

ALASKA LEGISLATURE

HOUSE and SENATE FINANCE COMMITTEE FILES, 2005-2006 3093

SB

305

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MAJOR PRODUCERS

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

Alaska State Legislature
House Finance Committee
27th 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.

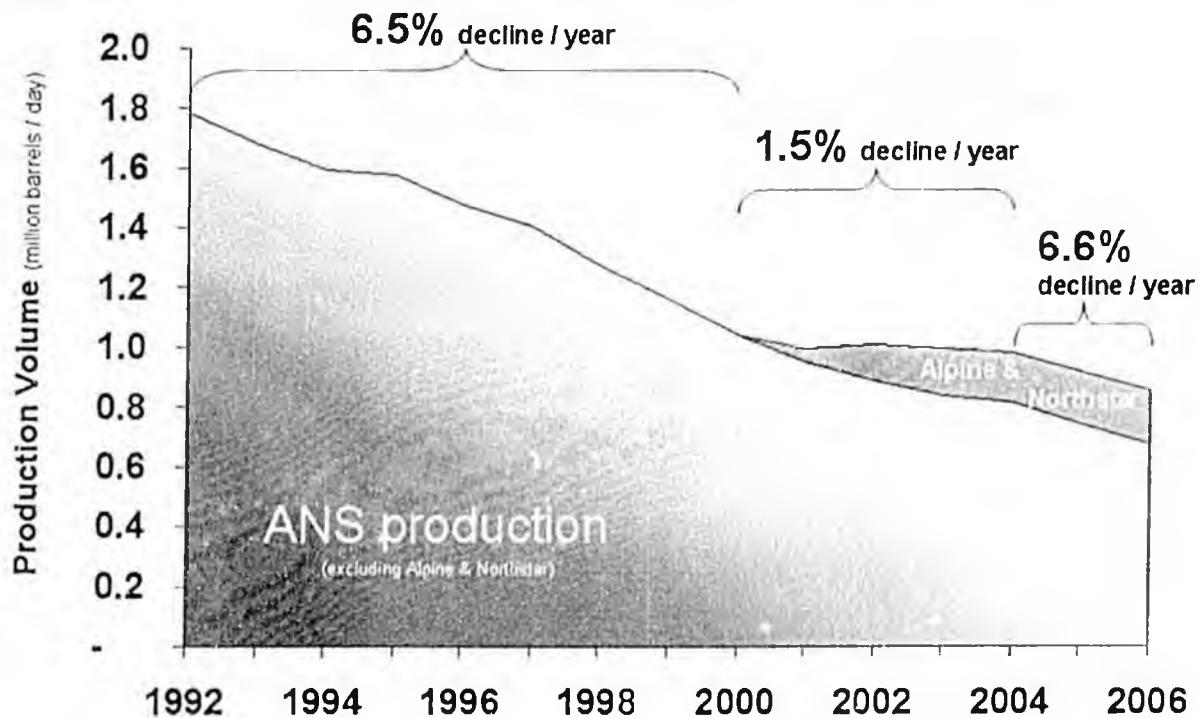
- **ANS production is declining rapidly, despite the current level of investment (circa 1 billion dollars per year).**
- **At the current rate of decline production will be about 450,000 barrels per day in 10 years.**
- **To achieve the DOR's latest production forecast, investment needs to be significantly 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).

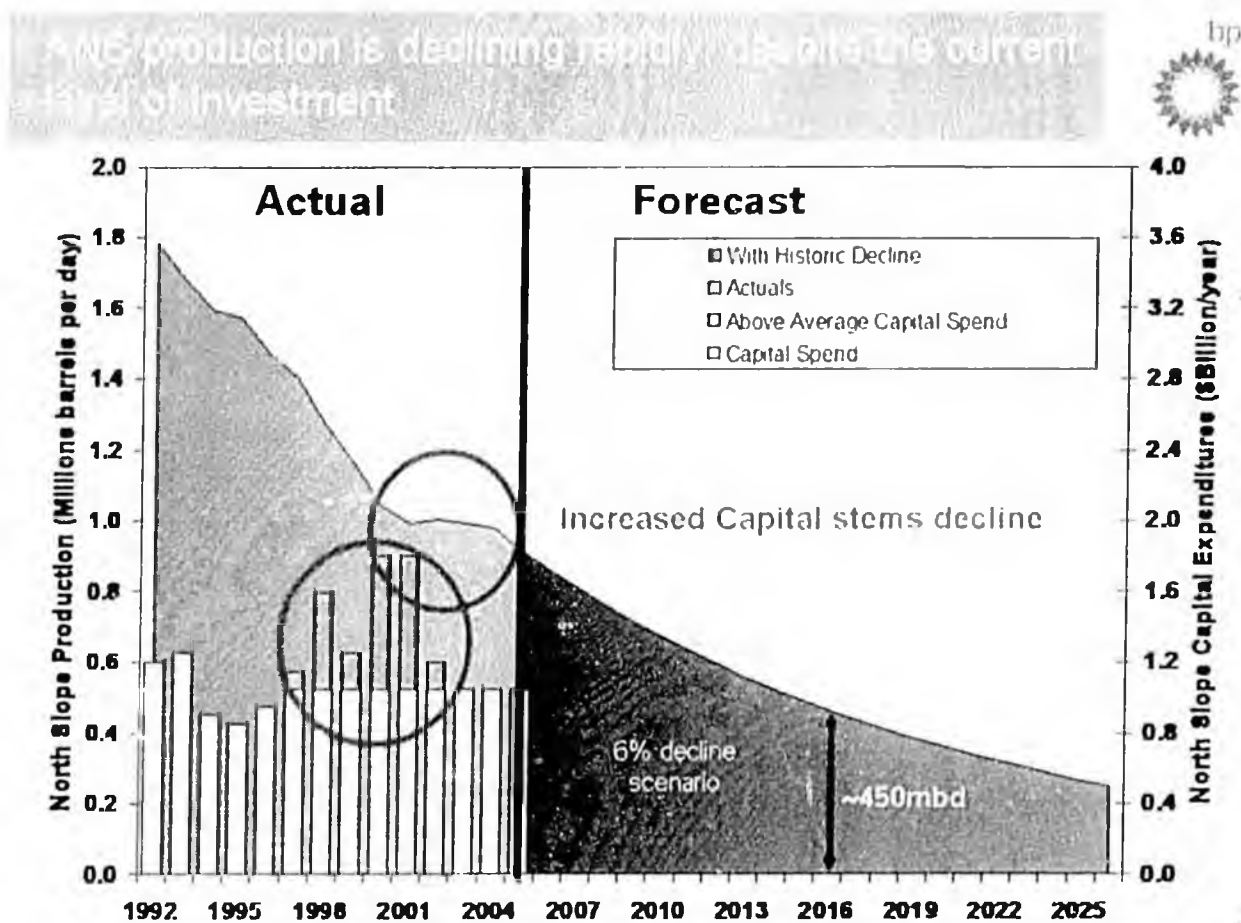


Many of you have heard us state that ANS production is declining at 6% per year. Why do we say that? For the eight years leading up to 2000, ANS production declined at a rate of about 6% per year. The development of Alpine, Northstar, and the Prudhoe Bay Satellites between 2000 and 2002 successfully 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

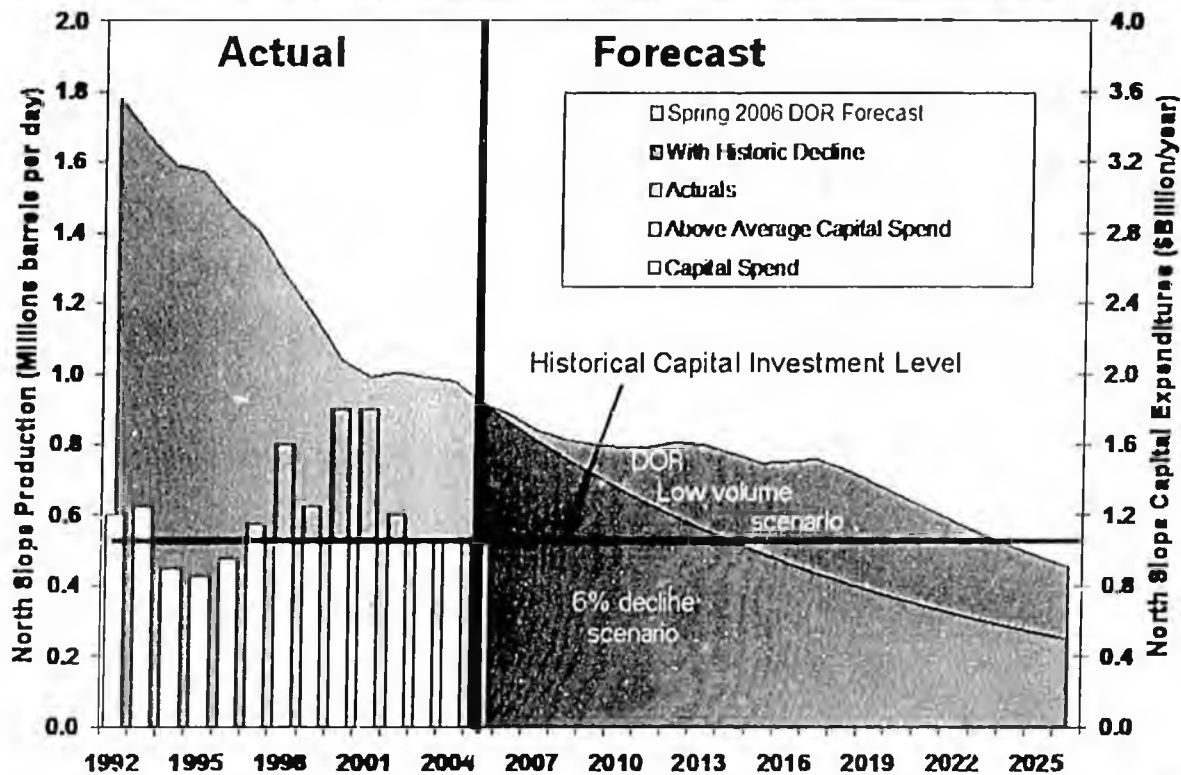
The decline abatement experienced about 2000 required investment levels above historical averages. This graph demonstrates the cause and effect relationship between investment and production.

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.

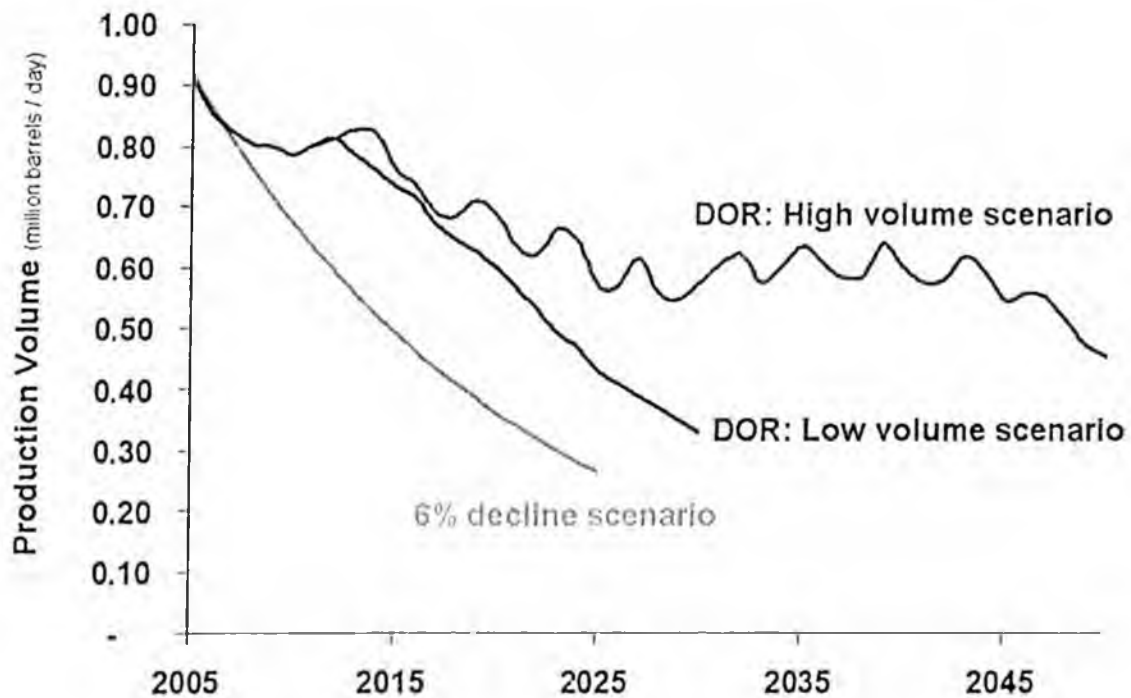
The blue wedge is 1.3 billion barrels of production over twenty years. At today's prices that represents tens of billions in state revenue lost because oil was left in the ground. This is before any consideration for the economic multiplier effect that the billions of investment would have created for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

- o 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.
- o 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 1st 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 a 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 13th 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 13th 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 13th 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
April 27, 2006
Page 5

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 rd 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

