

12013 SENATE RESOURCES

# 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?

**Administration did a good job  
balancing issues and priorities**

- *State vs. Companies*
- *Companies vs. State*
- *Companies vs. Companies*

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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.

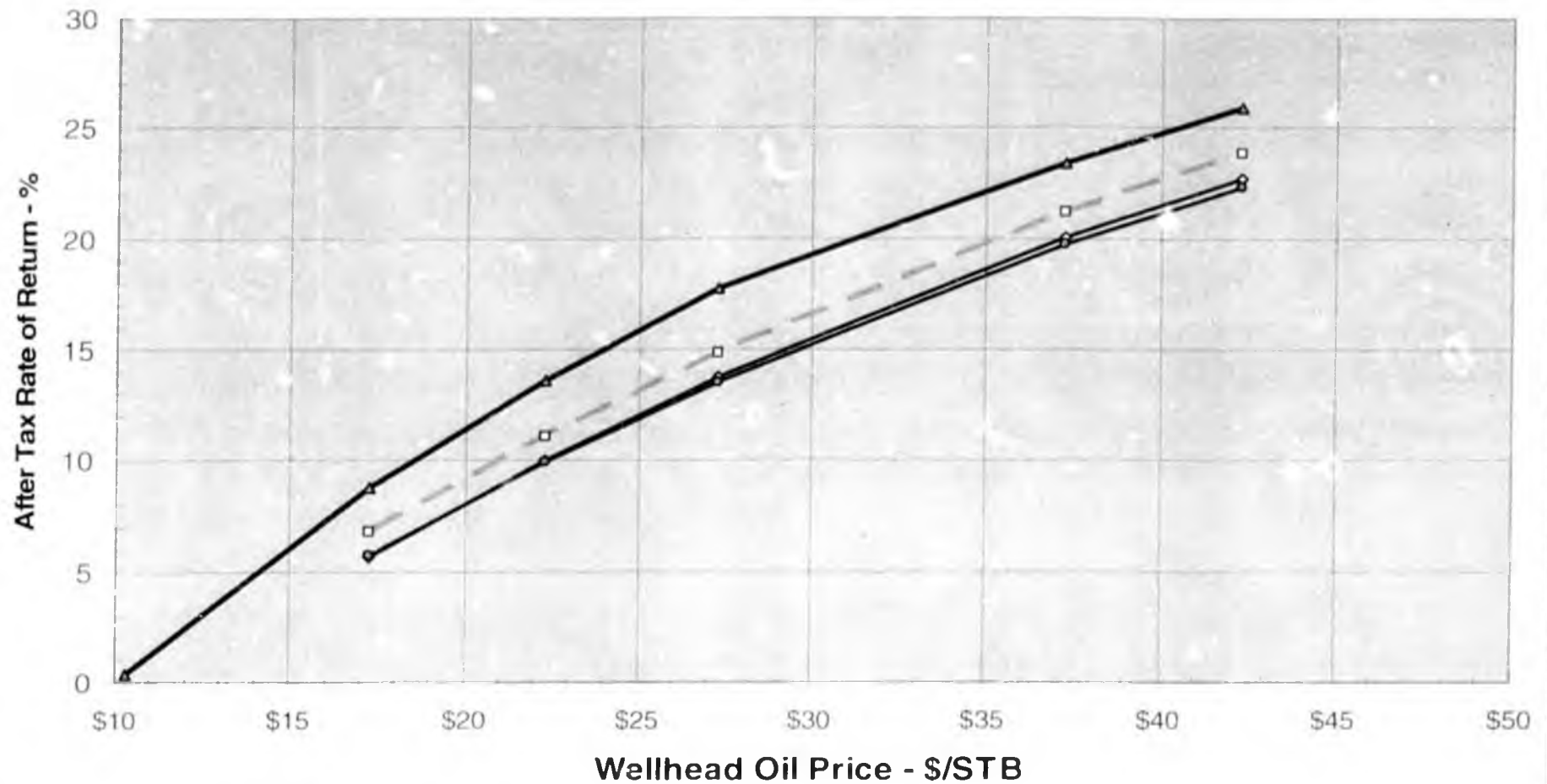
The development concept is a satellite to an existing oil field. The satellite has a separate ELF calculation from the existing oil field.

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

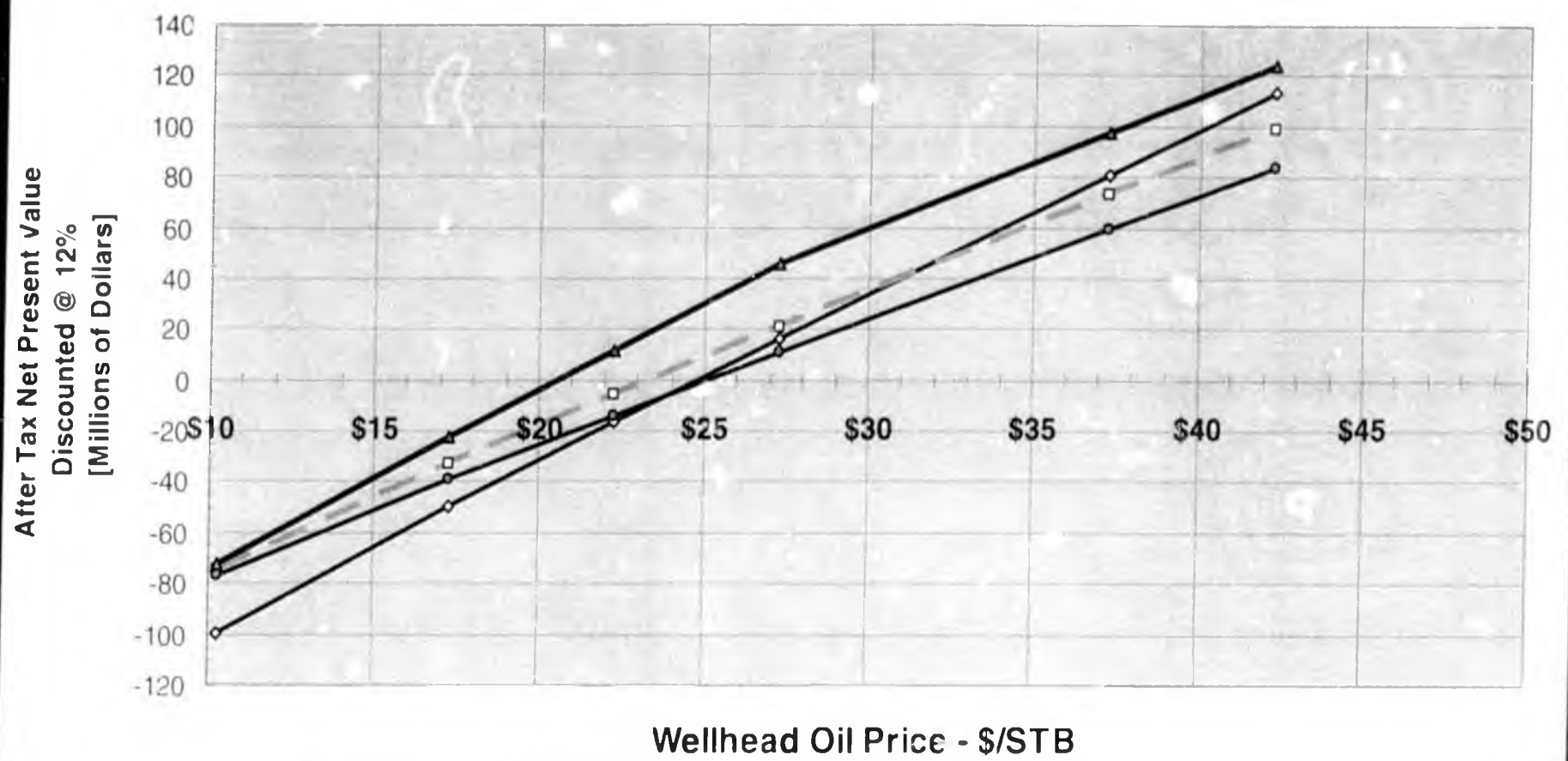


- ◇— Existing "ELF" Tax
- 20%-20%-\$73MM Proposal - Existing Producer \$73MM Exemption Applied Elsewhere
- △— 20%-20%-\$73MM Proposal - New Entrant \$73MM Exemption Applied to this Evaluation
- 25%-20%-\$73MM Sensitivity Calculation - Existing Producer \$73MM Exemption Applied Elsewhere

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# Small Oil Development Net Present Value

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



- 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

A N A D A R K O

# 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**

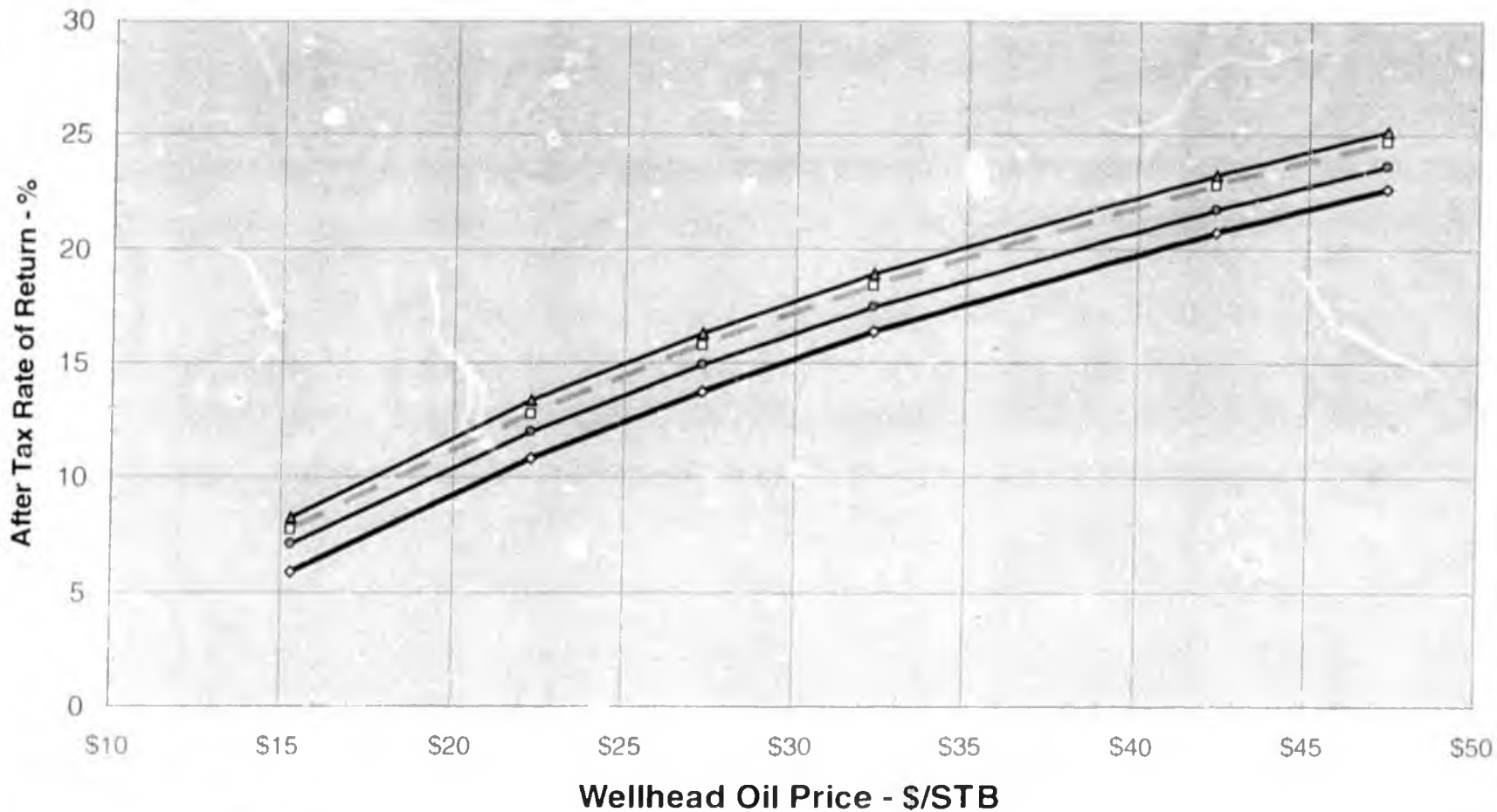
**Capital expenditure is 1.1 billion dollars**

