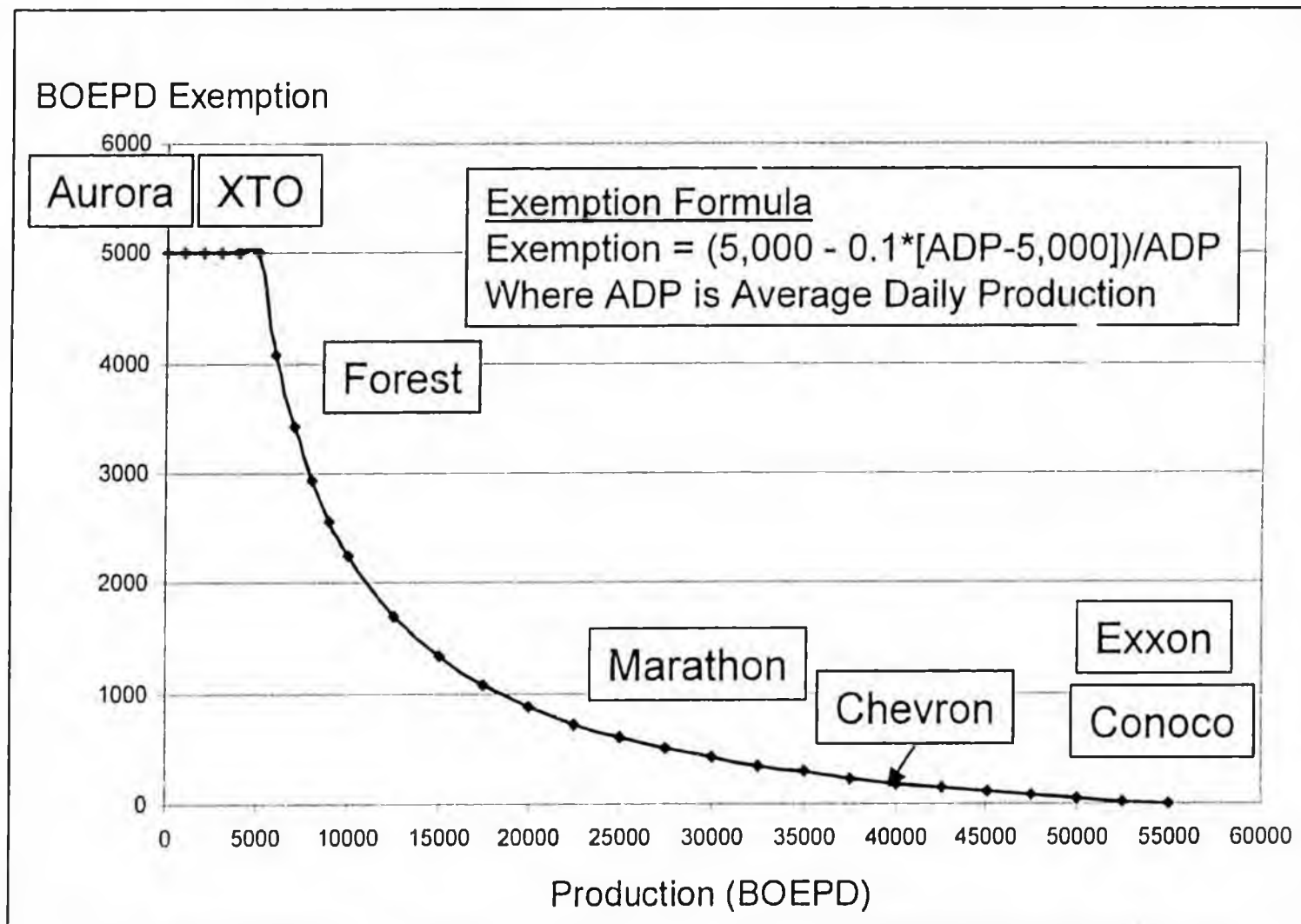


## Cook Inlet Provisions to Date

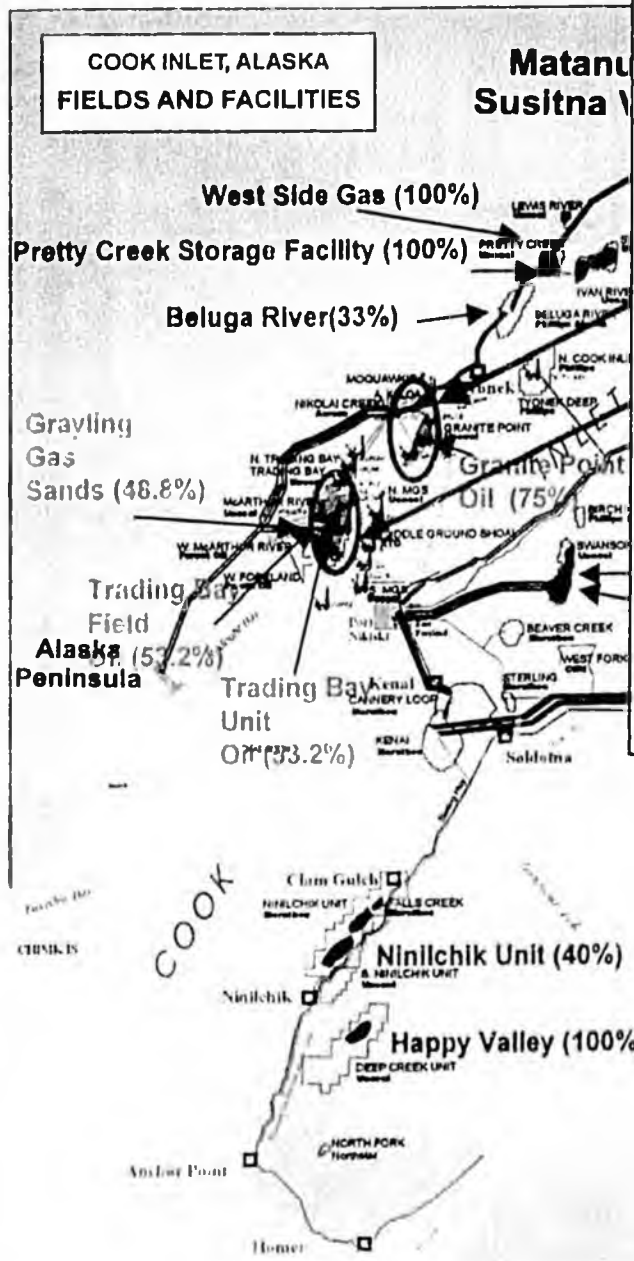
- House Resources – None
- Senate Resources – “5,000 BOPD exemption”
  - Fails to provide any real help to Cook Inlet
- Reasons given not to consider Cook Inlet provision
  - Adds complication
    - ▶ Some additional complication to help Cook Inlet is justified
  - System must be uniform over entire state
    - ▶ We already have statutes that distinguish geographic areas



# Impact of Senate 5,000 BOPD Exemption



# Any "Cook Inlet" provision should be specific to the Cook Inlet



It has been said that the 5,000 BOPD provision protects the Cook Inlet, but it does not help Chevron (or other major producers),  
Chevron operates 75% of the inlet's oil production

Why does it "not help" Chevron?

- Cook Inlet is the incremental asset
- These are incremental investments
- Therefore we run incremental economics
- Anything above 5,000 BOPD will be hit by PPT
- No effect on "end of life" decision
- Chevron is at ~40,000 BOPD
- Cook Inlet's aging oil fields can not afford additional tax
- Any "Cook Inlet" provision should be specific to the Cook Inlet (or areas outside of the North Slope)

<b>Net Production</b>
<b>Offshore Oil</b> 6,300 BOPD
<b>Gas</b> 112 MMCFPD
<b>25,000 BOEPD</b>

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# Biggest Disappointment of House Resources CS



- The unique value and challenged position of the Cook Inlet is not recognized
- Revisions as proposed lowers the economics of capital investments in the Cook Inlet
  - Puts Chevron's four year capital program in jeopardy
  - Without capital McArthur River Field is gone in ~4 years
  - Critical mass for Cook Inlet oil industry is gone



# Recommendation on Cook Inlet

Consider the following options:

- Carve out Cook Inlet
  - Leave under current system
  
- Special exemption for Cook Inlet
  
- Apply PPT to keep taxes at current levels
  - Retain overall incentive rates
  - Adjust tax rates lower



# General Comments on CS

- Balance of the original bill is gone
  - Applaud holding tax rate at 20%
  - Tax credit of \$12 million is okay as replacement for \$73 million standard deduction
- Lever's pulled in the same direction
  - Transition capital credit is gone
  - Progressivity - taking away the "windfalls", no matter how you couch it, lowers expected value to investors
    - + WTI vs. ANS
    - + If retained, base price must be inflated
  - April 1, commencement date, not practical, punitive penalty and interest rate



# General Comments on CS

## ■ Debate between "get it now" and "grow the pie"

- "Get it now" option will balloon short term revenue creating a state windfall that must be well managed
- "Grow the pie" option will create long term opportunities for investors and for Alaska
- I am optimistic about the ingenuity and technology available in our industry and the people of Alaska to greatly extend oil production for the next generation

## ■ Consultants will one day leave and we will be left to deal with our decisions

- First you vote on behalf of the people of Alaska
- Then over the coming years investors vote with their dollars
  - ▶ Original industry support was astounding
  - ▶ However, Investors big and small, old and new, are now saying that the House Resources CS structure will discourage investment in Alaska



# Summary Comments on CS

- Chevron cannot support the House Resources CS in its current form
- Urge return to original PPT terms, while inserting a Cook Inlet provision
- Recommend inclusion of an additional 5% capital credit (20/25) for heavy oil or tertiary recovery (CO<sub>2</sub>) projects statewide
- Chevron has been in Alaska for many years and intends to continue an active exploration and production operation in the state if a sound and stable fiscal regime can be offered

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# INDUSTRY RESPONSES

bp

3-30-06



BP Exploration (Alaska) Inc.  
900 East Benson Boulevard  
P.O. Box 196612  
Anchorage, Alaska 99519 6612  
(907) 561-5111

Date: March 30, 2006

To: House Finance Co-Chair Mike Chenault  
House Finance Co-Chair Kevin Meyer

Re: Follow Up Information to 3-29-06 Testimony – Per Request

Dear Representatives Chenault and Meyer:

During BP's March 29 presentation to the House Finance Committee, I agreed to provide additional information which I am pleased to attach as follows:

- 1) Copy of my March 15 letter and attachment to the House and Senate Resource Chairs providing details of the UK experience where lenient fiscal policy was successful in attracting significant investment to the UK oil and gas sector.
- 2) Answers to various questions relating to government and industry take previously shared with the House and Senate Resource Committees.

We are happy to discuss these issues further with the committee or individual members of it.

Sincerely,

A handwritten signature in black ink, appearing to read "Angus Walker", is written over the "Sincerely," text.

Angus Walker

## Follow-up to BP Presentation on CSHB 488 (PPT)

Alaska State Legislature  
House Finance Committee  
29th March 2006

Attached are answers to questions originally provided to House & Senate Resource Committees. The answers to these questions are relevant to questions raised during BP's presentation to the House Finance Committee on 29<sup>th</sup> March 2006.

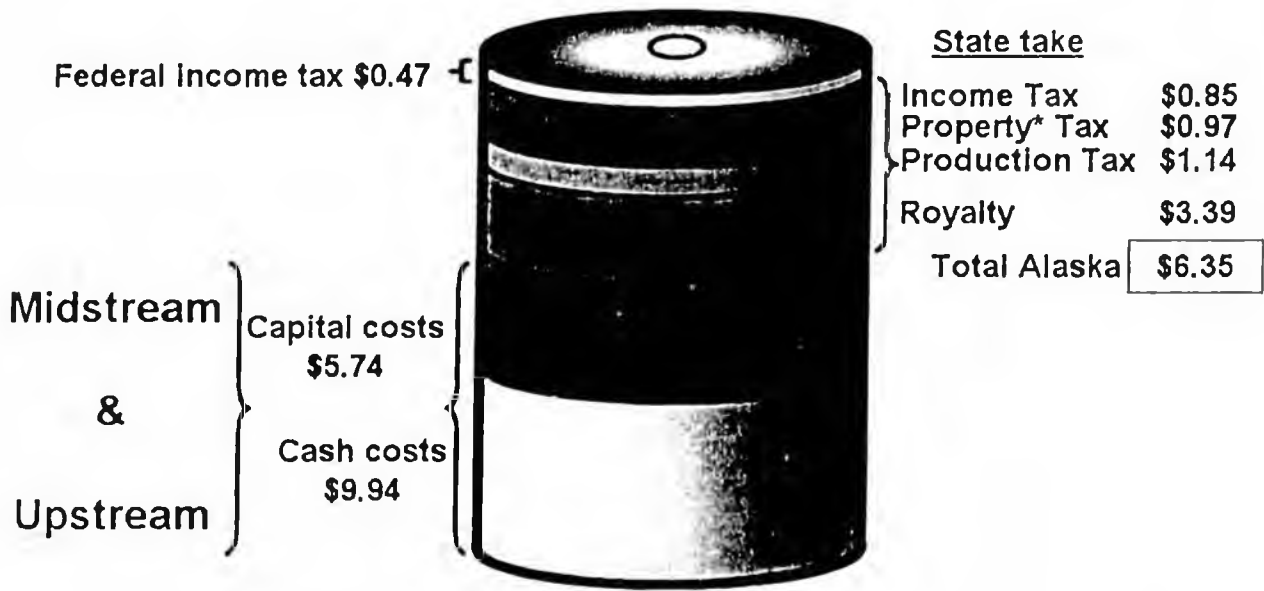
- Please explain why your analysis shows that BP makes a loss while the DOR shows that you still make money at oil prices below \$20/bbl?
- What is the effective tax rate under PPT vs under the Status Quo for BP?
- What is the relative profit share between the State, Federal Government and BP at different oil prices under the existing system and the proposed PPT.

BP is pleased to provide responses as follows:

**Please explain why your analysis show that BP makes a loss while the DOR shows that you still make money at oil prices below \$20/bbl?**

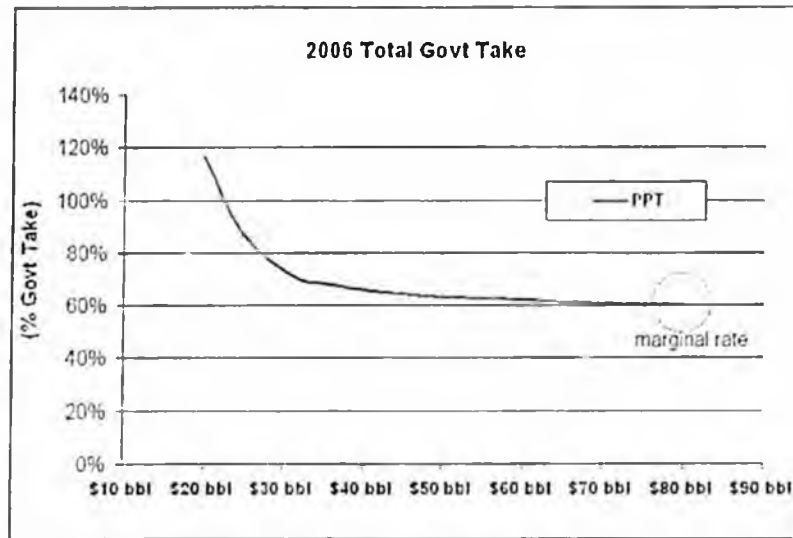
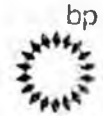
We have reviewed the DOR calculations and while we have some differences we get close to replicating DOR's revenue calculations. The key difference between the two approaches is that the DOR calculates revenue, and BP calculates profit. In the calculation of profit we include the non-cash costs (depreciation of capital investment). The capital component is shown in the breakeven barrel below. At our current breakeven price of \$22.50 / bbl the State receives \$6.35 / bbl and the federal government receives \$0.47 / bbl. It is only at prices above \$22.50 that BP starts to make a profit.

Breakeven Barrel \$22.50



Upward pressure created by inflation (driven by high oil price) and production decline

The following shows the government take at different oil prices applicable to BP's business in Alaska calculated for the PPT (20/20) system (i.e. without any price surcharge). It should be noted that at all but the current high oil prices the actual government take is substantially higher than the marginal rate.



Based upon BP net

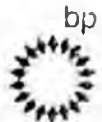
## What is the effective tax rate under PPT vs under the Status Quo for BP?

The effective tax rate is a useful way of comparing PPT to the current severance tax which is calculated on gross revenue. The effective tax rate is the tax rate which would have to be applied to gross revenue to achieve the same outcome as under PPT (20/20) which is calculated on net revenue (gross revenue less expenditures).

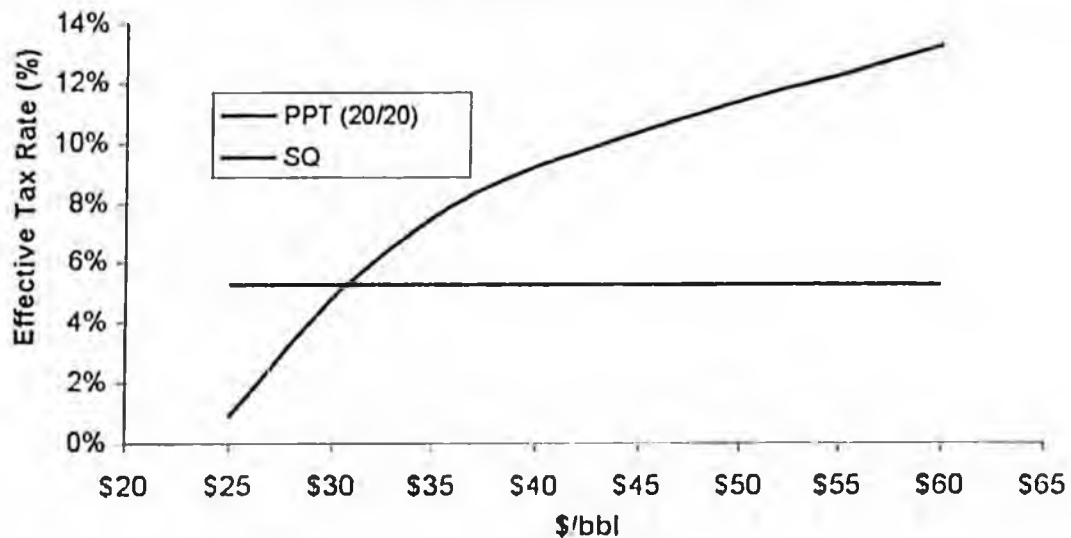
The effective tax rate under PPT is a function of oil price and costs. As such it will vary slightly by company depending on their assumptions re expenditure.

The effective tax rate under the Status Quo (SQ) will vary from company to company depending on their ownership in high and low Elf fields.

(The following example does not include transitions arrangements which are temporary by nature)



BP Alaska Effective PPT Rate

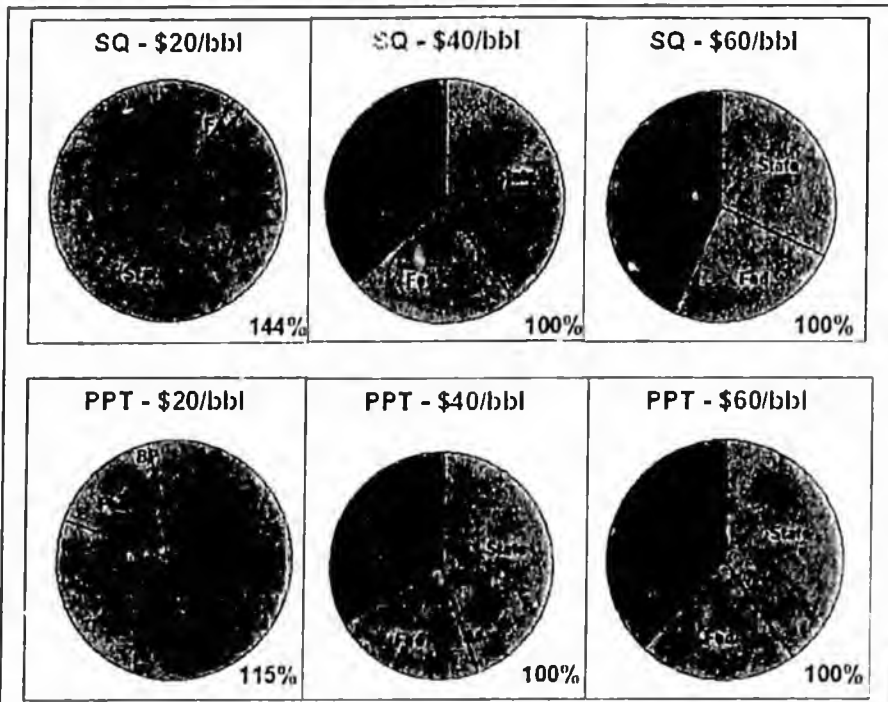


# What is the relative profit share between the State, Federal Government and BP at different oil prices under the existing system and the proposed PPT.

The pie charts below illustrate the split between State, Federal and BP take under the current regime and the original PPT 20/20 at low, medium and high prices.



Status Quo



PPT  
(20-20)

	\$20		\$40		\$60	
	SQ	PPT	SQ	PPT	SQ	PPT
<b>State</b>	143%	97%	40%	44%	32%	40%
<b>Federal</b>	1%	18%	23%	22%	25%	22%
<b>BP</b>	0%	0%	37%	34%	43%	38%

The left hand pies show the problem for industry at low prices. BP makes a loss when oil prices are less than \$20.50/bbl.

At \$60/bbl the current system provides a higher % to the industry than to the State, but that is not new news. Alaska's fiscal system was designed to protect the state at low prices and compensate the industry at high prices. That is the nature of a regressive tax regime.

Under PPT 20/20, we would continue to make a loss at \$20. At \$40 the State gets a considerably higher share than BP. At \$60 under under PPT 20/20, (i.e. without any price surcharge), the State's take is greater than BP's take.

*(Please note that the pie charts and percentages shown above have been updated since the presentation made on 28<sup>th</sup> February to the House Resource Committee to properly incorporate some costs associated with running the BP Alaska business, which had been omitted in error from the original analysis.)*



**Angus J. Walker**  
Commercial Vice President

BP Exploration (Alaska) Inc.  
P.O. Box 196612  
900 East Benson Boulevard  
Anchorage, Alaska 99519-6612  
(907) 564-4761  
(907) 561-5111  
Fax (907) 564-5598  
WalkerA4@BP.com

Date: 15/03/2006

**To:**

Senator Thomas Wagoner, Chair Senate Resources Committee  
Representative Ralph Samuels, Co-Chair House Resources Committee  
Representative Jay Ramras, Co-Chair House Resources Committee

**Re: Testimony of Mr Daniel Johnston on SB 305/HB 488 Production Profit Tax (PPT)**

Dear Senator Wagoner and Representatives Samuels and Ramras:

In his Testimony of 6th March 2006 to the House & Senate Resource Committees, Mr Johnston raised a number of issues related to BP's prior testimony to which I am compelled to respond. As well as setting the record straight I believe this response will be helpful to you and your committee's deliberations.

Our response relates to two issues raised by Mr Johnston:

- 1) The impact of 1993 tax cuts on investment in the UK North Sea.
- 2) The Marginal rate of taxation in the UKCS.

**1) The impact of 1993 tax cuts on investment in the UK North Sea.**

In BP's February 28<sup>th</sup> testimony, my colleague Ray Hall presented data from the UK North Sea, Gulf of Mexico and Alberta that illustrates the cause-and-effect relationship between fiscal policy and investment. With regard to the UK example, Mr Johnston contended that the data BP presented "is not a fair representation of what the result of lowering the tax rate in 1993 was". Clearly it is difficult to unequivocally attribute any outcome to the events that preceded it, and there will be many views of what might have happened without the tax change. However:-

**For BP, the position is clear**

- We increased capital investment in response to the 1993 changes
- We sanctioned 5 large projects in the matter of a few years (Andrew, Harding, Foinaven, Schiehallion and ETAP). These projects committed circa \$8 billion in capital and 2 billion boe in reserves.

**For the UK Government the position is clear**

- UKCS Exploration & Appraisal spend was the largest of any basin in the world between 1994-1999
- The number of development wells increased one and a half fold between 1993 and 1995
- Basin production rose following the reform
- Tax revenues increased following the reform

Mr Johnston himself is on record as saying:-

"Ordinary measures of Government take through out the 1990's made the United Kingdom government appear rather crazy and irresponsible. .... The "gross benefits" to the UK Government go way beyond direct tax revenues and royalties received from the upstream sector of the petroleum industry. **The economic impact of the industrial hyperactivity in the UK sector of the North Sea, a direct result of the "lenient" terms of the 1990's, is difficult to measure.** Furthermore, the activity in the UK started in the late 1980's and early 1990's when the UK Government dropped the ring fence for the 75% PRT before Government take, as it is ordinarily measured, was drastically reduced. **The UK offshore became the most active offshore province in the world. Reducing the Government take in the following years managed to sustain that boom.** Activity and employment in the British petroleum sector is healthy and robust.." (Source: *Petroleum Tax Design page 6 by Daniel Johnston 23 Oct 2002, Washington DC*)

It is our sincere belief that there is a close relationship between fiscal policy and investment, a relationship acknowledged by Mr Johnston in earlier publications, and that the UK offers one of several notable examples where reducing taxes has stimulated investment. The attached slide pack provides additional detail.

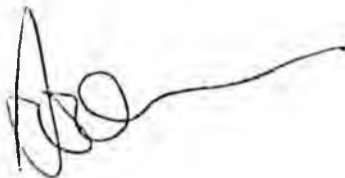
## 2) The marginal rate of taxation in the UKCS

In BP's testimony, Ray Hall compared the marginal government take under PPT 20/20 (61%) to that of the UK (50%). Mr Johnston challenged this figure, asking "why has nobody mentioned the 75% Government Take in the UK?" The 75% Government Take to which Mr Johnston is referring is that paid by the small number of the fields in the UK that are subject to Petroleum Revenue Tax (PRT). PRT is currently levied at 50% on fields given development consent prior to March 1993. Out of a total 208 fields in the UKCS, only 94 fields are liable to, and only 29 actually pay PRT (the rest are protected by volume and other allowances). These 29 fields contributed approximately 29% of the UK oil and gas production in 2005. In any event, the 50% marginal tax rate described by Mr Hall applies to all fields developed after 1993 and as such is a more appropriate comparator to future investments in Alaska.

I trust this letter is clear and would be happy to discuss any issues raised with you and your committees.

BP appreciates the opportunity to testify on this very important issue and intend to remain fully and constructively engaged in the process.

Sincerely yours,



Angus Walker

Commercial Vice President, BP Alaska

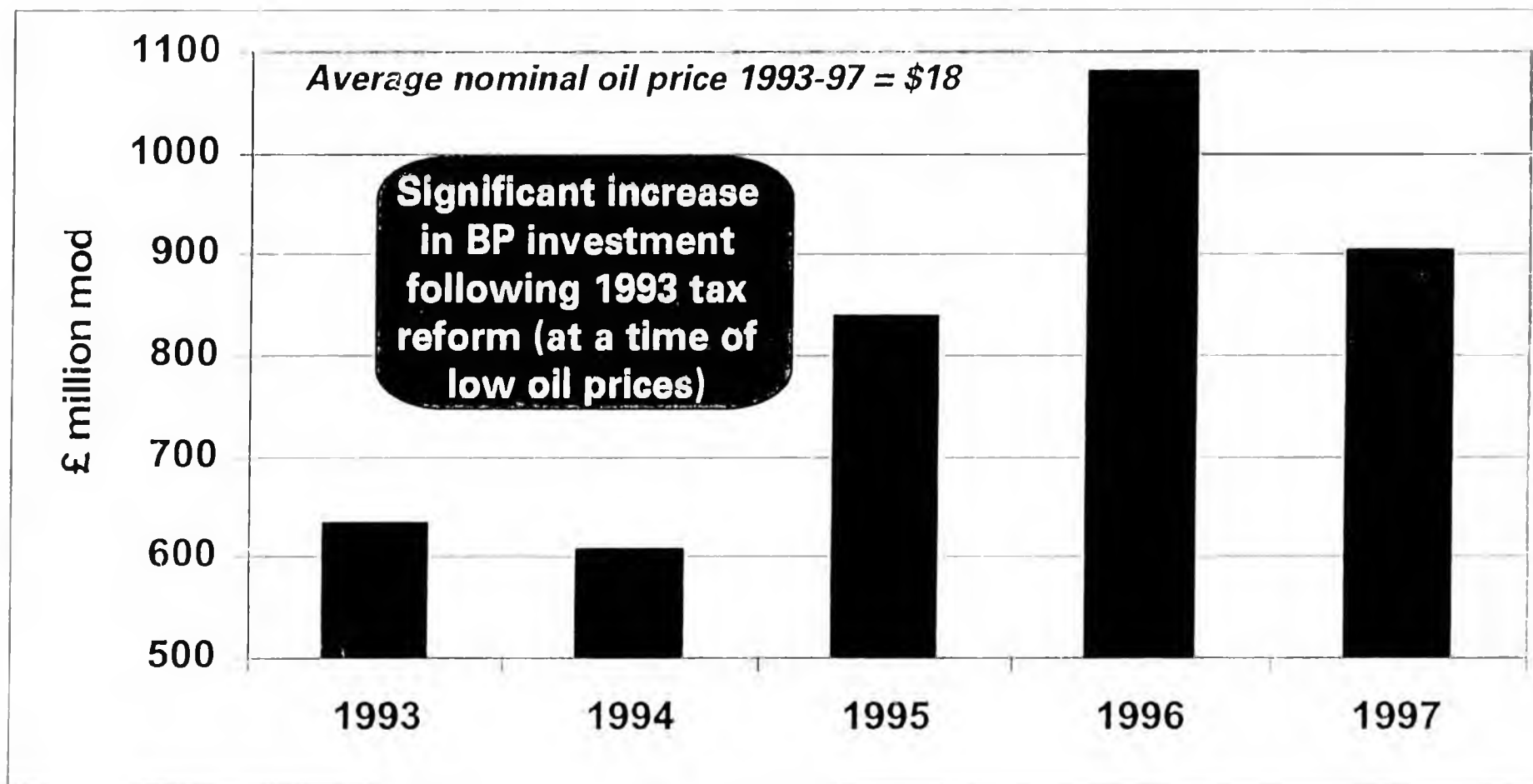
Attachments: 6 slides providing further context to the outcome of the UK 1983 and 1993 tax cuts

bp



15<sup>th</sup> March 2006

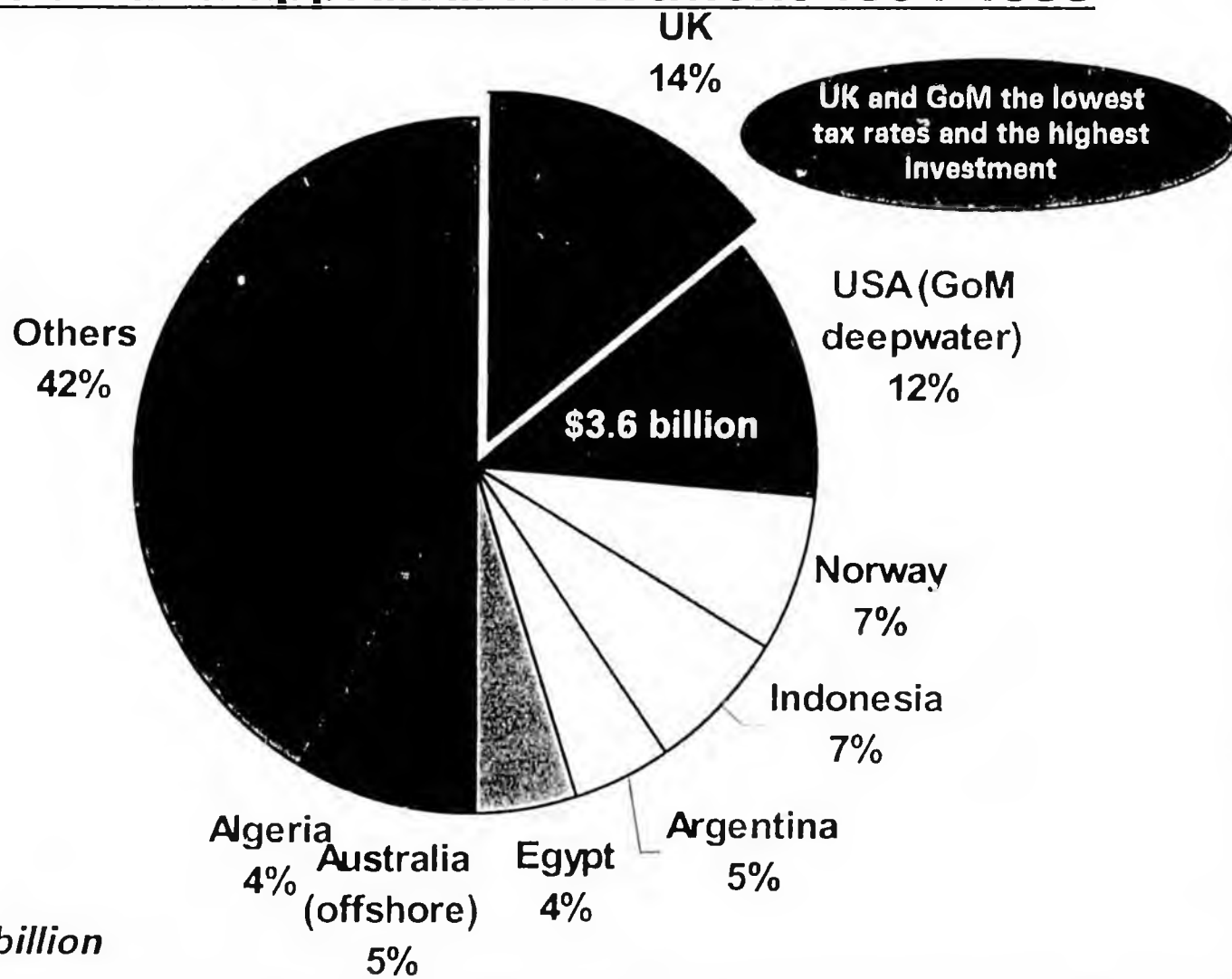
# Investment in UKCS



Source : BP Financial and Operating information

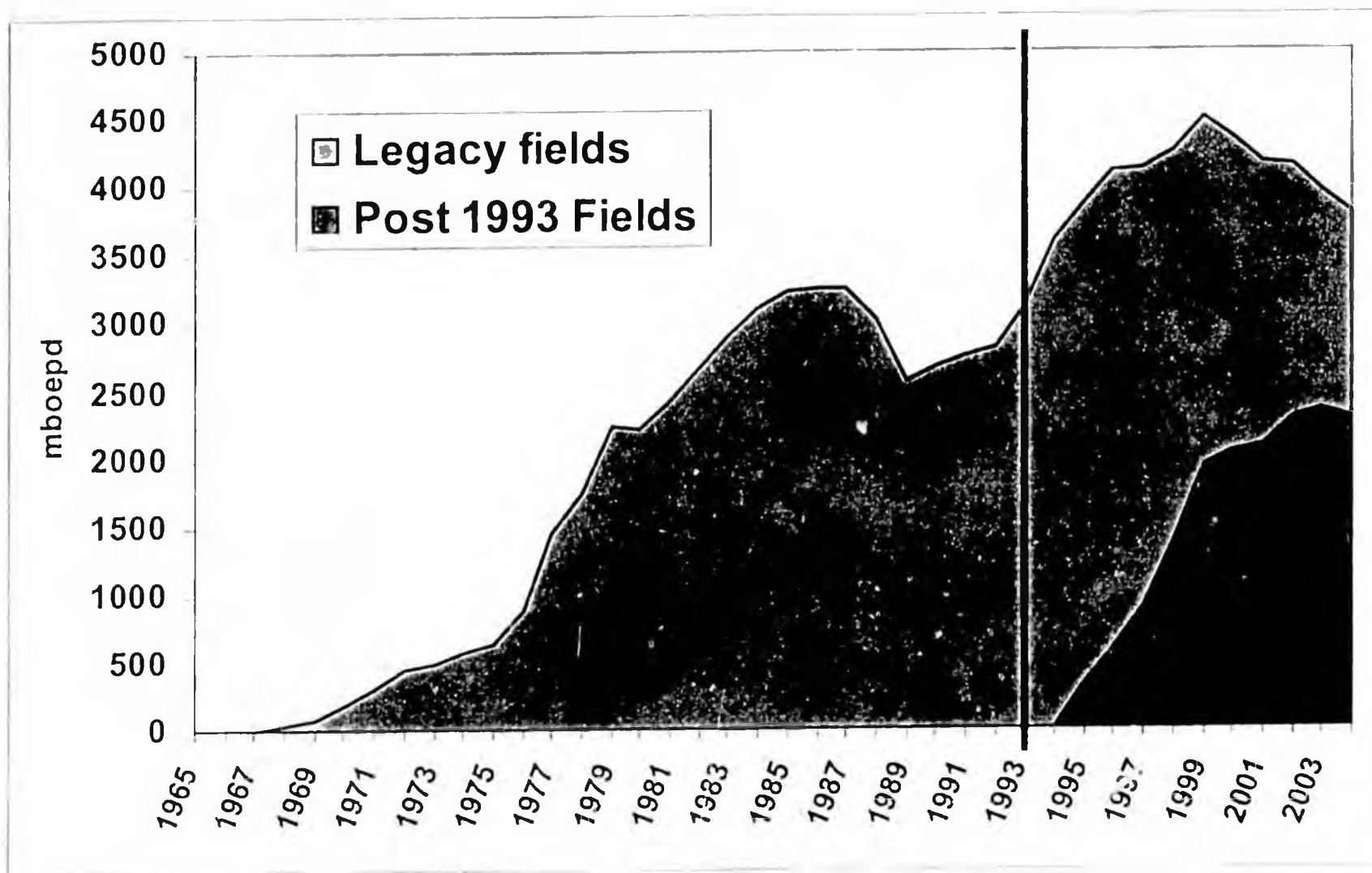


### Exploration and appraisal investment 1994-1999

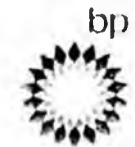


Source : Wood MacKenzie ' Global oil & gas risks and rewards study'

Oil production is clear



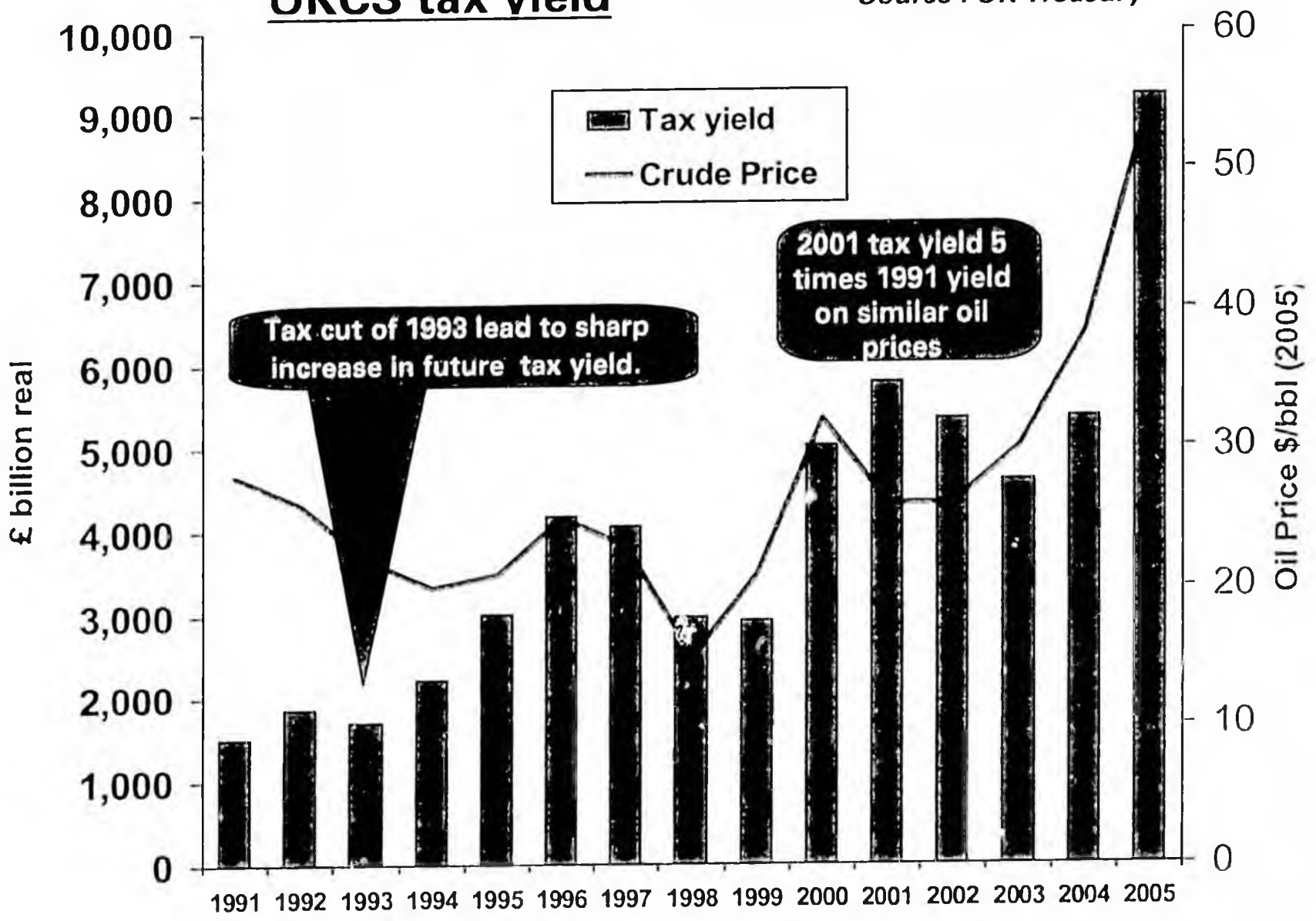
Source: Wood Mackenzie



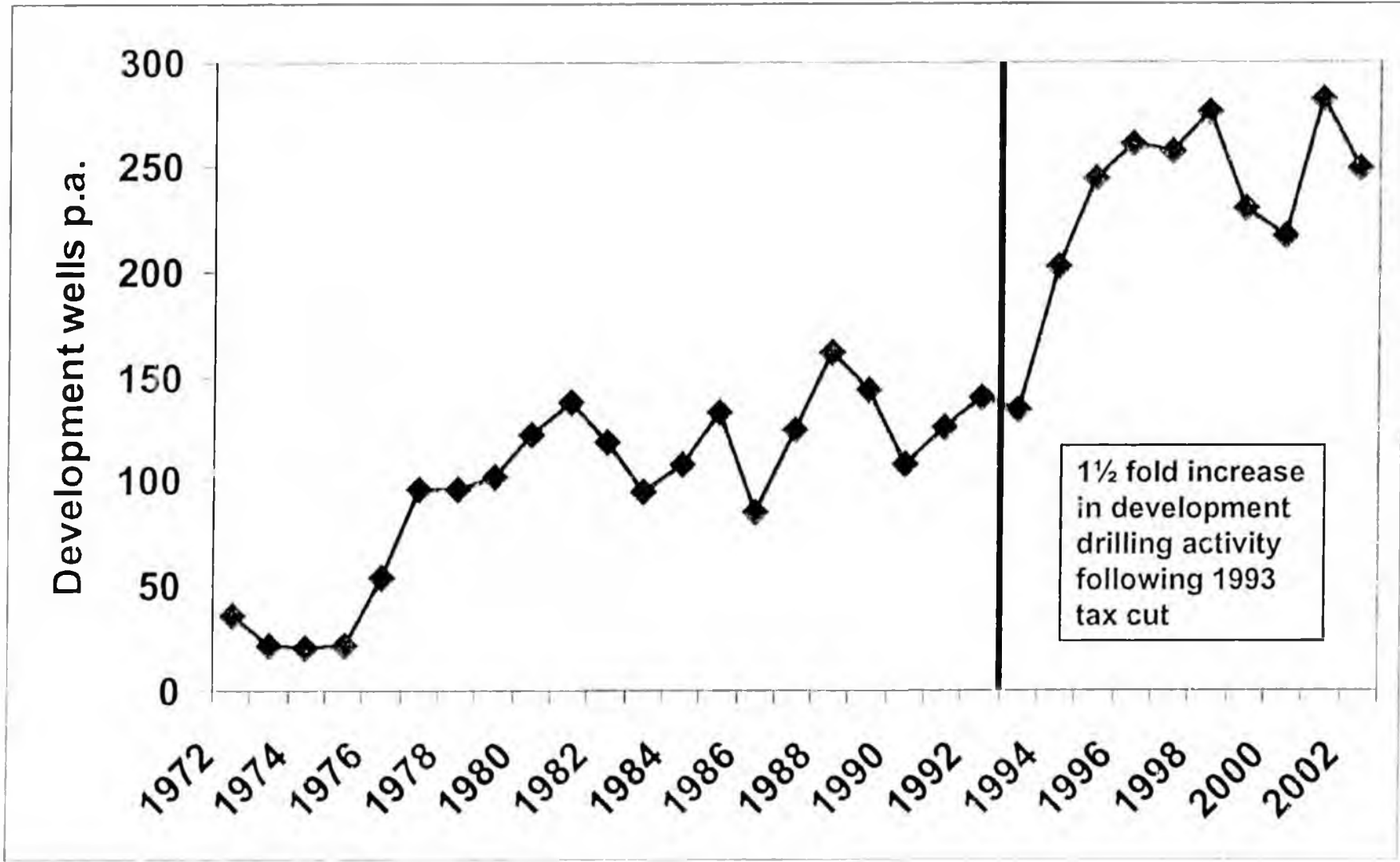
tax yield increase in response to 1993 reform

### UKCS tax yield

Source : UK Treasury



# Onshore Drilling Activity



Source of data: UK Department of Trade & Industry



“Ordinary measures of Government take throughout the 1990’s made the United Kingdom government appear rather crazy and irresponsible. .... The “gross benefits” to the UK Government go way beyond direct tax revenues and royalties received from the upstream sector of the petroleum industry. The economic impact of the industrial hyperactivity in the UK sector of the North Sea, a direct result of the “lenient” terms of the 1990’s, is difficult to measure. Furthermore, the activity in the UK started in the late 1980’s and early 1990’s when the UK Government dropped the ring fence for the 75% PRT before Government take, as it is ordinarily measured, was drastically reduced. The UK offshore became the most active offshore province in the world. Reducing the Government take in the following years managed to sustain that boom. Activity and employment in the British petroleum sector is healthy and robust..”

***Daniel Johnston***

***23 Oct 2002, Washington DC  
Petroleum Tax Design***

MINOR

PRODUCERS

**Chevron**



**Chevron - Alaska Area**

**Testimony on HB 488**

**Finance Committee**

**John P. Zager**

**General Manager**

**April 28, 2006**



# We Standby Our Previous Testimony on the PPT

- Overall tax/credit rate - believe that 20/20 is in the best interest of the state
- Cook Inlet - believe that 5% tax rate is appropriate
- Standard deduction - support either \$12 million credit or current 5,000 BOEPD exemption
- Transition capital - accept that it must be earned again on 2:1 basis, suggest extending time period to 10 years
- Effective date - April 1, is the earliest reasonable date
- Challenged Oil - additional credit is warranted
- Abandonment expense - Believe that it should be prorated and that it should be a qualifying expense
- Gas Storage Costs - *New item* - Gas storage costs should be explicitly recognized as qualifying costs
- Progressivity - do not support - lowers expected value to investors and will lower overall investments



## Progressivity Provision

- Reason for the state to want progressivity
  - To get a fair share when there is a price run up accompanied by large profits
  - NOT to raise taxes if the price increase is gradual over time and is accompanied by increases in costs and thus not accompanied by increased profits – NOT a creeping tax increase
- Problems with progressivity as currently proposed
  - “Trigger” price tied to ANS is not inflated
    - Over time costs will rise
  - “High cost” oil will be produced in increasing quantities
  - Over the long term a fixed trigger price will not work as intended and is grossly unfair

**House Finance Committee**  
**Testimony of Ken Sheffield, President**  
**Pioneer Natural Resources Alaska, Inc.**  
**April 28, 2006**

**Key Messages Regarding SB 305 – Oil & Gas Production Tax**

- **Governor's Bill**
  - Modest incentive for Pioneer to invest more aggressively
  - Struck a delicate balance between incentives/taxes
  
- **Tax Rate**
  - Oil – recommend 20% rate
  - Gas – support SB 305 (7.5% rate)
  - Cook Inlet – support SB 305 (5% rate)
    - Could affect Pioneer's decision regarding Cosmopolitan project
  
- **Base Allowance - 5000 BOPD equivalent credit capped at \$14 million**
  - Value deterioration due to:
    - Calculation methodology
      - More investment yields less tax credit in some cases
    - 10 year sunset provision
      - Long cycle time for exploration projects
  - Recommend House Resources CS methodology
    - Simpler, flat tax credit – currently \$12 million
    - Requested Changes
      - \$14 million vs \$12 million
      - Eliminate annual investment requirement
      - Eliminate sunset provision
        - If sunset required, 10 years following first utilization
  
- **Refundable Credits – House Resources CS: \$10 million annually**
  - Significant incentive to explorers (no current production)
    - Thin market for credits – few buyers
    - Allows explorers to receive full value for some credits
    - No extra cost to State of Alaska
  - Request increase to \$30 million annually
  - Request allowing credits to apply to lease bonus and rentals
  
- **Transition Capital – Sunset Provision**
  - Unable to utilize capital credits "earned" with 2:1 in 7 years
  - Disincentive to invest beyond 2:1
  - Request no sunset after credits are "earned"
  - If sunset required, allow 7 years following first utilization

- **Progressivity Surcharge**
  - If required, base upon net profits consistent with PPT structure
  - Recommend \$45/barrel net profit trigger in SB 305 draft version
  
- **Point of Production for Gas**
  - Gas treatment facilities should qualify for credits
  - Facility is required for marketable gas
  - Equal treatment for gas vs oil



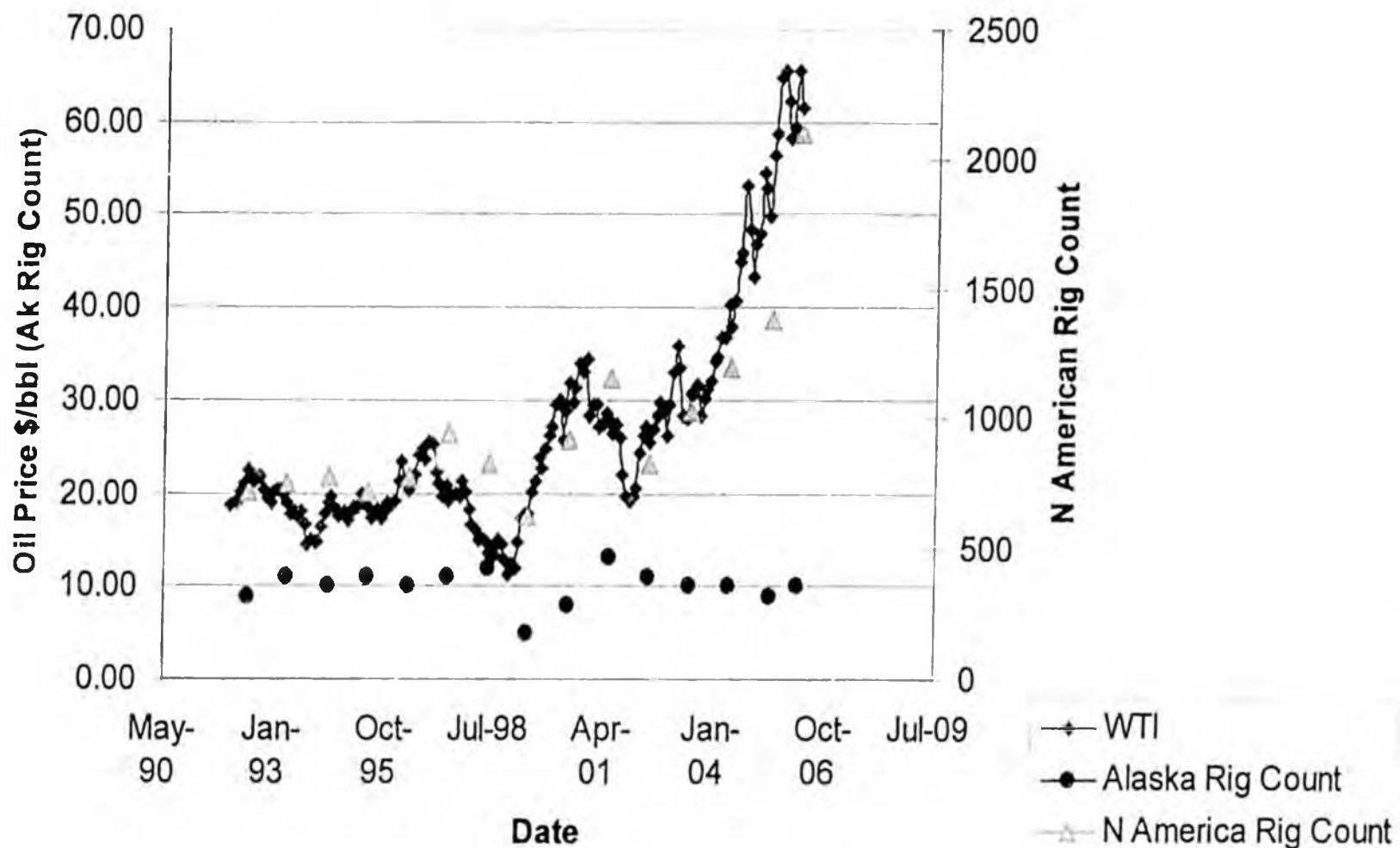
**State of Alaska  
Petroleum Production Tax (SB305 CS)  
John A Barnes**

**House Finance**  
*April 28, 2006*

**Marathon**



## High Oil Price and Alaska Response



# PPT – A World Class Tax Structure

- ▶ One “World Class Opportunity in Alaska”
  - North Slope Gas Line tied to PPT
  - Negotiated Settlement with “Producers”
  - Clearly Tied to Overall North Slope Oil and Gas Integrated Development
  - Strong North Slope Industry Benefits State of Alaska as well as Cook Inlet Industry
  
- ▶ But, the Cook Inlet is not the North Slope...
  - Previous testimony and recognition of need for Cook Inlet incentivization



# Cook Inlet PPT Concerns

- ▶ Cook Inlet Gas is not Cook Inlet Oil
  - CI Gas does not receive world market prices.
- ▶ Cook Inlet Gas Competes with N American Gas for Investment
  - Reduction to 7.5% or 5% would increase attractiveness of investment
- ▶ Gas Progressivity places volatility and risk on Alaska consumers and industry. If progressivity then...
  - Base on net and not gross
  - Base on actual value, not Henry Hub



**Testimony of James D. Weeks  
On SB 305/CS HB488  
Oil and Gas Production Tax  
Alaska State House Finance Committee**

**28 April, 2006**

Co-Chairmen Chenault and Meyer, distinguished members of the House Finance Committee. For the record, my name is Jim Weeks, and I am here today representing UltraStar Exploration LLC, a very small independent explorer. The Company was formed in 2002 by John Winther, Dale Lindsey and me, for the purpose of exploring and developing leases on the North Slope. UltraStar is 100% owned by Alaskans. I am Managing Member, and moved to Anchorage in 1984 with ARCO, and have had a presence here ever since. Dale, whom most of you know, was born and raised and still lives in Seward. John, whom most of you also know, was born in Fairbanks and raised in Juneau. He currently lives in Petersburg. Thanks for the opportunity to testify today.

During the last two months, I've testified and listened to a lot of testimony on the Governor's original proposal, not only to this committee, but to the other committees in both houses of the legislature. The bill seems to get more complicated with every iteration, but is still a program we can support, given a few modest changes. I'll go into details about them.

The Administration's original proposal was for a \$73 million base allowance for net profits below which there would be no PPT, with no sunset provision. The Senate, rightfully so in my view, changed that to 5000 barrels of oil per day, but established a sunset date of 2016, after which the allowance will expire. I question the need for a 10 year time limit after which the tax exemption will expire. UltraStar is a small, start-up company that is poking around the fringes of existing units and known reservoirs. Our leases are too small to stand alone, so access to existing facilities, owned mostly by the major producers, is the only way we can develop anything we might find. It took our sister company, Winstar, 6 years to negotiate access with the KRU to enable the drilling of the well that was completed in 2003. UltraStar has been in negotiations with the PBU for over 3 1/2 years now to get seismic data and facility access to enable the drilling of our Dewline Prospect. It takes a long time for these things to get done, and I question why our investments should be put at risk with this relative short sunset provision, whereas current producers can use the allowance immediately after the effective date of the bill, and receive the full ten years benefit. During this debate, I've heard more than once about the need for a "level playing field". No sunset provision does indeed level the playing field.

Next is the issue of the effective date for the PPT. We agree that July 1, 2006 is an appropriate date, but also suggest that taxpayers should be given a 6 month

"grace period" to come into complete compliance. I'm not suggesting that any taxes not be paid, or be paid late, but rather that companies be allowed to get their act together within 6 months before the stiff penalties and interest provisions apply. During this period, any adjustments can be made for under and/or over payments. This bill requires a complex calculation of the appropriate amount of tax, and conforming to it will take some time, even for the current producers with tax accountants and attorneys on staff. UltraStar hopes to have production in the future, and we will be glad to pay our fair share of taxes, but we will need to contract for tax accounting and legal services on the street at market rates, and frankly, I don't know whether or not we can even find them. Anyone we hire will need to get familiar with the law and regulations, and develop the algorithms needed to comply with them. This will take some time, and I think that 6 month grace period is the minimum amount of time necessary to assure compliance before the penalties and interest starts. Obviously, to accommodate production not yet on stream, the 6 month grace period should begin when taxes under the PPT are due, and not necessarily July 1, 2006.

Lastly, Mr. Chairman, I'd like to comment on the 20/20 provisions and the so called progressivity feature of the bill, and their relationship to the gas pipeline. I graduated from the University of Wyoming with a Petroleum Engineering degree in 1969. In the fall of 1968, nearly 40 years ago, as a class project, we designed a gas pipeline from Prudhoe Bay to Chicago. After graduation, I joined ARCO, and in the early 70's, spent several years working in project engineering and construction, based in Dallas, headquarters of ARCO's North American operations. I spent hours talking to the real life engineers who spent nights and weekends at the office, sleeping on cots, designing a gas pipeline from Prudhoe Bay to Chicago. For seven years in the late 80's and early 90's, I was in charge of all of ARCO's Prudhoe Bay interests, including the commercialization of natural gas. Except perhaps for Governor Hickel, I've probably worried longer than anyone in the State about getting North Slope Gas to market.

The legislature is to be commended for the fair and full hearing the PPT has been given. Many thankless hours of hearings, reviewing complicated drafts, and debate have been spent by you and your colleagues in both houses and in my mind you all deserve a medal. During the process, I've heard more than once that there is no linkage between PPT and the gas line project. But as the Governor said this week, there is indeed linkage between the two. I think we all know that.