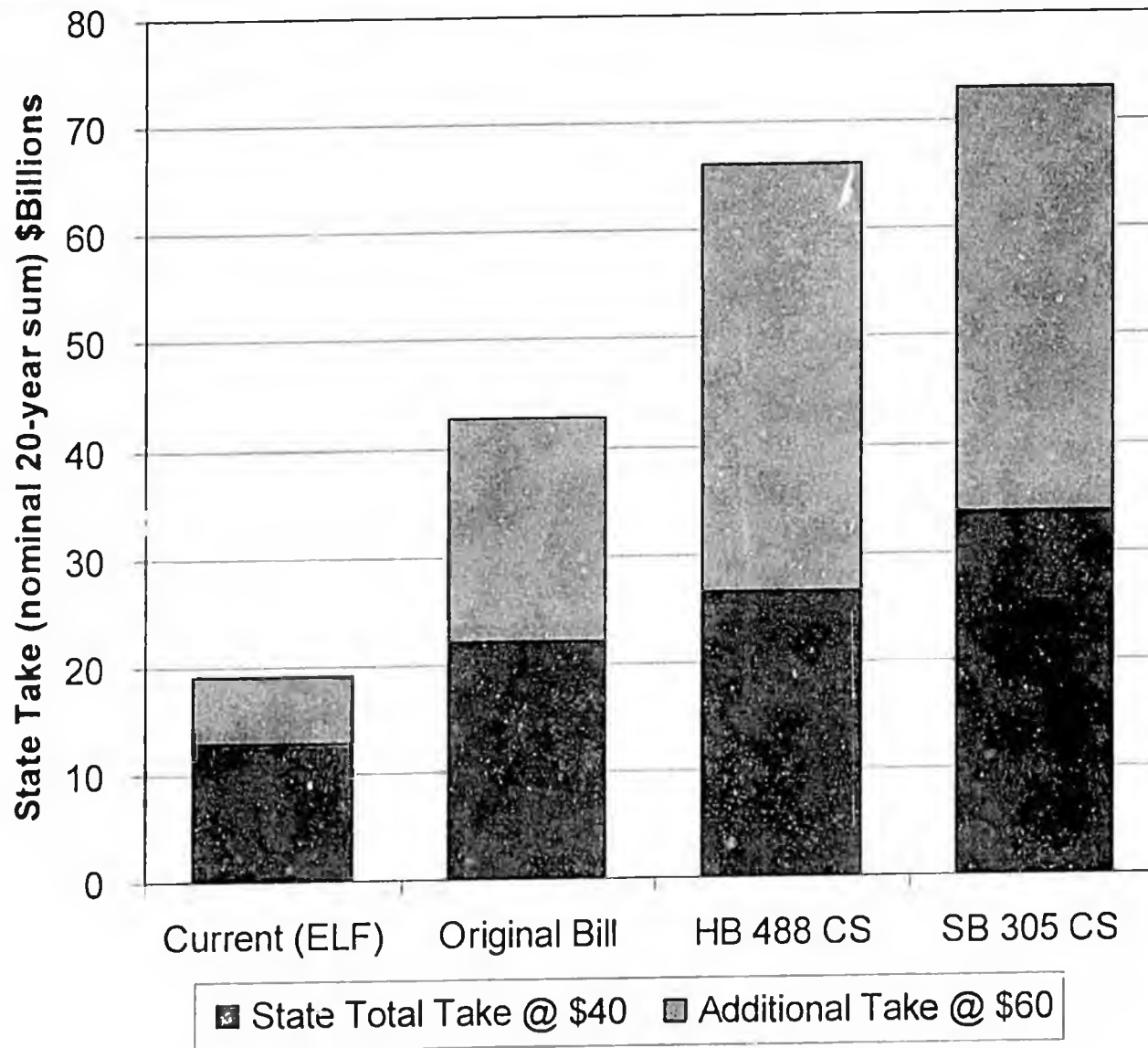
ConocoPhillips Alaska
March 30, 2006

Jim Bowles
President
ConocoPhillips Alaska

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 1980, the Alaska oil industry and the state of Alaska placed Alaska's #1 economic engine in jeopardy.

Oil and gas companies, the companies that support Alaska and depend on a pipeline which was part of a balanced tax and revenue policy, providing state revenue for Alaska's public day care, education and a host of other public programs.

Oil and gas companies and the state of Alaska have agreed to a new tax — one with additional cost. When the Legislature proposes a change of rate, it will change the pipeline bill to take care of the new tax.

What is the Pipeline and State Revenue. Instead of allowing the revenue to be used to increase education, health care and job training, the Legislature is diverting it to pay for the new tax. This will be a major step in the direction of Alaska's economic future.

Call your legislator. Let's face it, we're in for a long haul.

ConocoPhillips



ConocoPhillips Alaska



Alaska's No. 1 Oil Producer

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

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

OECD¹ 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

¹ Organization for Economic Cooperation and Development

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

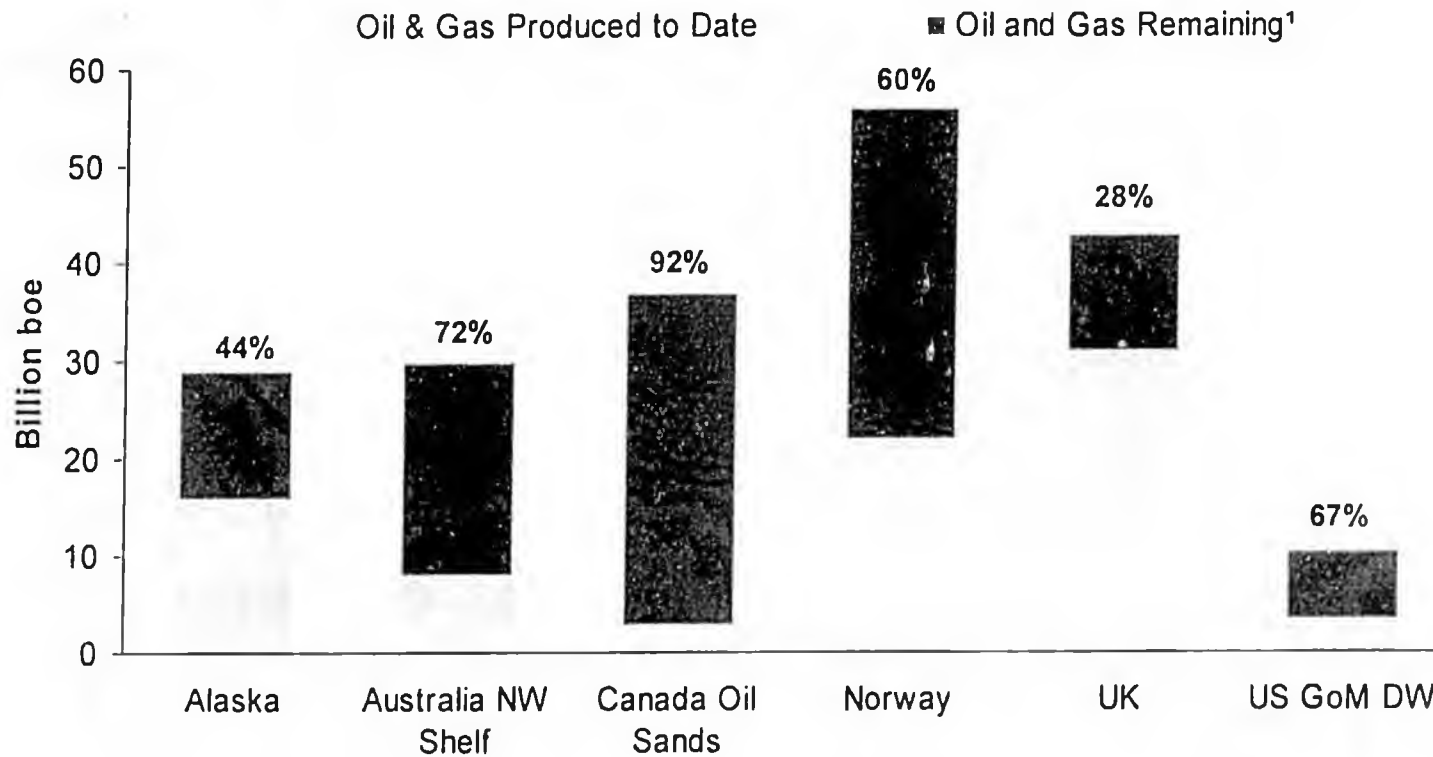
Total Hydrocarbon Production Change 2000-2004		
Region	2004 Production (mboe/day)	Growth/decline since 2000
US GoM SW	738	-27%
Australia NWS	403	-27%
UK	2,144	-19%
Alaska	946	-6%
Norway	3,180	8% ¹
US GoM DW	1,037	26%
Canada Oil Sands	997	64%

¹ 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



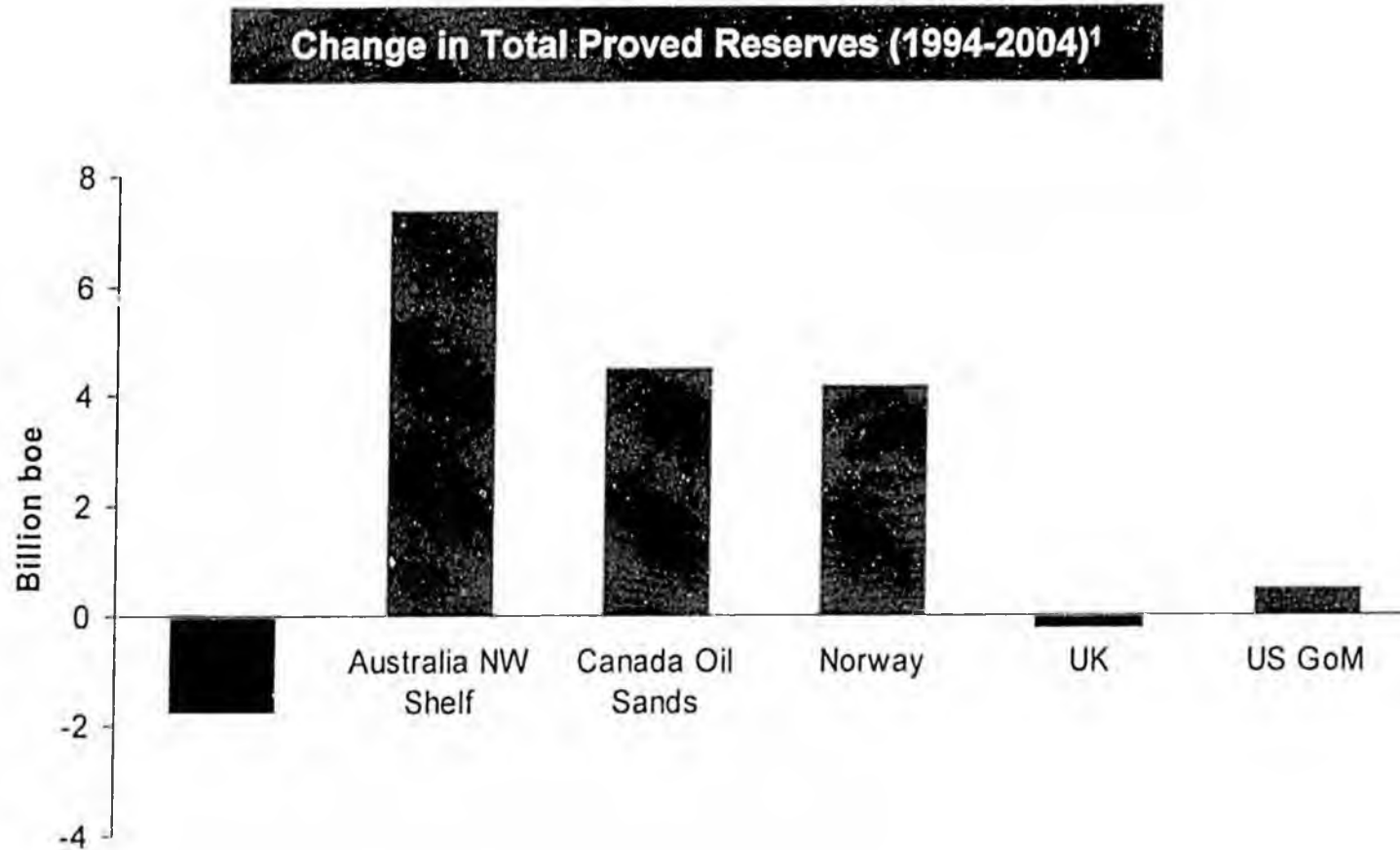
¹ Future estimates based on available data on '2P' or P50 basis: i.e. a central estimate of remaining potential