**← The peak production rate is 55,000 BOPD**

**Royalty is 12.5%**

# 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

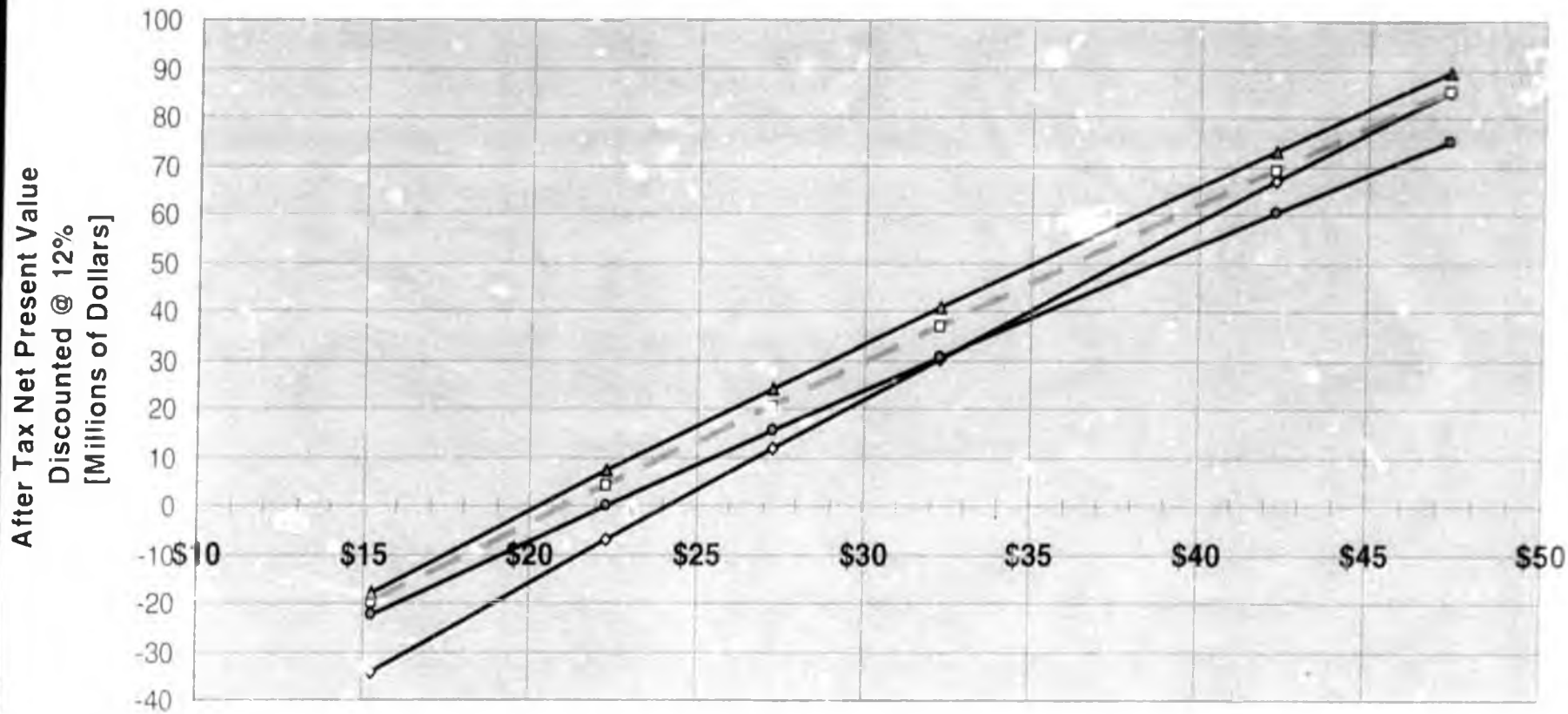


- Existing "ELF" Tax
- 20%-20%-\$73MM Proposal - Existing Producer \$73MM Exemption Applied Elsewhere
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A N A D A R K O

# 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



Wellhead Oil Price - \$/STB

- 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

A N A D A R K O

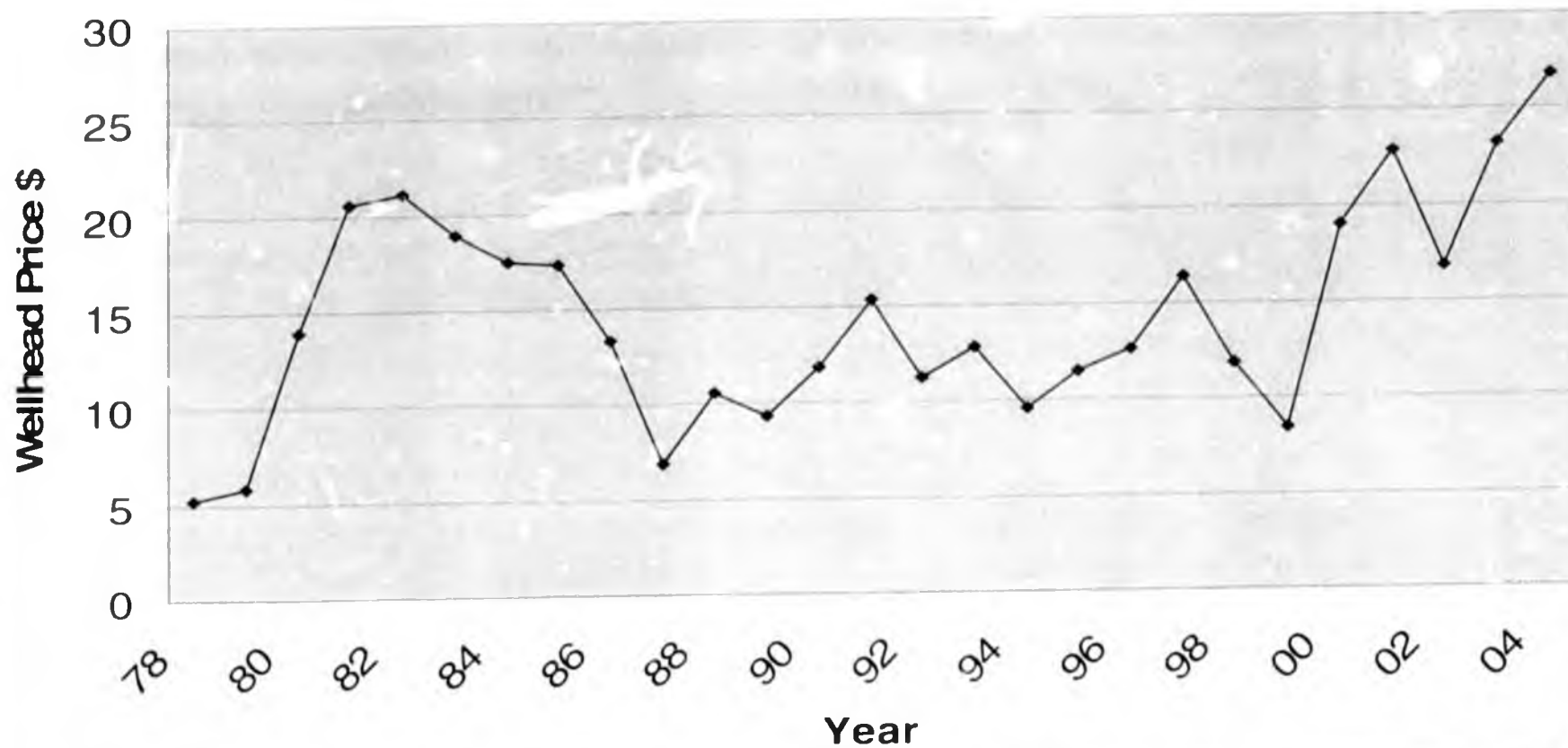
# Issues

- ▶ Look back's looking bad
- ▶ Price is King
- ▶ Independents are sensitive
- ▶ \$73 million is \$73 million right?
- ▶ Credits that aren't
- ▶ Be careful what you ask for
- ▶ Should you know?
- ▶ Let's talk