Also of concern to me as an Alaskan who hopes to build a business here that my kids and their kids can carry on, is the "so what" attitude I've heard from several legislators. They say "so what" if the big guys walk from the gas line deal over disgust with the PPT. Causing them to walk from the gas line as a result of the PPT would be a huge dis-service to the State of Alaska. To forego the long term benefits of the gas line in favor of short term higher taxes in the PPT would be a very mistaken, short sighted approach. Therefore, I encourage you to adopt the

Governor's 20/20 proposal, with no progressivity. Twenty percent of the net profits on seventy dollar oil is progressive enough. Oil companies compete worldwide. The governments of China, Russia and the Middle East don't put their domestic oil companies at a competitive disadvantage with windfall revenue or profits taxes. Why should the State of Alaska? However, if you feel compelled to take a bigger share at higher prices, then that bigger share should be on net profits, not gross revenue. Be careful, though, lest they walk. Enough has always been enough.

Thanks for the opportunity to comment.

Jim Weeks  
907-258-2969



**PIONEER**

NATURAL RESOURCES AGENCY

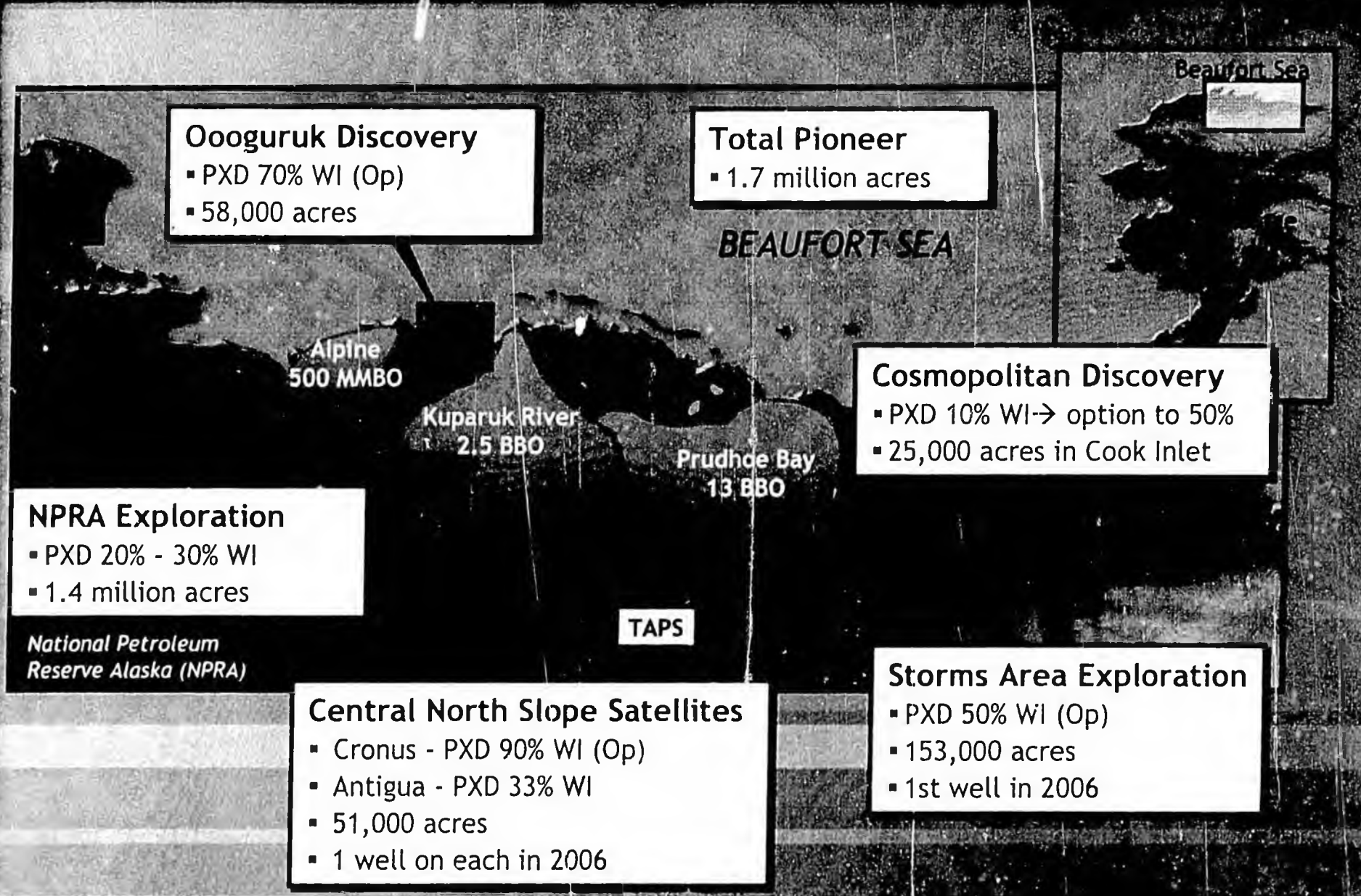
***HB 488 PPT***

***Juneau, Alaska***

***April 3, 2006***

*4/3/06*

# Pioneer's Alaska Acreage

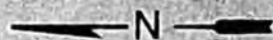


# Oooguruk Development Project

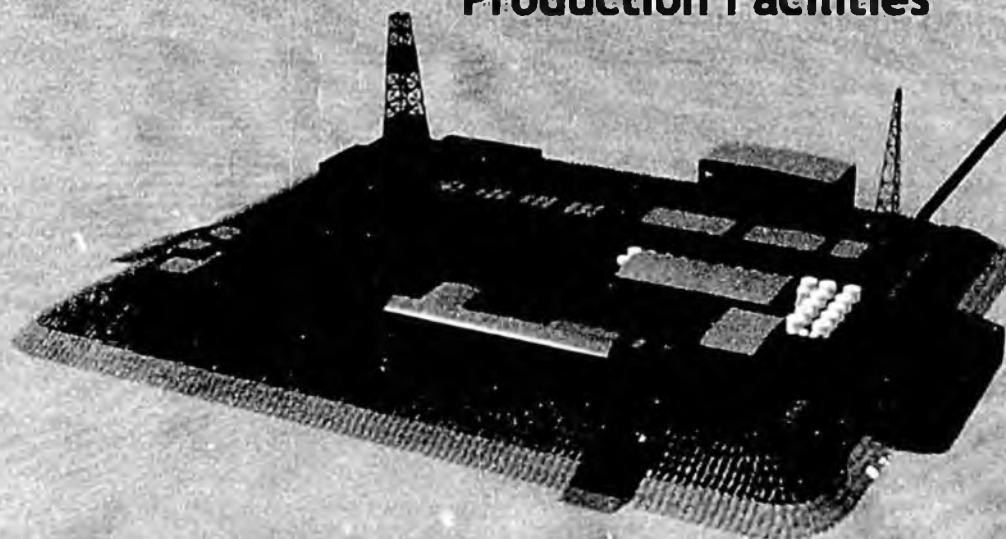


- Development Cost: \$450 – 525 million
- Reserve Potential: 50 – 90 million bbls
- Peak Flow Rates: 15 – 20,000 bbls per day in 2010

Tie-in to COP  
Kuparuk River Facilities



**Drillsite and  
Production Facilities**



Harrison Bay  
(4.5' water depth)

# Oooguruk Major Project Construction Components



## ▪ Winter 2006

- Gravel Mining
- Gravel Placement - Drillsite & Onshore Pad

## ▪ Winter 2007

- Flowline Installation
- Facility & Equipment Installation

## ▪ 2008 – 2011

- 38 Well Drilling Program



# *Alaska's Challenges*



- **Some of the Highest Costs in the World**
  - Large Minimum Economic Field Size
- **Future Exploration & Development Uncertain**
  - Smaller Reservoirs
  - Remote Resources
  - Viscous Oil Resources
  - Gas
- **Long Cycle Times (5 to 10 years)**
- **Investment Uncertainty**
  - Exploration & Reservoir Risk
  - Price Risk
  - Fiscal Certainty

## *Alaska Climate that Encouraged Pioneer*



- **Emerging Business Opportunities**
  - Investment Opportunities Offered by Major
  - Cooperation re: Facility Access
  
- **Attractive Fiscal Policy**
  - Reasonable Lease Terms & Availability
  - ELF Formula: Low Taxes on all but Largest Fields
  - Exploration Incentive Credits

## *Alaska's Competitiveness*



- **To Attract Most Independents, Alaska must effectively compete with onshore North America Resource Plays**
  - Resource Plays (tight sands, coalbed methane, shales) are attracting huge amounts of capital
    - Lower Risk
    - Lower Cost
    - Shorter Project Cycle Time
    - Lower State Tax

## ***Benefits of Administration's PPT Proposal***



- **Balanced Tax/Credit Rate of 20/20**
- **Fair Principles**
  - Tax Based Upon Profits
  - Compensation for Transition Capital
- **\$73MM Exemption Mitigates New Entry Costs**
- **Tradable Credits allow Quick Monetization**
- **Modest Incentives for Exploration, New Investors**
- **Reduces Minimum Economic Field Size**

***We believe the proposal would encourage new investment in Alaska, grow the resource pie and increase revenues to the State***

## ***PPT Tax Rate***



- **20% Rate Reasonably Balanced with**
- **Higher Tax Rate:**
  - Reduces Incentive to Invest
    - Raises Investment Threshold
      - Fewer Exploration Wells Drilled
      - Marginal Resources Left Undeveloped

# ***Tax Rate Progressivity***



- **Increasing Oil Prices = Increasing Costs**
  - 2005 W. Texas Drilling Costs Increased
  - Steel prices more than doubled in 2 years
  - Costs for all Services Escalating Rapidly
- **Profits not Directly Proportional to Oil Price Increase**
- **If Enacted, Progressive Tax Rate**
  - Should be Profits Based
    - Fairness Issue
    - Different basis is un-necessarily complex
  - Trigger Price Should be:
    - Based on ANS Posting (vs WTI)
    - Indexed for Inflation

## ***\$12MM "Start-up" Credits Encourage New Entrants***



- **New Entrant Challenges**
  - Smaller Investors lack Operating Experience
  - New Entrants do not hold Existing Investment
  - Most New Investment Opportunities are Challenging
- **High Alaska Start-up Costs**
  - Local, Highly Skilled Technical Employees Required
    - Engineers, Geoscientists, Land & Reg. Experts
  - Requires Building an Expensive G&G Database
- **Start-up Credits Mitigate Changes to ELF Based System**

***We believe this will bring in new investors and give them a better chance to succeed.***

## *Fair Value for Tradable Tax Credits*



- **Tax Credit Value is Diminished to New Investor**
  - Held Credits diminish through time value of money
  - Sold Credits would likely sell at a discount
  - Discount value captured by purchaser
  - Credit Cost to State remains 100%
  
- **“Refundable” Credits Increase Value to New Investor**
  
- **Pioneer’s Investments Will Generate Substantial Credits**
  - HB 488: State to Refund \$10 million per year per company
  - Consider Increasing at Higher Oil Prices

# *Transitional Capital Recovery*



- **Fairness Issue**
  - Investments were made under ELF system
  - Tax System is changing
  - Pioneer has recouped nothing from production
- **Pioneer's Alaskan Investment Began in 2003**
- **Pioneer's Cumulative Investment Over \$100mm**
- **Transition Capital Look-Back is Appropriate**

## ***Pioneer Key Messages***



- **Pioneer Goal: Establish Alaska as Core Production State**
- **Priorities for State of Alaska:**
  - Provide Incentives to Convert Resources to Production
  - Attract New Investment
    - Effectively Compete w/ North American Countries
- **Administration's 20/20 Proposal is Balanced & Fair**
- **Higher Tax Rates will Discourage Needed Investment**
- **Progressivity, if Enacted, Should be Structured Fairly**
- **"Start Up" Credits will Encourage New Entrants**
- **Refundable Credits are an Incentive to New Entrants**
- **Transition Capital Look-Back is Appropriate**

4/3

Alaska Venture Capital Group

April 3, 2006, Comments To Alaska House Finance Committee  
CS For HB 488 – Petroleum Production Tax  
By Ken Thompson

Introduction

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

AVCG has been very active in the past six North Slope (NS) areawide lease sales and we have acquired over 160,000 acres of exploration leases in five exploration prospect areas, including new acreage we acquired in the recent March 1, 2006, NS lease sale. Our exploration strategy is to explore in the central part of the North Slope for fields in the 25-150+ million barrels range, fields that may be too small for the giant producers but fields that can be produced profitably by smaller companies like ours. We believe there are hundreds of millions if not billions of barrels of oil left on the North Slope in smaller fields of this size and these fields near infrastructure can be brought on more quickly. Our first exploration well in partnership with Pioneer Natural Resources – the Cronus #1 about 10 miles southwest of the large Kuparuk Field – completed drilling last week but results remain confidential.

Let me focus my comments on the CS for House Bill 488. I reluctantly supported the Governor's proposed 20/20 PPT and I supported many elements of the original draft of HB 488 as fair to the State and fair to industry. But, somehow, things are beginning to derail and the CS HB 488 with its revisions from the original draft has evolved into a complex bill that is no longer a win-win for the State and industry, in my opinion. I don't fully understand how things began to derail...perhaps it was due to anger at the Big 3 producers and the Governor for not revealing the natural gas contract details before demanding a new oil tax fiscal structure. Perhaps its anger at the Big 3 companies who are demanding certainty for 30 years when asking for certainty for three full decades truly is an unreasonable demand.

I don't understand all the dynamics of the past three weeks in the legislature, but this I do know. The CS for HB 488 needs to be greatly simplified and it needs to move back closer to the Governor's proposal and the original HB 488 draft if a win-win solution is to be re-developed.

I am an optimist and always have been. I personally think there is still time to avoid a train wreck in this complicated business of a major restructuring of Alaska's

petroleum taxation system...if the House Finance Committee acts quickly. I, for one, have not given up hope that there is a version – easier to understand and to implement - that can be a win-win for both the State and industry. I repeat that the current draft of CS HB 488 is not a win-win. There is a simpler and better way, in my opinion, for the State to improve government take while not dampening exploration and development investment. Let me outline my suggestions for a win-win and my suggestions for simplification.

### AVCG Owners' Perspectives

First, however, let me say that while I am Managing Director of AVCG, our other owners disagree strongly that any change should be made to the 20/20 PPT formula proposed by the Governor. The 20% PPT tax rate and the 20% credit originally presented in the Governor's bill should be the tax rate and credit enacted. The AVCG owners representing 15 new exploration investors in Alaska are concerned enough that the current system is being revised after they have made almost \$10 million investment in North Slope leases and other costs and are planning a 3-year \$46 million exploration program with our first well recently drilled. With reasonable discovery success over the next 3 years in any of our upcoming prospects, we could see development capital spending at \$500 million to \$1 billion.

Quite honestly, the AVCG owners listened in disbelief when I told them the production profits tax rate being considered in the current CS to HB 488 draft could add a "progressive surcharge" that could place an additional 37.5% taxation of wellhead value by the state at high oil prices on to the base PPT, the State's 12.5-16.7% royalty, the ad valorem property tax, the 3-9% corporate income tax, lease bonus bid amounts, the ongoing annual lease rental amounts, and the Federal income tax rates averaging 20-35% of taxable income. It all adds up, and AVCG Owners are saying, "enough is enough."

Interestingly – and this is important – when I was communicating the latest CS to HB 488 details to the AVCG owners by teleconference and email recently, I felt two overwhelming emotions. The first emotion was discouragement. Under the original 20/20 proposal, I was recommending to our owners that considering the value of the tax credits, we could add a sixth exploration well for every fifth well drilled essentially at no cost to our company...this could lead to additional discoveries and production for all of us. This is good policy. However, in discussing the CS to HB 488 with its much higher taxation at high oil prices, I recommended to our owners that, in order to pay potentially higher production taxes under the surcharge concept, we sell our credits to other companies and save the cash to literally offset our higher taxes later. I suggested we not consider the additional sixth exploration well any longer...the AVCG owners concurred. This will result in potentially a new oil field that will never be drilled and lower production for all of us. This is bad policy. And this is discouraging.

But I also found interesting another strong emotion during that teleconference which surprised me a great deal. I felt embarrassment for the State of Alaska, and I felt embarrassment as an Alaskan. Here I was, telling a group of outside investors that recently put all of their focus and personal exploration budgets on the North Slope of Alaska, and now I was telling them that Alaska was creating the most complex, confusing production tax bill ever created since the disastrous Federal windfall profits tax. And I was telling them that Alaska was levying the highest tax rate and government take in North America, much higher than the other U.S. states where they invest. I was embarrassed that the anger – or the mistrust – of the Big 3 producers and the Governor has resulted in the State crossing the line between balancing State revenues and attracting outside investment.

Currently, the total Alaska and Federal governments' take is just over 50%. The Governor's proposal moved this to 53% or so then the original HB 488 moved the government take closer to 55%. Then the CS to HB 488 boosted the government take close to 60% with its "Progressivity Surcharge." This compares to total government take in the U.S. Gulf of Mexico of 45% or so, 50% or so in the U.K., and 39-56% in Canada. Including the U.S. government take share, this compares to a total government take of 51% in Colorado, 52% in Wyoming, 53% in Kansas (where AVCG investors are located), 53% in Texas, 53% in New Mexico, 53% in Oklahoma, 53% in California, and 57% in Louisiana. At least the State should not exceed a threshold of 55% total government take, 45% producer take...after all it is the producer who is taking the capital spending risks.

I'm excited about what's happening in Alaska's oil patch right now, and let's not dampen the spirit. When I first came to Alaska in 1994 as President and CEO of ARCO Alaska, there were a handful of companies leasing acreage on the North Slope. Today, there are 25 companies and individuals holding North Slope leases. In all oil and gas areas of Alaska including the North Slope and Cook Inlet, in 1994 there were 24 companies with leases; today in all basins there are 100 companies or individuals holding leases. Let's not dampen this activity. Activity with new discoveries is how the state will achieve the most in revenues. Let's have a new tax bill that encourages, not discourages new entrants.

#### My Personal Perspective

Now let me shift gears in my comments to you. Because I could not get buy-in for any alternatives from the AVCG owners except the 20/20 case, I have decided to speak out alone. As an Alaskan, I am concerned and feel I must try to share a personal perspective trying to balance what is best for my continued involvement on the North Slope in balance with how the State must change its system to be competitive in the world and realize more government share at high prices.

I realize by stepping out like this, I could jeopardize my management status with AVCG and perhaps even jeopardize how I am viewed by the major oil companies and my friends in the independent company sector. But I have taken such personal

risks in the past, and I don't mind doing so again today to simply do what I think is the right thing to do regardless of others' opinions.

So, let me turn my attention to what key changes I would make to the CS of HB 488. Again, my views are not supported by AVCG owners or others in industry; rather they are my personal views.

### 1) Make Tax Rate Progressive But Greatly Simplify The Taxation Formula

When the Governor's office first announced a 25% tax rate then amended that to 20%, I could see the move by legislators to somehow bridge the gap from 20% to 25%. However, the approach used by the House Resources Committee based on their outside consultants' work is simply too complex and will be arduous to implement. I think – and perhaps all of you think – the Federal tax code is too complex....the changes to HB488 are also too complex and will lead to different interpretation, "gamesmanship" possibly by some companies because of the unwieldy progressive tax structure formula, and future costly lawsuits when the State disagrees with a company's calculations. And the number of accountants to keep track of these complexities on both sides will balloon! I urge you to simplify, simplify, simplify...yet still have some progression that legislators seem set on.

For my company which drills the smaller oil traps that may add up, we do not have a lot of upside potential in seeing these smaller fields grow much larger in reserves over time in contrast to the giant Prudhoe Bay and Kuparuk fields. So our main upside is in oil price escalation to offset exploration risks and to offset the cycles of oil prices downward, a reality over time for any commodity. I find it disturbing – and personally unfair – that the House Resources Committee recommended a windfall profits tax, or "Progressivity Surcharge", as high as an additional 37.5% of value in addition to the base PPT.

I found it so interesting to see the Econ1 consultants and consultant Daniel Johnston saying the government should take more and more at high prices when not one member of the Resources Committee asked them a very important question they should have been asked: "how much are you investing in Alaska?" I was shocked to see that these consultants, when calculating the future revenues to the State at various escalating rates, used the same oil production curves. In reality, less capital will be spent by industry at exorbitant production profits tax rates (tax rates above 25% when coupled with all other payments such as royalty, corporate income tax, ad valorem tax, lease costs and rentals, etc.). With less capital spending, the production curve will be lower...an increasingly higher tax rate may not in the end yield the forecasted revenues for the State.

On a related note, our company plans to go into the private or public equity markets to raise funds and capital for any future development. Such equity investors invest in the oil markets to be fully exposed to crude price upside. When they look at investments all over the world, and see that Alaska could tax at much higher crude

prices with a "Progressivity Surcharge", they will place their capital elsewhere to continue their exposure to higher crude prices in investments without alternative taxing structures such as the Lower 48 states, the Gulf of Mexico deep water with royalty relief, the Canadian oil sands or other countries. The consultants did not address this issue that I face month in and month out...the private and public equity markets and the desire for such investors to fully benefit from upside commodity price swings without hedging or excessive, escalated taxation at high prices.

I could not believe the consultants did not show capital spending elasticity graphs from different countries. They did the legislature a disservice by not doing so. Their work showed a biased perspective in my opinion; by getting the House Resources Committee to adopt a complex progressive tax rate structure, or windfall profits tax, the consultants may feel they have been successful...but not one of these consultants will be around to defend their views in the future when capital spending does decline at exorbitantly high and unfair tax rates above the 25% level.

So, what is a simpler alternative? What is an alternative to yield more revenues to the State with a balance to attract increased investment? I have followed the progression of the PPT and noted when respected global consultant Pedro van Meurs recommended a 25/20 formula, i.e. a 25% tax rate and a 20% investment tax credit. Yet the Governor recommended a 20/20 formula with a 20% tax rate. Since that controversial time a few weeks ago, it appears the House Resources Committee and the Senate Resources Committee have spent a lot of time trying to recapture the perceived "lost revenue" from the Governor not taxing at the 25% level. On the other hand, the Governor does make a good case about increased cash flow to producers and resultant increased capital investment at the lower 20% tax rate level. But consultants Econ1 and Daniel Johnston did get things way off track by proposing too complex a solution to bridge this gap and get even more...the complex "Progressivity Surcharge." Having the PPT at higher prices being a mixture of taxation of profits and a separate incremental tax on incremental revenues is unwieldy and an accounting nightmare.

Let me address a way to transition from the 20% tax rate to the 25% tax rate without getting too complicated.

I suggest that the Finance Committee revise the bill to keep the production profits tax simply that...a tax on production profits, and not an underhanded way to further burden gross revenues with a surcharge. A simpler way getting the progressive rate from 20% to 25% without the surcharge treatment complexity is to adopt a graduated PPT that does accomplish a higher State take at higher prices, yet leaves a reasonable producer take.

I recommend the following production profits tax schedule as a suggested one to "simulate" revenue results somewhere between the Governor's proposal and the CS to HB 488 proposal. It is one that everyone could easily understand

and implement with the State realizing upside at higher oil prices yet not too much upside is taken away from explorers/producers for re-investment:

Up to monthly average wellhead price of \$50/barrel for a company: PPT rate of 20%

When monthly average wellhead price is between \$50-75/barrel: PPT rate of 22.5%

When monthly average wellhead price exceeds \$75/barrel: PPT rate of 25%

*By the way, if the State were to pass a complex, unwieldy windfall profits tax like that one proposed by Econ1 and favored by some on the Resources Committee with escalating production profits tax rates or surcharges, I predict Alaska will make the cover of the industry-wide influential magazine "The Oil and Gas Journal" and perhaps even a cover spot in the "Wall Street Journal." And I don't mean this media coverage in a positive way...I think all in industry will say the State is taking advantage of industry at high prices. Whether or not industry makes money or not and makes good, solid returns is not the issue with such extremes...the perceived fairness of taxation in a high cost, remote area like Alaska is the issue. This will discourage new entrants, in my opinion.*

I highly respect industry consultant Daniel Yergin who has an excellent reputation among industry personnel and government officials alike. In November, 2005, Mr. Yergin said this about a windfall profits tax: "What a windfall profits tax does is introduce a lot of distortion. It reduces investment, it increases a sense of political risk and it doesn't achieve the goal that is intended...it will really lead to decreased supply."

I urge the Finance Committee to seriously consider this simpler approach, and ask that you have the Department of Revenue run the above case to compare the State revenues to the Governor's proposal, to the current CS to HB 488 proposal, and to the existing ELF severance tax program. Please do away with the complex "Progressivity Surcharge" and simplify, simplify, simplify.

## 2) "Trigger Points" For Escalating PPT Should Not be WTI But Wellhead Value

I do not think the "trigger point" that increases the PPT tax rate from 20% should be based on West Texas Intermediate (WTI) oil price as suggested by Econ 1 and Daniel Johnston and by the House Resources Committee. The "trigger point" should be when a company's average realized wellhead price in Alaska exceeds \$50 per barrel. Some say lower, but I do think there is strong merit that those who have invested and taken exploration risk and exposure to low prices should be able to benefit from increased profits at higher prices..."share the pain, share the gain"...to this \$50/barrel wellhead level. However, I personally am fine with the State increasing the PPT tax rate eventually to a cap of 25% when wellhead prices exceed \$50/ barrel. Having said this, you need to know that I do not know anyone else in industry who thinks this; everyone I know continues to press the 20/20 formula.

Why should the State tie the PPT calculation to a company's realized wellhead price instead of to West Texas Intermediate (WTI) price? In reality on the North Slope, not one company sees WTI prices. Every crude oil in Alaska is different in quality with viscous crude receiving less and oil produced from wells farther away from infrastructure receiving less wellhead value due to higher shipping costs. Conversely, oil in the Cook Inlet is close to actual refining or on the water to ship out of state and thus realizes on average much higher wellhead value than most North Slope crude oils, a substantial plus to Cook Inlet operators who face higher operating costs with maturing fields. Our company's crude when discovered on the North Slope will be farther west, and when we have to transport the oil via the major producers' gathering system lines to TAPS pump station #1, we will pay the majors a certain tariff of \$0.50-1.00/barrel or more, and a facility processing fee of \$3.00/barrel or more, giving us a lower wellhead value for our crude while the major producers make an additional profit on shipping in their crude lines and processing. The majors further make profits from tariffs for shipping down TAPS and in their marine tankers.

So I ask, why should the tax rate increase with WTI price when there is such a variance in crude oil pricing factors on the Slope at the wellhead affecting each field's economics and economic limit differently? The production profits tax rate should not go up at the same time for those who produce viscous crude or oil from a farther distance as compared to those who have good quality oil right next to the TAPS line. If there is a "trigger point", it should be one based on a company's average monthly realized wellhead price for production.

I recommend that the "trigger point" for PPT tax rate escalation be \$50 per barrel realized wellhead price based on a company monthly average and not be based on \$50 WTI, thus allowing explorers and producers to share in the upside profits at prices to this level with no higher burden than the 20% PPT tax rate (plus burden of royalty, corporate income tax, ad valorem tax, Federal tax, etc.).

### 3) Reinstate The Transitional Deductible Allowance

Jumping immediately from the prior ELF severance tax to the PPT formula overnight wreaks havoc with a company's budgeting and their forecast of available cash flow for near-term capital investment. While this does not have a major impact on AVCG, I do greatly empathize with ConocoPhillips, who is the largest investor and most active explorer in Alaska, about having "look back" investment credits. Part of the current oil production bringing in much higher revenues to the State is due to investment over the past few years. Interestingly, the PPT will have the largest negative impact on ConocoPhillips, particularly on their production from the Kuparuk Field. ARCO used to own the ConocoPhillips properties on the North Slope, and I am concerned with the impact on Alaska's largest investor and most successful explorer. A transition adjustment of some sort is appropriate and is fair.

I recommend the Finance Committee re-institute the original HB 488 compromise to a three-year staged and tiered "look back"; while not as substantial as the Governor's proposal, the House Resources Committee's staged "look back" is fair and should be re-instated in the bill. The cost recovery allowed should be 75% of 2005 expenditures, 50% of 2004 expenditures, and 25% of 2003 expenditures to be deductible as costs for near-term PPT calculations as originally in HB 488.

#### 4) The \$12 Million Tax Credit Standard Allowance

The Governor proposed a \$73,000,000 annual allowance of production profits that would not be taxed by the PPT, essentially giving a \$14.6 million tax credit per company. The House Resources Committee revised this downward to a \$50,000,000 annual allowance as a reasonable compromise, or a \$10,000,000 tax credit. The CS to HB 488 further proposed that this be changed to a simple \$12,000,000 annual "standard tax credit allowance" as a reasonable compromise.

This "standard deduction" is very important to a startup company like AVCG/Brooks Range Petroleum trying to establish a foothold in Alaska and someday contribute substantial oil revenues to the State.

I recommend the Finance Committee endorse the \$12,000,000 tax credit allowance per company.

#### 5) Tax Credit Repurchase Program

As protection for explorers and new entrants to Alaska, the CS to HB 488 devised a tax credit repurchasing program for those credits a company earns on expenditures up to \$10,000,000 per year for investments in exploration and/or lease purchases in Alaska.

This is important to explorers like AVCG who does not yet have production revenues. Without such a repurchase program, our company might be able to sell our annual tax credits to one of the major producers but have to accept only 90-95% on the dollar or less. On the other hand, the State would not be giving up anything to repurchase the credits at 100% of value because the major producers would otherwise use the credits to reduce their tax bill and reduce revenue to the State. But using the State repurchase approach, the small explorer could turn around and re-invest the State-refunded credit into new leases, seismic or exploration drilling.

I recommend the Finance Committee support the tax credit repurchase program outlined in the CS to HB 488.

#### 6) Remote Exploration Tax Credit Extension

I thank the House Resources Committee for their proposal in extending the SB 185 exploration tax credits for the next 10 years.

I recommend that the Finance Committee also endorse this proposal that will extend the 40% tax credit for remote wildcat exploration wells more than 25 miles from existing facilities.

#### 7) Effective Date

The State has made far more money at high prices than anyone ever dreamed. The State has, in a way, already received a rich windfall at high oil prices. The change in the production profits tax is controversial in its own right. I would not dare "pour salt in the wound" by making the tax effective on April 1, 2006, but allow the transition as originally planned to a July 1, 2006, date. This will also give all of us time to hire additional accountants to do the monthly, complex filings!

I recommend that the Finance Committee amend the effective date to July 1, 2006.

#### Concluding Remarks

The above comments are my personal views offered with a hope that there can be an eventual win-win solution to this complex subject of the State realizing more revenues at higher prices while attracting exploration and development investors who can also realize upside at higher prices. I do believe the House Finance Committee can get things "back on track" and better balanced.

Importantly, many – if not most – in industry would disagree with some – if not all – my personal views expressed above. But I do feel compelled to "tell it like it is" from my perspective as an Alaskan who has worked the Cook Inlet and the North Slope oil and gas fields for over 12 years.

I sincerely thank the Committee for the opportunity to present my comments.

Respectfully submitted by:

Ken Thompson



State of Alaska Petroleum Production Tax  
Testimony to House Finance Committee  
(HB 488)  
John A Barnes

*April 3, 2006*

**Marathon**



4/3

## **Marathon Testimony – Alaska PPT Impact of HB 488 (RES) on Alaska Natural Gas**

- ◆ Cook Inlet Natural Gas Summary: Pre PPT
- ◆ Financial Impacts of PPT
- ◆ Consequences of PPT
- ◆ What Is Needed



## Cook Inlet Natural Gas Summary: Pre PPT

- ◆ Declining reserves and production rate.
- ◆ High operating and capital costs as compared to lower 48 natural gas provinces.
- ◆ Difficult permitting and regulatory arena.
- ◆ Need for additional exploration and development to moderate price increase to consumers and to continue to provide industrial feedstock.
- ◆ Historical price differential to Henry Hub.



# Cook Inlet Gas Supply and Demand

May 9, 2005

State of Alaska  
Department of Natural Resources  
Division of Oil and Gas



Alaska Department of  
Natural  
Resources

*http://www.dnr.state.ak.us/divisions/dog/pressrel/050505.htm*

## Cook Inlet Areawide Lease Sale Results

	Number Bids Rec'd	Number Tracts Sold	Multiple Bid Tracts	Total Acreage Sold	Total Bonus Rec'd	Avg Winning Bid	Max Bid Rec'd
				Acres	\$	\$/ Acre	\$/ Acre
2000	27	27	0	69,928	\$609,358	\$8.72	\$36.01
2001	31	29	2	102,523	\$928,085	\$9.05	\$22.18
2002	24	21	3	64,923	\$421,840	\$6.50	\$27.03
2003	28	27	1	103,680	\$887,059	\$8.56	\$33.28
2004	77	72	5	363,520	\$2,629,820	\$7.23	\$40.25
<b>TOTAL</b>	187	176		704,574	\$5,476,162		
<b>AVERAGE</b>	37	35	2	140,915	\$1,095,232	\$8.01	\$31.75

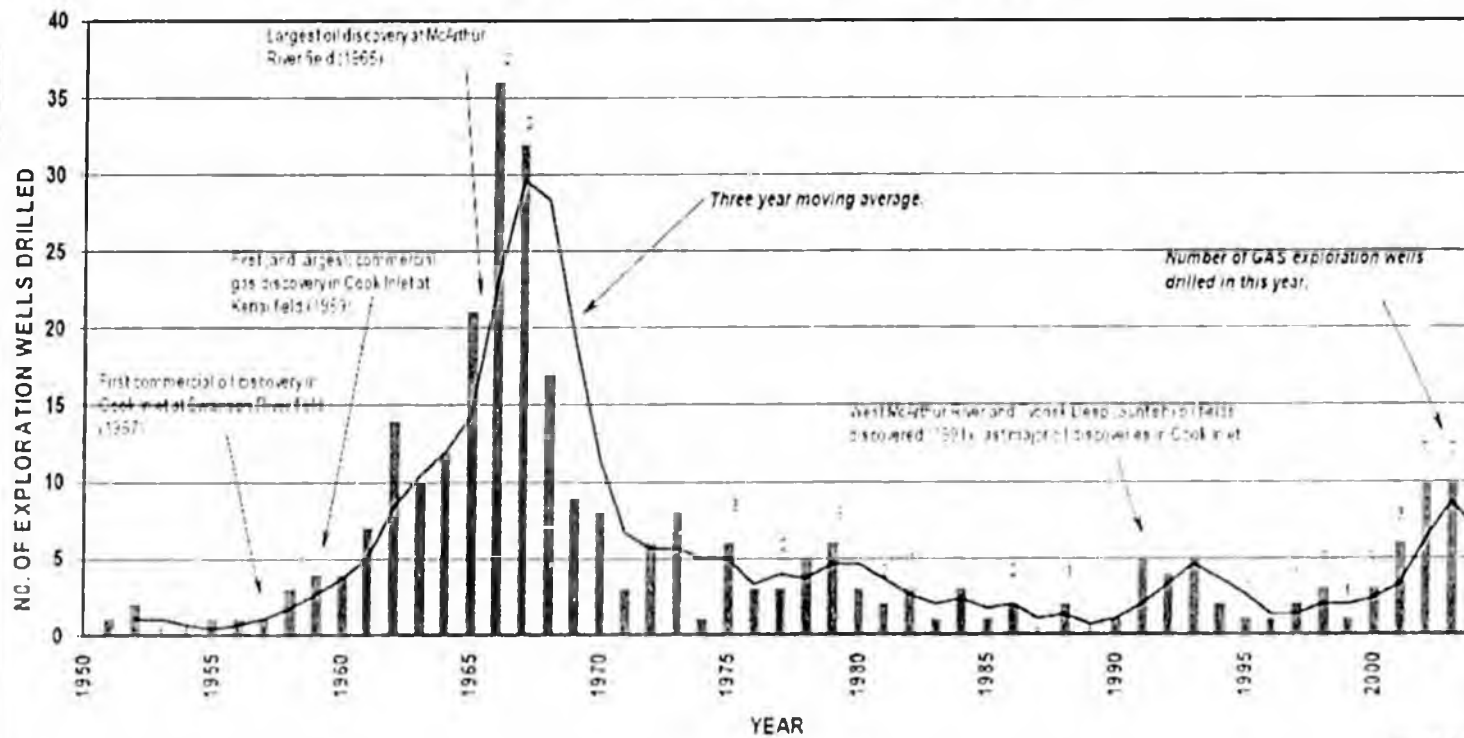
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**RICHFIELD HITS OIL**  
PRODUCTION BEGINS FALLS NEPE

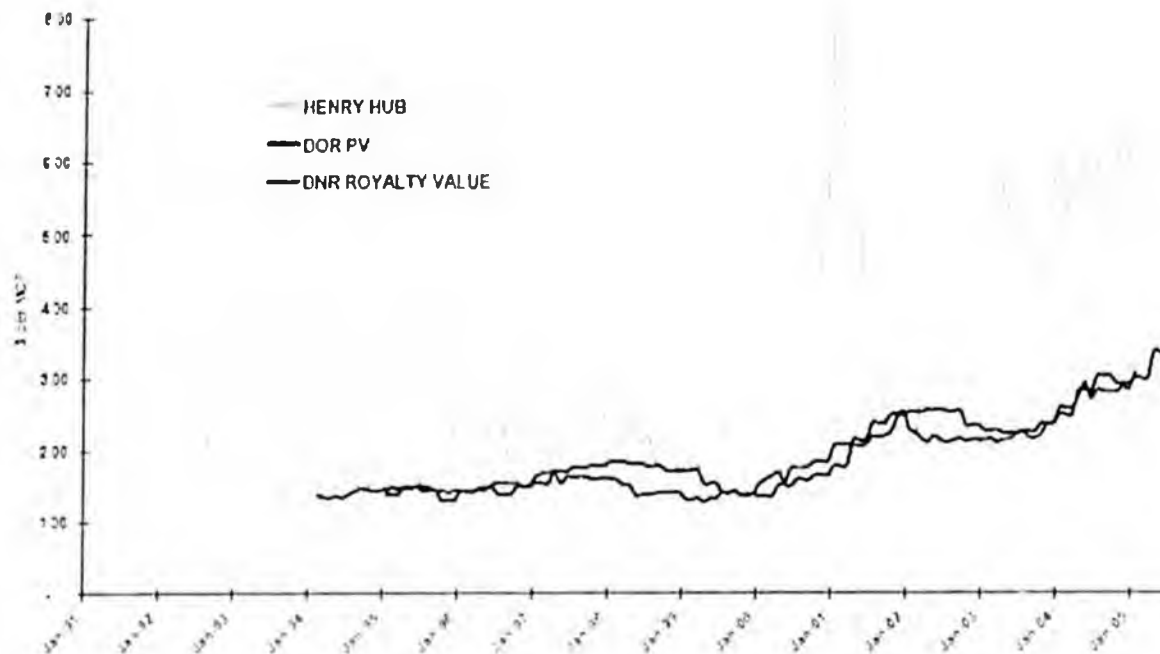


# Timeline of Cook Inlet Exploration

COOK INLET EXPLORATION WELL DATA AND IMPORTANT EVENTS



## Historic HH, DOR PV and DNR Royalty Value



## Future of Supply

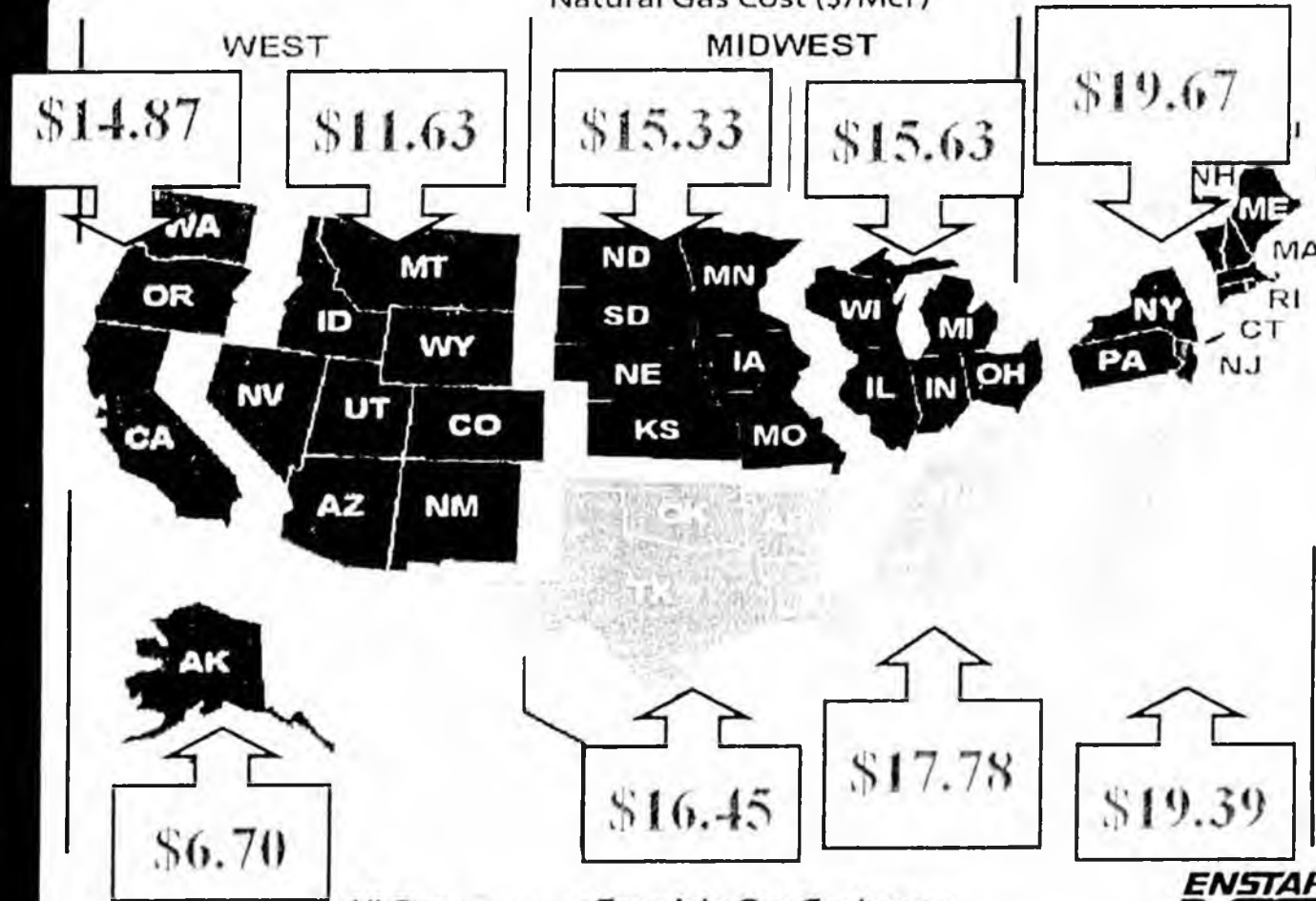
- We have moved from an “Excess Supply” market to a “Supply & Demand” market
  - Cost of Natural Gas will go up
  - More supply contracts are needed and will likely be for smaller volumes
  - Supply contracts will likely be more complicated
  - Pipeline system will be more complicated to operate
- We are working to identify and evaluate options to meet future demand
  - LNG Imports may be economic at some point
  - Storage options are being explored for peaking purposes
  - We have achieved Federal support for an in-depth DOE study of In-State demand and for conceptual engineering of a spur pipeline to Nenana Basin / Fairbanks

*All Our  Goes Into Our Customers*

**ENSTAR**  
Natural Gas Company

# Residential Costs-By Region

Natural Gas Cost (\$/Mcf)



All Our *Quality* Goes Into Our Customers

**ENSTAR**  
Natural Gas Company

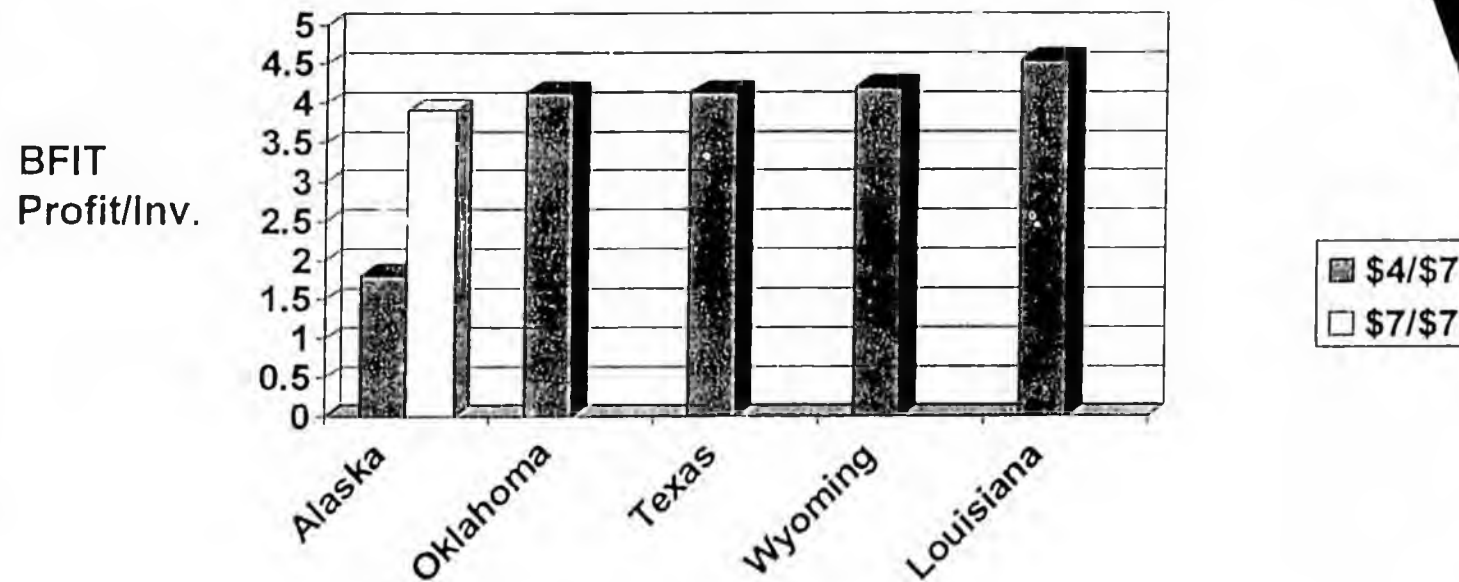
## Conceptual Competitive Comparison Common Input – Per Well Analysis

Recoverable Reserves	5 BCF
Development Cost (Capital)	\$5 million
Operating Cost	\$0.50/mcf
Royalty	1/8

Based on House PPT (HB 488, RES) and domestic severance tax rates



## Competitiveness Comparison: Cook Inlet Natural Gas Investments Disadvantaged Against Competition



Based on House PPT (HB 488, RES) and domestic severance tax rates



# Cook Inlet Competitive Analysis

- ◆ Must compare Cook Inlet to N American gas opportunities
  - Cook Inlet does not have world class exploration opportunities
  - However, viable smaller exploration opportunities exist
- ◆ Good access to lands
- ◆ Disadvantaged by high costs
- ◆ Disadvantaged by permitting and regulatory burden
- ◆ Disadvantaged by price and closed market
- ◆ Disadvantaged or incentivized by fiscal regime?????



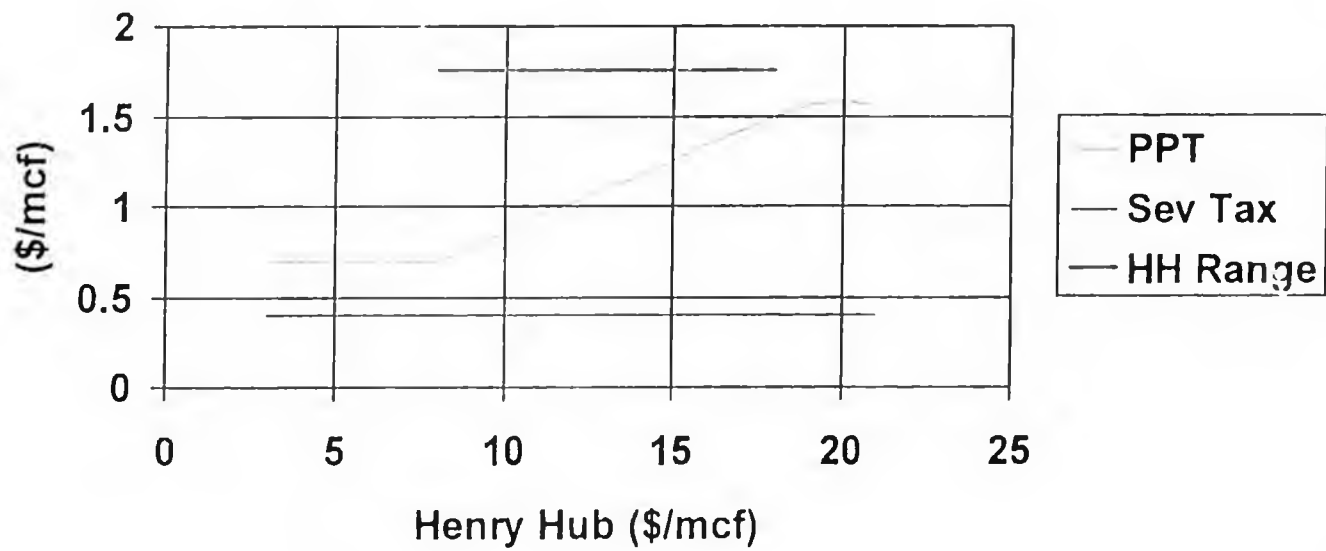
## Consequences of HB 488 (RES) – Cook Inlet Gas

- ♦ Existing Fields
  - Nothing wrong with ELF for Cook Inlet natural gas
  - Loss of ELF and higher tax rate in low gas price environment will result in
    - Higher rate required to pay for costs (economic limit)
    - Fields will be shut in at higher production rates
    - Reserves will be lost.
- ♦ New Exploration and Development
  - Higher taxes will result in:
    - Less competitive opportunities compared to N American gas provinces
    - Renewed decline in Cook Inlet exploration and development
    - Cancelled projects
    - **NO NEW RESERVES DEVELOPED**
- ♦ Loss of industrials and jobs
- ♦ **Higher and volatile costs to utility consumers**



# Impact of Link to HH for Gas Consumers

## PPT for \$4.00 Cook Inlet Gas



## Cook Inlet – What is Needed

- ◆ Must not link Cook Inlet PPT to volatile Henry Hub Price
  - Link to Cook Inlet Department of Revenue Prevailing Value
- ◆ Must include provision for marginal low rate fields
  - 5/20 Plan for Cook Inlet
- ◆ Prioritize efforts to incentivize, not hinder exploration and development
  - Include some form of transitional investments credit
- ◆ Actions by this Legislature will have immediate and measurable impact on Cook Inlet oil and gas industry



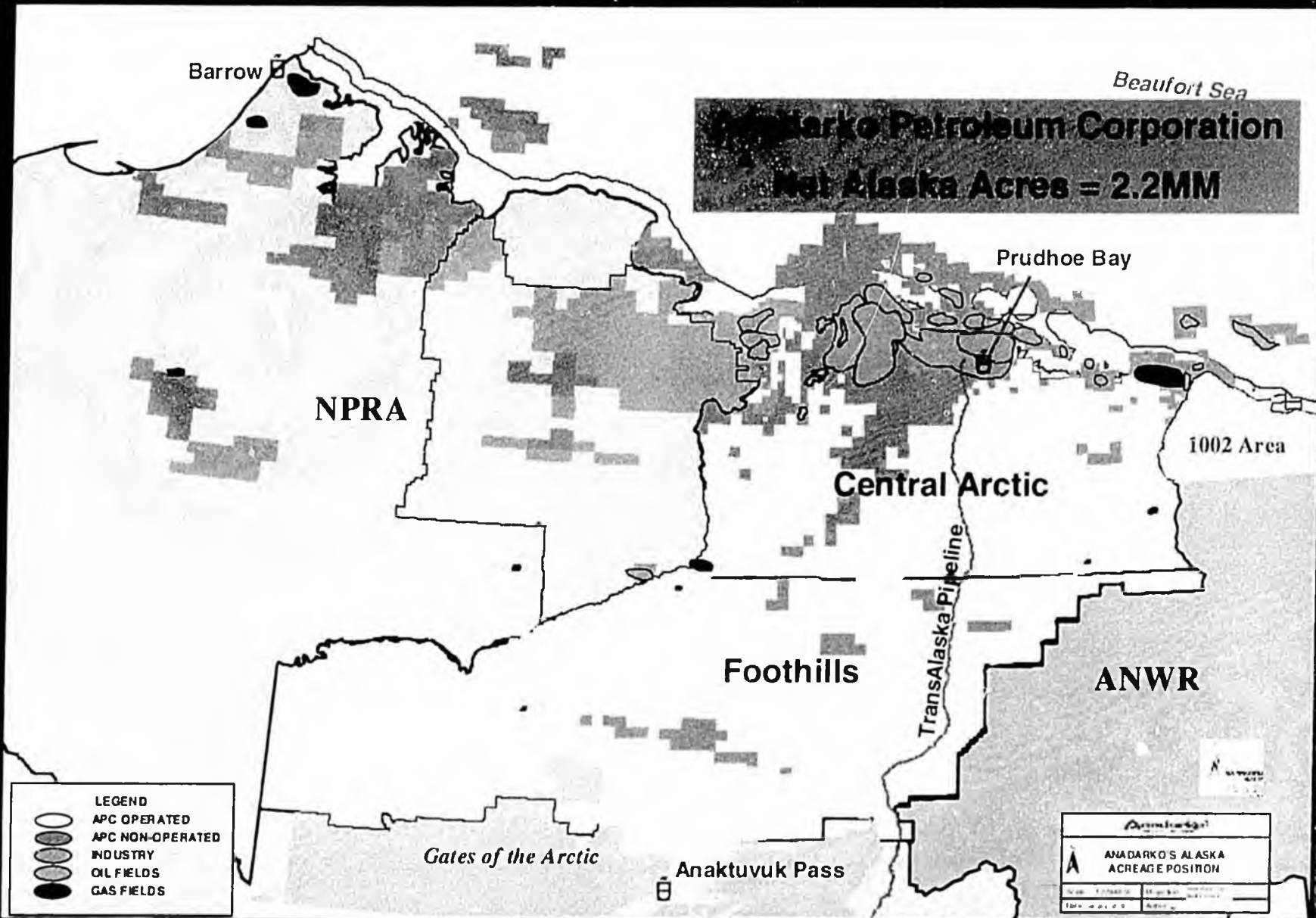


## PPT Discussion

March 31, 2006 House Finance Committee

**Anadarko**   
Petroleum Corporation

# Anadarko's Alaska Acreage Position



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# Alaska Opportunities

- ▶ **World class petroleum basin**
- ▶ **Significant remaining resource potential**
- ▶ **Legacy type prospectivity (i.e. Anchor Fields)**
- ▶ **Favorable political environment**
- ▶ **Abundant new entrants/partnering opportunities**

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# Alaska Challenges

- ▶ **Maturing basin/materiality**
- ▶ **High costs**
- ▶ **Lack of infrastructure and competition**
- ▶ **Limited access to facilities and pipelines**
- ▶ **Extremely long lead-time exploration**
- ▶ **Seasonal drilling & regulatory timing requirements**
- ▶ **Lack of gas market**

## How about PPT?

- ▶ **We support original bill**
- ▶ **Administration did a good job balancing issues & priorities**
  - *We pay more in taxes, but our exploration economics improve and there is some downside price protection- should increase exploration investment*
  - *State receives substantially more revenue than under current system*

## More production needed

- **Declining production is primary driver of lower state revenue**
- **Increased investment (compared with today's levels) needed to increase production & stem decline**
- **Original bill offset tax increase with credits & allowances**
  - *Our exploration economics generally improved*
- **Tax rate increases and allowance decreases (with no credit offsets) reduce our economics**
  - *Minimum economic field size increases*
  - *Amount of economically recoverable oil & gas decreases*

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## Key Issues

- ▶ Tax Rate
- ▶ Tax Escalator
- ▶ \$73 million allowance
- ▶ Transition allowance
- ▶ Point of production
- ▶ Gas economics
- ▶ Credit additions

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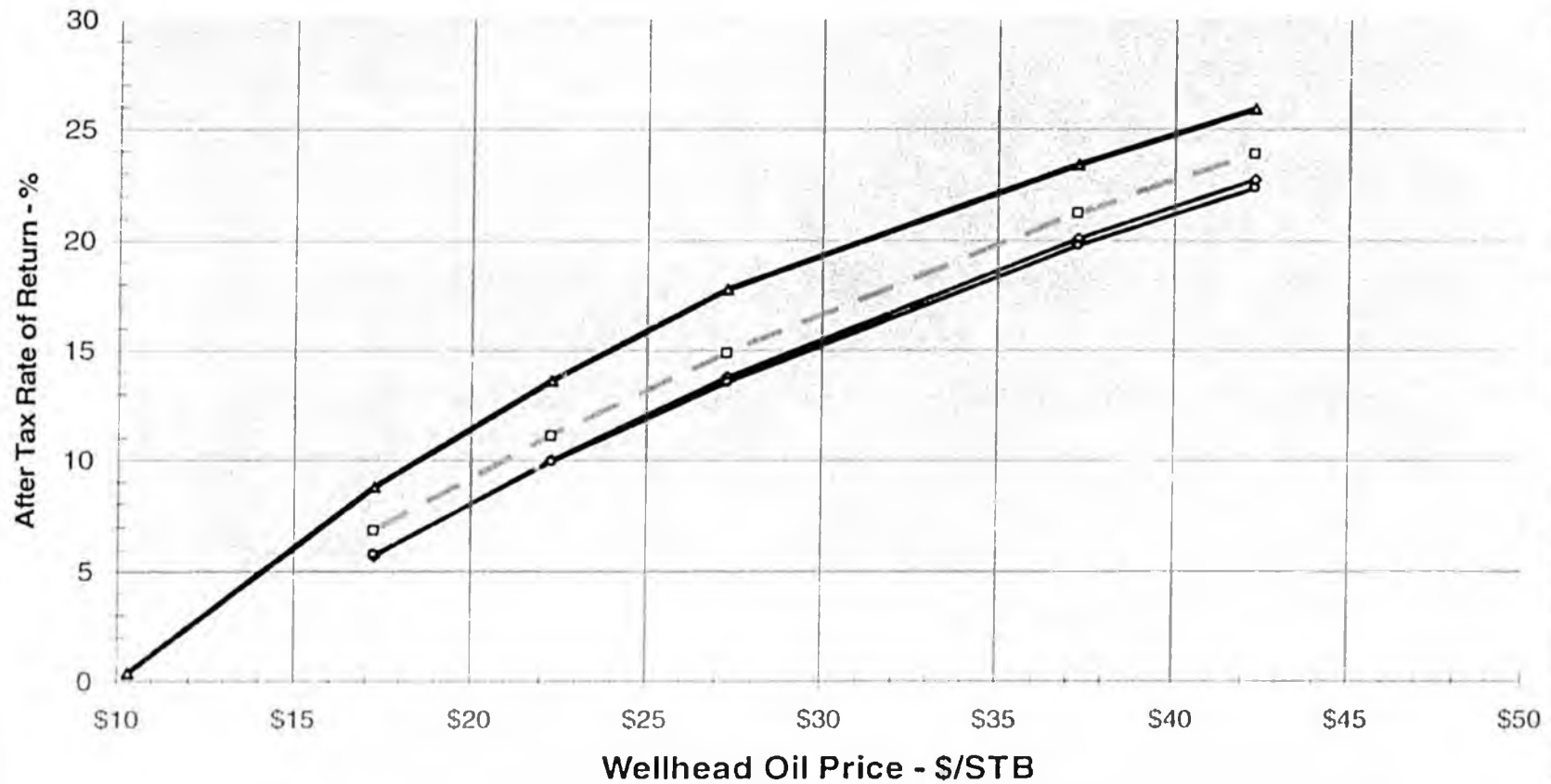
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# New Small Oil Development

