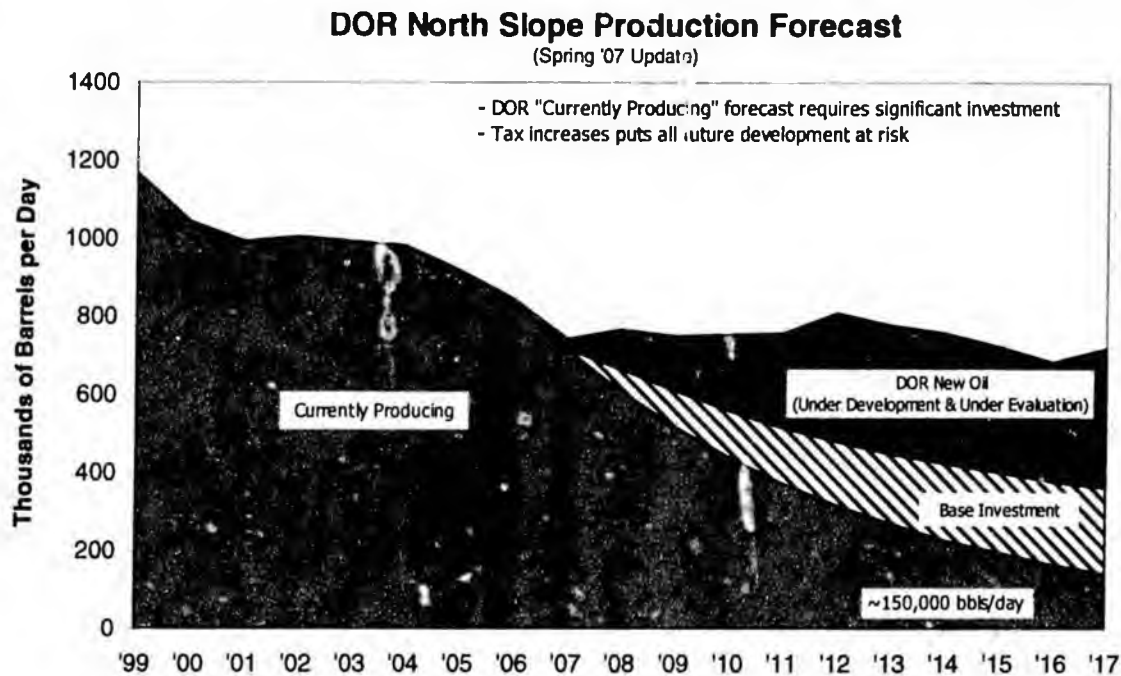


ALASKA LEGISLATURE COMMITTEE FILES 2007-2008 SRES 12711.

projected oil production in 10 years will come from new investments. Let me say that again, 50% of future oil production in 10 years is not even developed or producing today. Considering that most new projects take at least 5-7 years to bring to production on the North Slope, investment decisions for these activities, particularly in the near term, will be critical to underpin the future of Alaska's oil production.

As I mentioned earlier, the Department of Revenue forecast is based on a 9% annual decline in Alaska's current base production. However, this decline assumes that production enhancement investments at the core Prudhoe Bay, Kuparuk and Alpine areas continue. The Department of Revenue forecast, as shown, does not highlight that this activity requires investment decisions that are no different from the "Under Development and Under Evaluation" categories. As such, a more accurate representation of the future oil production and investment levels required to achieve the Department of Revenue forecast is illustrated in the following chart.



As this chart shows, Alaska's oil production from the North Slope could be as low as 150,000 barrels per day within 10 years, (assuming 15% decline, which is typical for large oil fields such as Prudhoe Bay), without ongoing and increasing investment. Based on this forecast, within 10 years, 75% of production will come from new investments.

Conservatively, we estimate that at least \$30-40 billion of investment is required within the next 10 years to achieve the Department of Revenue forecast. This does not include the billions of dollars of additional operating expenditures that would be required to support the developments once they are producing. This is a significant level of future investment and spending.

The high tax rate in PPT and the proposed tax increase put this investment at significant risk. Alaska needs to encourage the increasing investments required, not only in exploration activities, but also in the ongoing development of existing and new fields.

**ALASKA IS A HIGH COST REGION**

Complicating the significant future investments required to mitigate Alaska's production decline is its high costs. Alaska has unique challenges resulting in a high cost environment for exploration and development and very mature producing fields with growing unit costs. Many factors contribute to Alaska's higher costs including:

- Severe arctic conditions, placing limitations on when drilling and other operations can be undertaken
- A sensitive environment, requiring significant and due diligence measures to protect it
- Remote location of the resource and distance to market
- Current restrictions for future exploration opportunities

All combine to create a unique and high cost environment for Alaska.

**ALASKA'S SO-CALLED LEGACY FIELDS**

The two largest oil fields in Alaska - Prudhoe Bay and Kuparuk, have been producing since 1977 and 1981, respectively. Today these two fields account for over 70% of the State's North Slope oil production. Assuming that exploration and investment activity continues in these fields, they could remain at this level of production contribution for the next decade.

These so called legacy fields require continuous investment to keep the oil flowing and the facilities operating at capacity. This is the same for any oil field in the world. During the production phase there are many changes in operating parameters, such as reservoir pressure changes, oil, gas and water production changes, changes in operating conditions, and ongoing technical challenges. In order to keep the oil flowing these changes require additional investments, such as the addition of water and gas injection and gas compression facilities, which are historical significant investments at Prudhoe Bay.

Currently, the owners spend over \$2 billion dollars to optimize and enhance production from Prudhoe Bay and Kuparuk. These spending levels are in addition to the capital investments pursuing new wells, projects, and enhanced oil recovery opportunities. These operating expenditures are essential to mitigate production decline at these significant fields, which are critical to the future of Alaska's North Slope oil production.

Many of today's exploration and development activities are occurring in and around Prudhoe Bay and Kuparuk.

As an example, since the year 2000 there have been multiple Prudhoe Bay satellite fields developed - Aurora, Borealis, Midnight Sun, Polaris, and Orion - which are currently contributing over 40,000 B/D of oil production. These developments would not have been possible without the infrastructure and facility sharing of Prudhoe Bay, which reduced the development and operating costs of these satellites. As satellite fields are developed it reduces exploration and development costs for future new projects, as the infrastructure on the North Slope expands.

If the major Prudhoe Bay and Kuparuk developments did not exist these satellite fields would not have been economic to develop.

As another example, for the past seven years over 900 new wells have been drilled in Prudhoe Bay and Kuparuk. The drilling of these new wells has slowed the overall production decline from 12-15% to an estimated 6-9%. Almost 40% of Prudhoe Bay's production today is from these new wells.

For the past two years, development drilling at Prudhoe Bay has achieved the equivalent of the important Oooguruk development. This example highlights the importance of exploring for and developing new oil in and around the Prudhoe Bay and Kuparuk fields – all are important to the economic benefit and future of Alaska.

Let me re-emphasize that Prudhoe Bay and Kuparuk have the potential to continue to be critical contributors to Alaska's oil production. They have the potential to remain key hubs and enablers for exploration and development of heavy or viscous oil, light oil and gas. Encouraging increasing investment at these key fields is as important as encouraging investment in exploration and development of new fields. Without these two hubs, Alaska will be severely challenged to realize the full potential of its resources.

Progressing a tax policy that singles out and penalizes these fields will discourage investment not only at these fields but will also impact future investment attractiveness to explore and develop other Alaska oil and gas resources.

#### **PROPOSED TAX INCREASE MORE COMPLICATED**

In analyzing the Administration's tax proposal, we found that virtually all of the provisions are simply tax rate increases or further increases in complexity.

As an example, under the Administration's proposed tax increase the two so-called Legacy Fields, Prudhoe Bay and Kuparuk, would have a separate 10% gross minimum tax and be segregated from each other and all other North Slope fields. This gross tax would be in addition to the base royalty payments. With this minimum gross tax the State would be insulated from price and cost risks, whilst retaining the upside potential from the progressivity element. The Administration is simply proposing to increase its take while shifting the development risks to the producers. Essentially, at low price, producers are penalized.

October 25, 2007

Companies are willing to accept the risks of long-term, capital intensive investments when there is a corresponding opportunity for upside potential and a sharing of risk should prices fall. Under the Administration's proposed tax increase, investors will need to assume a higher economic risk when making funding decisions for future investments and spending.

The Administration has also proposed that all revenues and expenses for the Legacy Fields will have to be accounted for separately, with separate taxes paid for each unit and their satellites. This would include Alaska's heavy or viscous oil reserves produced from those Legacy Fields - a resource that already has significant economic and technical hurdles to overcome. No other fields, units or regions within the state would be subjected to these administrative burdens.

The ring-fencing of the Prudhoe Bay and Kuparuk Units makes the tax proposal more complex than the existing PPT.