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

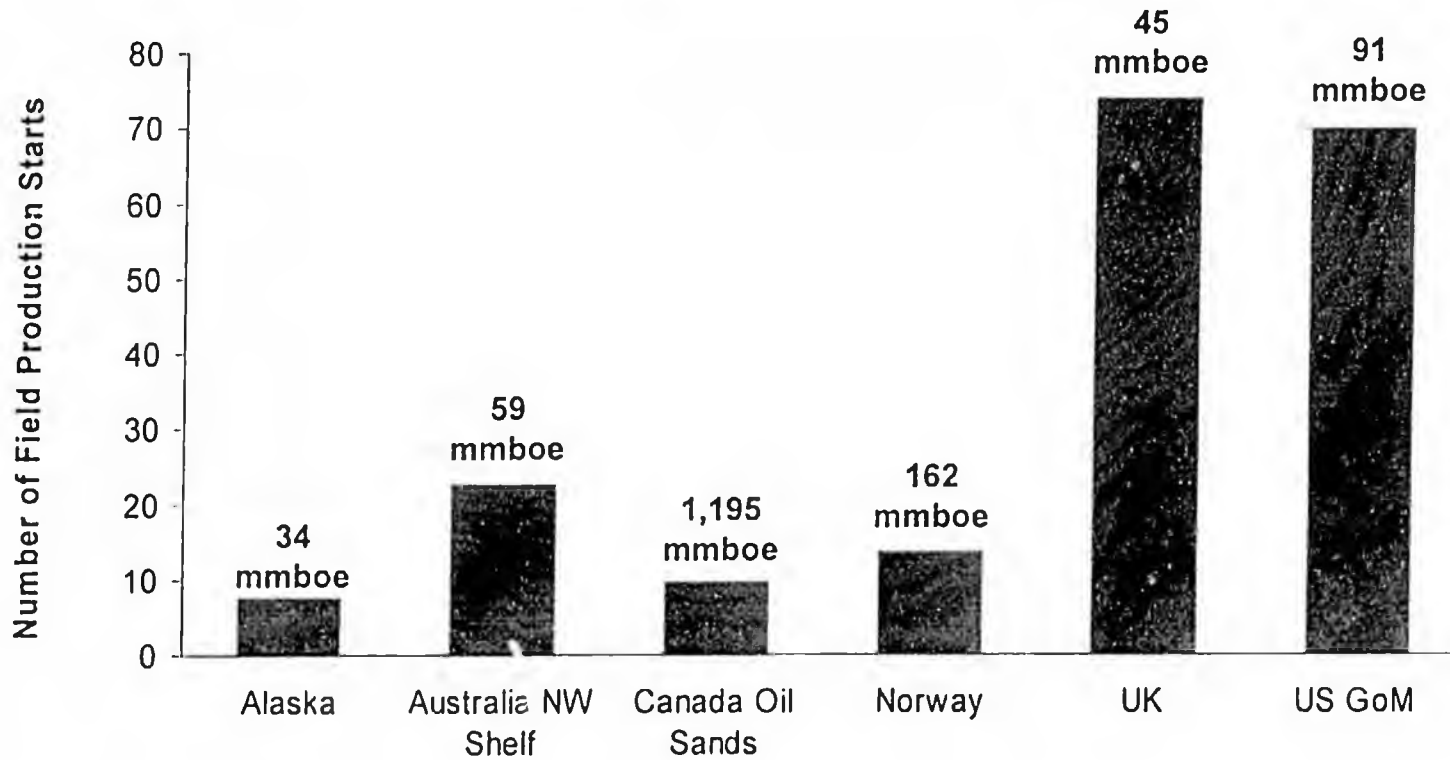


¹ – Figures based on proved (P1) reserves
Sources: BP Statistical Review & EIA



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

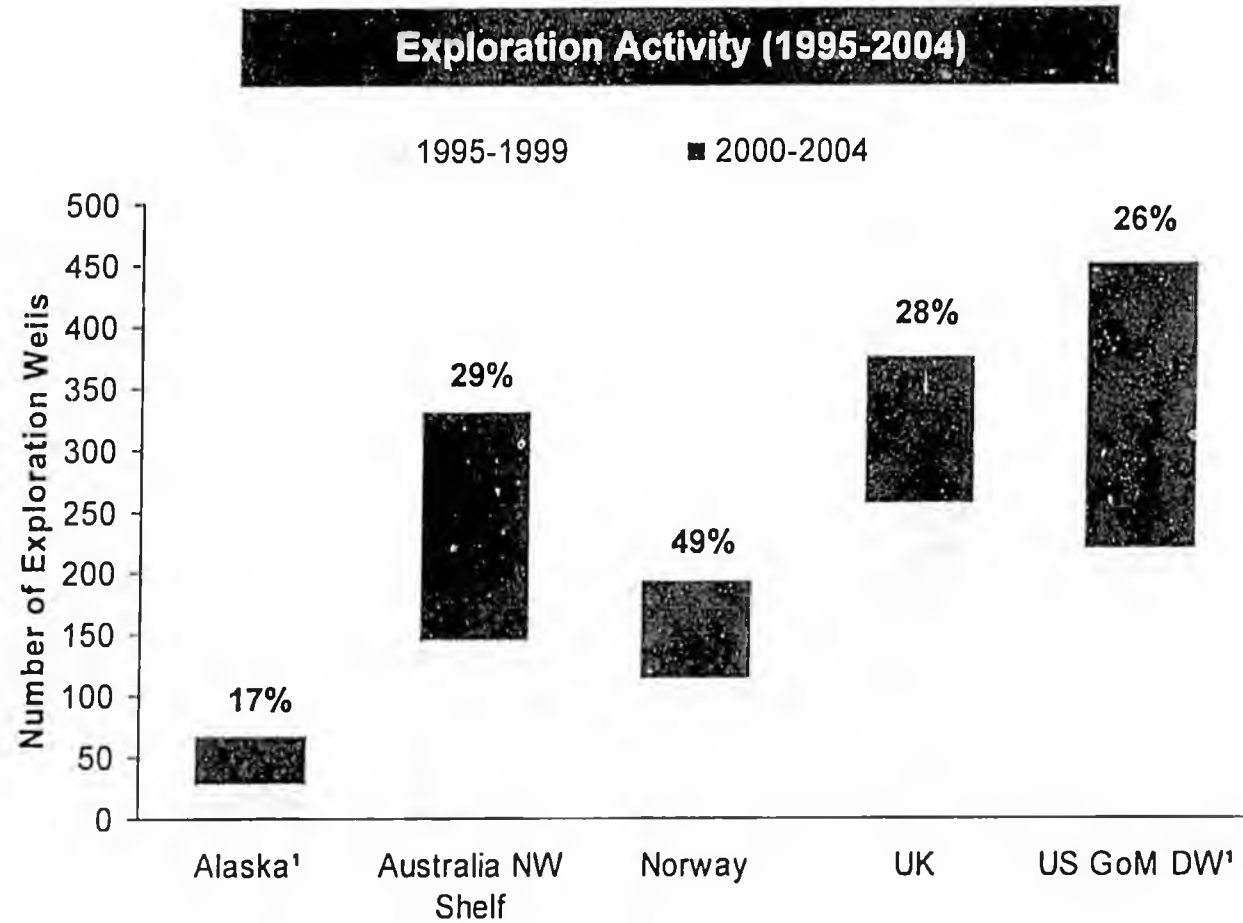
Field Production Starts (2001-2005)



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

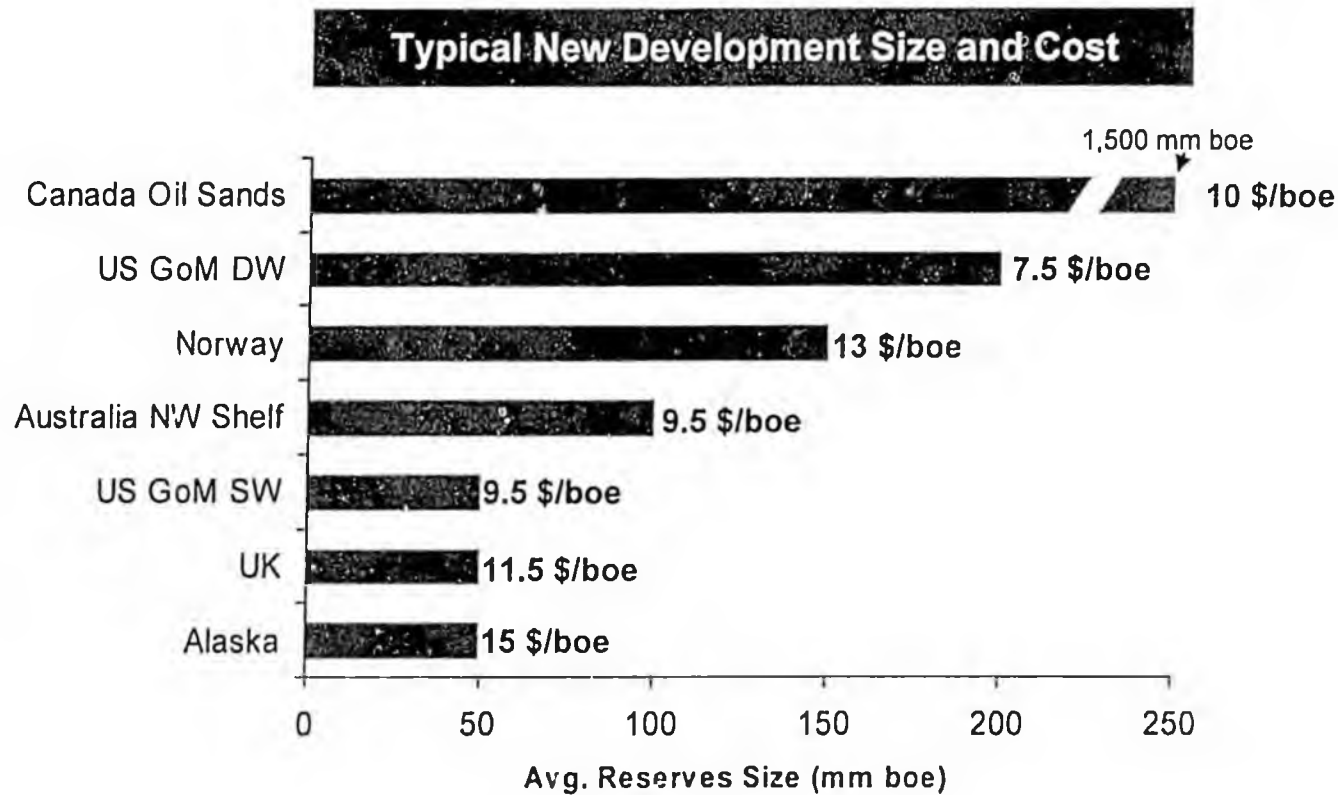
¹ Alaskan and US GoM drilling numbers discounted by 50% from DNR / MMS figures for Exploration and Appraisal drilling

