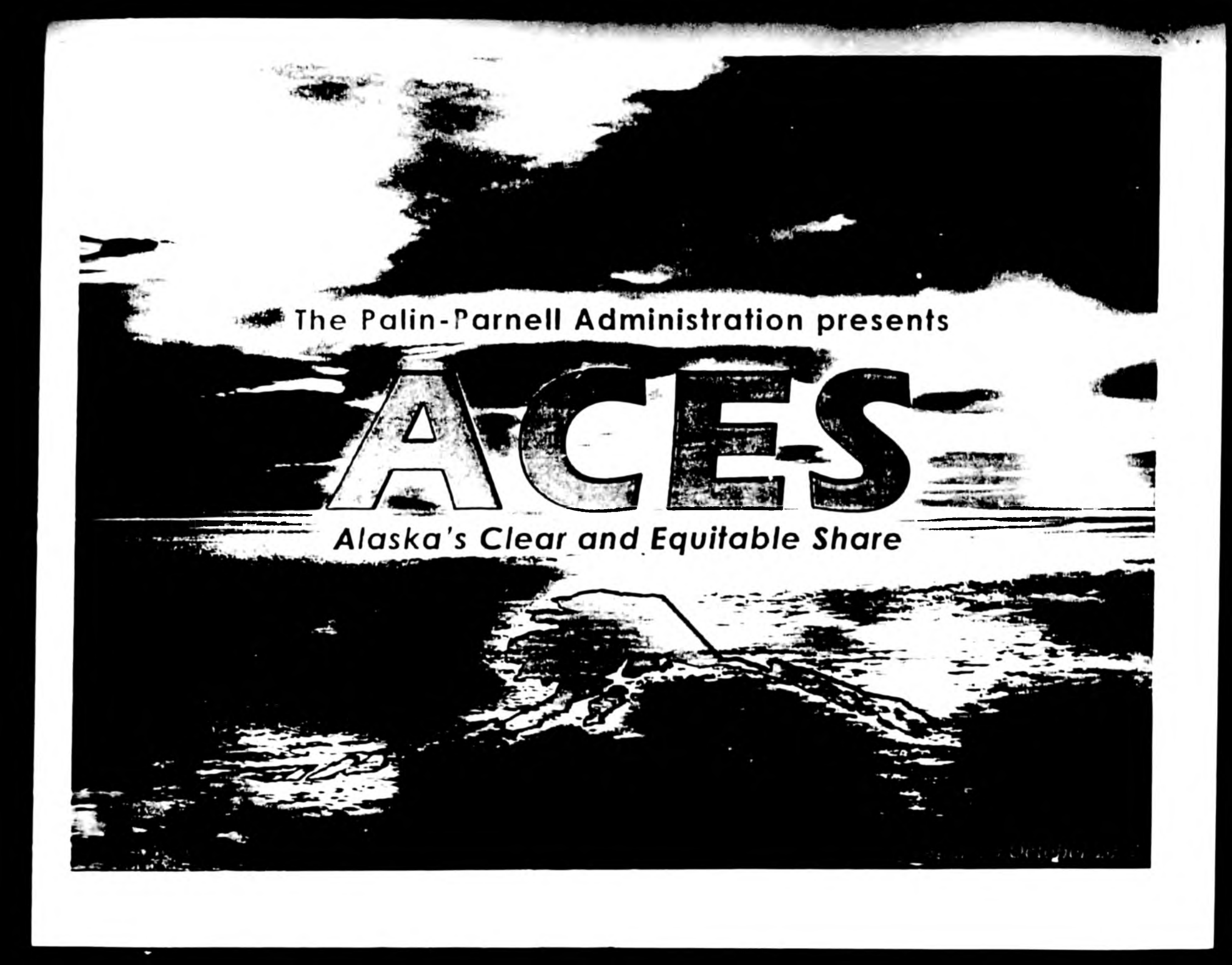


SB 2001

(FILE 2)

ADMIN.

**PRESENT'N
& MATER'LS**



The Palin-Parnell Administration presents

ACES

Alaska's Clear and Equitable Share

October 2008

Transportation Deductions

Antony Scott
Commercial Analyst, DNR
October 30, 2007

Overview



- Current law
- The commercial reality
- Some problems
- Potential remedies

- Gross value at point of production determined by subtracting “reasonable costs of transportation” from market prices
- “Reasonable costs” = “actual costs”
- “Actual costs” have historically been understood as FERC/RCA tariffs
- Exception for affiliate transactions, but only if “there are other reasonable modes of transportation” → exception is never met!

Transportation Deductions (Oil Pipelines)



- Deductions have historically relied on rates sanctioned by regulatory bodies
- Typically, this “sanction” does not reflect a regulatory determination
- Rather, the regulatory bodies have “blessed” settlement agreements between the state and the pipeline owner

Why does state base its tax policy for pipeline transportation deductions on pipeline rate litigation?

- MMS doesn't when pipeline is owned by producing affiliates.
 - They adopt a method promulgated through regulation

Pipeline Transportation Deductions



- Key reasons for state to avoid relying on regulatory process in setting tax value
 - Creates uncertainty: While litigation drags on tax value not fully known
 - Inefficient: Regulatory process unlikely to work well absent arms-length commercially sophisticated parties

TAPS Tariffs Example



Background:

- TAPS rates are currently ~\$5/bbl, set under a 1985-era settlement agreement between the State and the TAPS owners
 - Rates don't appear to reflect "actual costs"
 - RCA determined that actual costs ~\$2/bbl
 - FERC Administrative Law Judge determined that actual costs ~\$2/bbl
 - While litigation continues, State continues to allow a ~\$5/bbl transportation deduction
-

TAPS Tariffs Example



Indicative Value of “Tariffs by DOR”

- Assume:
 - TAPS tariffs are \$3/Bbl too high
 - 760,000 Bbls/day
 - Production tax rate of 22.5%
 - All barrels are shipped on affiliated transportation
 - Then production tax value to state of setting tariffs for affiliate transactions is **~\$160 million/year**
-

Transportation Deductions (Gas Pipelines)

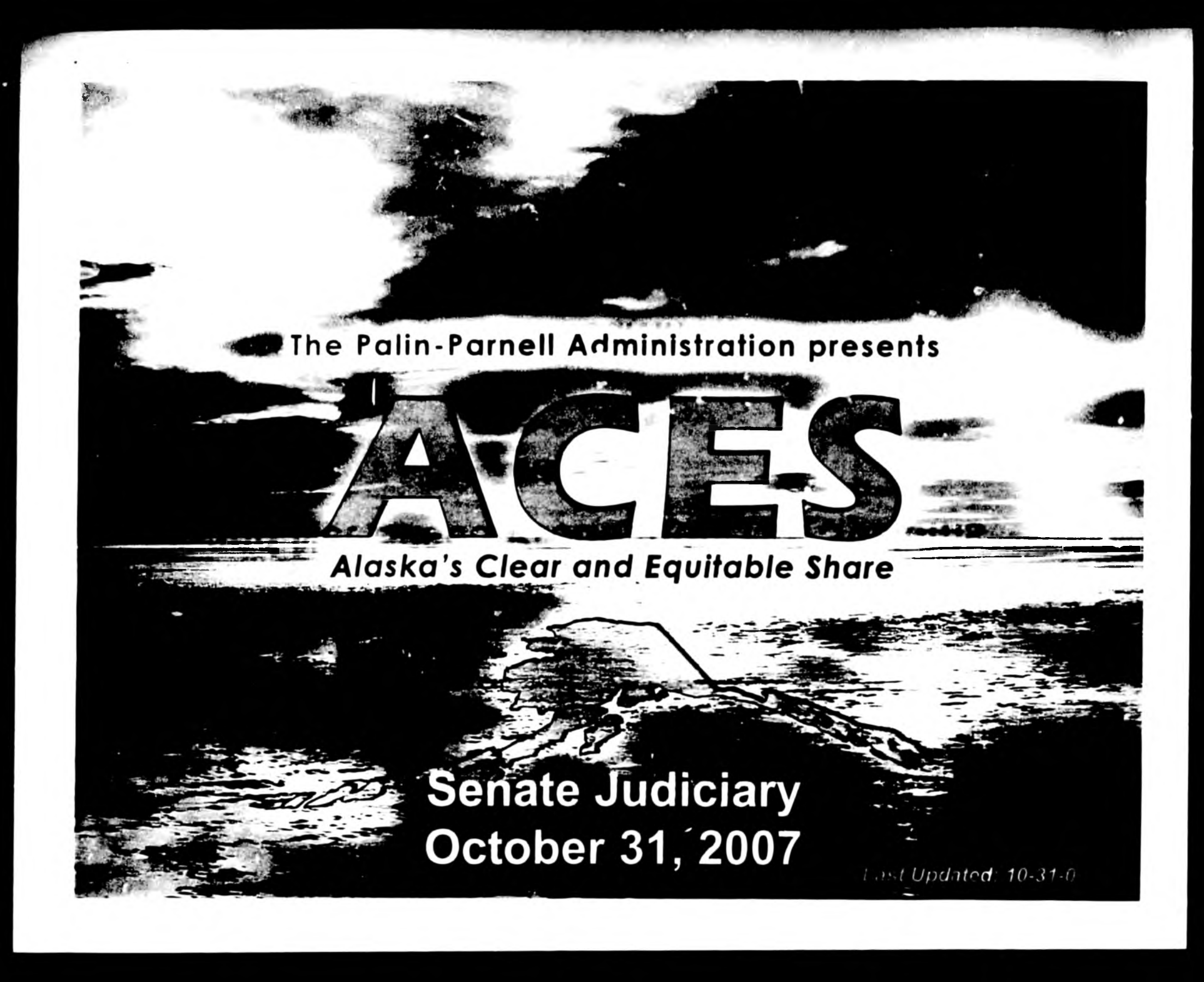


- Gas pipelines typically built on basis of “negotiated rates” between shippers and pipelines
- FERC typically gives no scrutiny as to whether the negotiated rates are a “fair” bargain between shipper and pipeline
- If Producers end up owning the gas pipeline, then they can negotiate rates with themselves

The Key to a Remedy



- At present, state is arguably forced to live with non-arms length transactions because it is never the case that “there are other reasonable modes of transportation”
- DOR could follow MMS’ lead and establish regulations that determine appropriate cost deductions for non arms-length transactions on pipelines
- Cleanup language needed to ensure that the arms-length shippers – who really do have “actual costs” of the posted tariffs – are not forced to use the DOR-established tax deduction



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**Senate Judiciary
October 31, 2007**

Last Updated: 10-31-07

October 31, 2007

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Comparison of Gross Based and Net Based Production Tax Systems

Pat Galvin

October 31, 2007

Pro's and Con's of Gross Tax and Net Tax



Gross Tax

- **Pro's**
 - More Transparent
 - Less Audit/Litigation Burden
 - Less risk to revenue projection
- **Con's**
 - Creates a "one size fits all" problem for varying project economics
 - Errors in assumptions can stifle investment
 - To protect project economics, may have to accept less revenue

Net Tax

- **Pro's**
 - Investment climate "self corrects" to adjust to changes in costs
 - Provides more attractive investment climate
- **Con's**
 - Less Transparency
 - Greater Audit/Litigation Burden
 - Errors in assumptions can reduce revenue

Balancing Act

UNSA 1986 JO 80001 1622 166006

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Revenue Investment Climate



Revenue from "Legacy" Fields Exploration & New Field Development



Transparency Economic Flexibility



Audit Risk Investment Challenge



Incumbents New Entrants



PRO, S and CON, S of

Factors to Consider

ACES

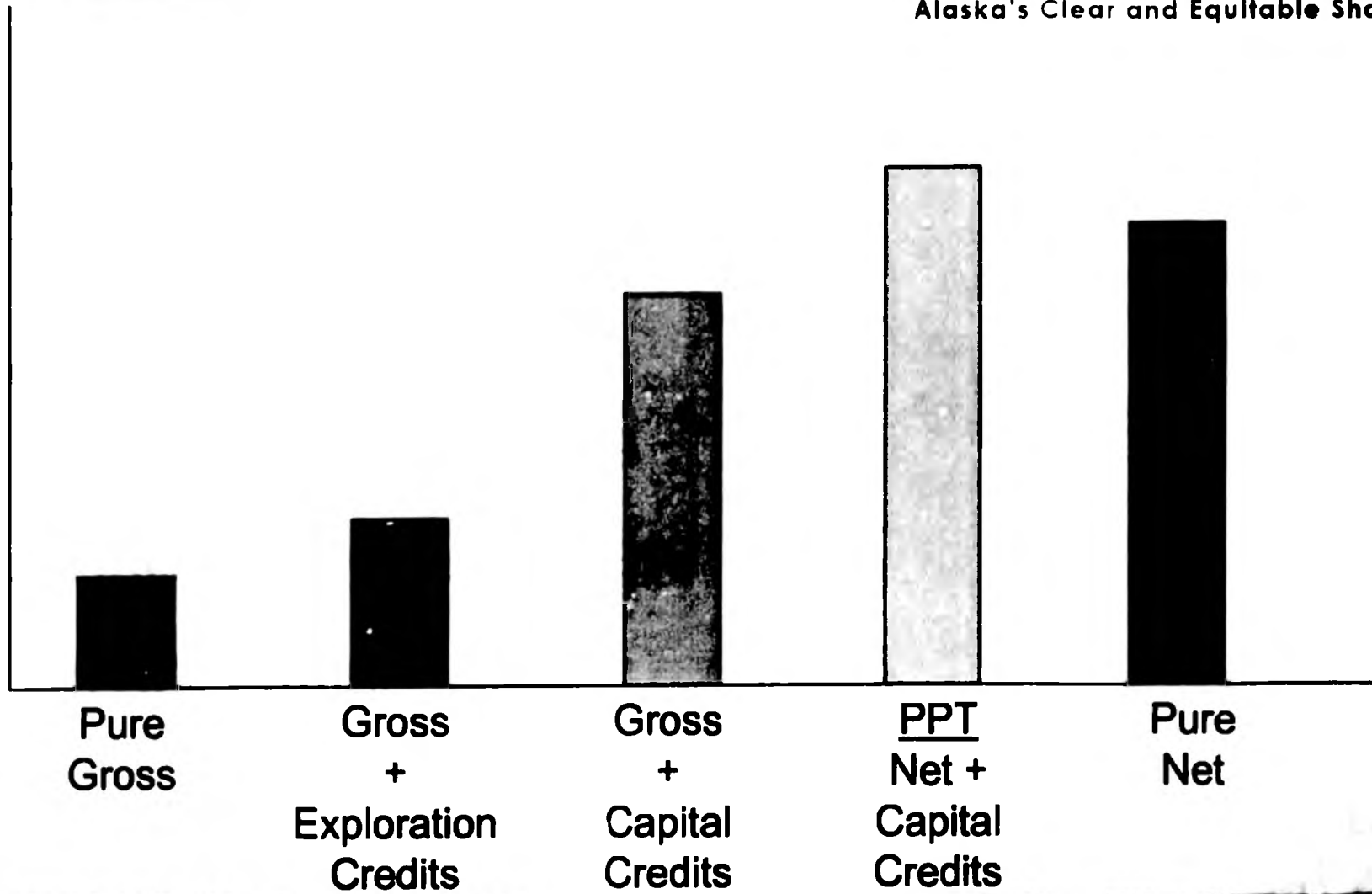
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- “Audit Risk”
- Revenue to the State
- Investment Climate

"Audit Risk"

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“Audit Risk”

How Do You Measure It?



- Experience of Other Jurisdictions
 - No Record of Someone Going from Net to Gross due to frustration over “audit risk”
- Similar Experiences In Alaska
 - Analogous to royalty disputes?
 - Net Profit Share Leases?
 - Distinction between contract and tax disputes
- “Trust Factor”
- Can You Mitigate the Risk?
 - Need the ACES Tools

Revenue to the State

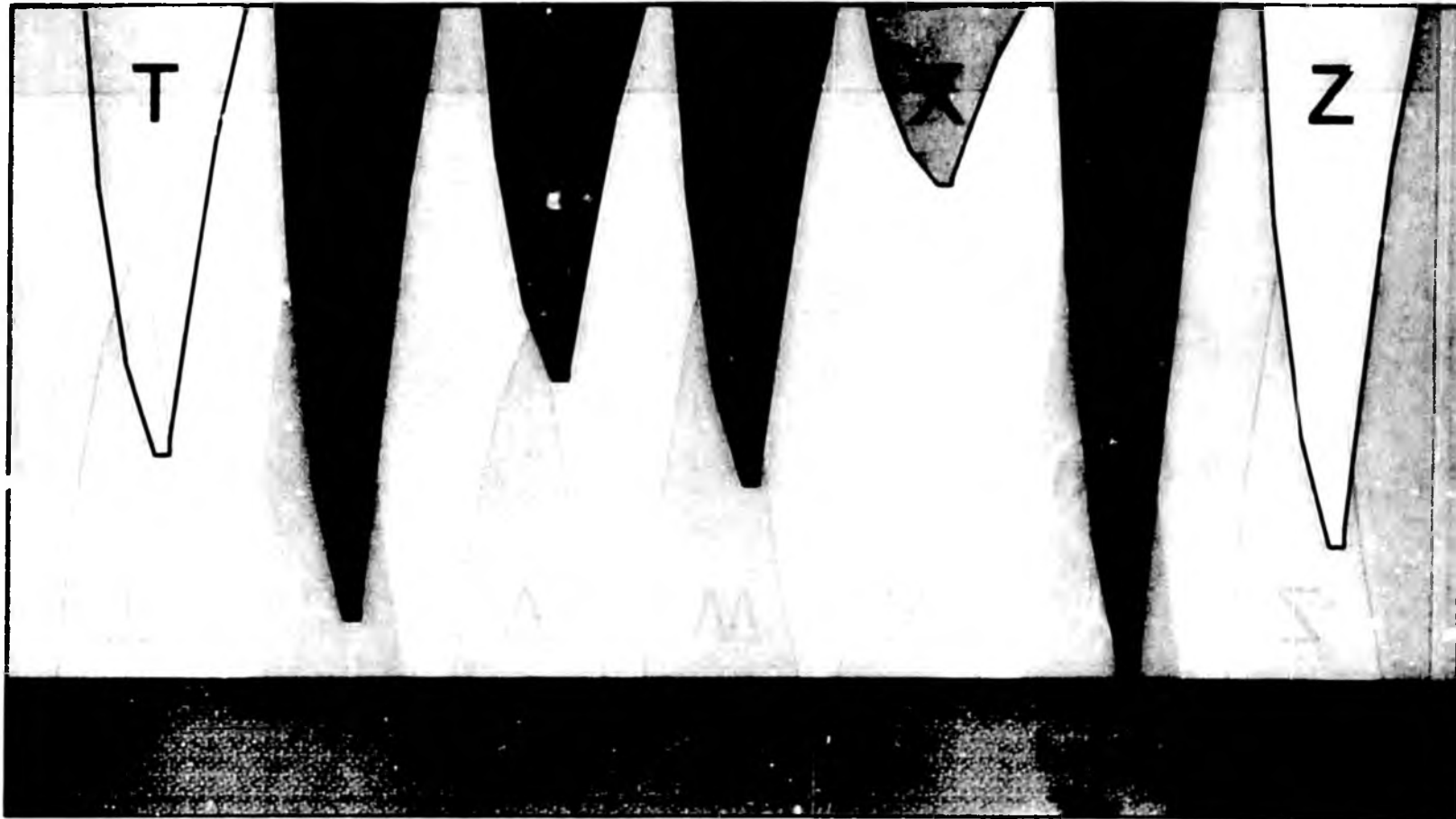


- Revenue Model with field costs and production assumptions
- Can Calibrate Any Tax System to Hit a Revenue Target
- How Sensitive is the System to Changes in Assumptions?