# Historic Alaska North Slope Crude Prices

## ANS Wellhead Crude Oil Price

From AK Dept. of Revenue, Tax Division



**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.**

**Chevron**



**Library**

*Senate Resources Committee*

**Chevron**

**Testimony on SB 305 & HB 488**

**John P. Zager**

**General Manager — Alaska Area**

**Juneau, Alaska  
March 1, 2006**

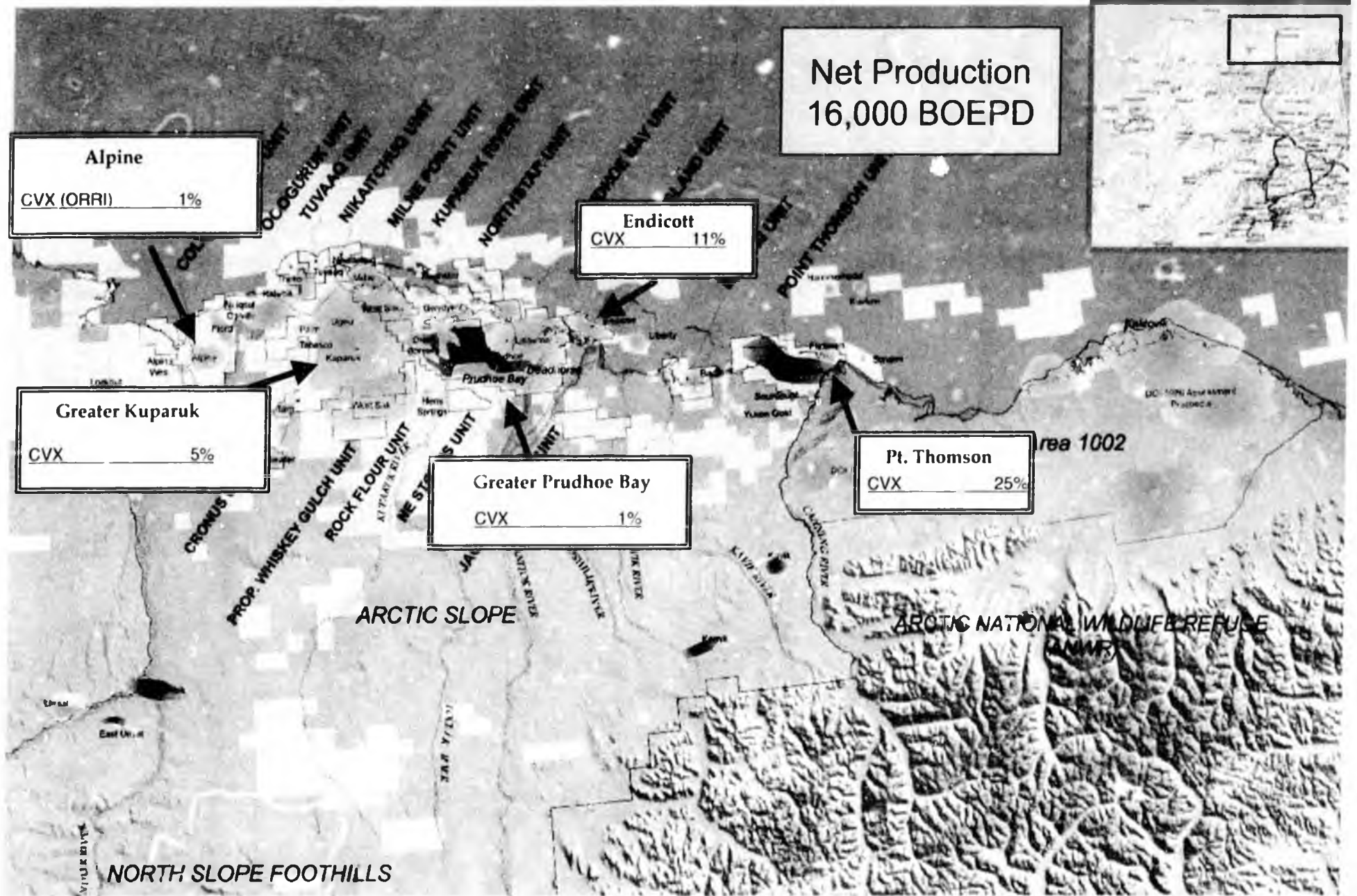


## Chevron's Alaska Presence

- 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

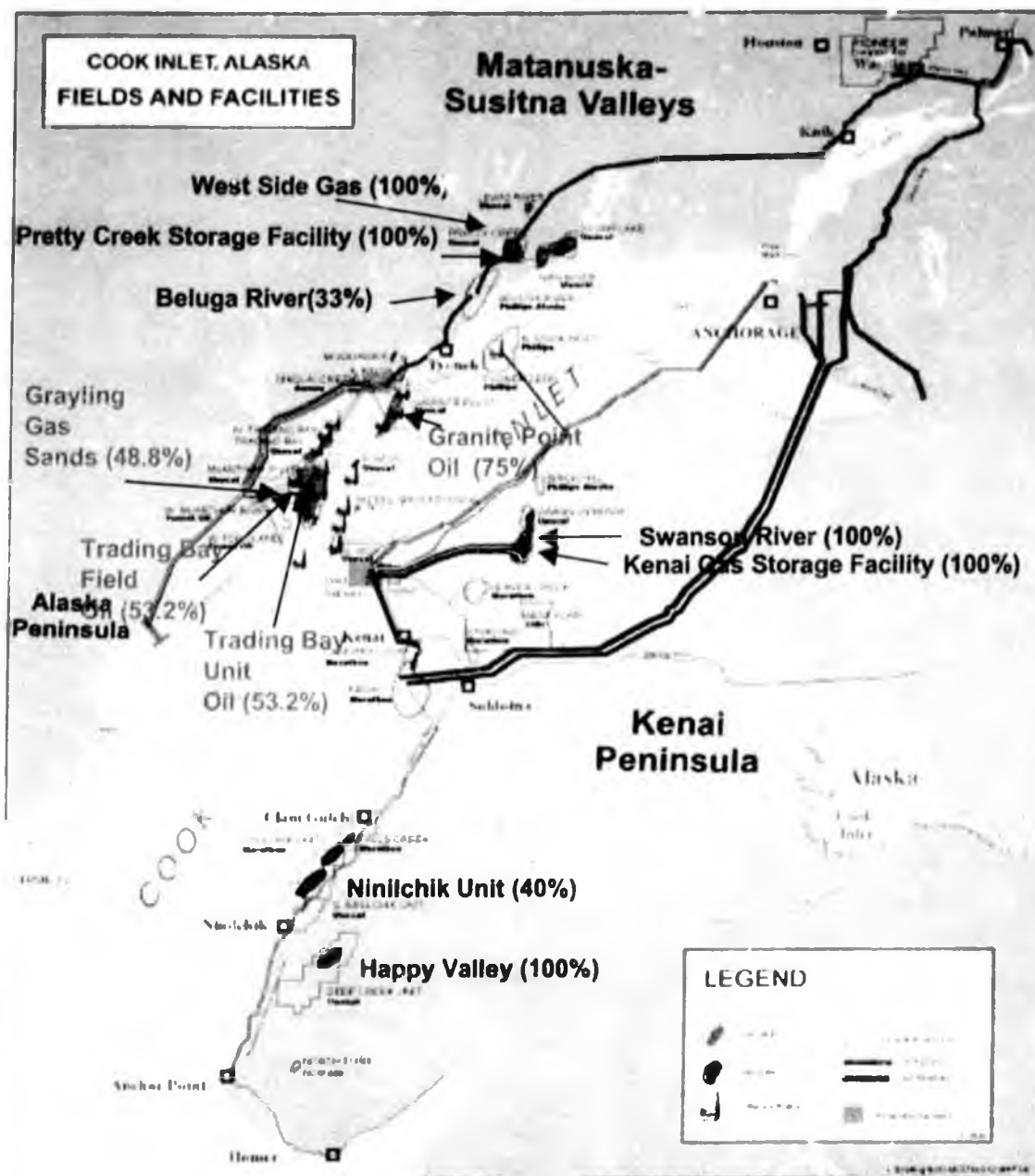


# Alaska North Slope Fields





# 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**

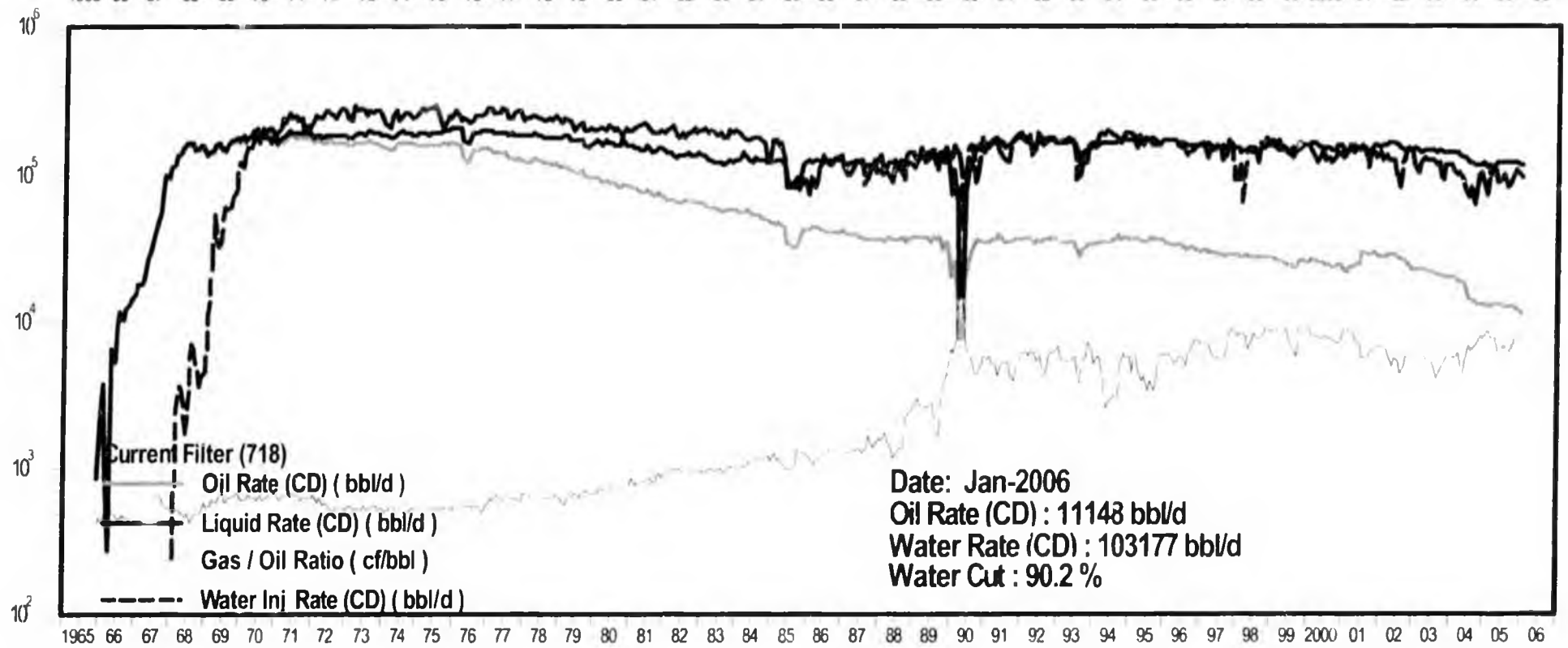
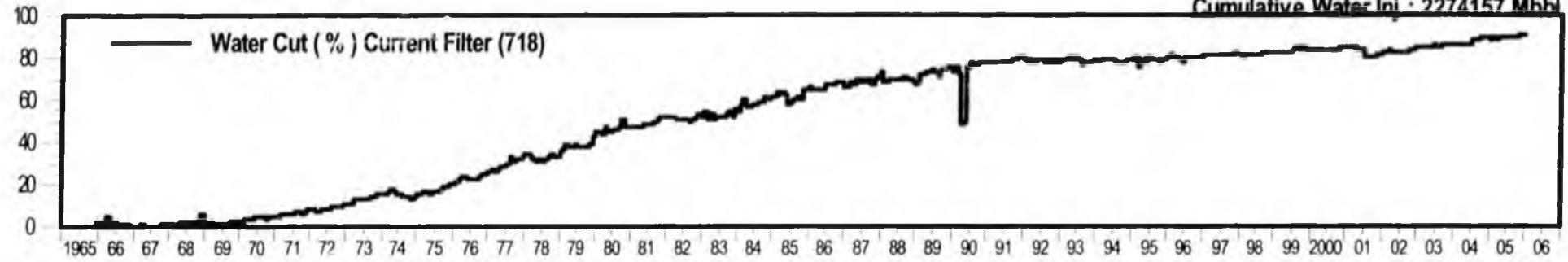
**25,000 BOEPD**



# Cook Inlet Offshore



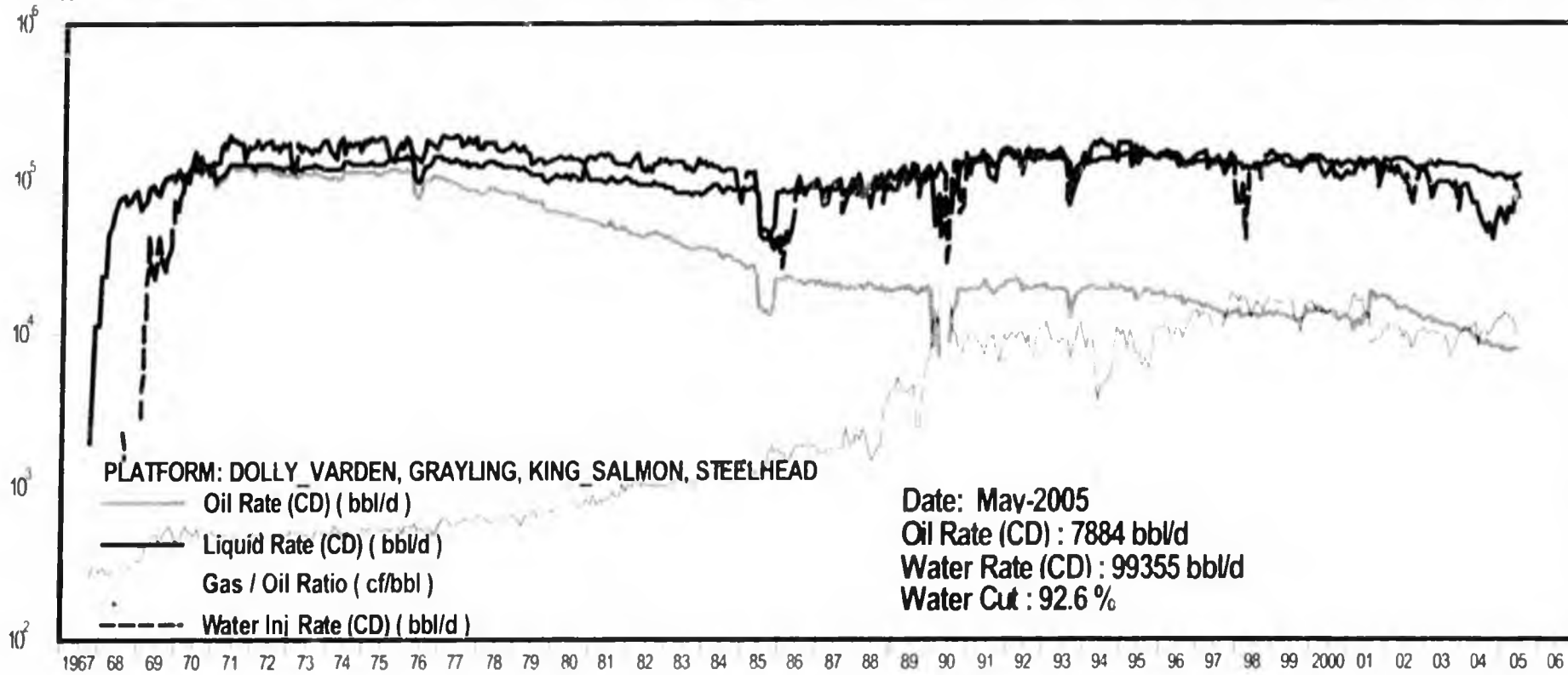
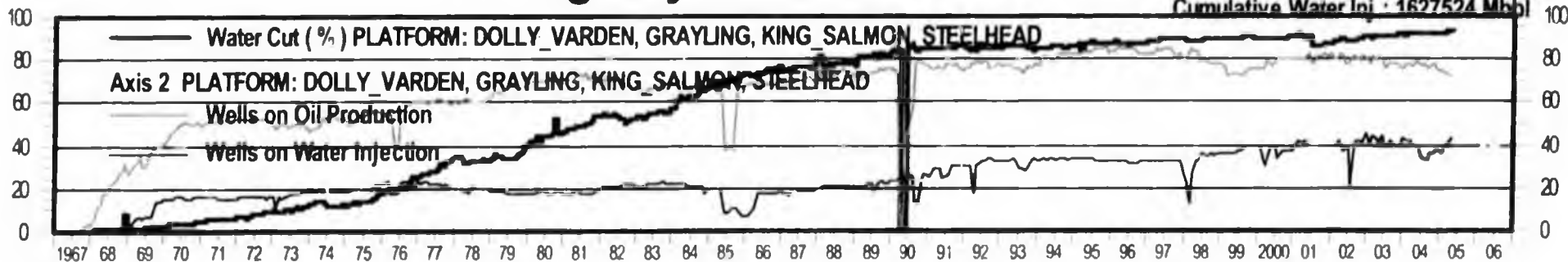
Cumulative Oil Prod : 1030570 Mbbl  
 Cumulative Gas Prod : 1587463 MMcf  
 Cumulative Water Prod : 1117781 Mbbl  
 Cumulative Water Inj : 2274157 Mbbl





# Trading Bay Unit

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



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## 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 @ ~ \$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