**EXXONMOBIL POSITION ON THE ENACTED PPT**

I believe it is important that I clarify ExxonMobil's position on the current PPT.

ExxonMobil did not support the PPT that was enacted last year. As we testified last year, we supported the concept of a net based tax but stated that the proposed 20% tax rate, in the original PPT bill, would not encourage the full development of Alaska's resources. We agreed with the 20% tax rate in order to support the progression of a gas pipeline project.

The PPT that was ultimately enacted increased the already high 20% base tax rate to 22.5% with progressivity - more than doubling industry's taxation. Alaska's current PPT tax rate is too high. When combined with the gross royalties and the high development and operating costs, it makes Alaska one of the most expensive regions to invest.

There has been a lot of discussion recently on PPT revenues and forecasts, which has been used in part to support the Administration's proposal to increase taxes. PPT has only been in existence for slightly more than one year. The Department of Revenue has not completed its PPT regulations or started any PPT audit. ExxonMobil, like a number of the other producers, met with the Department of Revenue several months ago to discuss ways to help the State better forecast its expected PPT revenues and we are willing to continue those efforts. We are also willing to work with DOR auditors to improve their understanding of joint interest billings.

**FISCAL PREDICTABILITY IS IMPORTANT**

I would now like to address another important element of the business environment - fiscal predictability. ExxonMobil, and I believe the industry, values a predictable fiscal environment in which to make long term investment decisions. Our investments are capital intensive and are evaluated over timeframes of decades. Any change in the fiscal regime has a direct impact on how we view predictability of the Alaskan fiscal environment, which in turn directly impacts how we evaluate on a risk basis future investment decisions. Let me reemphasize this point. Because of the nature and magnitude of the risks associated with any oil or gas investment, coupled with the amount of time required to recoup that investment, fiscal terms that are predictable are key to any investment decision.

The Administration's proposed tax increase would represent the third significant change to Alaska's fiscal terms in the past three years. Changing the fiscal environment for capital intensive projects, that take many years to generate a return, can only reduce the attractiveness of future investments. Each time taxes are raised, the attractiveness of any prospective well or project diminishes and the likelihood of it not being funded increases. For every well or project not progressed, additional production and State revenues are lost. As mentioned earlier, to mitigate oil production decline Alaska needs to increase investment. The Administration's proposed tax increase will reduce investment.

ExxonMobil expects to be involved in Alaska for many years to come. The policies established today and in the future will impact the attractiveness of future potential projects and the future of Alaska.

**ALASKA NEEDS A LONG-TERM RESOURCE DEVELOPMENT POLICY**

As I mentioned earlier, Alaska has significant resource potential, but with many unique cost challenges. It will take significant resources, technology, investment and teamwork from everyone to realize the full potential. Alaska and industry collaboratively need to create a resource development policy that encourages investment for long-term production and growth. This is a complex issue and needs significant time and effort from all parties. It is beneficial to look at what others have done.

The Canadian province of Alberta has enormous unconventional crude oil resources. Alberta's oil sands represent the potential of over 170 billion barrels of crude, and, like Alaska's resources, are located in higher cost, remote arctic regions that require significant investments to develop.

Alberta adopted a resource development policy approach, designed to increase industry investment and production. Their approach has proven successful due to a number of key factors:

- Collaborative pursuit of resource development objectives
- Development of technologies jointly with industry to reduce costs, increase oil recovery, and upgrade viscous oil to marketable products
- Creation of a level playing field for all projects
- Sharing risks with the investors by maintaining a lower gross revenue based tax, that is, lowering royalties significantly
- Providing long term fiscal predictability

Alberta's success suggests that Alaska should seriously consider what other regions are doing to encourage investment.

A long-term sustainable resource development policy is required to enable Alaska to maximize its oil and gas resource. There are many factors that need to be considered. It is a complex issue. I hope that key points addressed in my testimony are considered:

- Alaska has significant resource potential, but it is in a high cost environment
- Oil production is already one third of its peak, yet we have only produced one fourth of the oil resource potential
- In 10 years, 75% of Alaska's future oil production needs over \$30-40 billion of new investments - investments that are needed sooner than 10 years.
- Prudhoe Bay and Kuparuk are the "hub" of the North Slope, they
  - Represent 70% of North Slope oil production for the next 10+ years
  - Can be the backbone for future exploration and economic developments, whether it is existing production, future light oil, heavy oil, or gas
  - Need increasing investments to achieve their potential
- Development drilling at Prudhoe Bay and Kuparuk over the last 2 years has added 50,000 B/D of new oil production in 2007

We propose a collaborative approach to develop a sustainable long term resource policy that will encourage the needed increasing investments and build the future of Alaska for many generations to come. ExxonMobil looks forward to working with the Administration, the legislators, industry and the people of Alaska in the future pursuit and development of its oil and gas resources.

October 25, 2007

To encourage full development of Alaska's resources, the PPT tax rate needs to be lowered, and should not include a gross revenue based component. Increasing investment fuels the economy.

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

**SB**

**2001**

**(FILE 27)**

**FINEBERG**

Transportation  
Talking points

## Amendments to AS 43.55.150<sup>1</sup>

### General Comments

→ The following changes to existing production tax statute dealing with transportation deductions will enable ADOR to reduce the deduction for TAPS tariffs for shippers operating at less than arm's length without similarly penalizing independent shippers or producers, and without creating problems for tanker auditors.

→ The effect of this amendment will be to increase production tax revenues by an estimated \$100 million to \$160 million per year, depending on throughput levels, filed tariffs and prices. That money will come to the state treasury from the major owners of TAPS, who will still be earning a just and reasonable profit on their pipeline investment.

→ In addition to generating general fund revenue, this amendment will send a signal that the state is truly committed to leveling the North Slope playing field for independent developers.

### Background

The amendments to AS 43.55.150(a) and (b), as discussed and passed by both the House Resources and Senate Judiciary Committee and forwarded to their respective Finance Committees, would prevent TAPS owners shipping their own oil from taking a high deduction for transportation when they actually incur much lower costs for shipping their own oil.<sup>2</sup> The higher transportation deduction results in significantly lower production tax payments to the state for the shipper/owner, costing the state an estimated \$160 million per year at current pipeline throughput and tariff levels.<sup>3</sup> Subsequent to passing out of both committees, the administration recognized the need for the addition of clarifying language to assure that these amendments accomplished their purpose; that language was added to the existing statutory language on the attached draft.

### Final Comment

Since 2002, regulatory and court decisions that have consistently confirmed that the state has lost more than \$2 billion during the 30-year history of TAPS;<sup>4</sup> as noted above, the administration estimates that the state stands to gain \$160 million / year through the proposed correction to the PPT. As a matter of fairness – and, more importantly, to encourage independent development – I believe it is important to enact the appropriate statutory fix to remedy the aspects of this problem relating to the PPT during this Special Session.

<sup>1</sup> Attached amendment contains all of the administration's recommended modifications to AS 43.55.150.

<sup>2</sup> Secs. 52 and 53 of CSSB 2001(JUD) (version 25-GS0014\L) and Secs. 48 and 49 of CSHB 2001(RES).

<sup>3</sup> Estimate by Antony Scott, Department of Natural Resources, to Senate Judiciary Committee, Oct. 30, 2007. The reduction in production tax payments due to tariff overcharges accrues to the TAPS owners – not to the independent producer or shipper (see spreadsheets attached to my memos of Oct. 29 [rev5] and Nov. 5, 2007).

<sup>4</sup> References to source information on historical and current TAPS tariff issues can be found at <http://www.finebergresearch.com>.

AS 43.55.150(a) is amended to read:

(a) For the purposes of AS 43.55.011 - 43.55.180, the gross value at the point of production is calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation are the actual costs, except when the

(1) shipper [PARTIES TO THE TRANSPORTATION] of oil or gas is [ARE] affiliated with the transportation carrier or with a person that owns an interest in the transportation facility;

(2) contract for the transportation of oil or gas is not an arm's length transaction [OR IS NOT REPRESENTATIVE OF THE MARKET VALUE OF THAT TRANSPORTATION]; or [AND]

(3) method or terms of transportation of oil or gas is not reasonable in view of existing alternative [METHODS OF] transportation options.

AS 43.55.150(b) is amended to read:

(b) If the department finds that a condition [THE CONDITIONS] in (a)(1), (2), or [AND] (3) of this section is [ARE] present, the department shall determine the reasonable costs of transportation, if lower than actual costs, using the fair market value of like transportation, the fair market value of equally efficient and available alternative modes of transportation, or other reasonable methods; for marine transportation, the department may determine that reasonable costs are actual costs. Transportation costs fixed by tariff rates that have been adjudicated as just and reasonable by [PROPERLY ON FILE WITH] the Regulatory Commission of Alaska or other regulatory agency and transportation costs paid by parties not affiliated with an owner of the method of transportation in an arm's length transaction shall be considered prima facie reasonable.