Revenue vs. Investment

ACES

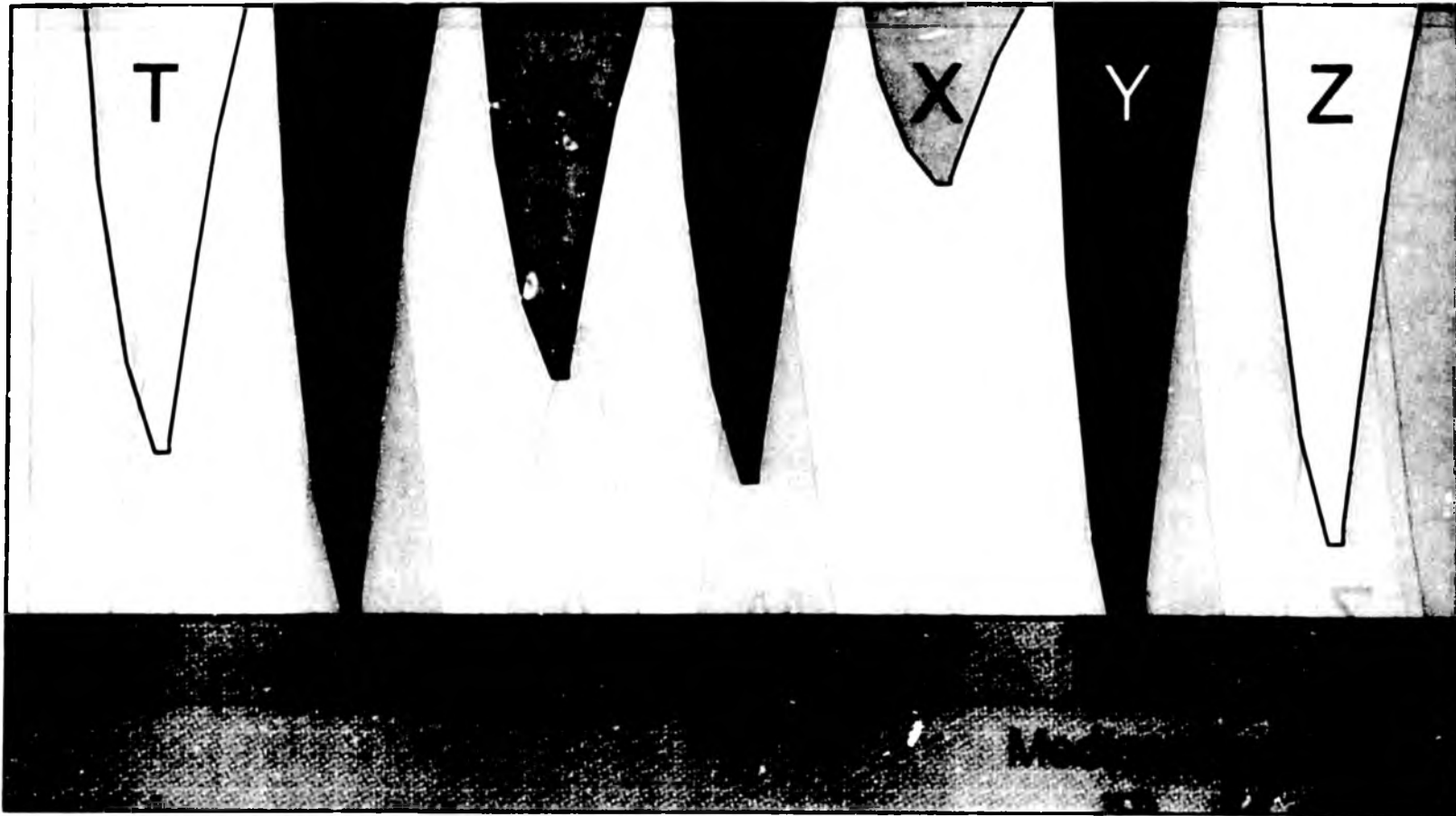
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Revenue vs. Investment

ACES

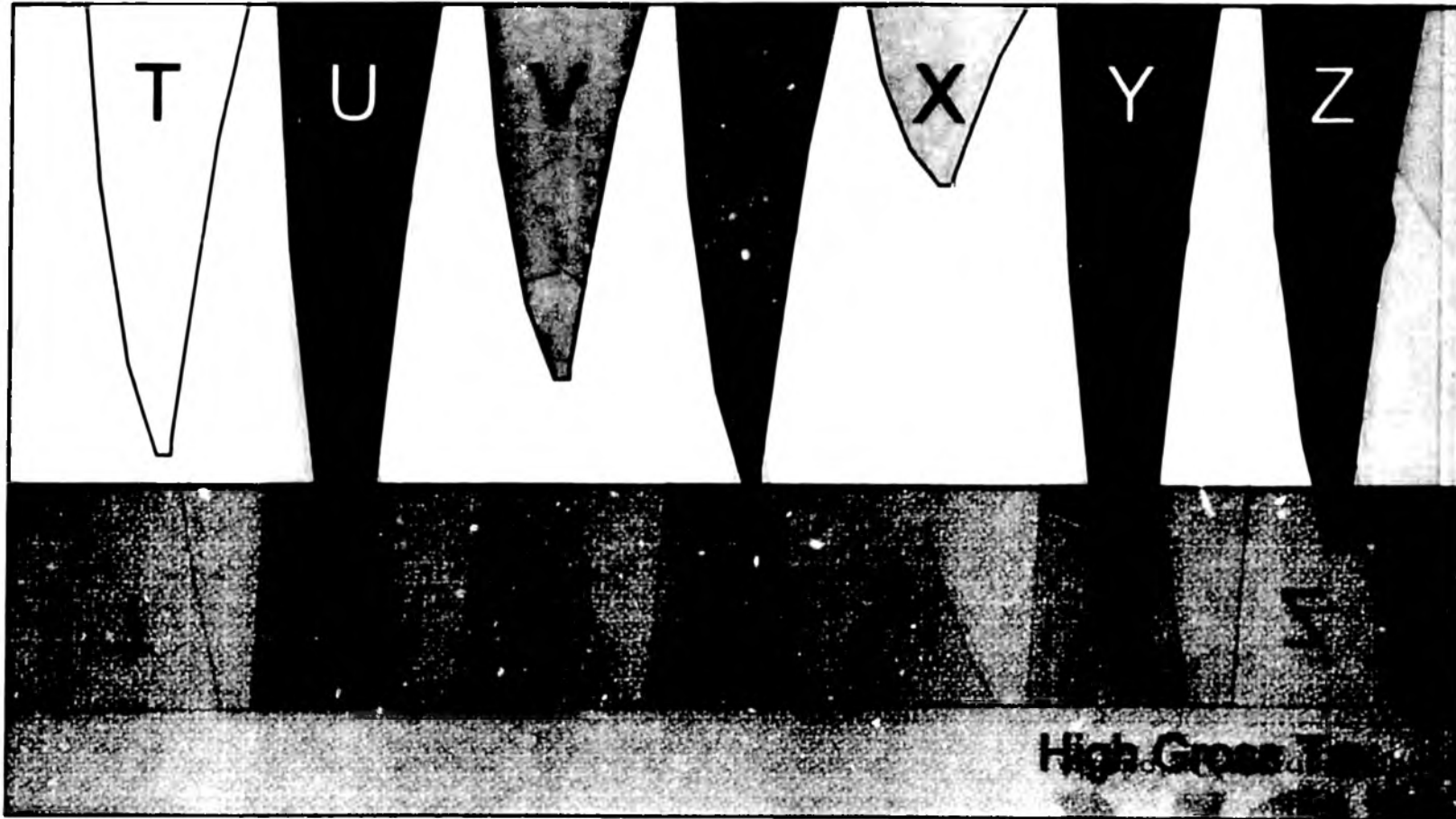
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Revenue vs. Investment

ACES

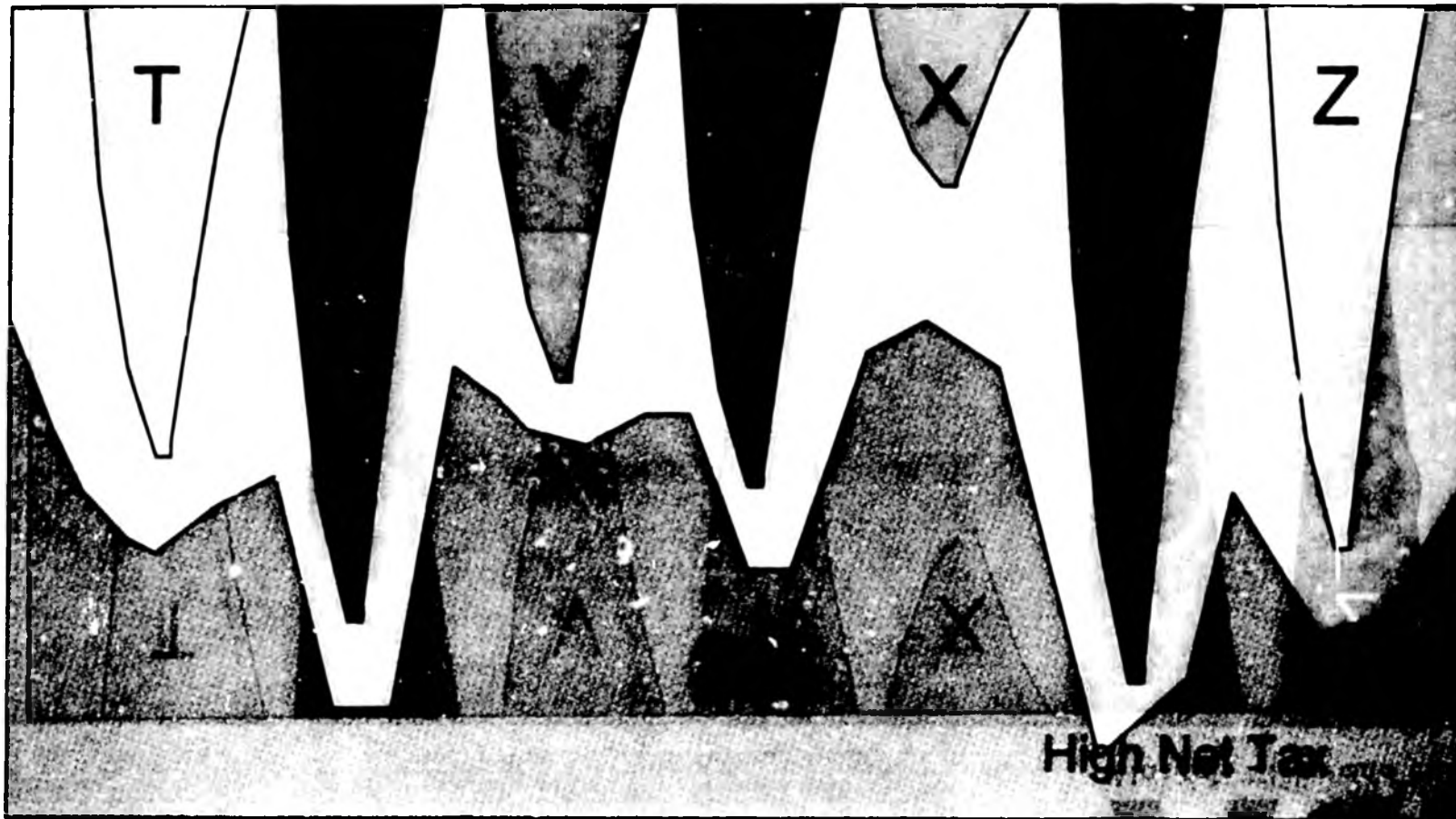
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Revenue vs. Investment

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Investment Climate - Tests



- **New Fields (7 Field Models)**
 - Actual project data - costs, production profile
 - NPV, IRR, Profitability Index at prices \$30 to \$100, and discount rates of 10% and 15%
 - Sensitivity Analysis to changes in cost assumptions
- **“Legacy” Fields**
 - Reinvestment Option analysis 3%, 6%, and 15% decline scenarios

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New Field Tax Analysis - NPV Impact

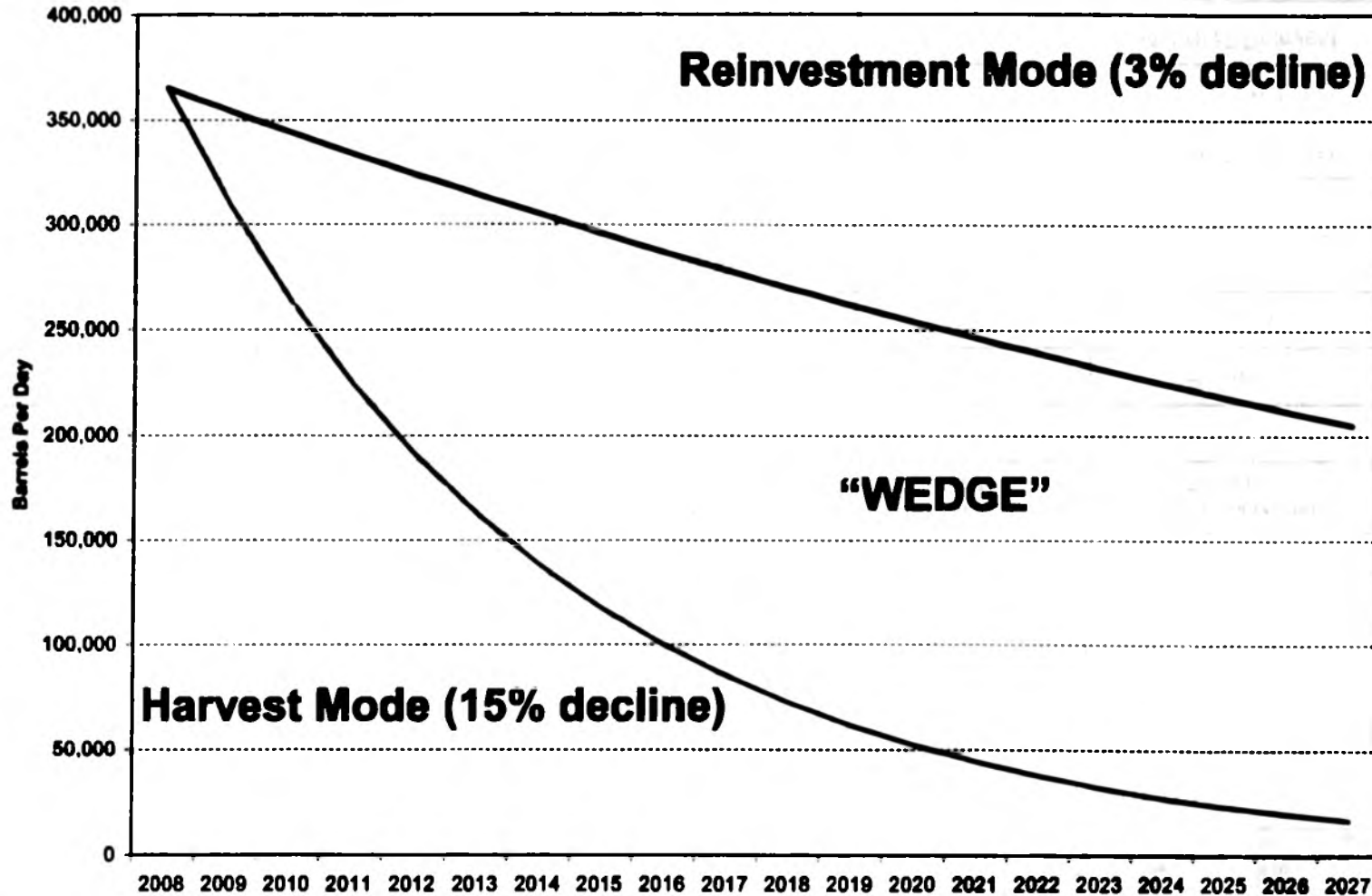
Scenario	Rate		Progressivity		Capital Investment Credit	Industry NPV @ 10% at \$40/bbl real ANS WC (mm\$)						
	Master Fields	Other Fields	Trigger	Rate		Field A	Field B	Field C	Field D	Field E	Field F	Field G
	ACES - 10% Floor	28.0%	25.0%	\$30	0.0020	20%	10	60	40	40	(500)	210
ACES - NO Floor	25.0%	25.0%	\$30	0.0020	20%	120	60	40	40	(300)	210	1,000
PPT Status Quo	22.0%	22.5%	\$40	0.0025	20%	160	60	60	10	(500)	220	1,100
High Net Tax	35.0%	22.5%	\$30	0.0020	20%	160	60	60	0	(200)	240	1,100

Scenario	Rate (All Fields)	Other Incentives	Progressivity		Capital Investment Credit	Industry NPV @ 10% at \$40/bbl real ANS WC (mm\$)						
			Trigger	Rate		Field A	Field B	Field C	Field D	Field E	Field G	
	Low Rate - No Credits	13%		\$40	0.0020	None	(30)	(40)	(30)	(500)	(600)	80
Medium rate	16%		\$40	0.0020	20%	30	0	0	(300)	(500)	130	800
Former Tax no ELF	16%		NA	NA	none	(40)	(50)	(30)	(400)	(600)	80	800
High Rate Flat Tax	19%		NA	NA	20%	20	(10)	0	(300)	(500)	130	800
Sliding Scale	Tax Table	5 Yr Holiday	NA	NA	20%	130	40	40	20	(400)	180	1,100

Legacy Field Scenarios

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Legacy Field Reinvestment Comparison @ \$40

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	Sustain Production Mode	Harvest Mode	Difference	
Decline Rate	3% per year	15% per year		
Oil Produced (mm Barrels)	2026	854	1172	
	NPV10 (\$M)	NPV10 (\$M)	NPV Difference (\$M)	Implied Investment Decision
Net Cases:				
ACES	8235	6893	1342	Reinvest
PPT(SQ)	9176	7133	2042	Reinvest
35% tax rate	8022	6130	1892	Reinvest
Gross Cases:				
13% + no credits	6860	7207	(348)	DO NOT Reinvest
16% + no credit	6248	6889	(641)	DO NOT Reinvest
16% + 20% credit	7180	7027	152	DO NOT Reinvest
19% + no credit + no progressivity	6246	6706	(460)	DO NOT Reinvest

Assumes: 20 year horizon, OPEX+CAPEX=\$5/BOE for Harvest, \$15/BOE for Reinvestment. All cases assume 10% progressivity unless noted.

Investment Climate Summary

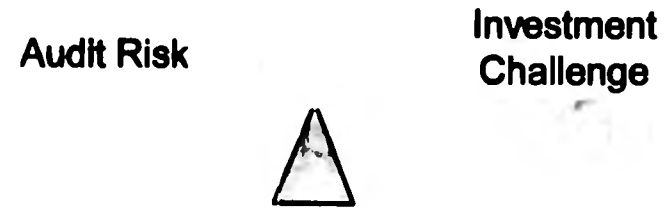
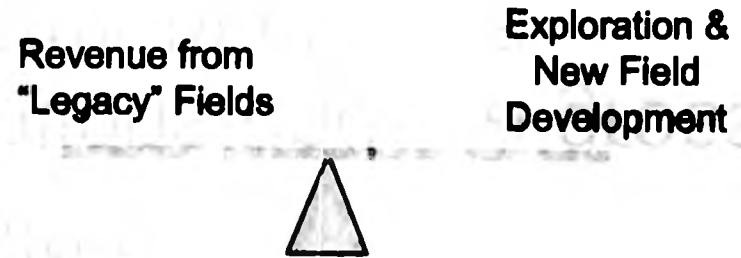


- Industry is more comfortable investing in a state that taxes based on net profits
- Net tax “self-adjusts” to changes in costs
- Heavy oil development is a challenge under a gross tax system
- Errors in cost assumptions under a gross tax can hamper investment climate

Balancing Act

ACES

Alaska's Clear and Equitable Share



Alaska's Equitable Share

Some Further Thoughts
31 October 2007



Topics

- **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?**

The Tipping Point



Where is the tipping point?

- **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

- **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**



Overall Observations

- **We agree with industry that there is significant upside in reducing the decline from existing producing assets**
- **The economics of reinvestment in producing assets on the North Slope are extremely profitable**
 - Evaluated with actual costs, production and prices as reported by BP
 - Profitable even when tested against various stress points



AOGA Testimony to the House

In discussing the merits of HB 2001 versus PPT and the Administration's concerns, we must always keep in mind the real-world situation that Alaska faces. The greatest challenge that confronts this generation of Alaskans and the next is the ongoing decline of oil production, which has been, is today, and promises to remain the cornerstone of the finances of state government.

- The fiscal system chosen must recognize the current and near-term importance of improving production from existing assets.**



AOGA Testimony – Recent Success

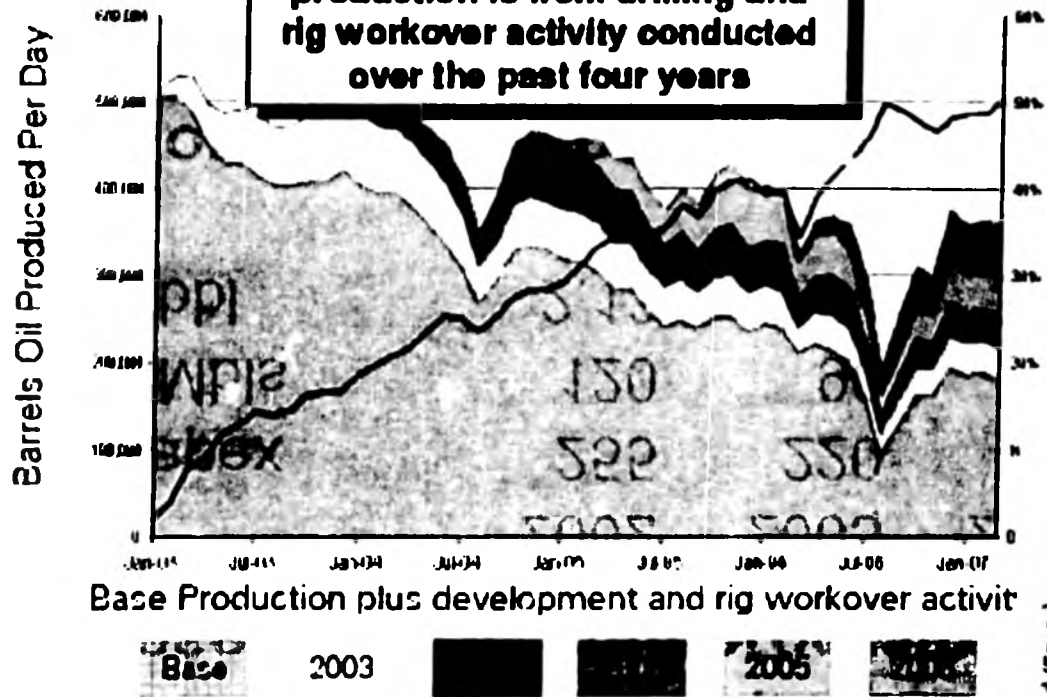
This gets us to investment in currently producing fields. Fortunately, there are investments that can be made, and are being made, in these fields to slow their decline. In the short term, this is in-fill drilling — that is, drilling new wells into the portions of a reservoir that are between the wells that have already been drilled. This accelerates the drainage of oil from the rock that currently lies in between existing wells. In-fill drilling last year contributed some 70,000 barrels a day to production from the Prudhoe Bay field. To put this into perspective, a 70,000 barrel per day field would be the 4th largest stand-alone field on the North Slope today.