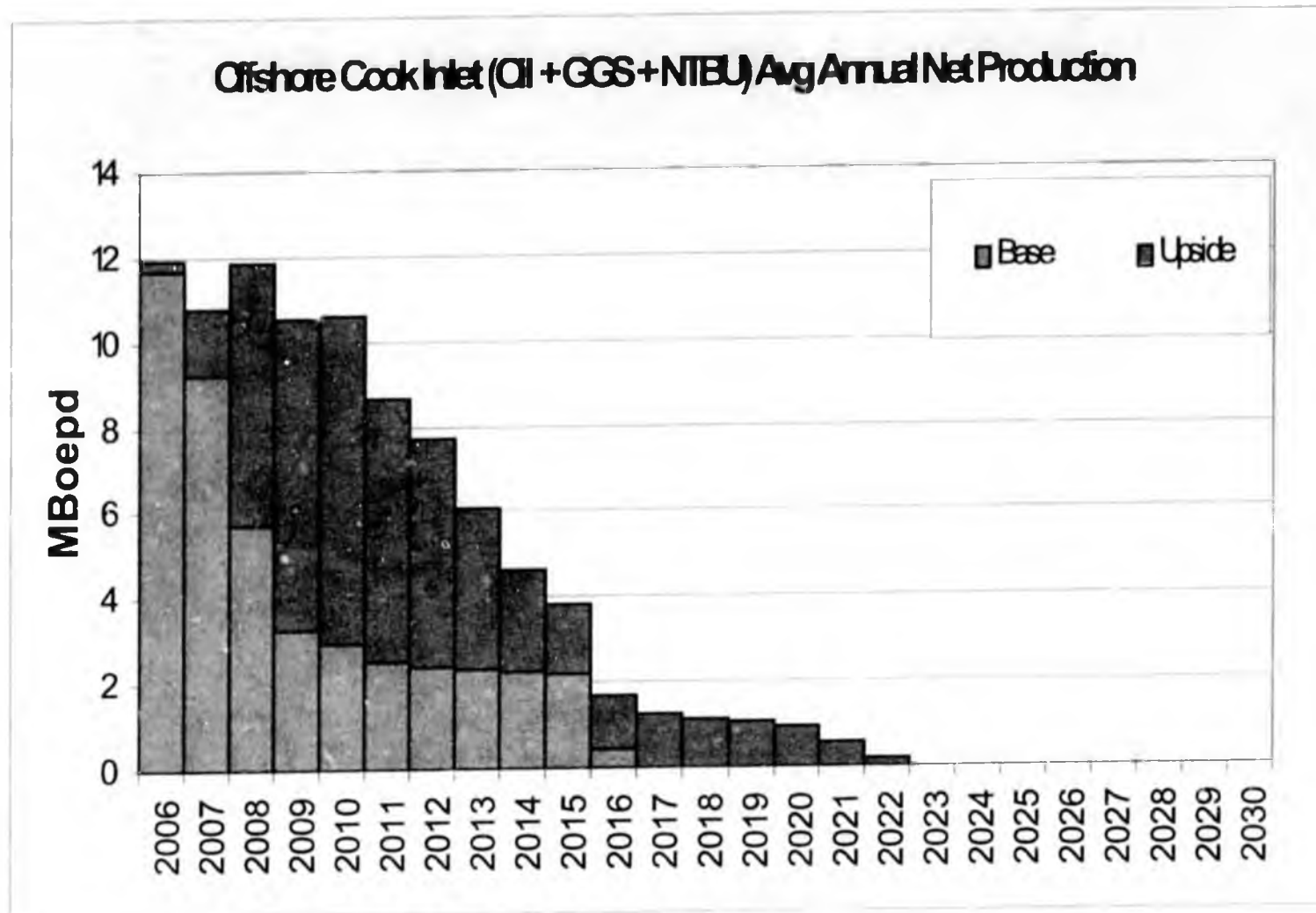
- August 10, 2005 Chevron acquires Unocal
  - Much speculation about Cook Inlet asset fit in Chevron Portfolio
- October 2005 – January 2006 – Strategy work completed
  - Determine that there are incremental investment opportunities in the Cook Inlet although they are in the lowest quartile of Chevron's investment portfolio, many other 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 PPT the economics on some projects are degraded, some projects are improved, overall poorer economics for the program
  - Will cause investment decision to be reconsidered
  - Enhanced PPT terms could significantly expand the list of economic projects in the investment program
  - Misalignment with joint venture properties

# Cook Inlet Production Forecast with Four Year Capital Plan





## Reasons to Spur Cook Inlet Investment

- Gas is running out
  - Home heating, electrical generation, industrial consumption
  - Additional gas supply is critical to state's economy
- Oil redevelopment will maintain and add new jobs and will extend field life
- New exploration efforts could add new fields
- Currently a lack of significant exploration
  - Last Cook Inlet lease sale was poorly attended



## Summary

- We will support the bill and the key terms as written with the following stipulations:
  - Cook Inlet must be treated differently
    - ▶ Re-apply \$73 million exemption
    - ▶ PPT rates – consider lowering the tax rate and/or increase the capital credit
- Recommend inclusion of an additional 5% capital credit (20/25) for heavy oil or tertiary recovery (CO<sub>2</sub>) projects statewide
- Need absolute clarity on terms and definitions
- 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

Chevron





# Potential Questions

- How much do you make in the State? NS? CI?
- How much severance tax do you pay in State? NS? CI?
- Why do you deserve the Enstar price?
- Will you pay more or less severance tax under the new PTT?
- Why separate CI from NS? Why would you use exemption for NS first?
- How important is the clawback? 20 vs. 25%, capital credit? \$73 million exemption?
-

**Comments On SB 305 and HB 488 Oil and Gas Production Tax  
By Ken Thompson, Managing Director of AVCG/Brooks Range Petroleum**

Personal Background

For the record, my name is Ken Thompson. I reside at 12031 Lilac Drive, Anchorage, Alaska. I am the Managing Director of Alaska Venture Capital Group, or AVCG LLC, 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.

AVCG LLC has been very active in the past six North Slope areawide lease sales and we have acquired over 160,000 acres of exploration leases in five exploration prospect areas, including new acreage we acquired earlier this morning in the NS lease sale. Our exploration strategy is to explore in the central part of the North Slope for fields in the 25-100+ 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.

Our company is excited to report that the first exploration well AVCG will participate in with an ownership interest should have started drilling last night...the Cronus exploration well about 10 miles southwest of the Kuparuk Field, operated by Pioneer Natural Resources. We plan two exploration wells next winter and two the winter after that. With success, we will continue exploring and producing.

My comments today represent the perspectives of a small, independent exploration company. Having said this, many of you also know me as the past President of ARCO Alaska, Inc. I also served as Executive Vice-President for ARCO and head of global oil and gas exploration for ARCO. I do have exploration and production experience in over 20 countries throughout the world, so I'll also share my perspective in how I see the new production profits tax bill in the context of competitiveness in the world.

Introduction

- In my first week as President of ARCO Alaska in June, 1994, our ARCO staff reviewed state policies with me to educate me about the oil and gas industry in Alaska. One of the items they reviewed with me was the production tax and the complicated policy of ELF. Our government affairs personnel told me that ELF was in jeopardy...that the production property tax was going to be changed. That did produce uncertainty in our project economics forecast. Every year since then, production taxes and the ELF have been topics...and uncertainty remains. Sixteen years have passed since that meeting, and every year, I hear discussion about production taxes, ELF, and the imminent

threat of change. I welcome change and I say, "It's time to put the new system into effect and let's get on with it."

- Our company, AVCG, supports the proposed production tax changes provided the most important terms remain as written.
- Alaska has long been challenged to be competitive with fiscal regimes in other countries that offer competing projects; as an Alaskan, I'm excited to see the State ensure that our State's new oil tax regime is more like that in other countries...a progressive, profit sharing type structure versus a regressive, straight tax on gross revenues.
- The State will "share the gain" at high oil prices, but will likewise "share the pain" at lower oil prices...this helps small investors like AVCG/Brooks Range Petroleum limit our downside risk in the event of price collapse. And we think it is fair to share our upside profits with the State at a 20% tax rate; the State owns the land and the oil...we realize that we only lease it and we do have implied covenants to be fair with the State.
- At this point, I would like to answer three questions from my perspective: 1) Is this new production tax good or bad for industry; 2) what three things should not be changed; and 3) what three things should be changed?

#### Is This New Production Tax Proposal Good Or Bad For Industry?

- Both...for a small explorer startup company like AVCG LLC with about 160,000 acres under lease for oil exploration on the North Slope, the exploration economics with the proposal are favorable with an improvement in the rate of return. Near-term cash flow because of the investment tax credits is higher which improves the return on investment. But cash flow is lower a few years after new production startup as the State shares a higher share of the profits than what it currently does. We think the State taking 20% of the upside profits is fair, and we recommend the tax rate stay at 20%...the old 80/20 rule has proven to be a good one over time. Keep in mind the State will also still receive a 12.5-16.67% royalty share of all oil and gas revenues on State leases, oil and gas property taxes, corporate income taxes, and other revenues, in addition to the production profits tax.
- A key part of the bill is the investment tax credit, and AVCG plans to use that...our only area of exploration investment is Alaska and we do plan to return a large share of our future production cash flow back into exploration and development only in this state so we can grow to a sizeable company...the tax credit creates a clear incentive for us to do that rather than take the money outside.
- For a large major producer who is planning to make large capital investments on the oil side or in the gas pipeline, the bill could possibly be favorable for them as well when all is said and done.
- For any producer – large or small - who is not planning to make large capital investments but plans to send cash flow outside without a high re-investment plan in Alaska, this bill is likely not good for that type of company in Alaska.

#### What three things should not be changed?

- I "panicked" when I saw the profit tax reported at 25%...this takes too large a chunk of positive cash flow away from small companies - or really companies of any size - and our company sees this as cash flow that could be re-invested into new exploration prospects and new oil leases. I started warming up to the bill only when the tax rate was changed to 20%...then the AVCG economics started showing sufficient improvement in capital investment rates of return for us to attract new capital from partners or investors. When the tax rate changed from 25% to 20%, I crossed over from opposition to support of this proposal.
- It is essential to keep the 20% investment tax credit. This will help us in attracting new capital from AVCG partners or equity investors for new exploration and development. With a tax credit of 20% and re-deployment of the tax savings back into our exploration in the State, we can essentially drill an extra exploration well for each five exploration wells we currently have budgeted.
- It is essential to keep the \$73,000,000/year operating cash flow "standard tax deduction" before production taxes are paid, at least for smaller producers. At a \$40/bbl oil price, this equates as a production tax exemption for the first 5,000 net barrels per day to encourage new producers. As our company is risking a lot of money currently with no revenues whatsoever and with our first revenues to possibly occur only 3-4 years from now, I cannot emphasize how important having such an exemption is while we get our feet on the ground to eventual financial strength. Having said this, I do suggest, however, that this "pill might be easier swallowed" if the exemption were simply changed to read "there is an exemption for the first 5,000 net barrels of oil per day;" this certainly sounds better to the general public and is much easier to understand than saying, "there is an exemption for the first \$73,000,000 of profits." This also implies that for larger companies, with say 300,000 barrels of oil production currently on the North Slope, they only get an exemption for the first 5,000 barrels per day...they still have to pay production profits tax on the other 295,000 barrels per day.

What three things should be changed in the bill?

- The bill allows for the investment tax credits to be sold to others in industry if a new explorer - like AVCG - does not yet have oil production revenues to use the credits. While this sounds good, in practical application these credits can only be sold to a few buyers...basically the major three oil producers who will literally set the market for these credits and the value they will receive when sold. With limited buyers, our company estimates the credits might be sold at only 70-75% on the dollar. This disadvantages new explorers...the majors get 100% of their credits while the new explorer must sell at 70-75% of value only to then see the major producers take 100% of the acquired tax credit against their production tax bill. It is suggested that the State consider establishing a pool of dollars from the production profits taxes taken in to buy the tax credits from small explorers. This makes sense...the State would not be giving up anything because the major producers would otherwise use the credits to reduce their tax bill and reduce revenue to the State....but using this approach,

the small explorer could turn around and re-invest the State-refunded credit into new leases, seismic or exploration drilling. In fact, the State might want to stipulate that if the State refunded the tax credits to a company, that company must use it for exploration or development. Our company would support such a concept. Explorers who don't want to do this option and re-invest in the State but just want the cash value of the credit could sell to the majors at 70-75% if they prefer that option.

- The section in the bill on "determination of net value of oil and gas" listed direct costs that could be deducted from gross oil revenues to calculate a profit, or "net value of oil and gas" to then be taxed at the 20% tax rate. For a new explorer in Alaska, the startup costs in the State can be very substantial, particularly for smaller players. This can include high costs for bonding, participation in the oil spill consortium Alaska Clean Seas, indemnification insurance, etc. These types of costs should be clearly mentioned in the bill as deductible.
- Again, we hope the \$73,000,000 "standard tax deduction" remains. But I certainly have seen that this item is a "hot button" to certain legislators. But I urge you that while you may be angry with certain large producers, please do not lose sight of how important this could be to a startup company like ours trying to establish a foothold in Alaska and someday contribute substantial oil revenues to the State. As an alternative, however, to the \$73,000,000 profits exemption, we offer that the State might choose to use an approach that the State has already approved in the 1999 "Charter for Development of the Alaskan North Slope" between the State of Alaska, BP and ARCO. In that charter, there was a section entitled "Purchases From Qualified Producers" that guaranteed that BP and ARCO (now ConocoPhillips) would agree to offer to purchase any "qualified producer's" crude oil so that new entrants or small producers would not be disadvantaged in marketing their oil. In that section there was a clear definition of a protected "small producer"... actually, the Charter called such a company a "qualified producer." I quote from the Charter: a "qualified producer" means an entity with assets of less than \$1 billion (worldwide) which produces not more than 10,000 barrels of gross working interest ANS liquid hydrocarbons per day." Again, we hope the deduction provision remains in the bill. If there is opposition in the end, AVCG does hope the small companies are protected in some way; perhaps an innovation such as using the Charter guidelines may help.