Note: The phrases "for marine transportation, the department may determine that reasonable costs are actual costs" and "and transportation costs paid by parties not affiliated with an owner of the method of transportation in an arm's length transaction" have been added to earlier drafts to accommodate concerns recently expressed. - Nov. 11, 2007

### **What We Know about Petroleum Pipeline Tariff Levels (Historical Lessons)**

With 95% overlap between Major Producers and Major TAPS Owners, the state's tax and royalty structure creates incentive to inflate tariffs

Excessive tariffs create two classes of producers on the North Slope:

- independents (non-pipeline owners), who are severely handicapped by excessive tariffs;
- TAPS owners, who are not.

Due to its royalty and tax interest in tariffs, the State is also severely penalized by inflated tariffs.

Litigation is a flawed but potentially effective means to deal with these problems. Litigation success – defined as an appropriate outcome – is problematical. Moreover, tariff litigation is liable to take 10 years to complete.

- Independent shippers may lack the standing or the resources to challenge excessive tariffs.
- Historically, state participation in litigation has been less than effective due to agency structure and workload and political vicissitudes.

### **Petroleum Pipeline Tariff Levels Today (Current Situation)**

In 2002, the RCA culminated a 6-year challenge to TAPS tariffs by independent shipper Tesoro with an order reducing tariffs under the 1985 TAPS Settlement Methodology (TSM) from approximately \$3.05/bbl. to \$1.96/bbl. The RCA ruling rendered the 1985 TSM irrelevant to current rates for oil under its jurisdiction – approximately 11% of the oil shipped on TAPS.

Although the state was publicly committed to standing "in the shoes" of the shippers, in 2004, the State, which had opposed Tesoro's efforts for seven years, joined the owners in a court challenge to the RCA ruling; in 2006, State Superior Court ruled in favor of the RCA "in every respect." That ruling was challenged by the TAPS owners before the State Supreme Court, which heard the argument in March 2007.

Meanwhile, under the TSM methodology, the TAPS Owners have increased tariffs on the remaining 89% of TAPS oil to approximately \$5.11/bbl.

Independent Shippers Anadarko and Tesoro have appealed the tariff at FERC; the FERC Trial Staff supported the A/T position; in May 2007, the FERC Administrative Law Judge (ALJ) hearing the case adopted A/T numbers and recommended the FERC reduce tariffs to approximately \$2.04/bbl.

Meanwhile, the higher tariffs remain in place for 89% of TAPS oil – to the detriment of state revenue and the open competition that would encourage North Slope development.

### **Fiscal Consequences**

Unlike pipeline owners (for whom excess charges are an internal transfer), independent producers pay excess tariffs out of pocket.

As a result, under the higher TSM tariff on 89% of TAPS oil the independent shipper clears about \$1.97/bbl. less than the TAPS owner on production and sale of a similar barrel of North Slope crude.

Primarily because transportation charges are subtracted from the tax and royalty base, under the TSM tariff the State loses approximately \$0.90/bbl. on overcharges in reduced royalties and production taxes.

### Recommended Solution

Going forward, correcting this problem for production taxes through AS 43.55.150 would get roughly half that revenue back immediately and would send a positive signal to potential independent investors. Note, however, that this is only a partial remedy to state petroleum pipeline tariff management issues.

An immediate correction to production tax effects is preferable to waiting for the conclusion of court decisions on past tariffs for two reasons: (1) Full refunds are always problematical; and (2) continued litigation over them would exacerbate uncertainty (adversely affecting the investment climate).

However, this "fix" must be carefully crafted to avoid harming the independent producers / shippers by causing them to pay higher production taxes without reducing their actual tariff payments (which are not regulated under AS 43.55).

Immediate correction of production tax tariff calculations also helps chart a clear course on present and potential future ratemaking proceedings.

### Classes of Shippers / Effects

TAPS Owner Shipping on Own Pipeline:

- Pockets Excess Charges

TAPS "Net Shipper" Owner Shipping on Another's Pipeline:

- With excess capacity on pipeline, the possibility exists for some shippers that lower tariffs on one carrier's pipeline may offset the higher tariffs on another's. Moreover, for the small percentage of barrels shipped under a co-owner's tariff, this is a problem of the TAPS owners' own making through their opposition to a single tariff on TAPS, adopted by the RCA and recommended by the FERC ALJ.<sup>1</sup>

Independent Producer/Shipper:

- The production tax levy under AS 43.55 requires calculation of transportation charges but does not actually set the tariff. Therefore, to avoid further penalizing the independent shipper by increasing production tax levy without reducing the actual tariff, the recommended statutory "fix" is designed to exempt independent Producer/Shippers who are still paying the higher tariff from the proposed production tax correction.

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<sup>1</sup> CY 2007 tariffs filed at FERC are:

BP (46.93%)	\$5.10 / bbl.
ConocoPhillips (28.29%)	\$5.29 / bbl.
Exx/Mobil (20.34%)	\$4.95 / bbl.
Koch (3.08%)	\$4.75 / bbl.
Unocal (1.36%)	\$4.63 / bbl.
<i>Weighted Avg. Tariff</i>	<i>\$5.11 / bbl.</i>

(State of Alaska, "Protest and Petition for Investigation into the Proposed 2007 TAPS Tariffs by the State of Alaska and Intervention in These and Any Subsequent Related Proceedings," Dec. 13, 2006 [FERC Docket # IS07-62-000, etc.], p. 8.)

CY 2006 filed tariffs were:

BP (46.93%)	\$4.08 / bbl.
ConocoPhillips (28.29%)	\$3.78 / bbl.
Exx/Mobil (20.34%)	\$3.93 / bbl.
Koch (3.08%)	\$4.41 / bbl.
Unocal (1.36%)	\$4.38 / bbl.
<i>Weighted Avg. Tariff</i>	<i>\$3.98 / bbl.</i>

(Regulatory Commission of Alaska, "Order Rejection 2006 Intrastate TAPS Methodology Rates," Docket P-06-01, Order No. 1, Dec. 16, 2005, p. 3.)

**Sharon Long**

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**From:** Davis, Marcia R (DOR) [marcia.davis@alaska.gov]  
**Sent:** Tuesday, November 06, 2007 4:04 PM  
**To:** Sharon Long; stevenbporter@gmail.com  
**Subject:** One word fix from Fineberg

Here was what Richard sent me today. This is a one word change for Jud Section 53 which affects .150(b):

**Amend Sec. 53 (AS 43.55.150(b) of CSSB 2001(JUD) at p. 36, line 29 by changing "shall" to "may."**

This was Richard's explanation of why change was needed:

**The Problem**

The operational change in the deduction for TAPS shipping charges is set in motion by the Senate Judiciary Committee's proposed change to AS 43.55.150(b) of "and" to "or" at Line 29 of p. 36 (Sec. 53). This amendment requires the Department of Revenue to determine the reasonable costs of transportation if any of the conditions in AS 43.55.150(a) are present; one of those conditions is that the contract for transportation is not representative of the market value of that transportation.<sup>2</sup> A principal purpose of this pair of amendments, as discussed in both committees, is to prevent TAPS owners shipping their own oil from taking a high deduction for transportation when they actually incur much lower costs for shipping their own oil. The higher transportation deduction results in lower production tax payments to the state for the shipper/owner.<sup>3</sup>

The problem is that the amendment to AS 43.55.150(b), as passed, would also require the Department of Revenue to reduce the deduction for TAPS tariffs for an independent shipper shipping under the higher tariff, even though the independent shipper actually pays the higher tariff to the TAPS owner.

### Attachment I. Proposed Statutory Language

**The following amendments to AS 43.55.150(a) and (b)** will enable the Department of Revenue to assure just and reasonable tariffs are applicable to production tax collections under AS 43.55 when producers or shippers do not have an arms' length relationship with the pipeline owners. The proposed amendments to AS 43.55.150 (below) rest on the understanding that transportation charges determined by ratemaking mechanisms – including filed tariffs, tariffs filed in accord with an approved settlement agreement and litigated tariffs – may not ensure that shipping charges are reasonable. Experience shows that state revenue and exploration and development by independent companies suffer when the overlap between pipeline owners and shippers removes the shipper's incentive to secure just and reasonable tariffs from the pipeline owner. Therefore, it is recommended that:

AS 43.55.150(a) is amended to read:

**Sec. 43.55.150. Determination of gross value at the point of production. (a)**

For the purposes of AS 43.55.011 – 43.55.180, the gross value at the point of production is calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation are the actual costs, except when the

(1) **both** parties to the transportation of oil or gas are affiliated, **for example, as subsidiaries of the same corporation or as co-owners of the pipeline:**

(2) contract for the transportation of oil and gas is not an arm's length transaction **and** [OR] is not representative of the value of that transportation; **or** [AND]

(3) method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

AS 43.55.150(b) is amended to read:

(b) If the department finds that **a** [THE] condition[S] in (a)(1), (2) **or** [AND] (3) **is** [ARE] present, the department **may** [SHALL] determine the reasonable costs of transportation, using the fair market value of like transportation, the fair market value of equally efficient and available alternative modes of transportation, or other reasonable methods. [TRANSPORTATION COSTS FIXED BY TARIFF RATES PROPERLY ON FILE WITH THE REGULATORY COMMISSION OF ALASKA OR OTHER REGULATORY AGENCY SHALL BE CONSIDERED PRIMA FACIE REASONABLE.]