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



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

Key to remaining prospectivity levels

High



Mid-range



Low

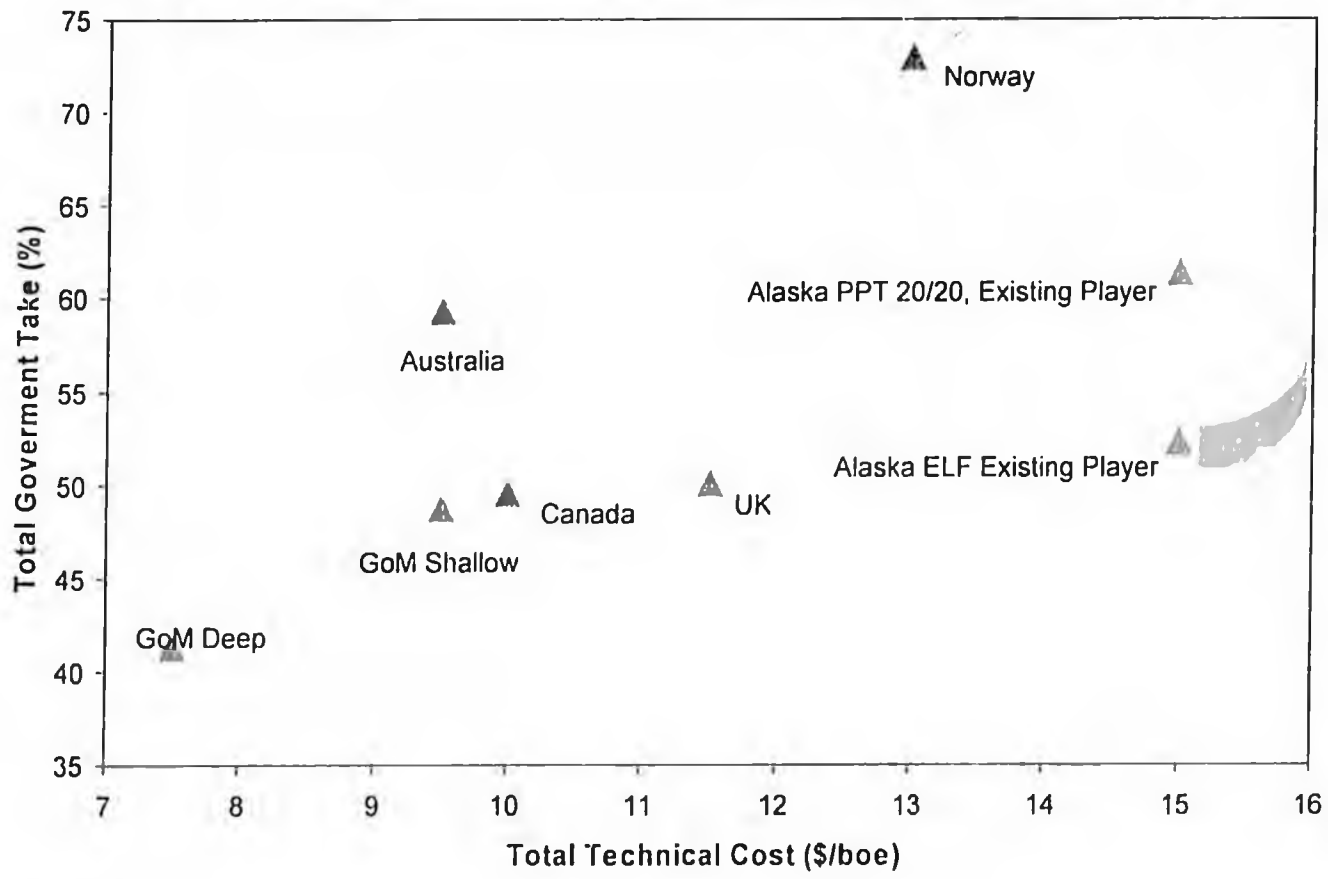


Source: CRA Analysis



The basic¹ 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

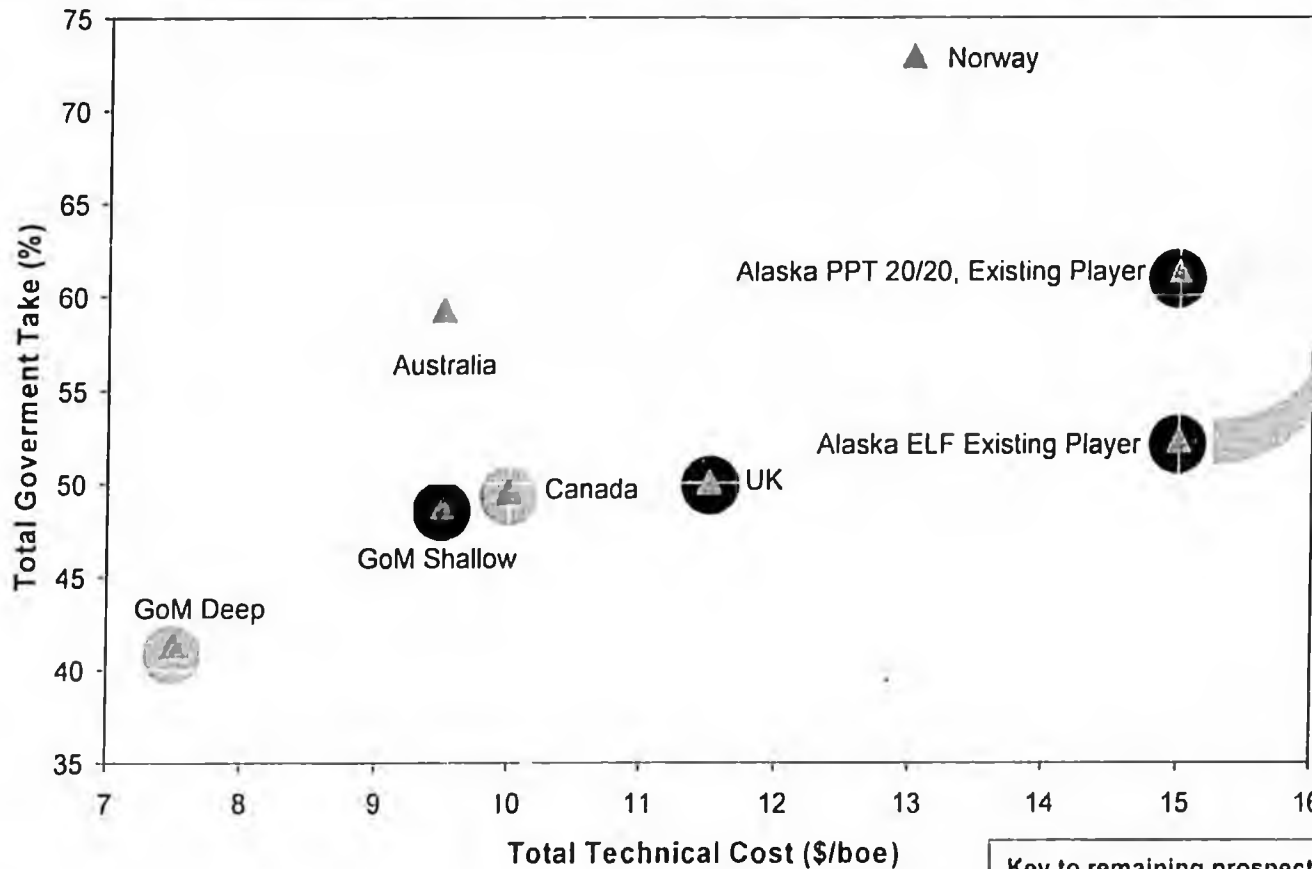


¹ i.e. the original HB 488 bill.
Source: CRA Analysis



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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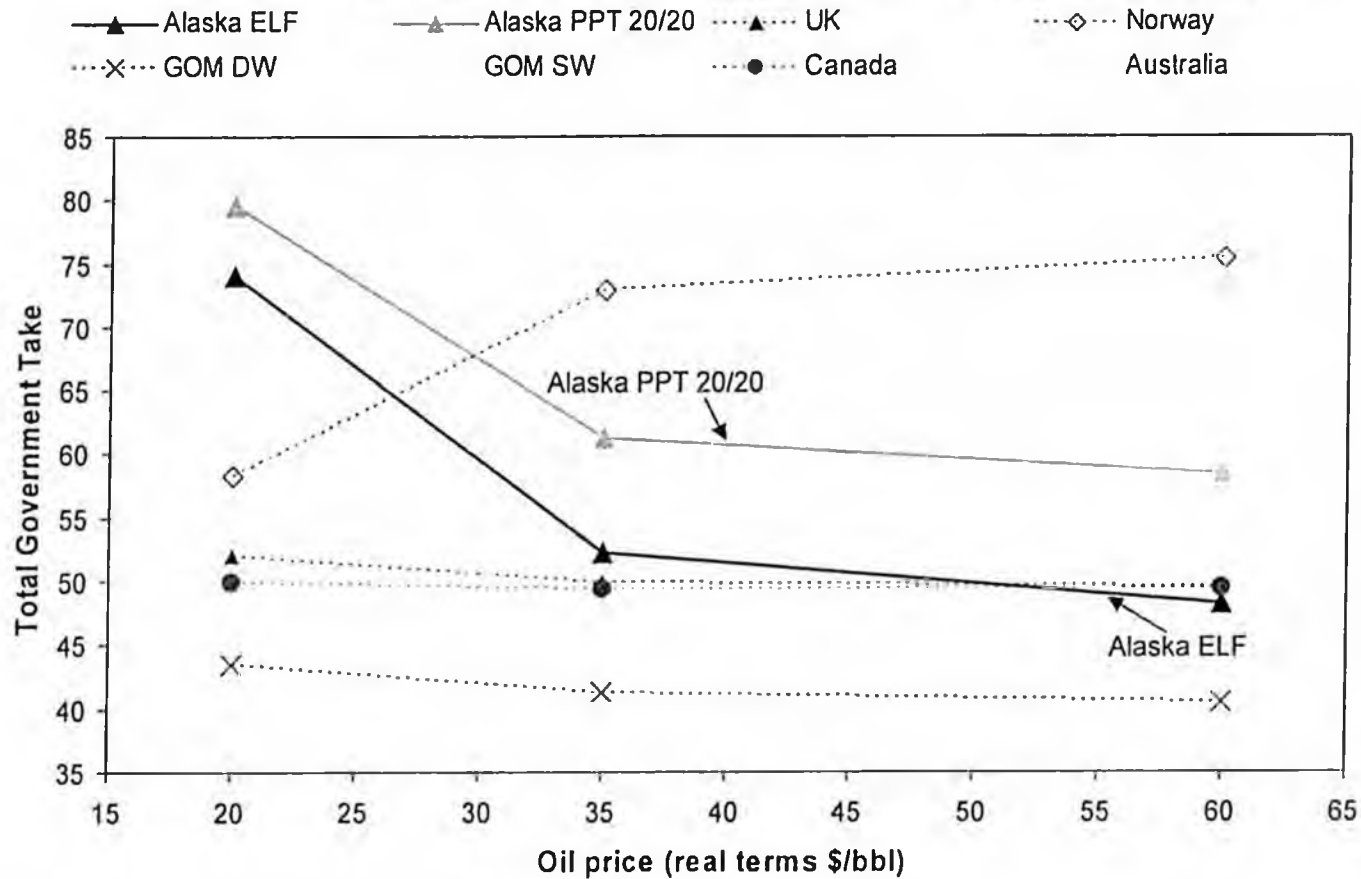


Norway's high tax rates are sustainable for an area with high prospectivity and other supporting factors

- **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

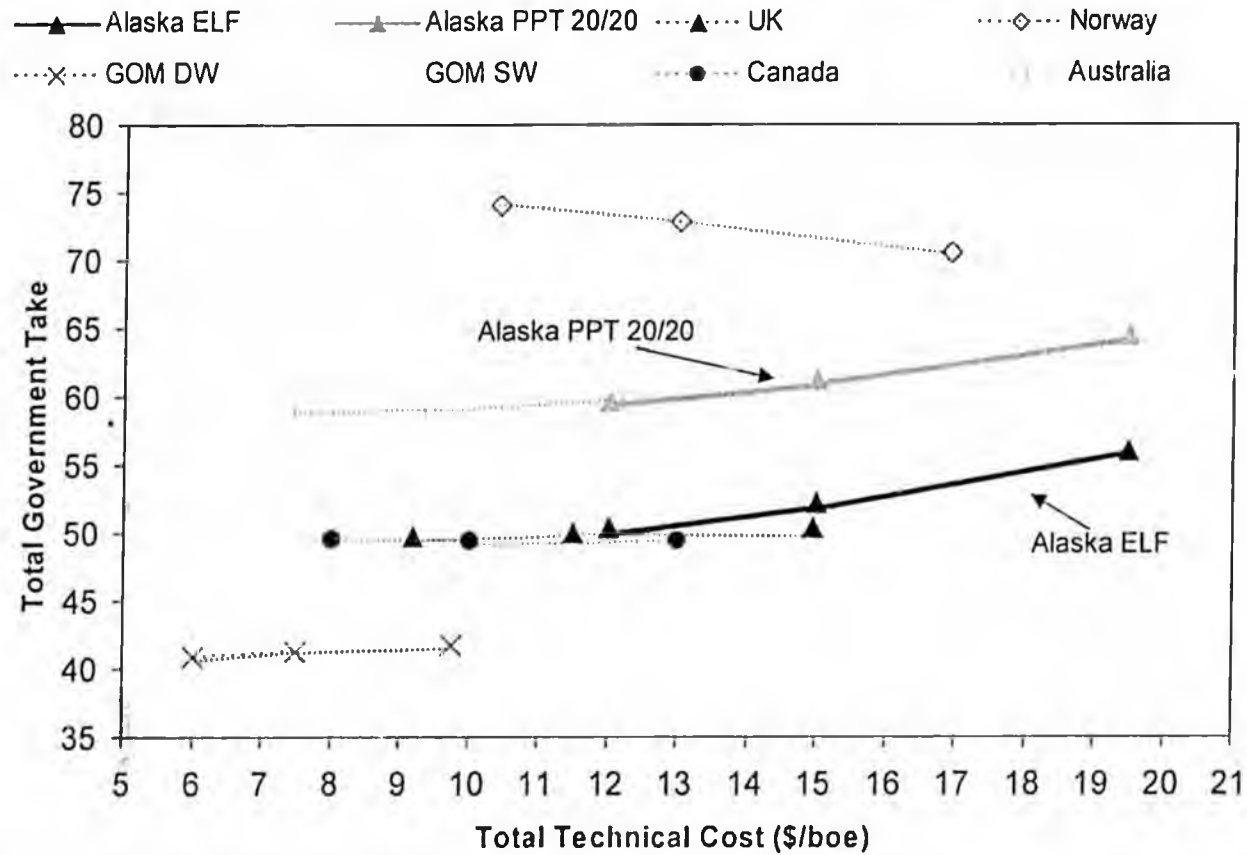
Total Government Take for Different Oil Prices



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

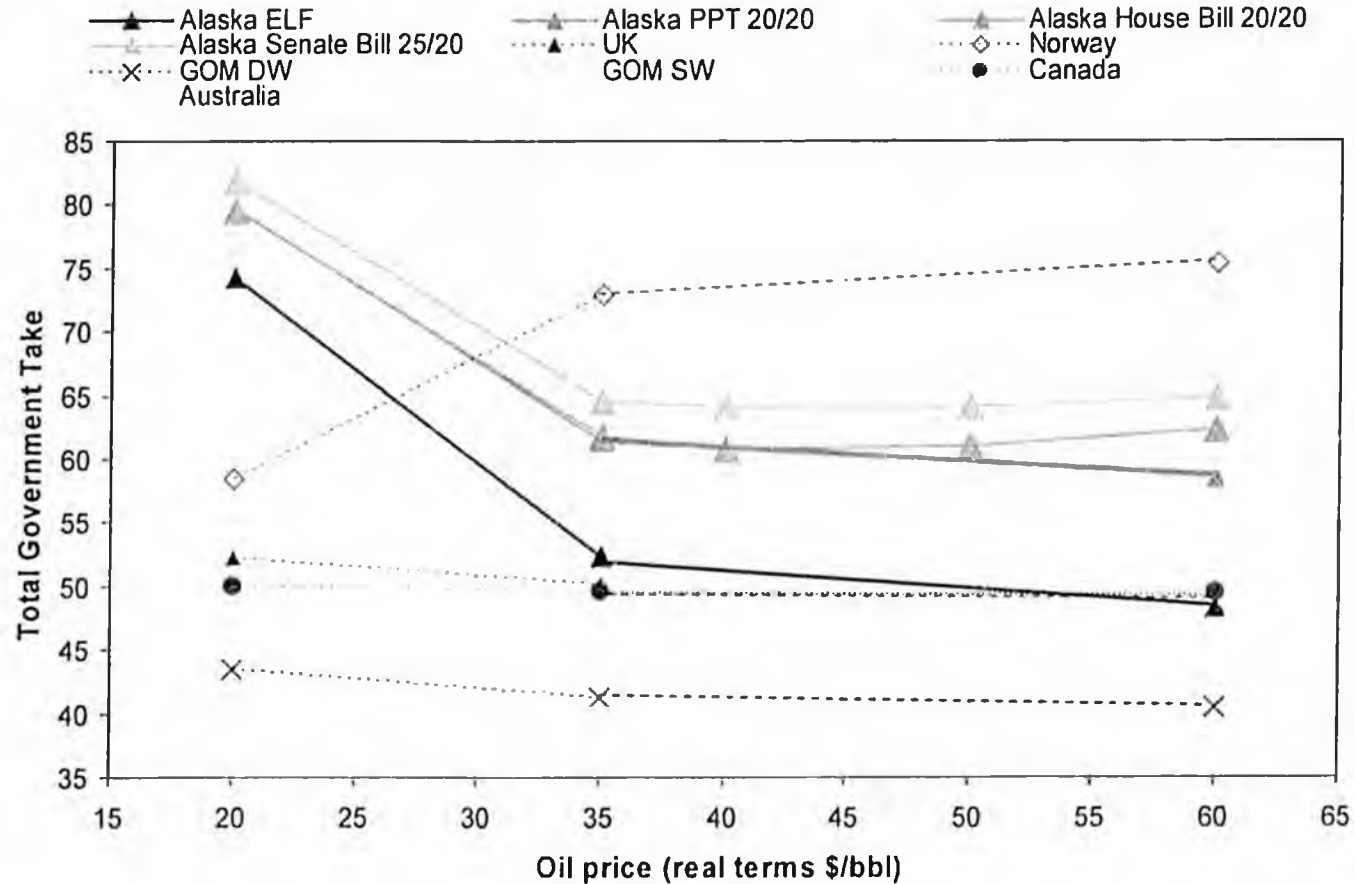


Source: CRA Analysis of Total Government Take for existing Alaskan participants



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 ¹	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

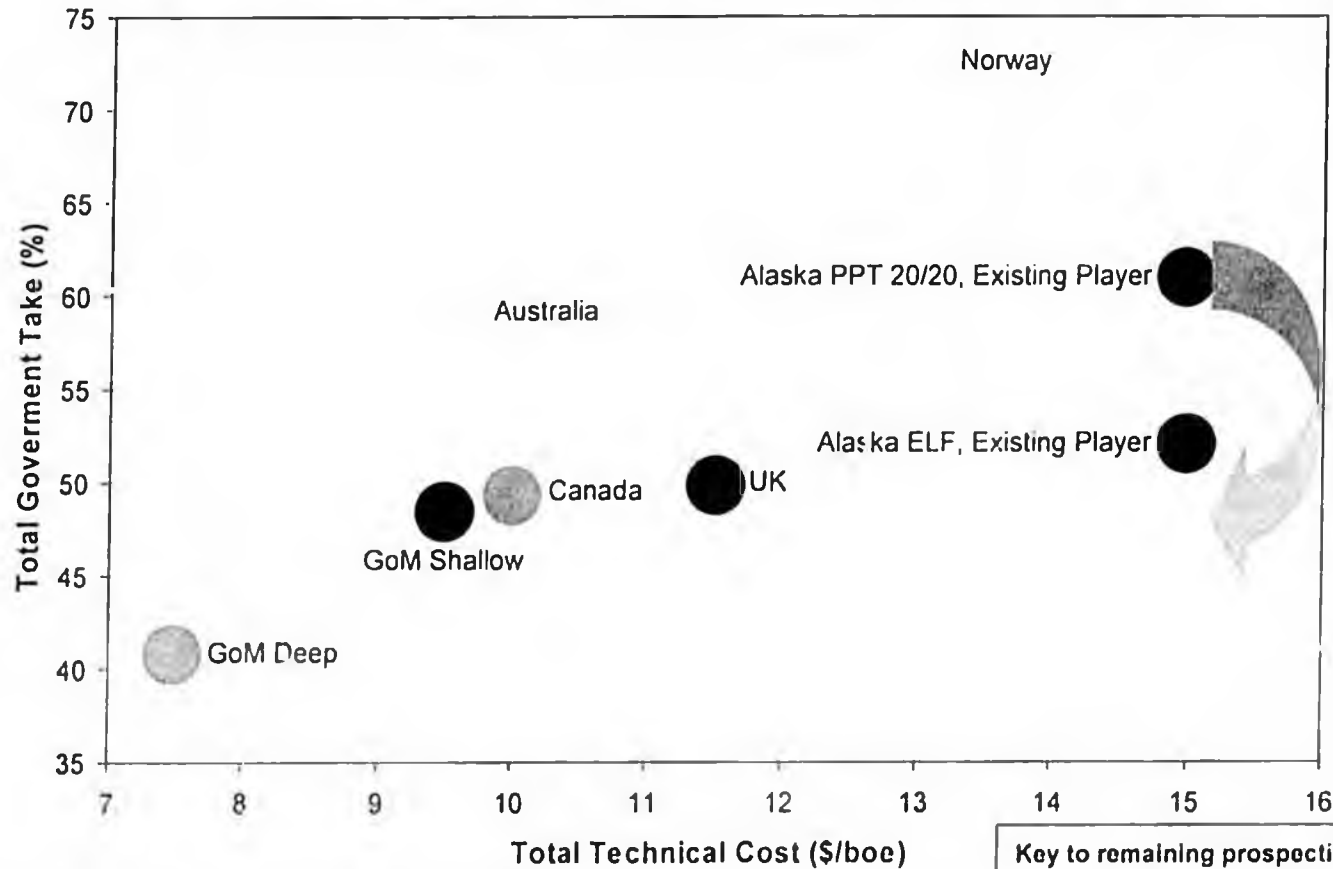
NB YTF = "Yet to Find"