- **AOGA noted that North Slope field life could be extended up to another 25 years with continued investment**
- **The oil companies achieved 70,000 bpd of additional production from the 2006 drilling program in Prudhoe Bay.**



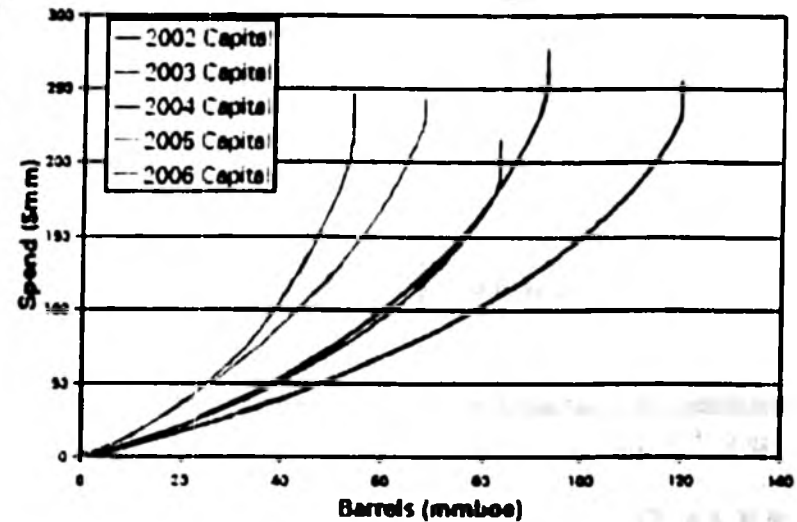
BP's infill drilling program

50% Of GPB's current oil production is from drilling and rig workover activity conducted over the past four years



Observations?

GPB Well Investments 2002-2006



BP House testimony page 12



Costlier Development

- It is getting more expensive to develop a barrel of reserves (BP Infill program)

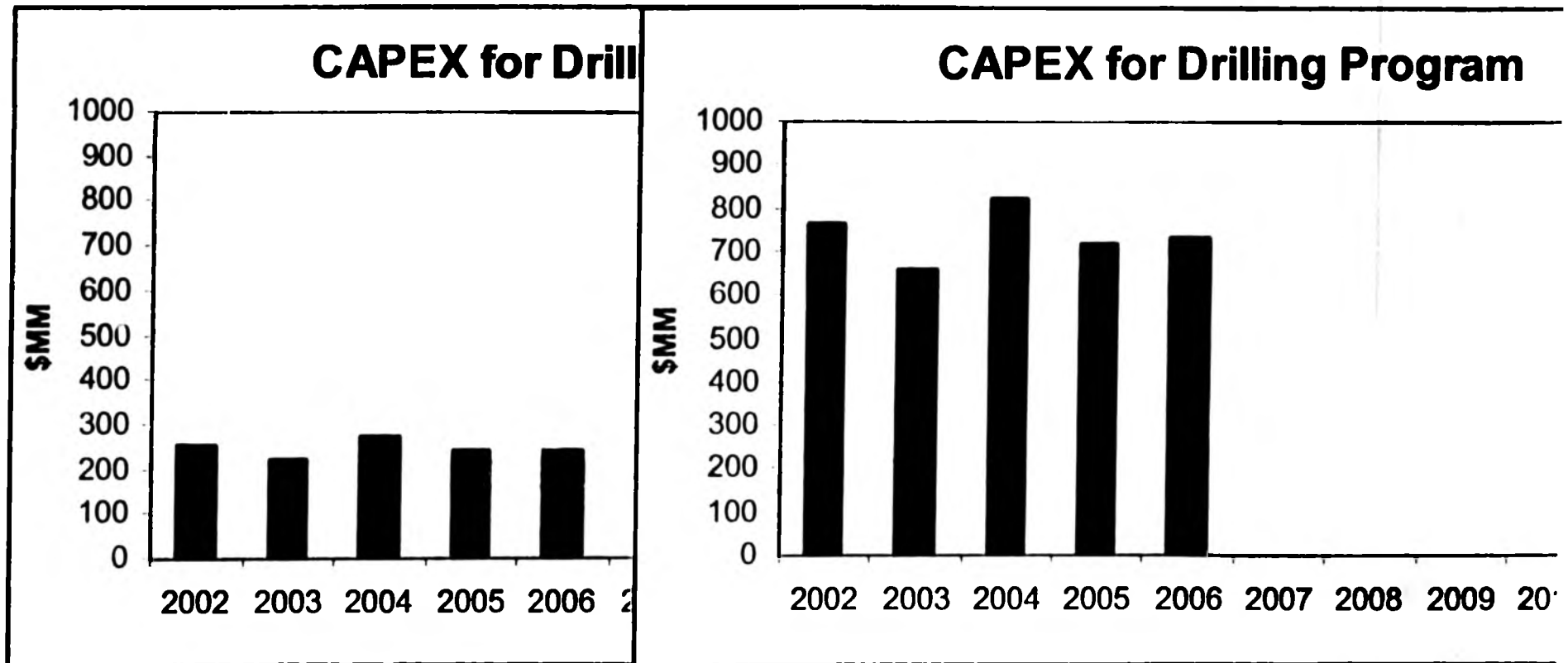
	2002	2003	2004	2005	2006
Capex	255	220	275	240	245
MMbls	120	90	80	60	50
\$/bbl	2.13	2.44	3.44	4.00	4.90

- Contrast the above per barrel F&D costs with:
 - \$2 or less CAPEX for Prudhoe and Kuparuk to date
 - \$19bn to produce 9.5 bn bbls
 - The P/K upside at \$3.5(15%), \$7.7 (6%), \$12 (3%)
 - Pioneer's view of average F&D for Lower-48 of \$14



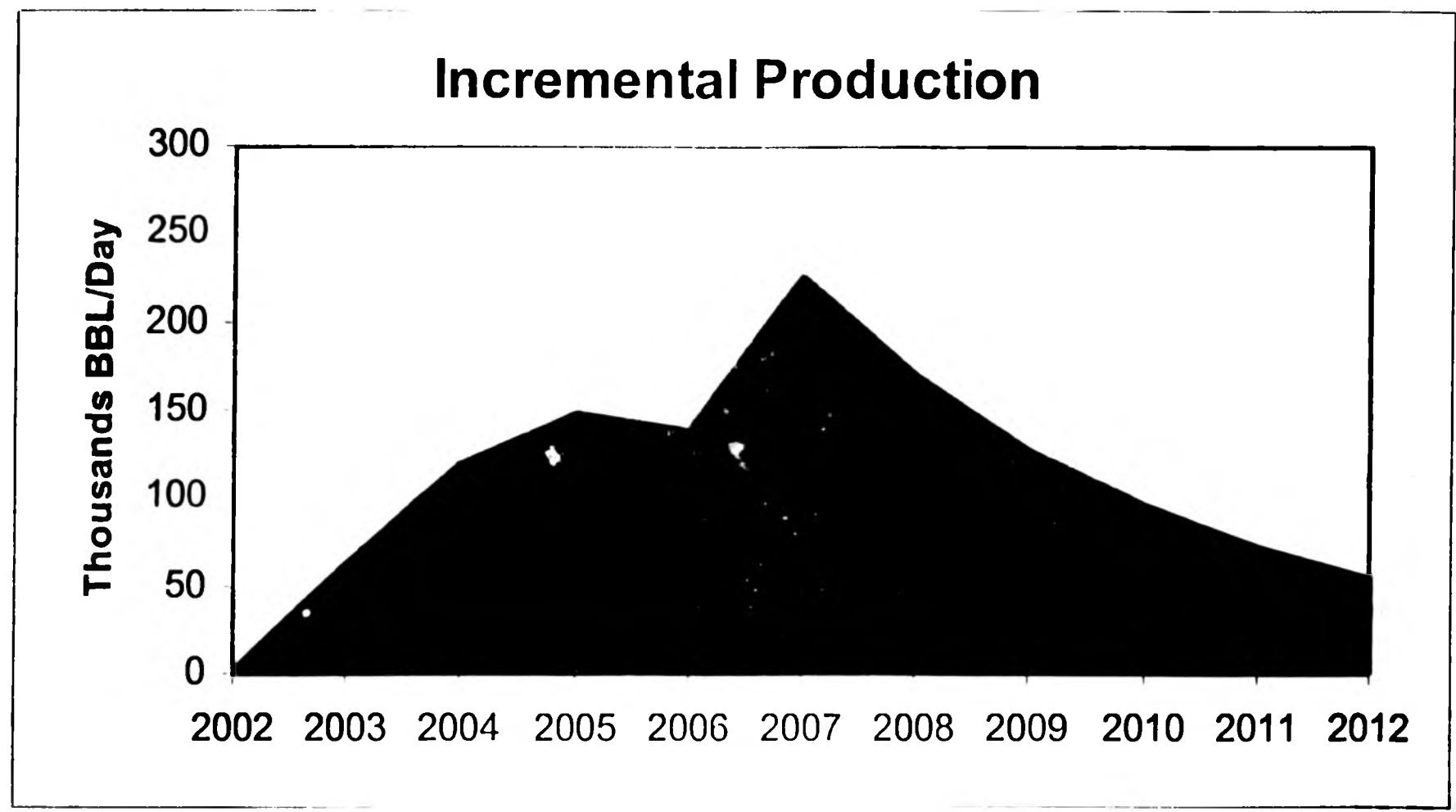
5 Year Prudhoe Drilling Program

- Drilling capex – 300% for added facilities/injection





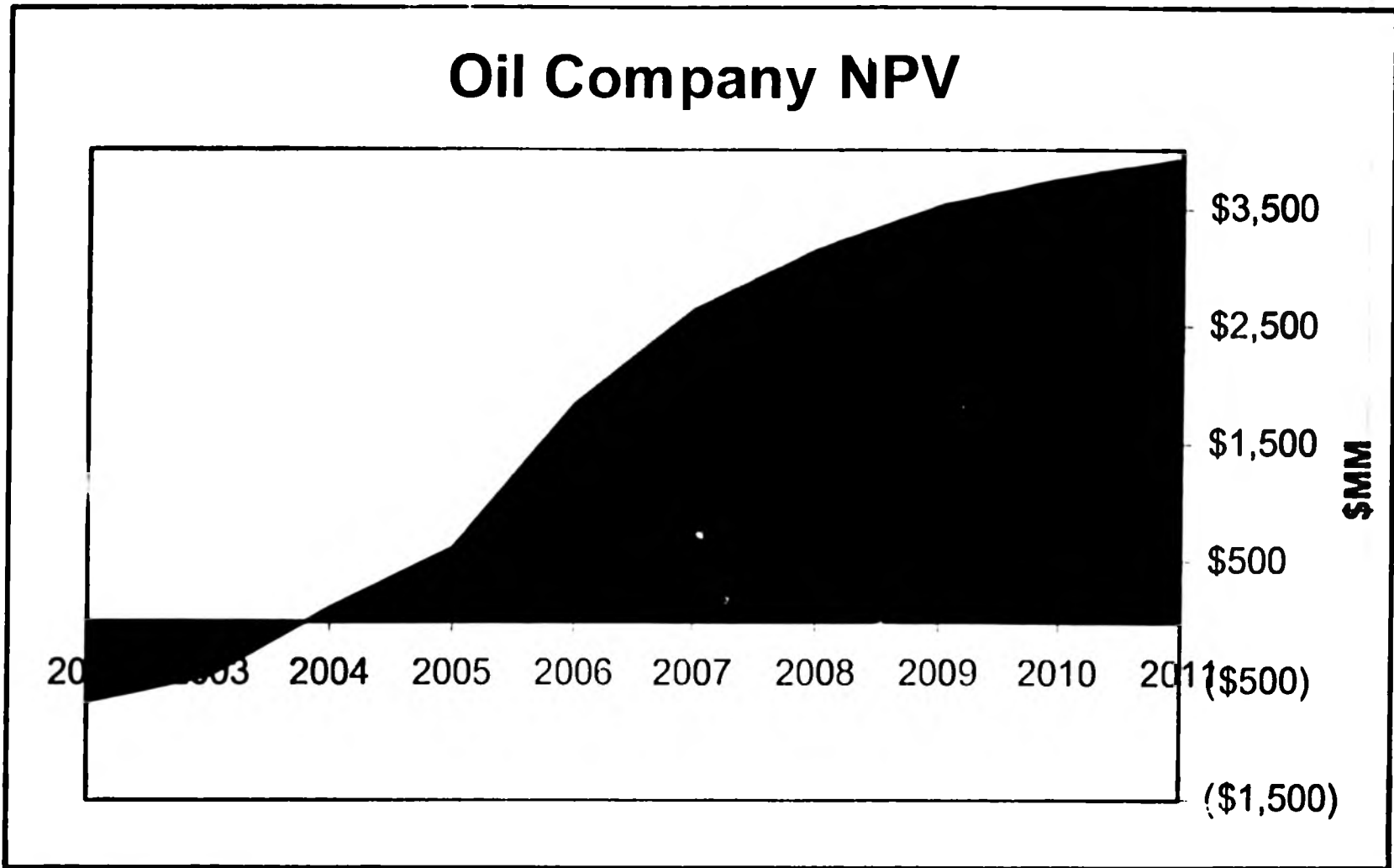
BP – Prudhoe Bay



Revised from House version to fix plotting error
– underlying financial data/results are unaffected



BP Prudhoe Bay



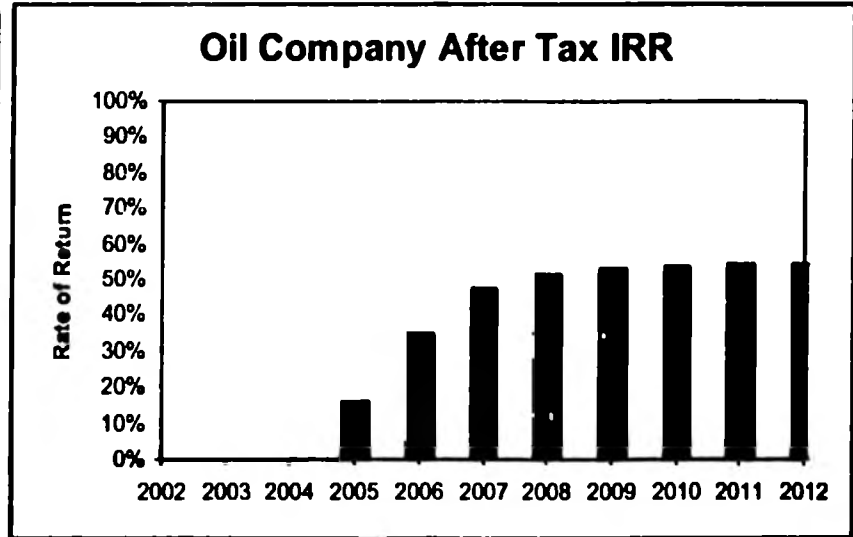
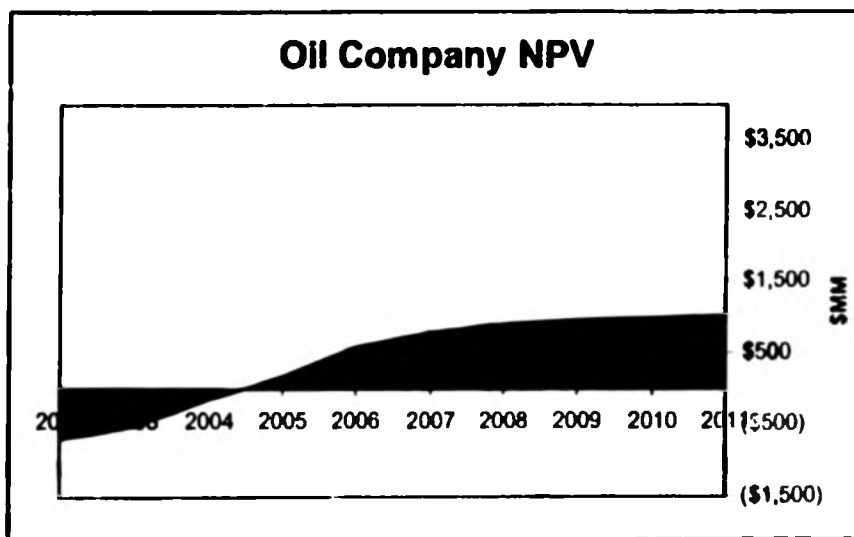
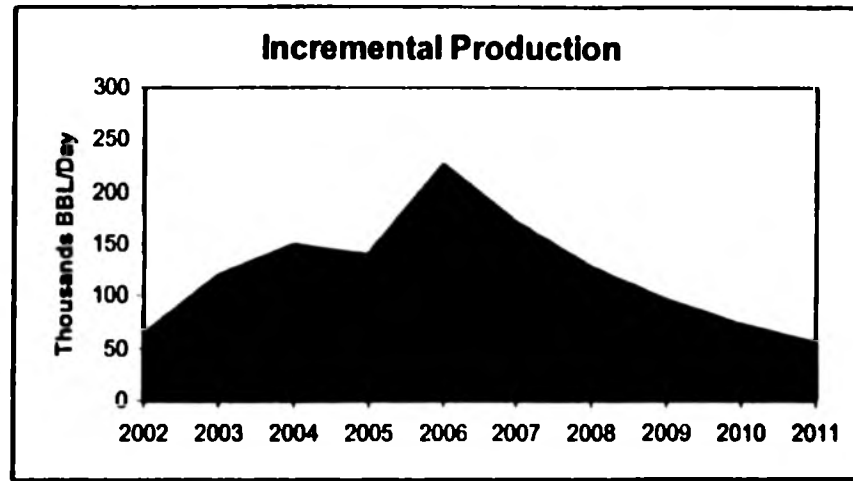
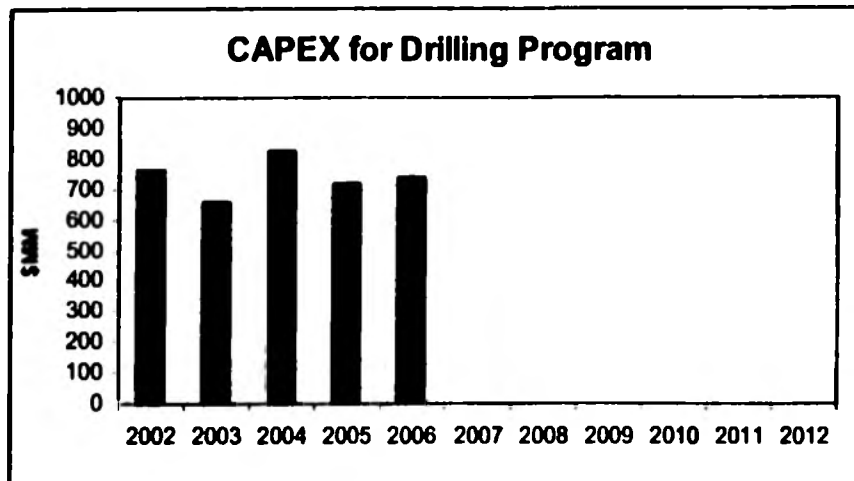
Robust drilling program



- **Remains profitable at:**
 - 300% capex
 - 200% opex
 - 25% discount rate
 - \$50 ANS
 - High progressivity



Overly Stressed Case





Model Demonstration

North Slope Potential



Production Drives Revenue



Decline Rate	15%	6%	3%
Produced Barrels	1.3 bn	3.9 bn	7.5 bn
Industry Investment	\$5 bn	\$25 bn	\$70 bn

Status quo

- **Built a generic model based on the above barrels and investments**
 - Used indicated decline rates
 - 250,000 bpd abandonment rate



Under PPT

Production Drives Revenue



Decline Rate	15%	6%	3%
Produced Barrels	1.3 bn	3.9 bn	7.5 bn
Industry Investment	\$5 bn	\$25 bn	\$70 bn