- ▶ **Ultimate recovery is 47 million barrels.**
- ▶ **Peak oil production rate is 15,000 BOPD.**
- ▶ **Capital expenditure is 316 million dollars.**
- ▶ **Timing from discovery to first production is 6 years.**
- ▶ **The development concept is a satellite to an existing oil field. The satellite has a separate ELF calculation from the existing oil field.**
- ▶ **The satellite field pays an oil processing charge to the existing facility of \$5.00 per barrel. This is treated as a deduction to the wellhead price.**
- ▶ **The royalty is 12.5%.**

# Small Oil Development- Rate of Return

After Tax Rate of Return as a function of Wellhead Oil Price  
Small Oil Development

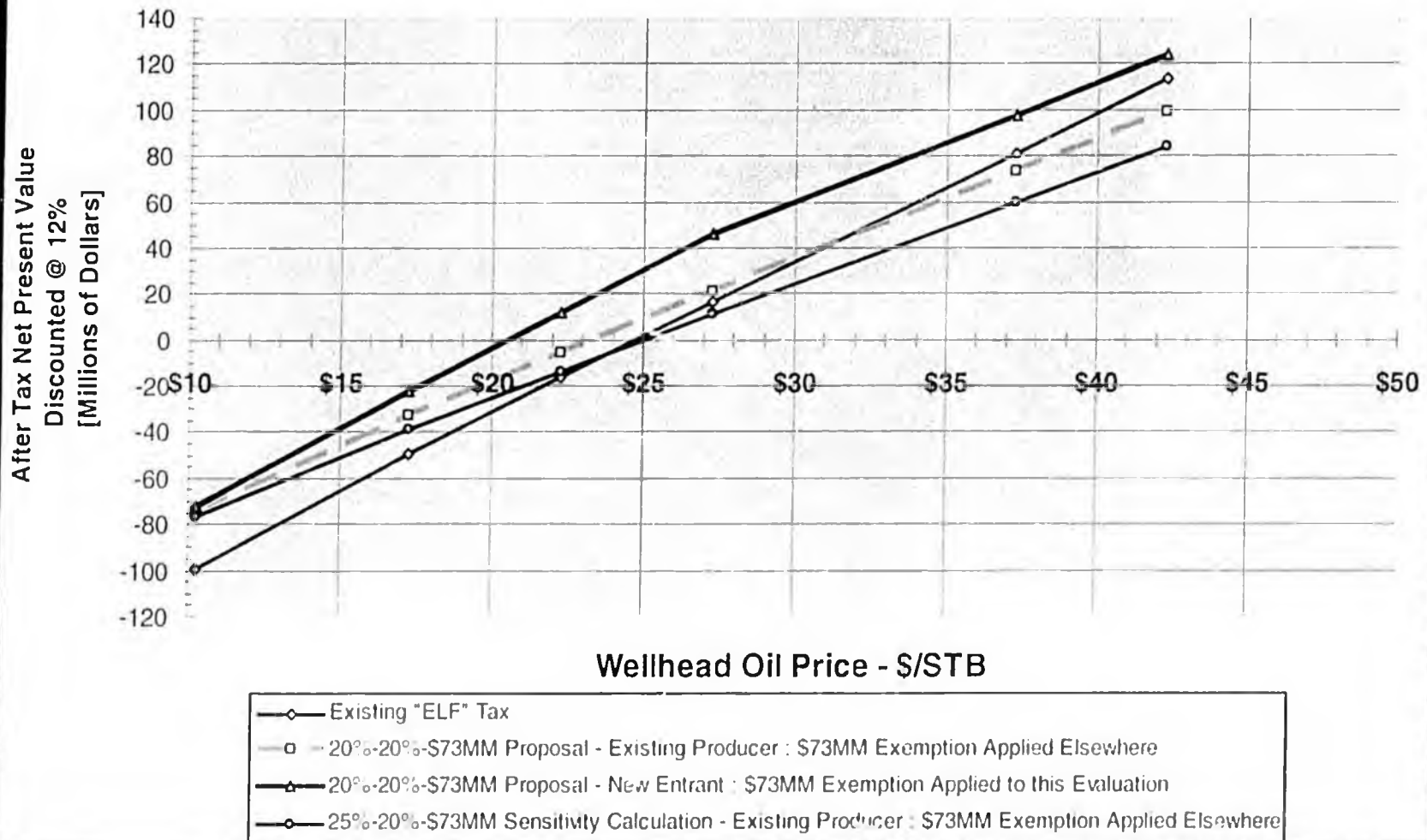


- Existing "ELF" Tax
- 20%-20%-\$73MM Proposal - Existing Producer : \$73MM Exemption Applied Elsewhere
- △— 20%-20%-\$73MM Proposal - New Entrant : \$73MM Exemption Applied to this Evaluation
- 25%-20%-\$73MM Sensitivity Calculation - Existing Producer : \$73MM Exemption Applied Elsewhere

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# Small Oil Development- Net Present Value

After Tax Net Present Value Discounted @ 12 % vs. Wellhead Oil Price  
**Small Oil Development**



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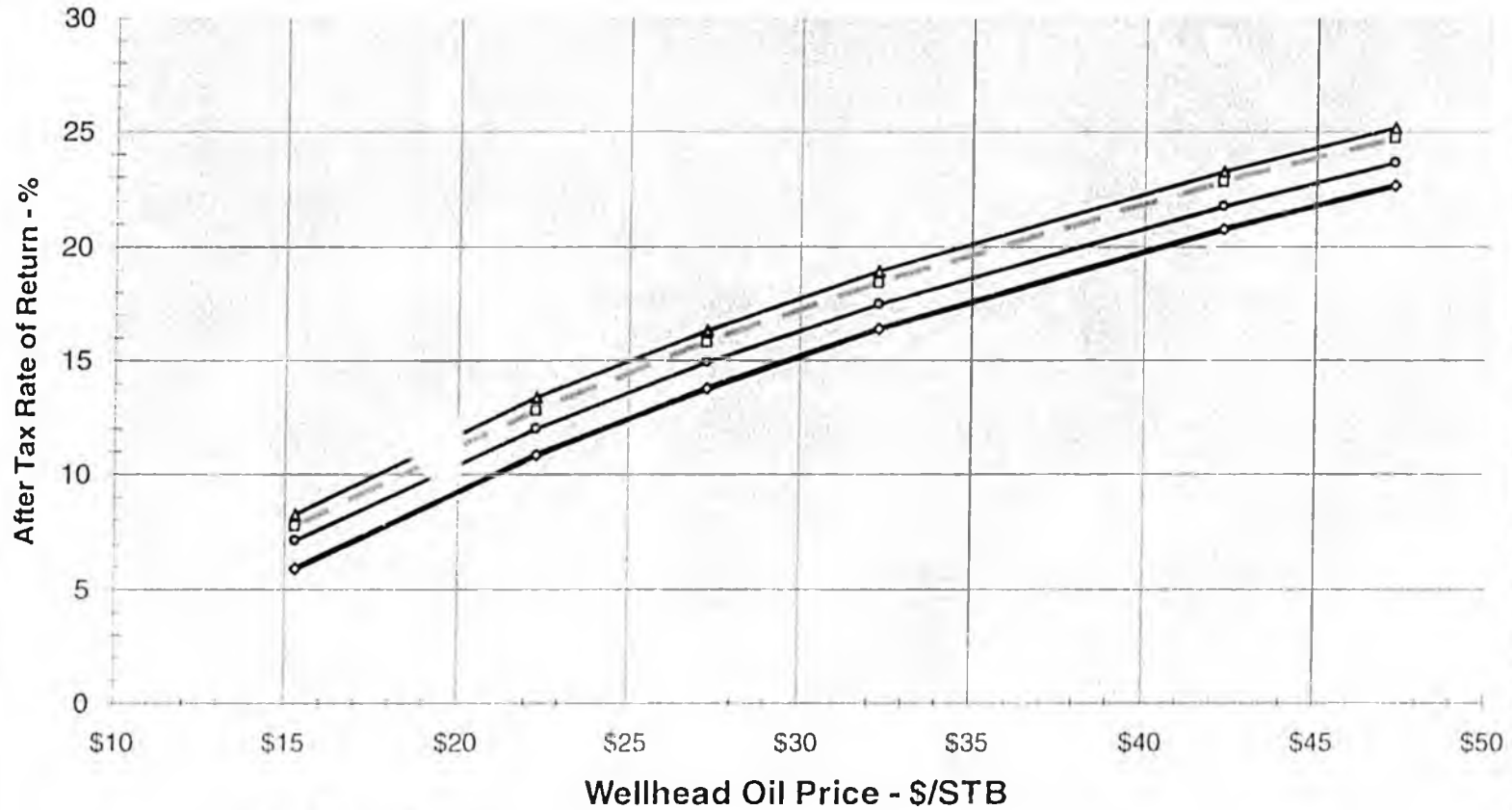
## **Risked Exploration Economics for Oil Prospect**

- ▶ **Commercial chance of success is 15% at a \$32/Bbl wellhead oil price**
- ▶ **Mean commercial prospect size is 345 million barrels**
- ▶ **Capital expenditure is 1.1 billion dollars**
- ▶ **The peak production rate is 55,000 BOPD**
- ▶ **Royalty is 12.5%**

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# Medium Oil Prospect- Risked Rate of Return

After Tax Rate of Return as a function of Wellhead Oil Price  
 Risked Pre Drill 345 MMBO Prospect Exploration Economics

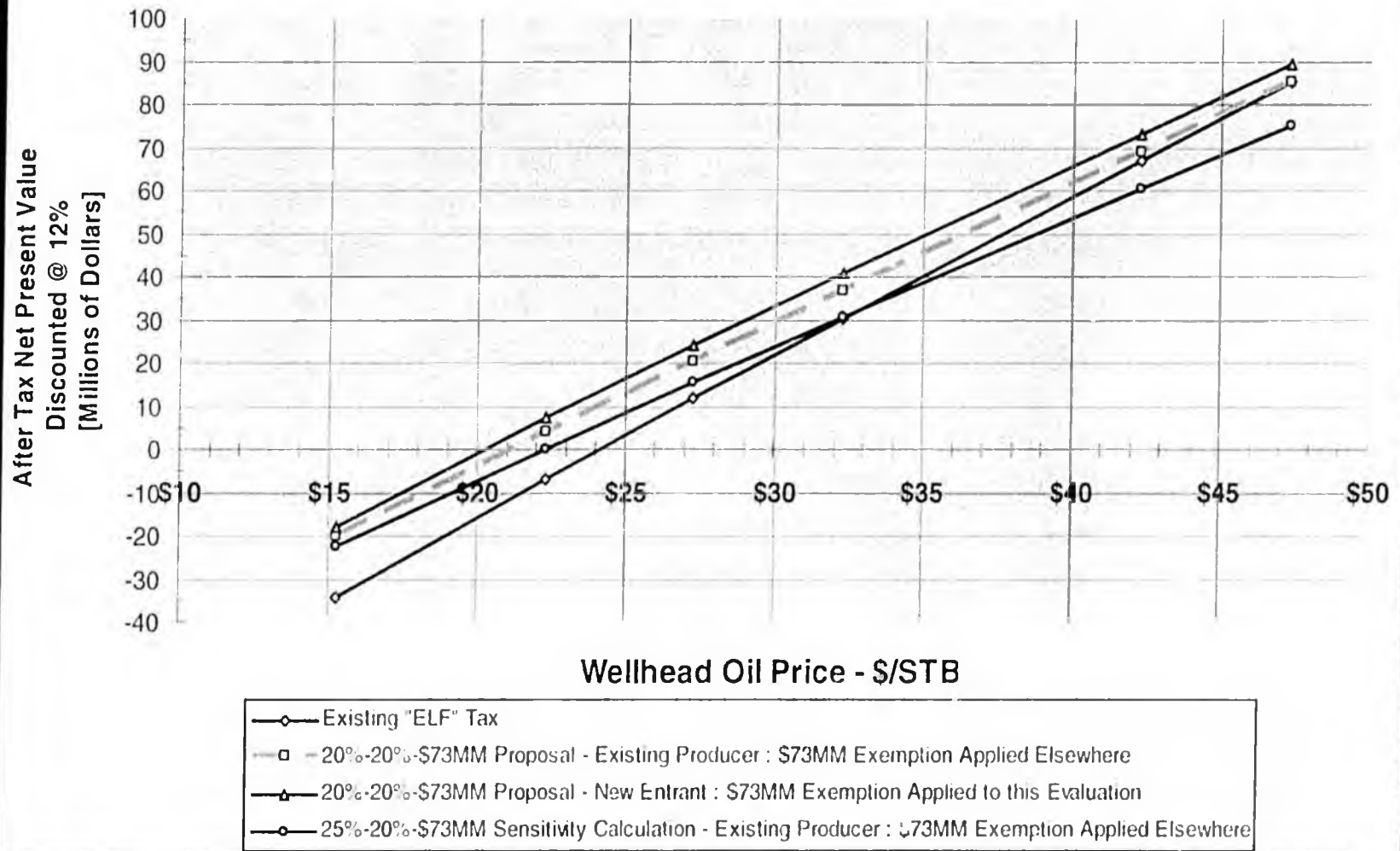


- Existing "ELF" Tax
- 20%-20%-\$73MM Proposal - Existing Producer : \$73MM Exemption Applied Elsewhere
- △— 20%-20%-\$73MM Proposal - New Entrant : \$73MM Exemption Applied to this Evaluation
- ◇— 25%-20%-\$73MM Sensitivity Calculation - Existing Producer : \$73MM Exemption Applied Elsewhere

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# Medium Oil Prospect- Risked Net Present Value

After Tax Net Present Value Discounted @ 12 % vs. Wellhead Oil Price  
 Risked Pre Drill 345 MMBO Prospect Exploration Economics

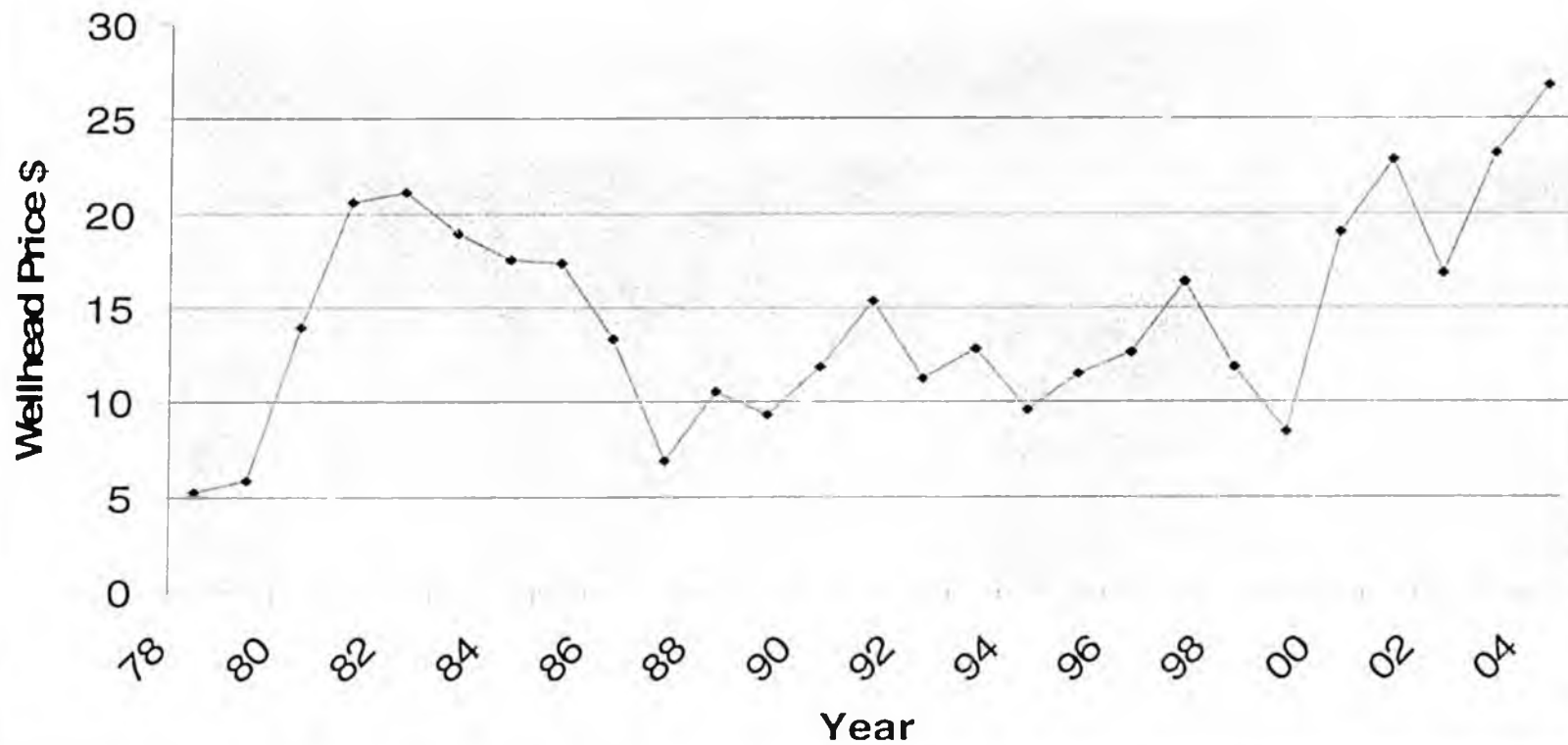


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# Historic Alaska North Slope Crude Prices

## ANS Wellhead Crude Oil Price

From AK Dept. of Revenue, Tax Division



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**This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities and Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that its goals will be achieved. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this release. While Anadarko makes these forward-looking statements in good faith, neither Anadarko nor its management can guarantee that the anticipated future results will be achieved. Anadarko discloses proved reserves that comply with the SEC's definitions. Additionally, Anadarko may disclose estimated reserves, which the SEC guidelines do not allow us to include in filings with the SEC. See Additional Factors Affecting Business in the Management's Discussion and Analysis (MD&A) included in the company's Annual Report on Form 10-K.**

**Testimony of James D. Weeks  
On HB 488  
Oil and Gas Production Tax  
Alaska State House Resources Committee**

01 March, 2006

Mr. Chairman, distinguished members of the House Resources Committee. My name is Jim Weeks, and I am here today representing UltraStar Exploration LLC, a very small all Alaskan owned independent explorer, with strategically located leases on the North Slope. UltraStar is based in Anchorage, with offices at 3111 C Street, Suite 500. The Company was formed in 2002 by me, John Winther, and Dale Lindsey, for the primary purpose of exploring and developing leases on the North Slope. UltraStar is 100% owned by Alaskans. I am Managing Member, and moved to Anchorage in 1984 with ARCO, and have had a presence here ever since. Dale, whom most of you know, was born and raised and still lives in Seward. John, whom most of you also know, was born in Fairbanks and raised in Juneau. He currently lives in Petersburg. Thanks for the invitation to testify on this important legislation.

First of all, I'd like to commend the Governor and members of the Administration for addressing this issue, and your Committee for the timely and thorough review it is being given. During the last several days, I've listened to a lot of testimony on the proposal. Some witnesses wanted the Committee to delay decisions on this issue. There should be no delay, nor should there be a rush. This is a very important piece of legislation, and you need to get it right, less it results in unexpected and/or un-desired outcomes. You are doing it right, giving the bill a thorough and fair hearing in a timely fashion.

I will now offer a few specific comments on the bill. You've heard lots of testimony supporting the 20-20 tax and exploration/development incentive split, and the arguments in favor of these provisions have been articulated very thoroughly and clearly, and I certainly cannot embellish on them, so I won't even attempt to. I'll just add UltraStar's strong support for the positions of the existing producers and independents and explorers on these issues.

John Winther testified to the Joint House and Senate Committee hearing last Saturday, echoing UltraStar's support for the 20/20 provisions, and the \$73 million deduction allowance in the bill. Since then, we've learned that the \$73 million allowance, granted to all companies in Alaska regardless of the size of their cash flow streams, may be a difficult pill for you and your colleagues to swallow. Thus, you may want to eliminate it from the bill. I encourage you not to jettison it entirely, but consider an alternative that will provide incentives for exploration and development of smaller fields.

It's generally agreed that the big Prudhoe Bay and Kuparuk sized fields have been found. The big structures have been drilled, and what remains are 10-100 million barrel accumulations. These are modest by North Slope standards, but can add up to significant amounts of oil and related economic activity. The stock market rewards reserve replacement. The current producers are huge, publicly traded companies that have become so large that their reserve replacement needs cannot be met by chasing small satellites on the North Slope. For instance, ExxonMobil produces 20 million barrels in 10 days. We'd do jumping jacks in downtown Juneau if we found that much oil on our leases.

But smaller accumulations can be attractive to small independents like us, provided the right incentives. Rather than the \$73 million allowance for all companies, I suggest you consider establishing a ceiling above which larger companies would not get the \$73 million allowance, and below which smaller companies would. There is precedent for this in the "Charter for Development", a 1999 agreement between the State, BP and ConocoPhillips that made the combination of ARCO and BP possible. There are many provisions in the Charter, but one of them requires BP and ConocoPhillips to give preferential treatment to small producers, called "qualified producers". The Charter defines qualified producers as those with worldwide assets of less than \$1 billion dollars, and establishes 5000 barrels per day as a maximum amount of crude oil that a qualified producer can produce to receive the preferential treatment. I realize that the provisions of the Charter were developed for a different purpose, but certainly it distinguished between "little guys", and "big guys", and established a maximum production level for which the benefits apply. Whether \$1 billion dollars or 5000 barrels per day are the appropriate ceilings for the PPT is subject to more debate, but such a two-tiered approach will accomplish what I believe you want: to provide incentive for entry by small newcomers without giving a subsidy to the established players. Please don't throw the baby out with the bathwater by eliminating the \$73 million allowance altogether.

My last issue is pretty specific, but could be significant for small independents. It regards the exclusion of "amounts paid for purposes of indemnification." on line 15 of page 14 of the bill. Small independents like UltraStar will need to indemnify facility owners and operators who will process our oil through their facilities. We will need to purchase real, third party, arms length insurance to satisfy these requirements. We will also need insurance to meet the bonding and financial responsibility requirements of the Departments of Natural Resources and Environmental Conservation, and the Alaska Oil and Gas Conservation Commission. Depending upon the circumstances, membership in an oil spill clean up cooperative may also be required. All these costs can broadly be characterized as costs for the purposes of indemnification, and could arguably be excluded when direct costs are calculated, as defined at line 21 on page 13.

Nearly 15 percent of the cost of the Winstar exploration well at Oliktok Point in 2003 was for insurance premiums, so these indemnification costs can be

significant for the little guy, and should clearly be deductible to determine direct costs. In his letter transmitting this legislation to this committee, the Governor said that a number of indirect costs are listed in the bill, and are to be excluded from the calculation of direct costs. Indemnification is one of the indirect costs listed. Trust me, Mr. Chairman, there was nothing indirect about the \$370,000 check I wrote for the insurance premium on our last well. The money went directly from our bank account into theirs. I urge you to clarify your intent on this issue, and allow real, invoice supported, arms length indemnification costs to be included.

Thanks for the opportunity to testify at this important proceeding.

James D. Weeks  
Managing Member  
UltraStar Exploration LLC  
907-258-2969

**Testimony of James D. Weeks  
On CS for SB 305  
Oil and Gas Production Tax  
Alaska State Senate Resources Committee**

20 March, 2006

Mr. Chairman, distinguished members of the Senate Resources Committee. My name is Jim Weeks, and I am here today representing UltraStar Exploration LLC, based in Anchorage, with offices at 3111 C Street, Suite 500. Thanks for the opportunity to testify on this important legislation again.

I want to make a few brief comments on the Committee Substitute: I've seen two options being proposed to replace the \$73 million allowance. UltraStar prefers Option 2, which eliminates the \$40/barrel oil price ceiling above which the exemption would not apply. It seems that if the legislature is willing to grant a 10,220,000 barrel per new field exemption, then it shouldn't matter how fast that exemption is recovered, and sooner is better than later for industry. I also hear that the Committee may be considering an increase of the 4000 barrels per day to 5000, and lifting the total of the exemptions to a corresponding 12,775,000 barrels. This is more consistent with the Administration's initial proposal, and is a change I encourage you to make.

I question the need for a 7 year time limit after which the tax exemption will expire. Again, it seems if you're willing to grant a 10 or 13 million barrel exemption, then there is no need for a time limit, and we recommend that it be deleted. Industry will do everything economically feasible to use up the exemption as soon as possible, but well productivity and conservation issues may not allow for that to be the case in all instances.

Both options to replace the \$73 million allowance name the Alaska Oil and Gas Conservation Commission (AOGCC) as being the "referee" to resolve disputes about what constitutes an oil and gas field or unit. We agree with the selection of the AOGCC for this role, but recommend you clarify your intent regarding eligibility for the 4000 barrels per day exemption described in the first three lines of Section 21(i). In addition to providing incentives and tax exemptions for the drilling of new field wildcats, if the Committee wants every company, large and small, current producer, or wannabes like us, to be poking around the fringes of existing reservoirs, as well as looking deeper and shallower within the boundaries of existing units; then I suggest the following:

When the PPT becomes effective, establish a "ring fence" around existing, producing units. Current production from these units would not receive the 4000 barrel per day exemption. If peripheral drilling outside of that ring fence confirms commercial hydrocarbons and justifies unit expansions, then those expanded

areas should be eligible for the tax exemptions and exploration and development credits contemplated in CSSB 305. Deeper and shallower accumulations, drilled within existing units after July 1, 2006, should also be eligible. If the current producing unit owners receive a 4000 barrel per day exemption on current production, which means very little to them, they have will no additional incentive to push the envelope. If however, the exemption applies only to new production within an existing or expanded unit, it provides a meaningful incentive.

Lastly, I'd like to register my support of Dr. Van Meurs "Two for One System" that he summarized on March 18.

Thanks for the opportunity to testify at this important proceeding.

James D. Weeks  
Managing Member  
UltraStar Exploration LLC  
907-258-2969

LEG. / GOV.  
CONSULTANTS

4-9-06

**Further Discussion  
of  
Senate Bill 305 and House Bill 488**

**Daniel Johnstons Testimony**

**Juneau, Alaska  
9 April, 2006**

**Daniel Johnston & Co., Inc.  
[www.danieljohnston.com](http://www.danieljohnston.com)  
60 Shady Lane  
Hancock, NH 03449**

## **Where do we stand today?**

### **Oil Industry threatens:**

- (1) That Investment will dry up with the 25/20% proposal and a progressive feature.**
- (2) Alaska reputation will be seriously harmed**
- (3) There may be no Gas Pipeline**
- (4) Philanthropic donations are at risk (ConocoPhillips)**

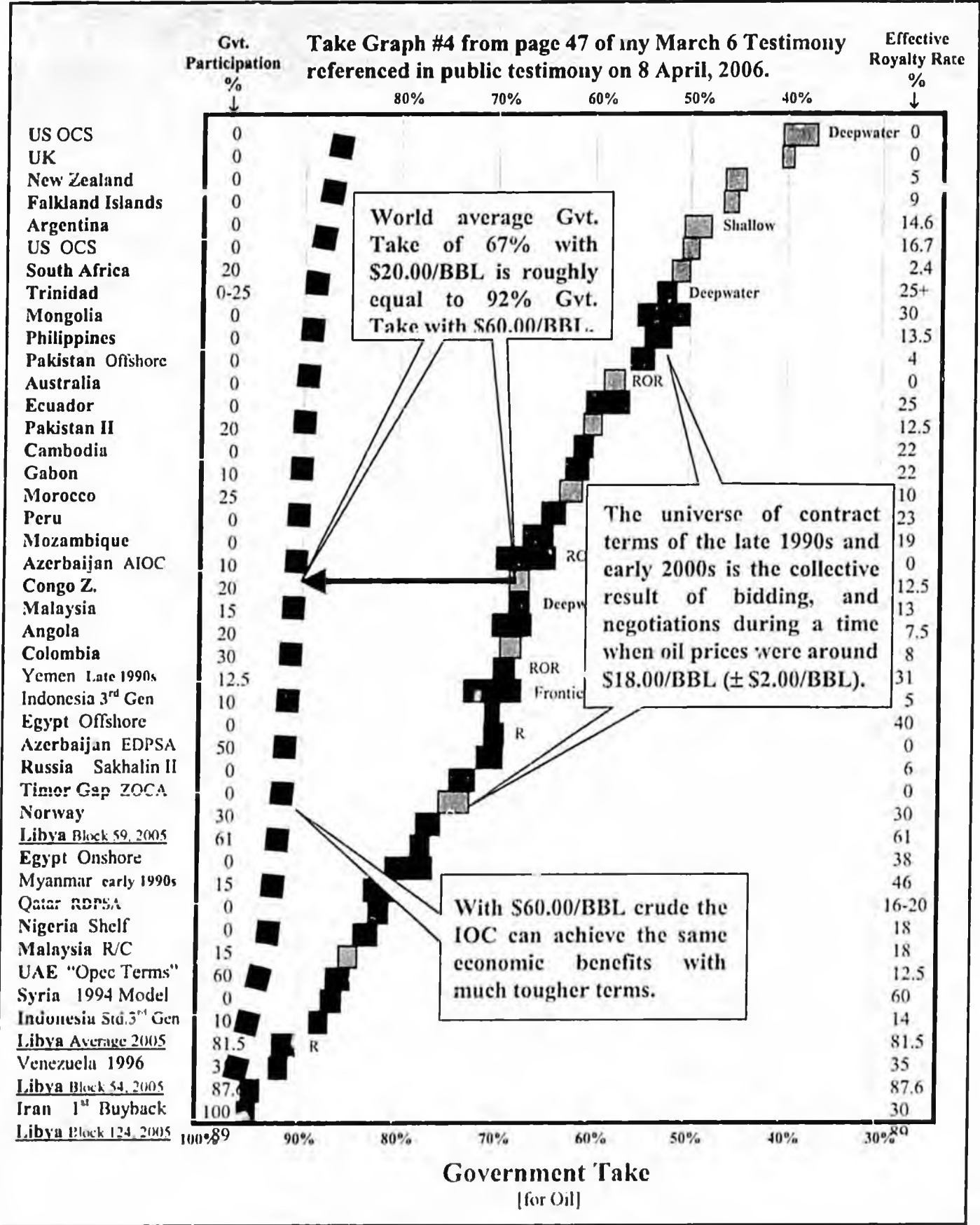
### **Oil Industry has lobbied hard with every means available**

**(Can't blame them, but . . .)**

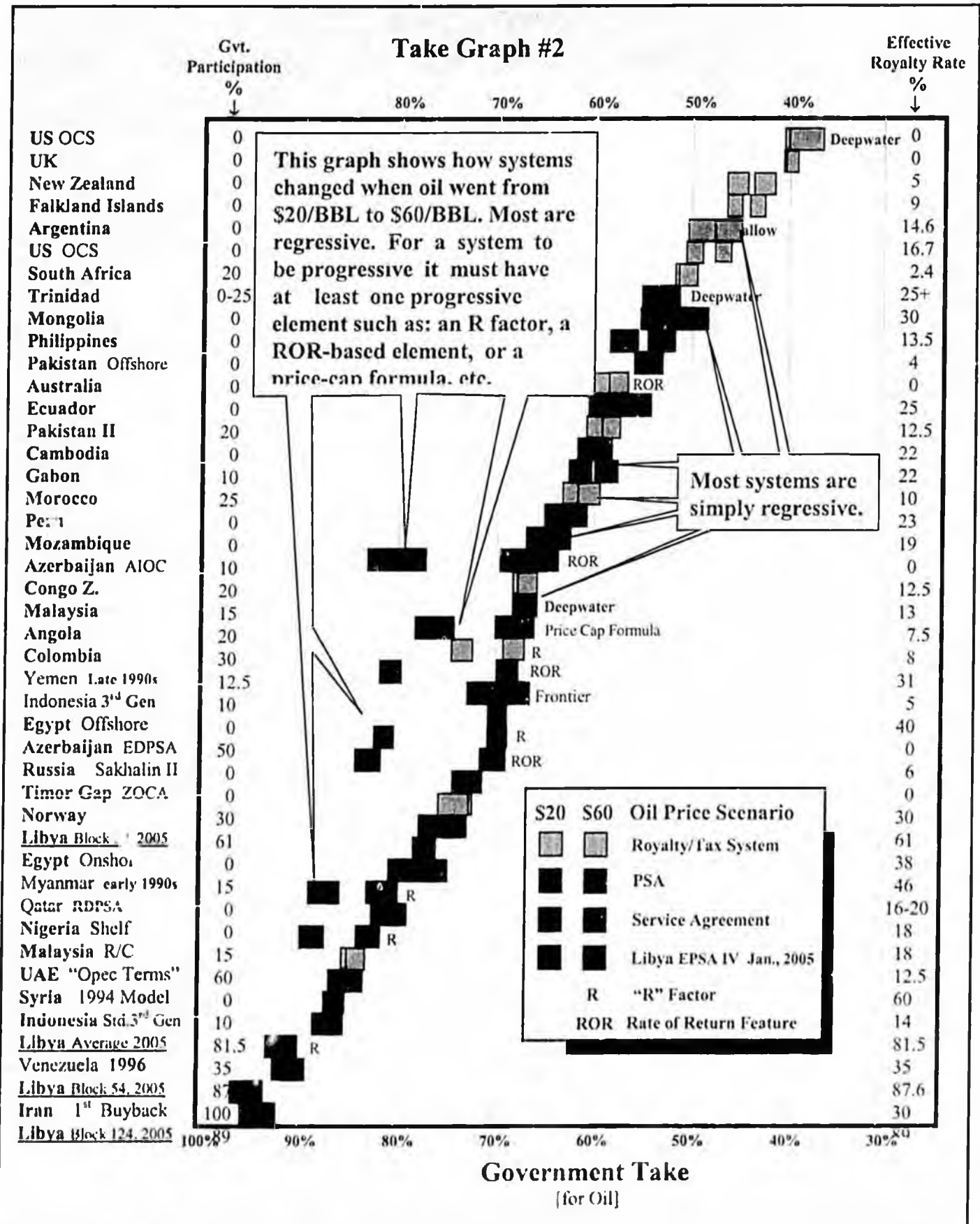
**I still have problems with some of the Peer Groups we keep getting compared to.**

Who really thinks comparing Alaska to the likes of Kansas or Colorado is reasonable?

Russia provides some good analogs: both with PSAs as well as the Royalty/Tax arrangements there: very tough terms.



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



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

<http://news.morningstar.com/news/DJ/M04/D04/200604040854DOWJONESD.JONLINE000295.html?Cat=Energy>

04-04-06 08:45 AM EST

Beijing -(Dow Jones)- China's Ministry of Finance Tuesday issued rates for a newly implemented windfall profit tax on crude oil that is sold above US\$40 a barrel in the country.

"(The tax is aimed at) pushing forward the reform on oil price mechanism and promoting continuous, healthy and coordinated development of the national economy," the ministry said on its Web site.

In late-March, the National Development and Reform Commission, China's top economic planning agency, said it was immediately implementing a windfall profit tax on domestic crude oil sales, but didn't disclose the tax rate.

The tax took effect on March 26 and the tax rate ranges from 20% to 40% of the amount that companies get above US\$40.

The tax applies to enterprises and joint-venture companies that produce and sell oil onshore and offshore China, the ministry said.

Income generated from the windfall tax will be included in the central government's budget management, and taxes will be collected by the MOF.

*The tax will be calculated monthly and should be paid quarterly, the ministry said, adding that since the tax is regarded as a company cost, it can be deducted before income tax.*

Below is a table of the tax rates

<u>Crude Oil Selling Price (US\$ per Barrel)</u>	<u>Tax Rate On Portion Of Price Above US\$40</u>
40-45 inclusive	20%
45-50 inclusive	25%
50-55 inclusive	30%
55-60 inclusive	35%
above 60	40%

-Zheng Kiaolu contributed to this story. Dow Jones Newswires; 8610 6588-5848;  
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Edited by Tracy Gan

## **Comments of Dr. Juan Carlos Boué**

The following selected quotes come from Chapter 11 of an upcoming book by Dr. Juan Carlos Boué of Oxford University in the UK. I sincerely appreciate the insights from Dr. Boué and his permission to quote him as extensively as I have here. My commentary is confined to sections within brackets [such as these] to preface or expand on quotes from Dr. Boué's work. I would like to take this opportunity to publicly thank Dr. Boué for his concern and for his insights. DJ

The following quotes are from:

### **A QUESTION OF RIGS, OF RULES, OR OF RIGGING THE RULES? UNDERSTANDING THE PROFITABILITY AND PROSPECTS OF UPSTREAM OIL ACTIVITIES IN THE OFFSHORE US GULF OF MEXICO.**

Copyright Oxford Institute for Energy Studies 2006. Juan Carlos Boué

### **11 CONCLUSIONS: WHAT SHOULD THE WORLD LEARN FROM THE SUCCESS STORY OF THE DEEPWATER GOM?**

[The first of Dr. Boué's quotes regarding "basin masters" comes from a McKinsey Company study by; Conn, C., and White D., 1994, Revolution in Upstream Oil and Gas - Strategies for growth beyond 2000; McKinsey & Company, Australia. DJ]

#### **"11.1 Basin Mastery: Adding Value in Global E&P Activities**

McKinsey gave the name "basin masters" to those companies that managed to build dominant acreage and logistical positions in difficult new plays, partly because of their skills at resource development, technology and integrated project management but chiefly by virtue of their stealing a march on competitors in remote areas where scale and infrastructure were of paramount importance. [pg 334-335]

The cornerstone of this type of control [as basin master] is their dominant position in early infrastructure corridors (often over-built, with a view towards future discoveries), which allows the basin masters to extract rents from other players through access charges to this infrastructure. Frequently, this is bolstered by cosy relationships with governments, licensing agencies and NOC partners (the latter in provinces where PSA's [production sharing agreements] prevail), all of which tend to complicate the lives of potential competitors (through the appearance of bureaucratic and other, less wholesome, type of barriers) while simplifying the lives of incumbents (cast as they are in the enviable role of 'operator of choice' for licensing agencies). In this way, basin masters can ensure that they will be able to capture the majority of the value in a given province, including that generated from operations in fields not discovered by themselves. [pg 336]

Basin mastery may translate into very comfortable lives for a few bureaucrats and politicians in key positions in the governments of certain countries. However, for these governments as a whole (and even more so for the populations they represent), basin mastery effectively means stunted competition for acreage and consequently lower acreage process, higher upstream entry barriers, a high degree of fiscal dependence on very few operators . . . [pg 339]

“Furthermore, during subsequent years [subsequent to 1998], the magnitude of oil company [share] buybacks [around \$20 Billion per year or so] and cash holdings has made it painfully clear that these companies always had far more funds available for investment than attractive prospects to plough them into. The way in which domestic Russian firms succeeded in ensconcing themselves in the driving seat in their country, largely marginalizing international oil companies from Western Siberia, has made the dearth of attractive investment opportunities for the latter even more conspicuous.” [pg 346]

### 11.3 The Issue of Tax Breaks

A landmark study commissioned by the Wyoming legislature (prompted in large part by a fiscal crunch in that US state, whose fiscal dependence towards oil income is second only to Alaska's) found that, *over a forty year period*, a once-and-for-all drop of 2 per cent in the state's severance tax rate would increase total oil recovery by less than one percent (50 MMBOE) and employment by 300 persons (i.e. 7.5 jobs *per year*), while causing a 17 percent reduction in the present value of severance tax collections. In contrast a doubling of the state severance tax (from 4 to 8 per cent) was found to reduce ultimate recovery by around 6 per cent, while increasing tax revenue, in present value terms, by over ninety per cent.<sup>35</sup> [pg 347]

[Footnote 35 is as follows: “Gerking *et al.* 2000. These conclusions had been foreshadowed by GAO 1990. This study found that some petroleum production incentives actually “provided incentives to make petroleum production investments that have pretax returns below those of investments in other industries” (p. 5). An even earlier GAO study 1985b: 32) had found that a 40 per cent reduction in Windfall Profit Tax for EOR projects had led to only one GOM project.”]

#### [The UK]

Likewise, the resurgence of UK North Sea output after what is seen to be its production peak in the mid-1980s is often put forward as a prime example of the power of more flexible taxation schemes to coax higher output from maturing fields.<sup>36</sup> A study focusing on this issue concluded that, out of a total production of 2,676 MMBD in 1995, only about 355 MBD would not have been produced without the modifications to the British fiscal regime introduced from 1983 onwards.<sup>37</sup> [pg 347]

[Footnotes 36 and 37 are as follows: “36 Production of liquid hydrocarbons in the UK peaked (for a second time) in 1999 at 2.82 MMBD, after having languished at 1.88 MMBD during 1988-89. 37 Martin 1997: ii-iv”]

## BP Graph of Production vs. Tax Rate

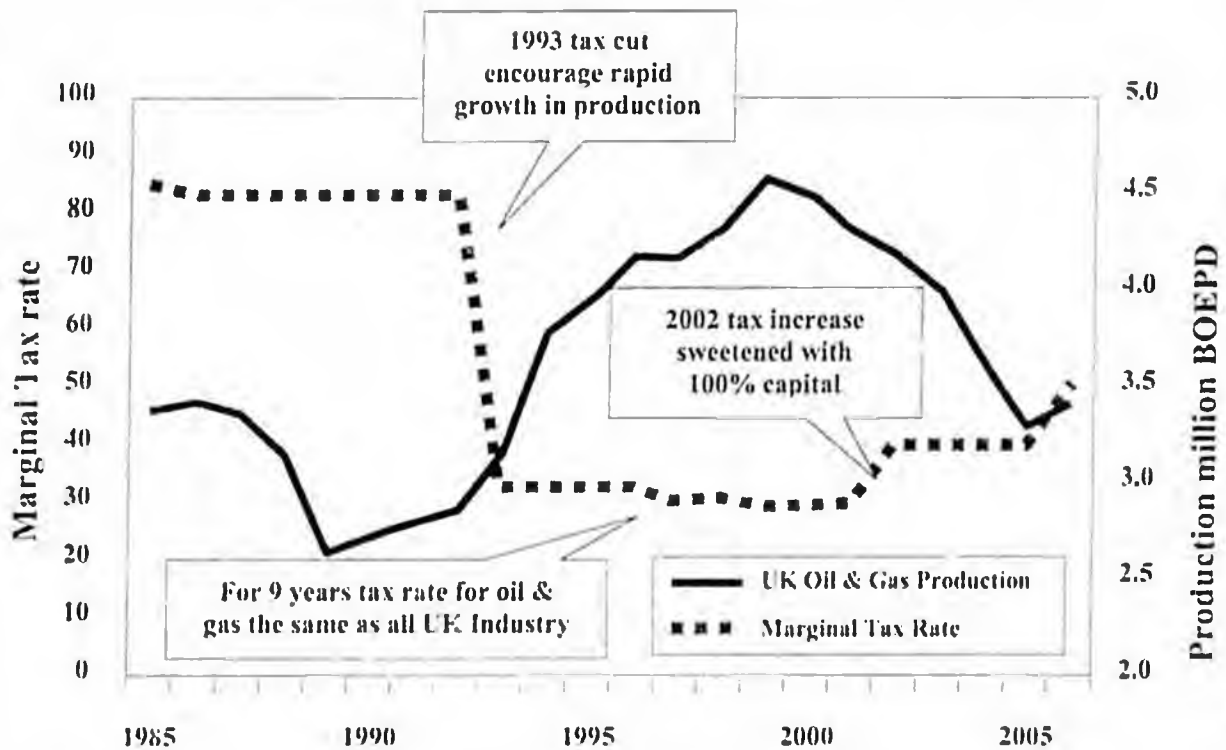
The graph below is not a fair representation of what the result of lowering the tax rate in 1993 was. In fact exploration expenditures went down significantly in 1994 and development expenditures did not go up (see following page). They went down but not as dramatically as exploration expenditures.

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

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

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

... But lowering tax rates will encourage investment



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

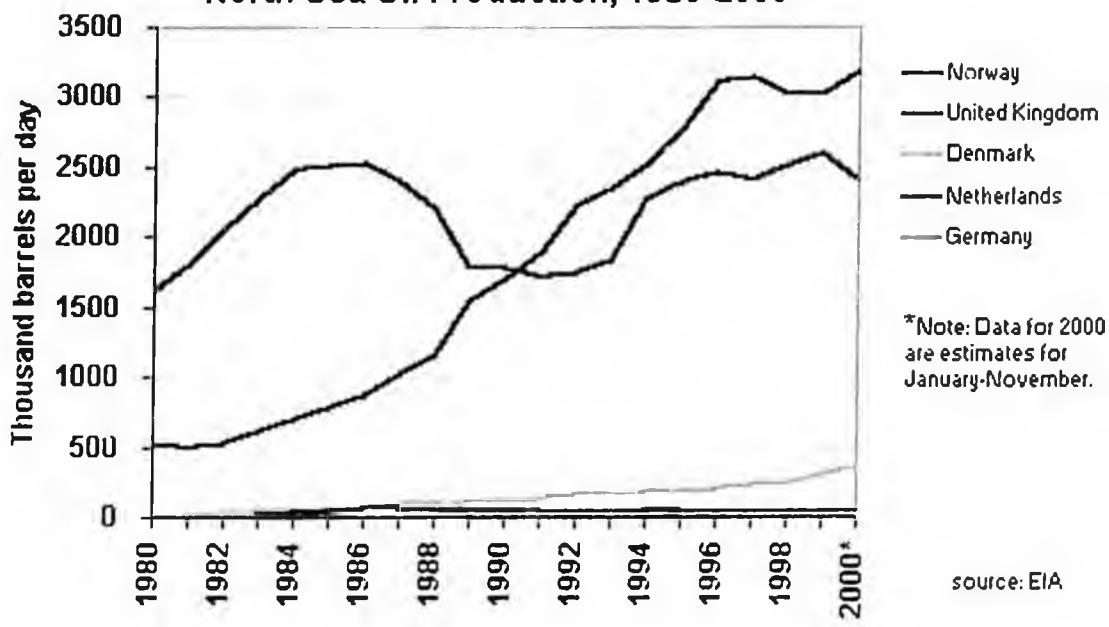
### UK Drilling Activity History — Wells Drilled per year

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

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

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

North Sea Oil Production, 1980-2000\*



\*Note: Data for 2000 are estimates for January-November.

source: EIA

## BP Fields Brought on-stream after 1993

Andrew, Harding, Foinaven, Schiehallion, and ETAP (Eastern Trough Area Project includes 7 fields in the Central North Sea).

BP fields brought on-stream after 1993						
	Recoverable Reserves		Discovery Date	Start-up Date	Production 2000 MBOPD	
	MMBBL S	TCF				
Andrew	160	0.25	6/1974	6/1996	50	
Harding	219	0.27	1/1988	4/1996	87	
Foinaven	362	0.22	10/1992	1/1997	92	
Schiehallion	±300		10/1993	1/1998	100	
ETAP	450	1.1				

## Norwegian Development Activity

### Development Activity Investment

---

5 years <u>Before</u> 1993 (1988-1992 inclusive)	NKr 134,251 MM	\$ 20,340 MM	
5 years <u>After</u> 1993 (1994-1998 inclusive)	NKr 205,730 MM	\$ 31,170 MM	+ 53%

## Norwegian Exploration Activity

### Exploration Activity Investment

---

5 years <u>Before</u> 1993 (1988-1992 inclusive)	NKr 30,112 MM	\$ 4,560 MM	
5 years <u>After</u> 1993 (1994-1998 inclusive)	NKr 30,978 MM	\$ 4,694 MM	+ 3%

(Assumed exchange rate = NKr 6.6/US\$ 1)

## North Sea oil and gas

### The long goodbye

March 16<sup>th</sup> 2006 ABERDEEN

From The Economist print edition

### High oil prices have helped slow the North Sea's decline. Government flip-flopping could accelerate it again

NOBODY disputes that Britain's part of the North Sea is past its prime. Oil and gas production peaked at 4.5m barrels a day in 1999 and has fallen steadily ever since, to 3.3m now (see chart). Yet in Aberdeen, Britain's main oil town, talk of an old "province" in decline is not tolerated. "The North Sea is enjoying a vibrant middle age," insists one oilman. "I think I'd describe it as mature rather than declining," muses another. Indeed, most of the industry's problems seem to be the sort associated with a boom, not a bust. Oil bosses complain about a shortage of skilled labour and the astronomical price of rig rentals, which have doubled since 2003.

A combination of high oil prices and some new government policies have made it profitable to keep working in what is an increasingly difficult and expensive place to drill for oil and gas. Investment has risen by 30% this year, and more exploration and appraisal wells are being drilled than at any time since 1997. The UK Offshore Operators Association (UKOOA), a trade body, thinks that the rate of decline will slow markedly next year. By 2007, production should be slightly higher than last year.

That will be music to the ears of a government determined that the North Sea should still be pumping 3m barrels a day in 2010. The petrochemical wealth off Britain's eastern shores supports a quarter of a million jobs and has helped to insulate the country from the vagaries of the international oil market for decades. Were the decline to continue at historic rates, production would be all but finished in 20 years.

There is no shortage of hydrocarbons: although 34 billion barrels have been produced, some 23 billion barrels are thought to remain. But many of the big, easily accessible fields are running down, and what is left is much harder to reach. That is changing the character of the industry.

One way to keep production up is to explore the waters off northern Scotland, the Shetland Islands and the deep Atlantic to the west of Scotland, where little exploration has so far been done. Two of the biggest recent finds—Buzzaard (with around 500m barrels of oil and gas) and Lochnagar (perhaps 250m barrels)—were found off the beaten track. But developing them can be difficult. Rhum, a big gas field in the northern North Sea, was first discovered by BP in 1977, but the high pressure and temperature in the field meant that gas was not produced until December of last year. "A decade ago, a lot of this stuff would have been literally impossible to extract," says

Mike Tholen, UKOOA's economics director. "But technology has moved on."

Another option is to scrounge every last drop of oil and gas from existing fields. Finance, not geology, determines when an oil company quits a field, and it may leave behind substantial amounts of oil that are technically (but not economically) recoverable. The dregs of the big fields are often of only marginal interest to the big firms, which prefer chasing bigger and easier finds in other parts of the world such as the Gulf of Mexico or west Africa. Smaller, leaner companies are often able to pull the remaining oil out at a profit.

With all that in mind, ministers have been changing the rules to encourage smaller and more innovative firms. New licences allow companies to explore patches of ocean before they have finance arranged, and to hold on to difficult areas for six years instead of four. New rules prevent companies from sitting on unexploited discoveries for years at a time. And changes to the code of practice on access to pipelines (which are often owned by big oil companies) ensure that smaller companies can get their oil to market.

The new rules have proved popular. The latest licensing round, held in the summer of 2005, was the most successful in years. A total of 152 licences were offered to 99 companies, many of them in the frontier areas around northern Scotland and the Shetlands. A quarter of the companies were new to the North Sea.

But government can hinder as well as help, and not all its policies are so popular. The oil industry's relations with the Treasury have been poisoned by a series of sudden tax changes.

The first came in 2002, when Gordon Brown, the chancellor of the exchequer, raised the corporation tax for oil firms to 40% (most companies pay 30%). In November last year, he bumped it up to 50%. Furious oilmen accused the chancellor of risking the North Sea's future. UKOOA says that the changes create uncertainty, threatening future investment, and that they will do the most harm to the small firms that the government wants to attract. In its defence, the Treasury points to record oil company profits and insists that its only aim is "a fair deal for the taxpayer".

**"The new taxes will probably bump the North Sea a few notches down the competitiveness ladder," says Geoff Gillies, an analyst at Wood Mackenzie, an energy consultancy. "But at today's oil price, the impact on development will be minimal." The danger will come if prices start to slip, as Wood Mackenzie thinks they will do over the next few years. Kieron McFadyen, a director at Shell UK, says that if expensive oil justifies higher taxes, then cheaper oil ought to bring tax cuts to compensate.**

The death of the North Sea has been predicted many times before, points out Melfort Campbell, the head of the Scottish branch of the Confederation of British Industry. Yet technological advances have always confounded the gloom-mongers. The region will be even more dependent on innovation in its old age than it was in its youth. Most of the government's reforms reflect that. It would be a shame to see them undone by another tax grab.

## Repeal Severance Tax Breaks for Oil and Gas

By Sarah Gorin, Equality State Policy Center

June 12, 2000

Since the beginning of fiscal year 1994, the people of Wyoming have lost over \$48 million dollars in severance tax breaks granted to our state's oil and gas industry on promises of greater - or at least sustained - production and employment. A new University of Wyoming study shows these promises were empty.

Over the past 15 years, the Wyoming Legislature has approved severance tax breaks - ranging from 33% to 75% - for several categories of oil production. Since 1993, it has also enacted a 67% break for certain categories of natural gas production.

Proponents of the tax breaks asserted they would result in increased production and employment, or would help preserve existing production and jobs. But no data was ever presented to support these assertions. **They were upheld entirely by the lobbying power of the oil and gas industry and the willingness of a majority of legislators to accept the industry's assurances without evidence.**

Thanks to an effort led by Senator Cale Case (R-S25, Lander), the evidence is finally in. Case successfully amended the most recent severance tax break legislation to include funding for a study to ask: Did the tax breaks trigger the well-advertised effect?

Part of that study has just been completed and released by a team of University of Wyoming economists, and the answer for oil and gas is: No. (The remainder of the study, focusing on coal, is in progress and will be completed by year's end.)

The UW economists created a oil and gas industry model capable of predicting the effects of changing tax rates. The model showed that cutting Wyoming's oil severance tax from 6% to 4% reduces the present value of oil severance tax revenues by 14%, while generating an increase in production of less than one-half of one percent (compared to a long-term "base case" of what would likely happen without any changes).

Similarly, a percentage point increase in the tax rate would still reduce production by less than one percent, but boost oil and gas severance tax collections by 17% compared to the base case.

One of the main reasons behind the minimal effect on production is that state taxes are deductible from federal taxes. A state tax break just means the producer pays more to the federal government. Thus the Wyoming Legislature sent oil and gas revenues to Washington, D.C. instead of to Cheyenne and to Wyoming's cities, towns and counties.

Second, because severance taxes are paid on oil and gas coming out of the ground, a severance tax break provides little incentive for the exploration and drilling activities that must come first.

Wyoming needlessly sacrificed just under \$48 million in oil and gas tax revenues for fiscal years 1994-99. This amount understates the loss because it does not include prior years when the tax breaks were in place but there was no reporting.