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

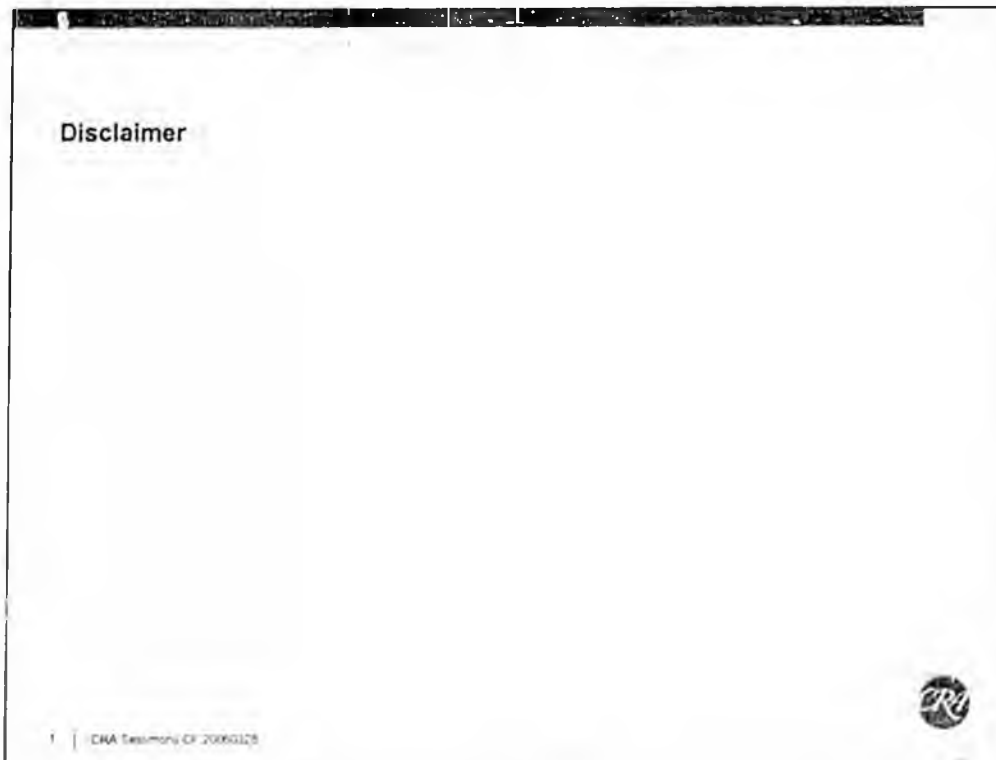
David Bramley
March 30, 2006

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.

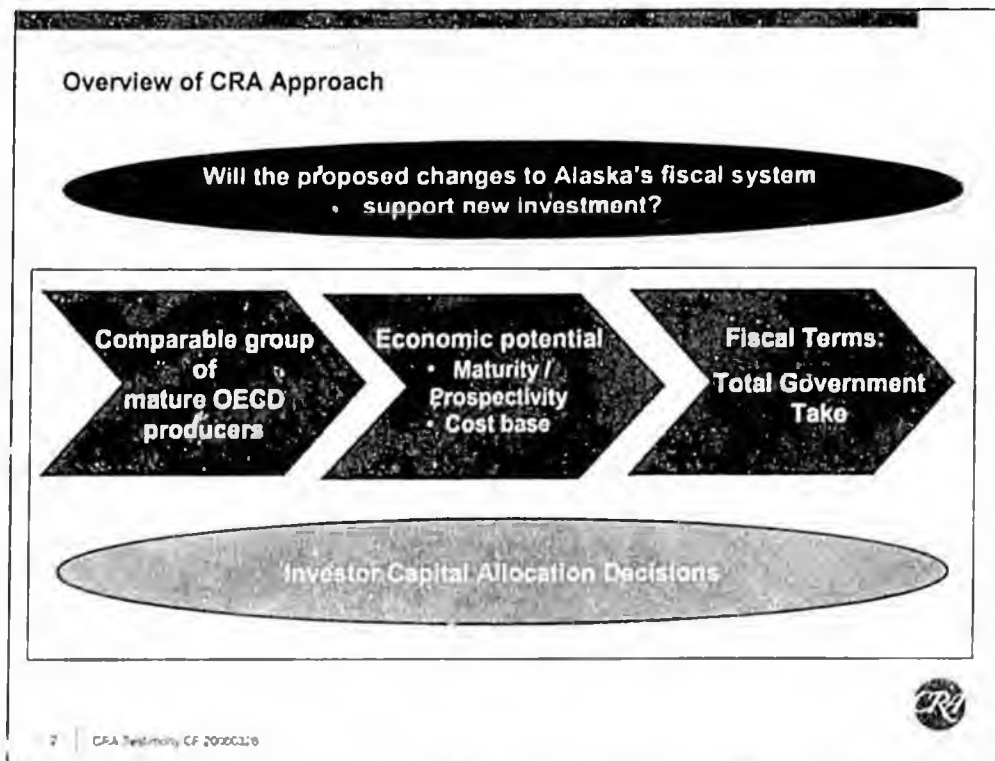
We have throughout used our independent professional judgement to generate working assumptions that we believe reflect the techno-economic realities in each of the comparison areas, and applied methodologies which we believe reflect the way investors will themselves assess the impact of fiscal terms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



DISCLAIMER

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

Organization for Economic Cooperation and Development

3 | CRA Testimony, CF 20060329



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%
UK	2,144	-10%
Alaska	948	-6%
Norway	3,180	8% ¹
US GoM DW	1,037	26%
Canada Oil Sands	597	64%

¹ 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.

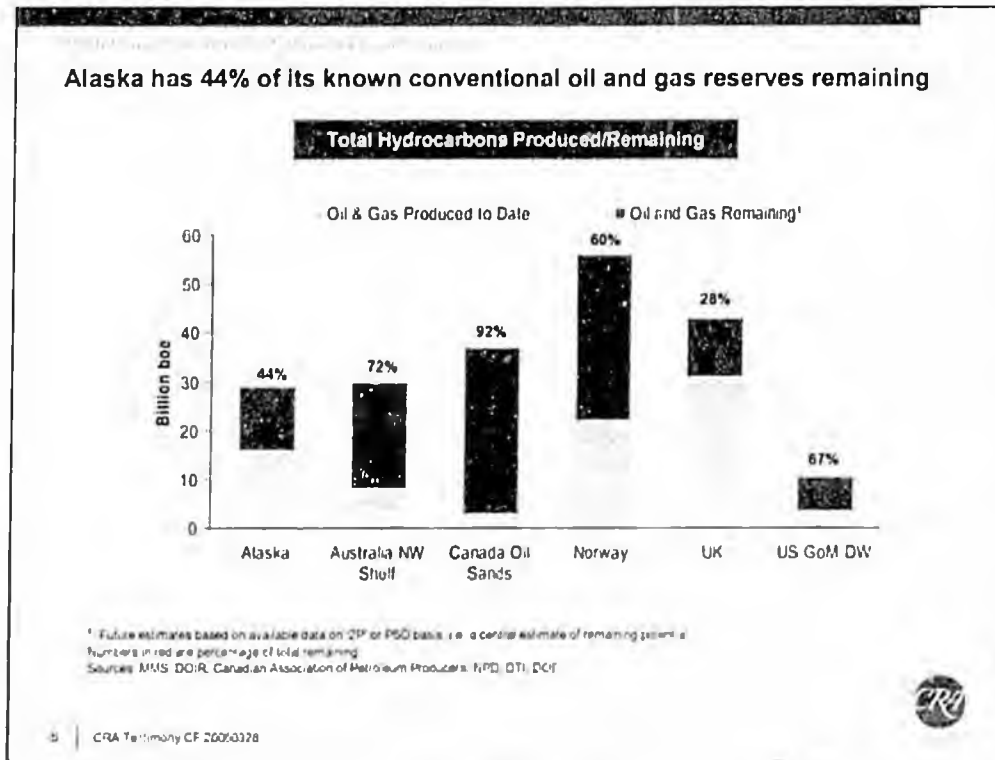
4 | CRA Testimony, CP 2005-028



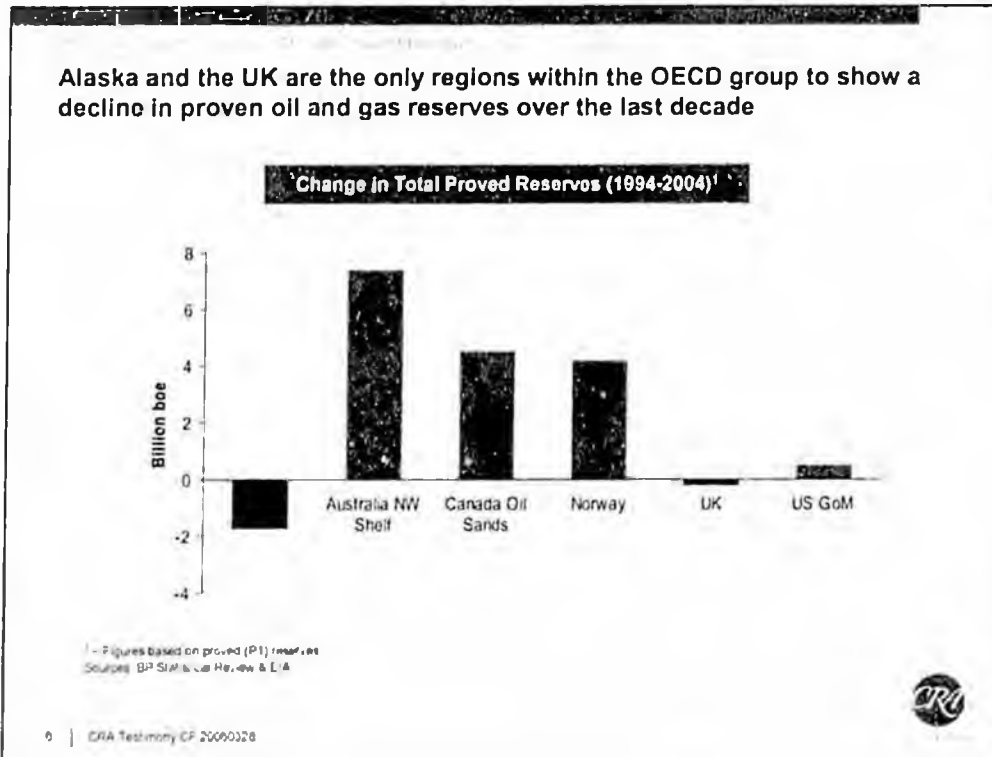
Petroleum is an extractive industry, and the overall economic potential of an area is a function of the nature of the hydrocarbon reserves present, and the technical and operational costs required to bring oil and gas to market. The concepts of maturity and remaining prospectivity of an area are useful 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.

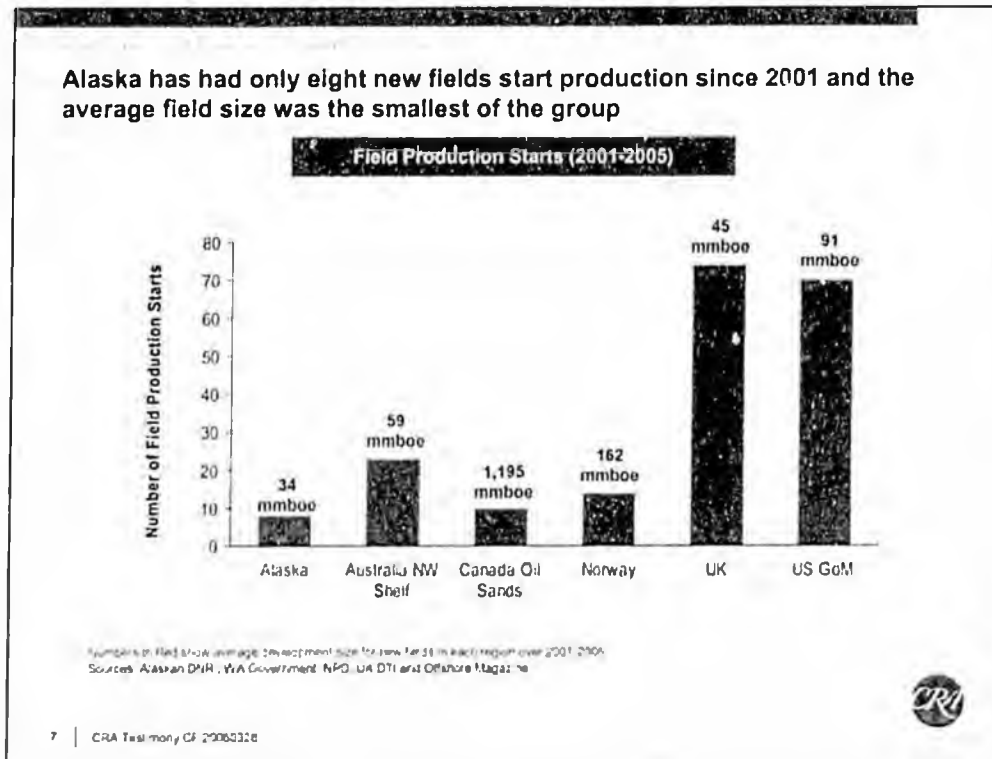
Overall production of oil and gas from an area tends, all other things being equal, to rise to a peak and then undergo a long steady decline. There are exceptions to this pattern – the UK is one. The table above shows that Alaskan production declined by a total of 6% between 2000 and 2004: in the middle 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%.