Status quo

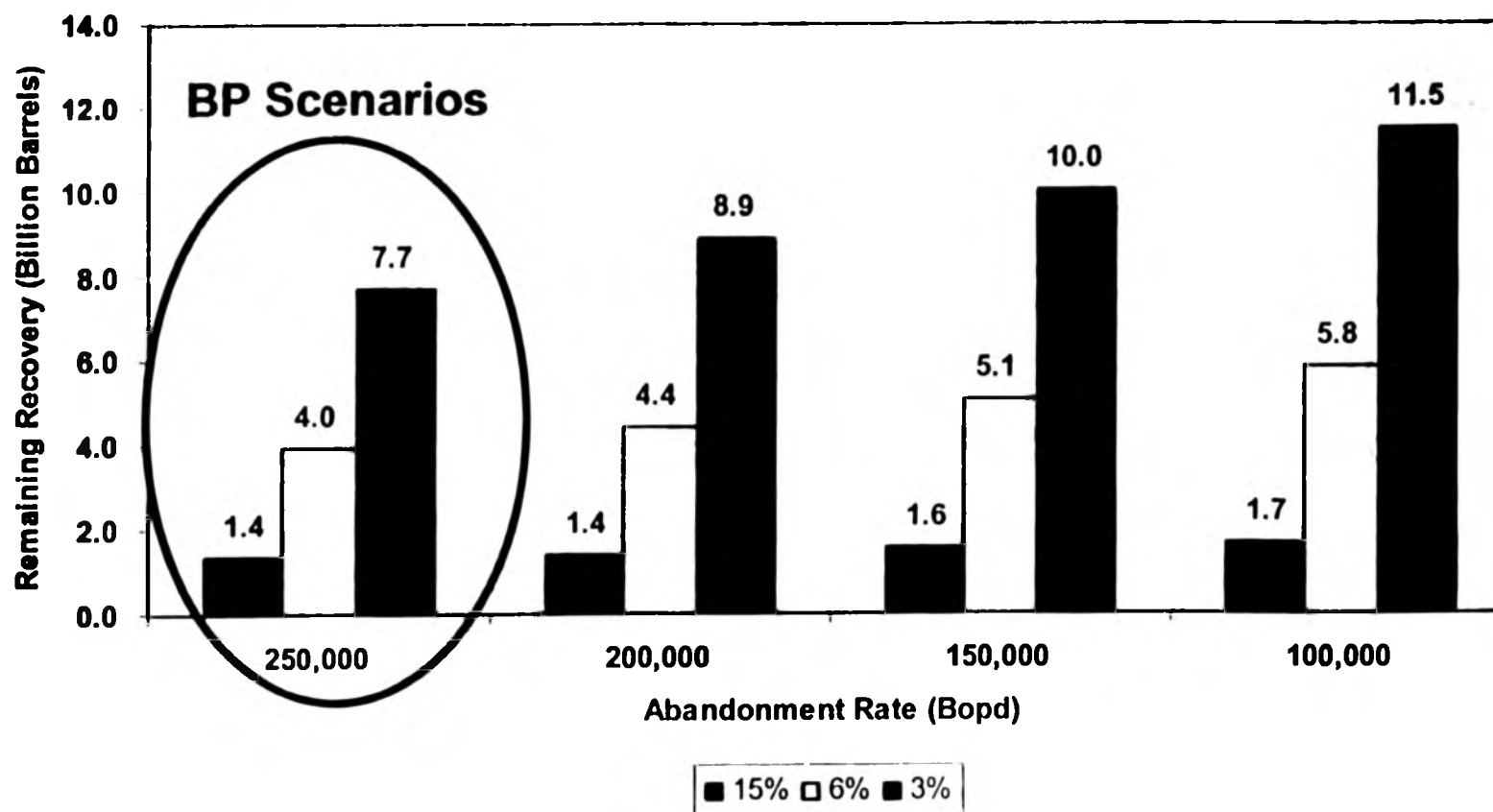
- | | | | |
|-----------------|---------------|---------------|----------------|
| • NPV10 = \$Bn | • \$15 - \$20 | • \$30 - \$40 | • \$35 - \$45 |
| • NPV0 = \$Bn | • \$22 - \$27 | • \$55 - \$75 | • \$90 - \$125 |
| • NPV0 = \$/bbl | • \$15 - \$20 | • \$14 - \$19 | • \$12 - \$17 |

~ \$80/bbl WTI, \$70/bbl NS



North Slope Abandonment

Impact Of Abandonment Rate On North Slope Recovery



Summary



- **Oil Company must show “reasonable certainty” about future spending to be able to book reserves**
 - There is pressure in the market place to declare ‘proved reserves’ as soon as feasible -- important to shareholder and analyst growth expectations
 - If the production volumes associated with the 6% and 3% decline scenarios have already been booked as proved reserves, then to **not** undertake the continuing investments would require a significant write down of reserves
- **Drilling prog' am is so profitable that under even the most extreme net tax structure, oil companies would want to continue their reinvestment program.**

Goals



Goals for Fiscal Design

- **Based on hearings, discussions and other dialog we (GCA) see the following as the goals you are trying to achieve in this special session:**
 1. Fields with larger **profitability** should be paying more taxes
 2. Encourage investment in existing units
 - Reinvestment in producing assets
 - Investment in new developments
 - ❖ Conventional
 - ❖ Unconventional (i.e. heavy oil)
 3. Encourage new investment outside legacy units
 - Level playing field for incumbents and new entrants
 4. Durability
 - Don't want to be back 'fixing' things
 5. Build on prior tax dialogue



(3) Encourage New Investment

- **Fiscal system should encourage investment in new fields**
 - Investment credits
 - Net Operating Loss credits
 - Aid to new entrants with no existing tax base
 - Lower tax rate for fields with higher cost structure
 - More distant from infrastructure
 - Heavy Oil
 - Gas
- **Is base rate low enough?**
 - Additional barrels down TAPS extends production from existing reservoirs



The Fiscal Design Challenge

- **The Take**

- (1) Fair share of the high margins currently being realized
- Progressive structure to adapt to changes in:
 - Price
 - Production
 - Cost

- **The Give Back**

- (2) Encouragement to reinvest profits for more development inside legacy units

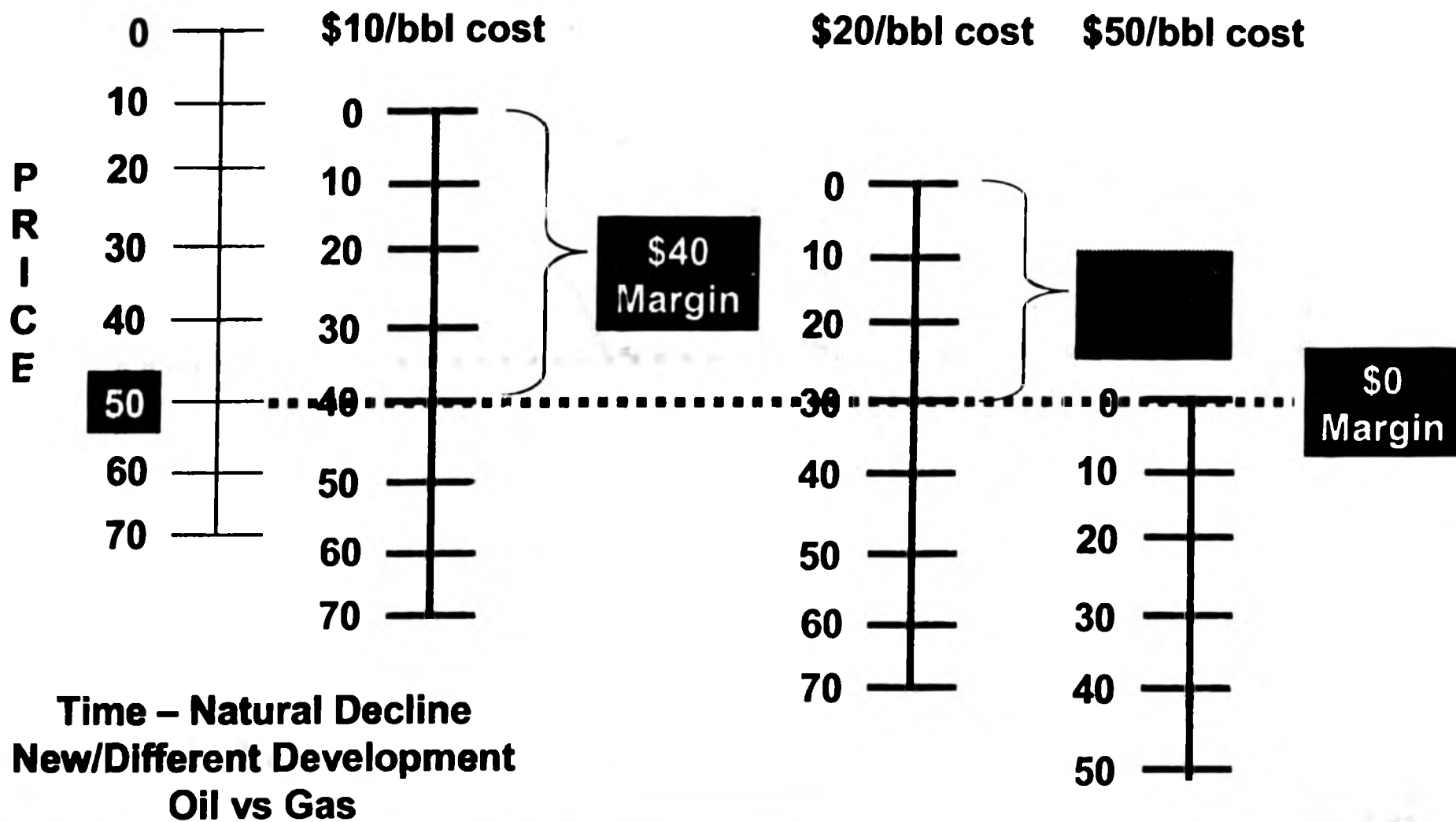


Key Point Easily Misunderstood

Price \neq Margin

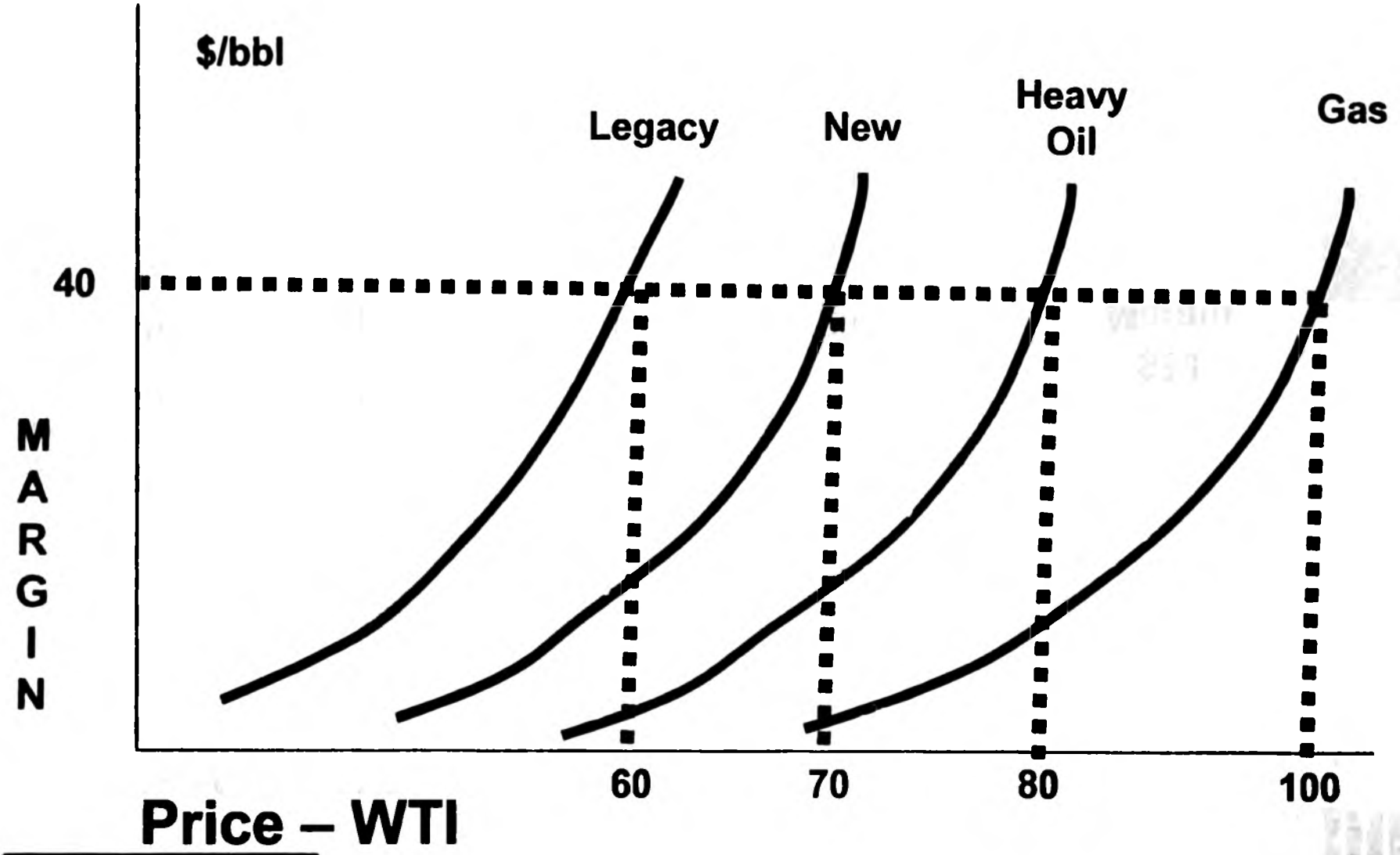


Price versus Margin





Margin versus Price



CONFIDENTIAL

The Net Tax Story





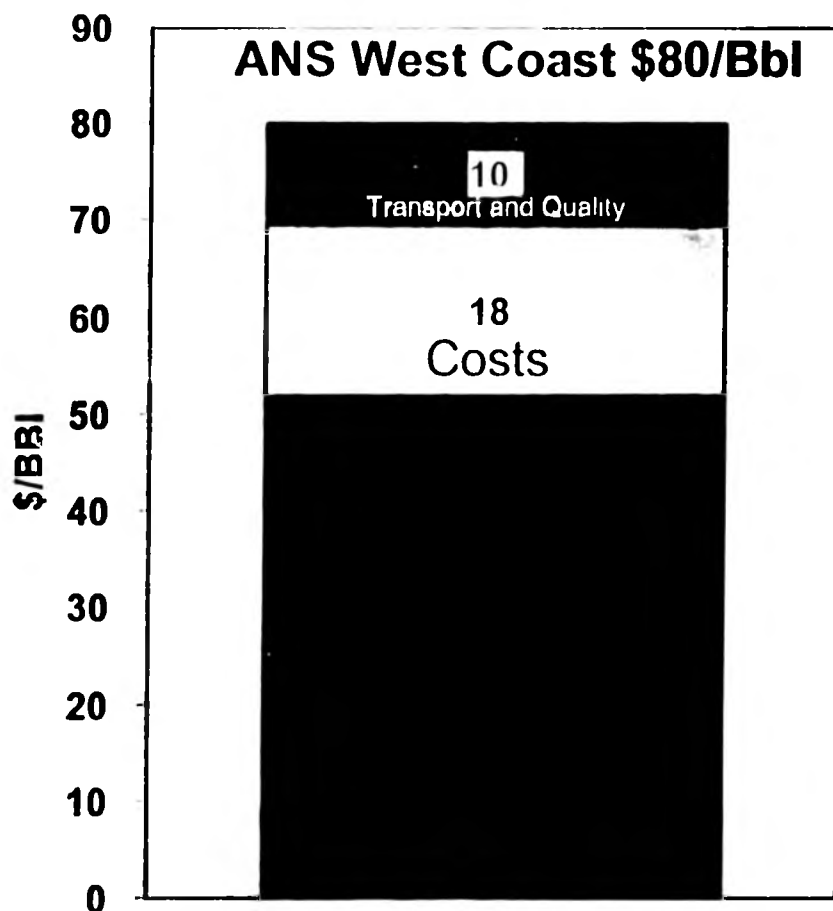
PPT As Often Described

- **Tax on net profits**
- **Contains progressivity feature that increases tax rate with increasing profitability per barrel**
- **Ringfenced so that profit per barrel reflects a company's entire portfolio**



The Information Used

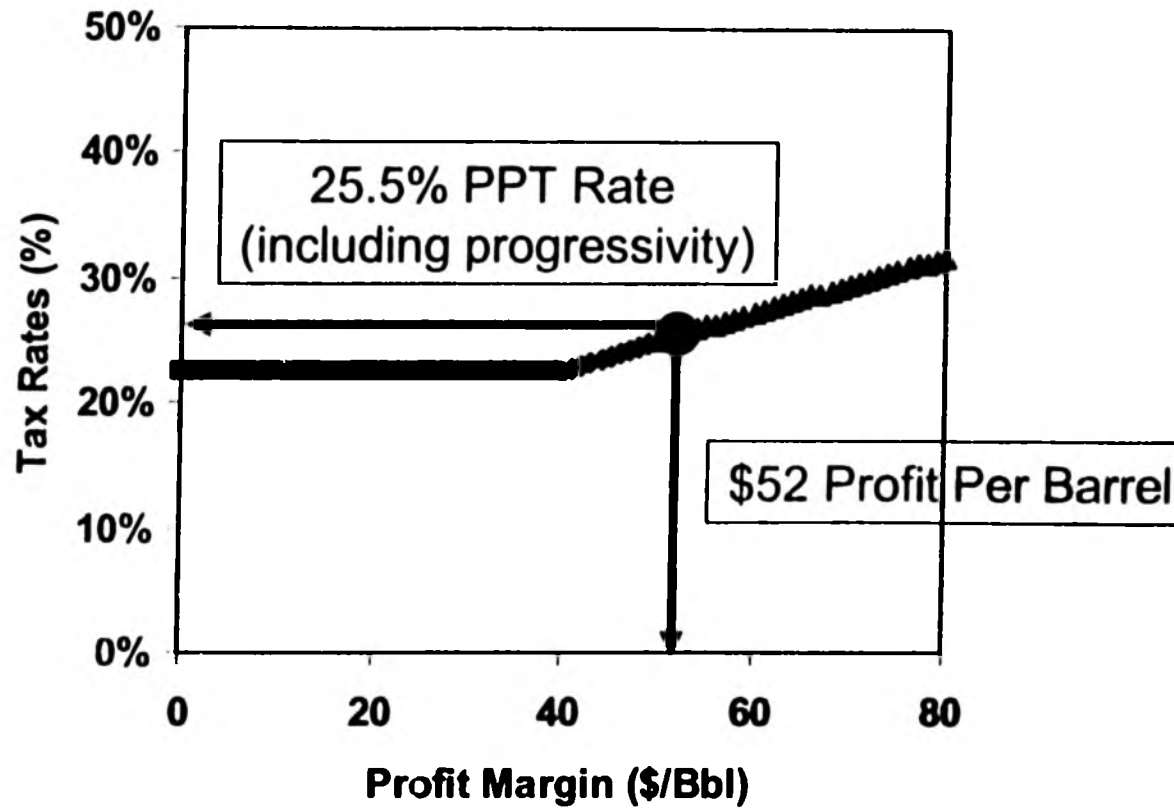
Portfolio Profitability



Based On \$52/Bbl Profit ...



Tax Rate Structure (Incorporating Progressivity)



Progressivity



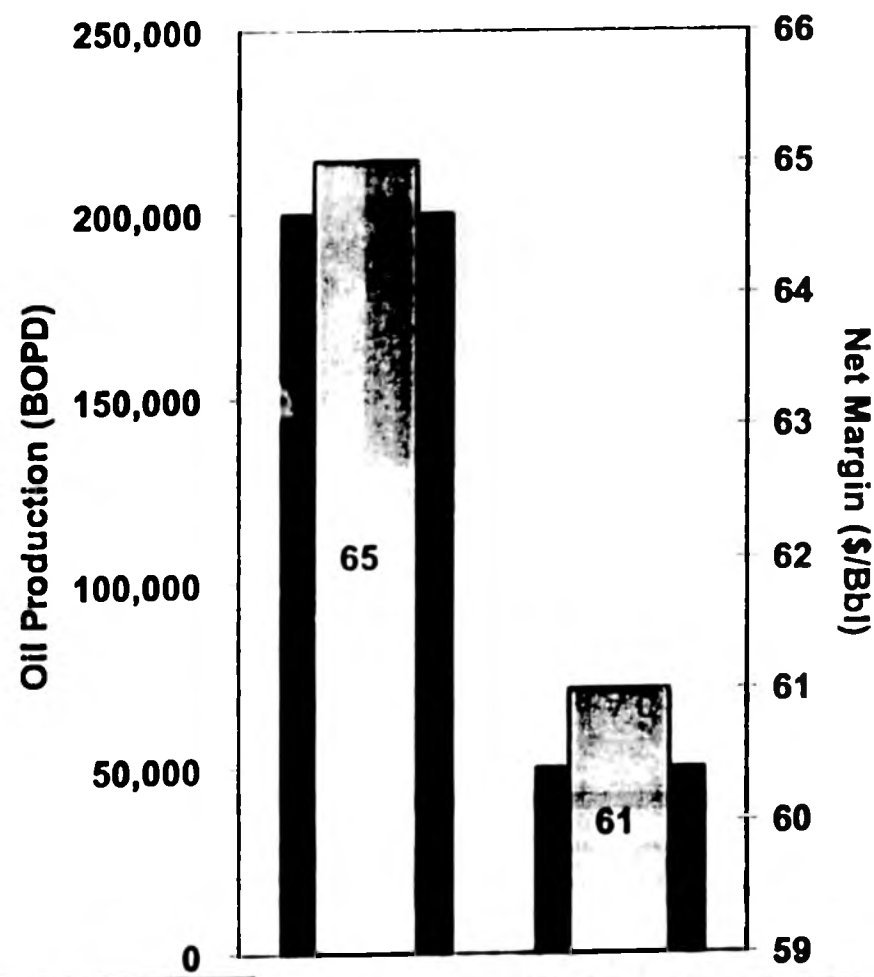
- **“Net” taxes all fields at a single rate**
 - No, it taxes different fields or reservoirs based on their individual profitability