That concludes my remarks. I tried to share the perspective of an independent exploration company that only invests in Alaska. I have shared the three things our company would not change in this bill and the three things we would change. All in all, I am optimistic that this bill with some tweaking could help AVCG/Brooks Range Petroleum attract new partners and new capital to Alaska, increase our exploration budget, and establish us as an important oil producer someday.

Thank you for this opportunity to make comments.

Ken Thompson

March 1, 2006

Senator Tom Wagoner and other members of the Senate Resources Committee

Thank you for the opportunity to share Pioneer's views regarding SB 305 eliminating the current severance tax system and replacing it with a Profit Sharing Production Tax.

Pioneer began its investment in Alaska in early 2003 with the drilling of 3 exploration wells in the shallow waters of the Beaufort Sea. Pioneer significantly expanded its Alaskan inventory at the October 2003 Alaska State Lease Sale where it was the largest participant and successful bidder on approximately 150,000 acres. We opened an office in Anchorage in early 2004 and now employ 26 persons in Alaska. In 2004, Pioneer concluded exploration agreements with ConocoPhillips and Anadarko across a vast portion of NPR-A. In 2005, Pioneer acquired a 10 percent working interest and the option to acquire up to an additional 40 percent working interest and possibly succeed ConocoPhillips as the operator of the Cosmopolitan Unit located in the Cook Inlet. Pioneer has significantly invested in the state and has assembled a substantial portfolio with an interest in approximately 1.6 million acres of leasehold.

On February 6, 2006, Pioneer announced that it approved and is commencing the development of the Oooguruk field on the North Slope of Alaska. Pioneer is the operator of the field, which is in the shallow waters of the Beaufort Sea approximately eight miles northwest of the Kuparuk River Unit. Pioneer has commenced operations to install an offshore gravel drilling and production site and we expect to complete gravel hauling activities by the end of winter. Following construction of the gravel drilling and production, a subsea flowline and facilities will be installed during 2007 to carry produced three-phase liquids to existing onshore processing facilities at the Kuparuk River Unit. Pioneer plans to drill approximately 40 horizontal wells to develop 50 million to 90 million barrels of estimated gross oil resources. Total gross capital to be invested in drilling and facilities is expected to range from \$450 million to \$525 million. The wells are expected to be brought on production as drilling progresses, with peak

rates of approximately 15,000 to 20,000 barrels of oil per day expected by 2010.

For independent companies like Pioneer, the challenges to building a business in Alaska are formidable. The remaining North Slope resources are nothing like the billion barrel fields that opened the Slope. The new wave of developers are working to commercialize: a) smaller, lower quality oil reservoirs, b) viscous oil resources, c) remote resources in NPRA, the foothills and offshore and d) natural gas resources, which will not have a market until the next decade. All of these resources are challenging to commercialize, but it is a challenge that must be met to insure new sources of supply for the state.

The North Slope is one of the highest cost areas in the world. Remote geography translates to some of the highest capital, lease operating and product transportation costs in the world. Additionally, North Slope projects have comparatively long cycle times. From buying a lease to selling oil takes 5 to 10 years depending upon drilling success and distance to existing infrastructure.

The largest challenge independents face on the North Slope is arguably uncertainty. To be successful, we must properly assess and make provision for a number of uncertainties related to exploration risk, future oil and gas prices, fiscal policy, regulatory processes and access to infrastructure.

The long cycle times for Alaska projects require that we make our investment decisions based upon a long term price projection. Although current prices exceed \$50 per barrel, the 10 year average price for North Slope crude is approximately \$25 per barrel. For Pioneer's Alaska projects, the price of oil in 2006 is irrelevant. The prevailing price in the next two decades will determine future cash flow for new projects.

Accurate assessment of risk is critical to the success of an exploration portfolio. Will the value of the fields we ultimately discover offset the cost of dry holes, land, seismic data and development costs? For many of the remote exploration areas in Alaska, it is difficult to project acceptable full cycle returns. In 2003, the state initiated exploration incentive credits for certain qualifying exploration expenditures. These incentives encouraged Pioneer to invest significantly in infrastructure challenged areas such as NPR-A.

When Pioneer was considering its first investments in Alaska, state officials were promoting the resource merits of Alaska basins. Alaska certainly contains world class petroleum systems. Additionally, the officials promoted the fiscal policy including the ELF formula and exploration incentives. Under the ELF formula, only very large new fields would pay severance tax and qualifying exploration expenditures in remote areas would receive exploration incentive credits at either a 20 or a 40% rate. With this fiscal system in place, Pioneer invested heavily in the state over the last several years. When we learned that a new severance tax policy was under development, we were quite concerned that any new system would be detrimental to our future investments and a departure from the fiscal system promoted to the independents by the state.

We recognize that the existing severance tax policy, as it applies to the large fields on the North Slope, is likely not sustainable and we are pleased that the proposed PPT taxes profits rather than revenues. Given that the state collects royalties right off the top, it makes sense that any additional government take should be assessed after costs have been recovered. This concept is important to the smaller, lower productivity and remote resources which are critical to future production growth. Although the proposed production tax rate of 20% is quite large when layered upon the other burdens of royalty, ad valorem tax, state income tax and federal income tax, the impact of the large tax rate is tempered by the allowance of cost recovery, investment tax credits and the proposed taxable income threshold.

Pioneer is pleased to see the provision included in the proposed legislation regarding the deductibility of transitional capital. The provision serves to compensate those companies, including Pioneer, who have made significant capital investments over the past five years based upon the fiscal terms in place at that time.

We have reviewed the testimony of the administrative and agree that the PPT, as proposed, will provide incentives for new investment by all companies. Economic metrics for new investments will improve under the PPT versus existing tax law. This should encourage the development of marginal fields and will reduce the minimum economic size for exploration prospects, thus prompting more exploration and increasing the chances of finding commercial-sized fields. In addition, it should encourage re-investment in existing fields. We believe the PPT as proposed will entice

more companies to Alaska and increase competition. More companies and more ideas will lead to smarter field development methods, smarter drilling and production equipment, which will further reduce the minimum economic size of exploration prospects and grow the resource pie.

The tradable tax credits are a particularly effective incentive for the exploration and development of new resources. Under the proposed PPT, the higher risk, higher cost and long project cycle times associated with new resource exploration and development are partially offset by the ability to monetize these credits shortly after investment. In an exploration portfolio, the large majority of projects are not successful resulting in a total loss from all lease acquisition, seismic and drilling costs. The tradable tax credits would lessen the negative financial consequences of the inevitable dry holes explorers will drill.

A significant concern to Pioneer is the potential for a lack of liquidity for the tradable tax credits. Pioneer's outlook is to continue with very large capital expenditures in the state over the next several years. With only a handful of very large producers as potential buyers for the credits, and the proposed limit that a company may utilize purchased credits to offset no more than 20% of its tax, we are concerned that the market for the credits may not be competitive. New investors could face selling credits at a discount to tax payers who would in turn cash them in to the state at full value. We appreciate that a buyer of tax credits should recover its transaction costs, but we are concerned that the required discount might be substantially greater. We respectfully ask the legislature to consider implementing refundable credits with appropriate limitations to protect the state's cash flow in the event of low oil prices. The program could provide that credits be refunded at a modest discount to face value. This would allow the State, and not a third party producer, to benefit from any discount that a seller would be willing to accept.

We believe that the PPT as proposed improves Alaska's competitive position with respect to other investment opportunities around the world. Mr. Van Meurs' testimony indicated that the proposed PPT would improve Alaska's competitiveness versus a number of mostly large, international investment opportunities around the world. To attract companies of Pioneer's size and smaller, we believe that Alaska must effectively compete with U.S. lower 48 opportunities as well. With higher prevailing natural gas prices in the lower 48, gas resource plays (tight sands, shales and coalbed

methane) are attracting huge amounts of capital due to the relatively low risk, low cost and short project cycle time relative to exploration. The size of some of these resources is quite large resulting in increased competition in the U.S. for independent's capital. If Alaska wants to improve its competitive position and attract new investors, we believe that the legislature should take great care in making changes to the administration's proposal that would make it less competitive.

For new investors to Alaska, particularly smaller companies, exempting the first \$73 million of cash flow from taxation is a valuable feature of the PPT. The obstacles to new investors are high. Most new investment opportunities in Alaska are either small, infrastructure challenged, risky (exploration) or some combination of these factors. New investors are also handicapped by not owning the existing infrastructure and they lack the economies of scale enjoyed by the large operators. To be an effective operator in the state requires a huge commitment in highly compensated personnel to effectively navigate the regulatory and operational challenges that are unique to Alaska. Under existing law, it is unlikely that an explorer would pay significant production tax unless a huge field was discovered. A number of new companies were recruited to Alaska by the state and made substantial investments based on the existing tax law. Under the proposed PPT, exempting the first \$73MM of cash flow from taxation will help deliver an investment climate more consistent with the system that initially encouraged Pioneer to explore in Alaska and will help offset the high "start-up" costs.

In general, we believe the proposed PPT is a balanced program with appropriate incentives to encourage new investment in the state. We encourage the legislature to carefully evaluate the proposal and take care to insure that it results in fiscal policy that makes Alaska more competitive. We also respectfully request your consideration to make the tax credits in this bill refundable to allow the new investors the full intended advantage of the tax credit program. Thank you for this opportunity to express Pioneer Natural Resource's views on SB 305.

Pioneer Natural Resources Alaska, Inc.

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

**01 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, 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 an un-deserved windfall 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

**JAMES D. WEEKS**  
**907-258-2969**  
**jweeks@gci.net**

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On SB 305  
Oil and Gas Production Tax  
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**01 March, 2006**

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BS (Petroleum Engineering), University of Wyoming, Laramie, WY.

March 1, 2006

Senator Tom Wagoner and other members of the Senate Resources Committee

Thank you for the opportunity to share Pioneer's views regarding SB 305 eliminating the current severance tax system and replacing it with a Profit Sharing Production Tax.

Pioneer began its investment in Alaska in early 2003 with the drilling of 3 exploration wells in the shallow waters of the Beaufort Sea. Pioneer significantly expanded its Alaskan inventory at the October 2003 Alaska State Lease Sale where it was the largest participant and successful bidder on approximately 150,000 acres. We opened an office in Anchorage in early 2004 and now employ 26 persons in Alaska. In 2004, Pioneer concluded exploration agreements with ConocoPhillips and Anadarko across a vast portion of NPR-A. In 2005, Pioneer acquired a 10 percent working interest and the option to acquire up to an additional 40 percent working interest and possibly succeed ConocoPhillips as the operator of the Cosmopolitan Unit located in the Cook Inlet. Pioneer has significantly invested in the state and has assembled a substantial portfolio with an interest in approximately 1.6 million acres of leasehold.

On February 6, 2006, Pioneer announced that it approved and is commencing the development of the Ooguruk field on the North Slope of Alaska. Pioneer is the operator of the field, which is in the shallow waters of the Beaufort Sea approximately eight miles northwest of the Kuparuk River Unit. Pioneer has commenced operations to install an offshore gravel drilling and production site and we expect to complete gravel hauling activities by the end of winter. Following construction of the gravel drilling and production, a subsea flowline and facilities will be installed during 2007 to carry produced three-phase liquids to existing onshore processing facilities at the Kuparuk River Unit. Pioneer plans to drill approximately 40 horizontal wells to develop 50 million to 90 million barrels of estimated gross oil resources. Total gross capital to be invested in drilling and facilities is expected to range from \$450 million to \$525 million. The wells are expected to be brought on production as drilling progresses, with peak

rates of approximately 15,000 to 20,000 barrels of oil per day expected by 2010.

For independent companies like Pioneer, the challenges to building a business in Alaska are formidable. The remaining North Slope resources are nothing like the billion barrel fields that opened the Slope. The new wave of developers are working to commercialize: a) smaller, lower quality oil reservoirs, b) viscous oil resources, c) remote resources in NPRA, the foothills and offshore and d) natural gas resources, which will not have a market until the next decade. All of these resources are challenging to commercialize, but it is a challenge that must be met to insure new sources of supply for the state.

The North Slope is one of the highest cost areas in the world. Remote geography translates to some of the highest capital, lease operating and product transportation costs in the world. Additionally, North Slope projects have comparatively long cycle times. From buying a lease to selling oil takes 5 to 10 years depending upon drilling success and distance to existing infrastructure.

The largest challenge independents face on the North Slope is arguably uncertainty. To be successful, we must properly assess and make provision for a number of uncertainties related to exploration risk, future oil and gas prices, fiscal policy, regulatory processes and access to infrastructure.