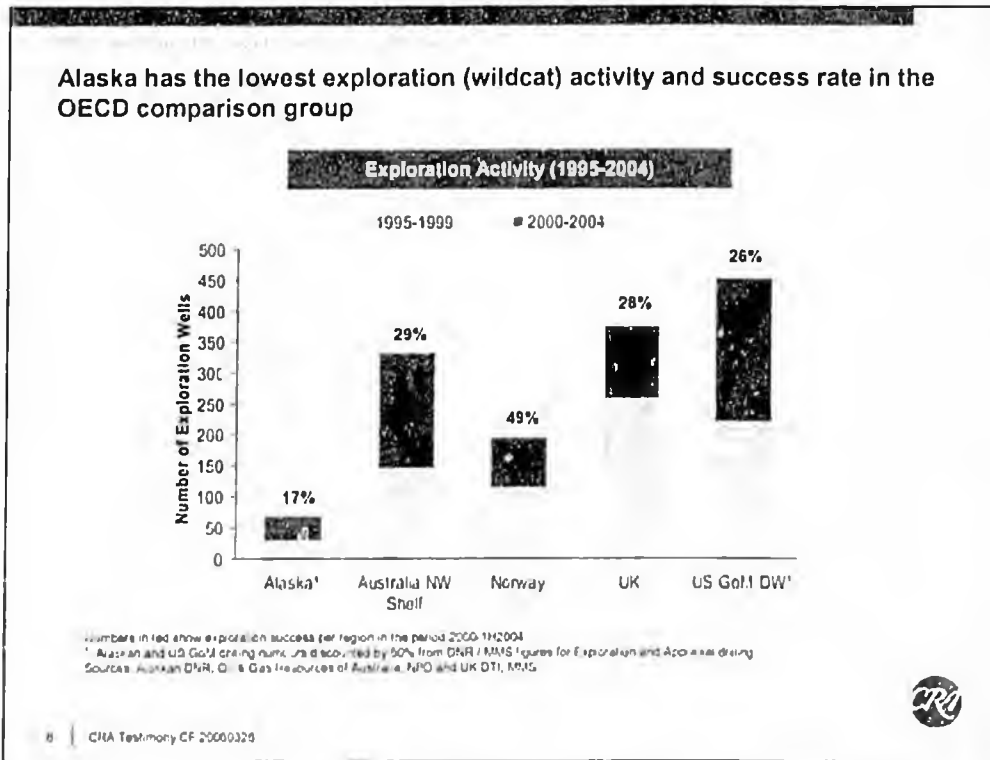
Remaining oil and gas reserves, and their size relative to past production from an area, are another fundamental measure of maturity. In a sense, these figures reflect 'gas in the tank', although any industry insider will acknowledge how elusive clearly-defined and verifiable reserves figures are for 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.



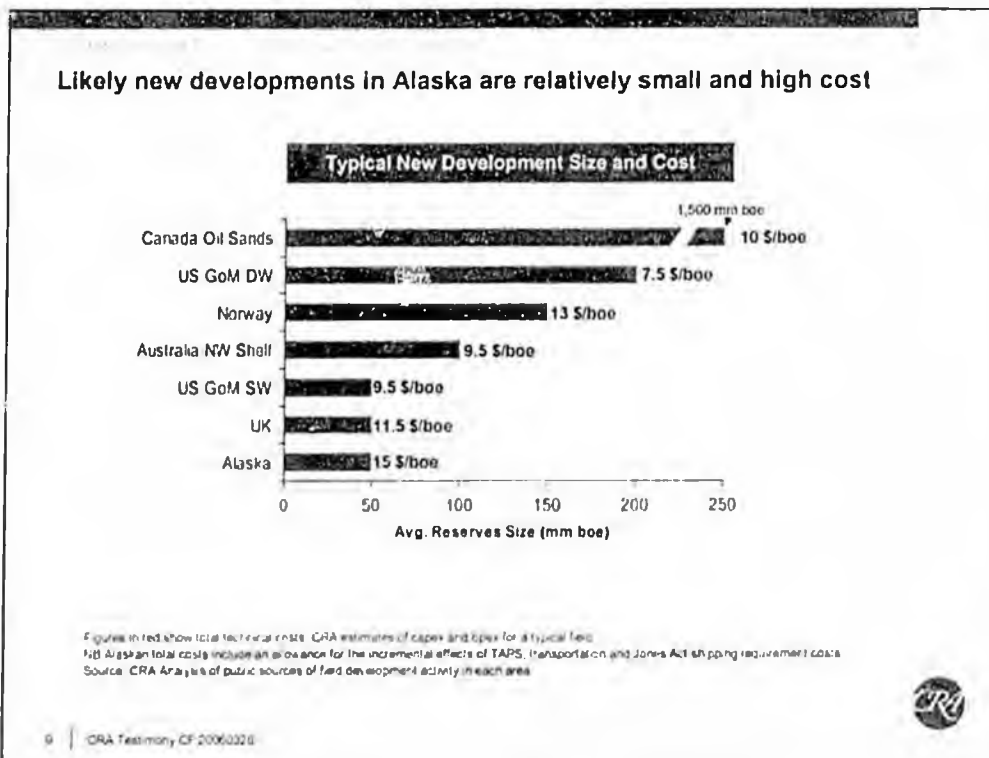
Another important measure associated with reserves reflects how successful an area is in replacing its year-by-year production with proved petroleum reserves. The chart above shows that amongst the comparison group, only Alaska – and by a small margin, the UK – have failed to replace production on a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



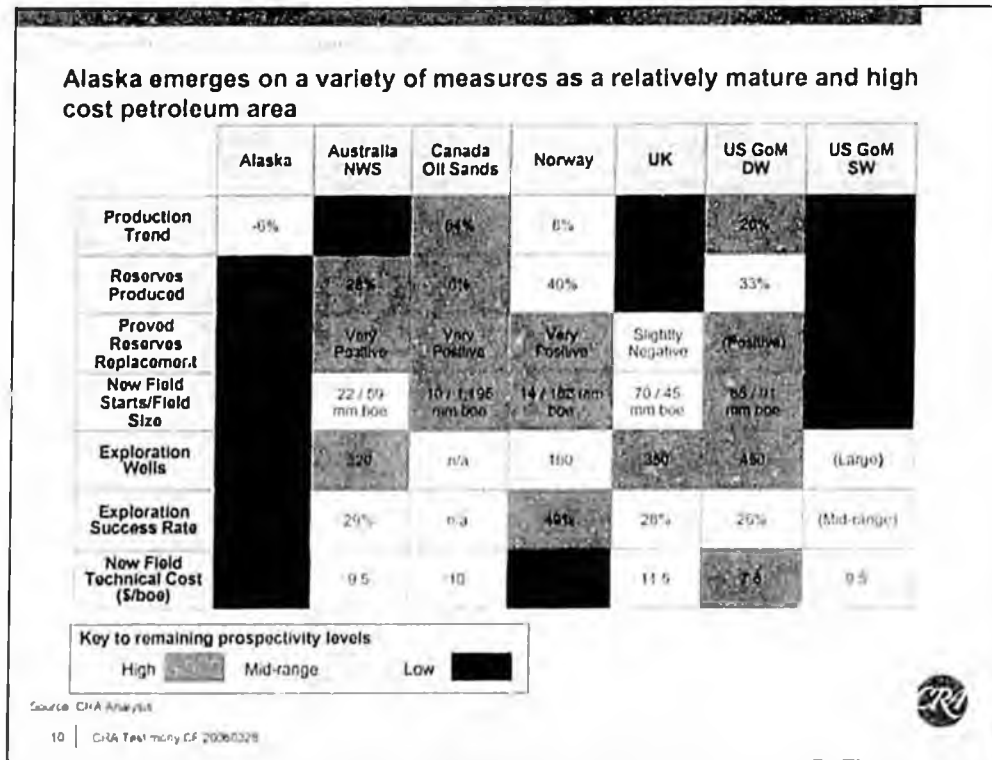
Looking at exploration activity, Alaska, clearly lags the other conventional oil and gas areas in the comparison group both in terms of number of exploration wells drilled and success rate. We have excluded the Canadian oil sands from this particular comparison, since exploration there makes little business 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.

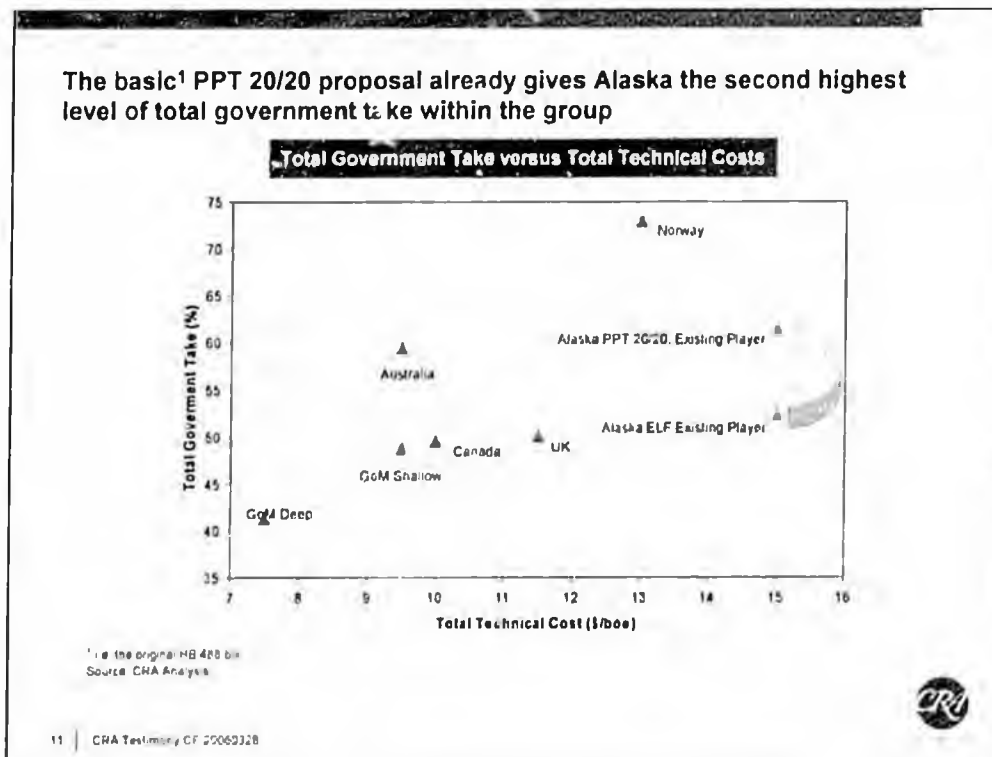


In the above chart we have drawn together all of these observations of maturity and indicated by colors the overall trends. Red indicates observations of low remaining prospectivity (or high maturity) and high unit cost; green indicates high remaining prospectivity, or low cost; and yellow signifies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



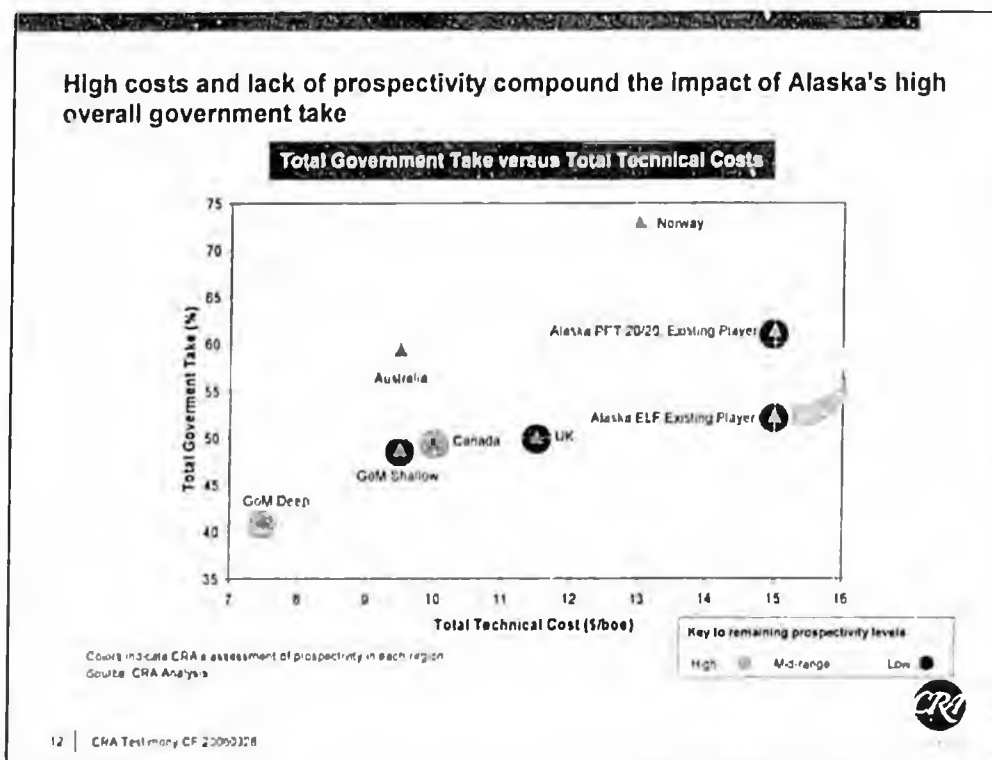
I would now like to move on to a direct comparison of total government take throughout field life for our representative fields for each area. Calculating this involves modelling the way in which the relevant fiscal system divides the available cash flow from a single additional new field between the 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



12 | CRA Testimony, 29 March 2006

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.

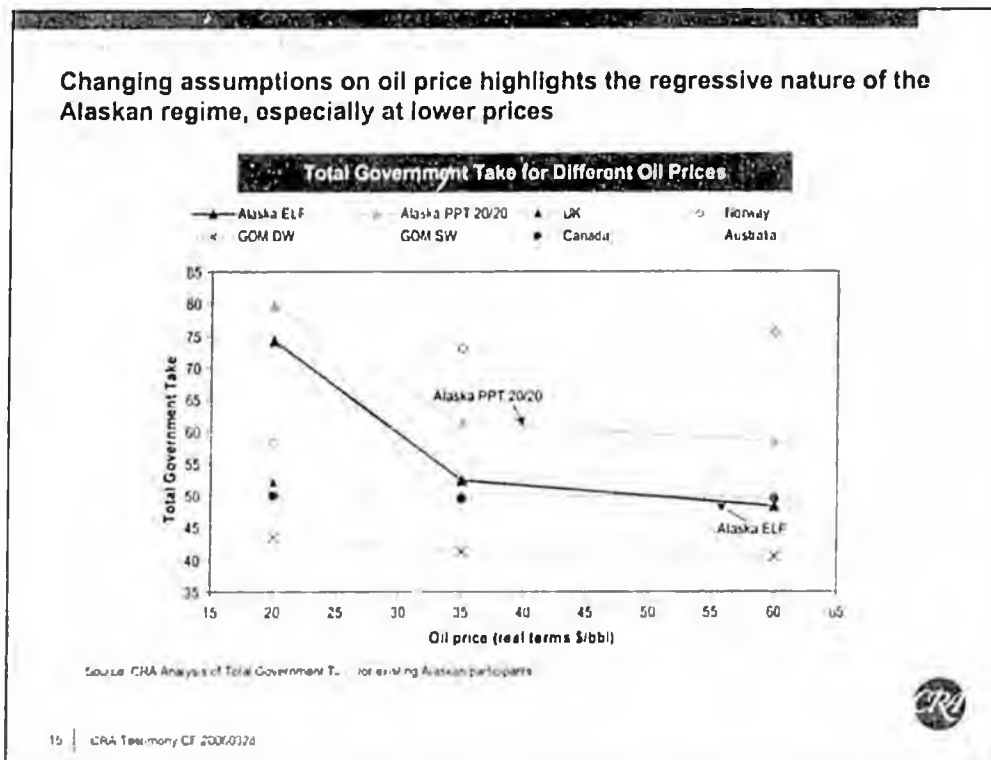
Norway is significantly less mature than Alaska for conventional resources. The results laid out earlier show clearly that on all important parameters – production maturity and decline, reserve replacement, new developments and exploration success rates – Norway has greater remaining growth potential 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.