Understanding How “Net” Works



Now, Add Another Field

Expanded Portfolio



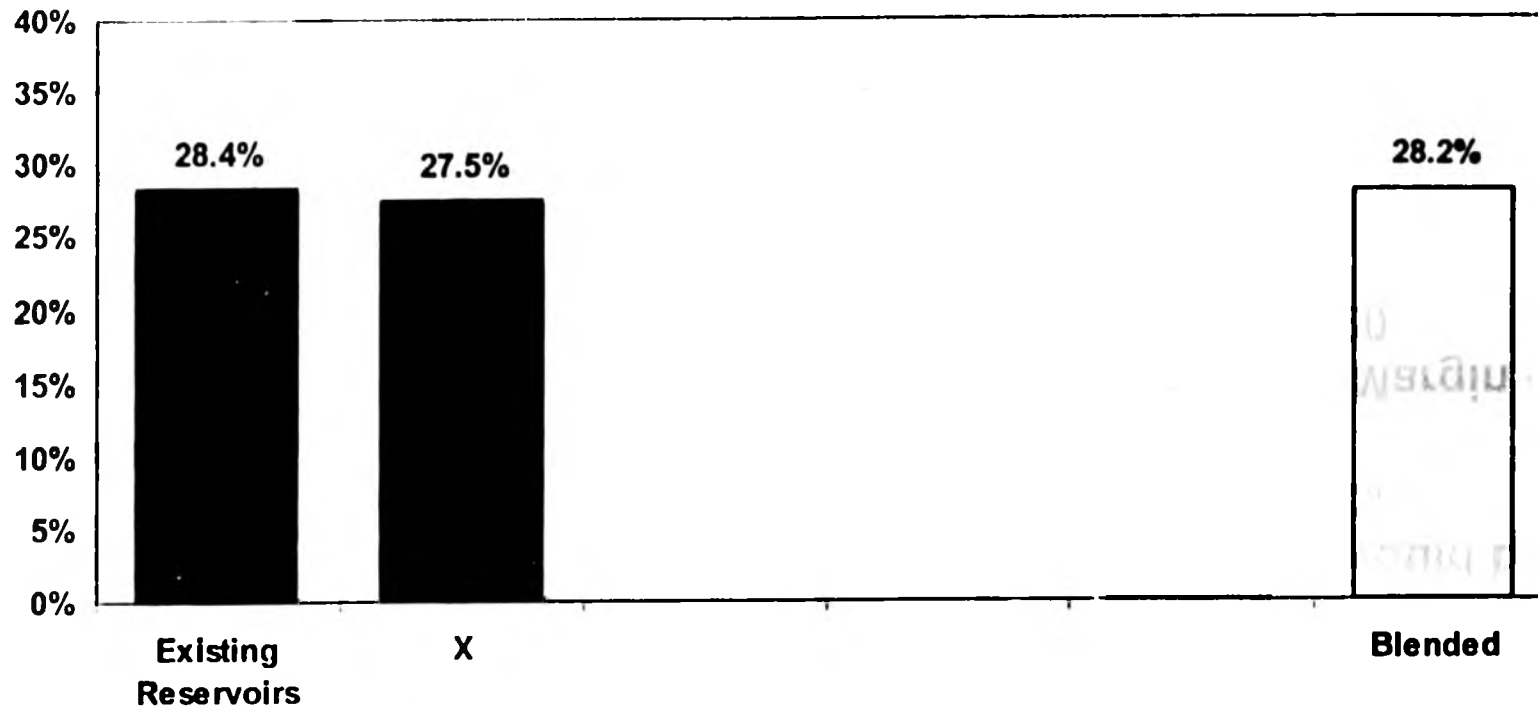
**PPT Rate on these fields
Combined would be
28.2%**

**Average Net Margin Is
\$64.20**

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



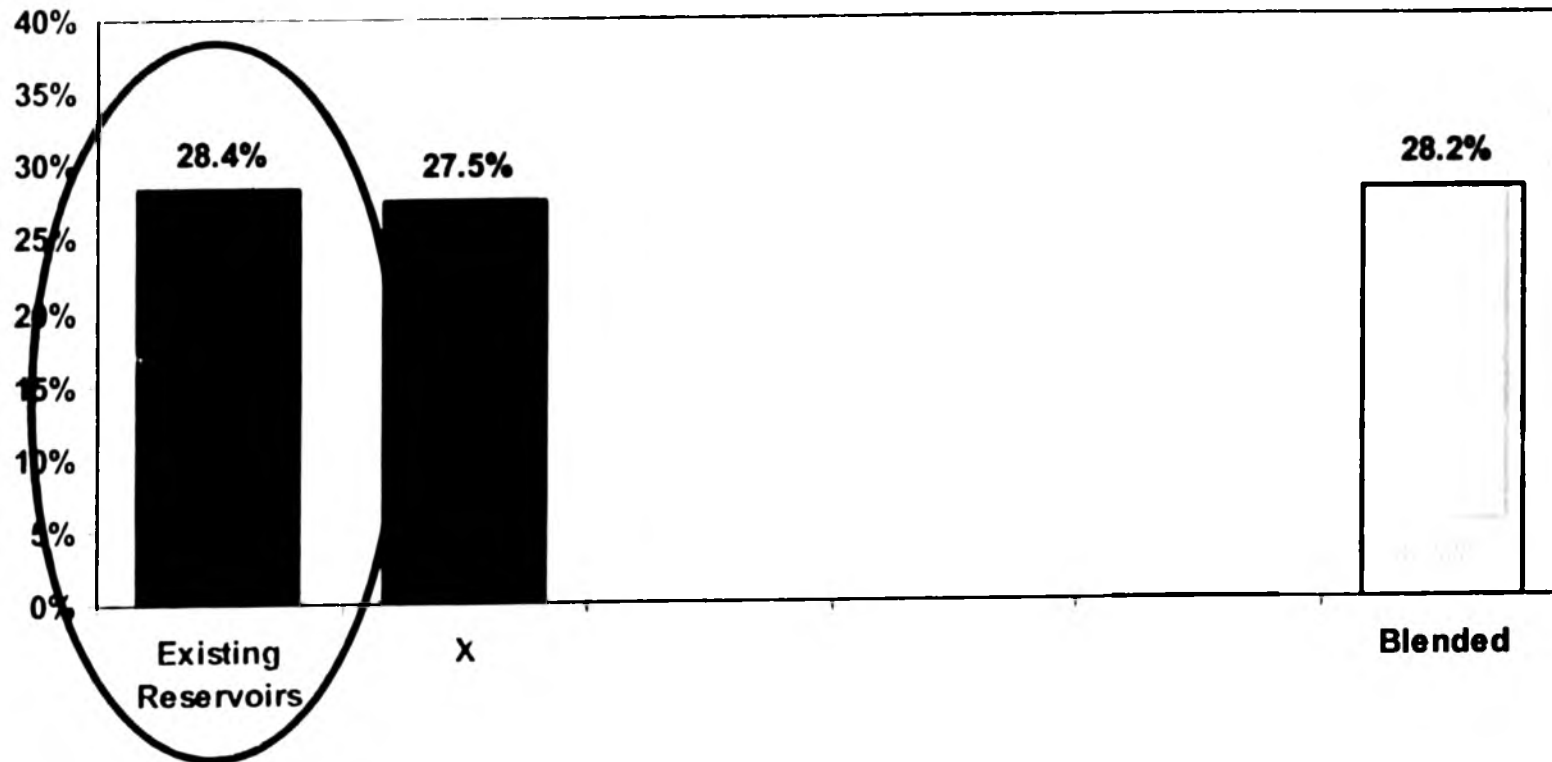
No

Look at this in the way that companies look at it when they make investment decisions

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

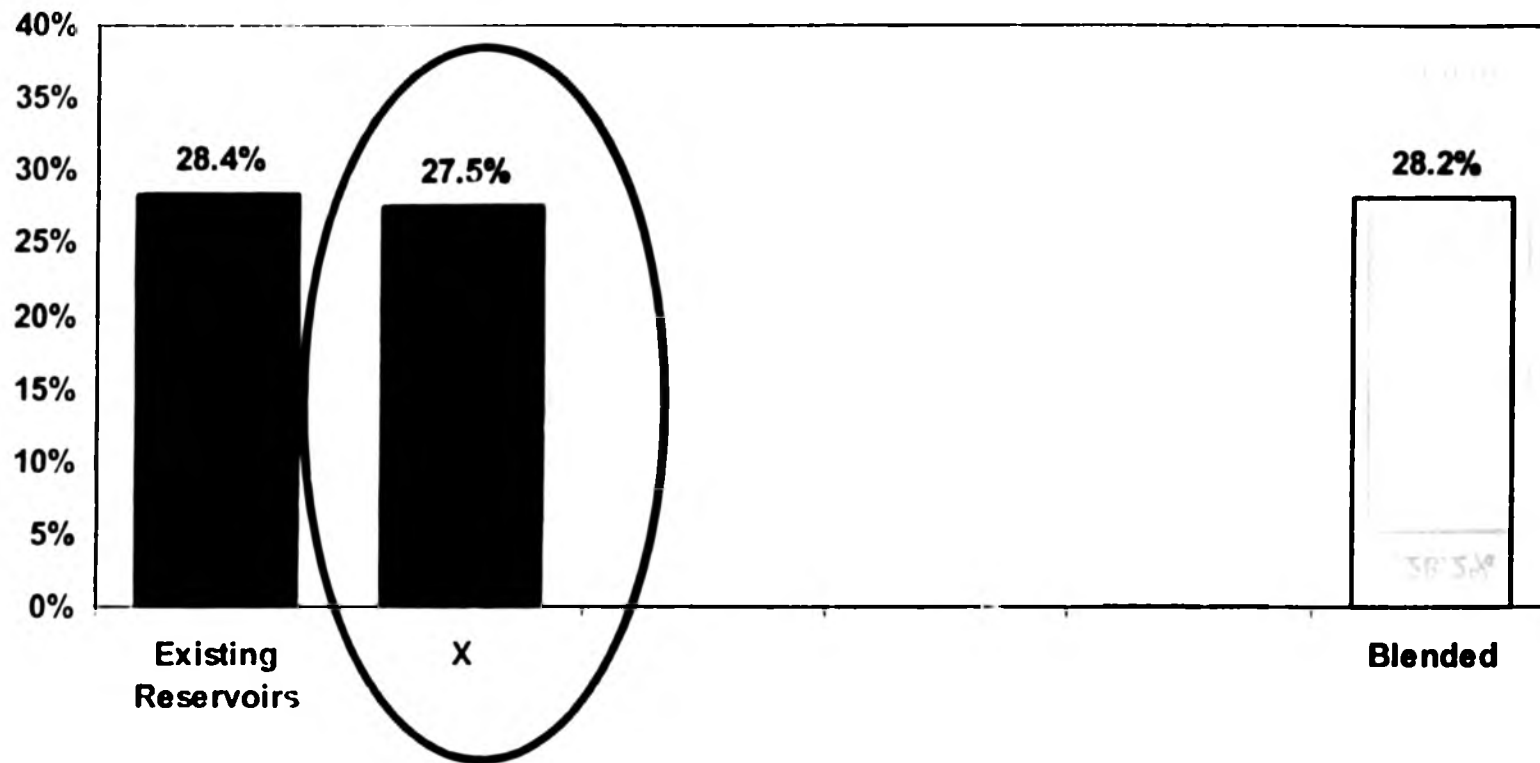


If I had just Existing Reservoirs, and
did not develop anything new, I
would pay tax on my profits at 28.4%

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

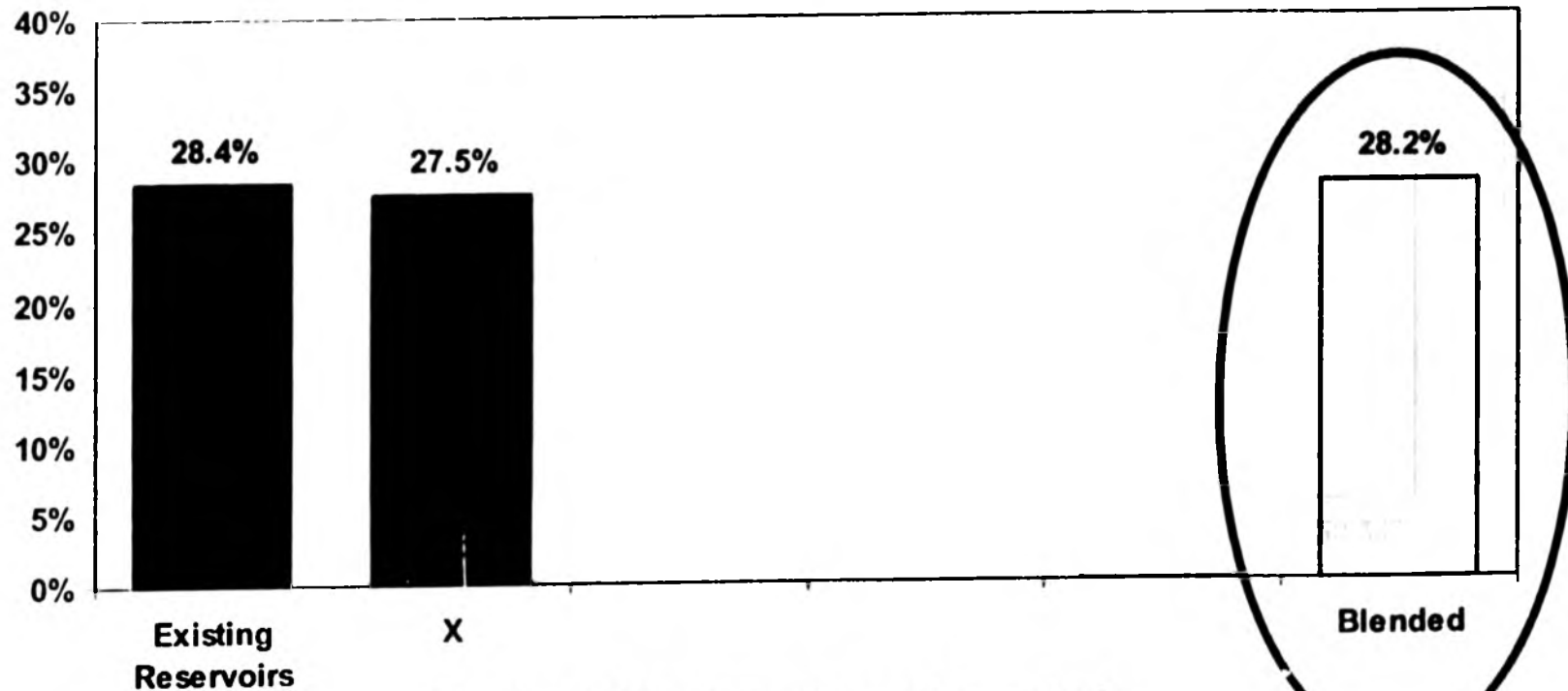


If I had just Field X, I would pay tax on my profits at 27.5% - its margin is slightly lower

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



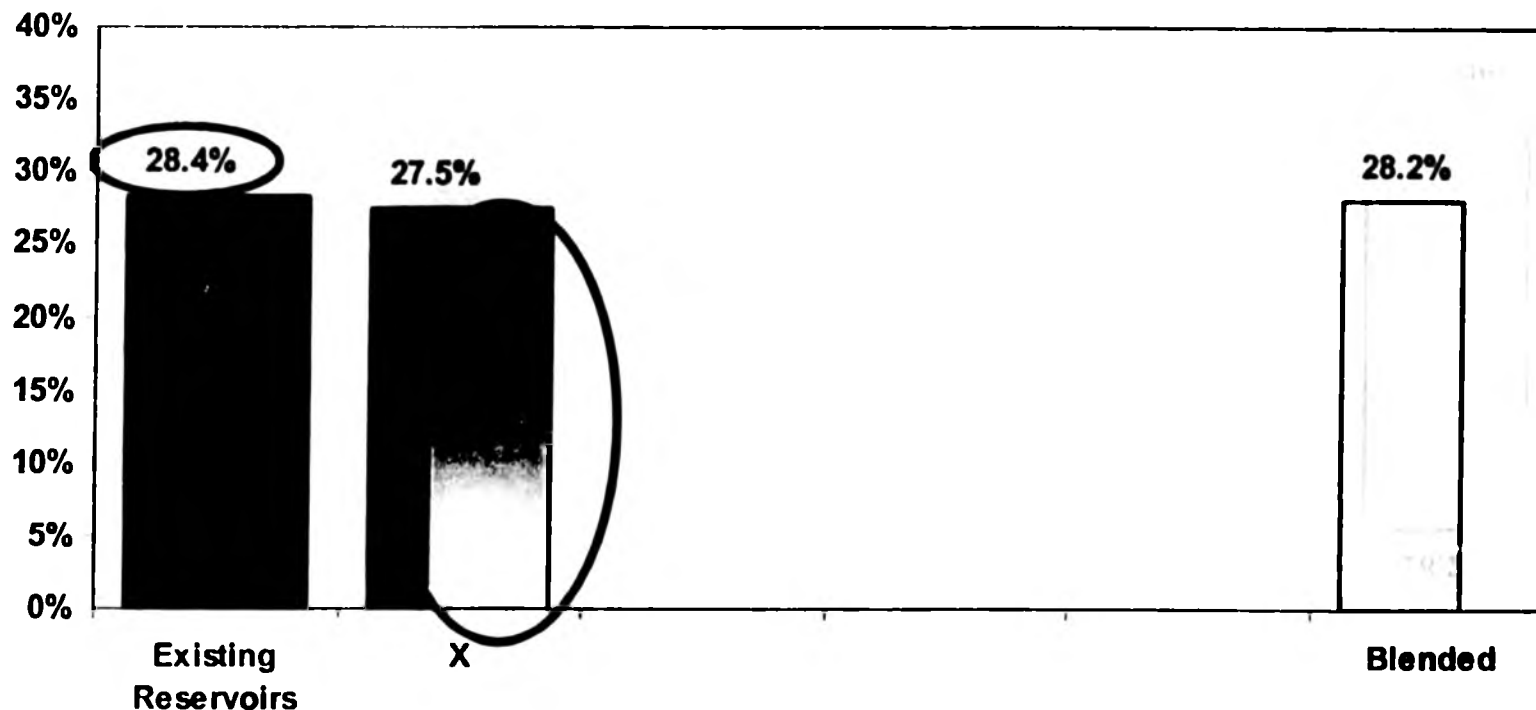
Both fields together, the rate is 28.2%

However, this is not all ...

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

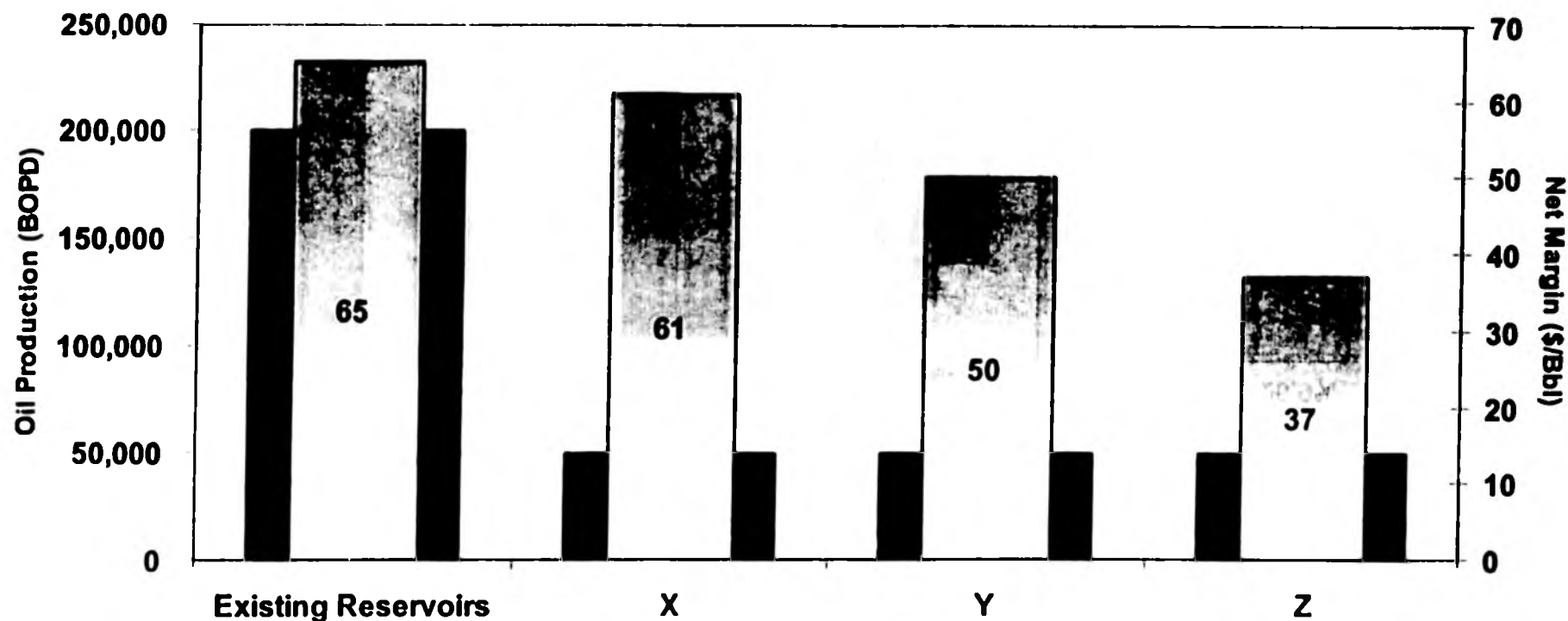


The mathematics of this reduction means that actually while Existing Reservoirs continue to pay tax at a rate of 28.4%, The effective rate on Field X is actually 27.4%
... less than it would be if it were developed stand-alone