# **PRESENTATION ON ALASKA GAS PIPELINE PROJECT**

**to Alaska State House and Senate Finance Committees  
April 5, 2006**

**Analysis of PPT**

**Barry Pulliam & Dr. Anthony Finizza**

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**econ  
ONE**

# 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

# Conclusions/Observations Regarding Oil Price Forecasts

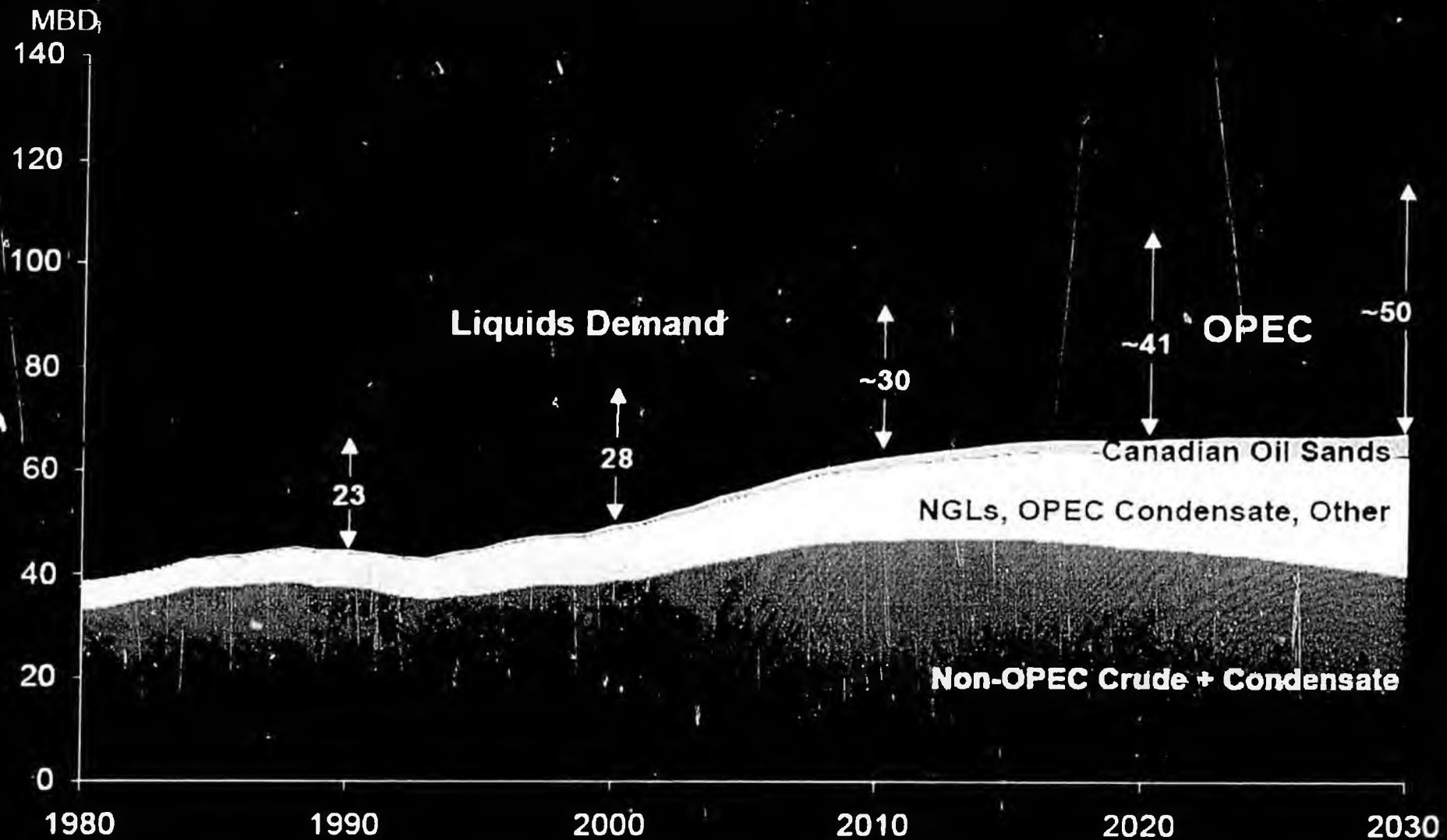
- Producers are using \$40 as a planning base case with \$30 as a stress price case. Majors may be using a slightly lower price range than independents, but are moving their views up.
  - This range may actually be lower than their best estimate, but is consistent with their “prudent” planning approach
  - 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

# 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 a \$73 Billion increase in total consumer costs per year

# ExxonMobil Outlook

## World Liquids Production Outlook



Source: ExxonMobil, *The Outlook for Energy*, December 2004

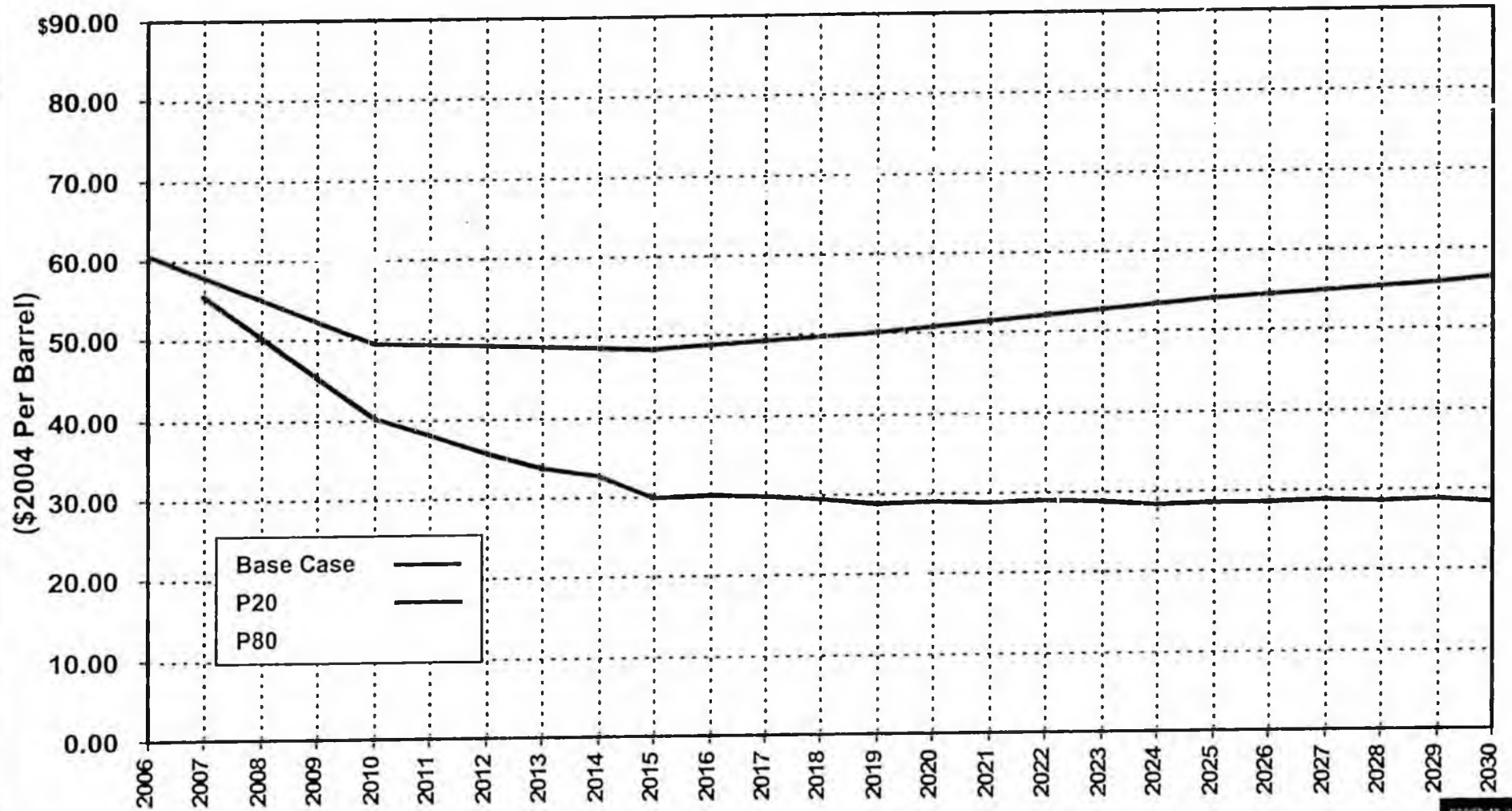


# Oil Price Forecasts

- **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

# Oil Price Outlook – EIA Annual Energy Outlook 2006

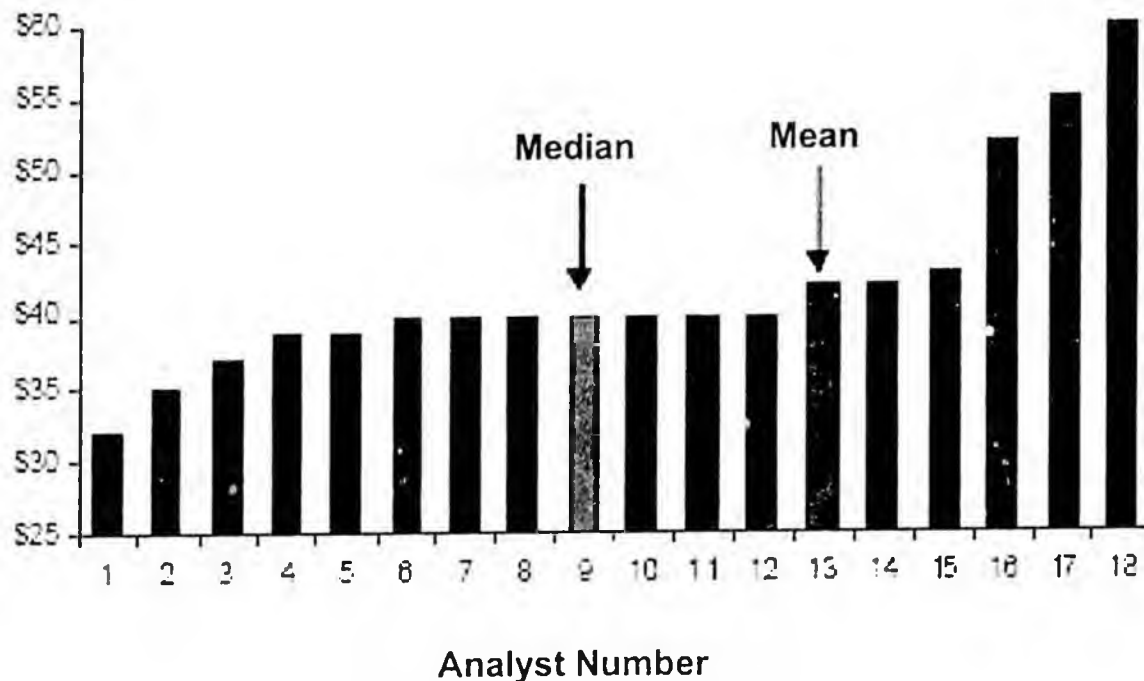
## EIA AEO 2006 WTI Crude Oil Price Forecast



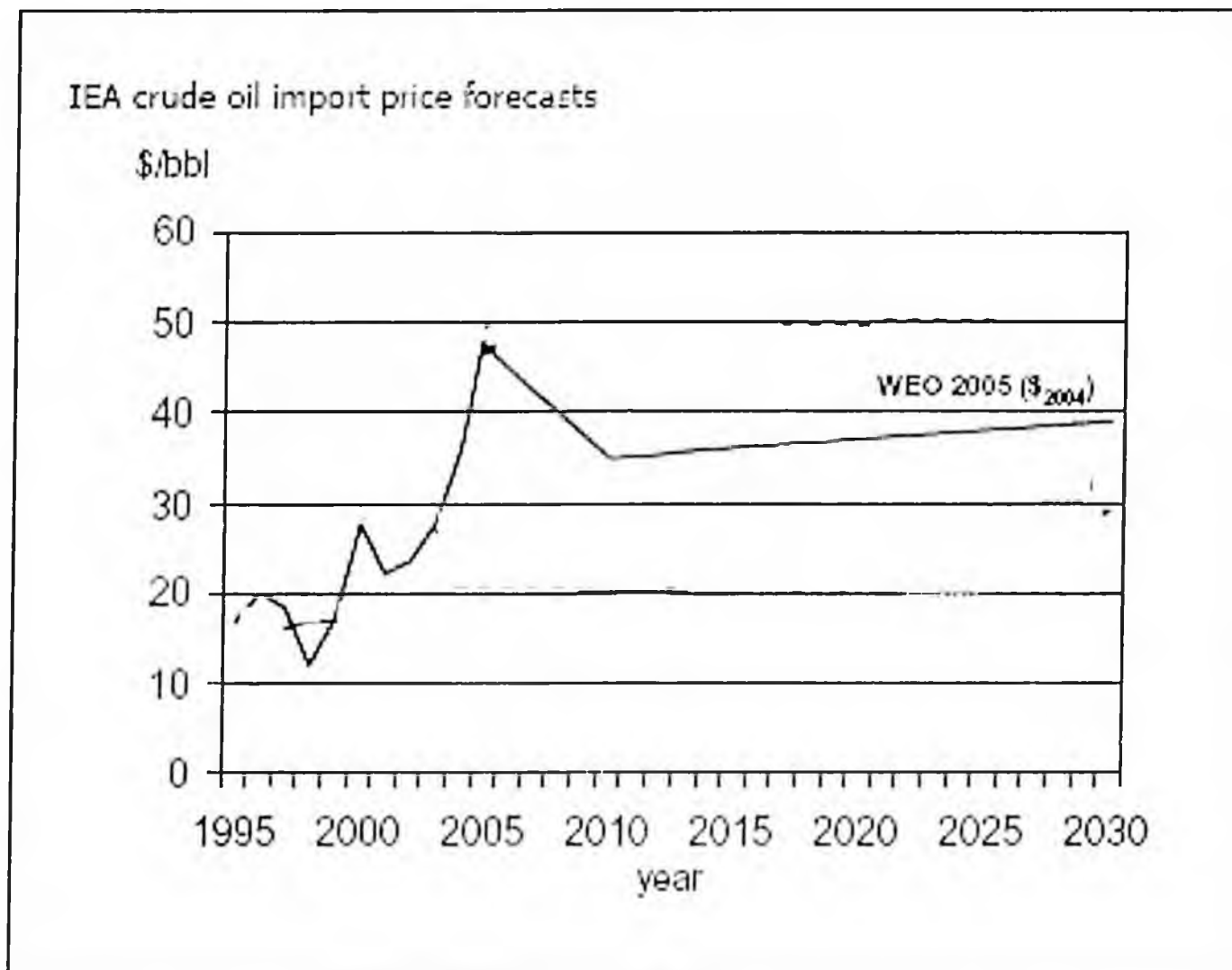
Source: AEO 2006 for Base Case; Econ One for Probabilistic Variance.

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

Price Forecast for WTI in 2010  
Reuters Poll of 18 Oil Analysts

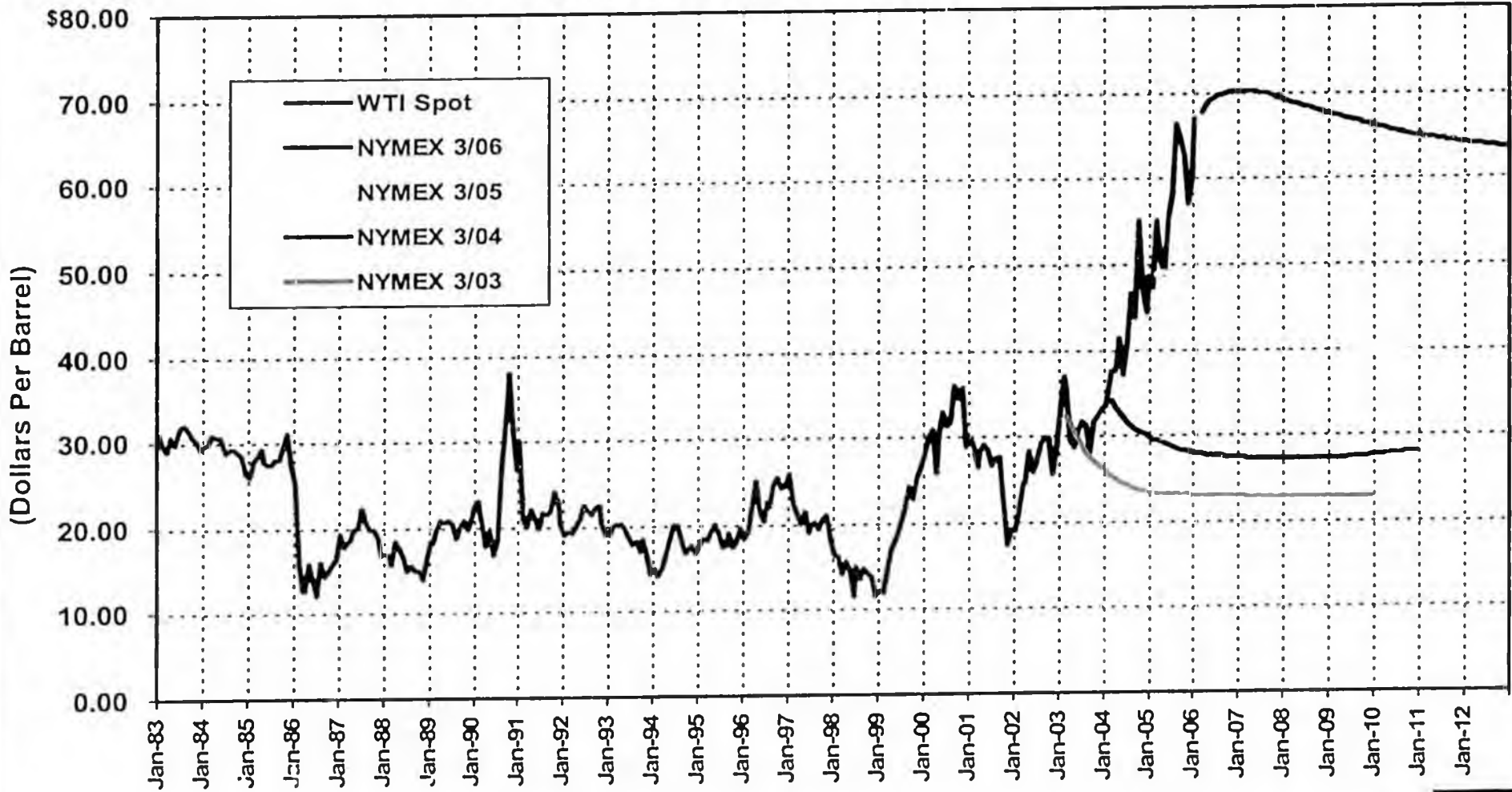


# IEA (2005) Oil Price Forecasts



# WTI Prices: History and Market Forecast

## WTI Spot With Selected NYMEX Strips



Source: NYMEX.



# 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

## Implied Oil Company Price Views

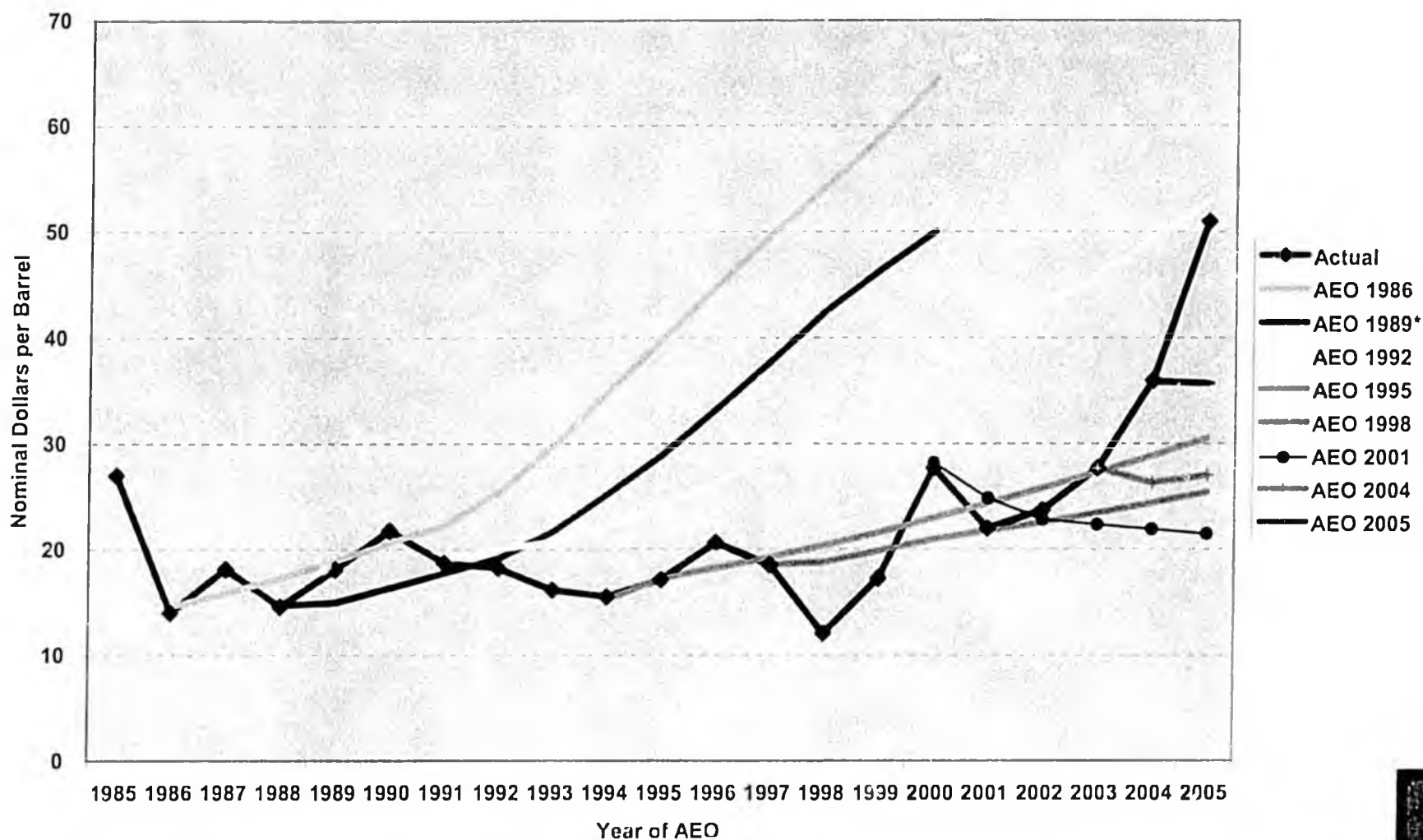
- **Marubeni acquisition (2/23/06) of Pioneer GOM assets: ~ \$40**
- **Norsk Hydro acquisition (9/19/05) of Spinnaker Exploration: ~\$35**
- **Statoil acquisition (4/28/05) of EnCana's Deepwater GOM: ~ \$30**

## Some Examples of Humbling Oil Price Forecasting

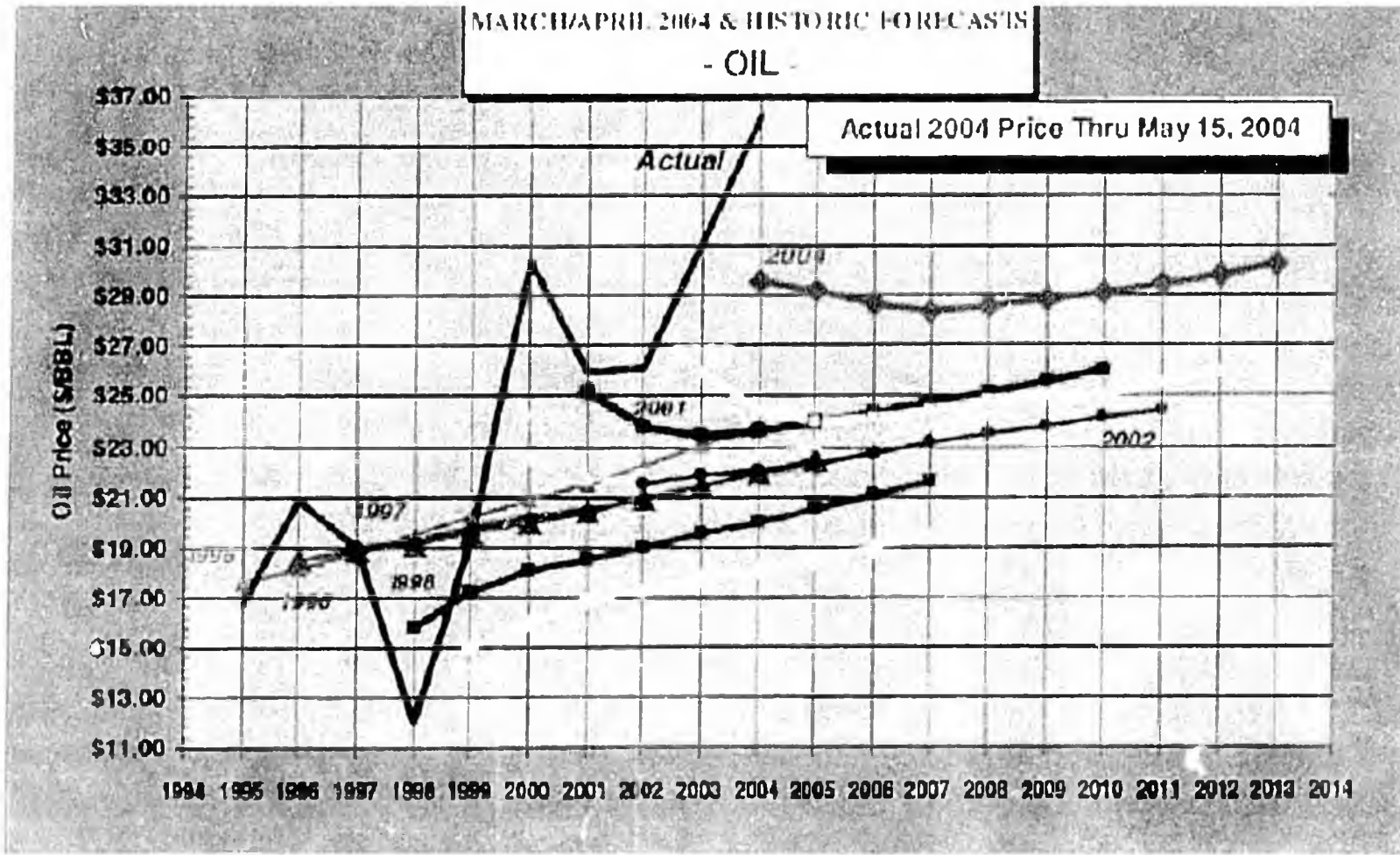
- **Energy Information Administration (US DOE)**
- **Polls of “experts” – Society of Petroleum Evaluation Engineers**

# EIA's Annual Price Outlooks

EIA's Annual Energy Outlook  
Forecast Evaluation



# SPEE Annual Delphi Poll

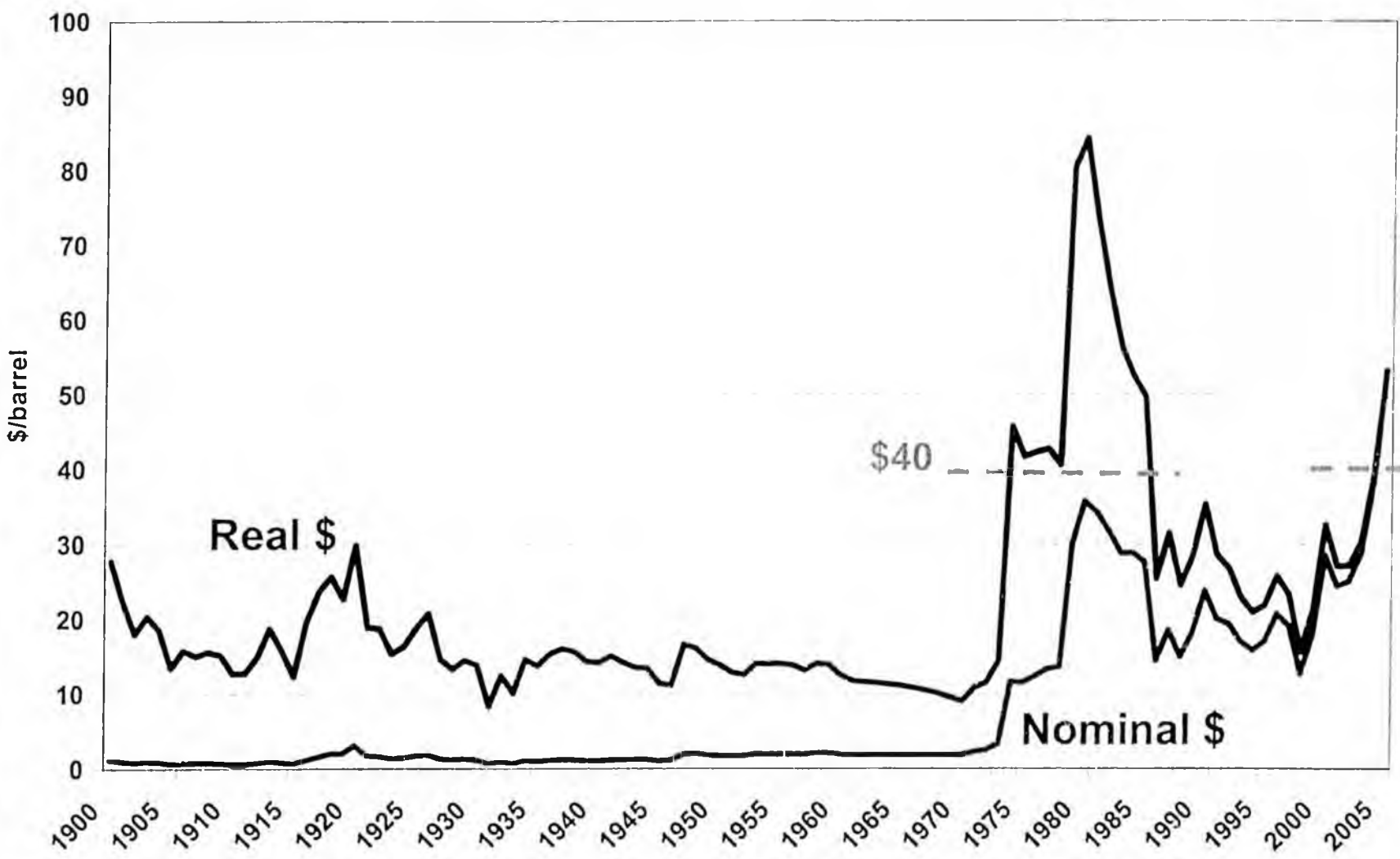


Source: Society of Petroleum Evaluation Engineers (SPEE)



# Historical Crude Oil Prices

World Crude Oil Prices

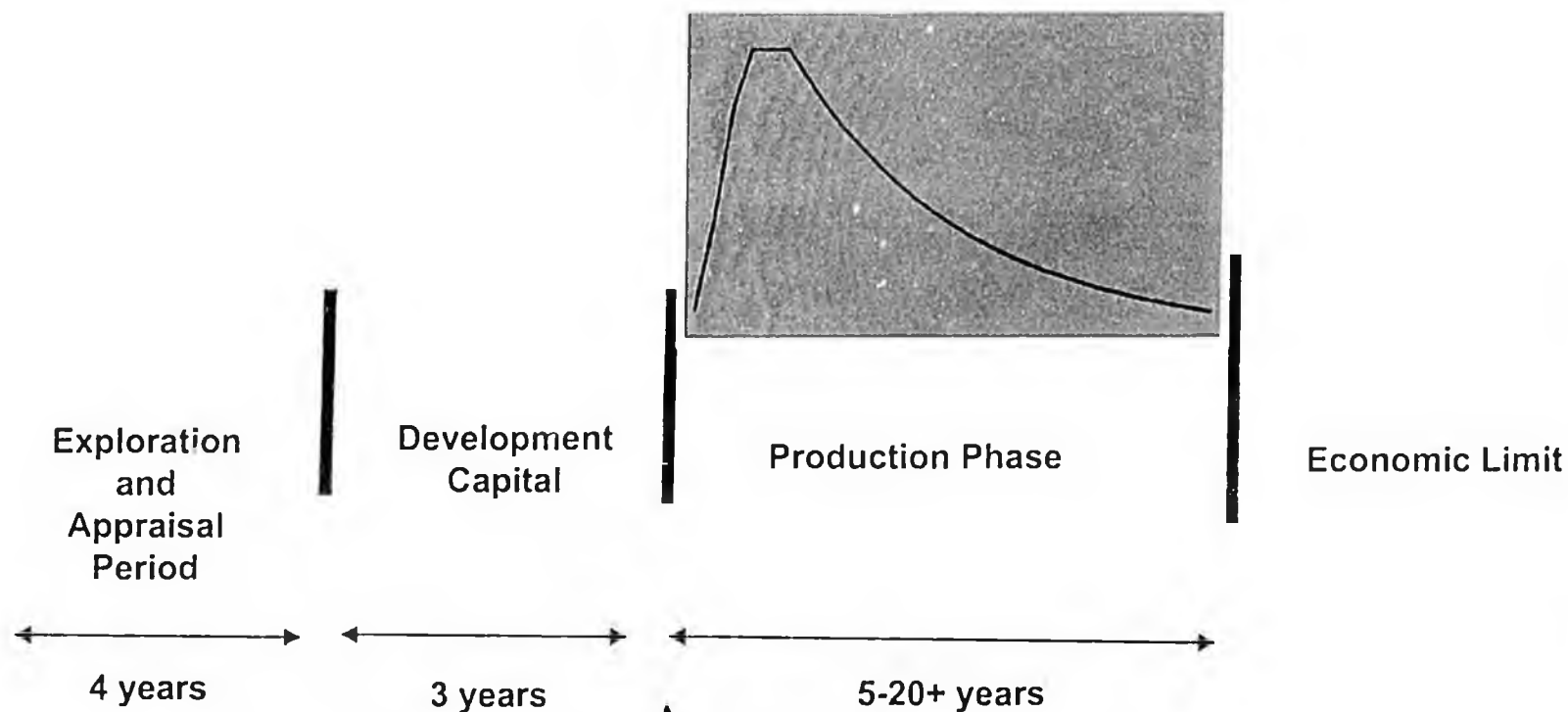


# **Economics of New Fields**

# 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, e.g. “production tax holiday”)
  - “Sunset” provision in tax free barrel allowance in Senate CS not likely to provide incentive due to long-lived exploration-production cycle
- At low prices, 20/20 and 25/20 preferred over SQ, in order to incent exploration

# Stylized Lifecycle of New Field



“Sunset” Provision in Senate CS for Tax Free Barrels  
(if New Exploration follows this pattern)

# Comparison of Reserves – Central North Slope vs. ANWR

## Undiscovered Technically Recoverable Oil Reserves

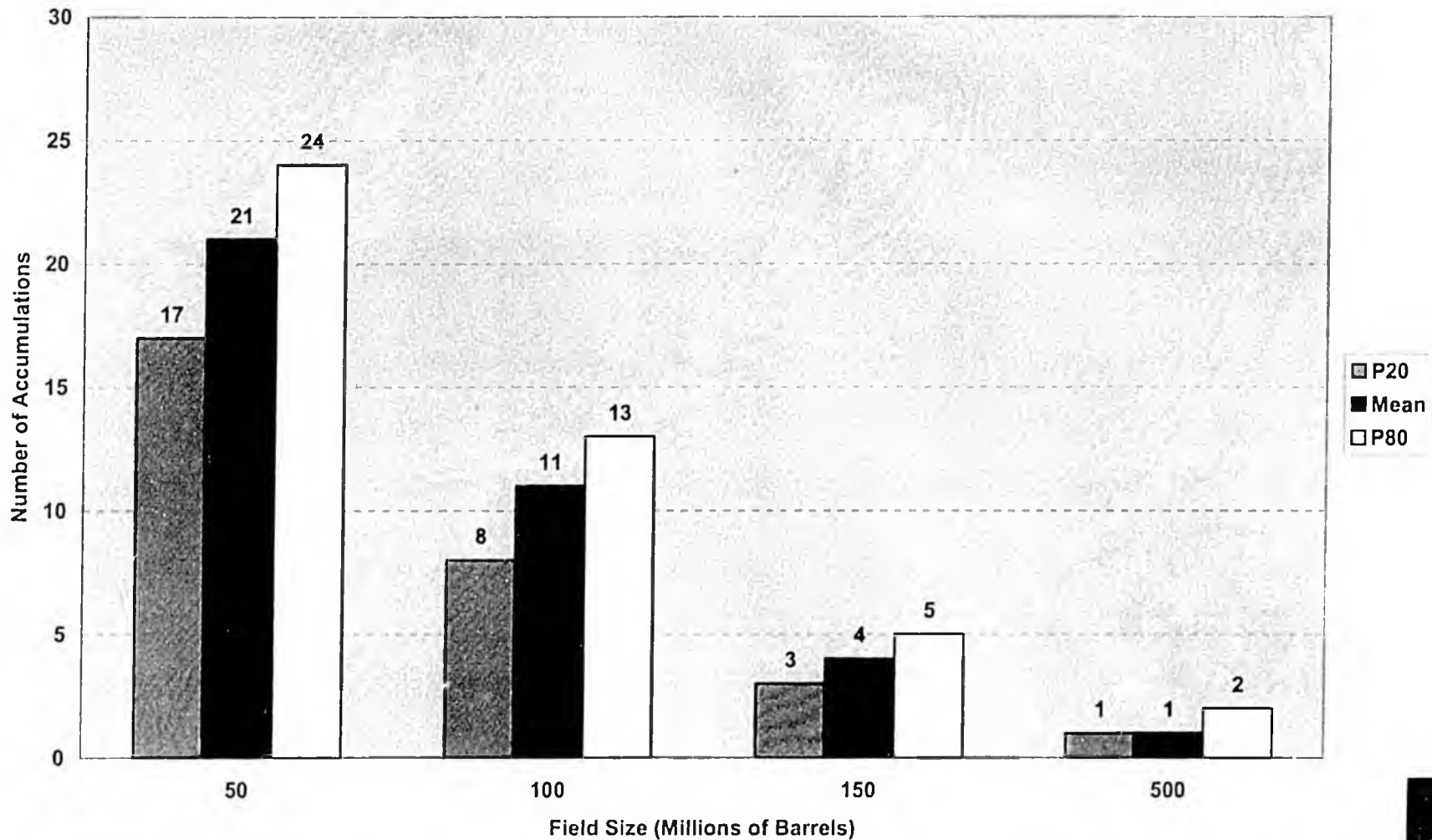
	Central North Slope	ANWR
Mean Estimate of Reserves (Billions of barrels)	4.0	10.4
Amount in Fields Over 1 B Barrels	0%	22%
Amount in Fields Over 500 M Barrels	2%	43%
Amount in Fields Smaller than 64 M Barrels	51%	1%

Note: Not all these reserves are economic

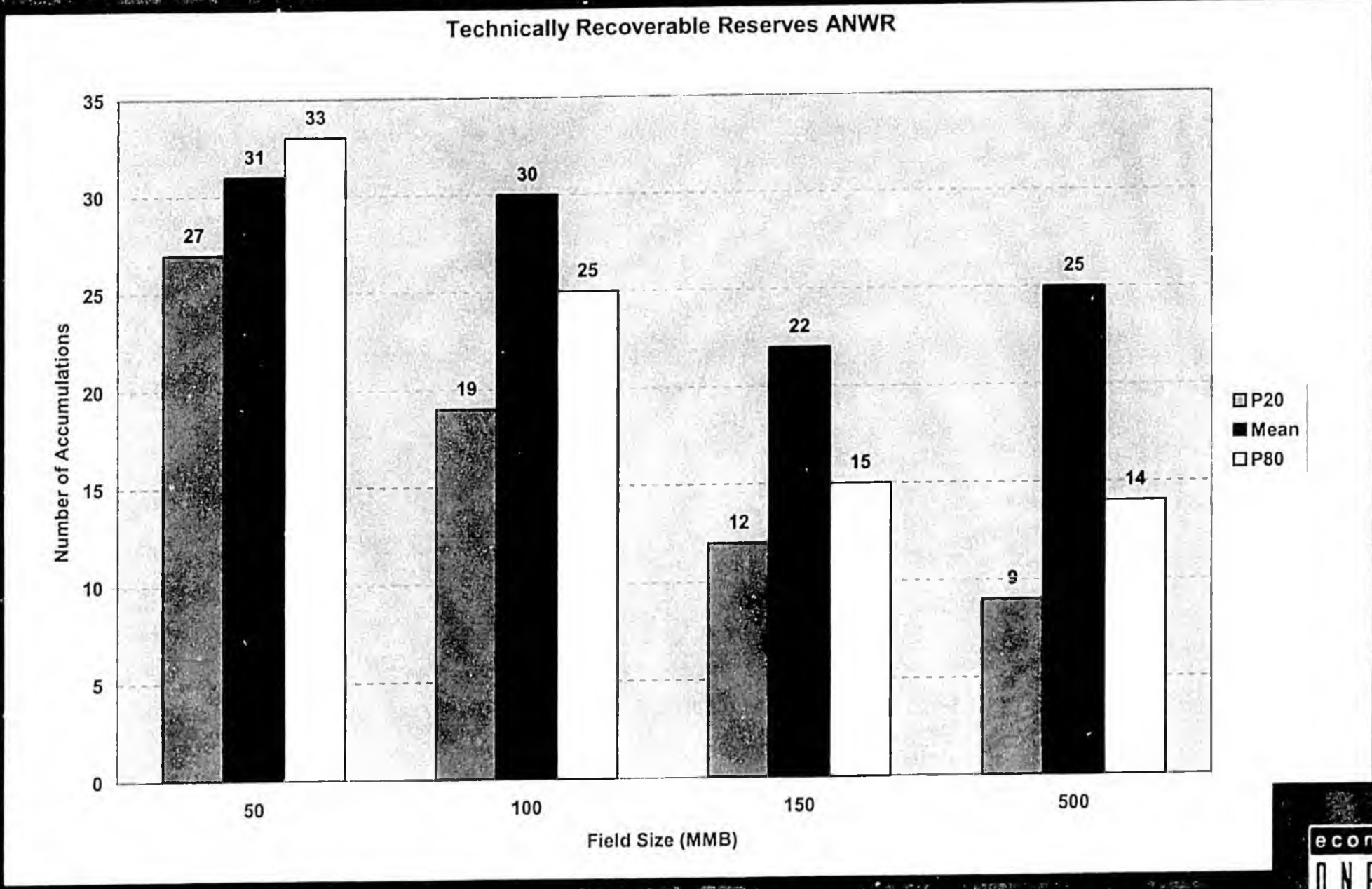
Source: USGS

# Size Distribution of Undiscovered Fields in Central North Slope

Technically Recoverable Reserves  
Central North Slope  
(no ANWR)



# Size Distribution of Undiscovered Fields – ANWR

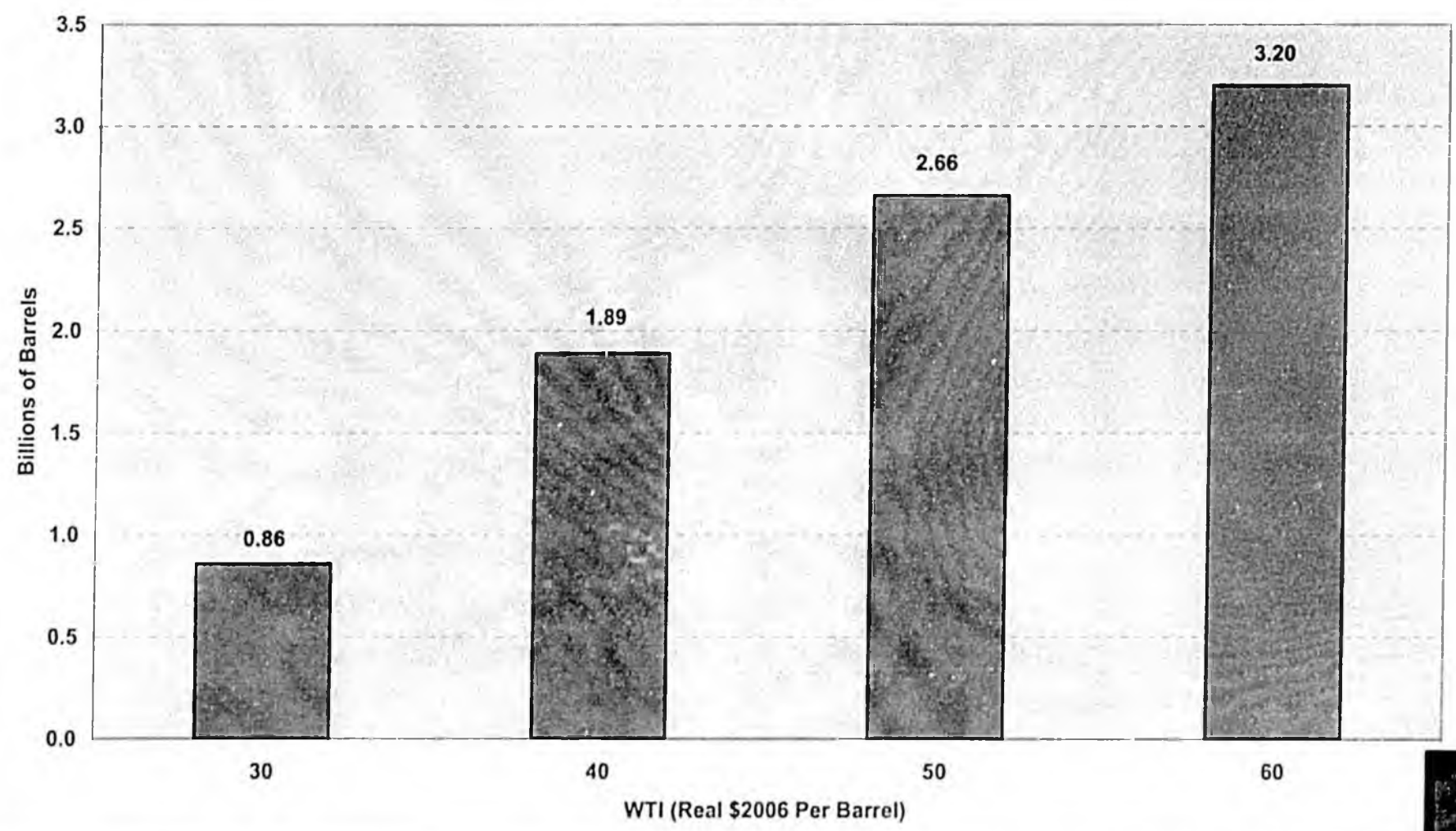


10 Billion Barrels of Technically Recoverable Oil Reserves in ANWR



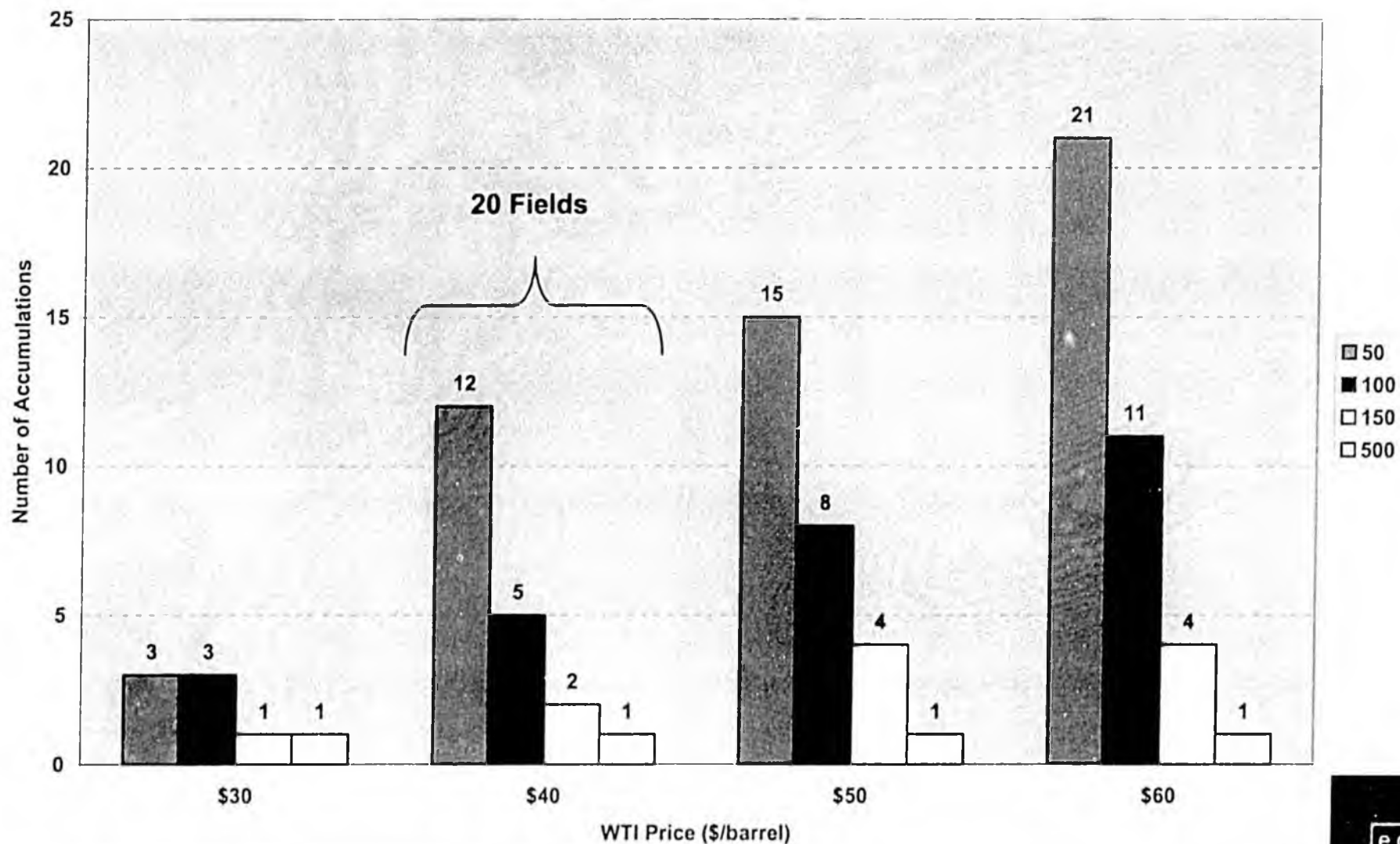
# Economic Oil Reserves in Central North Slope Alaska At Alternative Prices

Economically Recoverable Reserves  
Central North Slope  
Mean Estimate  
(No ANWR)



# Expected Discoveries Under Alternative Prices

Expected Discoveries under Alternative WTI Prices  
Central North Slope

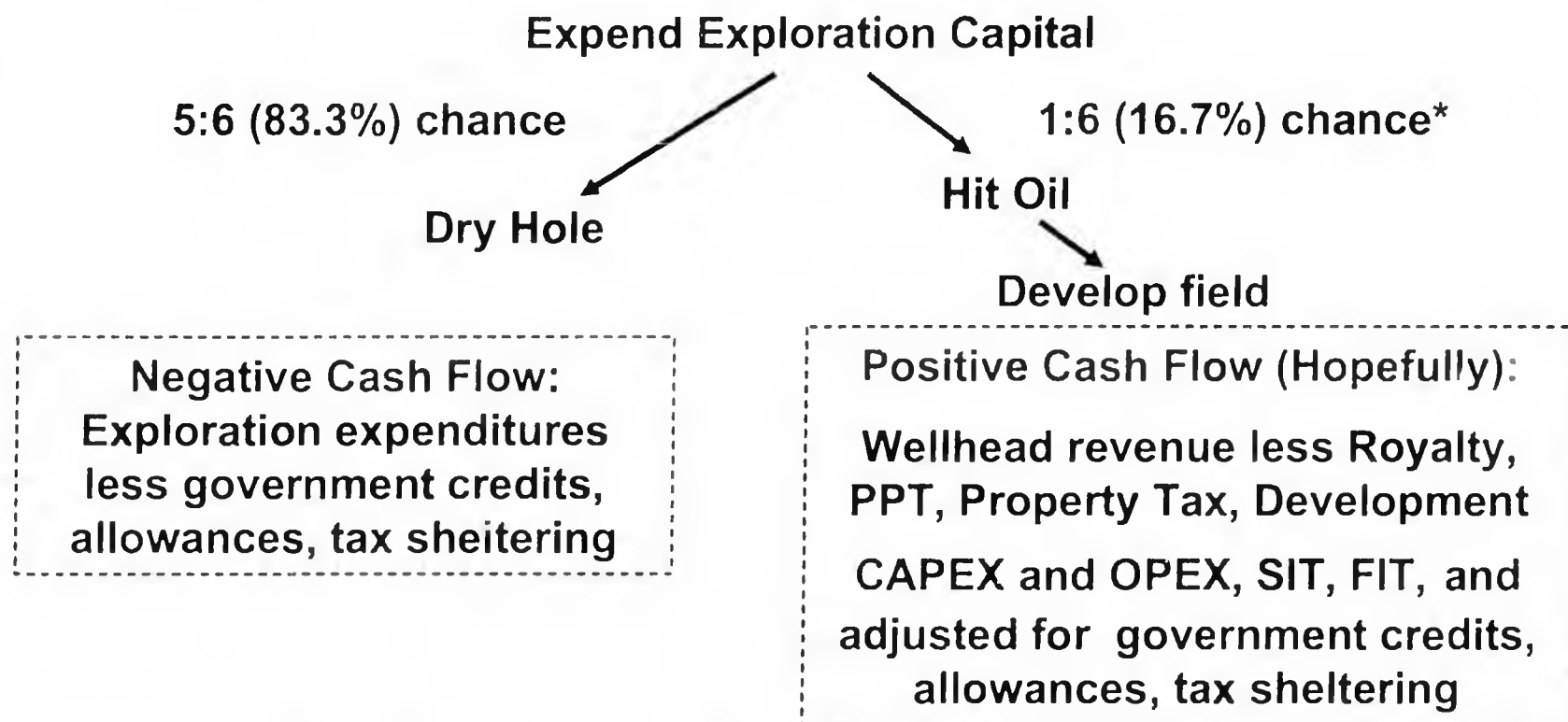


## Likely Distribution of New Field Discoveries

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

# How An Explorer Will Look At The Exploration Proposition

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

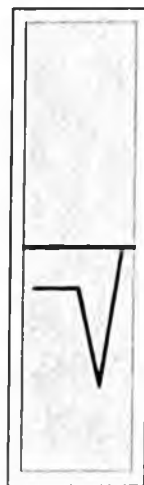


\*The experience in Alaska from 1994-2003 is 17.9% according to Wood Mac GOGRR 2004

# Schematic of Cash Flows For This Example

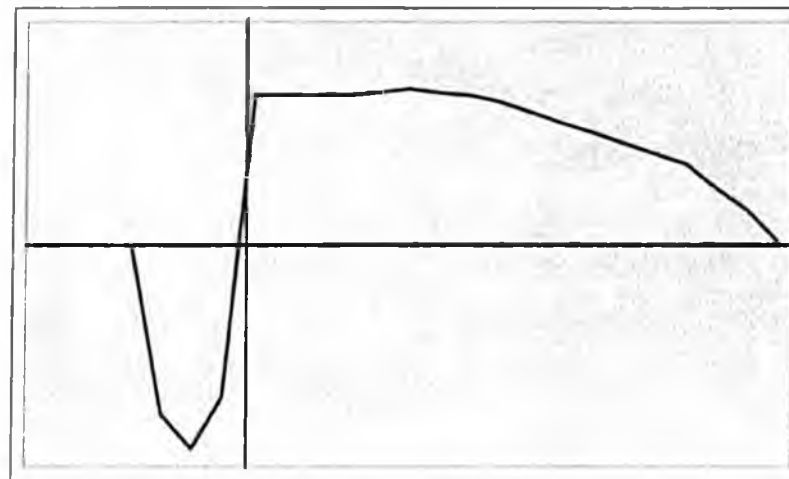
Cash Flow From  
Exploration

100% of Time



Cash Flow From  
Development  
and Production

16.7% of Time



# Avoiding Gambler's Ruin

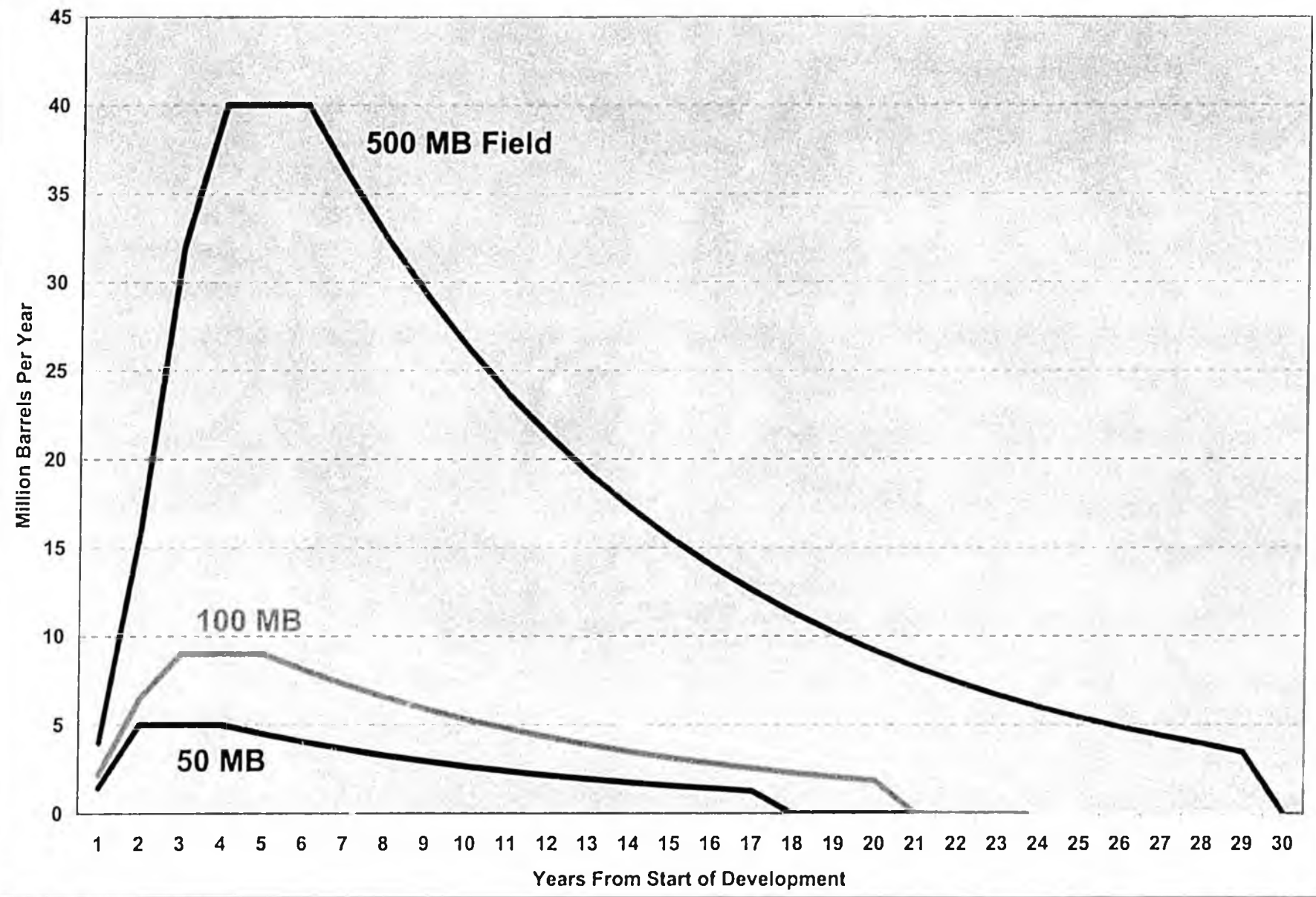
- Say the chance of drilling a successful well is 1-in-6, or .167
- An explorer will want to mitigate the risk of failure by drilling more wells. (Possibly shared.)
- The chance of failure with one well is .833 ( $=1-.167$ ). The chance of failure with a 6 well program is .334 ( $=.833^6$ )
- An explorer 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

# Illustration of A Failed Exploration Program

		SQ ELF	20/20	25/20
a	Revenue	0	0	0
b	CAPEX	120	120	120
c	Production Tax	0	-24	-30
d	Tax Credit	0	24	24
a-b-c+d	<b>Producer Cash Flow (pre SIT/FIT)</b>	<b>-120</b>	<b>-72</b>	<b>-66</b>
c-d	<b>State Revenue (pre SIT/FIT)</b>	<b>0</b>	<b>-48</b>	<b>-54</b>

# Oil Production Profiles



# Economics of an 6-Well Exploration Program

## 50 MM Field (High Cost, Low Productivity)

Without \$60 M Allowance

	Explorer NCF NPV10		
Price (Real \$2006)	20/20	25/20	SQ
\$ 30	-37.4	-36.1	-79.8
\$ 40	44.5	40.7	22.6
\$ 50	126.3	117.4	124.9
	Total State Revenues (\$M) NPV10		
\$ 30	-0.4	-2.5	68.8
\$ 40	64.5	70.7	100.3
\$ 50	129.4	143.9	131.7

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

With \$60 M Allowance

	Explorer NCF NPV10		
Price (Real \$2006)	20/20	25/20	SQ
\$ 30	-13.8	-6.6	-79.8
\$ 40	72.6	75.9	22.6
\$ 50	154.7	152.9	124.9
	Total State Revenues (\$M) NPV10		
\$ 30	-38.9	-50.7	68.8
\$ 40	18.5	13.2	100.3
\$ 50	83.0	86.0	131.7

# Economics of an 6-Well Exploration Program

## Without \$60 M Allowance

	Explorer NCF NPV10		
Price (Real \$2006)	20/20	25/20	SQ
\$ 30			-35.5
\$ 40			147.4
\$ 50			330.4
	Explorer IRR		
\$ 30			8.6
\$ 40			15.3
\$ 50			21.0
	Total State Revenues (\$M) NPV10		
\$ 30			137.7
\$ 40			198.4
\$ 50			259.0

# Economics of an 6-Well Exploration Program

## Without \$60 M Allowance

	Explorer NCF NPV10		
Price (Real \$2006)	20/20	25/20	SQ
\$ 30	5.1	3.3	-35.5
\$ 40	149.7	138.9	147.4
\$ 50	294.3	274.5	330.4
	Explorer IRR		
\$ 30	10.3	10.2	8.6
\$ 40	17.1	16.9	15.3
\$ 50	22.7	21.0	21.0
	Total State Revenues (\$M) NPV10		
\$ 30	51.2	54.0	137.7
\$ 40	165.7	183.4	198.4
\$ 50	280.3	312.7	259.0