The long cycle times for Alaska projects require that we make our investment decisions based upon a long term price projection. Although current prices exceed \$50 per barrel, the 10 year average price for North Slope crude is approximately \$25 per barrel. For Pioneer's Alaska projects, the price of oil in 2006 is irrelevant. The prevailing price in the next two decades will determine future cash flow for new projects.

Accurate assessment of risk is critical to the success of an exploration portfolio. Will the value of the fields we ultimately discover offset the cost of dry holes, land, seismic data and development costs? For many of the remote exploration areas in Alaska, it is difficult to project acceptable full cycle returns. In 2003, the state initiated exploration incentive credits for certain qualifying exploration expenditures. These incentives encouraged Pioneer to invest significantly in infrastructure challenged areas such as NPR-A.

When Pioneer was considering its first investments in Alaska, state officials were promoting the resource merits of Alaska basins. Alaska certainly contains world class petroleum systems. Additionally, the officials promoted the fiscal policy including the ELF formula and exploration incentives. Under the ELF formula, only very large new fields would pay severance tax and qualifying exploration expenditures in remote areas would receive exploration incentive credits at either a 20 or a 40% rate. With this fiscal system in place, Pioneer invested heavily in the state over the last several years. When we learned that a new severance tax policy was under development, we were quite concerned that any new system would be detrimental to our future investments and a departure from the fiscal system promoted to the independents by the state.

We recognize that the existing severance tax policy, as it applies to the large fields on the North Slope, is likely not sustainable and we are pleased that the proposed PPT taxes profits rather than revenues. Given that the state collects royalties right off the top, it makes sense that any additional government take should be assessed after costs have been recovered. This concept is important to the smaller, lower productivity and remote resources which are critical to future production growth. Although the proposed production tax rate of 20% is quite large when layered upon the other burdens of royalty, ad valorem tax, state income tax and federal income tax, the impact of the large tax rate is tempered by the allowance of cost recovery, investment tax credits and the proposed taxable income threshold.

Pioneer is pleased to see the provision included in the proposed legislation regarding the deductibility of transitional capital. The provision serves to compensate those companies, including Pioneer, who have made significant capital investments over the past five years based upon the fiscal terms in place at that time.

We have reviewed the testimony of the administration and agree that the PPT, as proposed, will provide incentives for new investment by all companies. Economic metrics for new investments will improve under the PPT versus existing tax law. This should encourage the development of marginal fields and will reduce the minimum economic size for exploration prospects, thus prompting more exploration and increasing the chances of finding commercial-sized fields. In addition, it should encourage re-investment in existing fields. We believe the PPT as proposed will entice

more companies to Alaska and increase competition. More companies and more ideas will lead to smarter field development methods, smarter drilling and production equipment, which will further reduce the minimum economic size of exploration prospects and grow the resource pie.

The tradable tax credits are a particularly effective incentive for the exploration and development of new resources. Under the proposed PPT, the higher risk, higher cost and long project cycle times associated with new resource exploration and development are partially offset by the ability to monetize these credits shortly after investment. In an exploration portfolio, the large majority of projects are not successful resulting in a total loss from all lease acquisition, seismic and drilling costs. The tradable tax credits would lessen the negative financial consequences of the inevitable dry holes explorers will drill.

A significant concern to Pioneer is the potential for a lack of liquidity for the tradable tax credits. Pioneer's outlook is to continue with very large capital expenditures in the state over the next several years. With only a handful of very large producers as potential buyers for the credits, and the proposed limit that a company may utilize purchased credits to offset no more than 20% of its tax, we are concerned that the market for the credits may not be competitive. New investors could face selling credits at a discount to tax payers who would in turn cash them in to the state at full value. We appreciate that a buyer of tax credits should recover its transaction costs, but we are concerned that the required discount might be substantially greater. We respectfully ask the legislature to consider implementing refundable credits with appropriate limitations to protect the state's cash flow in the event of low oil prices. The program could provide that credits be refunded at a modest discount to face value. This would allow the State, and not a third party producer, to benefit from any discount that a seller would be willing to accept.

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methane) are attracting huge amounts of capital due to the relatively low risk, low cost and short project cycle time relative to exploration. The size of some of these resources is quite large resulting in increased competition in the U.S. for independent's capital. If Alaska wants to improve its competitive position and attract new investors, we believe that the legislature should take great care in making changes to the administration's proposal that would make it less competitive.

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Pioneer Natural Resources Alaska, Inc.

**SB**

**305**

**(FILE 8)**

# ConocoPhillips

March 3, 2006

The Honorable Ralph Samuels  
Alaska House of Representatives  
Alaska State Capitol, Room 126  
Juneau, AK 99801-1182

The Honorable Tom Wagoner  
The Alaska Senate  
Alaska State Capitol, 427  
Juneau, AK 99801-1182

Dear Sirs:

I wanted to thank you again for the opportunity to express ConocoPhillips' views on HB 488/SB 305. During my testimony, there was some additional information requested by the committee members. This information is provided below:

#### House Resources Committee

1. (Rep. Berkowitz) What are your profit numbers for the last 10 years? How much of these are from your heavy oil investments?

Listed below are the publicly reported earnings for ConocoPhillips' operations in Alaska for the years 2000-2005 as reported in our Annual Reports. Earnings from heavy oil investments are not reported publicly. Unfortunately, ARCO did not separate out Alaska earnings data in their annual reports, so the figures for the years prior to Phillips Petroleum's acquisition of ARCO Alaska may not be disclosed.

	ConocoPhillips Alaska Operations					
	9 Months 2000	2001	2002	2003	2004	2005
Exploration and Production Earnings SMM	\$700	\$677	\$673	\$1,079	\$1,665	\$2,410
Other Earnings SMM (TAPS/Polar/LNG)	\$129	\$189	\$197	\$366	\$167	\$142
Total COP Alaska Earnings SMM	\$829	\$866	\$870	\$1,445	\$1,832	\$2,552

2. (Rep. Gatto) What is your public rate of return on investments for recent years (past 2 annual filings)?

Our Annual Report does include our corporate return on capital employed (ROCE) at a corporate level. The ConocoPhillips return on capital employed in 2004 was 15.2% and in 2003, the return on capital employed was 9.8% (GAAP

ROCE). The ConocoPhillips 2005 Annual Report has not been published as of this date.

3. (Rep. Berkowitz) What would be the decline in effective tax rate as a result of removing the Oil Spill 470 fund (AS 43.55.201)?

The conservation surcharge on oil has not been removed from the statute and must be paid by a producer of oil. The proposed legislation will allow this surcharge to be applied as a credit against the producer's taxes due. At a surcharge of \$0.03-\$0.05/bbl, this credit amounted to approximately \$3.4 MM for COP in 2005 and has essentially no impact on the effective tax rate at today's prices.

4. (Rep. Ramras) What is the depreciation mix of the \$700MM (this year's capital spend)? (e.g., 5-yr, 10-yr, etc.)

For 2005, ConocoPhillips Alaska's reported capital expenditures were \$746.2MM. A large portion of the assets have not yet been placed in service so no depreciation has occurred. Once the equipment is placed in service, it will be depreciated at IRS depreciation schedules for federal taxation purposes. The \$746.2MM can be broken down into these types of assets:

Field Life	2%	Leasehold Costs	<ul style="list-style-type: none"><li>Costs which are depreciated on a per unit of production basis over the life of the fields</li></ul>
7-10 Years	62%	Lease and Well Equipment (L&W)	<ul style="list-style-type: none"><li>Are tangible costs such as tankers, casing, tubing, wellheads, separators and producing equipment necessary to serve the well tanks, flowlines etc)</li></ul>
5 Years	11%	Intangible Drilling Costs (IDC) - Capitalized	<ul style="list-style-type: none"><li>Costs of drilling wells such as labor, location preparation costs, rig mobilization, drilling costs, completion costs, which generally have no salvage value</li></ul>
Immediate	25%	Intangible Drilling Costs (IDC) - Expensed	<ul style="list-style-type: none"><li>Costs of drilling wells such as labor, location preparation costs, rig mobilization, drilling costs, completion costs, which generally have no salvage value</li></ul>

5. (Rep. Kerttula) What would be the production tax on Fiord under the current ELF formula?

Fiord is expected to startup in the fourth quarter of 2006. In order to make the project economically viable, ConocoPhillips sought and obtained a letter from the Department of Revenue stating that Fiord would not be aggregated with Alpine for calculation of severance tax; hence, initial Fiord production would have an effective ELF severance rate of 0%. The ELF tax rate is currently expected to be

1.76% in 2007, and the total projected production would result in ELF production tax payments of just under \$20MM over the next 10 years at today's prices. This figure, of course, does not include royalties, State corporate income taxes, state and local property taxes, the oil and gas conservation surcharge, or federal corporate income taxes attributable to the Fiord project.

6. (Rep. Samuels) What have been your abandonment expenses over the transition period?

Abandonment expenditures are treated as expense rather than capital expenditures and thus do not result in tax credits under the proposed PPT production tax system. Our abandonment expenditures from 2001 to 2005 totaled \$33.7 MM. However, none of these expenditures would be counted as capital or included in the *transitional investment expenditures* under the proposed PPT HB 488. On a go-forward basis, we do experience limited abandonment expenditures each year for activities such as plugging and abandoning old wells and some gravel removal and restoration (e.g., \$12.6 MM in aggregate in 2005). However, these expenses, like our expenses for 2001 through 2005, are all anticipated to be operating costs that are not eligible for the capital credit. In addition, the bulk of the abandonment dollars would occur at the end of field life, when we expect limited, if any, production or revenue which will leave the production tax deductions associated with these expenditures with limited or no value.

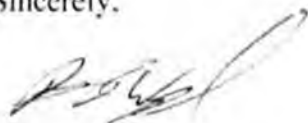
Senate Resources Committee

1. (Sen. Stevens) Please break down the 2005 capital expenditures into exploration, development, and production expenditures?

In 2005, ConocoPhillips reported capital expenditures of \$746.2 MM. Approximately, 67% was associated with development activities, 13% on production maintenance activities and 2% on exploration. The remaining 18% was associated with marine, pipeline and acquisition expenditures.

If you have any questions regarding this information, you may contact me at 907-265-1650 or make arrangements through our Juneau office at 907-586-3680.

Sincerely,



Brian R. Wenzel  
Vice President, Finance & Administration  
ConocoPhillips Alaska

LIBRARY

March 2, 2006

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

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

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

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

Dear Senator Wagoner and Representatives Samuels and Ramras.

Thank you for the opportunity to respond to questions posed during (and following) recent committee hearings.

Received 2/28/06, 12:00 p.m.

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

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

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

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

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

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

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

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

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

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

A very small amount, probably no more than 1% of total state revenue from oil and gas. It is limited to three areas: [1] Alpine and its satellites; [2] the National Petroleum Reserve Alaska; and [3] Cook Inlet.

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

No, it was not considered.

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

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

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

TO BE PROVIDED

9. How many private royalty owners are there in Alaska – all areas, not just the North Slope (i.e., Nenana Basin, Kenai Peninsula, native corporation holdings, etc).

We do not have information on the number of private royalty owners in Alaska, which would include private oil and gas leases that are not in production. Homesteads staked under certain (but not all) federal homestead laws included oil and gas rights, and any of the owners of such parcels might enter into an oil and gas lease.

10. Provide a graph showing the status quo, the PPT, and the gas line contract terms.

This question appears to query the relationship between tax under the status quo, the PPT, and the gas line contract terms. At this time, gas line contract terms are not public information.

11. Provide information on the effect of previous incentives – the costs.

Claimed expenses under SB 185 (43.55.025) total \$104.8 million and claimed credits total \$33.6 million [see table below]. A claim was received by the Department of Revenue last week, thus the totals has been updated from the \$95.5 million and \$29.0 million figures previously provided.

12. What is the rationale for offering the same amount of credits for non-state lease lands where the state receives no royalty tax benefit – was there discussion of a reduction in the credit to offset this?

The rationale is that the incentives have the potential to result in higher severance taxes; taxes that are assessed on any oil or gas production within Alaska's sovereign territory. Given the overall economic benefit of increased production of oil and gas (and particularly gas in the Cook Inlet where significant private lands occur), an incentive for exploration and development even in the event that a field would pay no taxes after incentives makes sense.

13. Why should Point Thomson be incentivised?

We believe the development of Pt. Thomson may be critical for the development of the gasline. Accordingly, incentivizing Pt. Thomson may well incentivize the gasline

Pt Thomson is particularly problematic for two reasons. First, it is a high cost field since it is a high pressure gas condensate reservoir and second we do need the gas reserves to underpin the gas pipeline economics. By providing incentives, the goal would be two fold. First any incentive to encourage Pt. Thomson improves the economics of the gas pipeline. Second, incentives may encourage early production of the liquids which requires expensive infrastructure to handle the high pressure production.

14. Can you provide better definitions for "point of production" and "oil" and "gas" and has the State litigated these terms?