**The following proposed amendment to AS 42.06.140(a)(10)** would vest responsibility for formulating tariff policy with the Department of Natural Resources.

AS 42.06.140(a), which enumerates the powers of the Regulatory Commission of Alaska (RCA), should be amended at subsection (10) to state that the RCA "shall provide all reasonable assistance to the Department of **Natural Resources** [LAW] in intervening in, offering evidence in, and participating in proceedings involving a pipeline carrier or an affiliated interest and affecting the interests of the state, before an officer, department, board, commission or court of another state or the United States."

### **Attachment II. Worksheets**

The following worksheets show how the various elements of petroleum prices, production, pipeline charges and government tax and royalty collections fit together to produce industry and government net revenue shares. Figure 1 shows how pipeline tariffs affect net revenues from Alaska petroleum operations. Figure 2 uses the same framework to delineate the differential effects on a pipeline owner shipping its own oil, v. an independent producer or shipper transporting its oil on TAPS (shown in Figure 2). This distinction is crucial to understanding the ways in which the overlap between the major North Slope producers and the TAPS owners handicaps independent North Slope operators.

Figure 1

## Estimated Industry-Wide Pipeline Tariff Effect on ANS Net Revenue Share (Production + Pipelines; \$60 / bbl.)

\$60 / bbl. case – Hypothetical Example – CY 2007 (Estimated from Public Data Sources)

<b>Major ANS Cost and Profit Elements *</b>	<b>How Calculated . . .</b>	<b>TSM Tariff</b>	<b>(Share %)</b>	<b>RCA Tariff</b>	<b>(Share %)</b>
1 ANS Market Price	(Assumed)	\$60.00		\$60.00	
2 TAPS Tariff	Approx. 2007 TSM (FERC) and RCA Tariffs	(\$5.10)		(\$1.96)	
3 Other Transportation	Est. \$0.60 Feeder P/L Tariff + \$1.80 Tanker	(\$2.40)		(\$2.40)	
4 Production Tax & Royalty Base	Sum of Lines 1 thru 3	\$52.50		\$55.64	
5 Royalty	((Line 4) less est. processing costs) * 0.125	(\$6.44)		(\$6.83)	
6 Operating and Capital Costs <sup>(1)</sup>	Estimated at \$4.00 lifting + \$4.00 capital	(\$8.00)		(\$8.00)	
7 Production Tax	18.7% per CS HB 3001 Fiscal Note graph	(\$7.12)		(\$7.63)	
8 Property Tax (including TAPS)	From ADOR Revenue Sources data	(\$1.00)		(\$1.00)	
9 Industry Production Profit (before income tax)	Sum of Lines 4 thru 8	\$29.94		\$32.18	
10 State Income Tax (Production) <sup>(2)</sup>	Est. (565.1/279.6) - (Line 14)	(\$1.69)		(\$1.98)	
11 Fed. Income Tax (Production)	(Sum of Lines 9 + 10) * 0.35	(\$9.89)		(\$10.57)	
12 Industry After-Tax Production Profit	Sum of Lines 9 thru 11	\$18.37		\$19.60	
13 Industry Pre-Tax Pipeline Profit <sup>(3)</sup>	TAPS + Feeder Line Profit	\$3.57		\$0.43 <sup>(3)</sup>	
14 State Income Tax (Pipeline)	(Est. Pre-Tax Tariff Profit) * 0.094	(\$0.34)		(\$0.04)	
15 Federal Income Tax (Pipeline) <sup>(2)</sup>	(Sum of Lines 13 + 14) * 0.35	(\$1.13)		(\$0.14)	
16 Industry After-Tax Pipeline Profit	Sum of Lines 13 thru 15	\$2.10		\$0.25	
<b>17 Total Alaska Net Revenue Share</b>	Sum of Lines 5, 7, 8, 10 and 14	<b>\$16.58</b>	<b>34.49%</b>	<b>\$17.48</b>	<b>36.37%</b>
<b>18 Total Federal Net Revenue Share</b>	Sum of Lines 11 + 15	<b>\$11.02</b>	<b>22.93%</b>	<b>\$10.70</b>	<b>22.27%</b>
<b>19 Industry After-Tax Net Revenue Share</b>	Sum of Lines 12 + 16	<b>\$20.47</b>	<b>42.58%</b>	<b>\$19.88</b>	<b>41.36%</b>

**Notes:**

- \* Assumed ANS production of 766,000 barrels per day (Spring 2007 Revenue Sources FY 2007 - 08 avg); additional information on calculating factors on pp. 2, 3.
- (1) Production costs fixed for purposes of this analysis.
- (2) State Income Tax estimated from Spring 2007 Revenue Sources (assumes all calculated industry net revenues are captured by the state and federal government at nominal income tax rates).
- (3) Pipeline tariff totals include estimated pre-tax profit from North Slope feeder pipelines + TAPS from Line 3. (See page 3 of this worksheet for estimated tariff calculations.) The difference between FERC (TSM) and RCA tariff (shown here as \$3.16 per barrel) is assumed to be industry pre-tax profit.

**Fig. 1. Estimated Industry-Wide Pipeline Tariff Effect on ANS Net Revenue Share (Production + Pipelines; \$60 / bbl.)**

**Line 2**

**TSM Tariff** shows the weighted average TAPS tariff charged in 2007 for 89% of TAPS oil regulated by FERC (\$5.10 / bbl.); this line includes profit on TAPS operations (see discussion in text).

**RCA Tariff** shows the TAPS tariff charged in 2007 for 11% of TAPS oil regulated by the RCA (\$1.96 / bbl.); this line includes allowed just and reasonable profit on TAPS operations (see discussion in text and p. 3 for tariff calculating inputs).

**Line 3**

This line includes the tariff element for North Slope feeder pipelines (estimated \$0.64 per barrel; see page 3 for tariff calculating inputs) and marine transportation charges.

**Line 4**

The reduced RCA tariff increases the production tax and royalty base for in-state oil. Because three companies that produce approximately 95% of North Slope oil also own a similar percentage of TAPS, tariff payments result in an internal transfer of funds and this is just a bookkeeping entry. But the independent shipper pays the entire tariff out of pocket. The results of this unusual circumstance are estimated in lines 5, 7, 10, 11 and 13 below

**Lines 5, 7, 10 and 11**

These elements of the government net revenue share are higher in the "RCA Tariff" column because the reduced tariff charge for in-state shipments increased the tax and royalty base in this column at Line 4. (Note that if a company pays less than the nominal income tax rate, government share estimates at Lines 10 and 11 may be overstated.)

**Line 13**

Since the RCA tariff includes a just and reasonable profit on allowable costs, the \$5.10 tariff in the "TSM Tariff" column does not represent an actual cost. The difference between the two tariffs is added into industry pre-tax profits here. (This line also includes a similar estimated excess profit from North Slope feeder line operations.)

**Lines 14, 15**

If a company pays less than the nominal income tax rate, these elements of government net revenue share also may be overstated.

**Lines 17, 18 and 19**

Bottom-line net revenue shares are summarized by adding net revenue from Alaska production and pipeline operations.

Figure 1

**Estimated Industry-Wide Pipeline Tariff Effect on ANS Net Revenue Share (Production + Pipeline; \$60 / bbl.)**

*This page reproduces the calculating values used to derive the estimated pipeline profits shown in Line 13 of Figure 1.*

**Estimated North Slope Feeder Line Revenue, SIT, FIT and Profits**

Estimated North Slope feeder line profits on \$0.64bbl.