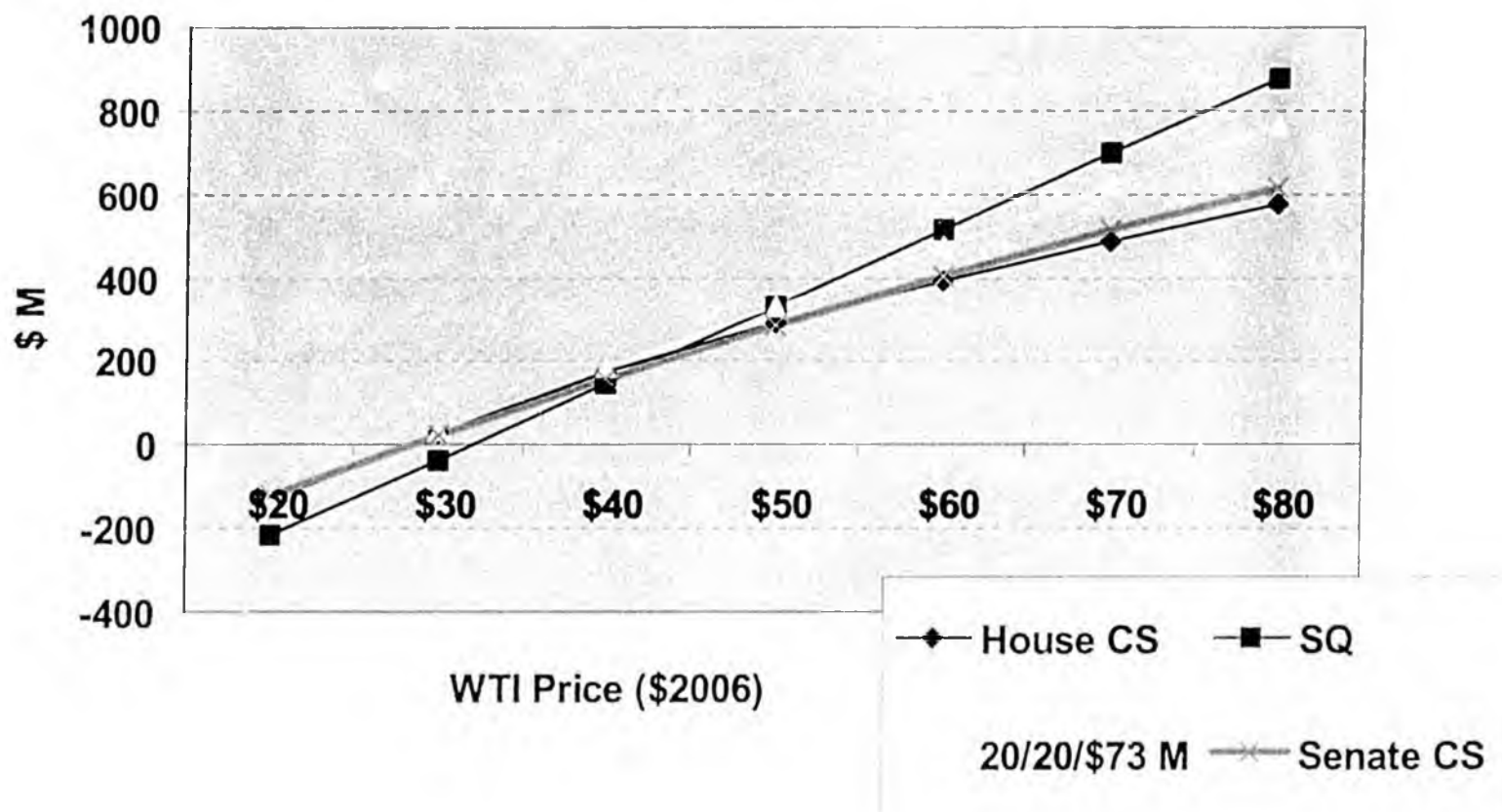
# Economics of an 6-Well Exploration Program

With \$60 M Allowance

	Explorer NCF NPV10		
Price (Real \$2006)	20/20	25/20	SQ
\$ 30	30.4	34.9	-35.5
\$ 40	178.8	175.3	147.4
\$ 50	323.8	311.1	330.4
	Explorer IRR		
\$ 30	11.5	11.8	8.6
\$ 40	18.2	18.3	15.3
\$ 50	23.7	23.7	21.0
	Total State Revenues (\$M) NPV10		
\$ 30	9.9	2.5	137.7
\$ 40	118.2	124.0	198.4
\$ 50	232.2	252.5	259.0

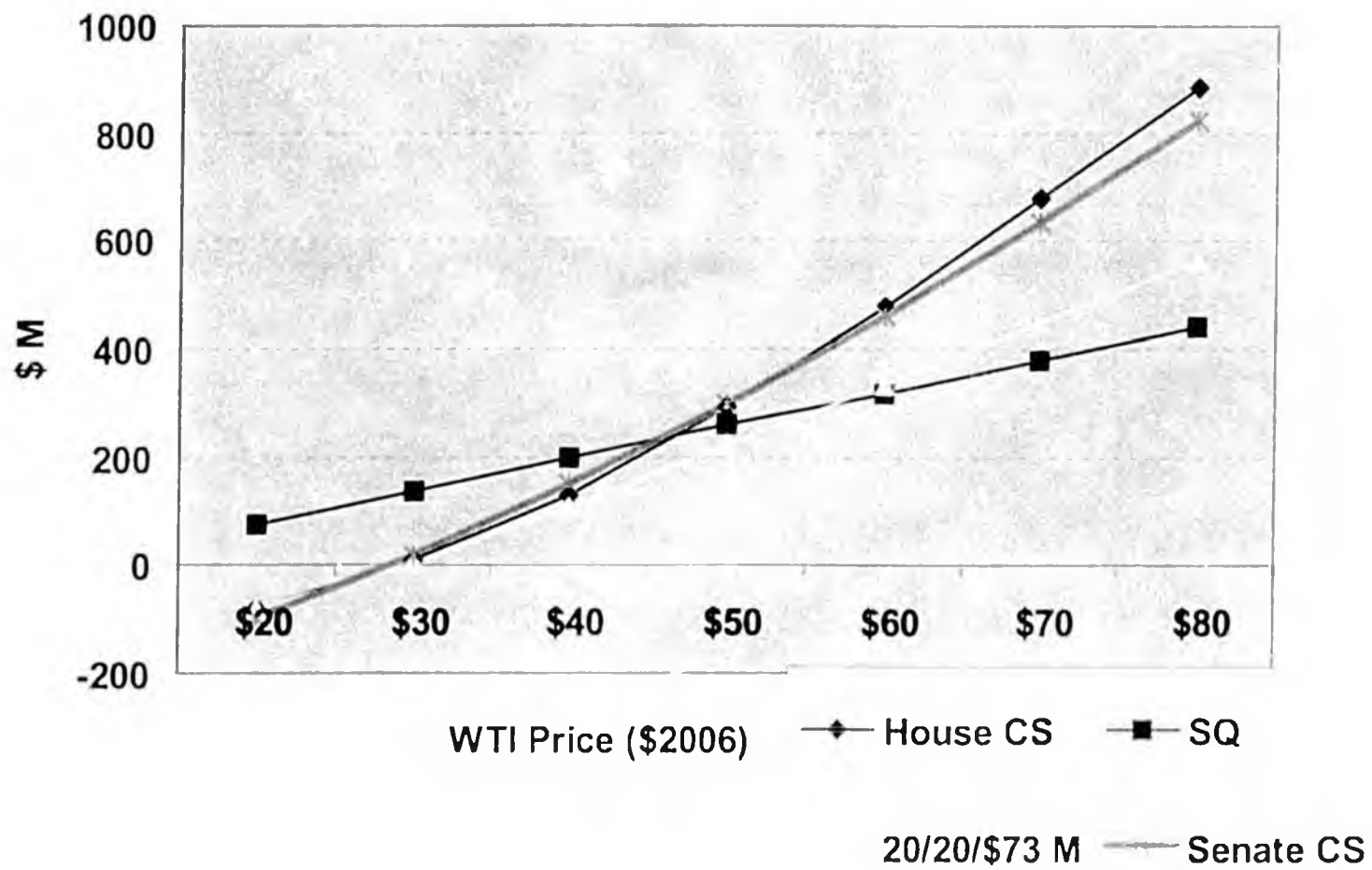
# Comparison of Tax Proposals

## Producer Net Cash Flow NPV 10



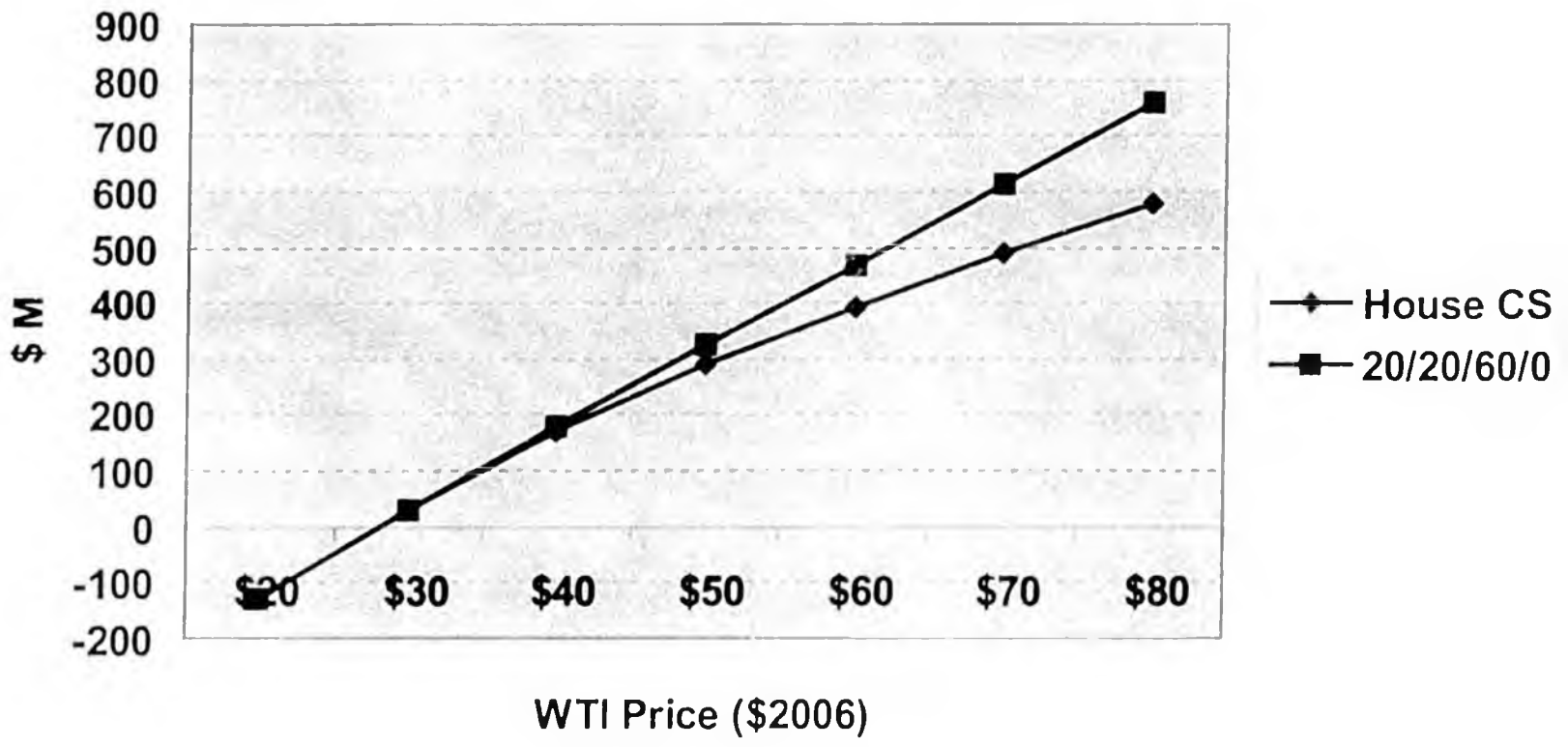
# Comparison of Tax Proposals

Total State Revenues  
NPV 10



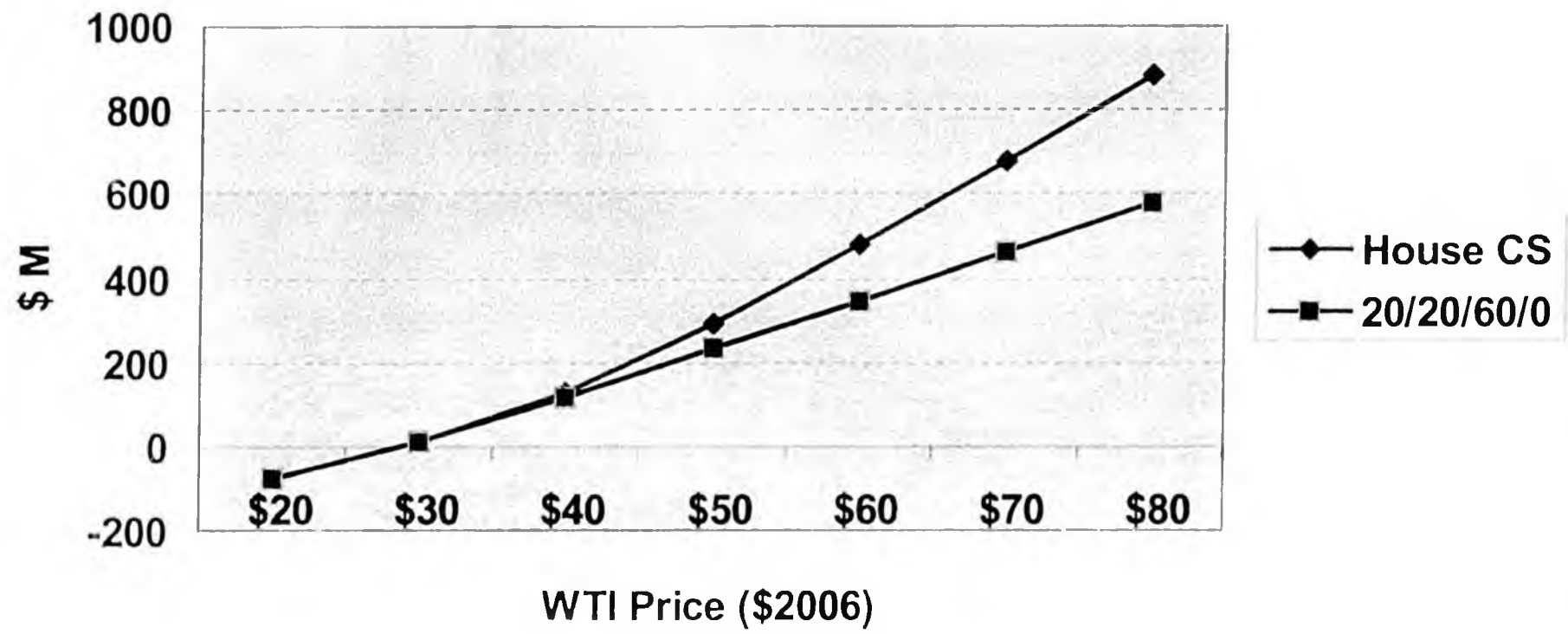
# Impact of Progressivity

## Producer Net Cash Flow NPV 10



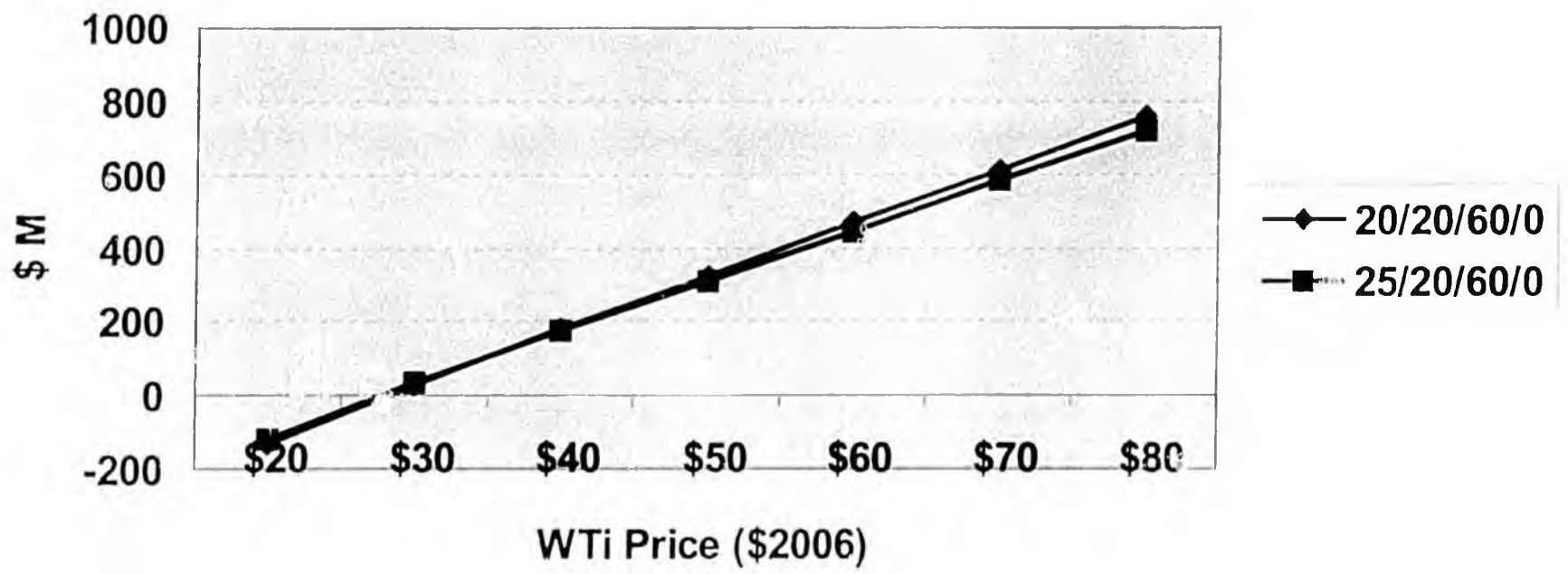
# Impact of Progressivity

## Total State Revenue NPV10



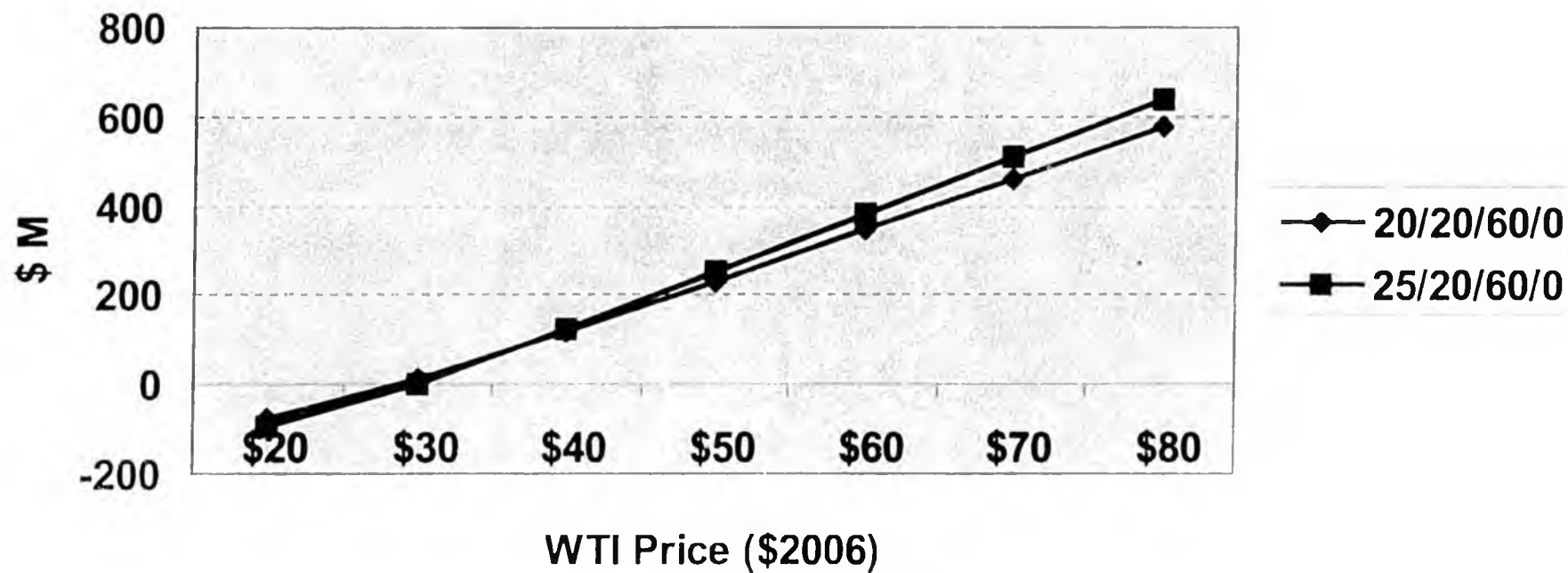
# Impact of 25/20 versus 20/20

## Producer Net Cash Flow NPV 10



# Impact of 25/20 versus 20/20

## Total State Revenues NPV 10

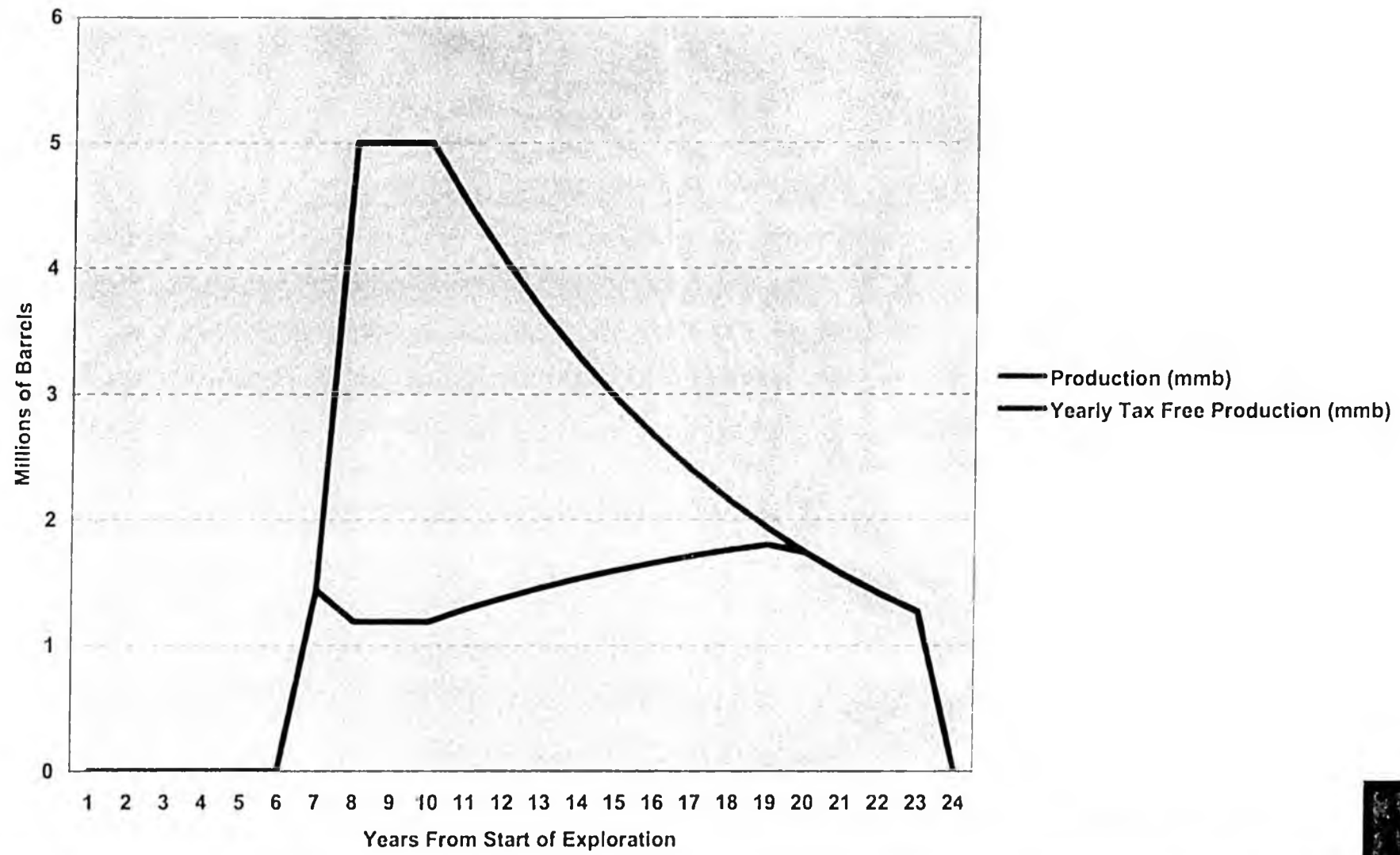


# Exploration Forgiveness - An Alternative to Tax Free Allowance

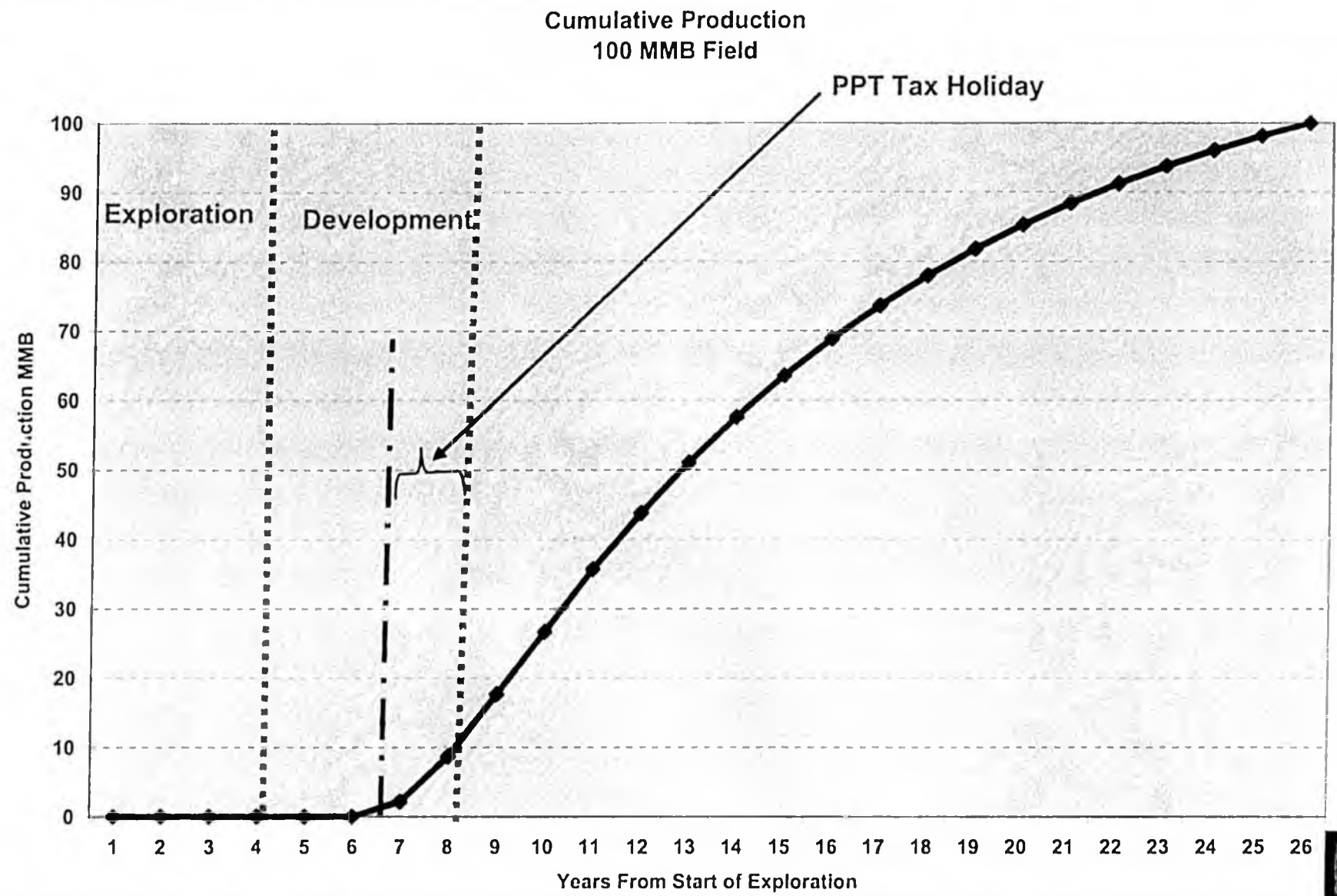
- For each new field give a “Tax Holiday” from the PPT for the first 10 million barrels of production
- This provides an incentive for new exploration
  - Improves producers cash flow in the early stages of the production process
  - Producers cannot seek royalty relief if they opt for the “Tax Holiday”
- Also provides incentive to put the field on early
- This tax holiday is NOT applied to existing fields
- The fiscal impact on the State of Alaska will be felt after the field is producing, e.g. seven years after exploration starts

# Tax Free Production – 50 MB Field

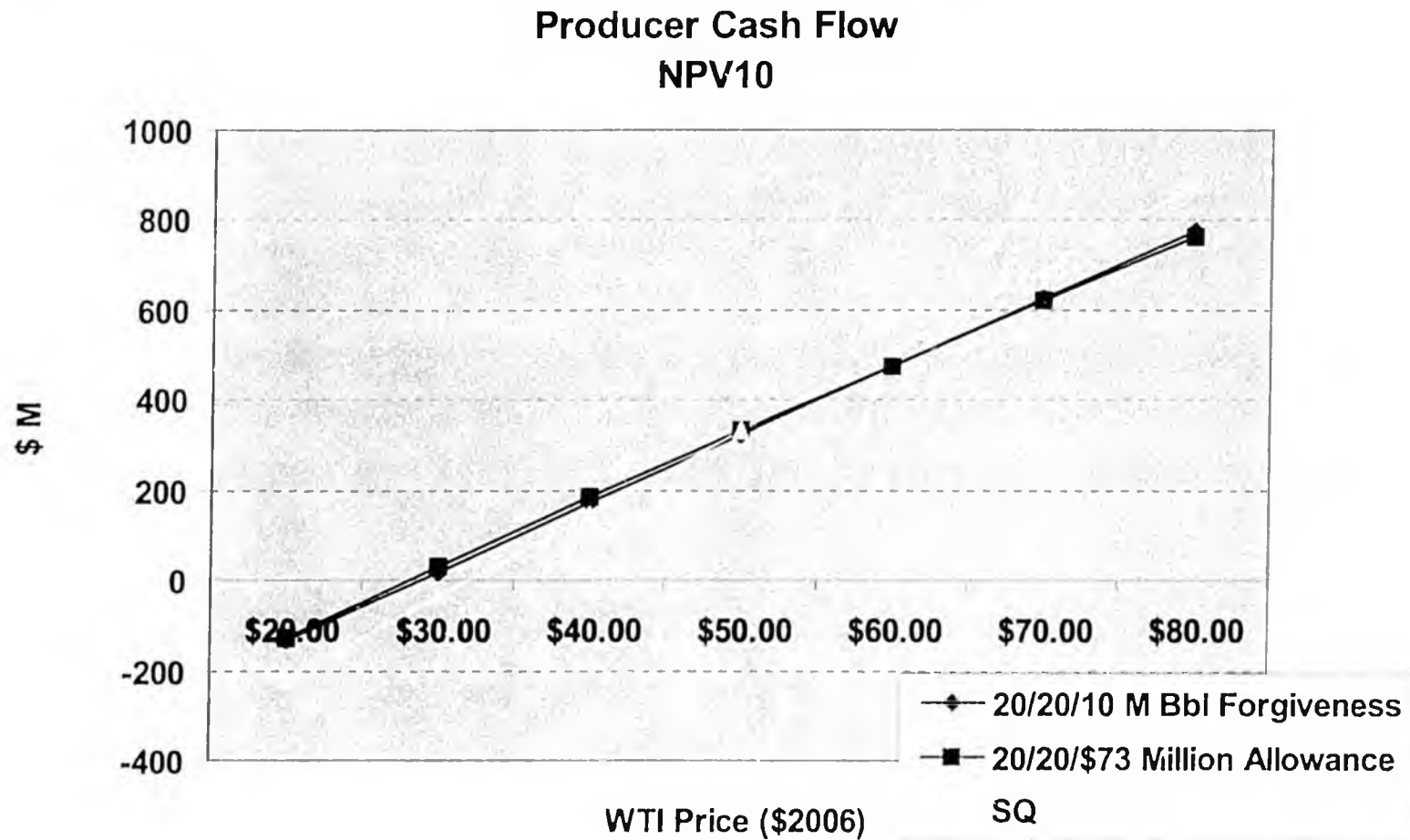
Annual Production 50 MB Field



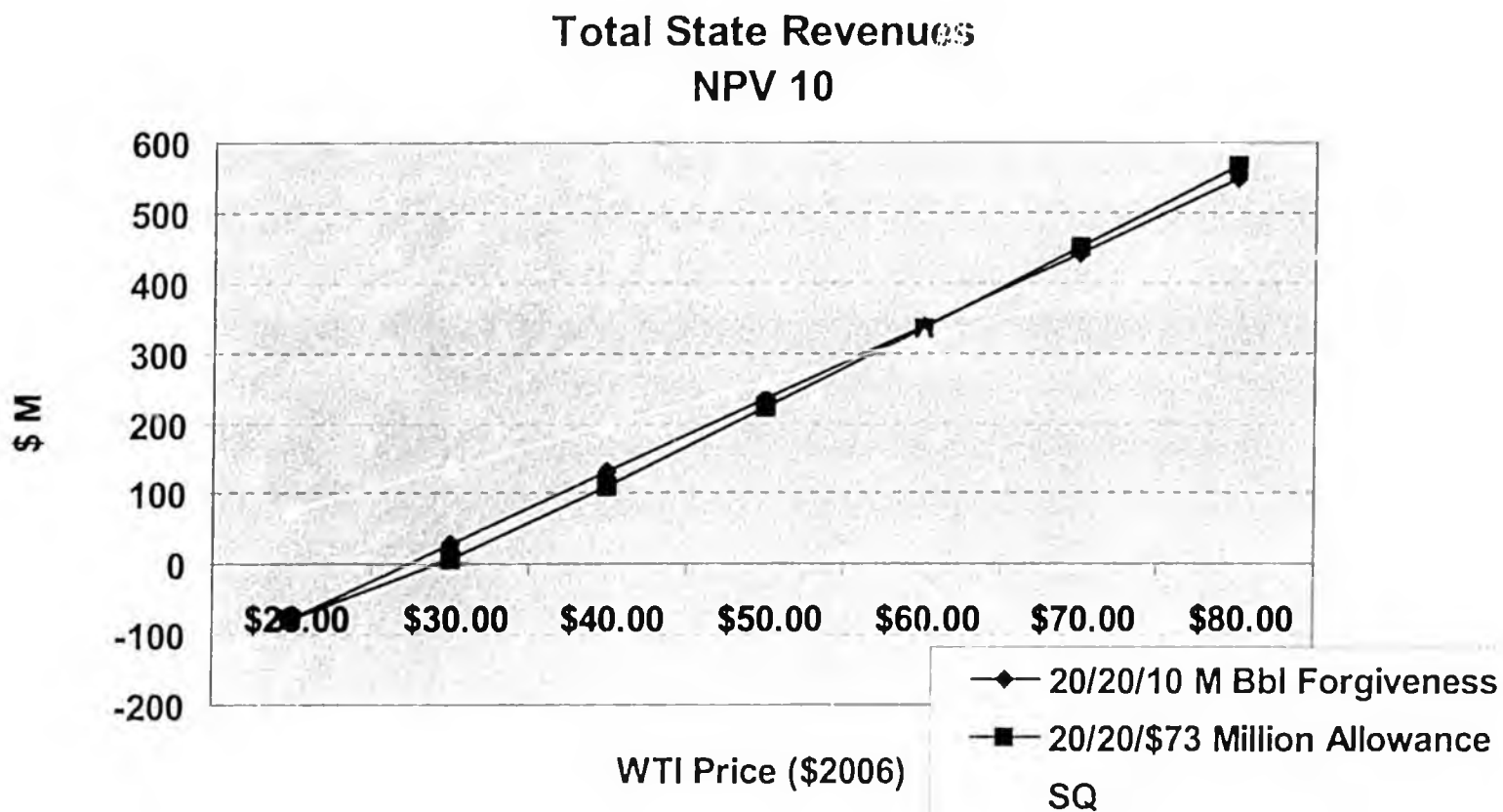
# Typical Cumulative Production Profile – 100 MMB Field



# Impact on Producer Economics

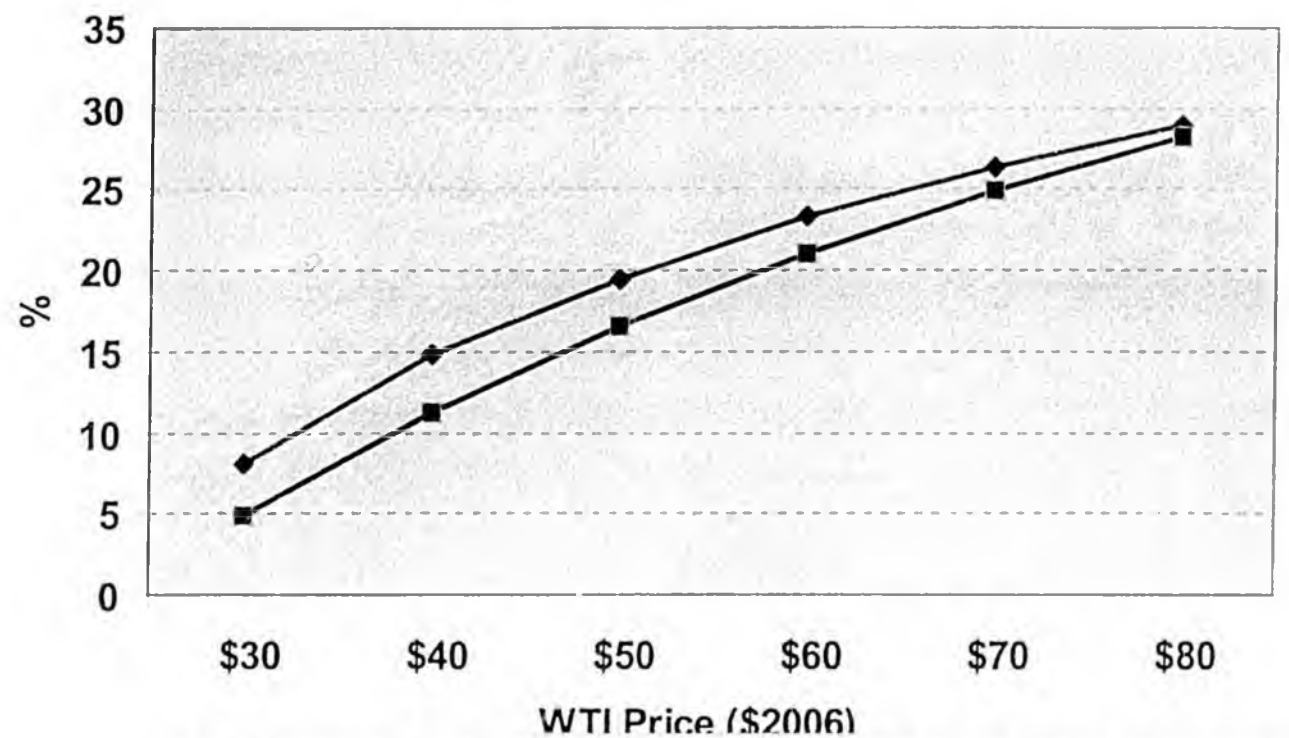


# Impact on State Revenues (NPV 10)



# Impact on Small Field Economics – 50 MB Field

## Producer IRR



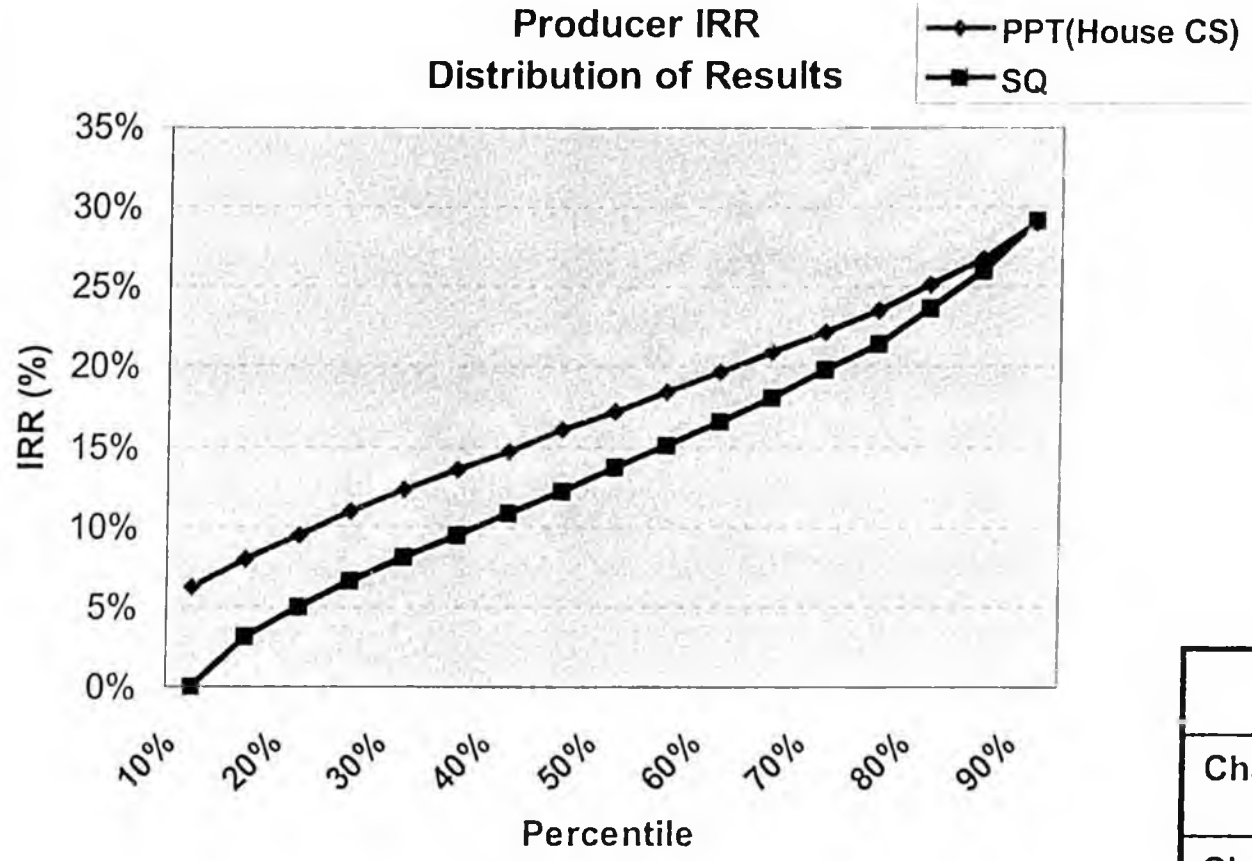
◆ House CS w/ 10 MB Forgiveness Instead of \$60 Allowance

■ SQ

## Probabilistic Results

- Producers may look at results on a probabilistic basis
- Suppose their view of future WTI prices is:
  - Mean (Most Likely) of \$40
  - P20 of \$25, P80 of \$55 (i.e.  $\$40 \pm \$15$ )

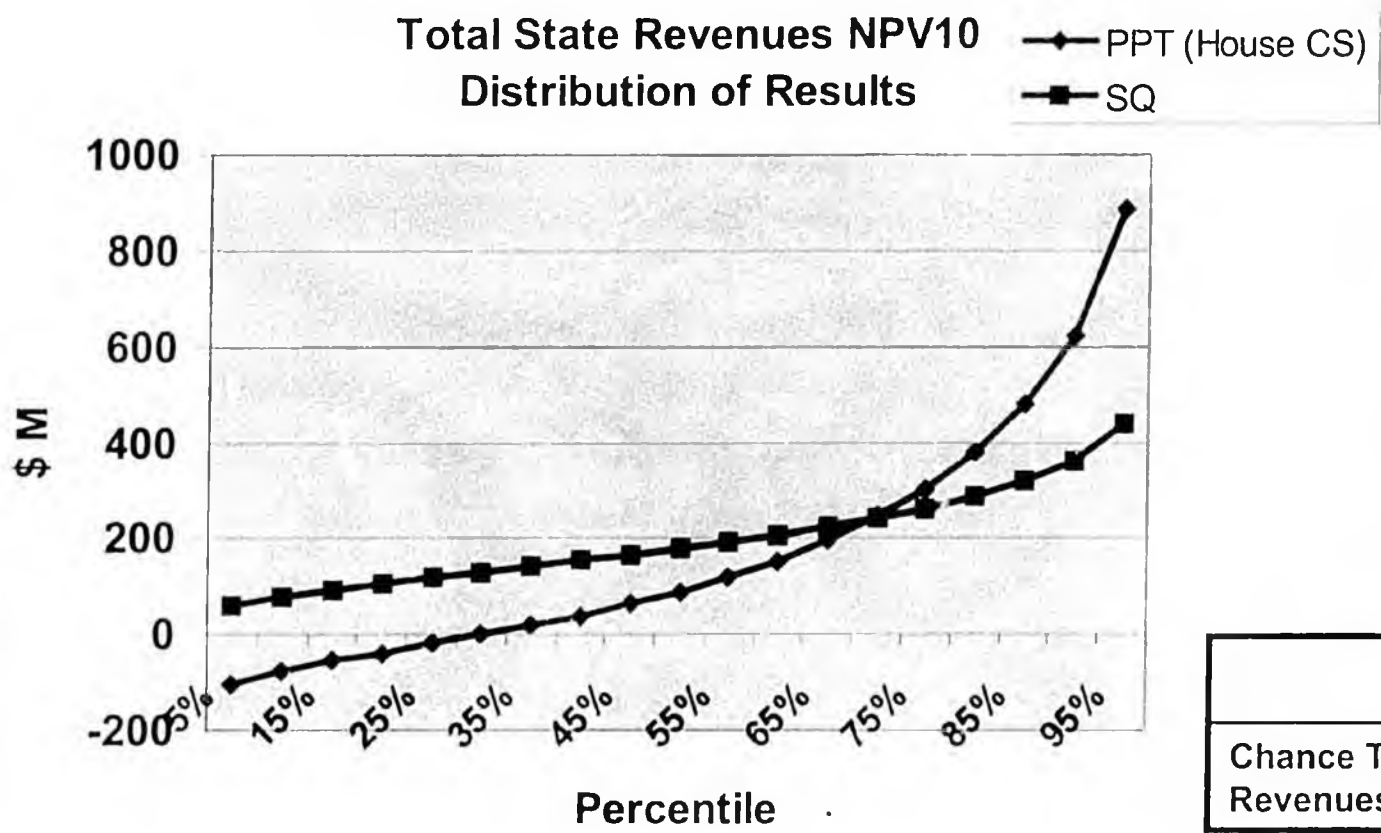
# Distribution of Results – Producer IRR



IRR	PPT	SQ
Median (P50)	17.2%	13.7%
P20	9.5%	5.0%

	PPT	SQ
Chance IRR < 12%	30%	45%
Chance IRR < 15%	40%	55%

# Distribution of Results – Total State Revenues NPV10



Total State Revenues NPV10 (\$M)	PPT	SQ
Median (P50)	89	180
P20	-38	107

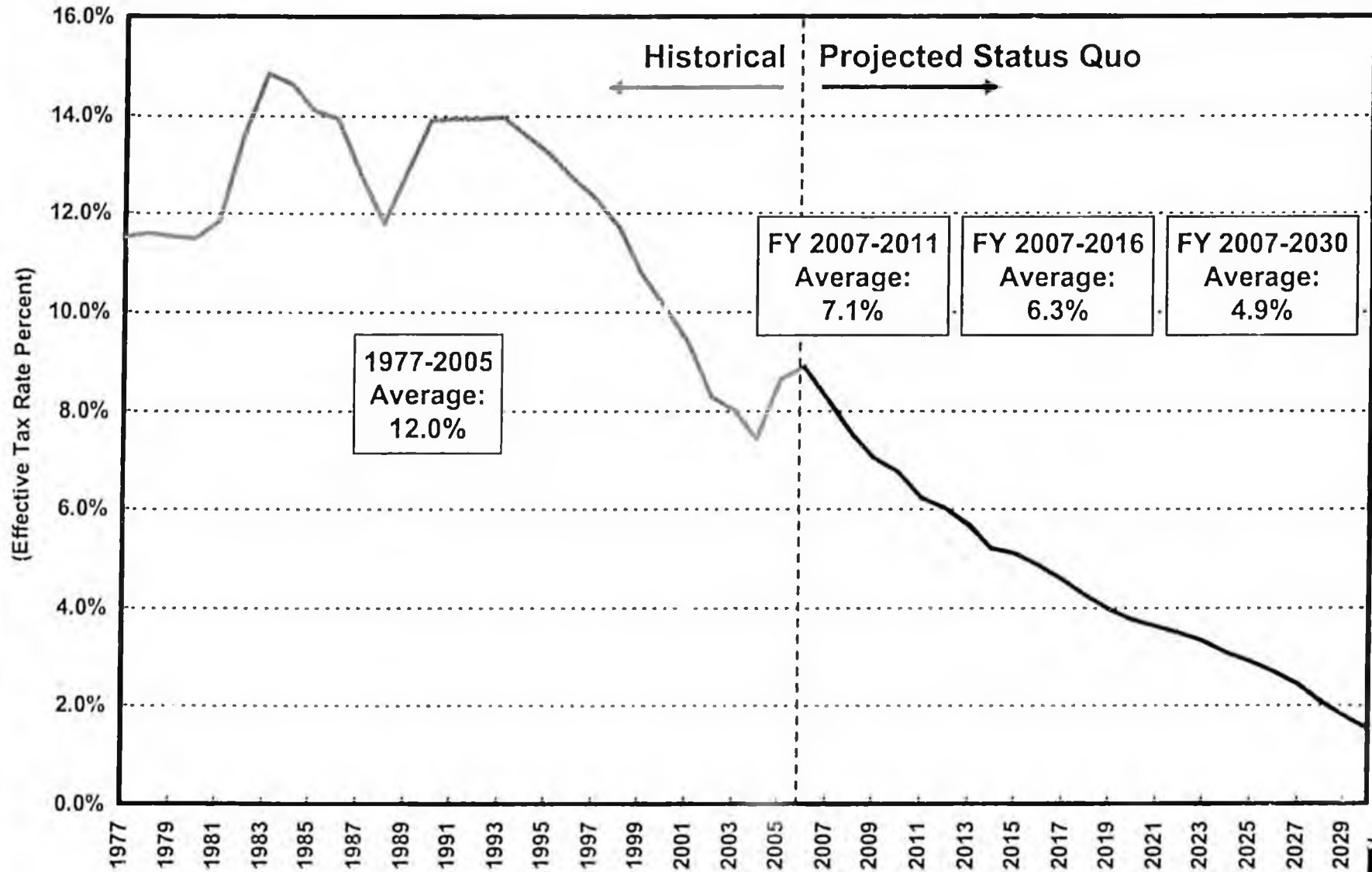
	PPT	SQ
Chance Total State Revenues <0	30%	1%

# 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, e.g. “production tax holiday”)
  - “Sunset” provision in tax free barrel allowance in Senate CS not likely to provide incentive due to long-lived exploration-production cycle
- At low prices, 20/20 and 25/20 preferred over SQ, in order to incent exploration
- Exploration is still a risky business. Probabilistic results using “Industry View” of oil prices yields smaller chance of a “losing IRR” under PPT than under SQ. Higher chance of “loss” for State under PPT.
- Under either a 20/20 or 25/20 program, remaining reserves are economic, except for low prices (<\$30?)

## Existing Fields

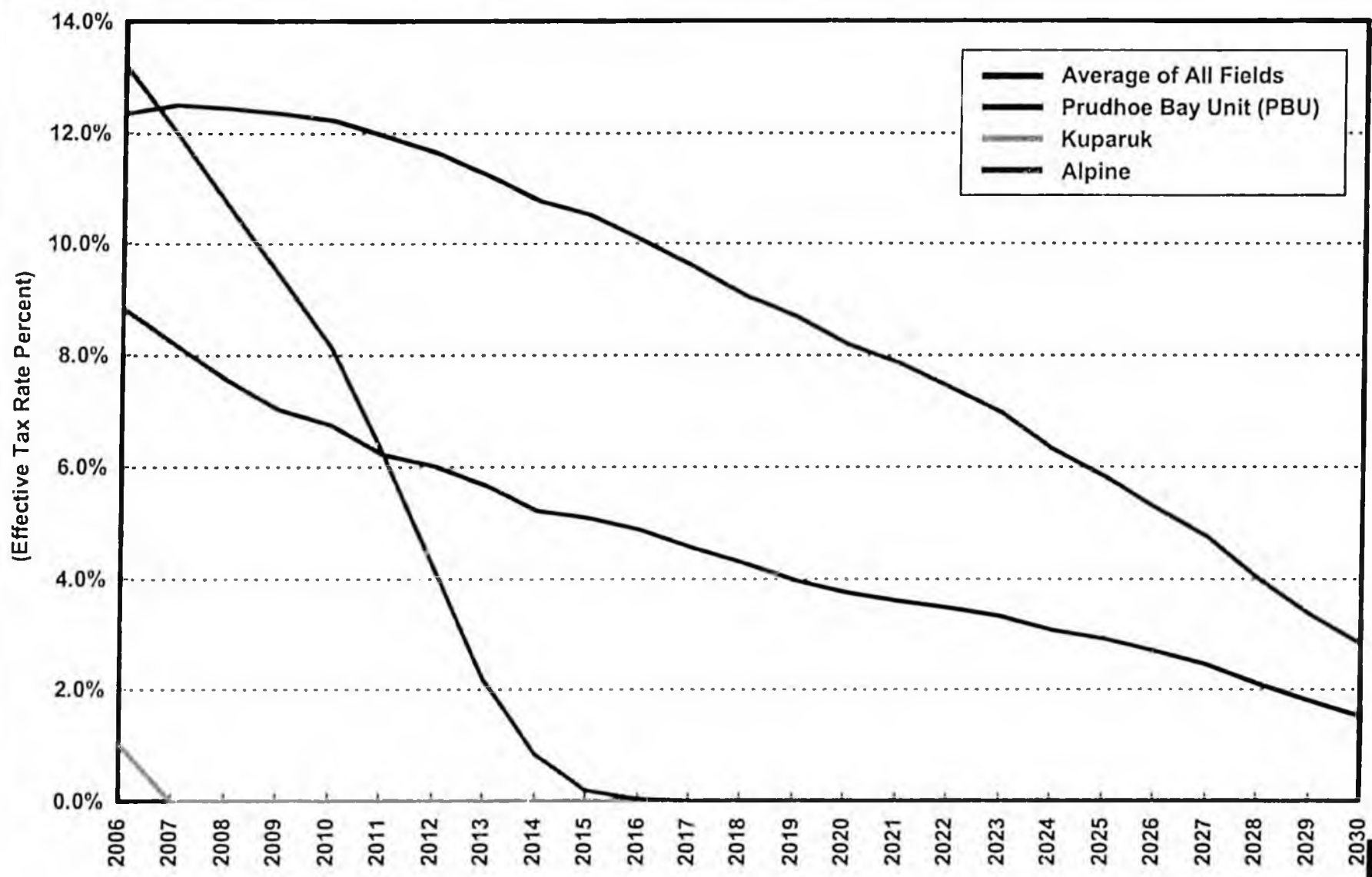
# Effective Severance Tax Rates Over Time



Source: Historical: Alaska Department of Revenue.



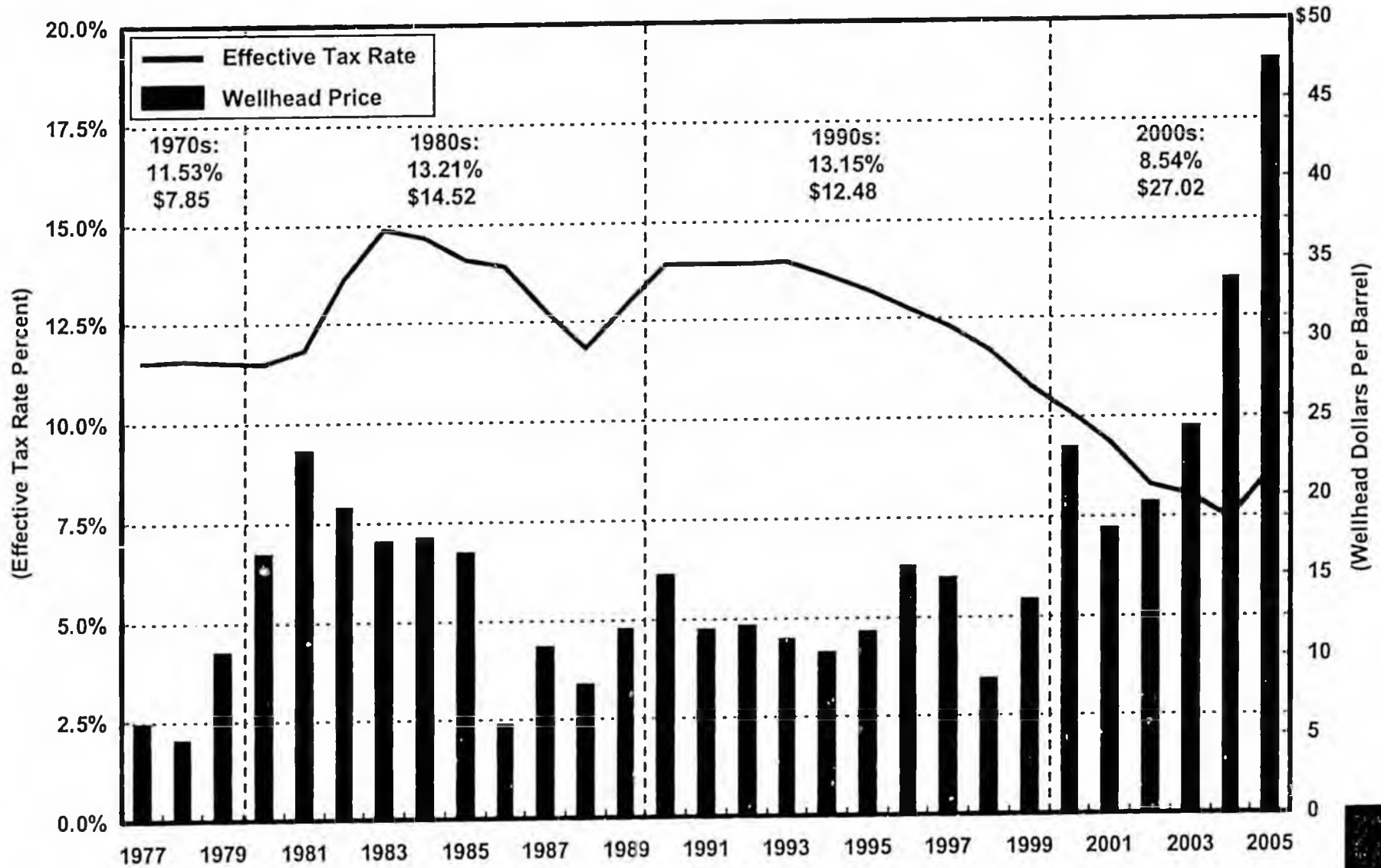
# Projected Effective Severance Tax Rates\* by Field



\* Volumes per DOR Fall 2005 Forecast with Oooguruk projection.