We're not clear whether this question seeks more explanation of the definitions in the bill or is requesting that we consider modifying those definitions. Please clarify. Regarding past litigation, in general the point of production and the definitions of oil and gas have not been major subjects of litigation under the production tax statute. In contrast, there has been considerable litigation of related concepts, though not necessarily the phrase "point of production," in the royalty context.

In the tax context, there was at least one dispute decided at the internal DOR appeal stage relating to point of production, but most of the controversy in this area played out in the development of regulations defining "gas processing plant," rather than litigation. The use of the term "gas processing" in the bill is consistent with existing department regulations, but under current law gas processing generally is considered an activity occurring downstream of the point of production, while under the bill it is considered an activity occurring upstream of the point of production.

15. What steps must be taken to make the tax credits refundable rather than transferable?

This would require a language change to Section 12 at Sec. 43.55.024(d) and (e). We are available to work with drafters on the exact wording.

16. On Page 13, line 24 of the bill, what does "payment in lieu of" tie into for oil?

Section 21 (Sec. 43.55.160(d)(1)(B)) clarifies that payments in lieu of property taxes are deductible. Sec. 43.55.160(c) presents the general rule that lease expenditures are deductible. Lease expenditures would include property taxes. Sub-section (d) provides clarification for items that are not clear, such as "payments made in lieu of property taxes."

17. Does the limit on transferable tax credits in section 12 (subsection (e)) limit the amount of tax credits that a single taxpayer can take against their own production tax in a single year?

Section 12 (Sec. 43.55.024(e)) limits the amount of tax that can be reduced through purchased credits. There is no limit on credits utilized by a taxpayer that were generated by that same taxpayer.

18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues; have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the

legislation on the State's legal position in past agreements, current disputes, or future disputes?

Yes, such counsel(not all of them) have been consulted and such assessments have been discussed but have not generally been generated in formal written form.

19. Have you asked the Department of Law to review this legislation in light of the 6<sup>th</sup> Circuit Court of Appeals' decision in Cuno v DaimlerChrysler that is now pending before the United States Supreme Court?

The Department of Law has examined this question. As a Sixth Circuit decision, it has no direct precedence for Alaska. It is currently before the U.S. Supreme Court and many analysts believe that it will not be sustained in its current form.

20. Please provide information regarding the expenditures that will qualify for the transition credits—including the depreciation method chosen under the federal and state income tax systems.

It appears that this question relates to the transition provision in Section 21 (Sec. 43.55.160(g)) which allows a deduction for capital expenditures made over the last five years, deductible over the next six years. The capital expenditures that qualify for transitional treatment are the same type of expenditures that qualify for ongoing credits. These are defined in Section 12 (Sec. 43.55.024(h)). These expenditures include exploration expenses and those expenditures that are capitalized for federal tax purposes. Exploration expenses include geological and geophysical exploration. Expenditures capitalized for federal tax purposes include intangible drilling costs. The capitalized expenditures are subject to a variety of useful lives under federal and state income rules. See Question 60 below.

21. Have any of the definitions in sections 30-33 been the subject of disputes with tax and/or royalty payers in the past? To the extent they have, please provide the definitions the state asserted in those disputes.

See question 18 above.

22. Please provide an identification of the point of production at each unit in the state under existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

23. Please provide an identification of 'gas treatment' and 'gas processing' facilities in the state under the existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

24. What standard will be used to determine whether oil or gas is of 'pipeline quality' under the definition of 'gross value at the point of production'?

This term only appears in the definition of "oil." It was not in the old definition, nor the new definition of "gas." The standard for "pipeline quality" has not changed under the bill. The standard is based on a series of court cases.

25. Provide a historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior.

TO BE PROVIDED

26. Will abandonment costs be eligible for deductions or credits under the legislation? If so, what estimates of the timing and costs of those activities does the Department project?

See Question 2 for deductibility of abandonment costs. With regard to costs, we are aware of no field having ever been abandoned in Alaska, and so we do not have any empirical data on costs.

27. How will AS 43.55.160(j) protect the State from a proliferation of corporate entities and/or companies claiming the tax free allowance?

TO BE PROVIDED

28. Provide the number of exploration and delineation wells estimated to be drilled over the first ten years of your economic models. Include the technical and economic success rates projected in the modeling.

Five [5] exploration wells per year are included in the model. The Department of Revenue assumes \$100 million is spent on exploration per year. With average costs of \$20 million dollars per well, this comes out to five [5] wells per year. Delineation wells are separate and included under development expenditures. The model assumes there are four [4] finds of large oil accumulations - reserves in place that would be on the order of 500 million barrels. There are four [4] relatively small fields that are characterized as being "heavy" oil. These fields would pay no production tax under the current system because their Economic Limit Factor [ELF] would be zero [0.0]. We did not include a "success rate" in our model.

29. Provide estimates for undiscovered resources in Alaska. Include the breakdown between technically recoverable and economically recoverable resources to the extent possible.

TO BE PROVIDED

30. Provide a historical analysis of the effective tax rate on each field in production on the North Slope over the past twenty years.

See Attachments A1 and A2. These tables contain effective tax rates since 1986 for all Alaskan fields on gross value at the point of production. The effective tax rate shown on these tables is the ELF x 12.25% for the first five years of production, and ELF x 15% thereafter. We note the effective rate varies between 15.0%, for Prudhoe Bay through 1987 (when the so-called "rounding rule" rounded the ELF up to 1), and 0.0% for a number of fields for a number of years.

31. How will Net Profit Share Leases be affected by this legislation? Will the gross costs of exploration and development go into the Development Account—or those costs net of the credits and deductions?

TO BE PROVIDED

Received 2/28/06, 2:30 p.m.

32. It's been reported that the gas line contract will propose the state take its gas production tax share in the form of gas. How does that work in this bill?

In the gasline contract the state has indeed proposed taking deliveries of gas in place of a production tax; this is not reflected in the PPT bill which will stand on its own, gasline or no. Under the PPT, if the producers sell gas, those revenues would be part of the net profit calculation. Under the gasline, they would not. Instead the state would receive a percentage of the gas, which it would monetize through marketing. Note that the costs of developing (for example Pt Thomson) or running (for example Prudhoe Bay) a field that produces both oil and gas would go into calculating the oil profits for the PPT.

33. Of the pre-PPT credit provisions (or claw back), what is the cost to the state for legacy fields and what is the cost to the state for frontier regimes?

See question 20.

34. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

Sale of credits under SB185 do not effect the ability of the seller to claim those credits as Transitional Investment Expenditures (that is to qualify for the claw back.)

35. If we have a gas pipeline in 2015, what will the ELF tax "take" be on North Slope gas and what will the "take" be under the PPT? What will the "take" be under PPT if we take gas in lieu of the production tax (the take would, I assume be the day-to-day value of the gas less the state's cut in selling the gas on the marketplace)?

Without getting into price sensitive forecast, or the confidential draft gas contract, we can make the following observations about the comparison: The upstream costs are covered in the PPT, so the difference could be as simple as:

- (a) under the PPT, a taxpayer would pay 20% of the gross value at the point of production, that is sales revenues less the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale would be paid to the state. (without taking into account the effect of the \$73 million dollar allowance).
- (b) Under the gas contract, the state will receive some percentage of the gas, and then pay the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale. If the state owns part of the pipeline, then the state will also receive that portion of the tariff which is profit accruing to the owner.

36. Is current production tax deductible from corporate tax? If no, is this impact in the models presented by the Administration?

Yes, current production is deductible from corporate tax.

37. Referring to Section five, what oil and gas is exempt from taxation—just what is discussed in Section 10?

The oil and gas royalty amounts paid to the state and federal government are exempt. (AS 43.55.900 (13) "ownership or right to which is exempt from taxation" means any ownership interest of the federal government or the state.")

Section 10 simplifies treatment of flared gas. Under current law there are three categories of gas – gas used in production operations which is exempt from tax, gas produced in excess of that needed for safety purposes which is taxable, and gas flared beyond the amount authorized for safety which is taxed and subject to a penalty. Currently there is no 'free use of oil' to produce more oil in statute. The bill

exempts from tax any oil or gas used in production operations, unless the Alaska Oil and Gas Conservation Commission determines that it was waste (instead of used to produce salable hydrocarbons), in which case it is taxed.

38. Referring to Section six, will there be any impact to current state taxes or municipality taxes from this change?

No, there should be no impact to current state or municipal taxes. This language change simply makes the description of Intangible Drilling Costs consistent with Internal Revenue Code language, which is how this item is interpreted currently.

39. Why was the payment for taxes and surcharges changed from the 20<sup>th</sup> day to the last day of the month? What is the economic impact of this change?

There is no economic impact and this just clears up current language. Under AS 43.55.020, payment for the tax is "due" on the 20th, however, the tax is not "delinquent" until the last day of the month. The significance of this is that according to AS 43.05.225 interest is assessed only when a tax "becomes delinquent." Thus this bill makes the due date the end of the month and in section 7 establishes that "an unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent."

40. Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

TO BE PROVIDED

41. What are the penalties for under-payment when sure-up is more than ten percent of the taxes owed?

If the taxpayer does not pay 90%, then interest will be due on the difference between the tax paid and the 90% amount.

42. Referring to Section 10, why does the AOGC [Alaska Oil and Gas Conservation Commission] role change from focusing on excess needed for safety reasons to whatever they determine to be waste? Does this provision provide more power to the AOGC on what is included/excluded for taxation?

Under current law, as applied by DOR regulation, the categories of flared gas recognized by DOR are different from (although related to) the categories recognized by AOGCC. The bill will simplify the categorization and harmonize it completely with AOGCC's. This simply creates one standard administered by AOGCC, in place of two standards administered by two agencies.

43. Why does it seem the credits and incentive [sic] are on production along with exploration if our focus is to provide incentives for exploration?

(The bill is based on the expectation that investment, both exploration and in existing fields, will increase production.

44. Can the carry-forward amount be used for a credit for more than the first year after the loss?

Yes, the credit carry-forwards can be used indefinitely. There is no time limit on the credit carryforwards.

45. Is it the case that any allowable expenses for the exploration, development, or production of gas can be deducted from oil revenues in determining net value? If so, could the expenses of a gas line be included in these deductible expenses?

Expenses are allowable only if they are "upstream" costs. A gas line is "downstream" and so would not be a deductible expense.

46. Why not use GAP [sic] accounting rules versus set up our [sic] system of defining revenues and expenses?

GAAP (Generally Accepted Accounting Principles) are useful for determining whether an item of expenditure can be classified as an "expense." GAAP does not differentiate between expenses incurred specific to a lease and those expenses that are indirect to a lease. For example, GAAP does not distinguish between wages paid to a lease-based worker, and an employee in the home office.

47. Which credits can be applied to multiple years?

There is no time limit for credit carryforwards under the bill, nor for the optional credit codified in 43.55.025. However, any dollar of investment can only generate one credit, and that credit can only be used once.

48. Can a tax credit be sold in any year or just the year after it was accrued?

Once the credit has been turned into a Credit Certificate, it can be sold at any time. A person can apply for a Credit Certificate at any time, but the bill allows the Dept. of Revenue a period of time in which to issue the Credit Certificate. (See Section 12, Sec. 43.55.024(g))

49. What is the estimated economic impact to the state of the ability to sell tax credits?

TO BE PROVIDED

50. Referring to Section 16, what is current system and why do we need this change in confidentiality?

The bill codifies current practice embodied in regulations in our treatment of taxpayer information. The only change here is that the bill makes clear that any person receiving information released under current department practices, is subject to the same criminal penalties that apply to a state employee.

The current confidentiality law is very general in its exception language – information must be kept confidential “except in connection with official investigations or proceedings . . . .” The Department believes that current law does allow disclosure under the circumstances specified in the bill, but there has been some question about that, and it would be desirable to clarify the meaning of the law, as the bill does. In addition, there is the new provision on penalties, referred to above

51. In what circumstances would oil and gas taxes go straight into the CBR.

Additions to the CBRF (Constitutional Budget Reserve Fund) are made for any oil and gas taxes collected in resolution of a dispute. That means that amounts collected because of an audit assessment, or subsequent settlement, are additions to the CBRF.

52. Referring to Section 18 and 19, why change from shall to is?

This change is made in accordance with the state style manual.

53. Why does the bill offer multiple methods to determine gross value? Who will choose a methodology?

The bill does not directly allow a taxpayer to elect alternative methods, it just allows the Department to authorize use of an alternative method. The election referred to would be an election between using an alternative method or just calculating gross value according to the usual rules – NCT an election among several different alternative methods. In implementing this provision, the Department will no doubt develop criteria for when a particular alternative method would be appropriate. I don't think we can predict now whether there might be circumstances under which more than one alternative method might be appropriate and under which the Department would authorize a taxpayer to elect among several alternative methods.

54. Section 21, page 1, line 8—why is this clause constrained by Dec. 1, 2005?

TO BE PROVIDED

55. Section 21, provision (h), which US CPI does the Administration plan on using?

This would be established by regulation. The Department has not evaluated the various CPI's at this time.