0.64000	Average FY2006 - 2007 tariffs, Spring 2007	<i>Revenue Sources</i> , pp. 94-95)
0.10484	Total feeder line pre-tax profit (grossed up to allow 12% after-tax return on allowable costs)	
0.09400	Nominal SIT Rate (9.4%)	
0.00985	per-barrel SIT	
0.09498	Pre-tax profit - SIT	
0.35000	Nominal FIT rate (35%)	
0.03324	per-barrel FIT	
<u>0.04310</u>	SIT - FIT	
0.06174	After-Tax Profit (\$0.095 - SIT - FIT)	

**Estimated TAPS Costs, Revenue, SIT, FIT and Profits**

Estimated TAPS pre-tax profit on \$1.96 per barrel (RCA Order No. 151, P-97-4, Nov. 2002, *et seq.*)

1.96000	Regulatory Commission of Alaska, Order No. 151 (Docket P-97-4), Nov. 2002, <i>et seq.</i>	
0.32106	Total TAPS Pre-tax Profit (grossed up to provide 12% after-tax return on estimated costs)	
0.09400	Nominal SIT Rate (9.4%)	
0.03018	per-barrel SIT	
0.29088	Pre-tax profit - SIT	
0.35000	Nominal FIT rate (35%)	
0.10181	per-barrel FIT	
<u>0.13199</u>	SIT - FIT	
0.18907	After-Tax Profit (\$0.321 - SIT - FIT)	

**Estimated Feeder Line + TAPS profit and taxes**

Sum of Feeder Line + TAPS Profits

0.42590	Total TAPS + Feeder Line Pre-tax Profit	
0.04003	per-barrel SIT	
0.13505	per-barrel FIT	
<u>0.17509</u>	SIT - FIT	
0.25081	After-Tax Profit (\$0.321 - SIT - FIT)	

**Note:** The weighted average TAPS tariffs for CY2007 at FERC is \$5.10 per barrel – \$3.16 in excess of the RCA tariff of \$1.96 per barrel.

Figure 2

**Estimated Pipeline Tariff Effect on State, Federal, TAPS Owner and Independent Shipper Net Revenue Shares  
(Production + Pipelines; \$60 / bbl.)**

*\$60 / bbl. case - Hypothetical Example -- CY 2007 (Estimated from Public Data Sources)*

<b>Major ANS Cost and Profit Elements *</b>	<b>TAPS Owner (Shipping Own Barrels)</b>				<b>Independent Shipper</b>				<b>TAPS Owner (Shipping Others' Barrels)</b>			
	<b>TSM Tariff</b>	<b>(Share %)</b>	<b>RCATariff</b>	<b>(Share %)</b>	<b>TSM Tariff</b>	<b>(Share %)</b>	<b>RCATariff</b>	<b>(Share %)</b>	<b>TSM Tariff</b>	<b>(Share %)</b>	<b>RCATariff</b>	<b>(Share %)</b>
1 ANS Market Price	\$60.00		\$60.00		\$60.00		\$60.00		\$60.00		\$60.00	
2 TAPS Tariff	(\$5.10)		(\$1.96)		(\$5.10)		(\$1.96)		(\$5.10)		(\$1.96)	
3 Other Transportation	(\$2.40)		(\$2.40)		(\$2.40)		(\$2.40)		(\$2.40)		(\$2.40)	
4 Production Tax & Royalty Base	\$52.50		\$55.64		\$52.50		\$55.64		\$52.50		\$55.64	
5 Royalty	(\$6.44)		(\$6.83)		(\$6.44)		(\$6.83)					
6 Operating and Capital Costs	(\$8.00)		(\$8.00)		(\$8.00)		(\$8.00)					
7 Production Tax	(\$7.12)		(\$7.63)		(\$7.12)		(\$7.63)					
8 Property Tax (including TAPS)	(\$1.00)		(\$1.00)		(\$0.80)		(\$0.80)					
9 Industry Production Profit (before inc. tax)	\$29.94		\$32.18		\$30.14		\$32.38					
10 State Income Tax (Production)	(\$1.69)		(\$1.98)		(\$1.69)		(\$1.98)					
11 Fed. Income Tax (Production)	(\$9.89)		(\$10.57)		(\$9.96)		(\$10.64)					
12 Industry After-Tax Production Profit	\$18.37		\$19.63		\$18.50		\$19.76					
13 Industry Pre-Tax Pipeline Profit	\$3.57		\$0.43						\$3.57		\$0.43	
14 State Income Tax (Pipeline)	(\$0.34)		(\$0.04)						(\$0.34)		(\$0.04)	
15 Federal Income Tax (Pipeline)	(\$1.13)		(\$0.14)						(\$1.13)		(\$0.14)	
16 Industry After-Tax Pipeline Profit	\$2.10		\$0.25		\$0.00		\$0.00	====>	\$2.10		\$0.25	
<b>17 Total Alaska Net Revenue Share</b>	<b>\$16.58</b>	<b>34.49%</b>	<b>\$17.48</b>	<b>36.37%</b>	<b>\$16.04</b>	<b>36.05%</b>	<b>\$17.24</b>	<b>36.19%</b>	<b>\$0.34</b>	<b>9.40%</b>	<b>\$0.04</b>	<b>9.40%</b>
<b>18 Total Federal Net Revenue Share</b>	<b>\$11.02</b>	<b>22.93%</b>	<b>\$10.70</b>	<b>22.27%</b>	<b>\$9.96</b>	<b>22.38%</b>	<b>\$10.64</b>	<b>22.33%</b>	<b>\$1.13</b>	<b>31.71%</b>	<b>\$0.14</b>	<b>31.71%</b>
<b>19 Industry After-Tax Net Revenue Share</b>	<b>\$20.47</b>	<b>42.58%</b>	<b>\$19.88</b>	<b>41.36%</b>	<b>\$18.50</b>	<b>41.57%</b>	<b>\$19.76</b>	<b>41.47%</b>	<b>\$2.10</b>	<b>58.89%</b>	<b>\$0.25</b>	<b>58.89%</b>

Notes

\* This worksheet starts (left-hand panel) with the values shown in Figure 1. (See Figure 1 and page 2 of this worksheet for additional information on these calculations.) The center panel and right-hand panels show the net revenue on production and pipeline transport of North Slope oil produced by companies that do not have an ownership share in TAPS. Total net revenue (the sums of Lines 17, 18 and 19) in the left-hand panel "TSM" and "RCA" columns - \$48.07 per barrel - equals the sum of producer and pipeline operator net revenues in the corresponding columns of the center and right panels.

*When three companies control 95% of North Slope production and own a similar share of the Trans-Alaska Pipeline System (TAPS), it is important to note how tariff revenues affect independent (non-owner) producers. According to a consistent stream of regulatory and court determinations since 2002, for the entire three decades of TAPS operations these revenues have included both allowable regulatory profits and excess profits. Building on the aggregate revenues shown in Figure 1 (left-hand panel), this worksheet contrasts estimated TAPS owner net revenues, which include pipeline profits, with independent producer net revenues, which do not (central panel). The pipeline profits paid by the independent producer/shipper (right-hand panel) wind up in the hands of one of the three major producers (as 95% owners of TAPS) or one of their two minor partners on TAPS.*

**Estimated Pipeline Tariff Effect on State, Federal, TAPS Owner and Independent Shipper Net Revenue Shares  
(Production + Pipelines; \$60 / bbl.)**

*This worksheet identifies the assumptions used to derive the estimated property taxes (Line 8 of Figure 1) and State Income taxes (Lines 10 and 14 of Figure 1).*

**Property Tax Adjustment (Line 8)**

Independent shipper property tax reduced by 20% to reflect the fact that the independent shipper does not have a taxable interest in TAPS. (Estimating factor derived from ADOR data.)

**State Income Tax Adjustments (sum of Lines 10 and 14)**

Total state income tax estimated from Spring 2007 *Revenue Sources* data, divided as follows: Pipeline SIT (Line 14) = (Line 13) \* 9.4%. Estimated Production SIT (Line 10) = Total SIT - Line (14).

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October 10, 2007

## MEMORANDUM

### INTRODUCTION

For many years, Alaska taxed oil and gas production based on the 'gross' wellhead value of the oil and gas. In 2006, Alaska passed legislation putting into place a Petroleum Production Tax (PPT) that essentially taxes production on the 'net' wellhead value of the oil and gas. With government take under PPT significantly below forecasted expectations, the State is again looking at possible changes to its petroleum fiscal policy. As part of the review of its oil and gas fiscal systems, the State of Alaska has asked Gaffney, Cline and Associates (GCA) to comment on its experience in working with many international governments on the relative merits and shortcomings of 'gross' tax structures versus 'net' tax structures.

In all but one country in the world, the state (government) owns the rights to all minerals. Bar very minor exceptions, it is only in the United States that private individuals can own mineral rights. In Alaska, the State owns the rights to minerals making it similar to other international locations.

States then lease or grant those mineral rights to petroleum companies for a period of time either via some form of licensing, concession, service agreement or production sharing agreement. In exchange for receiving the rights to exploit hydrocarbon resources, the oil companies are generally obligated to share with the state the revenues received from the sale of the extracted resources. In an ideal world, the oil companies recover their costs and a 'fair' return on those costs commensurate with the degree of risk taken in developing the licensed acreage. The remainder of the cash flow – "Economic Rent" – would then flow to the government.