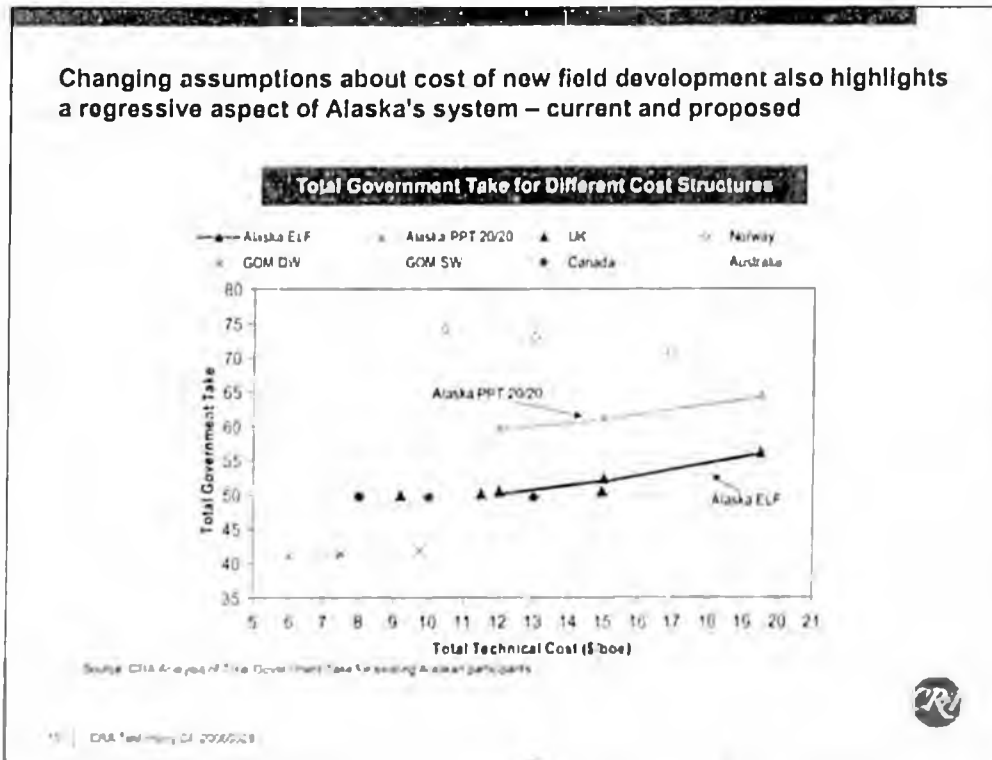


The fiscal response to changing oil price is also important to consider. Our base case considers an oil price of \$35/barrel. However, we must consider both higher and lower oil prices to reflect the way investors make decisions, and in order to capture the full range of possibilities that may affect 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.

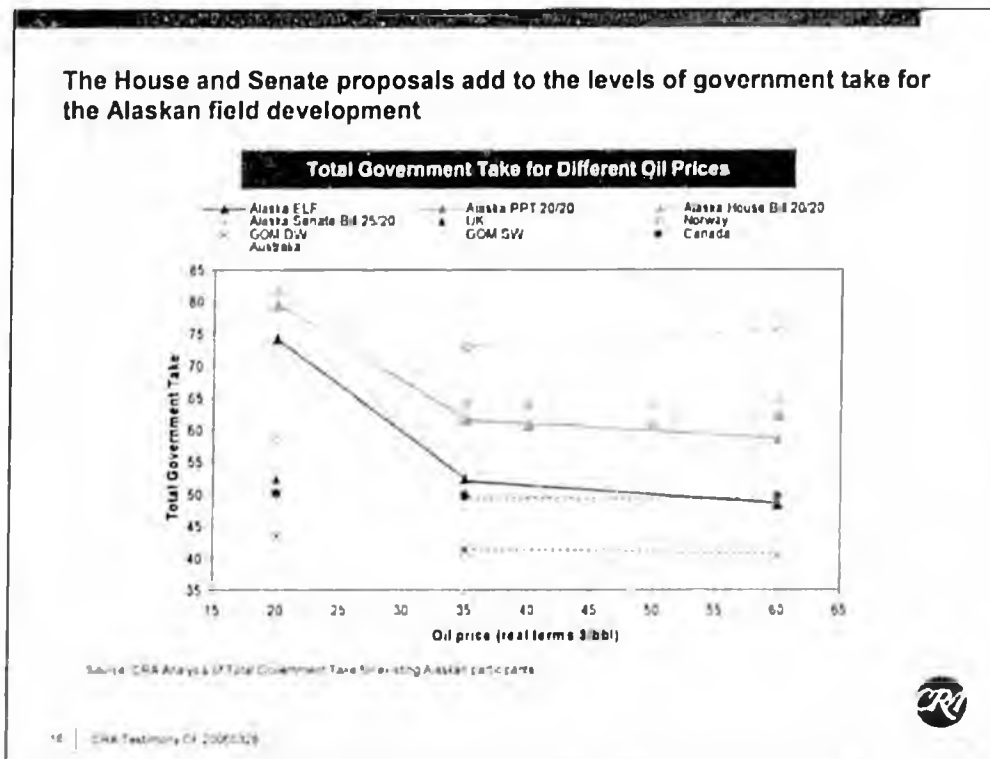
This 'regressive' feature of the Alaskan regime is not helpful in supporting positive investment decisions.

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 ¹	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

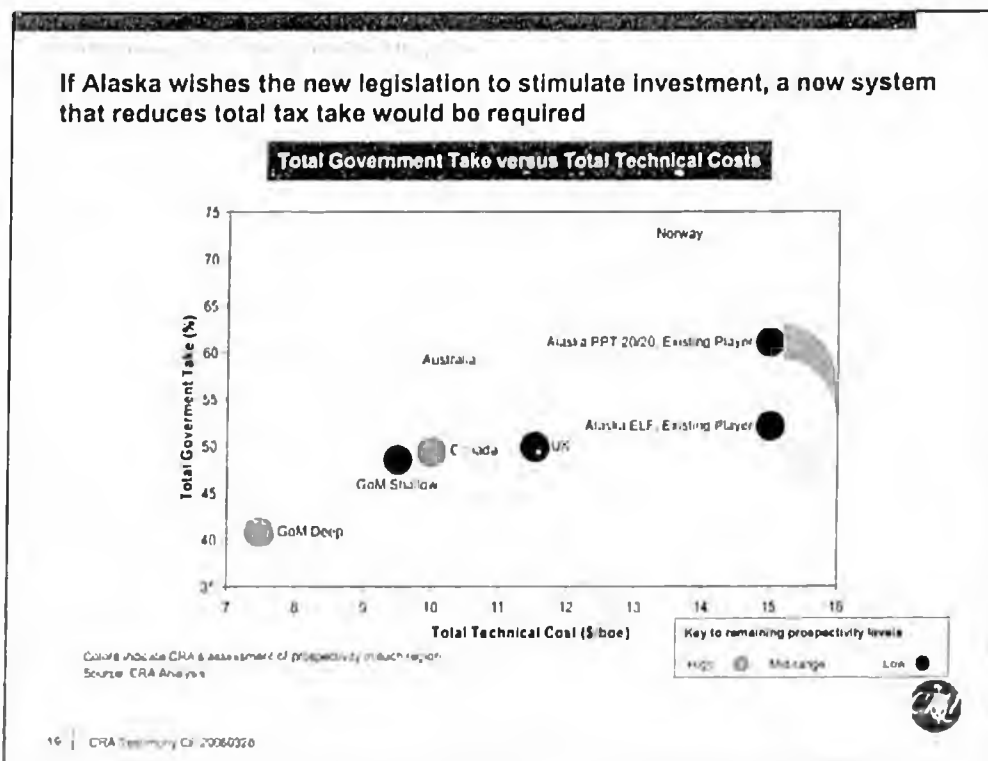
18 | CRA Testimony of 20060328



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.

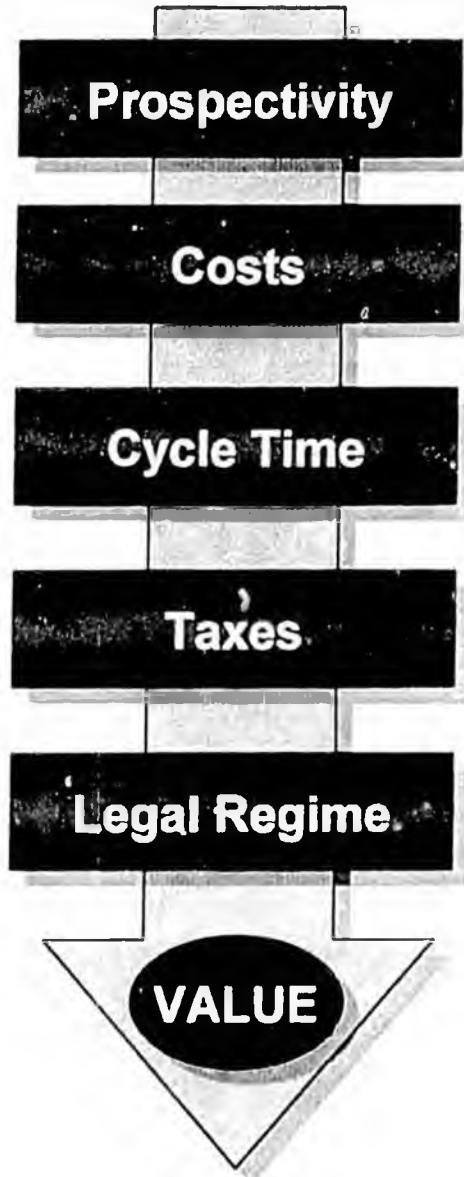


It is not in CRA's remit to suggest what the appropriate level of government take should be in Alaska. But based on the analysis I have outlined today we are led to an inescapable observation that the balance of the current proposals is slanted towards short term revenue collection over stimulation of 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.

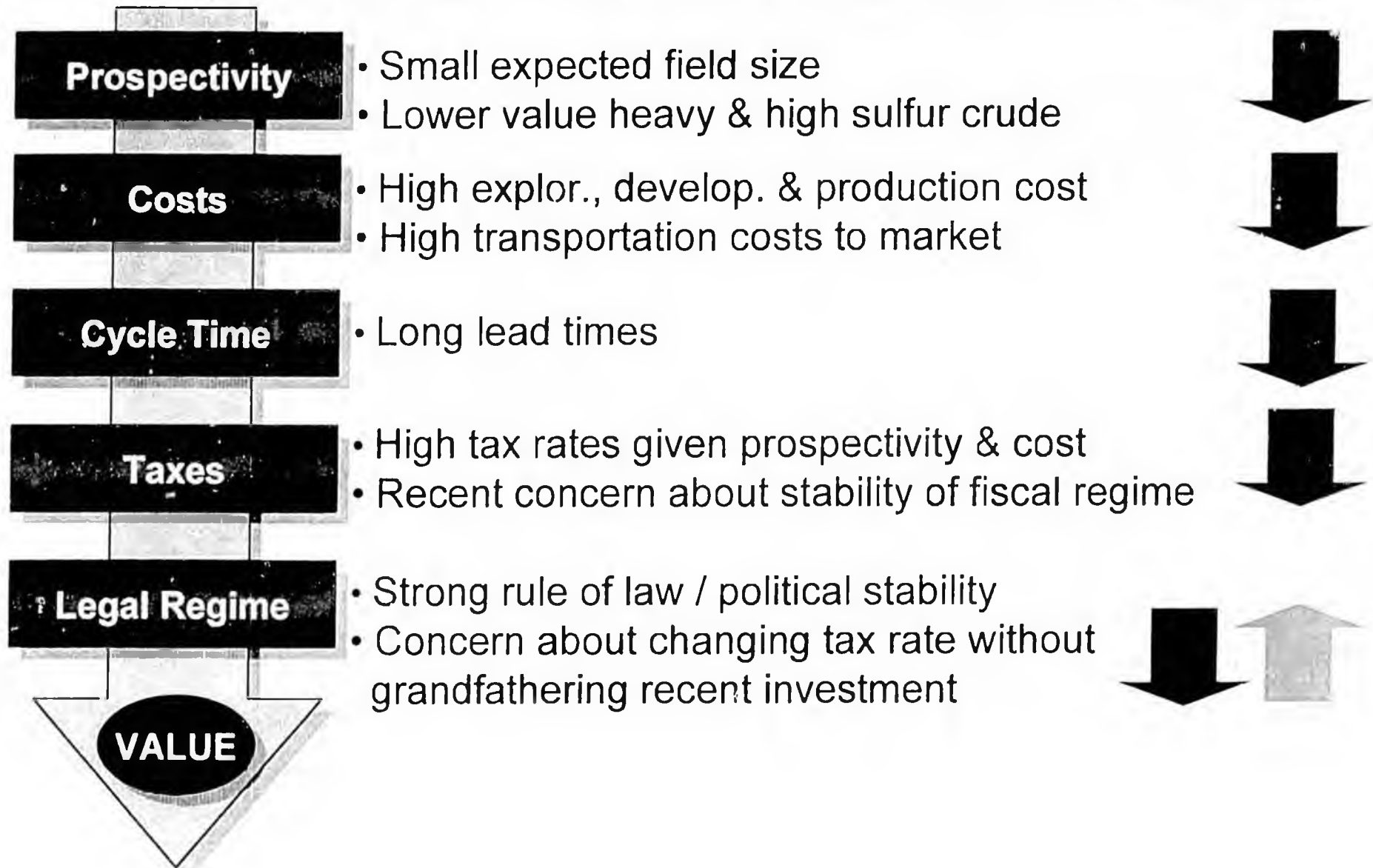
Marianne Kah
ConocoPhillips Chief Economist