56. Are the current oil conservation surcharges deductible from any other taxation? If no, what is the policy reason to make them a credit in SB 305 and what is the economic impact?

Yes, current oil conservation surcharges are deductible from corporate income tax.

Other Questions

57. Do any other state taxes have a "standard deduction"?

- a. Seafood Marketing Assessment (ASMI) tax is imposed only on processors/exporters that process or export fisheries resources with a value of \$50,000 or more in a calendar year. AS 16.51.120(g).
- b. Mining License Tax is not imposed when net income is less than \$40,000 in a fiscal year. AS 43.65.010(c).
- c. Gaming tax exempts gross receipts of less than \$20,000 from paying the additional fee under AS 05.15.020(b).
- d. Alaska's Estate Tax follows federal rules, but the most recent exemption (Fy05) included estates valued at under \$1.5M.

58. How many NPSL's (Net Profit Share Leases) are in the state, and how much are they paying in royalties?

Out of 19 NPSL's, seven are paying royalties. These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was \$81M. Total receipts from NPSL's from 2001—2005 were \$254M.

Out of 19 NPSL's, seven are paying net profit share payments (*in addition to royalties and production taxes*). These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was \$81M. Total NPS receipts from NPSL's from 2001—2005 were \$254M. Net profit share payments are not deductible for PPT purposes nor for the current production tax. Royalties and production taxes are deductible for NPS purposes.

Royalties, however, are paid on net profit share leases according to each individual lease contract. For example, one NPS lease in Duck Island Unit has a twenty percent (20%) royalty rate. Other NPS leases may have the standard royalty rate of 12.5% or another, negotiated royalty rate. Royalties and production taxes are due from a net profit share lease as long as there is production, even when there is no net profit share payment from the property.

Attached is an Xcel table of producing and non-producing NPS leases showing the lease number, the net profit share rate and the royalty rate for each lease. (See Attachment B)

59. What are the depreciable lives for O & G equipment for federal and state income tax purposes?

	Federal	Alaska
Equipment for exploration and production including drilling, gathering pipelines, pumping equipment, separation equipment, certain platforms	7	11
Offshore drilling	5	6
Pipelines, excluding gathering and transmission lines	15	17.5
Vessels, barge <sup>o</sup> other water transportation equipment	10	14.5

60. Please provide the tax calculation under the bill, with the following assumptions:

--Gross value           \$60M  
 --Opex                   15M  
 --Capex                 10M

Gross value	\$60M
Less: Opex	(15)
Capex	<u>(10)</u>
Tentative net profit	
Before standard deduction	\$35M
Less: standard deduction*	<u>(35)</u>
Net Taxable income	<u>\$ 0</u>

Tax	\$ 0
Capital investment credit available for carryforward (20% of \$10M)	\$5M

\* this calculation assumes that taxpayer has not reached \$73M limit for the standard deduction.

61. Are net profit lease payments included as a direct cost under 43.55.160?

Net profit share payments under NPSL's (Net Profit Share Leases) would not be deductible lease expenditures because they are in the nature of lease acquisition costs. Lease acquisition costs are not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

62. Are lease bonus payments eligible for capital credit under 43.55.024 and/or are they included as a direct cost under 43.55.160?

Lease bonus payments are neither deductible nor eligible for capital credits. Lease bonus payments are in the nature of lease acquisition costs which are specifically not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

63. How are payments for "spec 3D" handled? Are they credit eligible under 43.55.024 or only allowed as deductions under 43.55.160?

We understand "spec 3D" to be certain seismic exploration costs. Exploration costs are allowed as deductions under Section 21 of the bill (Sec. 43.55.160(c)). Such costs are also eligible for credits under Section 12 (Sec. 43.55.024) by reference to definition of "qualified capital expenditure" at Sec. 43.55.024(f).

64. Please explain the taxation or exemption of royalties.

Public royalties (paid to federal or state jurisdictions) never enter into the base of gross value. This is so because AS 43.55.011(a) levies the tax on oil except oil the "ownership or right to which is exempt from taxation." This phrase is then defined in AS 43.55.900(13) as follows:

"any ownership interest of the federal government or the state."

These sections are not changed in the bill.

Because the bill changes the tax to a tax on net profits, it is necessary to specify deductions. Royalties are specifically disallowed as a deduction under Section 21

(Sec. 43.55.160(d)(2)(B)). Royalties paid to state and federal jurisdictions cannot be deducted because they are not included in the starting "gross value." Private royalties cannot be deducted because the related production is subject to tax.

65. Under Section 21 (Sec. 43.55.160(d)), "direct costs... include..." Does the word "include" serve to restrict the list of allowable expenses to only those items included below in (A)—(C)?

No, Sec. 43.55.160(d) provides additional clarification for the general rule stated at sub-section (c). Sub-section (c) provides the general rule that lease costs are deductible. Sub-section (d) addresses only those items that may have been questionable under the general rule. Additionally, we note that under AS 01.10.040(b):

"When the words 'includes' or 'including' are used in a law, they shall be construed as though followed by the phrase 'but not limited to.'"

Questions Received 3/1/06 12:00 p.m.

66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO<sub>2</sub> re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

TO BE PROVIDED

67. What happens if the "Big Three" sell off their assets to 20 smaller companies? Will the significant tax benefits ever be realized?

TO BE PROVIDED

68. How is it possible that any corporation gets triple the sale price for a commodity, having invested capital at the expected lower returns, and then maintains that they need a claw back provision? Why should we offer it?

TO BE PROVIDED

69. Please show us an international competitiveness rank and score for PPT under the following tax/credit scenarios, both overall and for new producers:

- a. 30/15
- b. 30/20
- c. 25/20
- d. 20/20

TO BE PROVIDED

Letter to Senator Wagoner and Representatives Samuels and Ramras  
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70. Please present Mr. Marks' charts on pages 14-16 to show the difference between a PPT and status quo, annually under the following PPT plans at \$20, \$40, and \$60/bbl:

- a. 25/20
- b. 30/20
- c. 30/15

TO BE PROVIDED

71. Please show the corporate take chart on page 24 of Mr. Marks' presentation given the following tax/credit scenarios:

- a. 25/20
- b. 30/20
- c. 30/15

TO BE PROVIDED

72. Please show the price point where DOR estimates corporate profit margins hit 15% and 20%.

TO BE PROVIDED

**Attachment A1 (Question 30)**

**Effective Tax Rates, North Slope by Field, FY86 - FY05**

	<b>Prudhoe Bay</b>	<b>Midnight Sun</b>	<b>Polaris</b>	<b>Orion</b>	<b>Aurora</b>	<b>Borealis</b>					
FY86	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.07%	0.00%	0.00%	0.00%	0.00%
FY87	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.47%	0.00%	0.00%	0.00%	0.00%
FY88	12.66%	0.00%	0.00%	0.00%	0.00%	0.00%	8.33%	0.00%	0.00%	0.00%	0.00%
FY89	12.33%	0.00%	0.00%	0.00%	0.00%	0.00%	8.71%	0.00%	0.00%	0.00%	0.00%
FY90	14.71%	0.00%	0.00%	0.00%	0.00%	0.00%	12.89%	0.00%	0.00%	0.00%	0.00%
FY91	14.91%	0.00%	0.00%	0.00%	0.00%	0.00%	13.19%	0.00%	0.00%	0.00%	0.00%
FY92	14.90%	0.00%	0.00%	0.00%	0.00%	0.00%	13.33%	0.00%	0.00%	0.00%	0.00%
FY93	14.85%	0.00%	0.00%	0.00%	0.00%	0.00%	13.34%	0.00%	0.00%	0.00%	0.00%
FY94	14.81%	0.00%	0.00%	0.00%	0.00%	0.00%	13.09%	0.00%	0.00%	0.00%	0.00%
FY95	14.76%	0.00%	0.00%	0.00%	0.00%	0.00%	12.85%	0.00%	0.00%	0.00%	0.00%
FY96	14.67%	0.00%	0.00%	0.00%	0.00%	0.00%	12.35%	0.00%	0.00%	0.00%	0.00%
FY97	14.59%	0.00%	0.00%	0.00%	0.00%	0.00%	11.72%	0.00%	0.00%	0.00%	0.00%
FY98	14.44%	0.00%	0.00%	0.00%	0.00%	0.00%	11.38%	0.00%	0.00%	0.00%	0.00%
FY99	14.23%	0.00%	0.00%	0.00%	0.00%	0.00%	10.53%	0.00%	0.00%	0.67%	0.00%
FY00	13.96%	0.00%	0.00%	0.00%	0.00%	0.00%	8.97%	0.00%	0.00%	0.58%	0.00%
FY01	13.76%	0.00%	0.00%	0.00%	0.00%	0.00%	7.40%	0.00%	0.00%	0.05%	0.00%
FY02	13.44%	0.13%	0.00%	0.00%	0.00%	0.96%	5.29%	0.00%	0.00%	0.52%	0.00%
FY03	13.05%	0.10%	0.00%	0.00%	0.00%	1.40%	3.44%	0.00%	0.00%	1.22%	0.00%
FY04	12.82%	0.00%	0.00%	0.00%	0.00%	1.03%	2.70%	0.00%	0.00%	0.84%	0.00%
FY05	12.65%	4.43%	4.43%	3.63%	3.62%	3.69%	0.76%	0.00%	0.00%	0.15%	0.00%

Note: The effective tax rate for Midnight Sun, Polaris, Orion, Aurora, Pt. McIntyre, and Borealis for FY 05 reflects 5 months' effect of the aggregation decision effective Feb. 1, 2005.

**Attachment A2 (Question 30)**

	Millie Point	Endicott	Elder	Liaburne	Point McIntyre	Niakuk	West Beach	NPBS	Alpine	Northstar
FY86	2.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY87	0.62%	0.00%	0.00%	4.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY88	0.00%	8.17%	0.00%	7.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY89	0.00%	12.25%	0.00%	6.25%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY90	0.00%	10.37%	0.00%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY91	0.00%	9.44%	0.00%	0.09%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY92	0.00%	9.51%	0.00%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY93	0.00%	11.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY94	0.00%	11.53%	0.00%	0.00%	7.28%	1.56%	0.00%	0.00%	0.00%	0.00%
FY95	0.00%	11.30%	0.00%	0.00%	11.30%	6.15%	0.00%	0.00%	0.00%	0.00%
FY96	0.00%	10.39%	0.00%	0.00%	11.60%	1.76%	0.00%	0.00%	0.00%	0.00%
FY97	0.29%	7.10%	0.00%	0.00%	11.63%	1.51%	0.00%	0.00%	0.00%	0.00%
FY98	0.46%	4.54%	0.00%	0.00%	11.29%	0.89%	0.00%	0.00%	0.00%	0.00%
FY99	0.64%	1.29%	0.00%	0.00%	11.75%	0.70%	0.00%	0.00%	0.00%	0.00%
FY00	0.38%	0.73%	0.00%	0.00%	9.45%	1.32%	0.00%	0.00%	0.00%	0.00%
FY01	0.16%	0.13%	0.00%	0.00%	6.47%	0.17%	0.00%	0.00%	4.24%	0.00%
FY02	0.02%	0.02%	0.00%	0.00%	3.10%	0.15%	0.00%	0.00%	10.76%	5.14%
FY03	0.00%	0.01%	0.00%	0.00%	2.40%	0.02%	0.00%	0.00%	10.50%	10.59%
FY04	0.00%	0.00%	0.00%	0.00%	1.63%	0.00%	0.00%	0.00%	10.33%	10.37%
FY05	0.00%	0.00%	0.00%	0.00%	4.78%	0.00%	0.00%	0.00%	10.17%	10.18%

**Attachment B (Question 58)**

By: G. Rogers, March 1, 2006, source  
 DNR

**NPS LEASES, NPS RATES & ROYALTY RATES & STATUS**

Unit - lease number	Royalty Rate	NPS Rate	NPS Status
<b>Duck Island</b>			
1	312828	20%	79.5935% in payout
2	312834	20%	48.8703% in payout
<b>Milne Point</b>			
3	355016	12.5%	40.0000% in payout
4	355017	12.5%	40.0000% in payout
5	355018	12.5%	30.0000% in payout
6	355021	12.5%	30.0000% in payout
7	388235	12.5%	30.0000% in payout
<b>Kuparuk River</b>			
8	355023	12.5%	30.0000% not in payout
9	355024	12.5%	30.0000% not in payout
10	355030	12.5%	30.0000% not in payout
11	355032	12.5%	30.0000% not in payout
<b>Colville River</b>			
12	364470	12.5%	30.0% non producing
13	364471	12.5%	30.0% non producing
14	364472	12.5%	30.0% non producing
15	364477	12.5%	30.0% non producing
16	364478	12.5%	30.0% non producing
<b>Point Thompson Unit</b>			
17	312866	20%	52.352% non producing
18	343109	12.5%	40% non producing
19	343110	12.5%	40% non producing
20	343111	12.5%	40% non producing
21	343112	closed	closed non producing

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March 2, 2006