While in discussions of what is a fair level of government take a couple question inevitably arise:

- Why doesn't the state just develop the resources itself?
- Why do governments routinely turn to private capital?

Most often, the State does not have the requisite skills, technologies or resources to properly do so. Also, the capital required is significant. Many states do not have sufficient capital while for those that do, state development of hydrocarbon resources may not be the most efficient use of what is normally limited monetary resources.

Private capital is encouraged by giving investors the opportunity to expect returns better than other alternatives on offer. Returns are provided by sharing benefits. Sharing of benefits is a balance between a nation's right to benefit as the resource owner, and private capital's need to refresh its capital and to provide a sufficient return to its investors.

predictions further out in time are shown to be quite inaccurate when ultimately compared to the actual prices in those times. The most accurate predictor of future prices was the NYMEX commodity futures market for crude oil and gas. Even these forecasts only go out for five years at most and the majority of petroleum projects are on production for a decade or longer.

The challenge clearly then is defining a petroleum tax system that responds to market changes, not one based on predicted market conditions. Just as most 'expert' forecasts bear little resemblance to actual prices, fiscal systems based on predicted results often find themselves out of sync with actual realizations resulting in one or both parties seeking relief or change.

Another consequence of systems attempting to collect 100% rent is that they usually encourage a degree of "gold plating" as there are no incentives to keep costs down; in fact from the oil company's perspective additional 'profit' can only be earned by spending more as any gains in efficiency would flow through to the state. Additionally, the cost of capital, while generally measurable, varies by company, can vary by project and is also a function of a number of economic factors.

### **Gross Tax**

There are many different aspects to petroleum taxation worldwide, and many different ways in which governments receive value for their minerals. At the macro-level the government take mechanisms are either based on revenue ('gross') or profits ('net').

The most common form of a gross tax is royalty. The main reason governments like royalty is that royalty provides the government with early and continuous cash flow. Royalty is based on sales revenue received (with no deductions), making it simple to administer and to audit. While royalty subjects the government to variations in product pricing it also insulates the government from the varying cost structures and operating efficiencies of the different oil companies.

Not surprisingly, royalty, and other gross taxes, are generally disliked by the oil companies. The biggest issue with royalty, or for that matter any gross based tax, is that it is not aligned with the way in which private companies operate. Oil companies make decisions on the basis of profitability, not production. Gross taxes delay payout, do not differentiate between profitable and unprofitable fields and, if no relief is granted, generally lead to premature abandonment (or deferred development) of hydrocarbon reservoirs. In an effort to balance the obligation to maximize recovery of hydrocarbons with the desire to capture 100% of the Economic Rent, governments tend to write into their taxation policies a number of allowances or exceptions in an effort to account for known or anticipated variations in cost structures.

For the most part, gross tax systems require legislative or regulatory change whenever there are substantive changes in the market.

### **Net Tax**

The most common form of a profit or net-based tax system is corporate income tax. For many countries, this is the most common form of taxation and is levied against all industries, not

**M E M O R A N D U M**

October 16, 2007

Page 5

such as this is aligned with the way in which private companies function and does away with the need to offer up front concessions, investment credits and late life relief.

**Attracting New Investment**

New investment is necessary to keep oil field activity at the right level. In this regard, countries compete against each other for the limited oil company dollars. Alaska is looking for a fiscal system that will encourage the development of satellite, small and marginal fields as well as its heavy oil resources.

A gross-based tax does not give credit for new investment, nor does it differentiate between the various types of fields, levels of risk or relative profitability. To compensate, allowances or exceptions are generally made. These allowances must be made well in advance (in order to attract the investment dollar) and are based on best predictions at the time.

This is where a net-based system excels. Companies are allowed a deduction for their investment dollar with the government sharing in the costs of that investment. If costs are higher for one type of investment versus another, a net-based system is self-correcting in that it allows a greater deduction for the higher cost development thereby limiting the need for exceptions or allowances. In comparing net based systems, the rate of capital recovery becomes important.

**Fiscal Stability**

The United Kingdom (UK) is a country often mentioned as having one of the most stable fiscal systems; however, the UK has made more changes to its petroleum fiscal policy in the past 30 years than almost every other country. The reason the UK is viewed as stable while undergoing fairly constant change is that the modifications were responsive to changes in market conditions. Total taxes were raised or lowered depending on market circumstances. In short, the industry appears to view a flexible structure adapting to changing conditions as a stable structure.

Net-based tax systems offer much more flexibility and resilience than gross-based systems. Net-based systems also need less tinkering as many aspects of those systems are self-correcting. However, good fiscal design without complementary institutional structures may still not achieve the desired goals. The ultimate system chosen by any government is generally within the administrative and audit capacity of its relevant institutions. So long as it gets access to the right data and is ably administered and audited, a sophisticated net-based system will be a more effective capturer of Economic Rents over the long run and should ensure that the jurisdiction remains competitive for petroleum investment dollars.

In summary, net today is best practice; some countries are switching back to gross but they are not systems to benchmark (Venezuela, Bolivia, etc.). If a regime is sophisticated enough to have a net based corporate tax system (and almost all countries have one) then it is sophisticated enough to administer a net based petroleum tax. Access to the right type of data on a timely basis is key.

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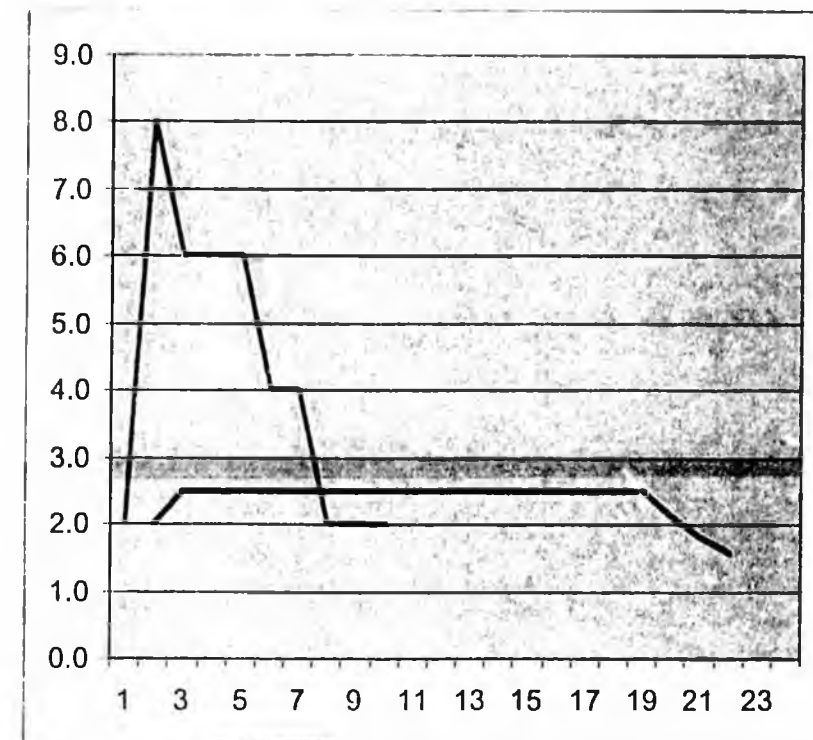
# Payout

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10-21-07

# What is expectation as to the time to recover initial investment?

- **Simple answer – As soon as possible!**
- **Rule of thumb – from date of first production plus:**
  - Oil – 3 to 6 years
  - Gas – 5 to 9 years  
(combination of higher costs and lower BOE)



# Other Countries - PSC

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- **Production Sharing Contracts**

- Recovery of costs is commonly known as “Cost Oil”
- Range of annual cost recovery varies
  - Some put no cap on cost recovery
  - Others may cap cost recovery at say, 40% of revenue
- To compensate for particular situations the recovery may be ‘tweaked’
  - Uplift
  - Share of First Tranche Petroleum (aka Royalty)
  - The “tweaks” are to provide some compensation for the time value ‘loss’ of longer recovery times

# Other Countries – Tax & Royalty

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- **Basically speed of deduction and credits**
  - Depreciation period
    - 1,3,10 years
  - Depreciation method
    - Straight line
    - Declining balance
    - Depletion (based on production to remaining reserves)
  - Credits
    - An additional deductions equal to a percentage of qualifying investment

# Another key impact

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- **The “Ring Fence” can provide very different value to the oil company**
  - Consolidated by taxing district (e.g. the entire State of Alaska)
    - Immediately write off against other income streams
    - Progressive systems provide possible increased benefit
  - Ring Fenced say by individual field or reservoir
    - Usually have to wait until a discovery is turned into a development and revenue starts before the oil company can begin to recover their costs

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# Attractiveness of Exploration Credits

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# **Alaska Exploration Investment Credits**