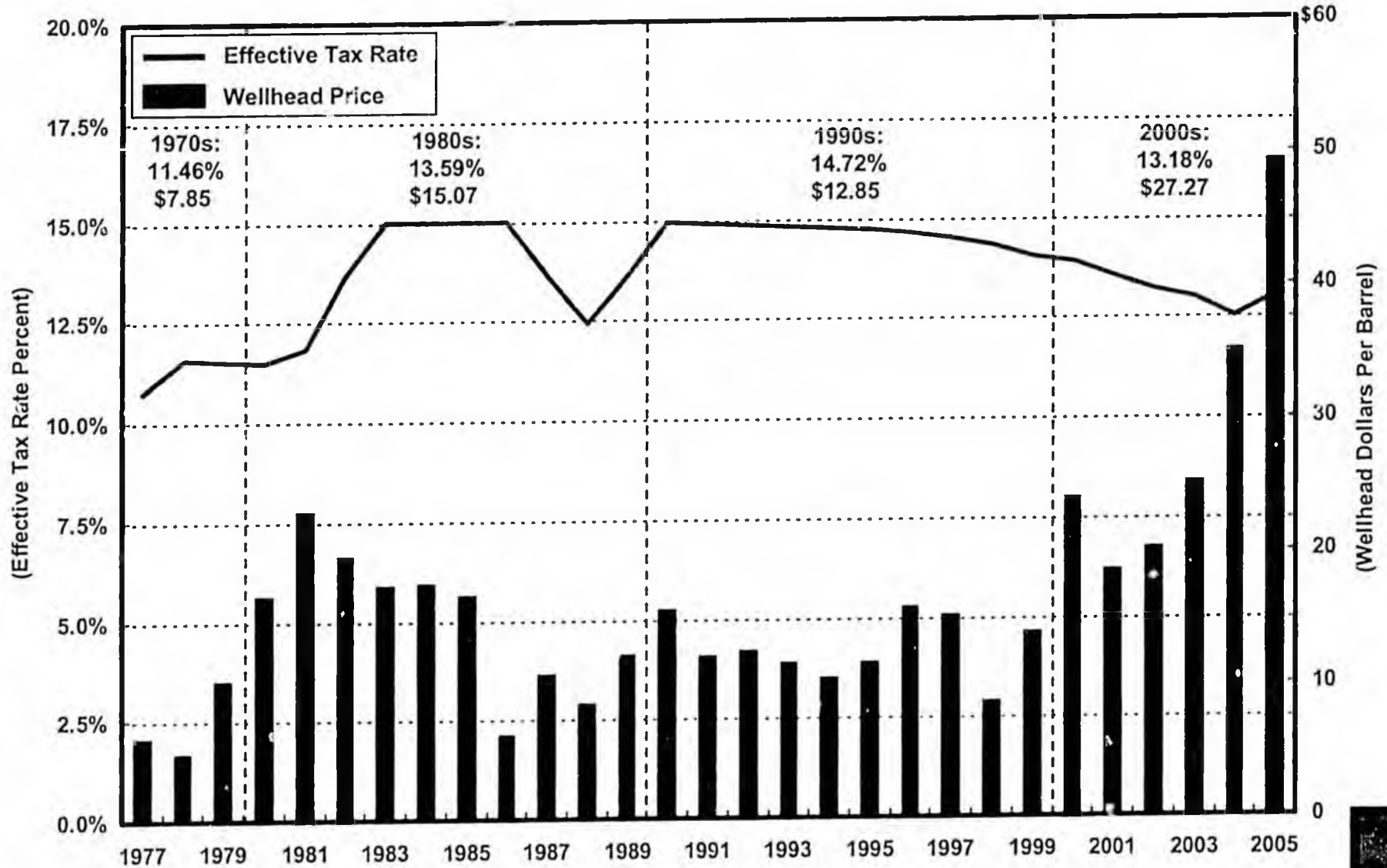
# Effective Tax Rates and Wellhead Prices Over Time (All North Slope Fields)



Source: Alaska Department of Revenue.



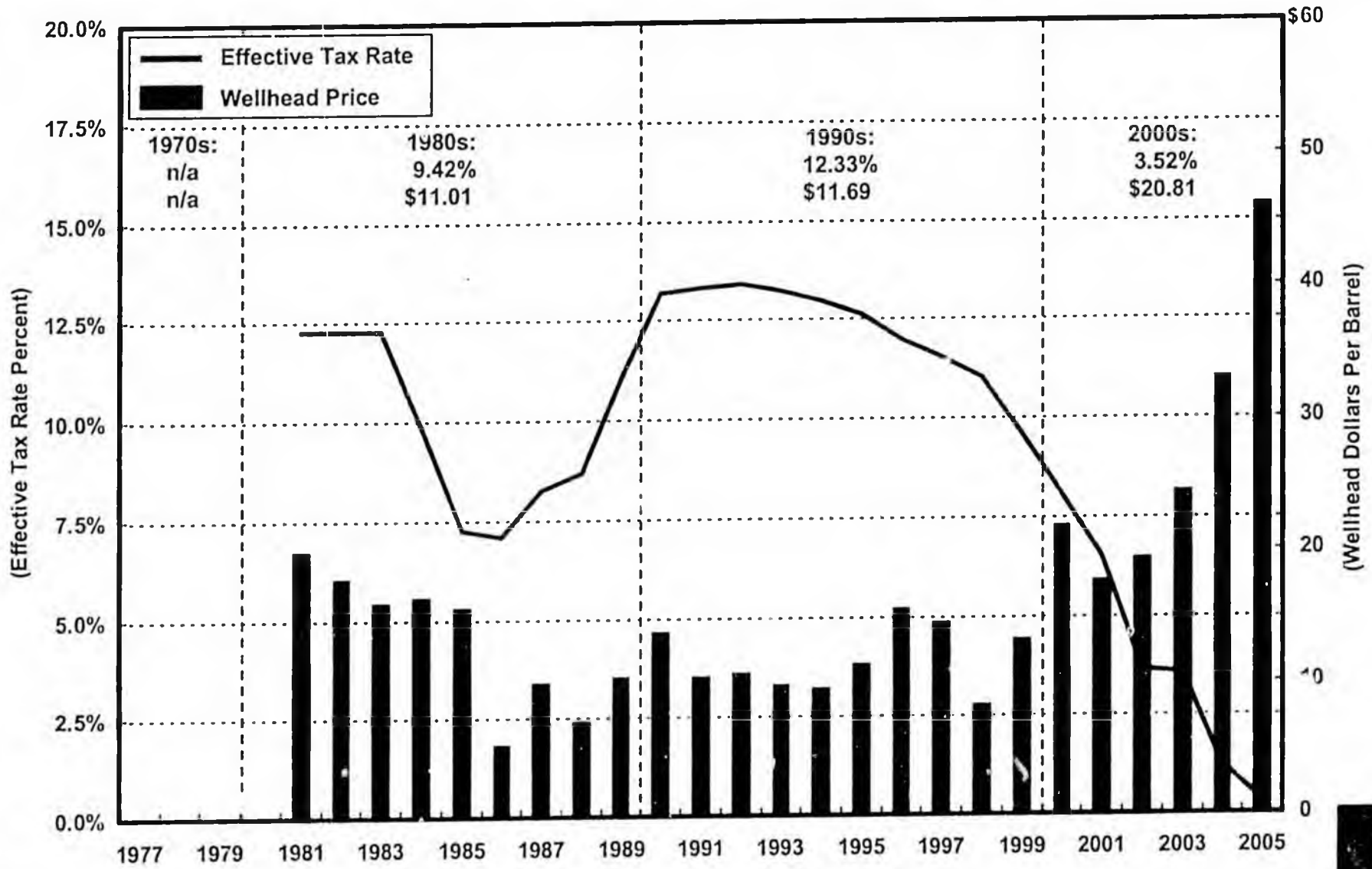
# Effective Tax Rates and Wellhead Prices Over Time (Prudhoe Bay Field)



Source: Alaska Department of Revenue.



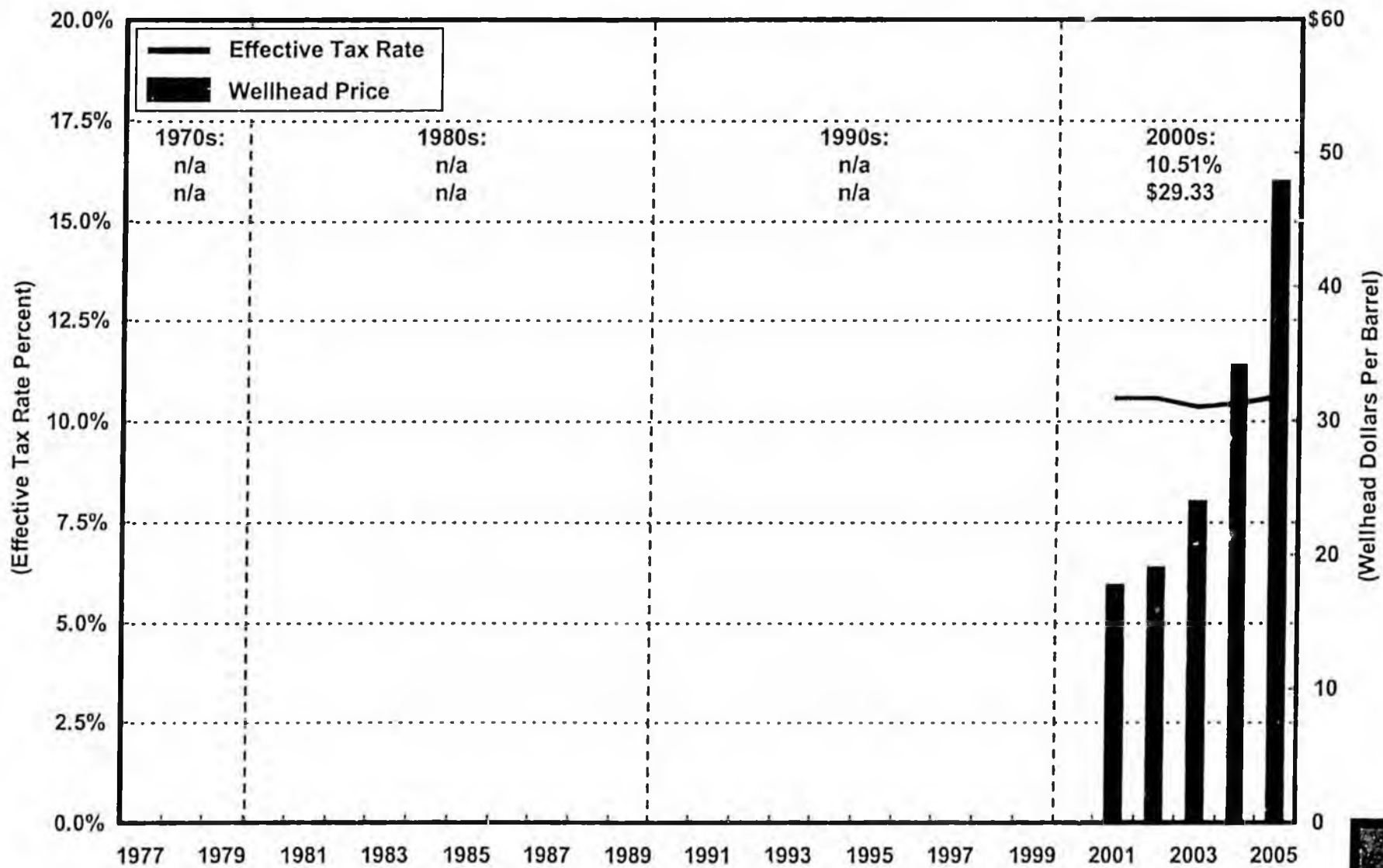
# Effective Tax Rates and Wellhead Prices Over Time (Kuparuk Field)



Source: Alaska Department of Revenue.



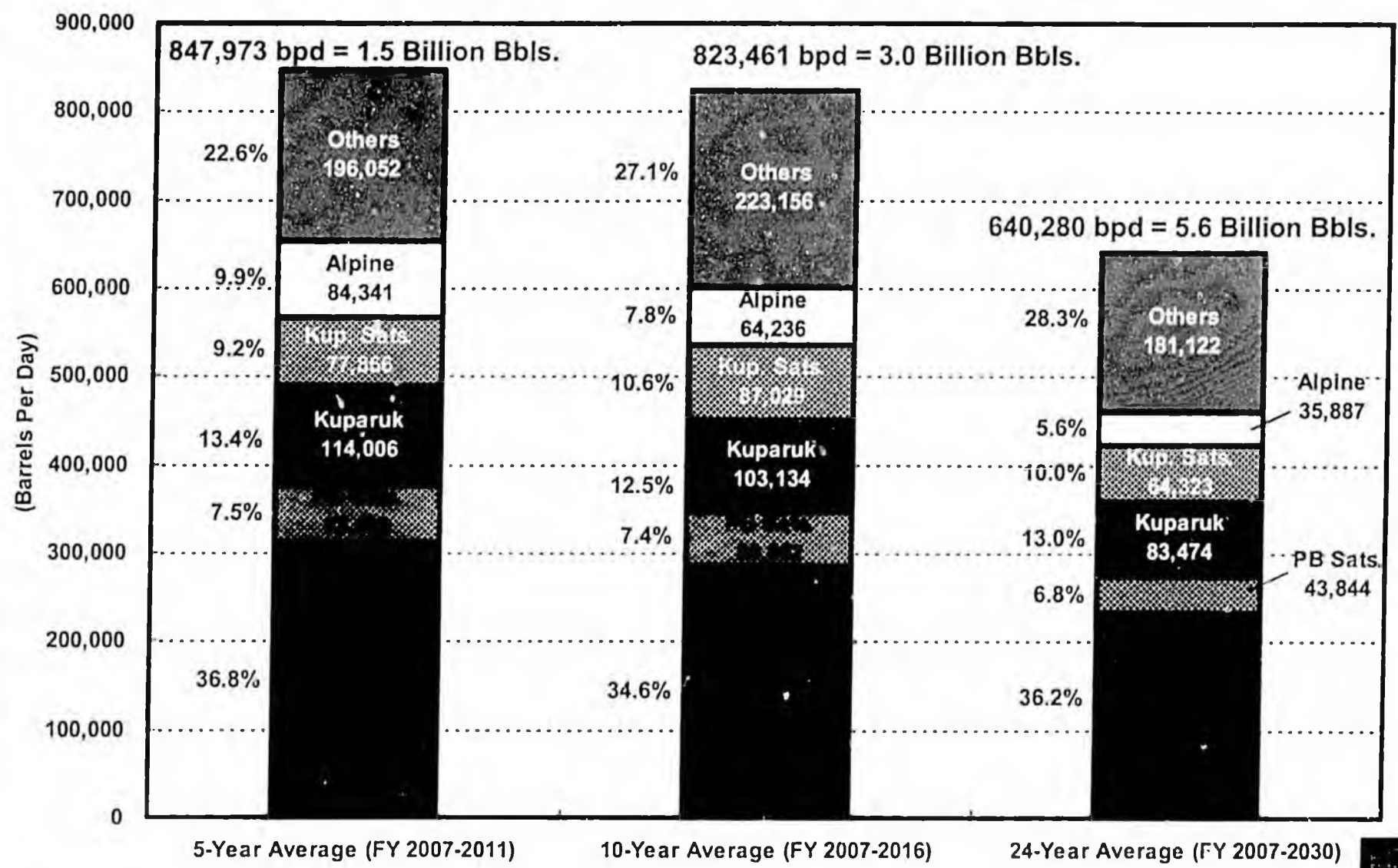
# Effective Tax Rates and Wellhead Prices Over Time (Alpine Field)



Source: Alaska Department of Revenue.



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

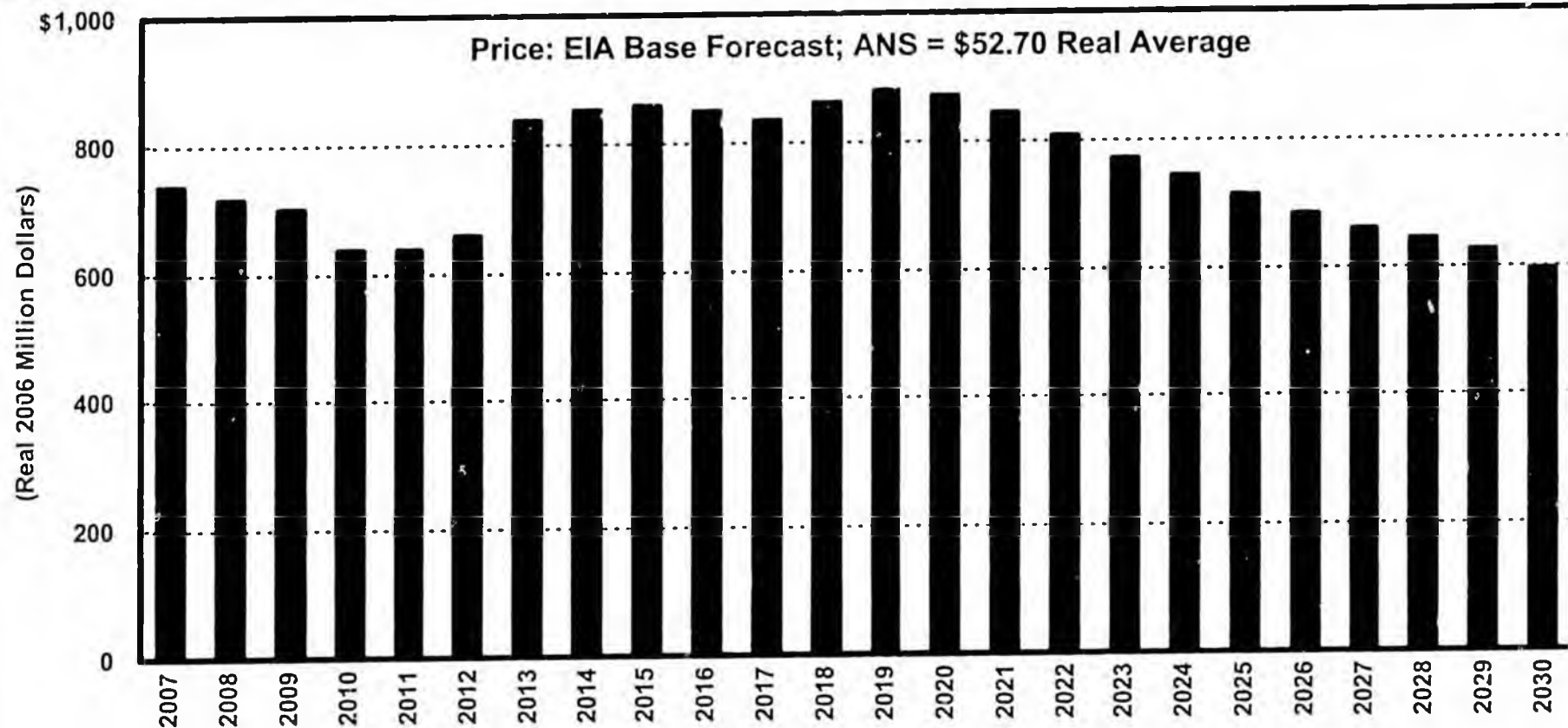


\* Includes NGLs.

Source: Alaska Department of Revenue.



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



	FY 2007-2011	FY 2007-2016	FY 2007-2030
Total Difference from SQ (\$Million)	\$3,417	\$7,471	\$17,971
Annual Average Difference from SQ (\$Million)	\$683	\$747	\$749
PPT Effective Tax Rate (Percent)	12.2%	12.4%	12.6%
SQ Effective Tax Rate (Percent)	7.1%	6.3%	4.9%

\* Calculated from July 2006; includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

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

	EIA WTI Price Forecast:			Fixed \$40 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
Average ANS Price in Real 2006 Dollars:	\$52.70	\$33.40	\$70.00	\$40.00	\$30.40	\$28.50	\$26.80

## FY 2007-2011

Total Difference from Status Quo (Million 2006\$)	\$3,417	\$2,459	\$4,637	\$1,673	\$0	-	-
Annual Average Difference from Status Quo (Million 2006\$)	\$683	\$492	\$927	\$335	\$0	-	-
PPT Effective Tax Rate (Percent)	12.2%	11.4%	13.2%	10.7%	7.2%	-	-
Status Quo Effective Tax Rate (Percent)	7.1%	7.2%	7.1%	7.1%	7.2%	-	-

## FY 2007-2016

Total Difference from Status Quo (Million 2006\$)	\$7,471	\$3,614	\$11,688	\$4,156	-	\$0	-
Annual Average Difference from Status Quo (Million 2006\$)	\$747	\$361	\$1,169	\$416	-	\$0	-
PPT Effective Tax Rate (Percent)	12.4%	10.3%	13.8%	10.8%	-	6.3%	-
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	-	6.3%	-

## FY 2007-2030

Total Difference from Status Quo (Million 2006\$)	\$17,971	\$4,824	\$30,262	\$9,796	-	-	\$0
Annual Average Difference from Status Quo (Million 2006\$)	\$749	\$201	\$1,261	\$408	-	-	\$0
PPT Effective Tax Rate (Percent)	12.6%	8.7%	14.5%	10.6%	-	-	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 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
Average ANS Price in Real 2006 Dollars:	\$52.70	\$33.40	\$70.00	\$40.00	\$34.80	\$32.60	\$30.50

## FY 2007-2011

Total Difference from Status Quo (Million 2006\$)	\$2,659	\$1,701	\$3,878	\$915	\$0	-
Annual Average Difference from Status Quo (Million 2006\$)	\$532	\$340	\$776	\$183	\$0	-
PPT Effective Tax Rate (Percent)	11.1%	10.1%	12.2%	9.1%	7.1%	-
Status Quo Effective Tax Rate (Percent)	7.1%	7.2%	7.1%	7.1%	7.1%	-

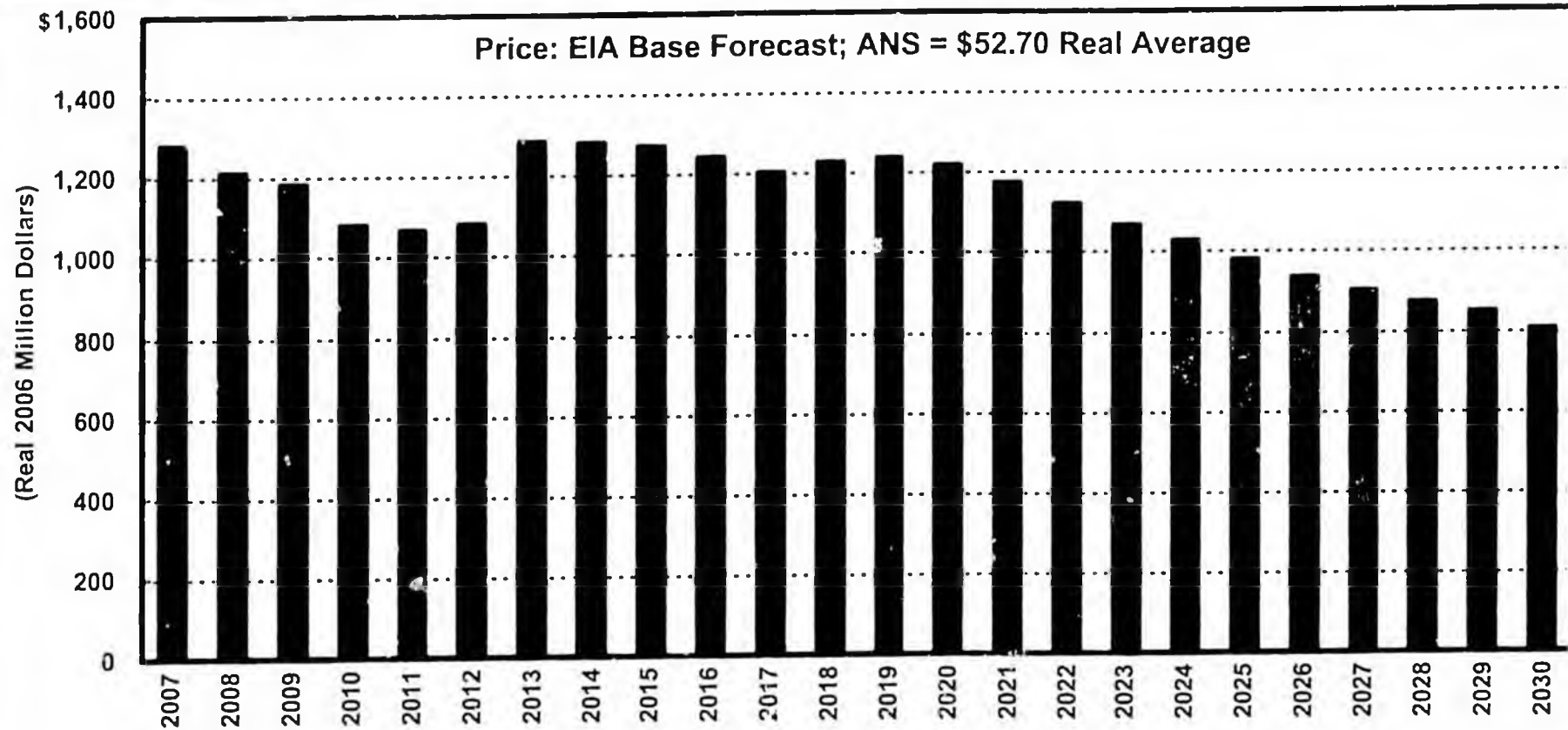
## FY 2007-2016

Total Difference from Status Quo (Million 2006\$)	\$6,002	\$2,145	\$10,219	\$2,687	-	\$0	-
Annual Average Difference from Status Quo (Million 2006\$)	\$600	\$214	\$1,022	\$269	-	\$0	-
PPT Effective Tax Rate (Percent)	11.2%	8.8%	12.9%	9.2%	-	6.3%	-
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	-	6.3%	-

## FY 2007-2030

Total Difference from Status Quo (Million 2006\$)	\$15,221	\$2,129	\$27,511	\$7,046	-	\$0
Annual Average Difference from Status Quo (Million 2006\$)	\$634	\$89	\$1,146	\$294	-	\$0
PPT Effective Tax Rate (Percent)	11.5%	6.8%	13.6%	9.0%	-	4.9%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	4.9%

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



	FY 2007-2011	FY 2007-2016	FY 2007-2030
Total Difference from SQ (\$Million)	\$5,816	\$11,968	\$26,555
Annual Average Difference from SQ (\$Million)	\$1,163	\$1,197	\$1,106
PPT Effective Tax Rate (Percent)	15.8%	16.0%	16.4%
SQ Effective Tax Rate (Percent)	7.1%	6.3%	4.9%

\* Calculated from July 2006; Includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Ooguruk projection.

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

	EIA WTI Price Forecast:			Fixed \$40 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
Average ANS Price in Real 2006 Dollars:	\$52.70	\$33.40	\$70.00	\$40.00	\$26.40	\$25.10	\$24.10

## FY 2007-2011

Total Difference from Status Quo (Million 2006S)	\$5,816	\$4,480	\$7,492	\$3,283	\$0	-	-
Annual Average Difference from Status Quo (Million 2006S)	\$1,163	\$896	\$1,498	\$657	\$0	-	-
PPT Effective Tax Rate (Percent)	15.8%	14.8%	16.9%	14.1%	7.2%	-	-
Status Quo Effective Tax Rate (Percent)	7.1%	7.2%	7.1%	7.1%	7.2%	-	-

## FY 2007-2016

Total Difference from Status Quo (Million 2006S)	\$11,968	\$6,740	\$17,656	\$7,317	-	\$0	-
Annual Average Difference from Status Quo (Million 2006S)	\$1,197	\$674	\$1,766	\$732	-	\$0	-
PPT Effective Tax Rate (Percent)	16.0%	13.6%	17.7%	14.2%	-	6.3%	-
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	-	6.3%	-

## FY 2007-2030

Total Difference from Status Quo (Million 2006S)	\$26,555	\$9,286	\$42,717	\$15,610	-	-	\$0
Annual Average Difference from Status Quo (Million 2006S)	\$1,106	\$387	\$1,780	\$650	-	-	\$0
PPT Effective Tax Rate (Percent)	16.4%	11.7%	18.5%	14.0%	-	-	5.0%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	-	5.0%

\* Calculated from July 2006; includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Ooguruk projection.

# Change in Projected Taxes Under a 25/20 Tax with Costs Increased by 20% DOR Forecast Production (FY 2007-2030)\*

	EIA WTI Price Forecast:			Fixed \$40 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
<i>Average ANS Price in Real 2006 Dollars:</i>	\$52.70	\$33.40	\$70.00	\$40.00	\$30.10	\$28.60	\$27.30

## FY 2007-2011

Total Difference from Status Quo (Million 2006\$)	\$4,938	\$3,602	\$6,614	\$2,405	\$0	-	-
Annual Average Difference from Status Quo (Million 2006\$)	\$988	\$720	\$1,323	\$481	\$0	-	-
PPT Effective Tax Rate (Percent)	14.5%	13.3%	15.8%	12.2%	7.2%	-	-
Status Quo Effective Tax Rate (Percent)	7.1%	7.2%	7.1%	7.1%	7.2%	-	-

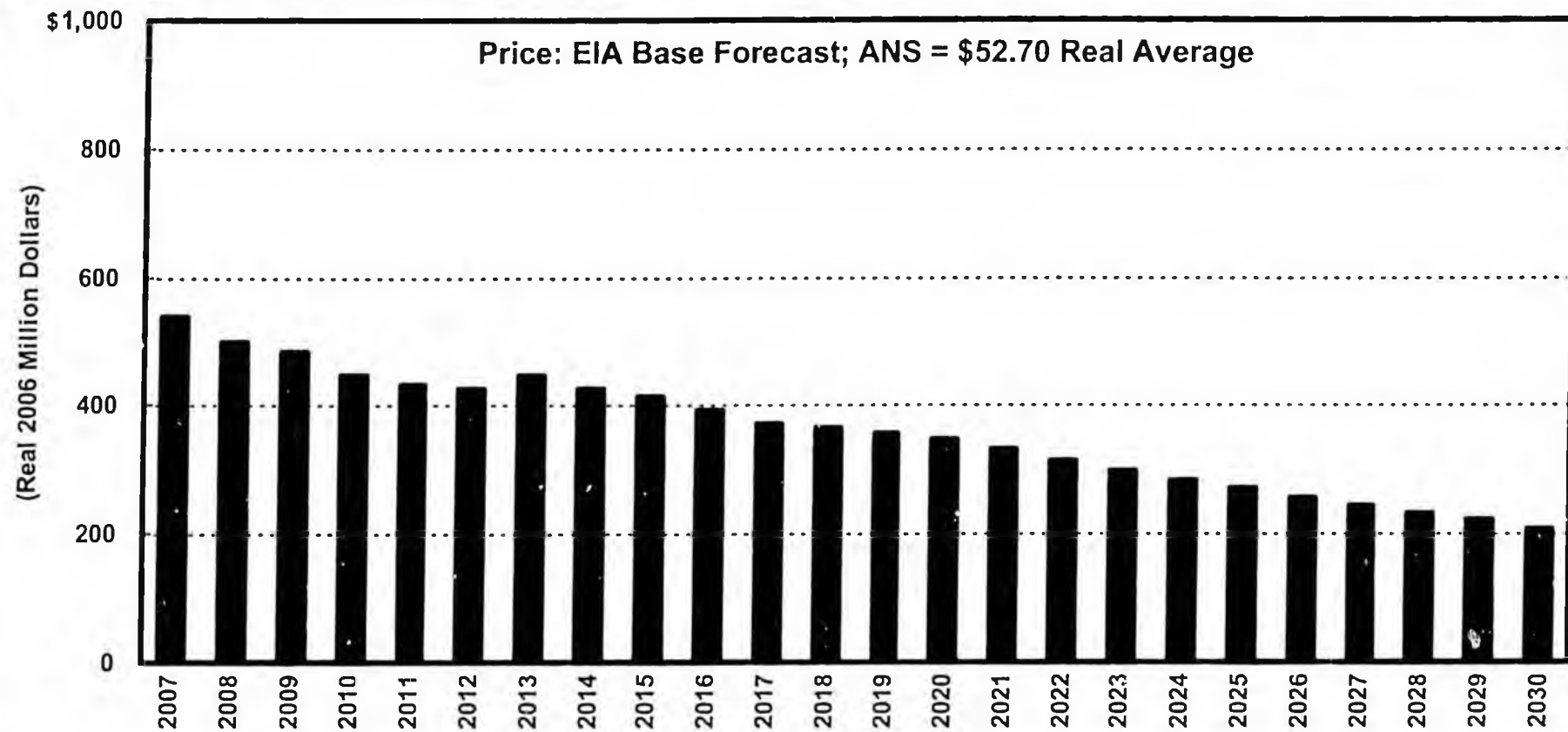
## FY 2007-2016

Total Difference from Status Quo (Million 2006\$)	\$10,268	\$5,040	\$15,956	\$5,617	-	\$0	-
Annual Average Difference from Status Quo (Million 2006\$)	\$1,027	\$504	\$1,596	\$562	-	\$0	-
PPT Effective Tax Rate (Percent)	14.6%	11.8%	16.6%	12.4%	-	6.3%	-
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	-	6.3%	-

## FY 2007-2030

Total Difference from Status Quo (Million 2006\$)	\$23,371	\$6,110	\$39,533	\$12,426	-	-	\$0
Annual Average Difference from Status Quo (Million 2006\$)	\$974	\$255	\$1,647	\$518	-	-	\$0
PPT Effective Tax Rate (Percent)	15.0%	9.5%	17.5%	12.1%	-	-	4.9%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	-	4.9%

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



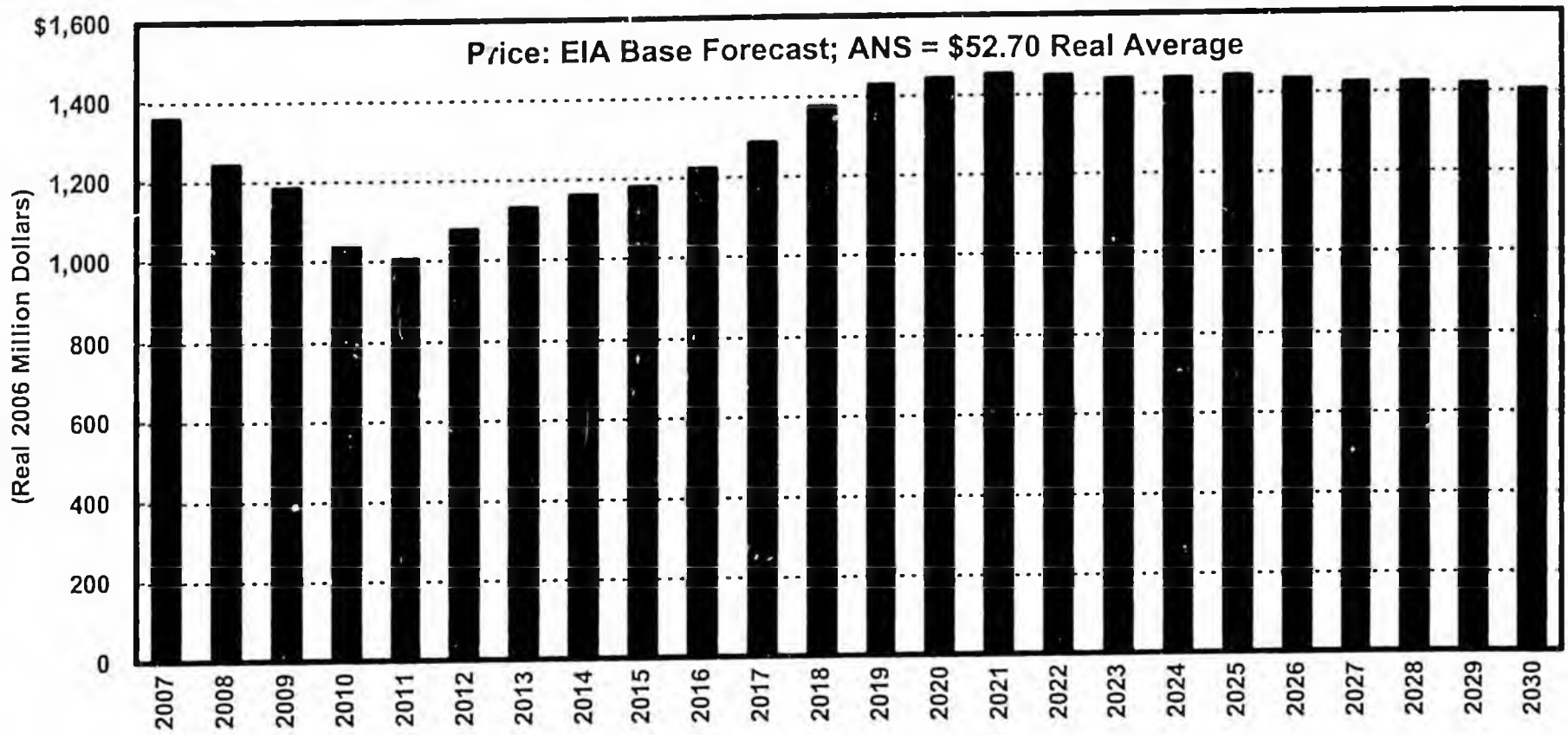
	FY 2007-2011	FY 2007-2016	FY 2007-2030
Total Difference from 20/20 PPT Tax (\$Million)	\$2,398	\$4,497	\$8,584
Annual Average Difference from 20/20 PPT Tax (\$Million)	\$480	\$450	\$358
25/20 PPT Effective Tax Rate (Percent)	15.8%	16.0%	16.4%
20/20 PPT Effective Tax Rate (Percent)	12.2%	12.4%	12.6%

\* Calculated from July 2006; includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

# 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 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
<i>Average ANS Price in Real 2006 Dollars:</i>	\$52.70	\$33.40	\$70.00	\$40.00	-	-	-
<b>FY 2007-2011</b>							
Total Difference from 20/20 PPT Tax (Million 2006\$)	\$2,398	\$2,021	\$2,855	\$1,610	-	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006\$)	\$480	\$404	\$571	\$322	-	-	-
25/20 PPT Effective Tax Rate (Percent)	15.8%	14.8%	16.9%	14.1%	-	-	-
20/20 PPT Effective Tax Rate (Percent)	12.2%	11.4%	13.2%	10.7%	-	-	-
<b>FY 2007-2016</b>							
Total Difference from 20/20 PPT Tax (Million 2006\$)	\$4,497	\$3,126	\$5,909	\$3,162	-	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006\$)	\$450	\$313	\$597	\$316	-	-	-
25/20 PPT Effective Tax Rate (Percent)	16.0%	13.6%	17.7%	14.2%	-	-	-
20/20 PPT Effective Tax Rate (Percent)	12.4%	10.3%	13.8%	10.8%	-	-	-
<b>FY 2007-2030</b>							
Total Difference from 20/20 PPT Tax (Million 2006\$)	\$8,584	\$4,462	\$12,455	\$5,814	-	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006\$)	\$358	\$186	\$519	\$242	-	-	-
25/20 PPT Effective Tax Rate (Percent)	16.4%	11.7%	18.5%	14.0%	-	-	-
20/20 PPT Effective Tax Rate (Percent)	12.6%	9.7%	14.5%	10.6%	-	-	-

# Change in Projected Taxes Under the House Resources CS DOR Forecast Production (FY 2007-2030)\*



	FY 2007-2011	FY 2007-2016	FY 2007-2030
Total Difference from SQ (\$Million)	\$5,823	\$11,578	\$31,386
Annual Average Difference from SQ (\$Million)	\$1,165	\$1,158	\$1,308
PPT Effective Tax Rate (Percent)	15.8%	15.7%	18.4%
SQ Effective Tax Rate (Percent)	7.1%	6.3%	4.9%

\* Calculated from April 2006; \$60 Million exemption over 8 companies for 10 years; volumes per DOR Fall 2005 Forecast with Ooguruk projection.



# Change in Projected Taxes Under the House Resources CS DOR Forecast Production (FY 2007-2030)\*

	EIA WTI Price Forecast:			Fixed \$40 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
<i>Average ANS Price in Real 2006 Dollars:</i>	\$52.70	\$33.40	\$70.00	\$40.00	\$30.30	\$28.30	\$25.40

## FY 2007-2011

Total Difference from Status Quo (Million 2006\$)	\$5,823	\$3,794	\$8,602	\$1,703	\$0	-	-
Annual Average Difference from Status Quo (Million 2006\$)	\$1,165	\$759	\$1,720	\$341	\$0	-	-
House Resources CS Effective Tax Rate (Percent)	15.8%	13.7%	18.4%	10.7%	7.2%	-	-
Status Quo Effective Tax Rate (Percent)	7.1%	7.2%	7.1%	7.1%	7.2%	-	-

## FY 2007-2016

Total Difference from Status Quo (Million 2006\$)	\$11,570	\$4,993	\$21,512	\$4,310	-	\$0	-
Annual Average Difference from Status Quo (Million 2006\$)	\$1,158	\$499	\$2,151	\$431	-	\$0	-
House Resources CS Effective Tax Rate (Percent)	15.7%	11.8%	20.3%	10.9%	-	6.3%	-
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	-	6.3%	-

## FY 2007-2030

Total Difference from Status Quo (Million 2006\$)	\$31,386	\$7,186	\$75,604	\$13,246	-	-	\$0
Annual Average Difference from Status Quo (Million 2006\$)	\$1,308	\$299	\$3,150	\$552	-	-	\$0
House Resources CS Effective Tax Rate (Percent)	18.4%	10.3%	29.2%	12.6%	-	-	5.0%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	-	5.0%

# Change in Projected Taxes Under the House Resources CS Costs Increased by 20% DOR Forecast Production (FY 2007-2030)\*

Average ANS Price in Real 2006 Dollars:

	EIA WTI Price Forecast:			Fixed \$40 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
	\$52.70	\$33.40	\$70.00	\$40.00	\$34.60	\$32.30	\$29.00

<i><b>FY 2007-2011</b></i>							
Total Difference from Status Quo (Million 2006\$)	<b>\$5,064</b>	\$3,035	\$7,843	\$944	\$0	-	-
Annual Average Difference from Status Quo (Million 2006\$)	<b>\$1,013</b>	\$607	\$1,569	\$189	\$0	-	-
House Resources CS Effective Tax Rate (Percent)	<b>14.7%</b>	12.4%	17.4%	9.1%	7.1%	-	-
Status Quo Effective Tax Rate (Percent)	<b>7.1%</b>	7.2%	7.1%	7.1%	7.1%	-	-

<i><b>FY 2007-2016</b></i>							
Total Difference from Status Quo (Million 2006\$)	<b>\$10,109</b>	\$3,524	\$20,043	\$2,841	-	\$0	-
Annual Average Difference from Status Quo (Million 2006\$)	<b>\$1,011</b>	\$352	\$2,004	\$284	-	\$0	-
House Resources CS Effective Tax Rate (Percent)	<b>14.5%</b>	10.2%	19.3%	9.3%	-	6.3%	-
Status Quo Effective Tax Rate (Percent)	<b>6.3%</b>	6.5%	6.2%	6.3%	-	6.3%	-

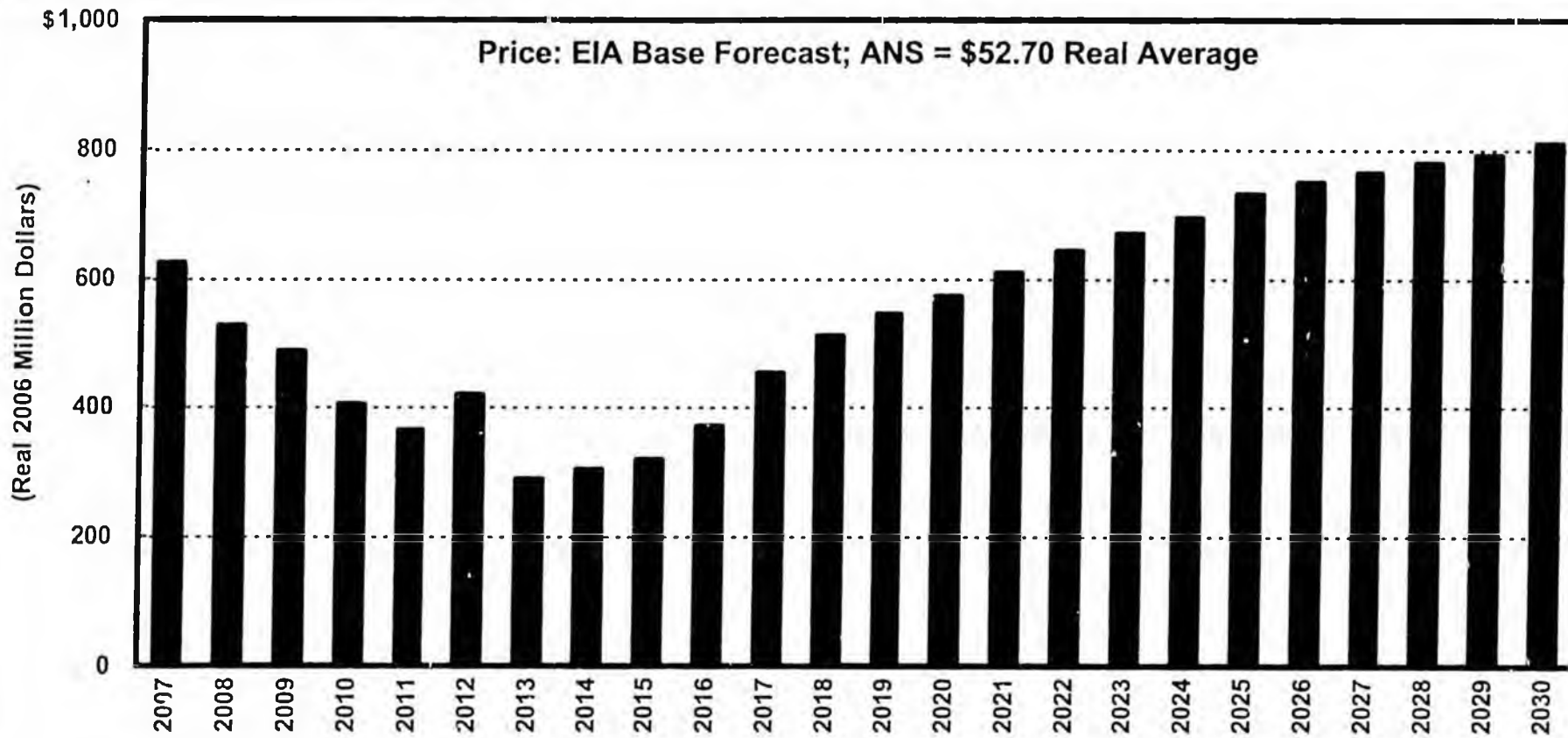
<i><b>FY 2007-2030</b></i>							
Total Difference from Status Quo (Million 2006\$)	<b>\$28,635</b>	\$4,435	\$72,854	\$10,496	-	-	\$0
Annual Average Difference from Status Quo (Million 2006\$)	<b>\$1,193</b>	\$185	\$3,036	\$437	-	-	\$0
House Resources CS Effective Tax Rate (Percent)	<b>17.3%</b>	8.4%	28.3%	11.0%	-	-	4.9%
Status Quo Effective Tax Rate (Percent)	<b>4.9%</b>	5.4%	4.7%	4.9%	-	-	4.9%

\* Calculated from April 2006; \$60 Million exemption over 8 companies for 10 years; volumes per DOR Fall 2005 Forecast with Oooguruk projection.



# Difference in Projected Taxes Between the House Resources CS<sup>1</sup> and a 20/20<sup>2</sup> Tax

## DOR Forecast Production (FY 2007-2030)



	FY 2007-2011	FY 2007-2016	FY 2007-2030
Total Difference from 20/20 PPT Tax (\$Million)	\$2,405	\$4,107	\$13,415
Annual Average Difference from 20/20 PPT Tax (\$Million)	\$481	\$411	\$559
House Resources CS Effective Tax Rate (Percent)	15.8%	15.7%	18.4%
20/20 PPT Effective Tax Rate (Percent)	12.2%	12.4%	12.6%

<sup>1</sup> Calculated from April 2006; \$60 Million exemption over 8 companies for 10 years; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

<sup>2</sup> Calculated from July 2008; includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.



# Difference in Projected Taxes Between the House Resources CS<sup>1</sup> and a 20/20<sup>2</sup> Tax DOR Forecast Production (FY 2007-2030)

	EIA WTI Price Forecast:			Fixed \$40 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
Average ANS Price in Real 2006 Dollars:	\$52.70	\$33.40	\$70.00	\$40.00	-	-	-

<i>FY 2007-2011</i>							
Total Difference from 20/20 PPT Tax (Million 2006S)	\$2,405	\$1,335	\$3,965	\$29	-	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006S)	\$481	\$267	\$793	\$6	-	-	-
House Resources CS Effective Tax Rate (Percent)	15.8%	13.7%	18.4%	10.7%	-	-	-
20/20 PPT Effective Tax Rate (Percent)	12.2%	11.4%	13.2%	10.7%	-	-	-

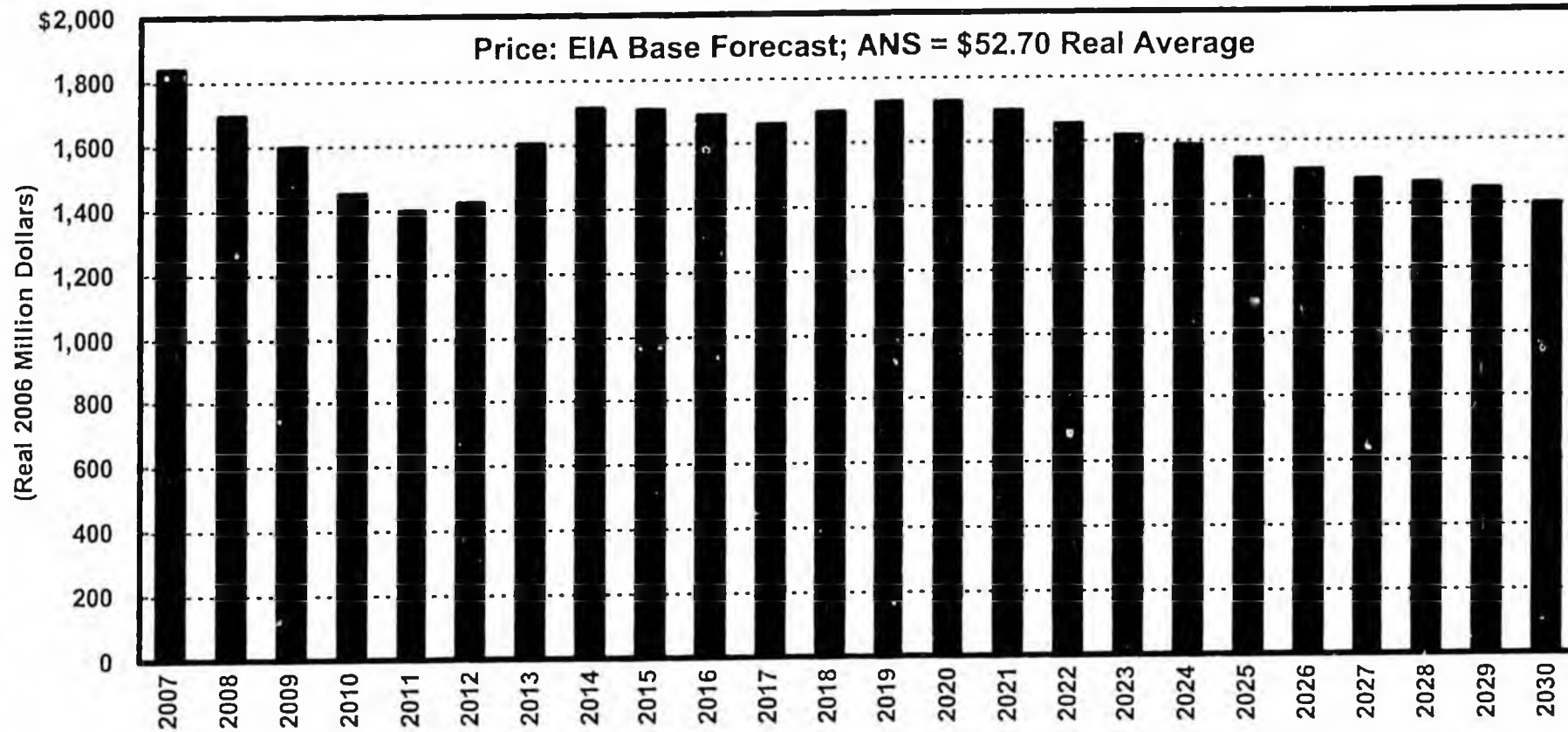
<i>FY 2007-2016</i>							
Total Difference from 20/20 PPT Tax (Million 2006S)	\$4,107	\$1,380	\$9,824	\$154	-	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006S)	\$411	\$138	\$982	\$15	-	-	-
House Resources CS Effective Tax Rate (Percent)	15.7%	11.8%	20.3%	10.9%	-	-	-
20/20 PPT Effective Tax Rate (Percent)	12.4%	10.3%	13.8%	10.8%	-	-	-

<i>FY 2007-2030</i>							
Total Difference from 20/20 PPT Tax (Million 2006S)	\$13,415	\$2,362	\$45,342	\$3,450	-	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006S)	\$559	\$98	\$1,889	\$144	-	-	-
House Resources CS Effective Tax Rate (Percent)	18.4%	10.3%	29.2%	12.6%	-	-	-
20/20 PPT Effective Tax Rate (Percent)	12.6%	8.7%	14.5%	10.6%	-	-	-

<sup>1</sup> Calculated from April 2006; \$80 Million exemption over 8 companies for 10 years; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

<sup>2</sup> Calculated from July 2006; includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

# Change in Projected Taxes Under the Senate Resources CS DOR Forecast Production (FY 2007-2030)\*



	FY 2007-2011	FY 2007-2016	FY 2007-2030
Total Difference from SQ (\$Million)	\$7,955	\$16,061	\$38,179
Annual Average Difference from SQ (\$Million)	\$1,521	\$1,606	\$1,591
Senate Resources CS Effective Tax Rate (Percent)	19.0%	19.3%	21.4%
SQ Effective Tax Rate (Percent)	7.1%	6.3%	4.9%

\* Calculated from April 2006; includes transition (50% of capex over 1<sup>st</sup> 7 years to maximum of \$5 Billion) and 15 BPD exemption; volumes per DOR Fall 2005 Forecast with Cooguruk projection.

# Change in Projected Taxes Under the Senate Resources CS DOR Forecast Production (FY 2007-2030)\*

	EIA WTI Price Forecast:			Fixed \$40 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
Average ANS Price in Real 2006 Dollars:	\$52.70	\$33.40	\$70.00	\$40.00	\$28.30	\$25.50	\$23.10

## FY 2007-2011

Total Difference from Status Quo (Million 2006\$)	\$7,955	\$5,716	\$10,644	\$2,909	\$0	-	-
Annual Average Difference from Status Quo (Million 2006\$)	\$1,591	\$1,143	\$2,129	\$582	\$0	-	-
Senate Resources CS Effective Tax Rate (Percent)	19.0%	17.0%	21.1%	13.3%	7.2%	-	-
Status Quo Effective Tax Rate (Percent)	7.1%	7.2%	7.1%	7.1%	7.2%	-	-

## FY 2007-2016

Total Difference from Status Quo (Million 2006\$)	\$16,061	\$8,192	\$25,540	\$7,641	-	\$0	-
Annual Average Difference from Status Quo (Million 2006\$)	\$1,606	\$819	\$2,554	\$764	-	\$0	-
Senate Resources CS Effective Tax Rate (Percent)	19.3%	15.2%	22.9%	14.6%	-	6.3%	-
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	-	6.3%	-

## FY 2007-2030

Total Difference from Status Quo (Million 2006\$)	\$38,179	\$12,112	\$68,505	\$19,417	-	-	\$0
Annual Average Difference from Status Quo (Million 2006\$)	\$1,591	\$505	\$2,854	\$809	-	-	\$0
Senate Resources CS Effective Tax Rate (Percent)	21.4%	13.6%	26.9%	16.2%	-	-	5.0%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	-	5.0%

\* Calculated from April 2006; Includes transition (50% of capex over 1<sup>st</sup> 7 years to maximum of \$5 billion) and 15 BPD exemption; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

# Change in Projected Taxes Under the Senate Resources CS Costs Increased by 20% DOR Forecast Production (FY 2007-2030)\*

	EIA WTI Price Forecast:			Fixed \$40 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
<i>Average ANS Price in Real 2006 Dollars:</i>	\$52.70	\$33.40	\$70.00	\$40.00	\$32.70	\$29.00	\$26.30

<b>FY 2007-2011</b>							
Total Difference from Status Quo (Million 2006S)	\$6,901	\$4,662	\$9,590	\$1,855	\$0	-	-
Annual Average Difference from Status Quo (Million 2006S)	\$1,380	\$932	\$1,918	\$371	\$0	-	-
Senate Resources CS Effective Tax Rate (Percent)	17.4%	15.2%	19.7%	11.0%	7.1%	-	-
Status Quo Effective Tax Rate (Percent)	7.1%	7.2%	7.1%	7.1%	7.1%	-	-

<b>FY 2007-2016</b>							
Total Difference from Status Quo (Million 2006S)	\$14,353	\$6,484	\$23,832	\$5,933	-	\$0	-
Annual Average Difference from Status Quo (Million 2006S)	\$1,435	\$648	\$2,383	\$593	-	\$0	-
Senate Resources CS Effective Tax Rate (Percent)	17.9%	13.4%	21.8%	12.7%	-	6.3%	-
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	-	6.3%	-

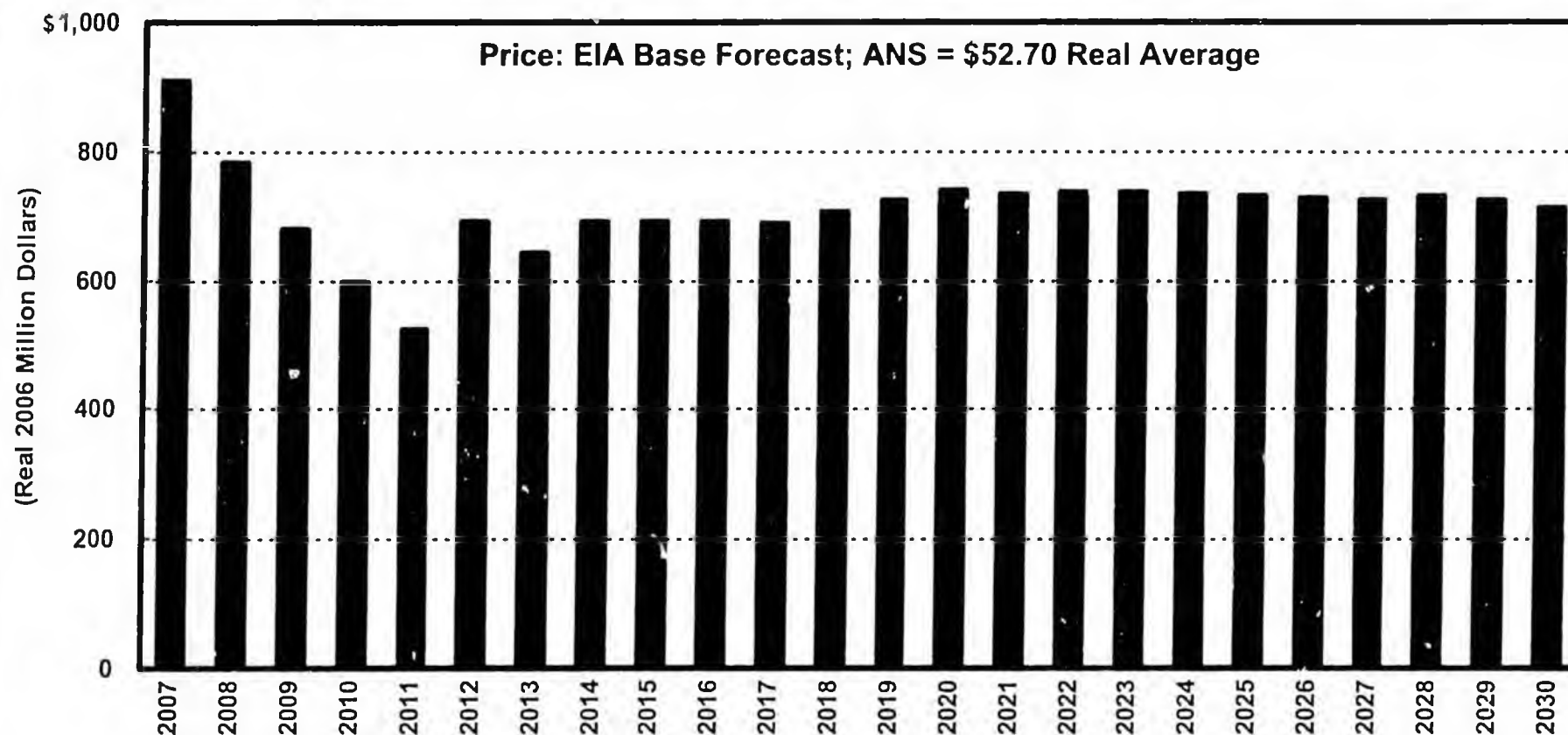
<b>FY 2007-2030</b>							
Total Difference from Status Quo (Million 2006S)	\$34,987	\$8,920	\$65,313	\$16,225	-	-	\$0
Annual Average Difference from Status Quo (Million 2006S)	\$1,458	\$372	\$2,721	\$676	-	-	\$0
Senate Resources CS Effective Tax Rate (Percent)	20.0%	11.4%	25.8%	14.4%	-	-	5.0%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	-	5.0%

\* Calculated from April 2006; includes transition (50% of capex over 17 years to maximum of \$5 Billion) and 18 BPD exemption; volumes per DOR Fall 2005 Forecast with Oooguruk projection.