This Impact Can Be Seen In A Broader Portfolio



Portfolio Production Rate and Net Margin

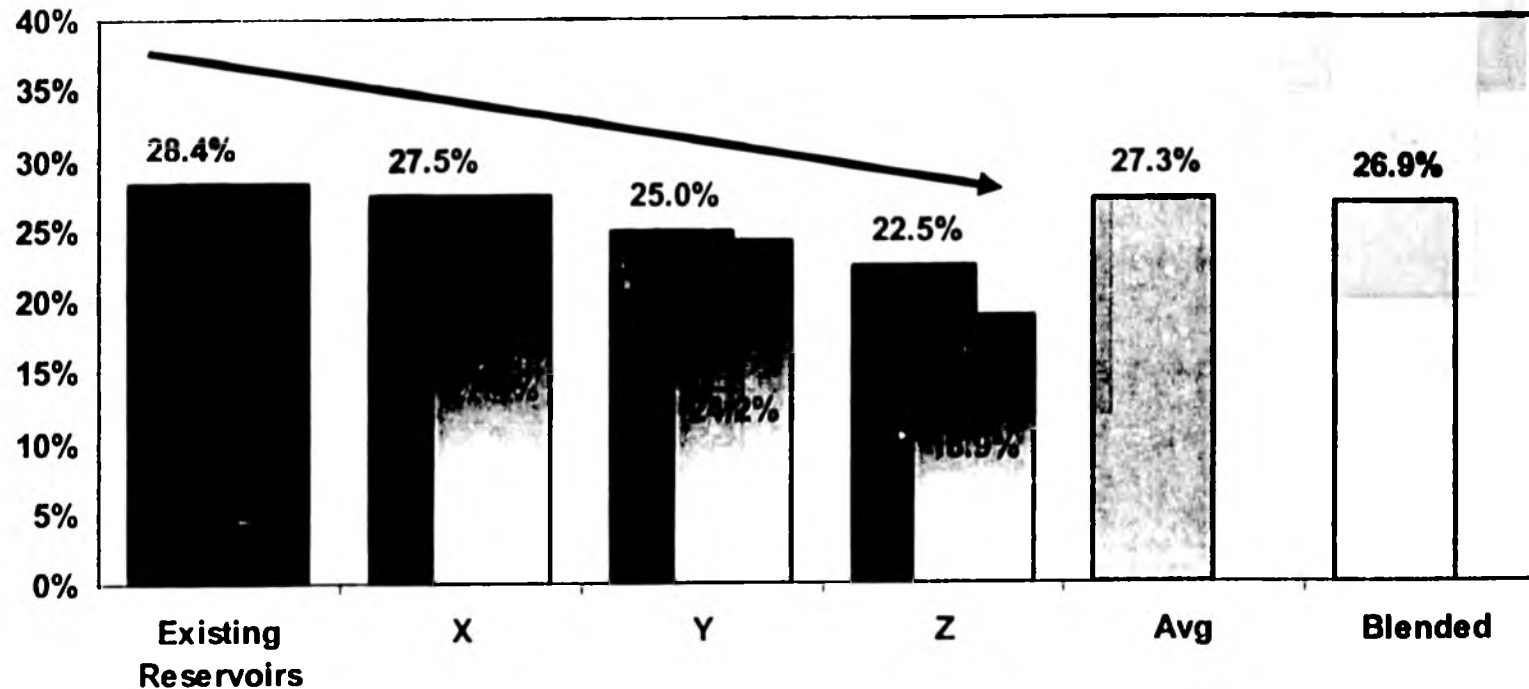


**In this example we have four fields ...
.. One producing 200,000 bopd and
three others each producing 50,000 bopd but of decreasing profitability**

The Impact On The Lower Margin Fields Is More Noticeable



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

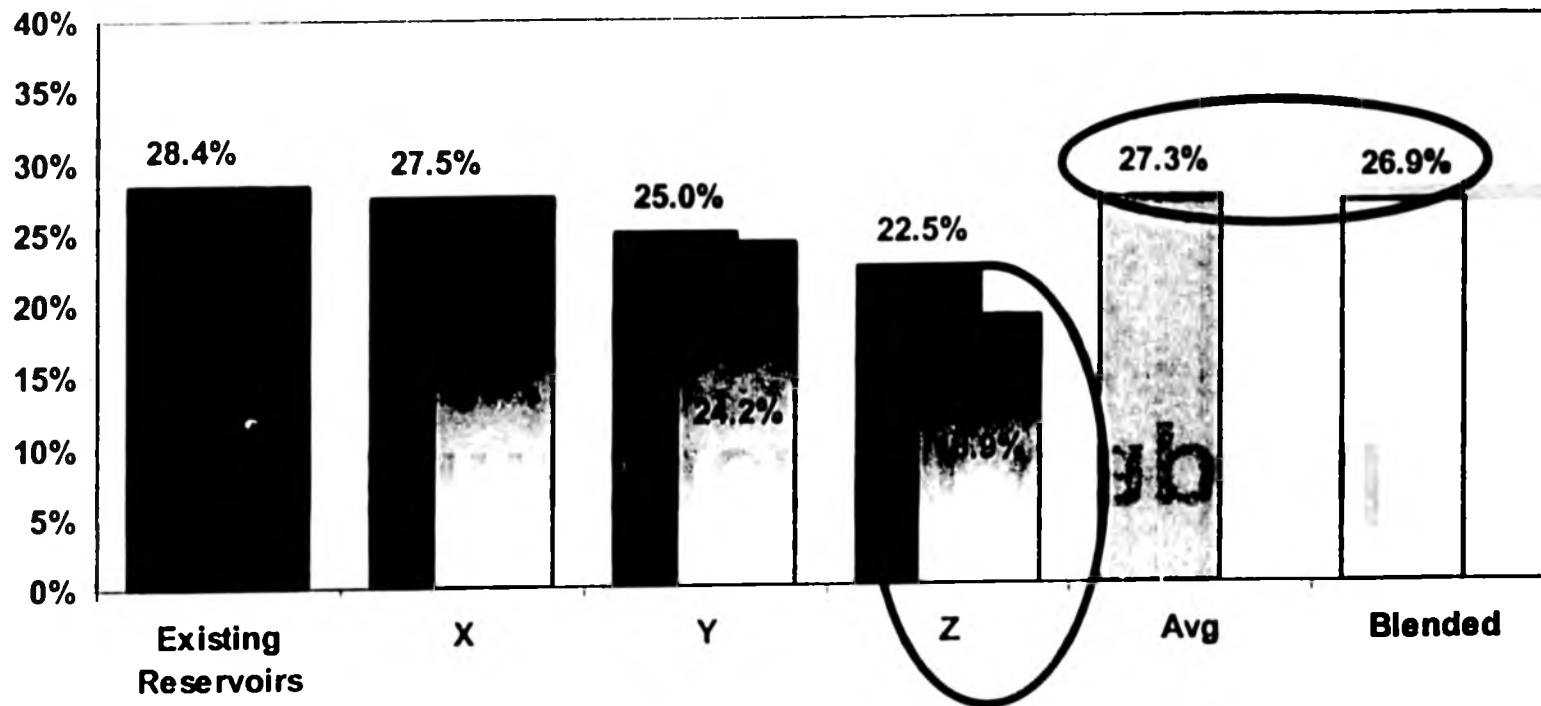


The progressivity can be seen through the lower effective tax rate on lower margin fields

The Impact On The Lower Margin Fields Is More Noticeable



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



The effective rate on some lower-margin fields may even be lower than the basic rate (22.5% in PPT)

This is manifested in the blended rate being lower than the weighted average rate

The Impact Of Capital Investment

1001-1901-01





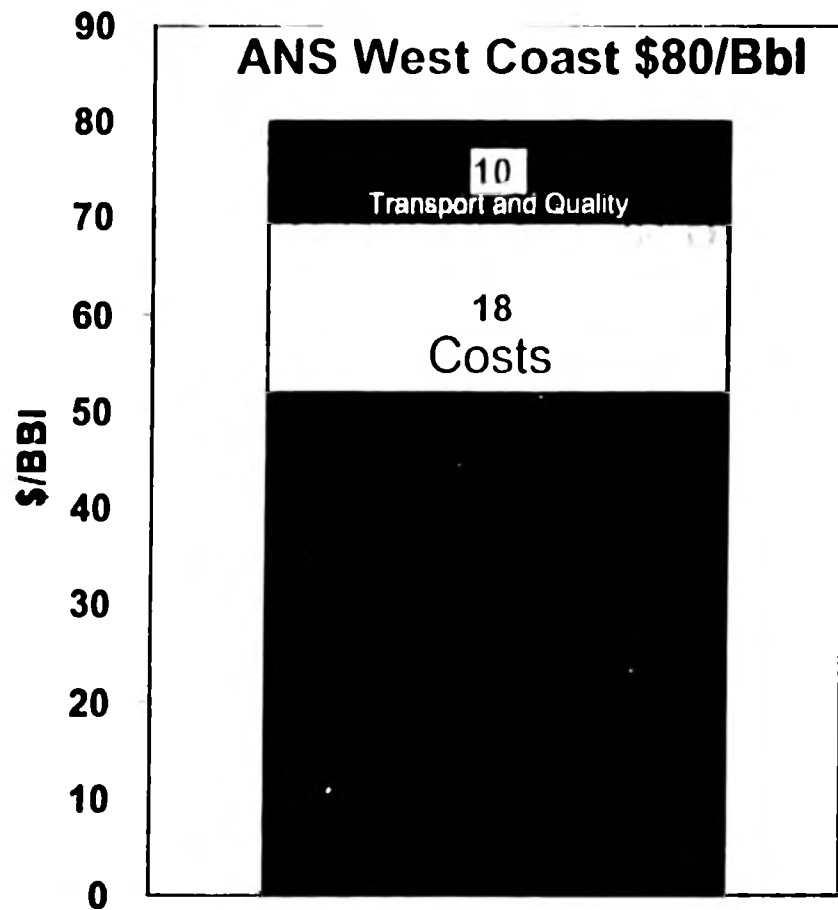
Cash Flow, Not Profit

- **PPT taxes all fields at a single rate**
 - No, it taxes different fields or reservoirs based on their individual profitability
- **Is based on profit per barrel**
 - Not exactly, it is based on net cash flow per barrel after capital investment (for future production)



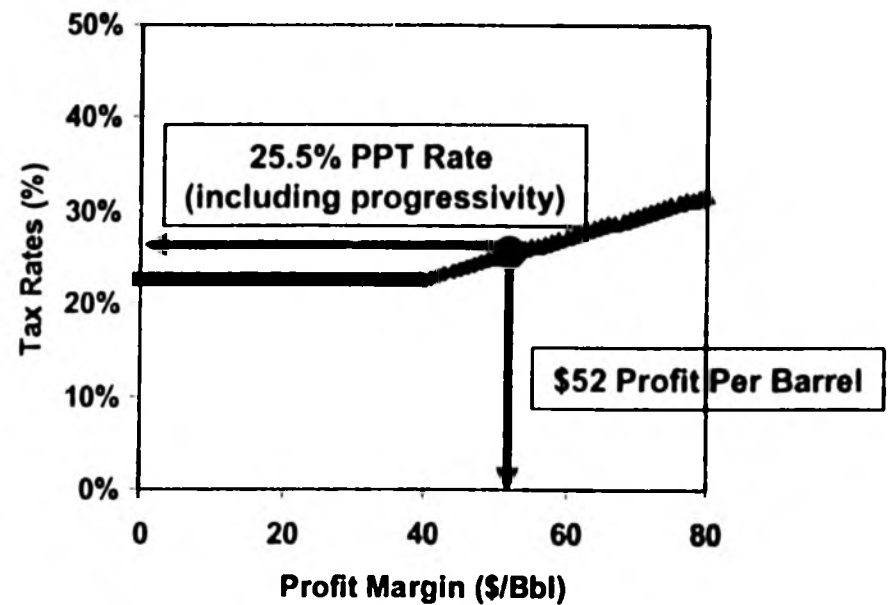
Remember These Slides ?

Portfolio Profitability



The portfolio on the previous slides had a blended rate of 26.9%, not 25.5%

Tax Rate Structure (Incorporating Progressivity)



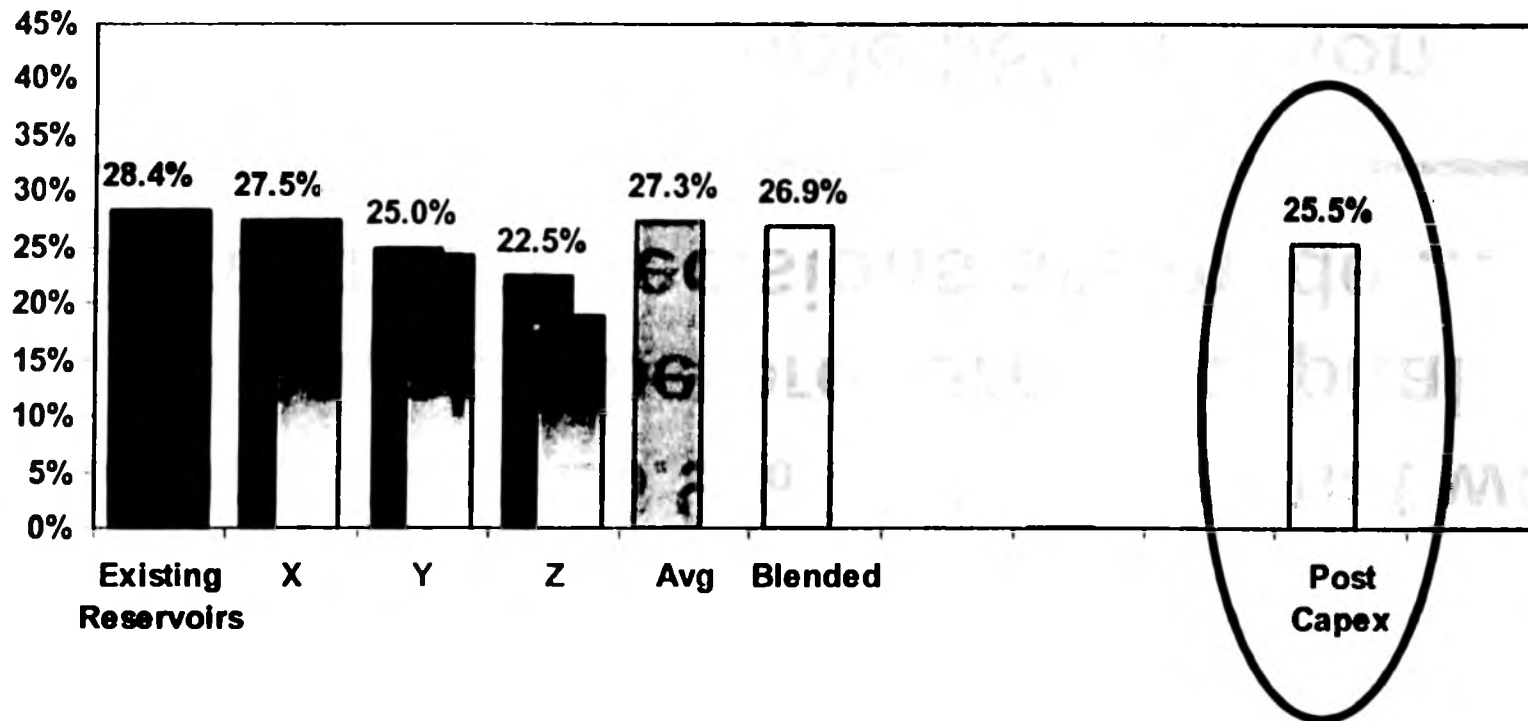
**Assume that 26.9% is the rate that will
be payable before further capital
investment decisions are made ...**

... in this example \$800 million

Capital Spending Has An Impact On Rate, Too



Tax Rate By Field Within A Company - As Affected By Portfolio Blending, Capex And Tax Credit



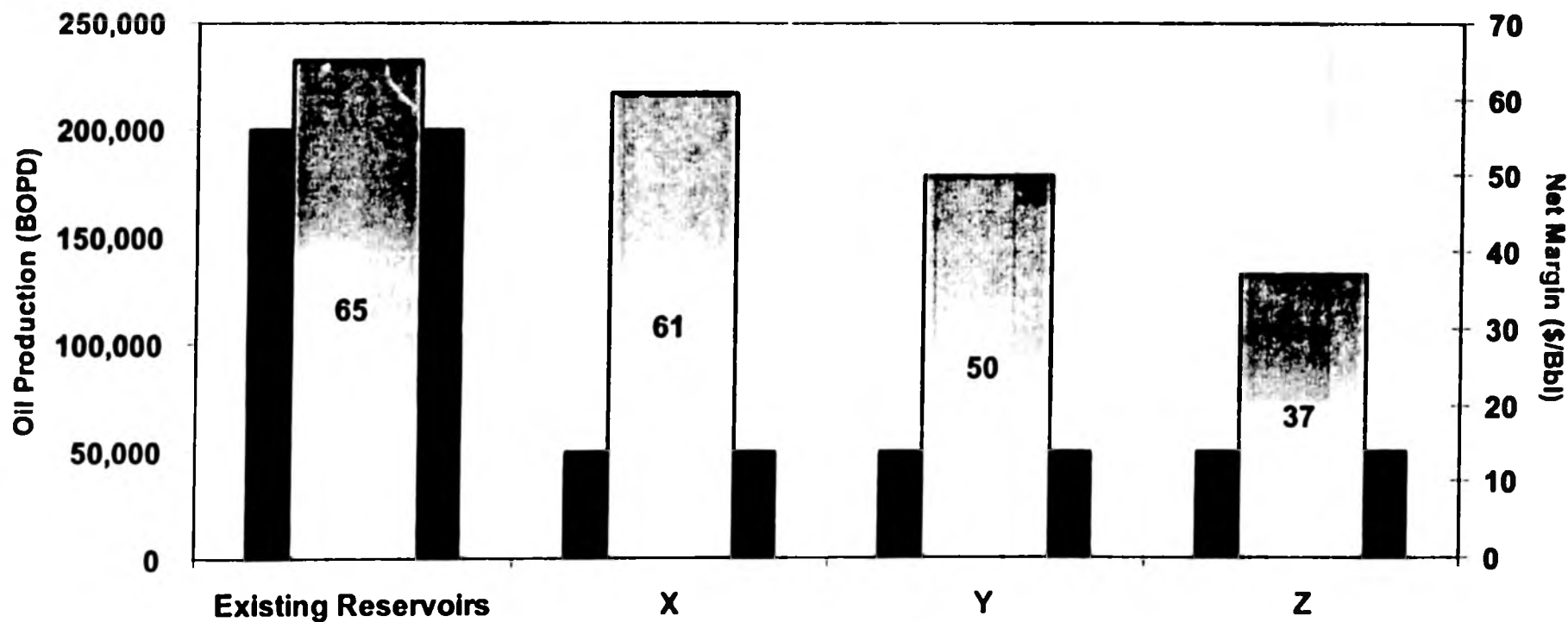
This reduces the rate payable to 25.5%

How ?

\$800 million amounts to \$6.26 Per Barrel Based On This Portfolio



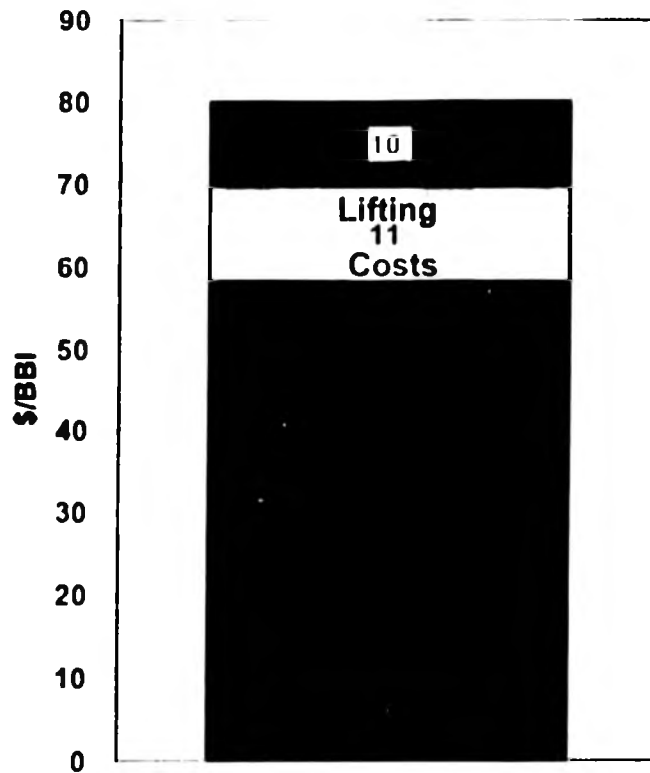
Portfolio Production Rate and Net Margin