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- **One of the stated goals is to attract new exploration, new investment**
- **How does Alaska compare to other regimes?**
  - Compares very favorably on a global basis
  - State / Feds effectively becomes a major 'investor'
- **Comes close to leveling the playing field between incumbents and new entrants**
  - A feature that is not available in most countries
  - Usually there is a high barrier to entry

## Alaska is offering...

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- **Depending on parameters such as start date and distance from other existing oil and gas units and wells, investors can:**
  - Earn credits of 20% up to 40% of qualifying expenditures
  - Deduct money spent against current state and/or federal income tax liability
    - If no current PPT/ACES income can request and receive loss carry forward credits
  - Achieve favorable potential outcome after State/Federal Income Tax impact is considered
    - Contractor share – 21 to 36%
    - State/Federal share – 64 to 79%

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# Example

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# Example of timing of take

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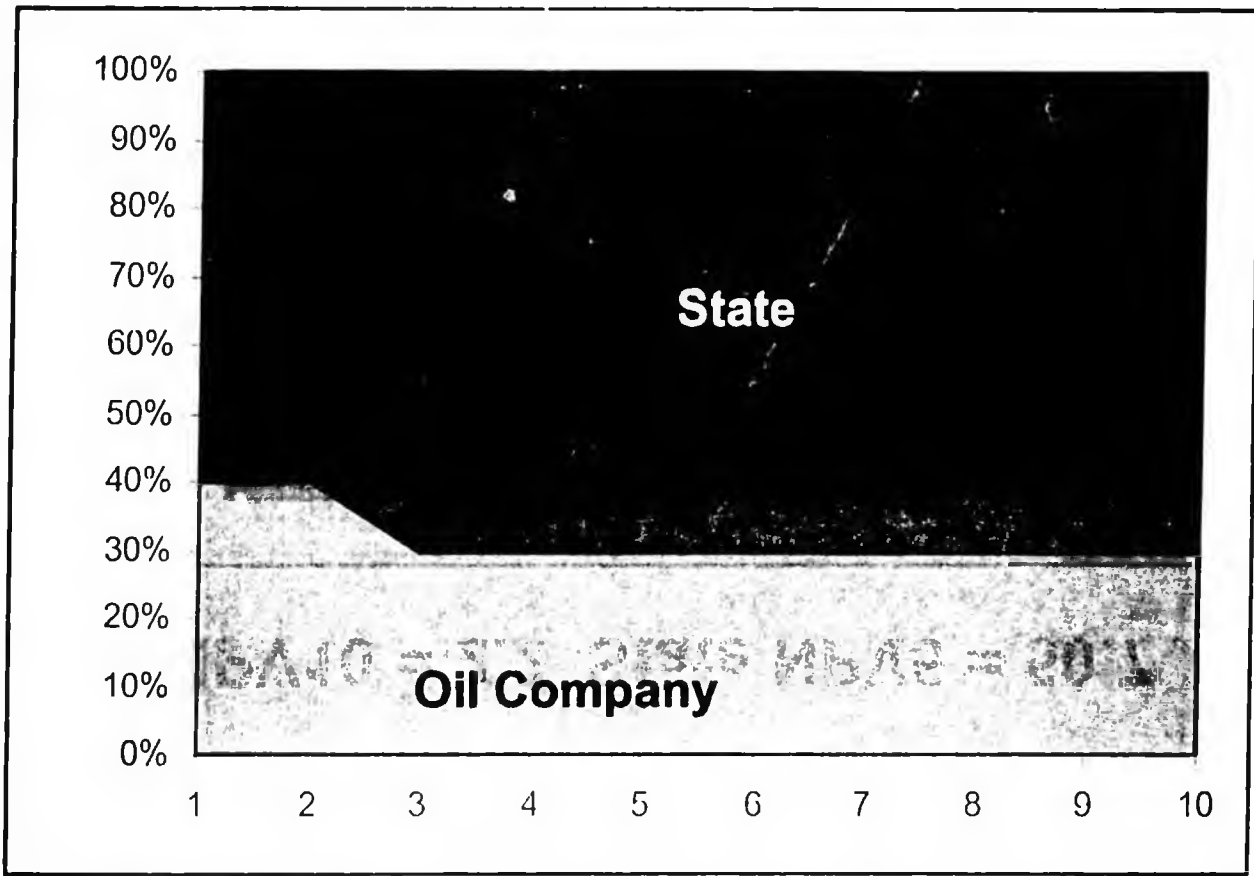
- **Assumptions**

- Investment of 20
- 10 years of flat cash flow = 100
  - 10 per year
  - Overall State gets 68, Oil Co gets 32

- **How does timing impact IRR (Internal rate of return), IOC NPV and State NPV?**