# Difference in Projected Taxes Between the Senate Resources CS<sup>1</sup> and a 20/20<sup>2</sup> Tax

## DOR Forecast Production (FY 2007-2030)



	FY 2007-2011	FY 2007-2016	FY 2007-2030
Total Difference from 20/20 PPT Tax (\$Million)	\$3,484	\$6,882	\$17,016
Annual Average Difference from 20/20 PPT Tax (\$Million)	\$697	\$688	\$709
Senate Resources CS Effective Tax Rate (Percent)	17.4%	17.9%	20.0%
20/20 PPT Effective Tax Rate (Percent)	12.2%	12.4%	12.6%

<sup>1</sup> Calculated from April 2006; Includes transition (50% of capex over 147 years to maximum of \$5 Billion) and 15 BPD exemption; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

<sup>2</sup> Calculated from July 2006; Includes 8-year transition (100% 2001-2008) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.



# Difference in Projected Taxes Between the Senate Resources CS<sup>1</sup> and a 20/20<sup>2</sup> Tax

## DOR Forecast Production (FY 2007-2030)

	EIA WTI Price Forecast:			Fixed \$40 ANS Price	FY2007-2011 Breakeven	FY2007-2016 Breakeven	FY2007-2030 Breakeven
	Base	Low	High				
Average ANS Price in Real 2006 Dollars:	\$52.70	\$33.40	\$70.00	\$40.00	-	-	-

### FY 2007-2011

Total Difference from 20/20 PPT Tax (Million 2006\$)	\$3,484	\$2,203	\$4,953	\$182	-	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006\$)	\$697	\$441	\$991	\$36	-	-	-
Senate Resources CS Effective Tax Rate (Percent)	17.4%	15.2%	19.7%	11.0%	-	-	-
20/20 PPT Effective Tax Rate (Percent)	12.2%	11.4%	13.2%	10.7%	-	-	-

### FY 2007-2016

Total Difference from 20/20 PPT Tax (Million 2006\$)	\$6,882	\$2,870	\$12,144	\$1,778	-	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006\$)	\$688	\$287	\$1,214	\$178	-	-	-
Senate Resources CS Effective Tax Rate (Percent)	17.9%	13.4%	21.8%	12.7%	-	-	-
20/20 PPT Effective Tax Rate (Percent)	12.4%	10.3%	13.8%	10.8%	-	-	-

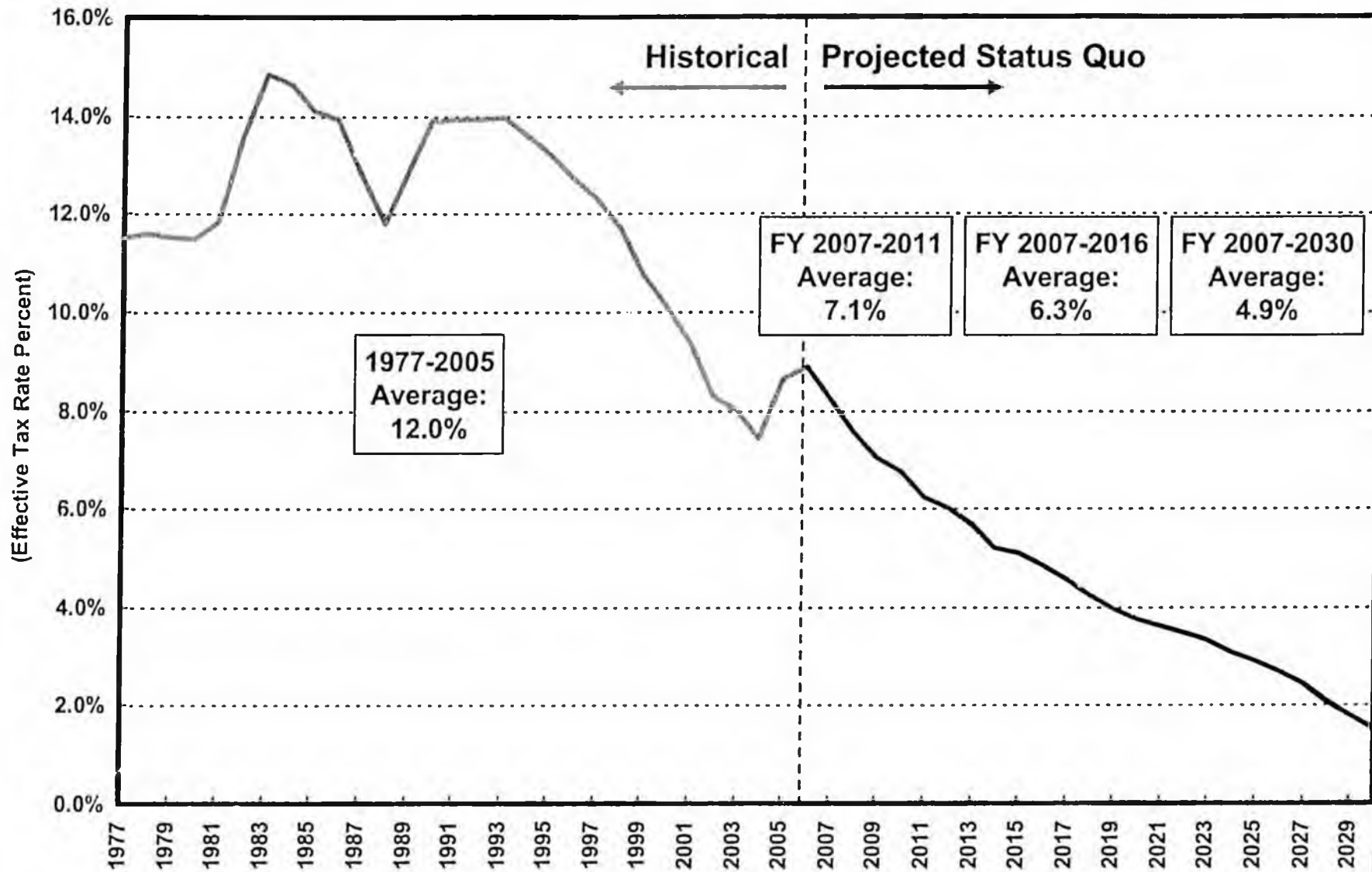
### FY 2007-2030

Total Difference from 20/20 PPT Tax (Million 2006\$)	\$17,016	\$4,096	\$35,051	\$6,429	-	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006\$)	\$709	\$171	\$1,460	\$268	-	-	-
Senate Resources CS Effective Tax Rate (Percent)	20.0%	11.4%	25.8%	14.4%	-	-	-
20/20 PPT Effective Tax Rate (Percent)	12.6%	8.7%	14.5%	10.6%	-	-	-

<sup>1</sup> Calculated from April 2008; includes transition (50% of capex over 1<sup>st</sup> 7 years to maximum of \$5 Billion) and 15 BPD exemption; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

<sup>2</sup> Calculated from July 2008; includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

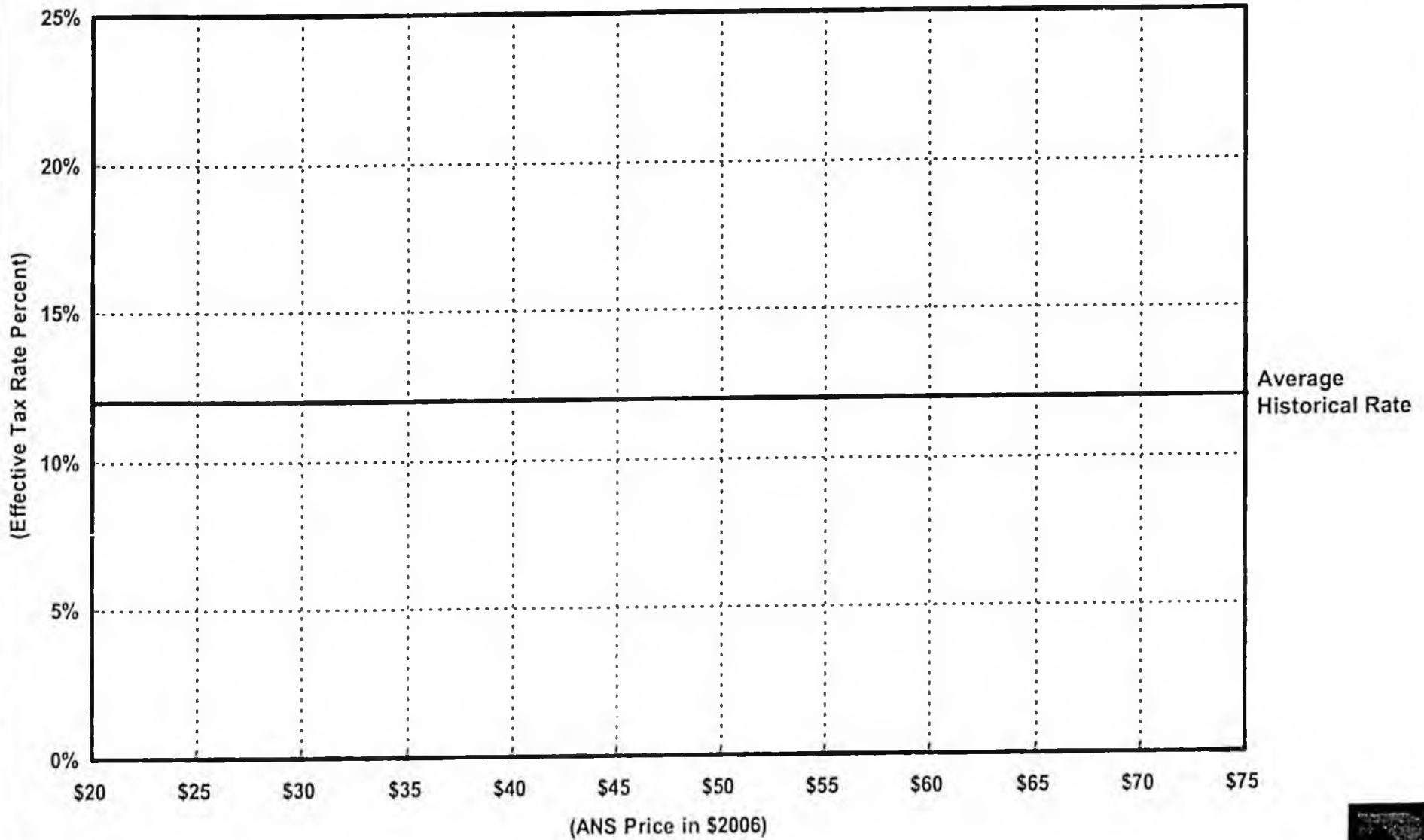
# Effective Severance Tax Rates Over Time



Source: Historical: Alaska Department of Revenue.



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

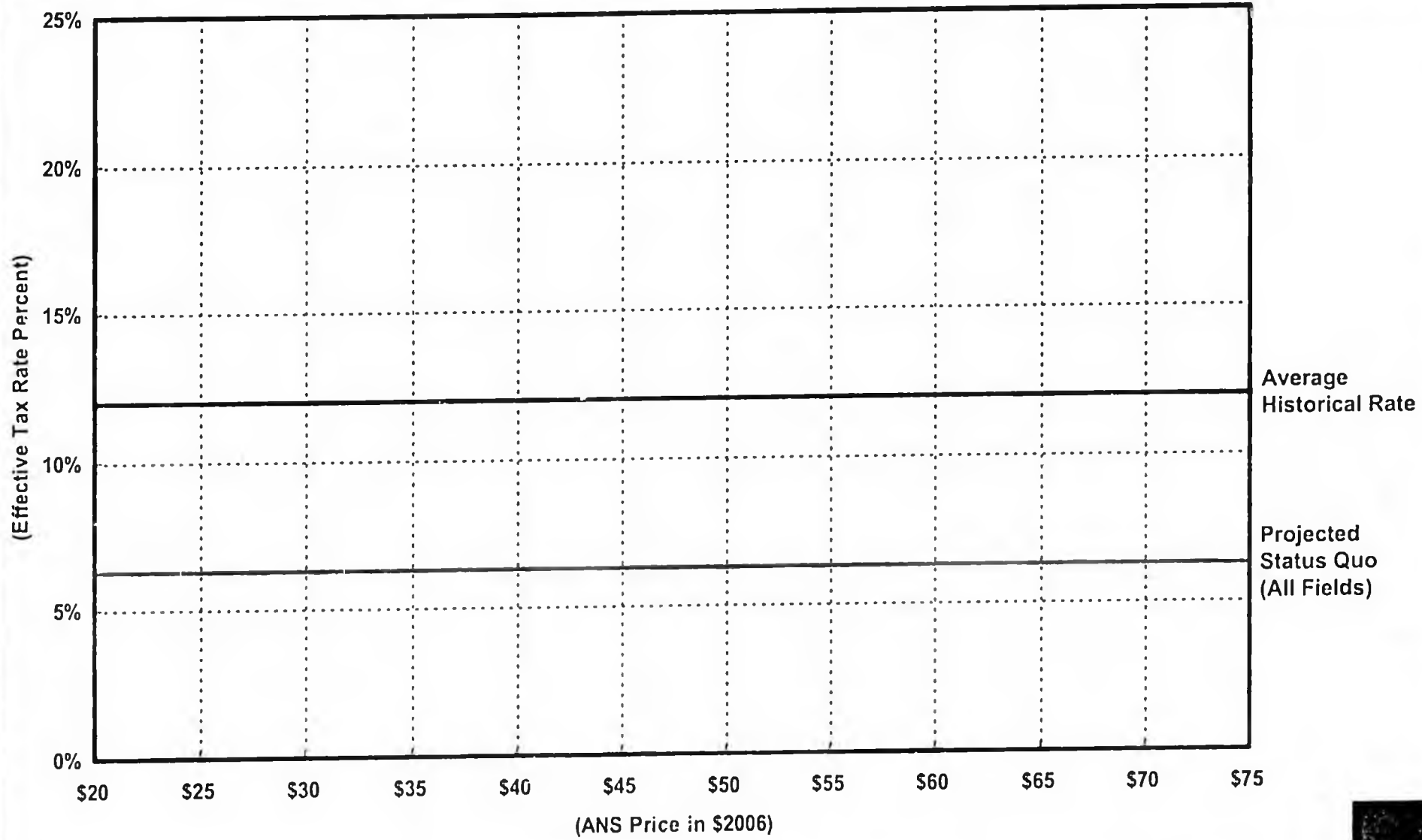


Source: Alaska Department of Revenue.



# Effective Average Tax Rates at Various Price Levels

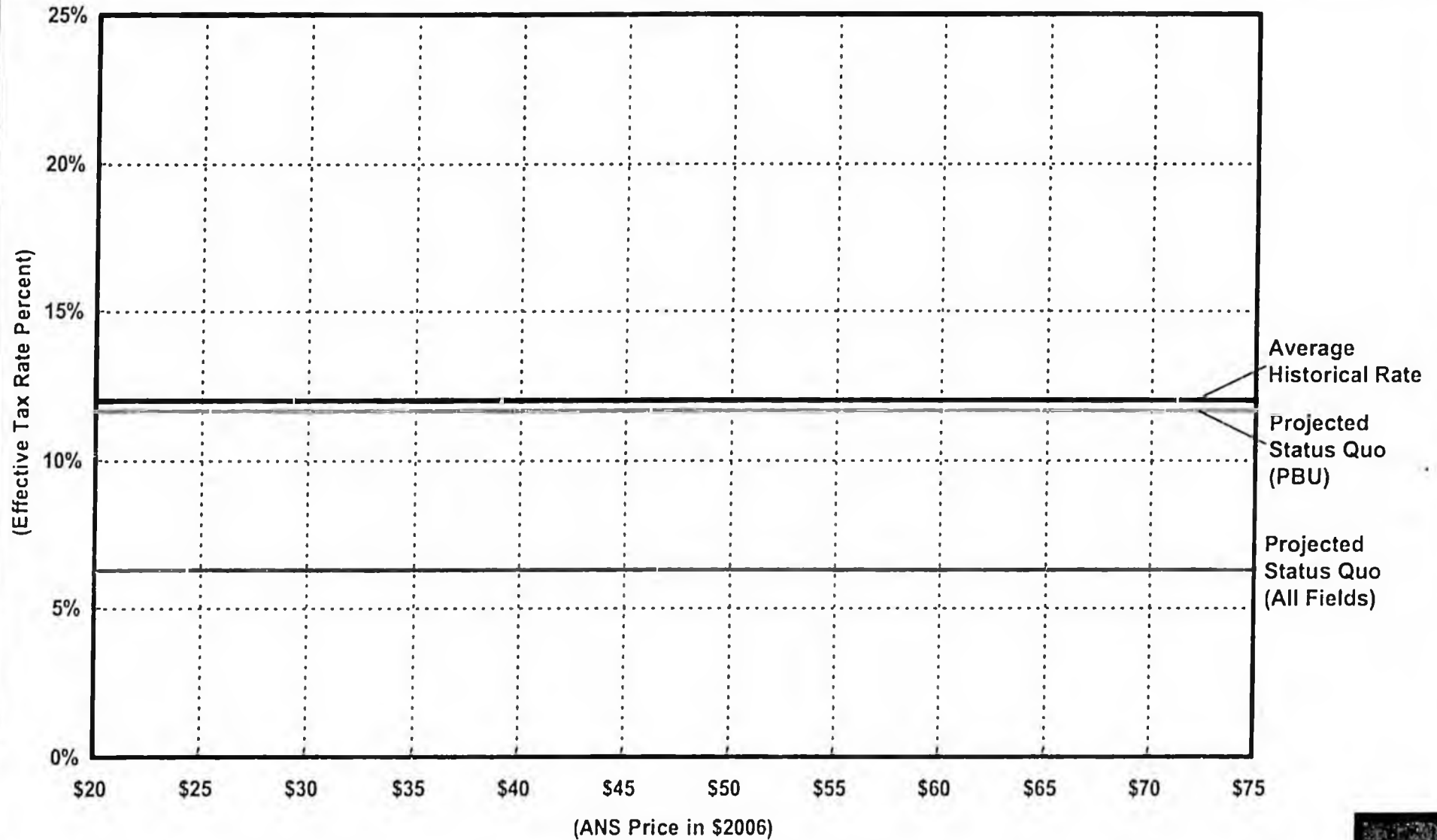
(FY 2007-2016)



Source: Historical: Alaska Department of Revenue.

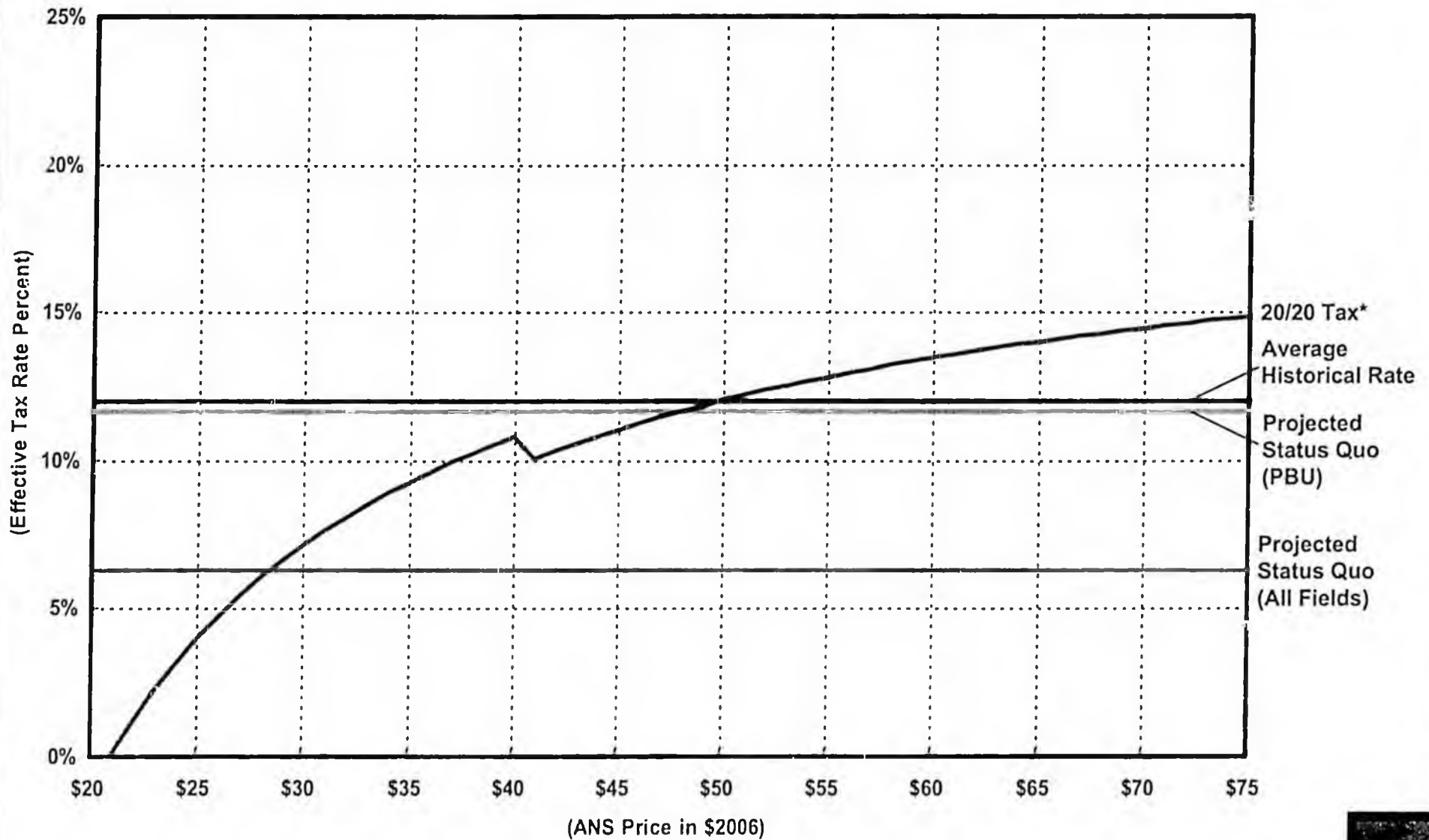


# Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



Source: Historical: Alaska Department of Revenue.

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

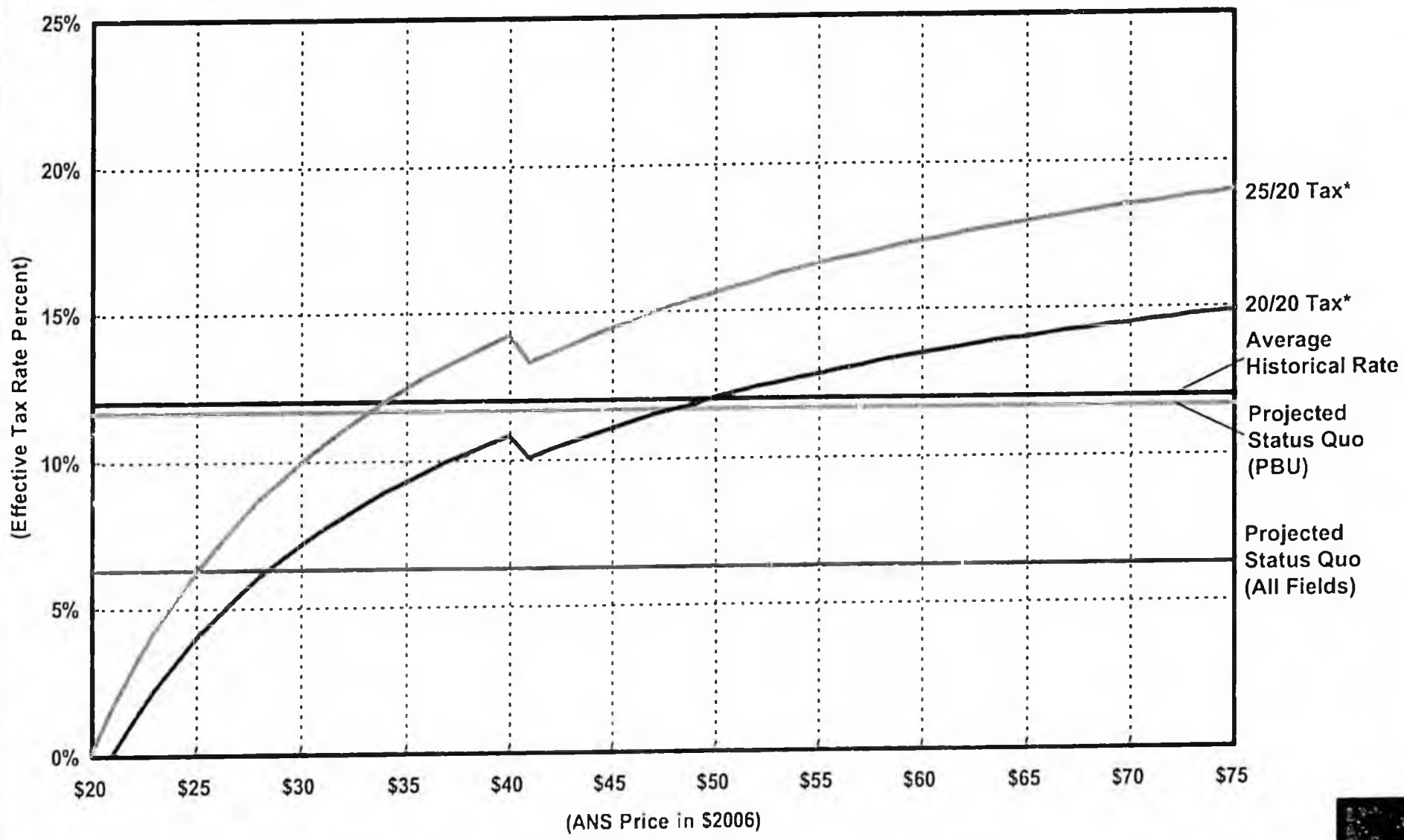


\* Calculated from July 2006; Includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Ooguruk projection.

Source: Historical: Alaska Department of Revenue.



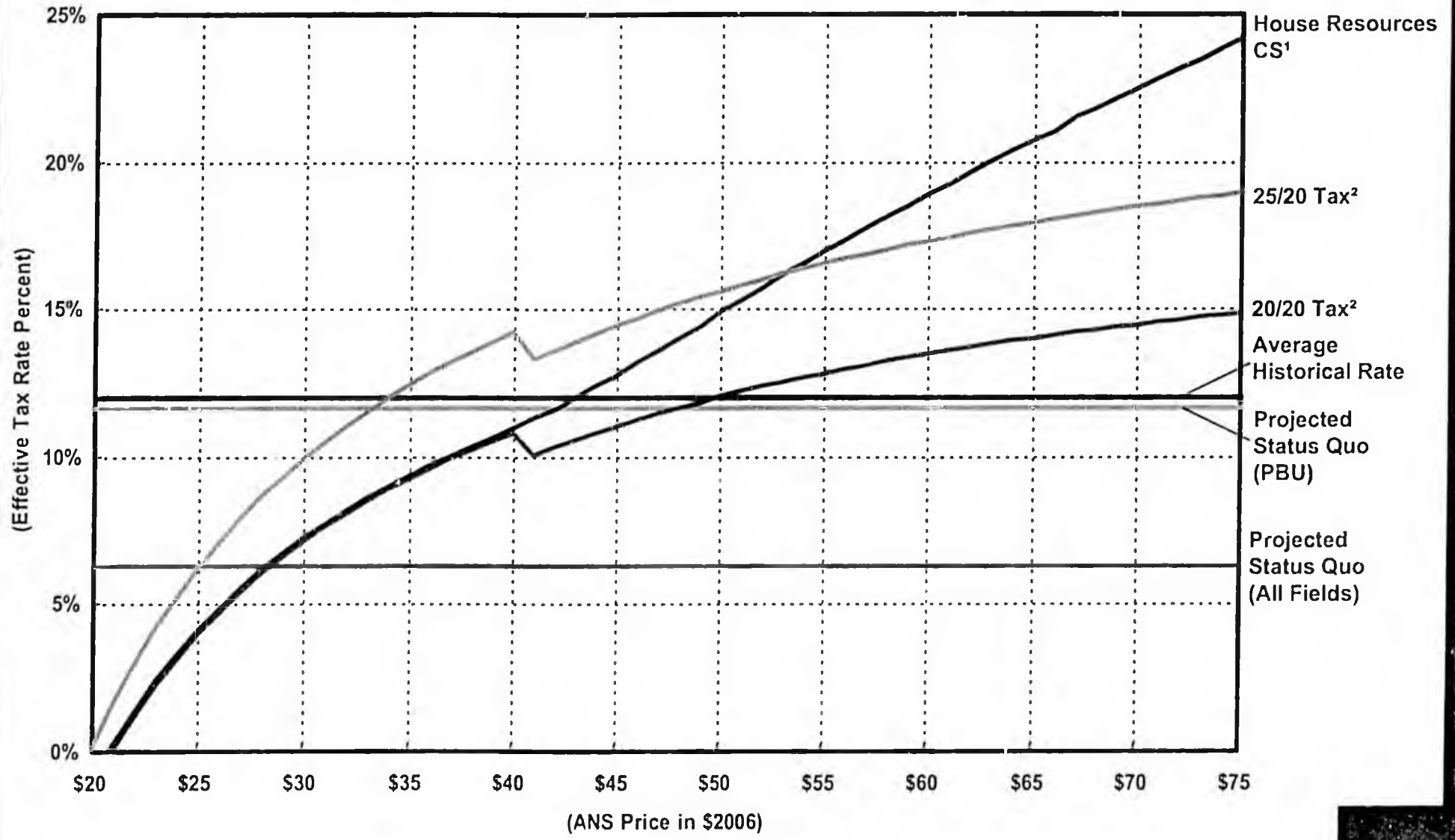
# Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



\* Calculated from July 2008; Includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Qooguruk projection.  
Source: Historical: Alaska Department of Revenue.



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

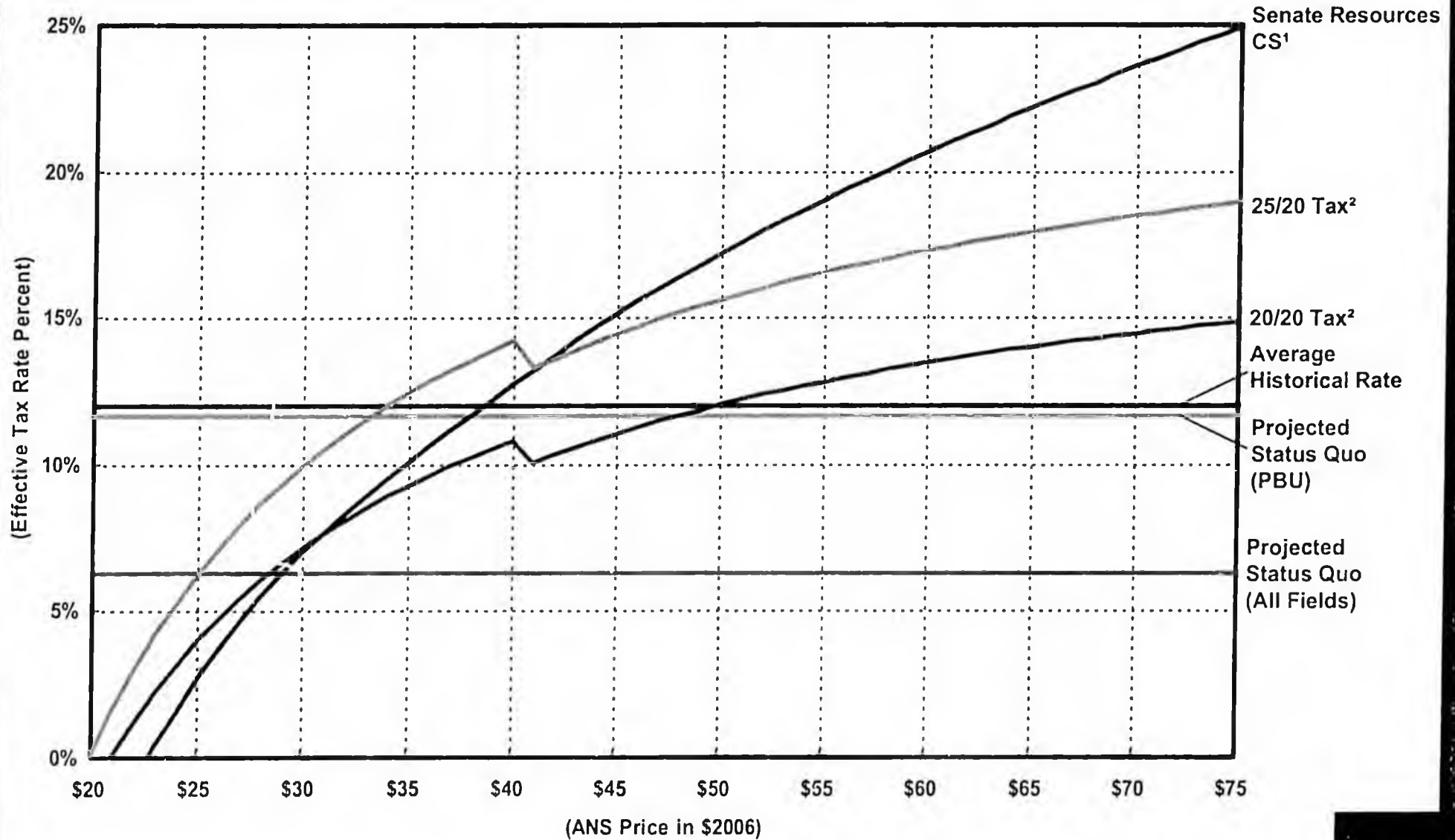


<sup>1</sup> Calculated from April 2008; \$60 Million exemption over 8 companies for 10 years; volumes per DOR Fall 2008 Forecast with Oooguruk projection.

<sup>2</sup> Calculated from July 2008; includes 6-year transition (100% 2001-2008) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2008 Forecast with Oooguruk projection.



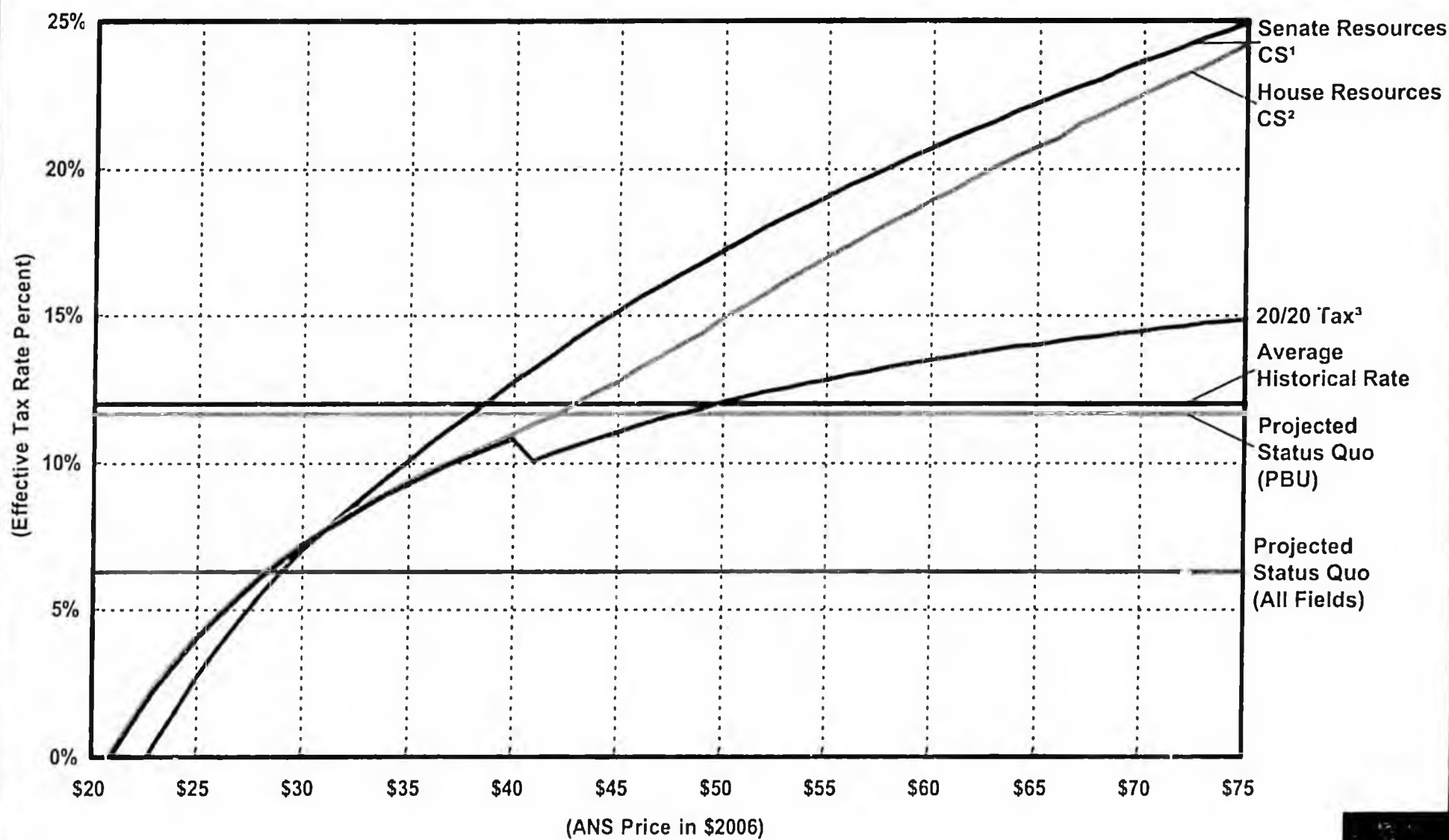
# Effective Average Tax Rates at Various Price Levels (FY 2007-2016)



<sup>1</sup> Calculated from April 2006; Includes transition (50% of capex over 1<sup>st</sup> 7 years to maximum of \$8 Billion) and 15 BPD exemption; volumes per DOR Fall 2005 Forecast with Ooquruk projection.  
<sup>2</sup> Calculated from July 2006; Includes 6-year transition (100% 2001-2006) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Ooquruk projection.



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



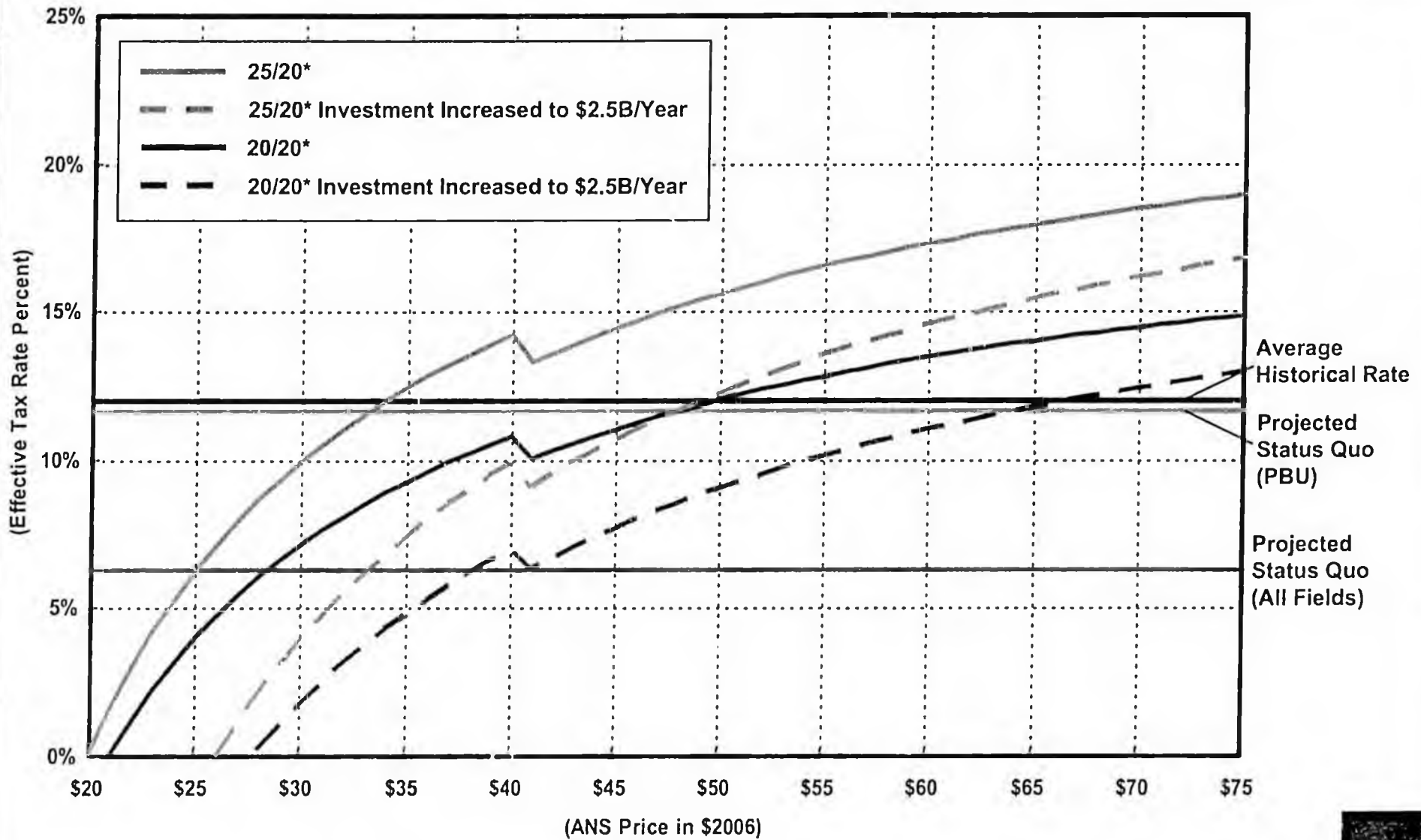
¹ Calculated from April 2006; Includes transition (50% of capex over 1<sup>st</sup> 7 years to maximum of \$5 Billion) and 15 BPD exemption; volumes per DOR Fall 2005 Forecast with Oooguruk projection.  
 ² Calculated from April 2006; \$40 Million exemption over 8 companies for 10 years; volumes per DOR Fall 2005 Forecast with Oooguruk projection.  
 ³ Calculated from July 2006; Includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.  
 Source: Alaska Department of Revenue.



# Effective Average Tax Rates at Various Price Levels

## Impact of Increased Investment

(FY 2007-2016)



\* Calculated from July 2006; Includes 6-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.  
 Source: Historical: Alaska Department of Revenue.



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

Average ANS Price in Real 2006 Dollars:	Total Government Take (Percent)				Alaska Take (Percent)			
	EIA WTI Price Forecast:			Fixed \$40 ANS Price	EIA WTI Price Forecast:			Fixed \$40 ANS Price
	Base	Low	High		Base	Low	High	
	\$52.70	\$33.40	\$70.00	\$40.00	\$52.70	\$33.40	\$70.00	\$40.00

## FY 2007-2011

Status Quo	54.4%	55.3%	53.8%	56.9%	25.9%	26.8%	25.2%	28.2%
20/20 PPT <sup>1</sup>	57.7%	58.1%	57.6%	59.4%	31.0%	31.0%	31.1%	32.1%
25/20 PPT <sup>1</sup>	60.0%	60.3%	59.9%	61.7%	34.5%	34.6%	34.8%	35.7%
House Resources CS <sup>2</sup>	60.0%	59.5%	60.8%	59.4%	34.5%	33.4%	36.2%	32.1%
Senate Resources CS <sup>3</sup>	62.3%	62.0%	62.8%	61.5%	37.4%	36.3%	38.6%	34.3%

## FY 2007-2016

Status Quo	53.3%	55.0%	52.4%	55.0%	24.8%	26.9%	23.7%	26.7%
20/20 PPT <sup>1</sup>	57.2%	57.6%	57.1%	58.1%	30.9%	30.9%	31.0%	31.5%
25/20 PPT <sup>1</sup>	59.6%	59.9%	59.6%	60.5%	34.5%	34.5%	34.8%	35.2%
House Resources CS <sup>2</sup>	59.4%	58.6%	61.1%	58.2%	34.2%	32.5%	37.2%	31.7%
Senate Resources CS <sup>3</sup>	62.0%	61.2%	63.0%	61.0%	37.8%	36.0%	39.8%	35.4%

## FY 2007-2030

Status Quo	51.9%	54.7%	50.8%	53.3%	23.4%	27.2%	22.0%	25.2%
20/20 PPT <sup>1</sup>	56.9%	57.1%	56.9%	57.3%	31.2%	30.9%	31.3%	31.4%
25/20 PPT <sup>1</sup>	59.3%	59.3%	59.3%	59.6%	34.9%	34.3%	35.2%	35.0%
House Resources CS <sup>2</sup>	60.6%	58.2%	65.9%	58.7%	37.0%	32.7%	45.4%	33.5%
Senate Resources CS <sup>3</sup>	62.7%	60.8%	64.7%	61.3%	39.9%	36.2%	43.3%	37.3%

<sup>1</sup> Calculated from July 2006; includes 8-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

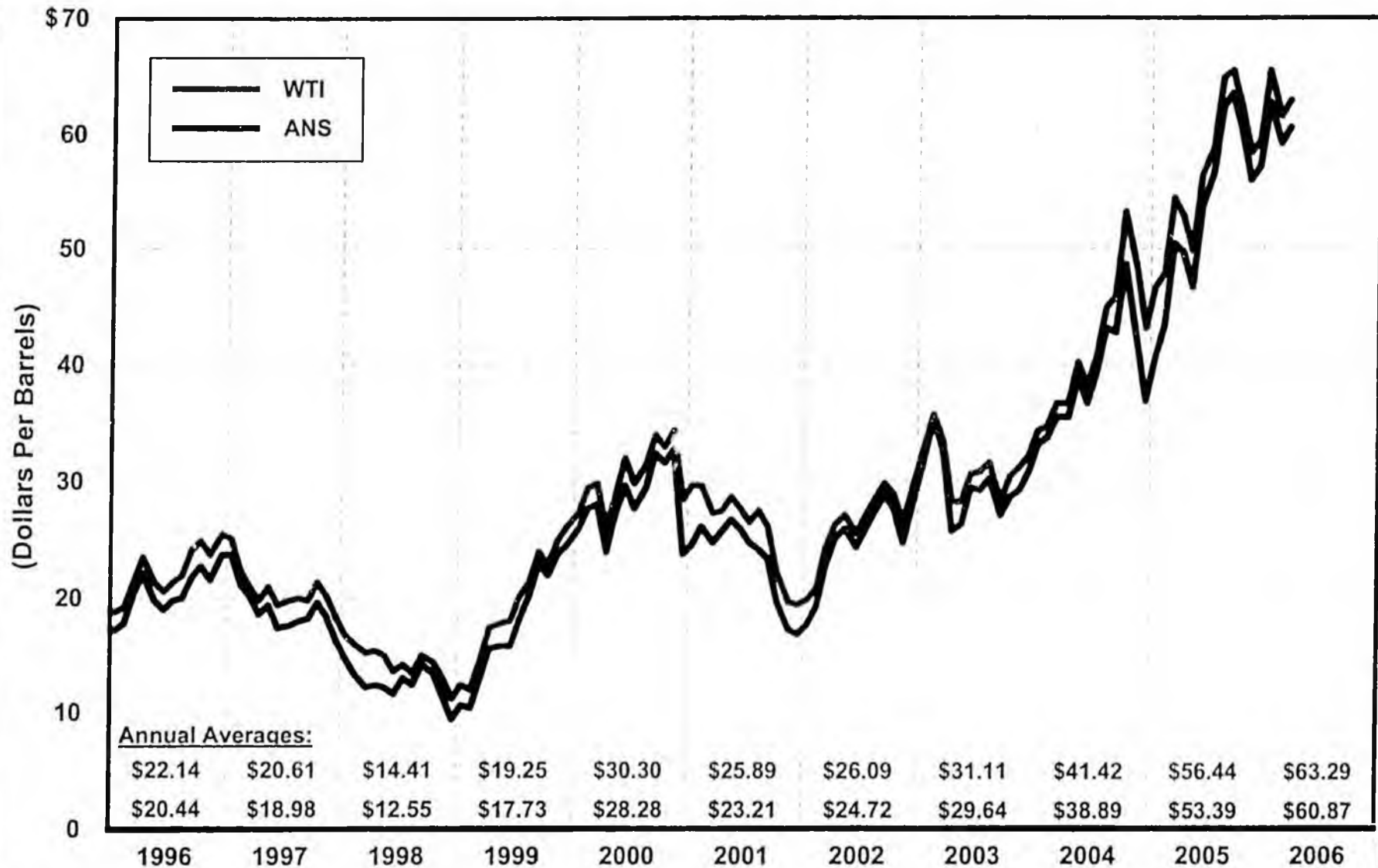
<sup>2</sup> Calculated from April 2006; includes transition (50% of capex over 1<sup>st</sup> 7 years to maximum of \$5 Billion) and 15 BPD exemption; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

<sup>3</sup> Calculated from July 2006; includes 8-year transition (100% 2001-2005) and \$73 Million exemption over 7 companies; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

# Progressivity Issues

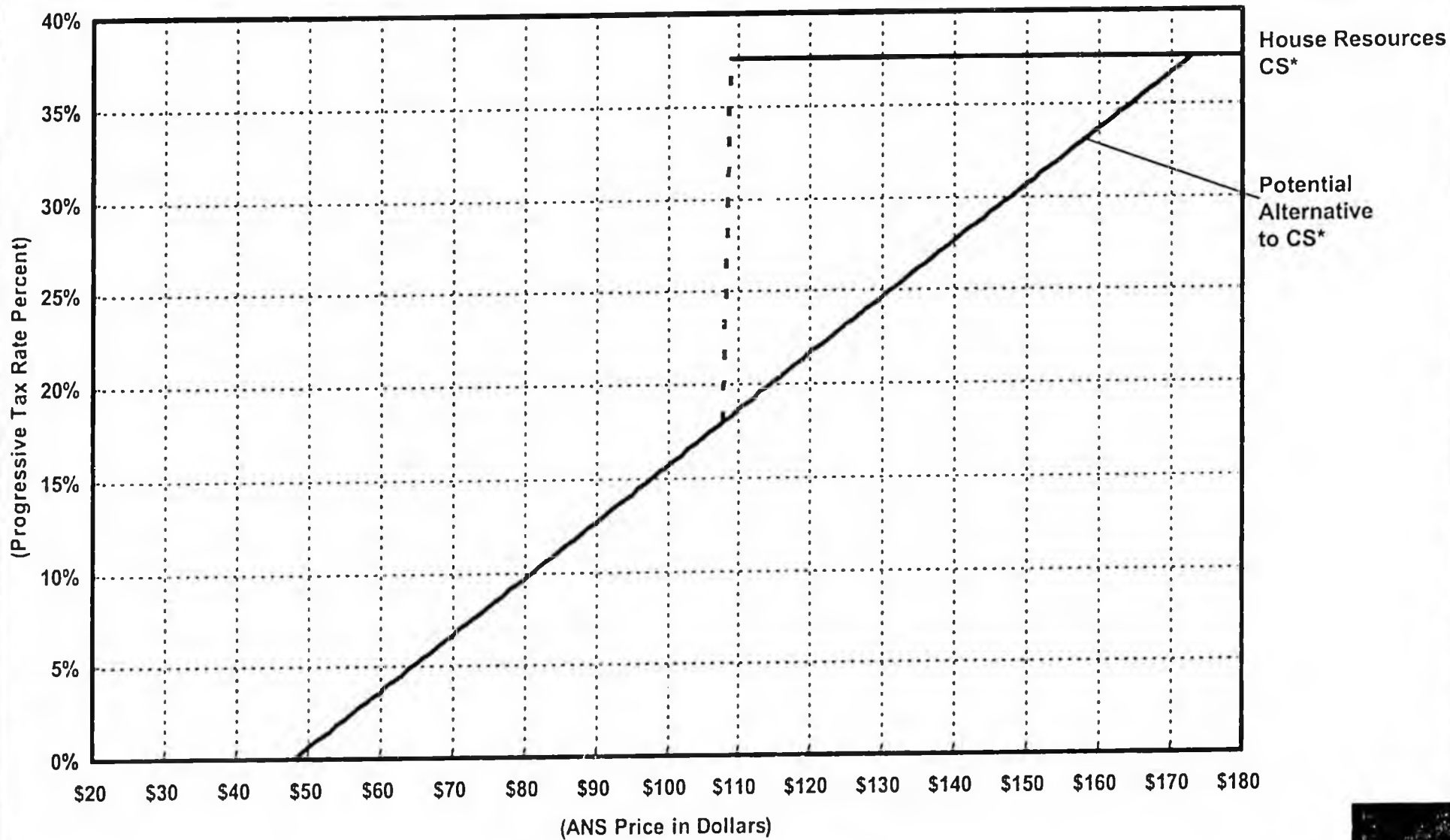
- **Choice of Threshold Price**
- **WTI v. ANS**
- **Real v. Nominal**
- **Deductibility**
- **Cap**

# Platt's WTI and ANS Prices (January 1996 - March 2006)



Source: Platt's.

# Progressive Tax Rates at Various Price Levels (FY 2007-2016)



\* Calculated from April 2006; \$60 Million exemption over 8 companies for 10 years; volumes per DOR Fall 2005 Forecast with Oooguruk projection.

Source: Historical Average; Alaska Department of Revenue.



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# Alaska State Legislature

Please enter into the record my testimony to the \_\_\_\_\_ HFIN \_\_\_\_\_  
(committee name)

committee on \_\_\_\_\_ HB488 \_\_\_\_\_, dated 040106

Thank you Chairman Chenault and Members of the House Fin. Comm. for allowing me to speak on HB 488. Like all us Alaskan Resource owners we "trust embody" your decisions on making proper adjustment to collect a fair Tax Revenue from our depleting oil resource. Elf was a fair Tax Scheme some 15 years ago when oil profits and world markets seemed more proportional to Alaska's economy and it's extraction & producing Partners but that's not the case today as we all know. Its time that our Partners need to share like any good 50/50 Partner should.

Over thirty years of Tax incentives and investment credits given to our Partners has qualified Alaska as a "Rightful Partnership Share" of current Windfall Profits. Evidence provided to your committee proves that today's profits at today's price per barrel of oil sold on the world market exceeds most traditionally normal levels. War in the middleeast continues and any sight of market change is unforeseeable at present. So it's prudent that Alaska change ELF and get it's fair share of today's inflated world market prices.

I propose that your committee keep the 25/20% initial Tax portion of the bills tax scheme but modify the after certain price addition/escalation balance of the bill. We know that the producers make 23% on 20 dollar oil and we know they make 38% on 40 dollar oil and so on. I propose that Alaska at 40 dollars a barrel price, start to get our fair share. This would be a "keep it simple stupid" additional tax with an 50% "Partnership Share" on every dollar a barrel thereafter. Period

Additionally if the State Dept. of Revenue forecasts a future drop in price to say 47 dollars a barrel and places the risk of future budget deficits upon Alaska we will not be back here in a year or so redoing this work all over again. We have learned that unless conflict in today's world changes dramatically, history will be correct in its view that resource prices don't drop in such social climate. Infact if public/private opinion was to be a good indicator the price of non-renewable resources can and will continue to go up. A boom for Alaska's resource owners!

With that being said, it makes even more sense that Alaska get it's share before it's gone and with gratitude to all those in the industry for their unselfishness in the making of Alaska's Great State's future even more greater. Thank you very much for listening to my two cents of wisdom.  
Sincerely, Ed Martin Jr. P O Box 521, Cooper Landing, AK 99572

## Louanne Christian

---

**From:** Rep. Kevin Meyer  
**Sent:** Saturday, April 01, 2006 12:51 PM  
**To:** Louanne Christian  
**Subject:** FW: Fwd: teleconferences 3-31

Can you provide this to the committee members? Thank you.

---

**From:** Kathleen Martin [mailto:keaaumartins@yahoo.com]  
**Sent:** Saturday, April 01, 2006 11:49 AM  
**To:** LIO Kenai  
**Subject:** Re: Fwd: teleconferences 3-31

Mary Bea,

If, I for what ever reason can't personally testify today please read and/or forward this to the House Fin. Comm. today. Thank you so very much...Ed

Thank you Chairman Chenault and Members of the House Fin. Comm. for allowing me to speak on HB 488. Like all us Alaskan Resource owners we "trust embody" your decisions on making proper adjustment to collect a fair Tax Revenue from our depleting oil resource. Elf was a fair Tax Scheme some 15 years ago when oil profits and world markets seemed more proportional to Alaska's economy and it's extraction & producing **Partners** but that's not the case today as we all know. Its time that our 50/50 **Partners** need to share like any good 50/50 **Partner** should.

Over thirty years of Tax incentives and investment credits given to our **Partners** has qualified Alaska as a "Rightful **Partnership Share**" of current Windfall Profits. Evidence provided to your committee proves that today's profits at today's price per barrel of oil sold on the world market exceeds most traditionally normal levels. War in the middle east continues and any sight of market change is unforeseeable at present. So it's prudent that Alaska change ELF and get it's fair share of today's inflated world market prices.

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Additionally if the State Dept. of Revenue forecasts a future drop in price to say 47 dollars a barrel and places the risk of future budget deficits upon Alaska we will not be back here in a year or so redoning this work all over again. We have learned that unless conflict in today's world changes dramatically, history will be correct in its view that resource prices don't drop in such social climate. Infact if public/privite opinion was to be a good indicator the price of non-renewable resources can and will continue to go up. A boom for Alaska's resource owners!

With that being said, it makes even more sense that Alaska get it's share before it's gone and with gratitude to all those in the industry for their unselfishness in the making of Alaska's Great State's future even more greater. Thank you very much for listening to my two cents of wisdom. Sincerely Ed Martin Jr.