Investment Criteria



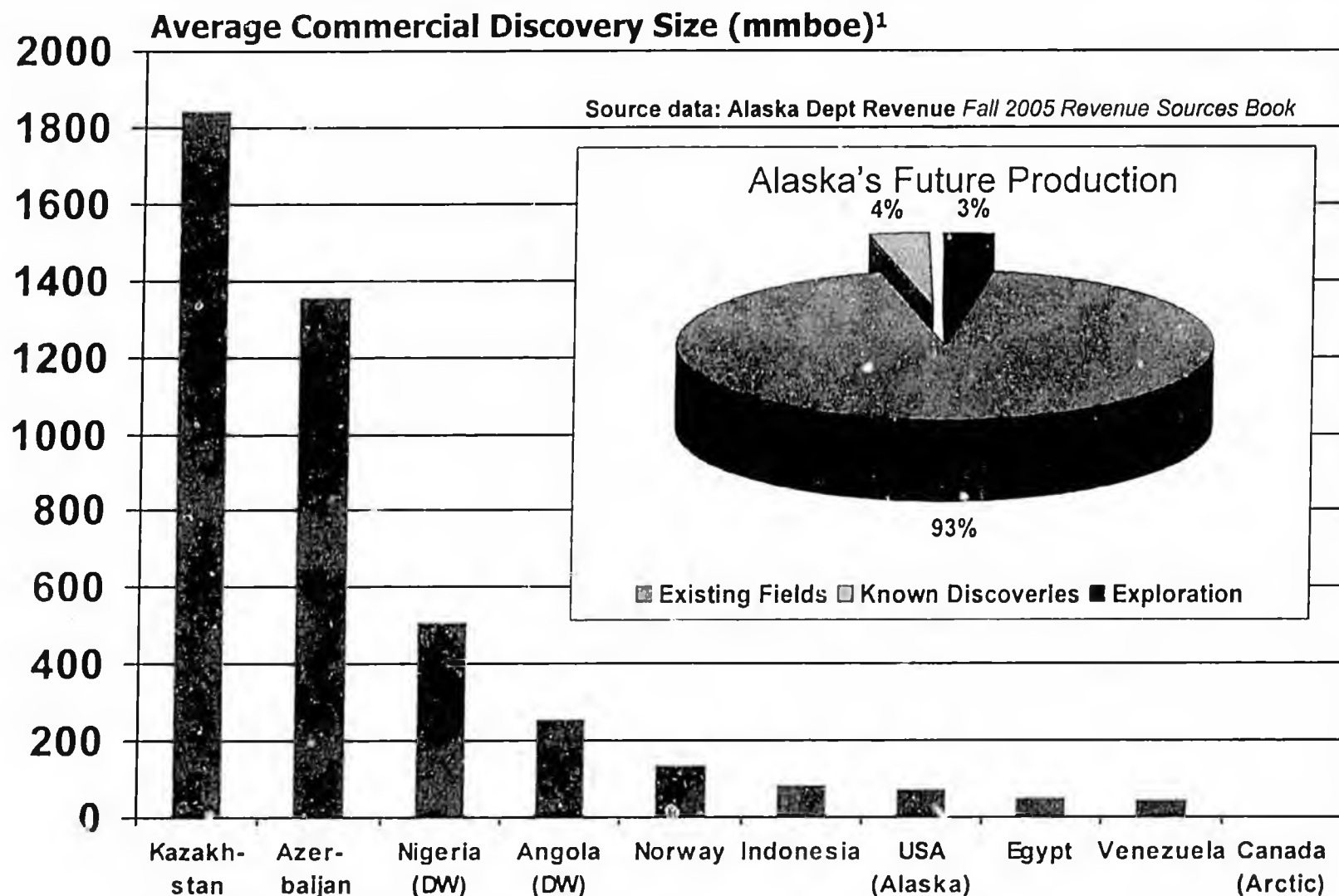
- Expected field size / maturity
- Crude quality
- Exploration, development & production cost
- Transportation costs to market
- Time to production
- Tax rates given prospectivity & cost
- Stability of fiscal regime
- Strong rule of law / political stability

Investment Criteria - Alaska Rating



#3

Global Average Commercial Discovery Size

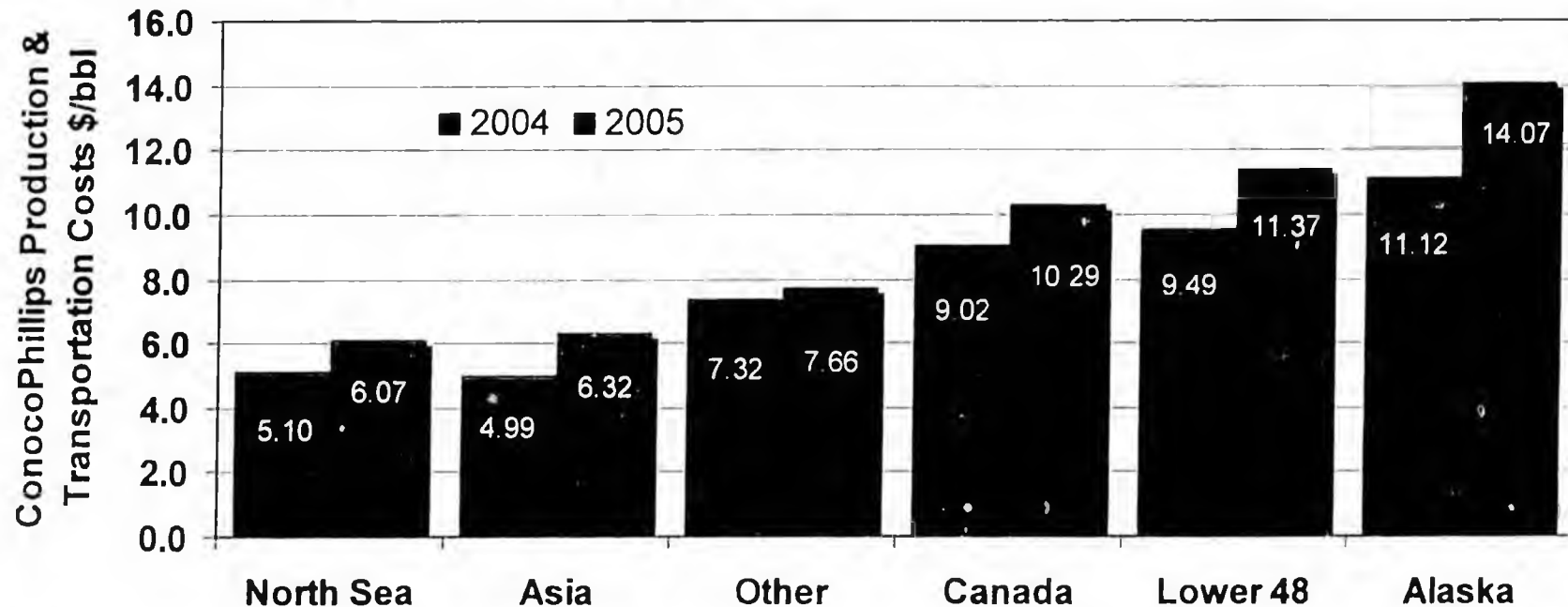


¹ Average commercial discovery size from 1994 to 2003.

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

Increasing Production Costs #4

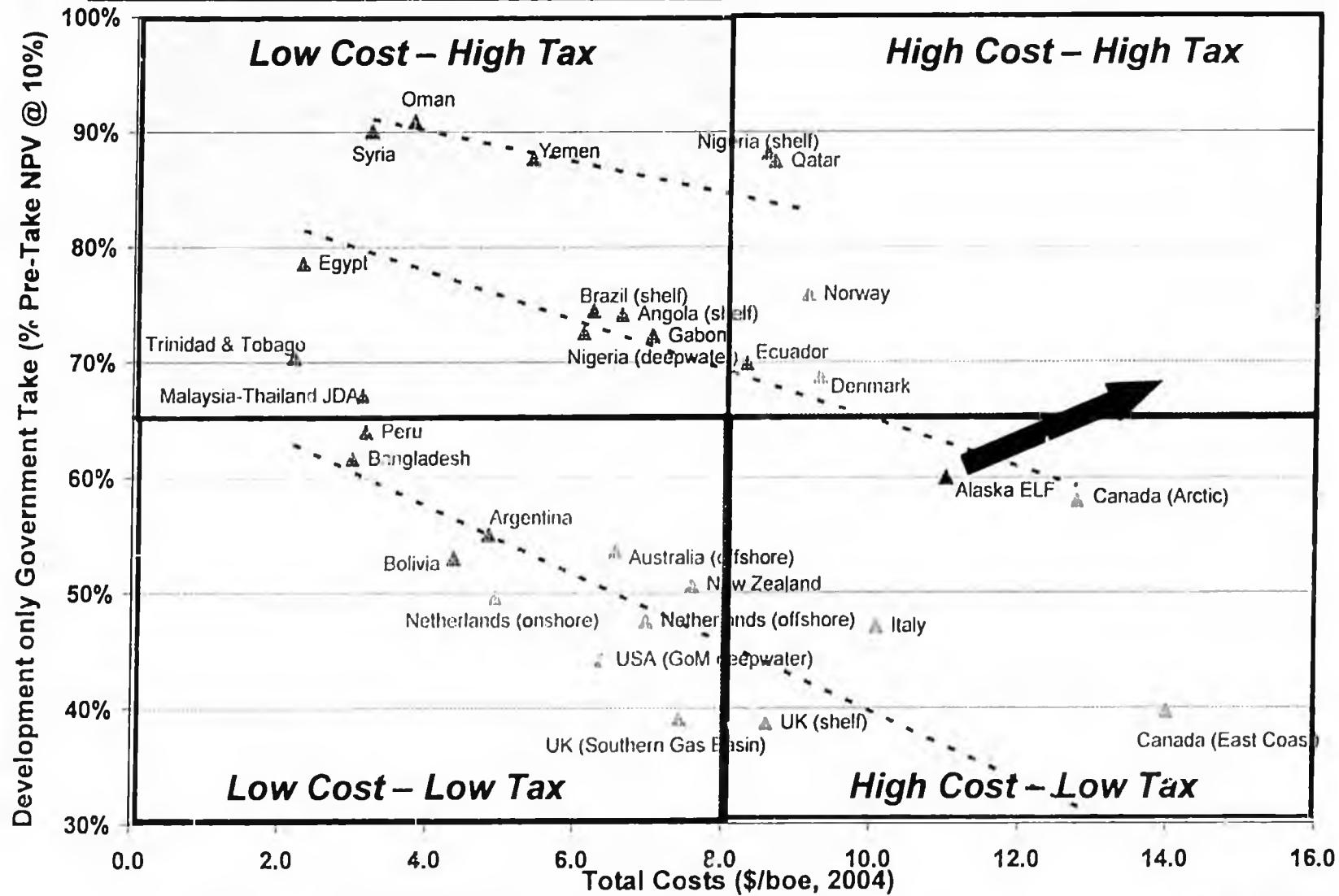
Source: ConocoPhillips 2004 Annual report and 2005 10-K



- 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

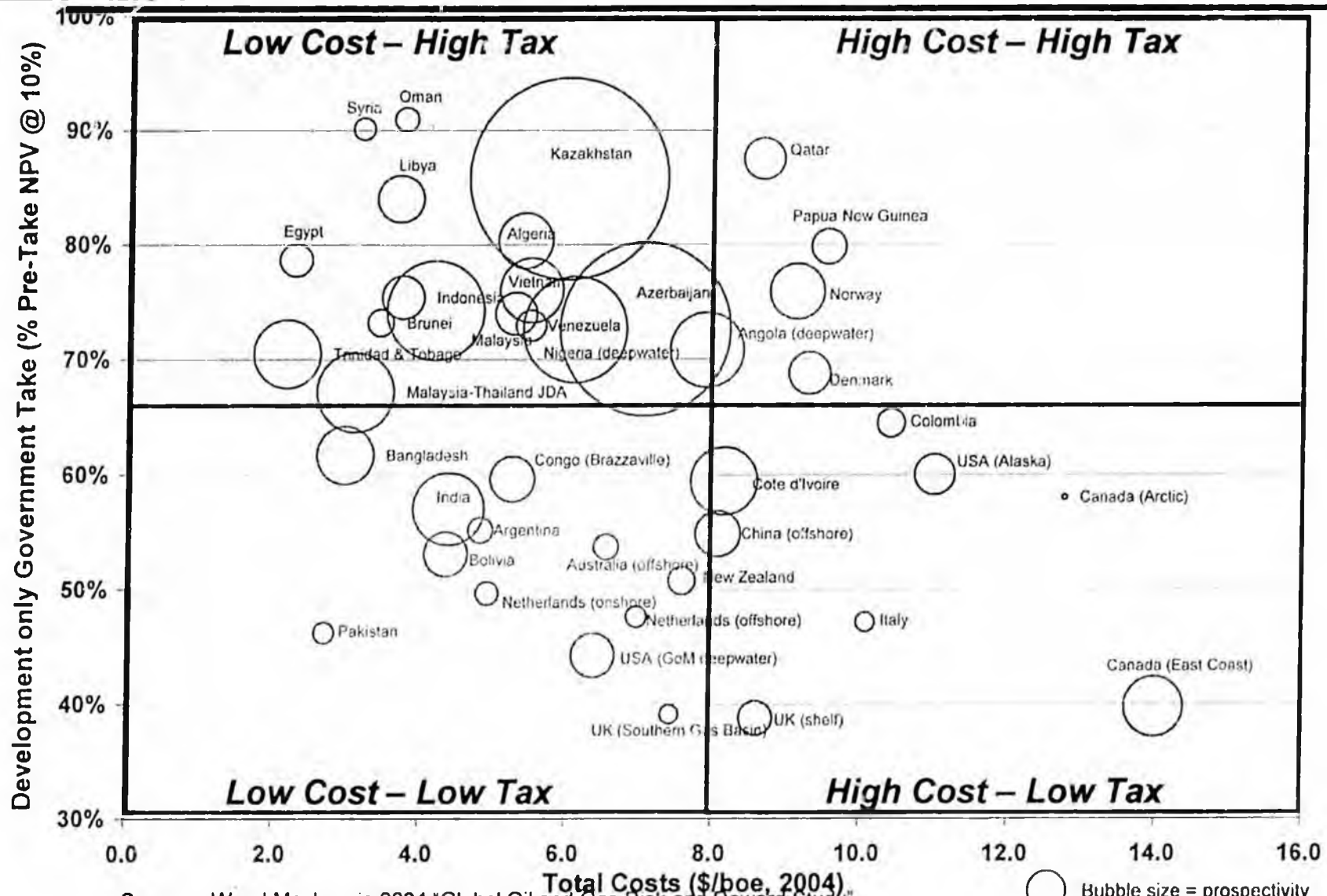


Source: Wood Mackenzie 2004 "Global Oil and Gas Risk and Reward Study".

▲ 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

- 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



¹ 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