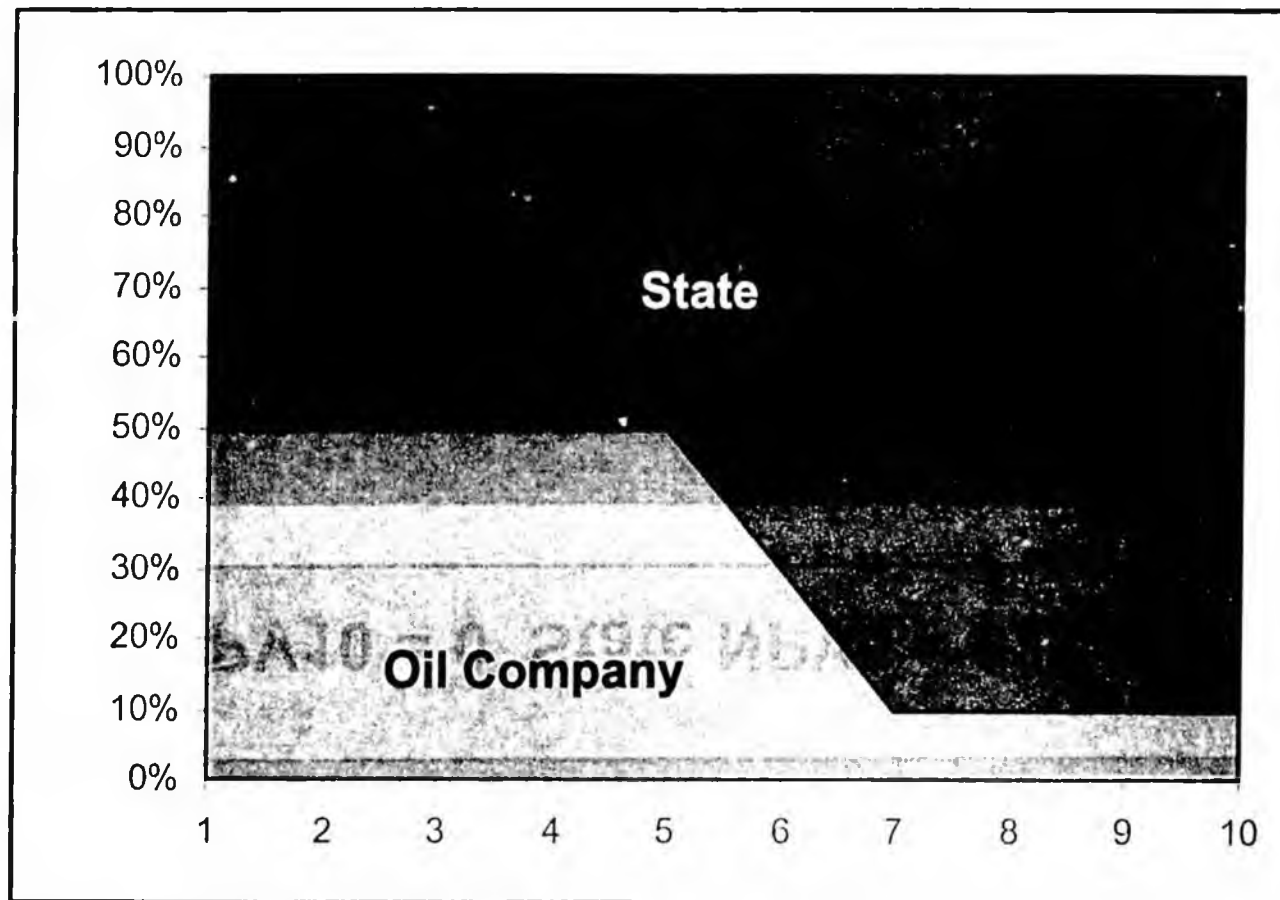
# Case 1 – IRR 10%

- IOC NPV10 = 0 State NPV5 = 52



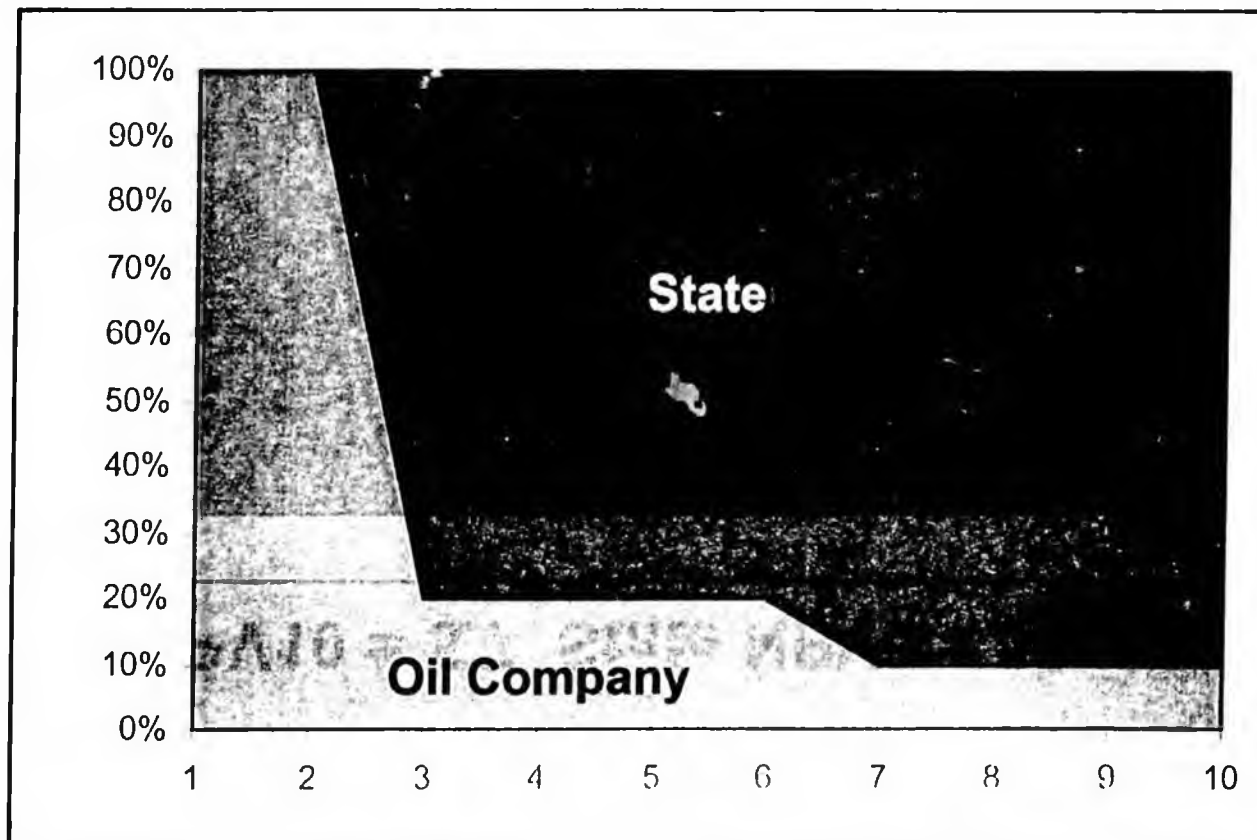
## Case 2 – IRR 14%

- IOC NPV10 = 2.2 State NPV5 = 50.7



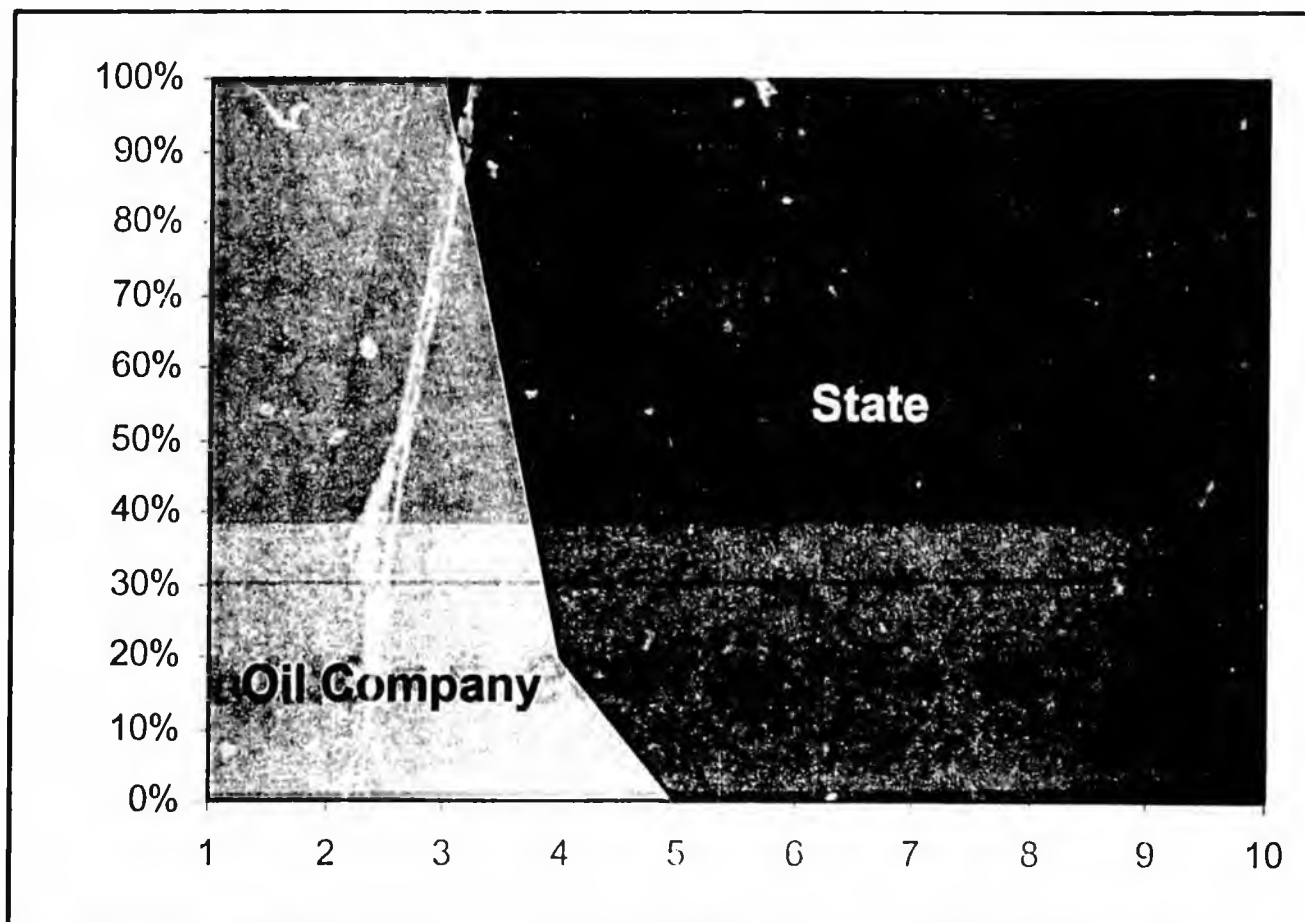
## Case 3 – IRR 19%

- IOC NPV10 = 4 State NPV5 = 49.5



## Case 4 – IRR 26%

- IOC NPV10 = 5.7 State NPV5 = 49.3



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# **Alaska's Equitable Share**

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**Some Further Thoughts  
30 October 2007**



# Topics

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- **What is the risk of raising state revenue share on the existing producing reservoirs?**
  - Look at AOGA, BP and other industry data
- **What are the goals or drivers for Alaska's Petroleum Fiscal System?**
  - List what we have discerned since arriving in Juneau
- **From a 50,000 foot viewpoint, what fiscal system structure accomplishes the above goals with a minimal need for intervention?**

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# The Tipping Point

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# Where is the tipping point?

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- **Quite legitimately several legislators have asked their advisors and the companies how far is just right and how far is too far?**
  - The companies have complex decision making processes with many external factors at play and can't articulate what impact a change in Alaska taxes will have
    - Rock (Prospectivity) trumps Scissors (Fiscal) - Chevron
    - *Scissors (Fiscal) cut Paper (Profit)*
    - *Paper (Buy Reserves) covers Rock (Develop Reserves)*
  - Consultants acknowledge that taxes are but one of many factors that control decision making, and cannot say with certainty what tax rate is just right



# Testing the Tipping Point

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- **We can read lines, and between the lines, of industry testimony to construct a picture of the Alaskan investment climate**
  - AOGA letter which reflects “the full consensus of the members of the AOGA Tax Committee, with no dissent”
  - BP’s very detailed presentation on Prudhoe Bay area
  - Conoco’s useful insight on project economics
  - And other information supplied by Anadarko, Chevron, Exxon and Pioneer.
- **Details presented were then double checked against annual reports, SEC filings, analyst presentations and other company press releases where available**