*Kathleen Martin* <keaaumartins@yahoo.com> wrote:

Note: forwarded message attached. Subject: teleconferences 3-31  
Date: Fri, 31 Mar 2006 20:24:47 -0900  
From: "MaryBea Byrne" <MaryBea\_Byrne@legis.state.ak.us>  
To: "etree" <liocmbb+etree@legis.state.ak.us>,  
"education" <liocmbb+education@legis.state.ak.us>,  
"fish" <liocmbb+fish@legis.state.ak.us>

See the attached.  
mb

**Alaska State Legislature  
HOUSE FINANCE COMMITTEE  
AGENDA**

**\*Testimony by invitation only.**

**April 1, 2006 – Saturday**

**10:00 a.m. – 2:00 p.m.**

**HB 488-OIL AND GAS PRODUCTION TAX**

**Public Testimony:**

**10:00 a.m. 11:15 a.m. Anchorage**

**11:30 a.m. – 11:45 a.m. Testimony by invitation:**

**Paul Laird, The Alliance**

**Bob Stinson, Conam Construction**

**Chris Johansen, Flowline Alaska**

**David Gottstien,**

**12:00 p.m. – 1:15 p.m. Fairbanks**

**1:15 p.m. – 2:00 p.m. All other sites (including Juneau)**

**Kevin Ritchie, Executive Director, Alaska Municipal  
League**

## Testimony of Mike Koy on HB488

The table below (Table 1) shows the yearly impact to State revenues of the Governor's proposed oil tax legislation and consequent Legislative revisions relative to the current oil tax system. The incremental revenues shown are the cumulative impacts to State revenues from each version of the oil tax bill. For example, as introduced HB488 generates an extra \$810 million for the State at \$60/bbl relative to the current tax system. Implementing a graduated profit tax rate of 0.3% per \$1/bbl increases the State's revenue to \$1,175 million at the same oil price. The impact of the graduated profit tax is therefore \$365 million at \$60/bbl. No clawback (removing credits on historic investment) increases the State's revenues \$145 million at \$60/bbl making the total change of the new oil tax legislation including revisions, relative to the current tax system, to be \$1,320 million. At the same oil price, the changes made by the Senate give an increase of \$1,980 million in State revenues relative to the current tax structure. This is through the 50% clawback reduction shown in Table 1. Completely eliminating the clawback, is shown for completeness. With this basic understanding let's consider the current versions of the oil tax legislation under review by the House and Senate.

**Table 1. Change in Yearly State Revenues Relative to the Current Fiscal Regime**

	Break-even Oil Price	Oil Price (\$/bbl)					
		15	20	30	40	50	60
<b>HB 488</b>							
As introduced	29	(250)	(260)	10	275	550	810
0.3% per \$1/bbl after \$50	29	(250)	(260)	10	275	550	1175
No Clawback	24	(220)	(110)	160	430	695	1320
<b>SB 305</b>							
As introduced	29	(250)	(260)	10	275	550	810
0.2% per \$1/bbl after \$40	29	(250)	(260)	10	276	735	1175
25% Base Rate	24	(250)	(150)	240	635	1220	1900
50% clawback	22	(225)	(75)	320	710	1295	1980
No clawback	20	(180)	1	395	785	1370	2055

### HB488:

As introduced - impact of Governor's proposed oil tax changes

0.3% per \$1/bbl after \$50 - total change after including sliding scale of an extra 0.3% in tax for every \$10/bbl increase above \$50/bbl

No clawback - cumulative change after including sliding scale and eliminating tax credit (clawback) for investment made in the previous five years

### SB305

As introduced - impact of Governor's proposed oil tax changes

0.2% per \$1/bbl after \$40 - total change after including sliding scale of an extra 0.2% in tax for every \$10/bbl increase above \$40/bbl (actual language might say 2% for every \$10/bbl, but these are approximately equal for illustrative purposes here)

25% base rate - cumulative impact after including sliding scale and increasing the base profit tax rate from 20% to 25%

50% clawback - cumulative impact after including sliding scale, increasing the base profit tax rate from 20% to 25%, and reducing the number of years that tax credits (clawback) can be earned for previous investment

100% clawback - cumulative impact after including sliding scale, increasing the base profit tax rate from 20% to 25% and eliminating tax credit (clawback) for investment made in the previous five years

First, both versions of the oil tax legislation are progressive in nature. That is, they increase the State's share of oil revenues earned by the industry as oil price increases. This is seen more clearly in the graph below (Figure 1). In Figure 1, it is clear that under the current oil tax system (the red line) the State's share of oil revenues goes down as oil price goes up - flattening out at about 29% of oil revenues. This leads to the world of today where oil companies are earning excessive profits with really high oil prices and the State isn't proportionally sharing in that upside.

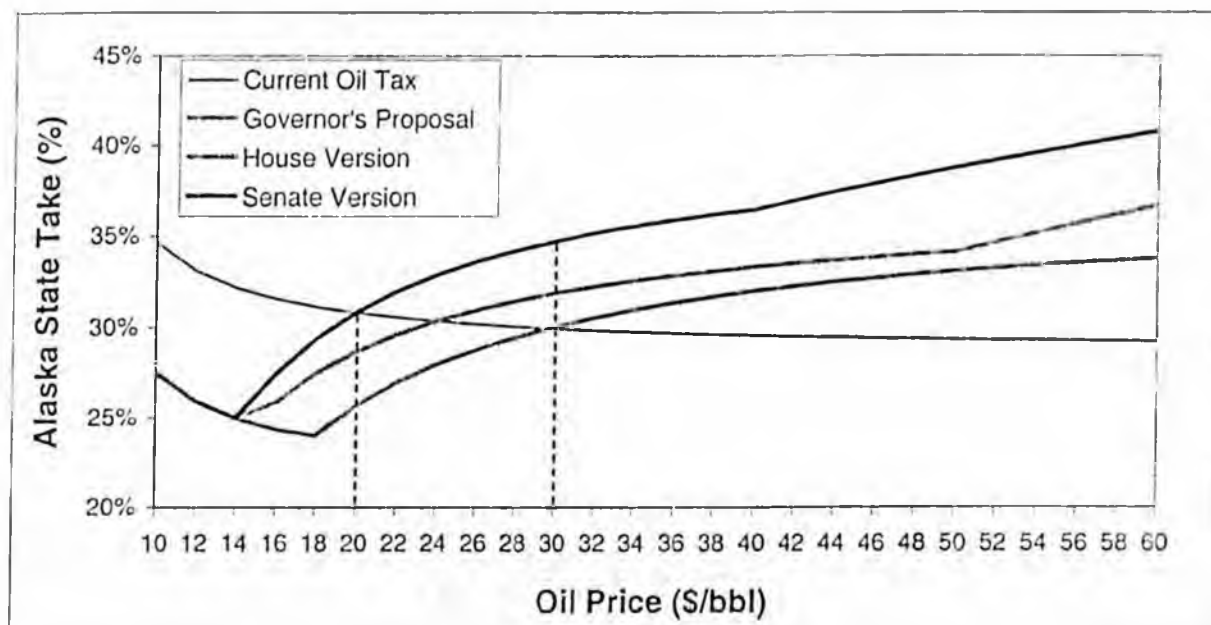


Figure 1. Alaska State tax as a percentage of Pump Station 1 netback prices

The next three lines show that the Governor's proposal (the pink line), the House version (the green line) and the Senate version (the blue line) of the Governor's proposed oil tax legislation all correct the problem with the current oil tax structure and increase the State's share of oil revenues as oil price increases. This is good. The question is, does any version of new oil tax legislation meet the State's needs of increasing revenues from oil & gas production while providing incentive for further investment? To answer this we need to look at how oil companies make investments and something called risk/reward balance.

#### Investments by Oil & Gas Companies

Most oil companies, and likely all the major oil companies, use a fixed oil price when making investment decisions. For the majors this oil price is usually between \$20-\$30/bbl. In this price range projects need to look attractive relative to other projects the company has around the world in order to attract investment dollars. Alaska currently has a regressive tax structure that makes Alaska in this price range, all else being equal, look unattractive relative to other regions of the world. To attract investment dollars, any new tax structure should make Alaska look more attractive within this price range than does the current oil tax structure. Looking back at Figure 1, the Governor's proposed tax structure indeed does make Alaska look more attractive in the \$20-\$30/bbl price range while the Senate's version makes it look distinctly less attractive. The House version splits the difference. Because the \$20-\$30/bbl oil price range is the only set of prices that really matter when making investment decisions, the Governor's proposal will attract more investment to Alaska while the Senate's version will attract investment away from Alaska all else being equal.

#### Risk/Reward Balance

Now the discussion needs to be put in context of risk & reward. The premise here is that greater risk should attract greater reward. No rational person or organization should be willing to take on additional risk without being compensated for it (i.e. receiving higher reward). To see how the State has done we'll look at three risks: oil price risk, profitability risk and exploration risk.

#### Oil Price Risk

With the current oil tax structure the State is rather immune to oil price in terms of the share of oil revenue it takes. In fact, as seen in Figure 1 the State's share of oil revenues actually goes up as oil price goes down (this doesn't mean that the State's revenue goes up - it just means that the decrease in State revenue isn't as much as the decrease in oil price). This is called a regressive tax system and it allows the State to slightly insulate itself from low oil prices. To move to a progressive tax structure where the State shares more in the upside when prices are high it is

reasonable to expect the State would give up some of this insulating affect (make oil taxes less regressive) on the downside. On balance, given that the State is increasing its exposure to oil price risk by doing this we'd expect the State to earn a higher reward. Does this happen?

Long term oil prices are between \$18-\$22/bbl. This means for every year that oil prices are \$60/bbl, as they are today, there needs to be eight years with oil prices at \$15/bbl in order for oil prices to average \$20/bbl - the long term average oil price. Look back at Table 1. With any of the oil tax versions the State makes \$225-\$250 million per year less than with the current tax structure when oil prices are \$15/bbl. This is supposedly offset by the extra revenues being earned at \$60/bbl. The extra revenue is \$810 million under the Governor's proposal, \$1,320 million under the House version and \$1,980 million under the Senate version. The net impact to State revenues is shown in Table 2.

**Table 2. Impact to State Revenues over Long-Term**

	Governor's Proposal	House Version	Senate Version
8 years at \$15/bbl	(\$2,000)	(\$1,760)	(\$1,800)
1 year at \$60/bbl	\$810	\$1,320	\$1,980
Net Impact	(\$1,190)	(\$440)	\$180

Table 2 doesn't include changes to investment, natural decline in production or other timing issues, but the point is still the same. Under the Governor's proposal the State actually loses over \$1bn every nine years. For taking on the extra risk of a progressive tax system the State clearly is not getting enough reward. Only with the Senate's version does the State earn enough additional revenue at \$60/bbl to justify reducing the tax rate at lower oil prices.

#### **Profitability Risk**

Unlike severance tax which is largely a tax based on revenues, a profits tax is obviously based on profits. To get from revenues to profits one must include operating and capital costs (in terms of depreciation). This means that State will be taking on operating and capital cost risk as part of a new oil tax structure since the amount of revenue the State collects is directly dependent on the costs of generating the profits which are taxed. In principle this might be fine, but the additional risk the State is taking on and should come with additional reward. Look back at Table 2. Where is the additional reward? After considering price risk only the Senate version generates a net increase to State revenues. Assuming the price risk is perfectly balanced, is \$180 million (or \$20 million per year) in the Senate's version enough of a reward payment for taking this additional risk? What about the Governor's proposal and House version?

#### **Exploration Risk**

Exploring for new oil and gas reserves is arguably the riskiest part of the oil & gas industry and thus why successful exploration companies earn higher returns than say refineries. With the current oil tax system the oil companies for all practical purposes take 100% of the exploration risk. Under the Governor's proposal, and the House and Senate versions, oil companies will be able to earn tax credits on all capital investment including exploration costs. In addition, these tax credits are transferable which means that companies will be able to buy and sell the credits. Doesn't sound important, but it is. With transferable investment tax credits the State becomes a de facto equity investor in exploration - the riskiest part of the business. Every time there is a well drilled looking for oil that finds anything but oil the State will be obligated to pay 20% of the costs just as if it were an investor in the well. However, if the well finds oil the State doesn't get a 20% equity stake in the discovery. Some will say that the State will benefit through more oil being discovered which will be more oil that can be taxed. Maybe, but what is more certain is that a lot more exploration wells will be drilled and way more often than not these wells will not find commercially viable reserves and the marginal well drilled will be more risky than if the State weren't involved. This means the State's risk profile will increase even more. There are better ways for the State to create incentives for more oil production that expose the State to a lot less risk.

#### **Summary**

Where does this leave us? In terms of providing incentive for investment, the only price range that is relevant is the \$20-\$30/bbl range. In this range only the Governor's proposal reduces the tax on the oil industry which will provide an incentive for investment. However, the Governor's proposal does this while exposing the State to some

horrendous oil price risk not to mention cost and exploration risk. The Senate version fixes the oil price risk issue but at the same time creates a disincentive for future investment by increasing taxes substantially in the \$20-\$30/bbl range. The House version is a halfway house that doesn't protect the State enough from oil price risk and doesn't create enough incentive for investment in the all important \$20-\$30/bbl range.

What can the State do? Below are some suggestions that would allow the State to meet it's objectives of increasing State revenues, increase incentives for oil companies to invest and keep the State's risk/reward balance in line:

**Oil prices below \$20/bbl** – The biggest decrease in taxes generated by the State relative to the current tax structure occurs when oil prices are below \$20/bbl. While this is a fairly important price range for oil companies it is not that important. This means that the State is giving away value in this range that it does not need to as the oil companies won't give the State credit for doing so. Oil prices in this range also happen to be where the State will really be hurting for funds. The State needs to do a better job of protecting itself when prices drop below the \$20/bbl range, but any system needs to be less regressive than the current tax structure.

**Solution:** The easiest solution is to implement a minimum tax per barrel of oil produced. Depending on the profit tax rate selection, a per barrel rate of \$0.35-\$0.75 is reasonable.

**Oil prices between \$20-\$30/bbl** - This is the important oil price range as this is the range of prices oil companies reference when making investment decisions. Incentives, or an advantaged tax regime in this price range, are fully valued by oil companies which means the State gets the largest bang for its buck by making concessions valid in this range. The State should do what it can to concentrate its efforts to make Alaska look as attract in this range as possible.

**Solution:** A 20% profits tax works well in this range.

**Oil prices above \$30/bbl** - While it may not seem like it now, oil prices above \$30/bbl are pretty high. This range is where excess profits are generated and where the State should be looking to gain a growing proportion of revenues. This price range also is where the State needs to cover (i.e. earn reward) for the risks it is taking on by making the tax structure less regressive and for providing an advantageous tax structure at oil prices between \$20-\$30/bbl. Will increasing taxes in this range reduce investment by the oil companies? Absolutely not! Oil companies do not value highly what happens in this price range so increasing the State's share of revenue, within reason, will not impact investment because the price used by oil companies to balance their business (\$20-\$30/bbl) looks good. They also know the State is taking on greater risks and needs to be compensated for doing so.

**Solution:** A graduated progressive tax allows the State to continually increase its share in revenues as oil price increase, but the rate needs to be higher than any of the current proposals in order to protect the State from the oil price risk it is taking. A graduated progressive tax of 0.3 per every \$1/bbl increase in oil price above \$30/bbl accomplishes this. The State could easily also phase out the investment tax credit at higher oil prices since higher oil prices themselves provide enough incentive for investment.

**Exploration Risk:** There is no reason for the State to take on exploration risk. This is especially true when there is a significant resource of discovered heavy oil sitting on the North Slope close to infrastructure. There is no exploration risk to get this to market, but it does need some additional economic incentive.

**Solution:** Eliminate the investment credit for exploration costs and instead increase the investment credit for viscous oil development. Traditional development only – we don't want tar sands mining in Alaska.

These changes to the prevailing oil tax proposals are pretty basic, but they fundamentally alter the shape of the tax structure in a positive way that increases investment and provides more revenue for the State.

*Note: Mike Koy has over eleven years experience in the oil & gas industry with BP. In addition to working in Australia, Papua New Guinea, Russia and England, he has extensive oil & gas experience in Alaska including strategy development and economic modeling of various North Slope gas development options.*

# BACKBONE II

## FOR ALASKA'S FUTURE

Mr Chairman, and other distinguished members of the committees, thank you very much for the opportunity to present to you today. My name is David Gottstein, and I live at 2341 Hialeah Drive in Anchorage, Alaska. I, along with former Governor Walter Hickel, Co-Chair a group called Backbone2. I thank you, as all Alaskans do, for your hard work and efforts on this most important topic.

You have the daunting task of ferreting out a very complex subject. One I do not envy you for. You must assess the balance between making sure that Alaska gains the maximum value for it's oil and gas resources, while at the same time, not discourage in more than an offsetting manner, a tax structure that is sound, fair, and rational.

We must incentivize exploration, but not sacrifice the values of economic production. As a capital markets analyst, I am gravely concerned that you are being asked to evaluate the impacts of such hugely important fiscal matters with meager access to suitable revenue sensitivity models. You should, as a normal course of analysis, as is done in the private sector for fractions of the value at risk here, have full access to a robust model to conduct a full sensitivity analysis of all the key components extended to their reasonable extremes in isolation, and in aggregate, just to get a sample profile of the impacts of the decisions you are faced with.

I first must offer that it would be my preference that the State enact an understandable and enforceable severance tax that is based upon a progressive structure levied against the well-head value of the resources. It has all the advantages of being able to assess a tax that rewards appropriately, risk takers, with a higher level of percent of value at lower oil and gas prices, insuring adequate returns on capital, with higher shares going to the state as prices rise.

Inasmuch as this body has focused on a net profits tax, it places a very heavy burden of enforcement in the natural environment where the oil and gas industry has ample incentive to account for costs in manners that are self-serving. We should expect nothing else. In order to protect the State from being victim of efforts that are primarily under the control of industry executives in terms of cost allocations and other decisions, I would strongly encourage you to consider two protective devices;

One would be to conduct an audit, conducted by a large public accounting firm, not directly retained by the companies themselves, to audit their financial statements, but with that accounting firm reporting to the State of Alaska as it's client in verifying what the oil companies report, in addition to what our Department of Revenue can otherwise hopefully confirm. The second would be to impose a severe penalty, that is bonded,

perhaps costing the industry five to ten times the amount of any under-reporting, in a manner that requires immediate payment even in the event of challenge. Thus creating a strong economic incentive to be forthright and honest. If you don't do that, you will expose the State to great risk of substantial losses.

Another important point is that the question of fair share is critically important. We are constantly being barraged by the industry in their information campaigns that higher taxes are always unfair and act as a disincentive. When in fact the word tax should not solely be viewed as a cost or burden of doing business, but rather it just happens to be the method by which the State is able to garner its fair value of the resource. It is really the state revenue base collected by way of taxing authority.

As you consider questions of rates and oil price base-lines for a progressive tax structure, and how to achieve a fair apportionment, it might be constructive to be reminded that income is an accounting opinion, but cash is a fact. In my prepared statement, which I have provided you a copy of, I have included, for illustrative purposes, both copies of key portions of Conoco Phillips annual reports for years 2003 and 2005, along with a spreadsheet analysis that uses both their own published numbers, along with other oil price numbers obtained from our Department of Revenue.

It is a cash-flow analysis of apportionment, not income. The severance tax is supposed to be a tax on the depletion of our non-renewable resources, and therefore exploration expenses are not included. As they are an investment in future production, not an expense of current production. It also doesn't include depreciation, amortization, or depletion allowances. Instead it appropriately considers revenue, production expenses, and transportation expenses primarily. A truer direct cash generating picture. What share of the cash value of the resource does the State get to keep is really the most important metric, I believe.

In the analysis there are some glaring conclusions that can be reached, that would not otherwise be obvious absent this analytical approach. The first is that the claw-back provision has a less than accurate basis for justification in arguing that the oil industry wasn't anticipating as high a tax payment when the investments were made in past years. The truth is that the incremental tax that has been suggested, even at the highest levels proposed, is more than offset by the higher than anticipated oil prices that have occurred. It is after-tax cash-flow that is important, not simply taxes paid.

Another important observation is that as prices have risen, Conoco's before-tax profit margin has expanded over the last five years from 50% to 80%, and their after-tax margin has increase from 37% to 57%. That is consistent with dramatically higher resources values without commensurately higher expenses. In other words, the industry is making huge profits at our expense, well beyond their prior investment planning projections.

Another set of remarkable statistics show that the multiple of Conoco Phillips share of revenue versus the State's ranges from a low of 340% to over 950% at times over the last five years. Not even close to the 1/3, 1/3, 1/3 parity take that is often argued as being

fair. Additionally, when you do the analysis on a net cash-flow basis, after production and transportations costs, etc., it still ranges between 250% and 450%. Indicating the State in the past has received a dismal share.

If we were to approach our ownership position as the private sector would as shareholders, we are falling significantly short of the scrutiny that our shareholders deserve. The secret pact to promote a 20/20 PPT, as bait to get a gas line via a secret contract, would not even come close to passing muster with the S.E.C. This kind of lack of transparency is sometimes what sends executives to jail. Even the stranded gas act negotiations are circumspect as we can't rationally conclude the gas is stranded unless we put the gas out to open bid, and nobody shows up. That is why it is essential to pass HB71, retrieve Pt. Thomson, and put our gas out to bid.

The oil and gas industry spends millions of dollars a year to blur our vision with advertising, lobbying, philanthropy, and threats, to serve their shareholders, because they understand the magnitudes of the equations. They are prepared for the invasion of Normandy, while the administration, in comparison, is only prepared for Wimbledon. You as the legislature are our last line of defense, against overpowering forces. We plead with you to not fail us.

We need to step up to the plate, be tough, and do it right. We need a fair and rational oil and gas tax structure irrespective of whether a gas line is ever built. And let's not forget that the administration has already said that their secret contract only contains a commitment to study the gasline for 4 or 5 more years, not an actual commitment to build a project.

Alaskans will be forever thankful for those of you who are not unduly influenced by the oil industry spin doctors, and not be bullied by their tactics, and instead carefully look at the facts. Listen to your consultants who say the state takes too much risk in the deal, and doesn't get enough reward. I would be very surprised if we even bump up against our fair share with a base rate of 25% at \$49 a barrel, 30% at \$50, and 35% at \$60 per barrel, with further progressivity from there. Let's do the math right, and not give the farm away. We've done that in the past. Let's not repeat those costly mistakes.

I thank you very much for taking the time to listen, and encourage you to take a serious look at what I have offered you.

Thank you again.

	2,005	2,004	2,003	2,002	2,001
Dept. Revenue Tax Division					
Ak North Slope Average Spot Price					
Calendar Year		\$38.84	\$29.64	\$24.72	\$23.20
Percentage Change		31.0%	19.9%	6.6%	
Fiscal Year	\$43.43	\$31.74	\$28.15	\$21.78	\$27.85
Percentage Change	36.8%	12.8%	29.2%	-21.8%	
Average Well Head Value					
Calendar Year		\$32.20	\$24.61	\$19.96	\$17.36
Percentage Change		30.8%	23.3%	15.0%	
Fiscal Year	\$38.76	\$26.78	\$23.27	\$16.80	\$22.24
Percentage Change	44.7%	15.1%	38.5%	-24.5%	

Alaska Results From Operations From Conoco Phillips Annual Reports  
Conoco Philips Annual Report

	2,005	2,004	2,003	2,002	2,001
Total Production Revenues (1,000,000)	\$5,927	\$4,378	\$3,656	\$3,097	\$3,020
Cash Expenses					
Production Costs	\$488	\$430	\$792	\$769	\$784
Transportation Costs	\$665	\$598	\$666	\$681	\$726
Other Related	\$67	\$14	\$7	\$23	\$2
Total Cash Exp.	\$1,220	\$1,042	\$1,465	\$1,473	\$1,512
Expense % of Revenue	20.6%	23.8%	40.1%	47.6%	50.1%
Conoco Pre-Tax Production Cashflow	\$4,707	\$3,336	\$2,191	\$1,624	\$1,508
Conoco Pre-Tax Profit Margin	79.4%	76.2%	59.9%	52.4%	49.9%
Cashflow Percentage Change	41.1%	52.3%	34.9%	7.7%	
Provision for Taxes	\$1,342	\$888	\$595	\$294	\$392
Conoco Net Cashflow	\$3,365	\$2,448	\$1,596	\$1,330	\$1,116
Percentage Change	37.5%	53.4%	20.0%	19.2%	
Conoco After-Tax Profit Margin	56.8%	55.9%	43.7%	42.9%	37.0%
Conoco Revenue Share %	77.4%	79.7%	83.7%	90.5%	87.0%
State Revenue Share %	22.6%	20.3%	16.3%	9.5%	13.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Conoco Multiple of Revenue Share	341.7%	393.0%	514.5%	953.4%	670.4%
Conoco Net Cashflow % of Revenue	56.8%	55.9%	43.7%	42.9%	37.0%
Production Expense % of Revenue	20.6%	23.8%	40.1%	47.6%	50.1%
State Tax % of Revenue	22.6%	20.3%	16.3%	9.5%	13.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Conoco Net Cashflow Multiple of State Share	250.7%	275.7%	268.2%	452.4%	284.7%
Conoco Share of Net Cashflow %	71.5%	73.4%	72.8%	81.9%	74.0%
State Share of Net Cashflow %	28.5%	26.6%	27.2%	18.1%	26.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Conoco Multiple of State Share	250.7%	275.7%	268.2%	452.4%	284.7%

## ■ Results of Operations

Years Ended  
December 31

Millions of Dollars

	Consolidated Operations								Equity Affiliates	Combined Total
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total		
<b>2003</b>										
Sales	\$3,564	2,464	6,028	3,872	879	225	677	11,681	423	12,104
Transfers	103	545	648	903	142	841	77	2,611	266	2,877
Other revenues	(11)	93	82	8	33	31	10	164	34	198
Total revenues	3,656	3,102	6,758	4,783	1,054	1,097	764	14,456	723	15,179
Production costs	792	657	1,449	645	175	271	170	2,710	179	2,889
Exploration expenses	56	143	199	121	51	94	127	592	2	594
Depreciation, depletion and amortization	436	571	1,007	954	163	326	40	2,490	104	2,594
Property impairments	—	65	65	160	—	5	—	230	—	230
Transportation costs	666	188	854	266	40	40	23	1,223	20	1,243
Other related expenses	7	78	85	29	13	91	44	262	27	289
Accretion	25	18	43	50	5	11	2	111	2	113
	1,674	1,382	3,056	2,558	607	259	358	6,838	389	7,227
Provision for income taxes	595	486	1,081	1,539	225	57	362	3,264	83	3,347
Results of operations for producing activities	1,079	896	1,975	1,019	382	202	(4)	3,574	306	3,880
Other earnings	223	34	257	51	3	68*	(46)	333	(51)	282
Cumulative effect of accounting change	143	(1)	142	20	—	(8)	(12)	142	(2)	140
E&P net income (loss)	\$1,445	929	2,374	1,890	385	262	(62)	4,049	253	4,302
<b>2002</b>										
Sales	\$2,997	927	3,924	1,194	347	125	400	5,990	180	6,170
Transfers	102	401	503	1,315	—	235	—	2,053	62	2,115
Other revenues	(2)	3	1	63	7	7	14	92	12	104
Total revenues	3,097	1,331	4,428	2,572	354	367	414	8,135	254	8,389
Production costs	769	444	1,213	343	76	118	114	1,864	57	1,921
Exploration expenses	101	108	209	67	45	32	231	584	—	584
Depreciation, depletion and amortization	552	334	886	480	59	105	26	1,556	30	1,586
Property impairments	4	8	12	41	—	—	—	53	—	53
Transportation costs	681	87	768	125	10	—	5	908	8	916
Other related expenses	23	16	39	75	1	14	11	140	12	152
	967	334	1,301	1,441	163	98	27	3,030	147	3,177
Provision for income taxes	294	66	360	981	79	49	196	1,665	(18)	1,647
Results of operations for producing activities	673	268	941	460	84	49	(169)	1,365	165	1,530
Other earnings	197	18	215	10	(2)	24*	(4)	243	(24)	219
E&P net income (loss)	\$ 870	286	1,156	470	82	73	(173)	1,608	141	1,749
<b>2001</b>										
Sales	\$3,020	1,178	4,198	546	154	31	324	5,253	8	5,261
Transfers	119	119	238	1,039	—	—	—	1,277	—	1,277
Other revenues	34	26	60	23	(4)	5	—	84	1	85
Total revenues	3,173	1,323	4,496	1,608	150	36	324	6,614	9	6,623
Production costs	784	328	1,112	165	37	6	55	1,375	2	1,377
Exploration expenses	61	69	130	31	33	—	121	315	—	315
Depreciation, depletion and amortization	531	203	734	233	22	4	27	1,020	2	1,022
Property impairments	—	—	—	—	—	—	23	23	—	23
Transportation costs	726	77	803	60	—	3	6	872	—	872
Other related expenses	2	5	7	(8)	5	1	23	28	2	30
	1,069	641	1,710	1,127	53	22	69	2,981	3	2,984
Provision for income taxes	392	173	565	779	22	7	117	1,490	—	1,490
Results of operations for producing activities	677	468	1,145	348	31	15	(48)	1,491	3	1,494
Other earnings	189	8	197	17	—	—	(9)	205	—	205
E&P net income (loss)	\$ 866	476	1,342	365	31	15	(57)	1,696	3	1,699

\*Includes \$63 million and \$27 million in 2003 and 2002, respectively, for a Syncrude oil project in Canada that is defined as a mining operation by U.S. Securities and Exchange Commission regulations.

- Results of operations for producing activities consist of all the activities within the E&P organization, except for pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, and crude oil and gas marketing activities, which are included in Other earnings. Also excluded are non-E&P activities, including our Midstream segment, downstream petroleum and chemical activities, as well as general corporate administrative expenses and interest.
- Transfers are valued at prices that approximate market.

- Other revenues include gains and losses from asset sales, including net gains of approximately \$165 million in 2003; certain amounts resulting from the purchase and sale of hydrocarbons; and other miscellaneous income.
- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include taxes other than income taxes, depreciation of support equipment and administrative expenses related to the

## Results of Operations

Years Ended  
December 31

Millions of Dollars

	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
<b>2005</b>											
Sales	\$ 5,927	3,385	9,312	5,142	2,795	1,642	423	—	19,314	1,055	2,415
Transfers	172	1,206	1,378	2,207	26	—	640	—	4,251	455	1,003
Other revenues	2	168	170	(253)	11	40	4	—	(28)	37	1
Total revenues	6,101	4,759	10,860	7,096	2,832	1,682	1,067	—	23,537	1,547	3,419
Production costs excluding taxes	488	492	980	611	274	316	115	45	2,341	196	256
Taxes other than income taxes	537	311	848	41	26	33	18	2	968	3	1,632
Exploration expenses	120	66	186	86	139	147	69	42	669	—	56
Depreciation, depletion and amortization	443	848	1,291	1,074	329	399	53	—	3,146	140	148
Property impairments	—	1	1	(10)	—	13	—	—	4	—	—
Transportation costs	665	350	1,015	296	64	59	5	—	1,433	—	255
Other related expenses	67	48	115	28	38	(12)	32	8	209	21	5
Accretion	29	19	48	84	7	16	2	—	157	—	1
	3,752	2,624	6,376	4,886	1,955	717	773	(97)	14,610	1,187	1,066
Provision for income taxes	1,342	900	2,242	3,311	747	228	759	(19)	7,268	370	303
Results of operations for producing activities	2,410	1,724	4,134	1,575	1,208	489	14	(78)	7,342	817	763
Other earnings	141	15	156	53	—	93	(28)	35	316	(58)	(32)
(Cumulative effect of accounting change)	1	(3)	(2)	(2)	—	—	—	—	(4)	—	—
Net income (loss)	\$ 2,552	1,736	4,288	1,626	1,213	582	(14)	(43)	7,654	759	731
<b>2004</b>											
Sales	\$ 4,378	2,568	6,946	4,215	1,777	1,214	704	—	14,856	470	397
Transfers	121	832	953	1,255	71	—	75	—	2,354	359	122
Other revenues	4	(36)	(32)	9	10	116	5	14	122	32	1
Total revenues	4,503	3,364	7,867	5,479	1,858	1,330	784	14	17,332	861	520
Production costs excluding taxes	430	422	852	523	216	271	120	36	2,018	154	46
Taxes other than income taxes	373	267	640	38	17	35	12	1	747	—	206
Exploration expenses	82	101	183	85	106	112	67	144	697	—	5
Depreciation, depletion and amortization	426	586	1,012	1,095	275	349	43	—	2,774	94	43
Property impairments	6	12	18	2	—	47	—	—	67	—	—
Transportation costs	598	241	839	296	48	43	2	—	1,228	—	57
Other related expenses	14	43	57	20	(2)	4	14	7	100	39	—
Accretion	21	21	42	72	6	14	2	—	136	—	1
	2,553	1,671	4,224	3,348	1,192	455	524	(174)	9,569	566	162
Provision for income taxes	888	584	1,472	2,233	477	127	514	(94)	4,729	67	41
Results of operations for producing activities	1,665	1,087	2,752	1,115	715	328	10	(80)	4,840	499	121
Other earnings	167	23	190	102	(2)	130	(35)	(10)	375	(53)	(6)
Net income (loss)	\$ 1,832	1,110	2,942	1,217	713	458	(25)	(90)	5,215	446	115



# THE ALLIANCE

... for responsible development of Alaska's Oil, Gas & Mineral Resources

## HOUSE FINANCE TESTIMONY On CS HB488 April 1, 2006

Thank you, Chairman Chenault. My name is Paul Laird, and I'm general manager of the Alaska Support Industry Alliance. I'm testifying on behalf of the Alliance, a trade organization representing companies and individuals that provide goods and services to Alaska's oil, gas and mining industries.

Throughout this debate on a new profits-based oil and gas production tax, we've heard a lot about finding the right tax rate and investment credits. Is ~~20%~~ 20% the right tax? 25%? 30%? How about 17½% ... or 12½%? Should it be progressive? How about the investment credits?

Frankly, Mr. Chairman, we don't know. But here are some things we do know:

We know that the 20/20 deal reflected in the original legislation will result in roughly \$1 billion a year in additional state revenues, and the state already projects a \$1.4 billion budget surplus this year.

We know that the major North Slope producers have agreed to this unprecedented tax increase, and have said that with fiscal certainty, it can be the catalyst to a \$25 billion gas project.

We know that the changes contained in the committee substitute would increase taxes by hundreds of millions of dollars on top of the \$1 billion in the original bill, and it would water down the incentives for investment.

We know that every dollar in additional taxes is a dollar that won't be invested in sustaining production, in creating business opportunities for Alaskan companies, in generating good-paying jobs for Alaskans.

We know that our 400 members and their 30,000 Alaskan employees will be here long after the legislature's consultants on this issue are gone, and they'll be the ones to bear the consequences if higher taxes really do result in less investment ... a novel economic concept, to be sure.

So will their children ... and theirs, and theirs ... as long as there are still enough opportunities to keep them here.

### ALASKA SUPPORT INDUSTRY ALLIANCE

Mr. Chairman, we know that we're not just talking about a tax bill here. We're not just talking about a revenue bill, or a resource development bill.

We're talking about Alaska's future.

And we know that Alaska's future has never held so much potential ... or so much peril.

We can encourage investment and have a gas project, continuing oil exploration and development and 50 years of good-paying jobs, robust business activity and steady state revenues.

Or we can impose the highest possible tax rate on production and have an even bigger state government for a while ... at the expense of a strong and sustainable economy ...

At the expense of our future.

We know that that's what's at stake here. Mr. Chairman and members of the Finance Committee, don't put oil investment and a gas project ... don't put generations of jobs and business opportunities ... don't put our future at risk.

Thank you.



# Alaska Conservation Alliance

*Uniting for Alaska's Future*

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March 24, 2006

The Honorable Kevin Meyer  
Co-Chair, House Finance Committee  
House of Representatives  
Alaska State Capitol, Room 519  
Juneau, Alaska 99801-1182

The Honorable Mike Chenault  
Co-Chair, House Finance Committee  
House of Representatives  
Alaska State Capitol, Room 519  
Juneau, Alaska 99801-1182

Dear Representatives Meyer and Chenault,

I am writing to thank members of the legislature for work thus far in analyzing the proposed revision to the oil production profits tax (PPT). Clearly, this debate is of far-reaching consequence to every Alaskan, and the diligence undertaken by legislators to this point is highly encouraging.

On behalf of the 40 conservation groups and businesses represented by the Alaska Conservation Alliance, I urge you to continue to take the time necessary to ensure that the proposal is a good deal for the State of Alaska and the citizens and communities who are depending on you to represent their interests in this debate.

Talk of intense pressure to sign off on a handshake deal, and of the PPT being tied to an as-yet-unseen gas line project, gives one reason for concern. I trust that your committee will take as much time as needed to fully understand the proposal and to ensure that Alaskans are indeed receiving the best possible outcome.

As you well know, the stakes could not be higher, and I am sure there is pressure from many different sides. In the end, I am encouraged that you will make the tough choices at the end of the day, and history will look kindly on your work.

Thank you, again, for your efforts on behalf of the people of Alaska.

Sincerely,

Kate Troll  
Executive Director



# Alaska State Legislature

Please enter into the record my testimony to the House Finance  
committee name

Committee on HB 488, dated 4-1-06  
bill # / subject public hearing date

What we do with regard with taxing "OUR" oil is and will effect Alaska and it's citizens for years to come or until the oil runs out. We currently allow the oil companies to produce from the "best producing wells" and those wells could and do happen to be those wells that Alaska doesn't receive any tax revenue. Check it out! The oil and gas committee can colaberate that fact.

If, in fact, the oil companies are our partners, than our fair share surely is 50 % after their 38% profit margin would you not think? At 47 dollars a barrel and at a rate of 50 cents on the dollar for every dollar over 40 dollars a barrel the state would not see a deficit ever. Think "PEAK OIL" it's that time folks better get our fair share now!

Do what is right with regard to this tax situation ,please push my Tax scheme 50% On every dollar over 40 dollars a barrel and the state will not see a budget deficit after next year.

Why would you approve a tax scheme that will ultimately place us in a future continued budget deficit ? Approve my idea and we will still benefit if the price does as the Department of Revenue's wizards say it will.

(See also attached 2 page article from the Anchorage Daily News, March 30, 2006)

Signed: Ed Martin, Jr.  
Testifier  
Self  
Representing (optional)  
PO Box 521 Cooper Landing, AK 99572  
Address  
595-1632  
Phone number



Print Page

Close Window

## Budget approved by House

**\$7.5 BILLION: Lawmakers on both sides of aisle call it unsustainable.**

By MATT VOLZ  
The Associated Press

(Published: March 30, 2006)

JUNEAU -- Good thing the price of North Slope crude closed at \$64.50 Wednesday.

If not for the windfall profits brought by those high oil prices, the state would be operating in the red next year under the budget approved Wednesday by the Alaska House.

The House's budget for fiscal 2007, which begins July 1, includes a 6 percent increase over last year in state treasury spending for operating costs.

That doesn't take into account another \$1.2 billion in state money that would go to the state's public education fund and for capital projects, according to an analysis by the Legislative Finance Division.

The \$7.5 billion budget includes federal, state and other sources of money that will be used to increase spending in every state governmental agency.

The budget passed the House 27-12, but lawmakers on both sides of the aisle say it's unsustainable and something needs to be done about the rise in spending.

"This budget is underwater, it's in deficit," said Rep. Norm Rokeberg, R-Anchorage.

The Senate Finance Committee is still in the process of closing out its own budget subcommittees. The two chambers will eventually meet in a conference committee to finalize the spending plan for next year.

Without the surpluses from this and last year paying for some of next year's programs, the House's budget would have the state in a \$285.5 million deficit next year, the Legislative Finance Division's analysis reads.

The creeping budget is due to a number of things. The increase in federal money coming to Alaska has slowed. The price of fuel has made running the Alaska Marine Highway System and other operations more costly. Fixed program costs continue to rise steadily, and there is also pressure to increase the number of state programs and employees when fiscal times are good like now.

Even with the increases over last year's budget, the House's spending plan still reduces by 5 percent the one Gov. Frank Murkowski proposed in December.

The governor's budget director, Cheryl Frasca, told House Finance Committee members last week that their cuts to Murkowski's budget were too deep, particularly those to the Department of Corrections and for rural energy aid.

Most House Democrats also disagreed with the House's product, saying while bloated, the budget shortchanges municipalities, the elderly and some health services.

Democrats failed to pass amendments to save an additional \$700 million of next year's surplus, restart the \$250 dividend program for elderly residents and bulk up funding for substance abuse and fetal alcohol syndrome programs.

adn.com | legislature : Budget approved by House

Page 2 of 2

If oil prices remain high next year, the state can count on saving more money. But after that, the price of oil is forecast by the Department of Revenue to drop to \$46.90 per barrel, which would plunge Alaska into a deficit if there isn't a fix.

One change in the works that would affect that outcome is a plan to replace Alaska's oil production tax with a tax based on oil companies' net profits. That system, if approved, would bring the state hundreds of millions more in revenue each year when the price of oil is high.

But that's not enough, lawmakers say. A long-range fiscal plan is needed.

"The state can't afford to wait any longer," said Rep. Max Gruenberg, D-Anchorage.

### Vote tally on state operating budget

Results Wednesday as the Alaska House, on a 27-12 vote, passed the 2007 state operating budget. Conferees from the House and Senate will meet later in the session to work out a final budget.

Voting yes were 24 Republicans and three Democrats. Voting no were 11 Democrats and 1 Republican.

A yes vote is for passing the budget.

Representatives are listed by name and hometown.

### YES VOTES

• Republicans: Anderson, Anchorage; Chenault, Nikiski; Coghill, North Pole; Elkins, Ketchikan; Gatto, Palmer; Harris, Valdez; Hawker, Girdwood; Holm, Fairbanks; Kelly, Fairbanks; Kohring, Wasilla; Kott, Eagle River; LeDoux, Kodiak; Lynn, Anchorage; McGulre, Anchorage; Meyer, Anchorage; Neuman, Big Lake; Olson, Kenai; Ramras, Fairbanks; Rokeberg, Anchorage; Samuels, Anchorage; Seaton, Homer; Stoltze, Chugiak; Thomas, Haines; Weyhrauch, Juneau.

• Democrats: Kapsner, Bethel; Foster, Nome; Moses, Unalaska.

### NO VOTES

• Republicans: Dahlstrom, Eagle River.

• Democrats: ...kowitz, Anchorage; Cissna, Anchorage; Crawford, Anchorage; Croft, Anchorage; Gara, Anchorage; Gardner, Anchorage; Gruenberg, Anchorage; Guttenberg, Fairbanks; Joule, Kotzebue; Kerttula, Juneau; Salmon, Beaver.

### DID NOT VOTE

• Republicans: Wilson, Wrangell.

Print Page

Close Window



P.O. Box 230126  
Anchorage, Alaska 99523-0126  
phone (907) 562-5818  
fax (907) 562-5816

**RE: House Finance Hearing RE: CS HB 488 April 1, 2006**

**Good morning Mr. Chairman and distinguished members of the House Finance Committee. My name is Lynn Johnson, and I am a 32 year Alaska resident and President and co-founder of Dowland-Bach Corporation, a 31 year old Alaska manufacturing and specialty design and fabrication firm. I am a past President of the Alaska Support Industry Alliance, the Anchorage International Rotary Club, and currently serve on several boards, including the American Red Cross of Alaska, Girdwood 2020, and the Whittier Ports and Harbors Commission.**

**As many of you know, our firm is one of the rare manufacturing firms in the State of Alaska. We employ 28 people year round, and have taken great pride that we essentially avoided the cyclical ramp up and ramp down over the past 31 years. We were the Export Council's "Small Business" Exporter of the Year in 2002, primarily for our manufacturing and exporting of wellhead control systems to Colombia, South America. In this instance, we used the knowledge and expertise that we learned on the North Slope to expand our controls and systems business to another oil basin of the world. This controls and systems niche that we compete in serves us well worldwide, but the bulk of our business still does originate from the North Slope and Cook Inlet. For that reason, I urge you to think very seriously about substantially changing any portion of Governor Murkowski's PPT proposal. To make additional investment in Alaska unattractive through excessive taxation would devastate companies like ours and my fellow member companies of the Alaska Support Industry Alliance.**

As a business owner, I am a firm believer that economies grow through the private sector, and not necessarily public sector expansion. Greatly increased production taxes on North Slope oil will curtail investment in facilities and additional expansions necessary on the North Slope and Cook Inlet to extend production the keep TAPS full. With excessive taxation, as we have all heard time and time again, investment capital from the major producers will flow to other oil basins of the world.

In summary, lets think about this increased taxation issue from our personal perspective. If the personal tax rate on our individual incomes suddenly doubled or tripled, would you be that willing to work that extra two or three hours of overtime?? In addition, let's consider the message that we are sending to the oil industry head corporate offices worldwide. We want to double or triple your taxes on oil, we want you to continue to invest hundreds and hundreds of millions of dollars yearly in our Alaskan economy and we also you want to build a 25 billion dollar gas pipeline as soon as possible. Does that sound like to good plan to a shareholder of one of the major producers that owns stock and has no real concern about Alaska?? That shareholder is just concerned that his investment in that oil stock and where the oil comes from is none of his or her concern. For that very reason, hold the tax rates down and keep Alaska competitive with other oil producing basins of the world. Do we want the industry in Alaska for another ten or fifteen years or another fifty??? I think the answer to that question is crystal clear. We need to let the industry know this by making Alaska a good climate in which to invest over the long term. Please think long and hard about any substantial changes in taxation. The economic future of Alaska depends on it. Thank you.

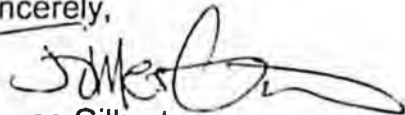
4-1-2006  
HFIN  
HB 488

April 1, 2006

## House Finance (CS HB488)

- Every one of the changes in the Governor's bill jeopardizes oil & gas investment in our state, which means the House Finance Committee is jeopardizing the future of every small business owner in Alaska that supports the oil & gas industry if you modify the governors bill. Every current **AND** prospective producer has testified to that effect, including the independents Alaska is trying to lure to explore here. Even the independents are watching what you do with this bill.
- If enacted, the CS will leave Alaska with the **highest tax rate and highest cost structure in the United States**, putting Alaska at a competitive disadvantage for new investment. Already two of the three majors do not explore, why make it a slam dunk and have three out of three curtail their exploration activity. We've all seen the charts and graphs, we need another Kuparuk or Alpine every 5 or 6 years to sustain growth, you will not find them without exploration.
- Our concern for the future of Alaskans is compounded by the lack of a state fiscal plan for managing surpluses in high-price environments like we're currently experiencing. How will we balance the budget when prices are low? The state budget was slightly more than \$2 billion two years ago; it's projected to be as high as \$3.8 billion in another two years.
- As the President of the Alliance and also as President of my own company, I urge you to choose sustainable economic growth through new investment over unsustainable government growth through higher taxes in crafting new severance tax methodology.
- **Please consider this as you move on this bill, House Finance (CS HB488).**

Sincerely,



James Gilbert  
President of the Alliance

President of Udelhoven Oilfield Services, Inc.  
184 E 53<sup>rd</sup> Ave  
Anchorage, AK 99518

home address:

9201 Main Tree Dr.

Anchorage, AK 99507

1 April 2006

To: Members of the House Finance Committee:-

My name is Maynard Tapp, I am an Alaska dreamer since 1954; an Alaskan worker since 1972; an Alaskan business owner since 1985; and an Alaskan resident since 1990.

I prefer a Production Profits Tax of 15% / 20%.

I appreciate the time you, and your Senate colleagues, have given me over the past month. I am fortunate to belong to a great organization, The Alaska Support Industry Alliance. I have gained great insight and understanding of the PPT issue through their educational campaigns.

I have also learned from the various presentations on the PPT presented by the economists, and producers, and the legislators of the State of Alaska.

I believe these bills need to be viewed as "Resource Development" legislation not as state tax revenues.

I believe we are all partners in this deal; the government, the people, and the "producers".

The "producers" reinvest the revenues and grow the source of those revenues.

The people get jobs from/and related to the "producers" reinvestment and grow their wealth; spend money in the community, and grow its wealth and viability.

The government takes its share and grows the government.

As a partner, shouldn't the government support the growth of the revenue resource and not the growth of the government. Ultimately, the growth of the revenue source supports the growth of government but within our means.

I believe the 20% / 20% is the wrong number, it should be closer to a 15% / 20% PPT. What should the PPT number be to get to a 0% to 3% rate of decline? What are we doing to ensure the states revenue source viability lasting to our next generation?

In today's economic climate we are declining at 6% per year. Starting at 880,000 bbl/d I calculate the pipeline being mechanically inoperable by 2015. Then what?

The new technologies to bring viscous oil to market are not guaranteed and not cheap.

What can the government do to encourage investment? It doesn't seem like raising the rent does anything to put more money into exploration. We cannot tax our way to state solvency, in the long run we must invest our way to state solvency and success.

I started a business here twenty years ago waiting for the stars to align.

1. Continuing investment on the Northslope
2. Build the Alaska Gas Pipeline to the lower 48.
3. Get legislation in place to encourage development of ANWR.

What are our state representatives in the House and Senate doing to encourage development and growth of our resource pool, the source of our state revenues? Please invest in maintaining the "seed corn" to keep Alaska growing, now and into the future.

Thank-you  
Maynard Tapp  
200 West 34<sup>th</sup> Ave. #809  
Anchorage, Alaska -- 99503



# NORTHWEST TECHNICAL SERVICES

HFIN  
HB 488

April 1, 2006

Testimony at Anchorage LIO Office

The Honorable Kevin Meyer  
The Honorable Mike Chenault  
Co-Chairmen, House Finance Committee  
and Committee members  
Juneau, Alaska

Subject: CSHB 488

Thank you for hearing my testimony, today, Saturday, April 1, 2006. At this time, I ask that you and your committee reexamine the changes made to HB488 which are contained in House Resources Committee substitute, CSHB 488.

As General Manager for Northwest Technical Services, a company which provides employees to a variety of industries, including the oil industry, I usually approach you and other members of the Legislature on matters that deal very specifically with Wage and Hour, Worker's Compensation and Workforce Training both in title and content. In this case, however, I am concerned that the impact on the workforce and future employment for NWTS' 100+ employees and other Alaska workers may not be quite as evident to others as it is to us.

The crux of the matter is – the more money that goes into the State government in taxes, the less money there will be for investment by the companies in the private sector into new projects and the redefinition of current fields to stem declining production. Reduction of investment will mean reduction of jobs some of which are directly related to the oil and gas industry, many of which are the "fallout jobs" where most Alaskans work, i.e. at grocery stores, hardware stores, the State of Alaska, etc.

It has also been made very clear that the PPT is, in some fashion, being tied to the gas contract. This impacts even more jobs and opportunities – for Alaskans and, to go beyond our borders, for other U. S. citizens. It has taken us too long to get to this point in history to jeopardize it now with a taxation rate that could result in a tax and cost rate higher than anywhere else in the United States. This gas line is our future and the future of our state. The monies it will generate will far outweigh those we might realize by the change in the tax rate that has been proposed by the House Resource Committee.

Representative Kevin Meyer  
Representative Mike Chenault  
Co-Chairmen, House Finance Committee  
and Committee Members  
April 1, 2006  
PageTwo

I ask that as you deliberate over the next few days as to which changes you are going to retain prior to sending this Bill forward, you step back and consider all the ramifications of these decisions, particularly the impact on jobs, future development and the quality of life for this and the next generations of Alaskan citizens.

With the resistance of the U.S. Congress to the opening of ANWR, this is our next "big strike". As Senator Ted Stevens' stated in his address to the Legislative body, it is a decision that will set the course of the State of Alaska for many years to come.

Respectfully yours,



Mary E. Shields  
General Manager

4-1-2006  
HF  
HB 488

Good morning & thank you for this opportunity

My name is Mike Koy.

I've worked with BP for over eleven years in various capacities including numerous roles in business development, strategy, economic evaluation and long term planning. The last three positions I've held in BP are Business Development Manager in Alaska, Planning Manager in BP's corporate headquarters in London and Project Manager in BP's Global Mergers & Acquisitions Team, also in London.

I am currently on a leave of absence from BP, representing myself and not the company, and therefore free to speak with all the knowledge and perspective of someone from within the industry but without any of the associated limitations or constraints.

There ~~are~~ three things I would like to address in the time I have investment <sup>me</sup> ~~and~~ <sup>taxed</sup> ~~as a gas pipeline~~ projects.

Let me start by saying that most oil companies, and all of the majors, use fixed prices when making investment decisions and those prices have tended to be in the \$20-\$30/bbl range. Within this price range is where the tax regime needs to look attractive relative to other places in the world in order to attract investment. What happens outside of this range is important, but largely immaterial when companies are making investment decisions.

With that as background, the version of HB488 as passed out of the Resources committee, creates a higher tax burden on industry through most of the \$20-\$30/bbl range than the current oil tax structure. To attract investment, the tax rate in this range only should be lowered from the 20% currently in the bill.

At oil prices below \$20/bbl, is where HB488 provides the greatest reduction in taxes relative to the current oil tax structure ironically right when the State will need funds most. While some relief in this price range would be welcomed by the oil industry, the State will not get full credit for providing reduced taxes in this range which means the State is giving away value for nothing in return. HB488 should include a provision which increase the regressive nature of oil taxes in the under \$20/bbl range relative to what is currently in the bill but less regressive than the current oil tax structure. This is easy to do.

WHAT THAT IN MIND, HB488 reduce oil taxes too much at oil prices below \$20, too little at oil prices between \$20-\$30/bbl, and leaves taxes too little at oil prices above \$30/bbl

For oil prices above \$30/bbl, in a range that increased taxes will not impact investment or the health of the underlying business, it is reasonable for the State to progressively share in revenues. HB488 implements a progressive, or graduated, profits tax structure, but it does not go as far as it could and still not impact investment and more importantly doesn't go far enough to cover the State's oil price risk. In fact, as HB488 currently stands the State will take in less tax revenues on average than they currently do with the existing tax structure. To overcome this, HB488 should include a more progressive tax structure which easily could be done by lowering the oil price at which the graduated profits tax kicks in from \$50/bbl to \$30/bbl.

With regards to risk/reward balance, oil companies understand this as well as anyone and it is clear in HB488 where the State is taking on most of the risks and not getting compensated with a proportional share of reward. I've already mentioned price risk, but the State would also be taking on cost risk and exploration risk as part of this bill. With exploration in particular, the State is going to find it very expensive including investment tax credit on exploration with little in the way of benefit. The State would do much better to eliminate the investment tax credit on exploration costs, thereby eliminating the State's exposure to this risk, and instead place a greater investment tax credit on heavy oil which has already been discovered in large quantities, is close to infrastructure and can be brought on-line much quicker with a bit of economic help.

The final thing I would like to say is around the relationship of oil fiscal terms and a gas pipeline project. Oil fiscal terms have no bearing whatsoever on the economics of a gas pipeline project. They are not related at all except through negotiation with the oil companies recognizing they have an opportunity now to create leverage for better oil terms than they could otherwise get. Oil taxes will not impact the viability of a gas pipeline project or the interest in the oil companies of progressing a gas pipeline project. The State needs to stop treating one as having an impact on the other as it gives away value for no reason. Related to this, the legislature should consider including only the oil tax terms in HB488 and remove gas related components and ask that these be included in the gas contract ~~not the oil terms~~. There are components in there which have much more of an affect than pure tax consequences and need to be considered in totality with the rest of the gas contract. No oil consultant will be able to help in this area.

Losses the state <sup>relative to the current tax structure</sup> In terms of risk, with HB488 is <sup>since</sup> making an independent estimate amount of risk. <sup>was planned never pl</sup>

In summary, while I think there are better starting points for amending the State's oil fiscal terms than this bill, if it is to be the basis for a new system amendments should be made to make it slightly more regressive on the low price side, implement a higher graduated progressive tax on the high side, consider a tax incentive for viscous oil and most importantly consider oil tax legislation separate from a gas pipeline project and ensure oil fiscal terms are not included in a gas contract. Remember, the oil companies want to develop a gas project as much as the State wants them to.

Thank you.

4-1-2006  
HFIN

**Thank you, Mr. Chairman, for this opportunity to speak today on the Committee Substitute to HB 488.**

My name is Joanna Caselli, and I have lived in Alaska for more than 15 years. I went to college here, and I am now carving out a career for myself here. Having recently married, I also wish to have children here, raise them here, and give them every opportunity to succeed—that is, if the future of Alaska's economy remains strong.

My livelihood and my husband's—and, consequently, that of our future family—is directly linked to the oil & gas industry. We want to stay here and continue to be productive Alaskans, but we need to know there's a future for us here.

That said, what happens if this higher tax rate *does* have the negative impact on investment that oil producers are predicting? My husband faces the very real possibility of losing lucrative contracts, of seeing his business decline. Losing contracts translates into having to eliminate positions—and the men my husband works with are supporting families and can absolutely not afford to lose work. No one can.

If the work opportunities are not here for my husband and I, we certainly won't stick around to raise a family in that kind of environment, no matter how much we love Alaska.

Higher taxes equal less investing. Less investing means fewer job and work opportunities. Please, play your cards right. There is no room for mistakes at this poker table. The jackpot is the future of this state.

Thank you.

Joanna Caselli  
13342 Diggins Dr.  
Anchorage, AK 99515

Thank you for this opportunity to speak on the Committee Substitute to HB488. Mr. Chairman, my name is Hillary McIntosh and I live in South Anchorage. I am here to tell you how your decisions on this tax bill will affect my family. My husband and I both derive our livelihood from the oil and gas industry...reaching further, so does my sister, brother-in-law, uncle and many friends. I am sure this is a common statement among most Alaskans.

Every producer, majors and independents, has indicated that higher taxes as proposed by the legislature will result in less investment in the Slope. What does that mean to me? What does that mean to my husband, my family members and friends that support the oil and gas industry? I believe it means fewer opportunities for professional growth, a fear of job instability and a distinct disincentive to stay in Alaska.

Short term revenues for government are not worth throwing away long-term investment for Alaska's future. How will this all pan out when my daughter graduates from college in 2027? Will she want to stay in Alaska? Will the oil and gas market be thriving then? It may not be if you overstep the producers' threshold. Don't let Alaska's biggest export become its children.

Less money to invest in the majors' own industry will certainly mean less money to invest in Alaska's communities as well. Between my husband and me, we sit on several boards and are involved in many area non-profit entities. In fact, I even work for a non-profit. The oil industry, majors and their contractors, have been very generous to the non-profit community and it would be detrimental if their support is reduced due to your important decisions on this tax. Less investment in our communities means less support for programs that I value and feel Alaska's children need.

In the event that community support is reduced, will the State of Alaska subsidize the difference? What plan is in place to manage these windfall profits?

You can shave a sheep many times, but you can only skin him once. I watch gavel to gavel, I read the papers, I watch the news, I've read the bills themselves...and I think the changes made to the Governor's bill have destroyed the delicate balance between state and industry needed to ensure a healthy economy and much-needed gas line. Let's not forget that two year of negotiations went into the agreement. I am not asking you to "give in" to the producers' every whim, but I am asking you to think about the negative externalities your changes will cause and how Alaska's future may look in 10, 20 or 30 years. Do not stray too far from the Governor's proposal. Please do not jeopardize my family's future in Alaska.

Hillary McIntosh  
2530 Cleo Avenue  
Anchorage, AK 99516