The \$6.26 Per Barrel Capital Increases "Costs" And Lowers The Tax Rate

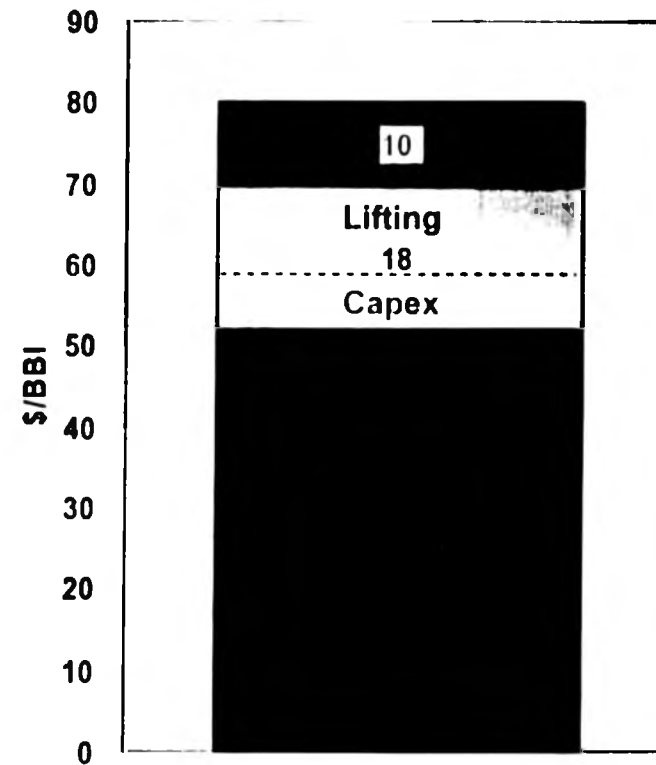


Pre-Capex Margin



Tax Rate
26.9%

Portfolio Profitability

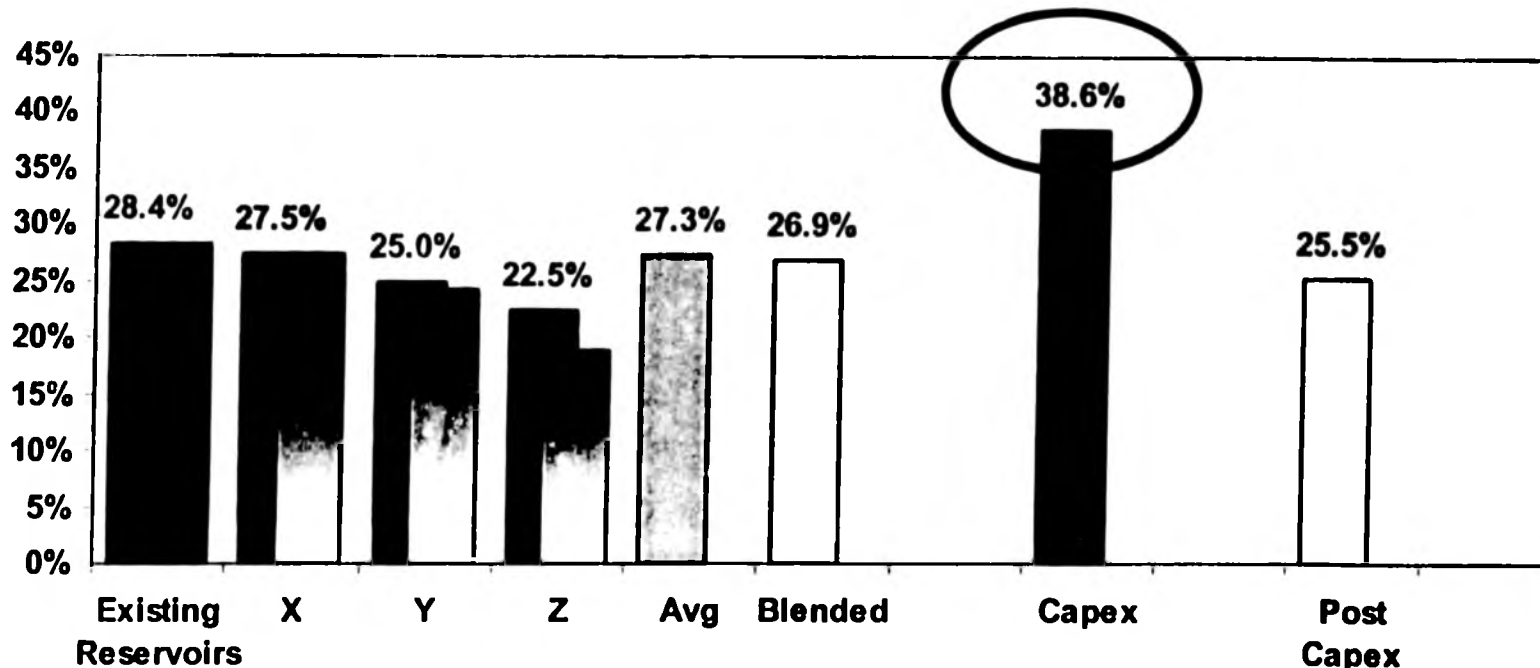


Tax Rate
25.5%

There Is Another Way To Look At This, Though



Tax Rate By Field Within A Company - As Affected By Portfolio Blending, Capex And Tax Credit



It is the same as still paying the blended rate of 26.9% on the portfolio production (or having an effective rate of 28.4% on Existing Reservoirs .. down to 18.9% on Field Z) and Alaska paying* 38.6% of that \$800 million capital

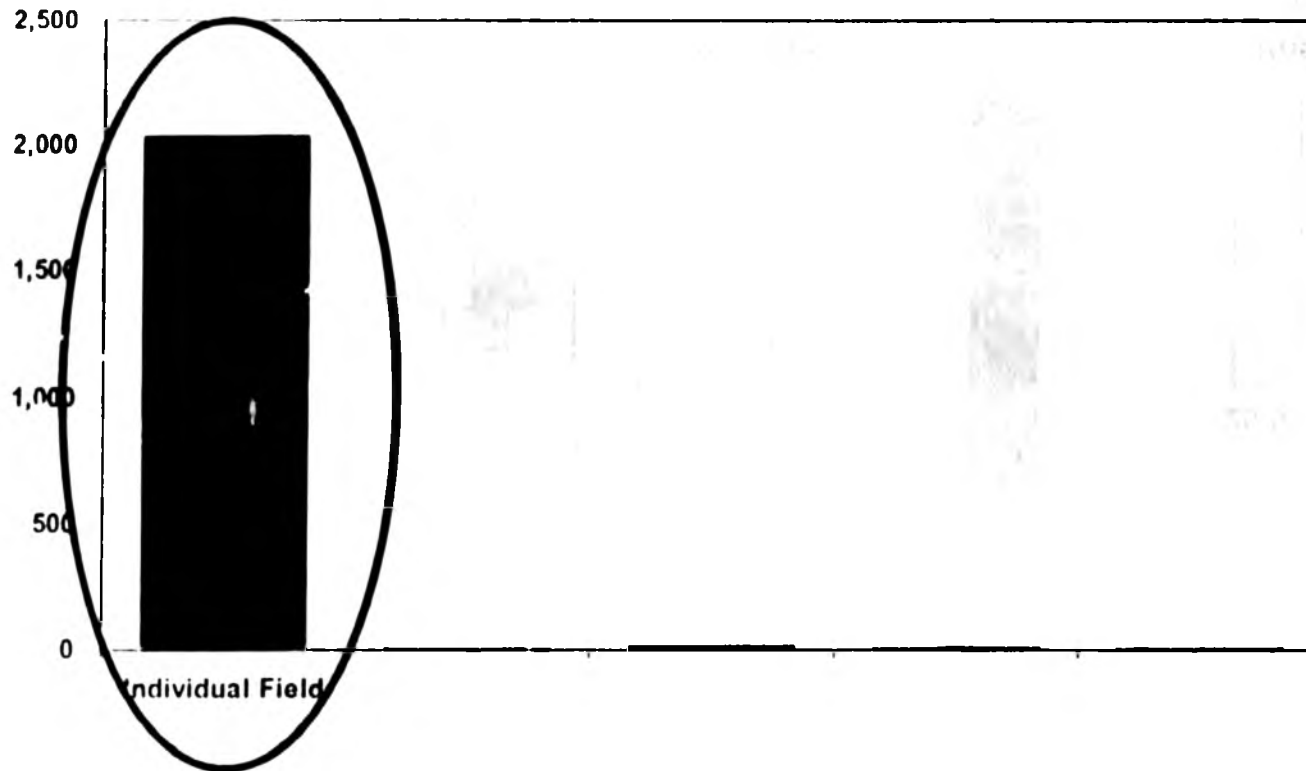
This 38.6% is higher than the Blended tax rate ... and is a function of the capex per barrel and the overall portfolio cost and margin structure

* from PPT only - does not include State and Federal tax effects

Look At The Tax System Through The Amount Of Tax Payable ...



Tax Allocable By Field Within Portfolio



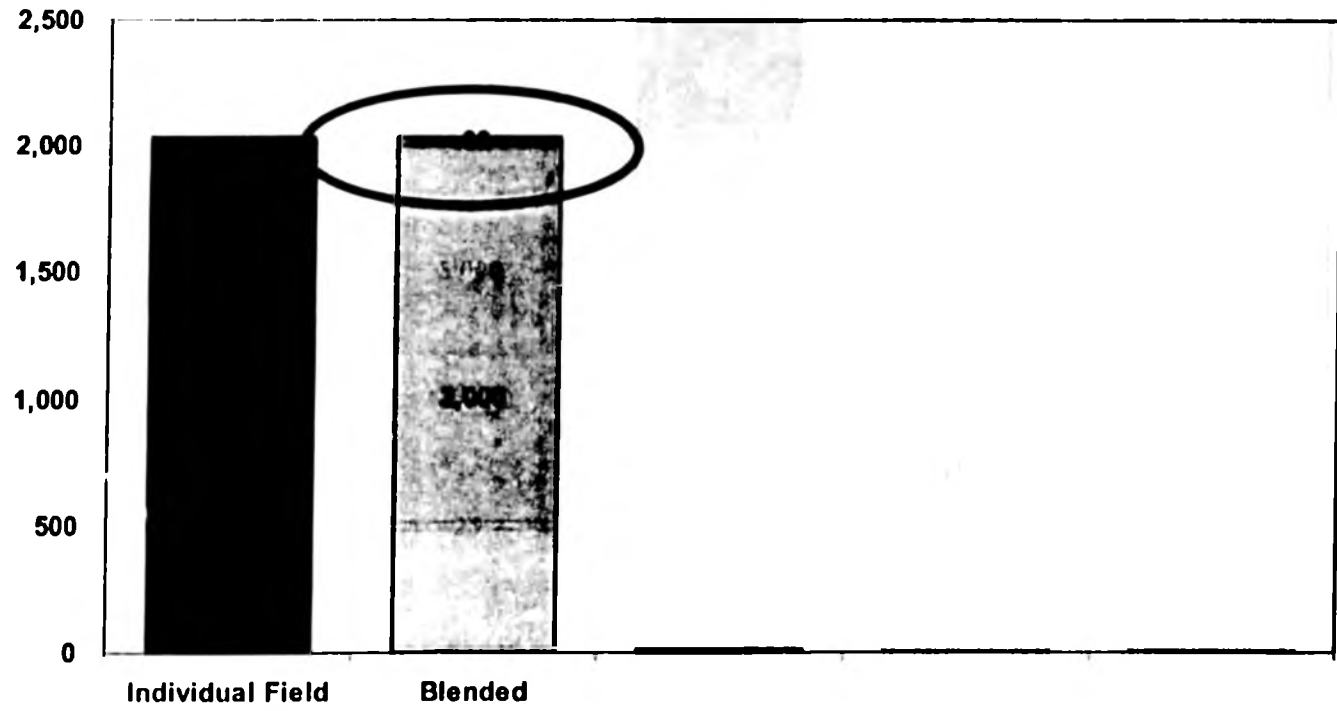
As individual fields, this portfolio would pay just over \$2,032 million in PPT

* from PPT only – does not include State and Federal tax effects



Portfolio Effects Lower Total Tax

Tax Allocable By Field Within Portfolio

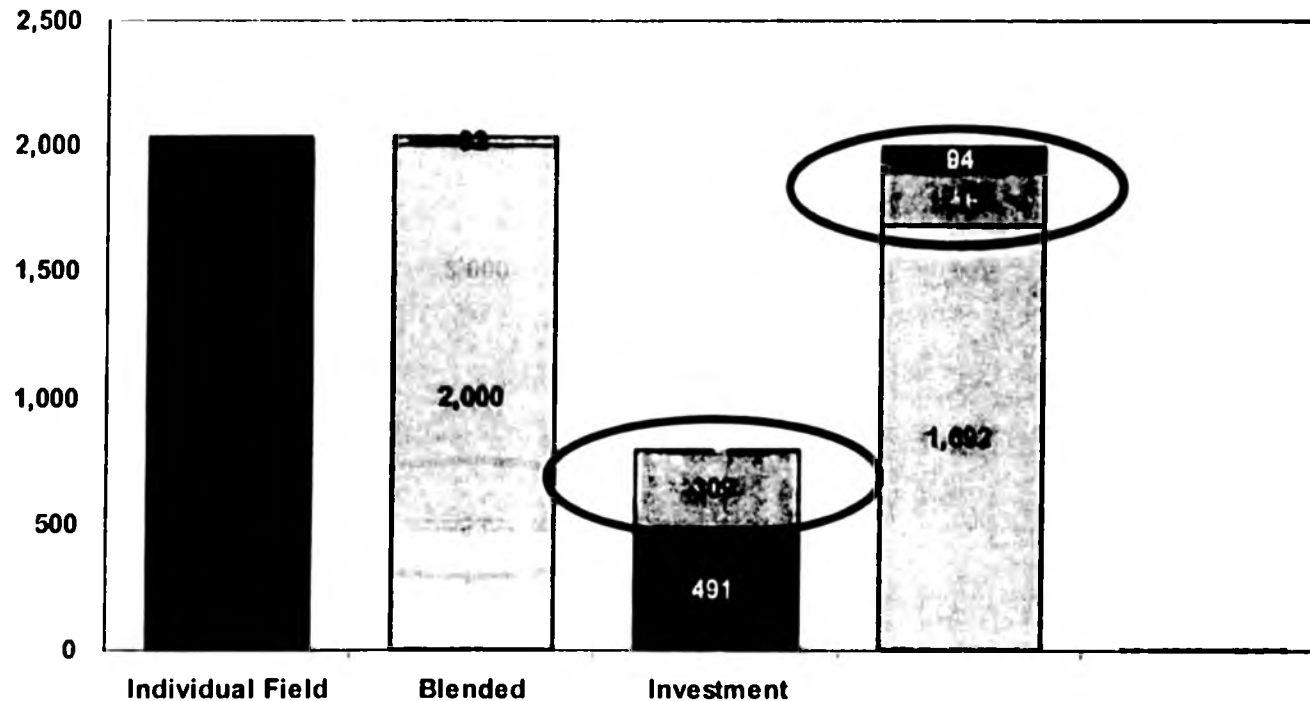


**Putting all fields in one portfolio (company) lowers this to \$2Bn ...
... a saving of \$ 32 million**

The Big Winner Though Is Capex



Tax Allocable By Field Within Portfolio

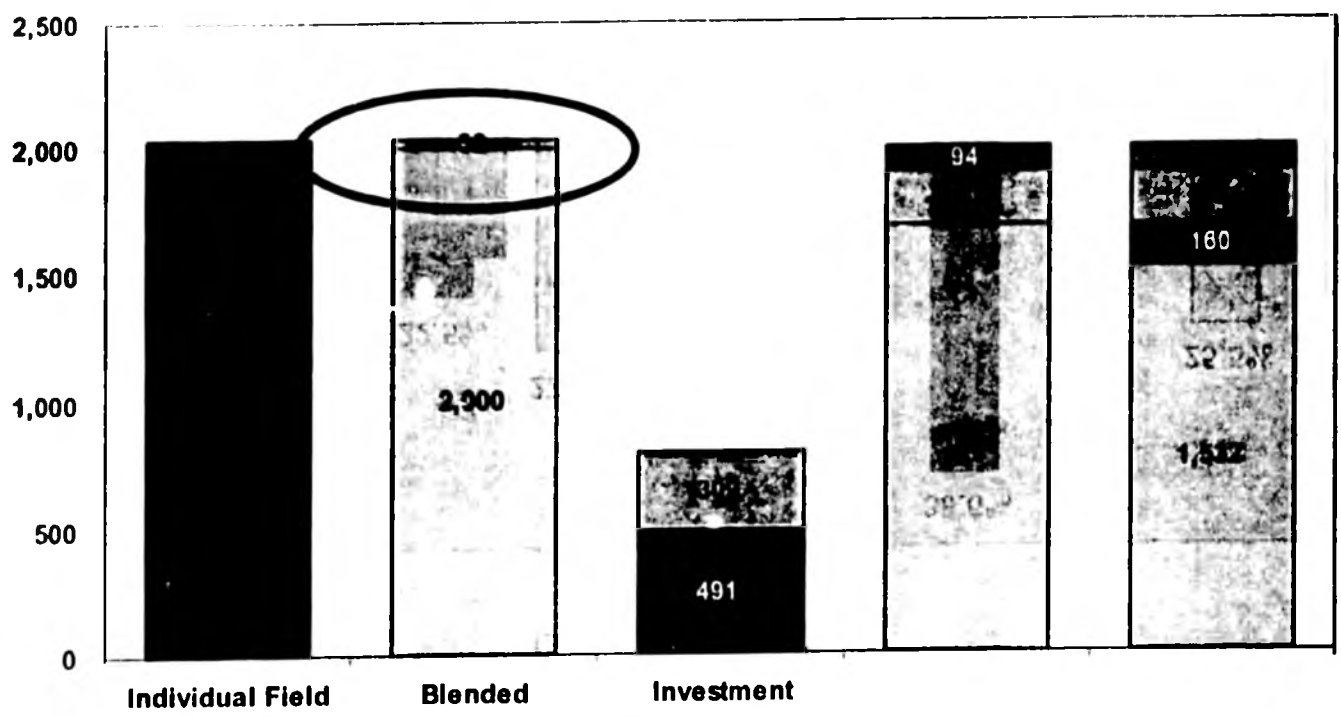


In this example the State pays \$309 million (38.6%) of the capital (the percentage will vary based on overall portfolio net margin per barrel)
The \$309 million can be allocated as \$215 million from reducing taxable income at 26.9% and \$94 million from lowering the rate from 26.9% to 25.5%



But Wait ! That Is Not All

Tax Allocable By Field Within Portfolio

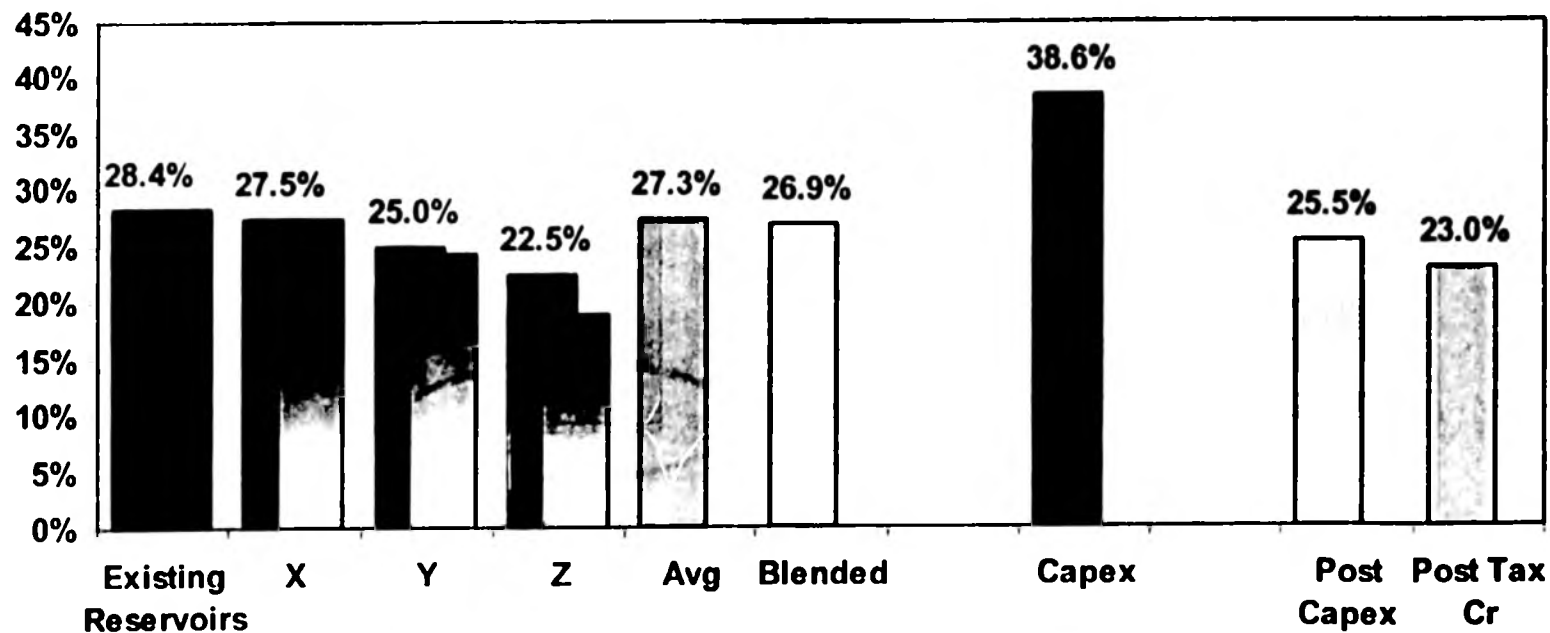


Investment Credits Take a further \$160 million (20% of \$800 million) from the tax payable

After Investment Credits ...



Tax Rate By Field Within A Company - As Affected By Portfolio Blending,
Capex And Tax Credit



... the effective tax rate is lowered further to 23%*

* In this example

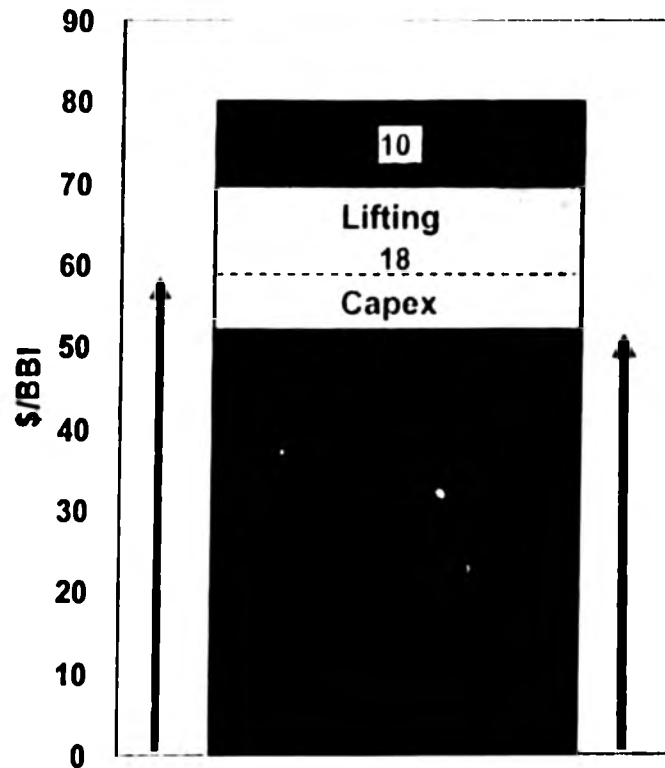
PPT Is Really A Tax On Net Cash Flow Per Barrel



... or, a tax on net revenues that are not reinvested ...

**Operating Margin
Per Barrel**

\$58



**Net Cash Flow
Per Barrel
(after
reinvestment)**

\$52

**Tax Rate
25.5%**

House Oil & Gas Committee

Gross Progressivity Amendment



Progressivity

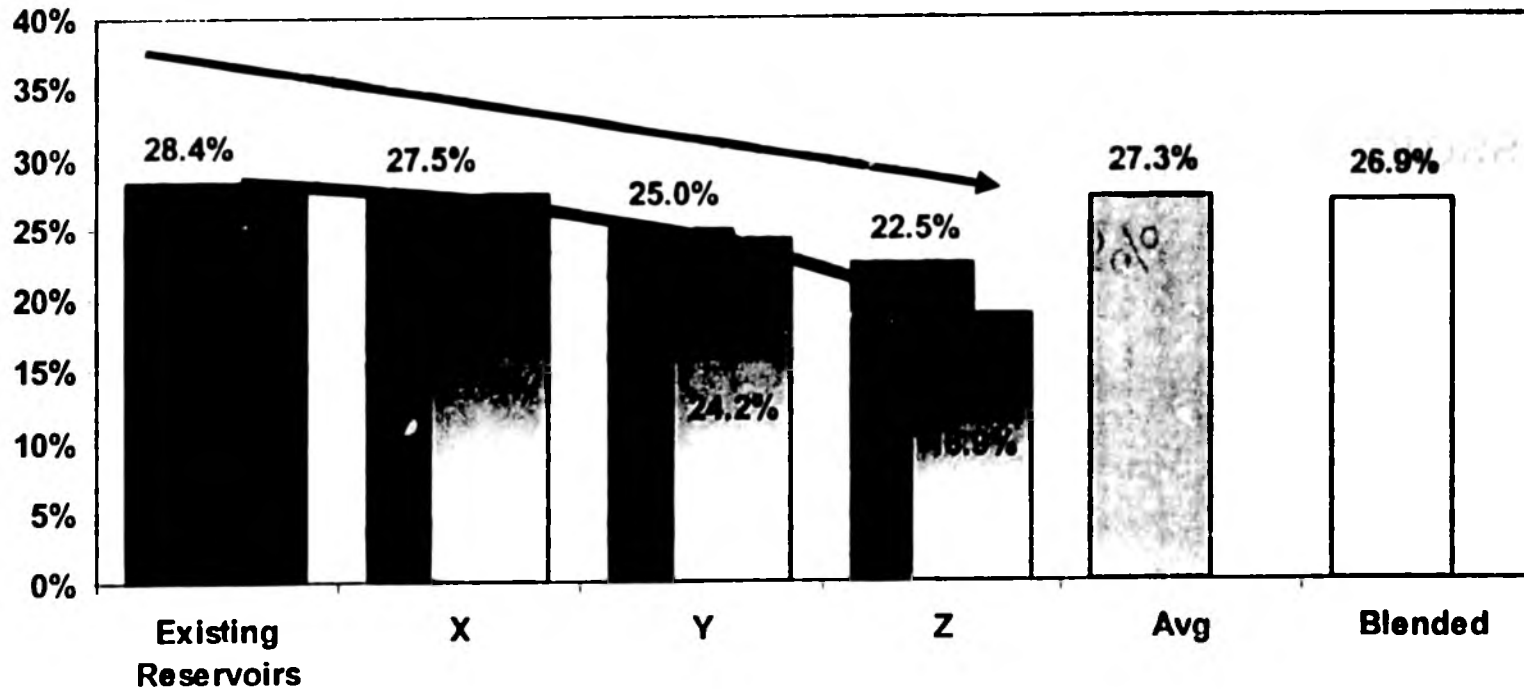
- **PPT**
 - Tax rate increases 0.25% for every dollar that net cash flow per barrel exceeds \$40

- **House O&G Amendment**
 - Maintains the PPT basic rate of 22.5%
 - Adds a tax of 0.225% for every dollar that the gross value at the point of production exceeds \$50
 - Applied to the gross value at the point of production



PPT Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending

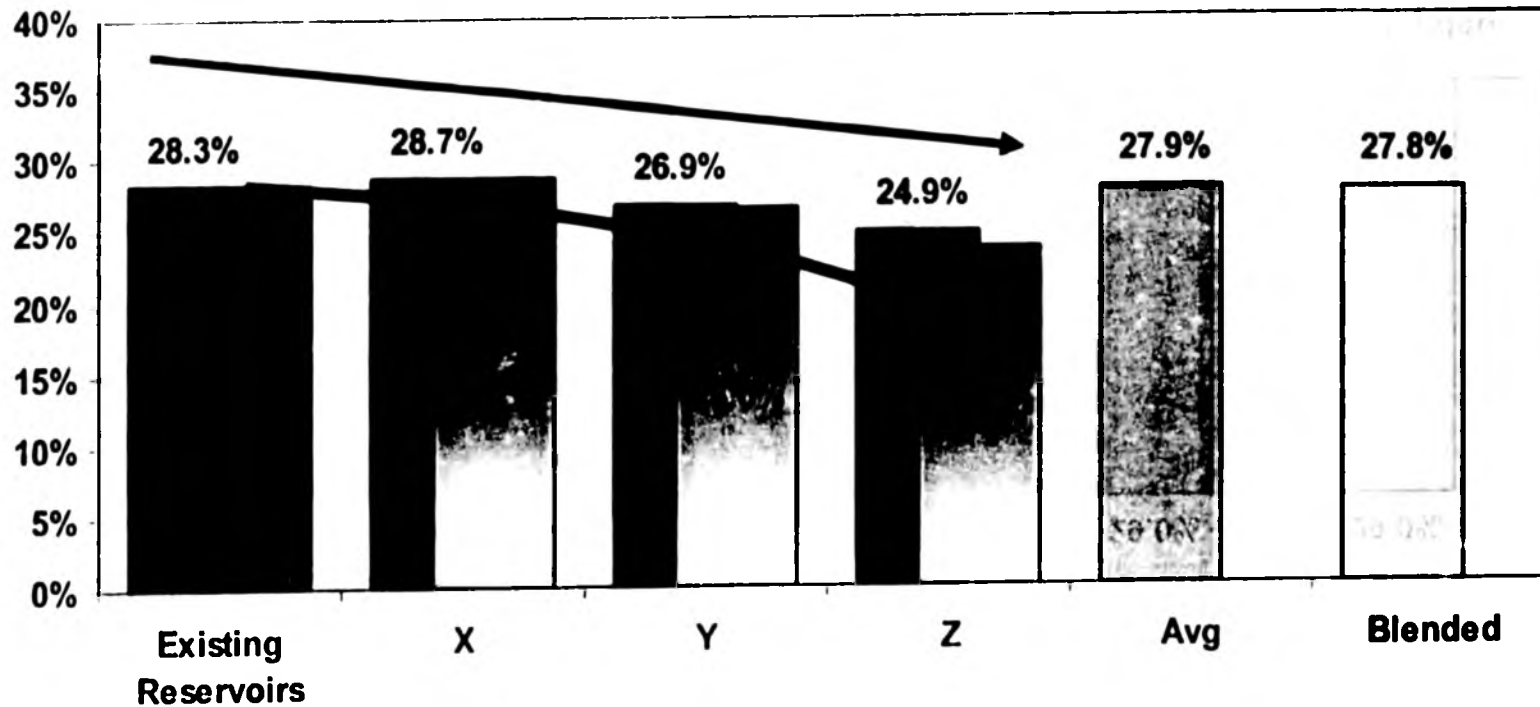


The progressivity can be seen through the lower effective tax rate on lower margin fields



House Oil & Gas Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending

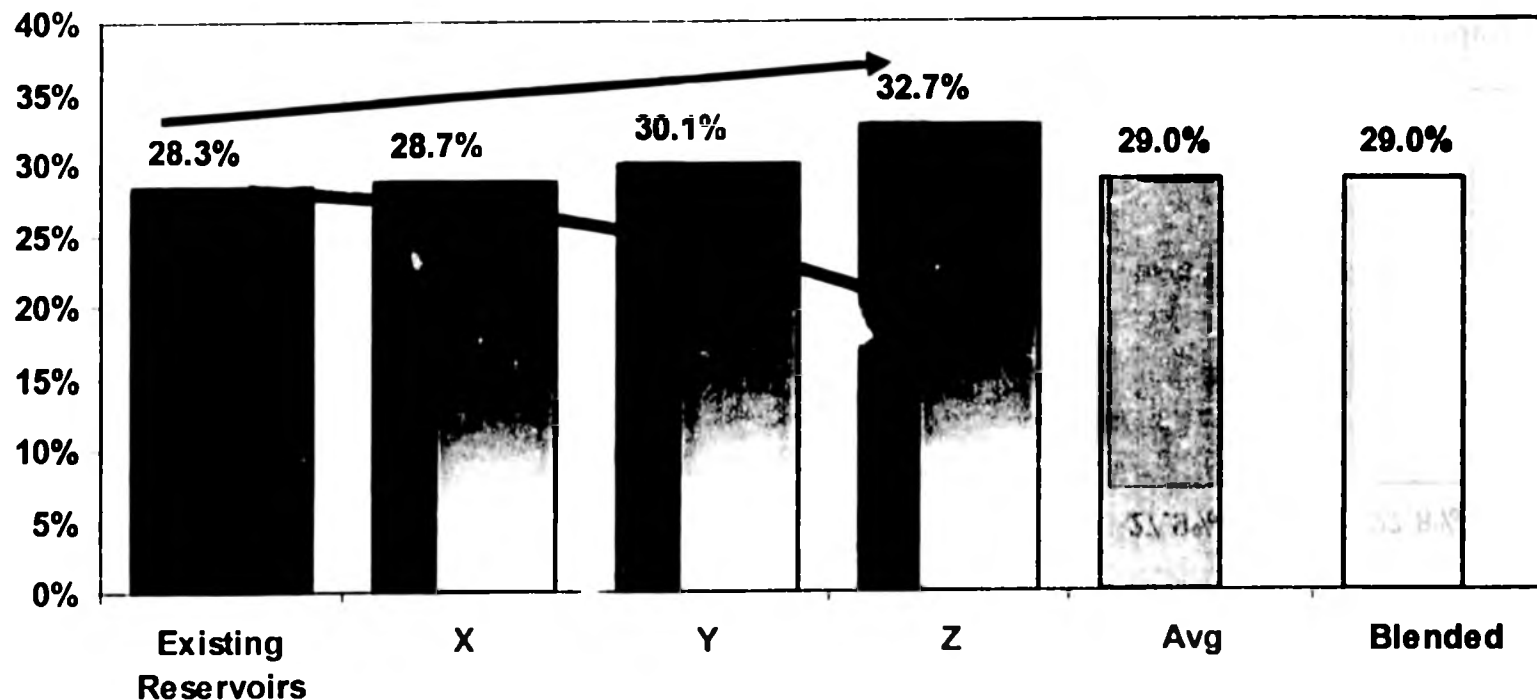


The bulk of the increased burden in this case is being borne by the lower margin fields ...



House Oil & Gas Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending

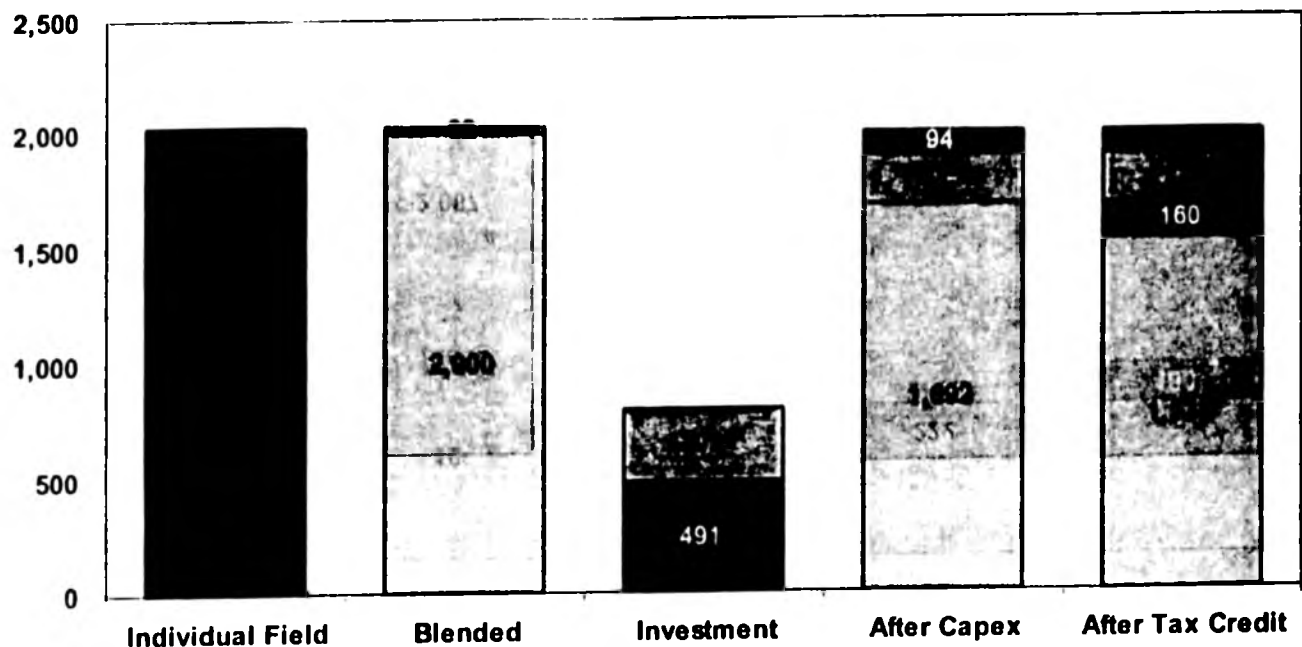


If all of the lower margin results from higher field operating costs then clear regressivity can be seen as more tax is collected and lower margin fields are actually taxed at a higher effective rate than higher margin fields



PPT Progressivity

Tax Allocable By Field Within Portfolio

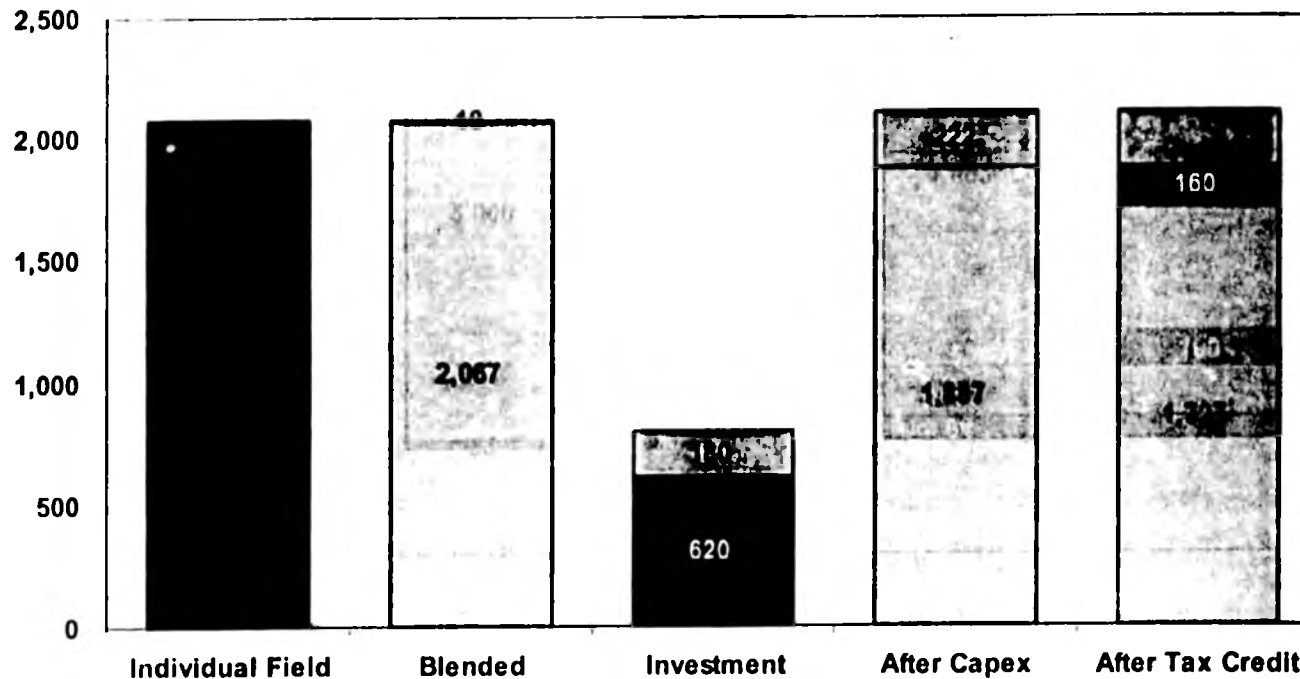


**Under PPT progressivity this portfolio would pay \$1,532 million
at \$80 ANS West Coast
\$2 Bn before the capital investment**



House Oil & Gas Progressivity

Tax Allocable By Field Within Portfolio



**Under House O&G progressivity this portfolio would pay \$1,727 million
-only \$67 million before the capital investment
The net cost of the investment rises from \$331 million to \$460 million***

* Before State and Federal tax impacts



Conclusions

- **A net tax on the margin is a tax on the retained cash flow and not just a tax on simple profitability**
- **Corporate ring fence for production tax allows the effective rate to vary between more, and less, profitable fields**
- **More aggressive net progressivity provides a greater differentiation on the effective rate than simple gross progressivity**
 - **Less/lower taxes at low margins**
 - **More/higher taxes at high margins**



Conclusions - Progressivity

- **Progressivity, based on “net”, as manifested in the PPT/ACES structure is more responsive to individual field profitability than that in a “gross” structure**
- **Greater progressivity (raising the maximum rate and / or slope) can achieve even greater differentiation**
 - More tax on legacy investments benefits from current higher prices – that will drop back if prices drop back
 - Lower tax rates on higher cost / lower margin new investments



The Palin-Parnell Administration presents

ACES

Alaska's Clear and Equitable Share

Last Updated 11-01-07

“Point of Production” (For Oil)

Patrick Galvin, Commissioner
Department of Revenue
Senate Judiciary
November, 01 2007

Economic Incentives



- For oil, definition of “point of production” was unchanged in the transition from ELF to PPT
- Producer in some circumstances has latitude in determining location of the POP
- Under ELF, producer had incentive to move POP as far **upstream** as possible
- Under PPT, producer has an incentive to move the POP as far **downstream** as possible

Some Unintended Consequences



- The retained definition of “point of production” seems likely to exacerbate the facilities access problem
- The retained definition generates very different rewards for a producer on Federal land vs. State land
- The differential rewards are not necessarily consistent with the State’s fiscal interest.

AS 43.55.900(20)(A)



- “for oil, the automatic custody transfer meter or device through which oil enters into a carrier pipeline or other transportation carrier in a condition of pipeline quality; in the absence of an automatic custody transfer meter or device to measure the quantity of oil that has been approved by the department for that purpose, through which the oil is tendered and accepted in a condition of pipeline quality into the facilities of a carrier pipeline or other transportation carrier...”
-

What does this mean?



The point of production does not occur until:

1) The oil is “of pipeline quality”, meaning it is “of good and merchantable condition” (AS 43.55.900(19); **and**

2a) The oil has been metered prior for entry into a pipeline carrier, **or**

2b) The oil has been “tendered and accepted into the facilities of a pipeline carrier”

Note: a reasonable read of statute is that that “pipeline carrier” is a separate entity from the production subsidiary

“Gaming” of the POP



Move unprocessed oil as far as possible

- In NPR-A, build pipelines (potentially many dozens of miles long) that carry unprocessed crude so as to maximize PPT tax benefits
 - Such pipelines will not offer third party access
 - State ROW Leasing Act limits this “game” from being played on state lands.
 - Upshot: Oil from Federal lands gets much more help *despite state’s reduced royalty interest*, exacerbating third party access issues
-

“Gaming” of the POP



Move processed crude, but never meter and keep the pipeline “private”

- No third party access
- State ROW Leasing Act limits this “game” from being played on state lands
- Upshot: Oil from Federal lands gets much more help *despite state's reduced royalty interest*, exacerbating third party access issues

“Gaming” of the POP



- Initially, have pipeline that is “upstream” of the POP so as to enjoy tax credits and deductions
- After some later period, move the pipeline to be “downstream” of the POP – either by installing metering, or by building new processing facilities
- Upshot: state pays for the same pipeline twice (first through credits and deductions, again through transportation deductions)

Conclusion



- There would seem to be room for updating the definition of “point or production” so that:
 - Facilities access problem is not exacerbated
 - Tax benefits for oil on federal land are significantly greater than those from state land
 - State bears no risk of paying for the same pipeline twice

Why ACES?



- PPT is Not Stable
- PPT Does Not Protect Alaska's Interests
- ACES is Needed for Alaska

State of Alaska

Department of Revenue
Commissioner's Office



SARAH PALIN, GOVERNOR

333 Willoughby Avenue, 11th Floor

P.O. Box 110400

Juneau, Alaska 99811-0405

Phone: (907) 465-2300

Fax: (907) 465-2394

To: All members of the Legislature
From: Marcia Davis, Deputy Commissioner, DOR

October 25, 2007

Dear Members:

The attached memorandum was requested of Spencer Hosie by the Department of Law regarding the litigation risk and burden associated with a profits-based oil production tax. The memo provides a short history of the ANS Royalty Litigation and outlines issues the State is likely to experience in enforcing and collecting taxes under a net tax regime. I hope you will find the document useful in your coming deliberations.

Sincerely,

A handwritten signature in cursive script that reads "Marcia Davis".

Marcia Davis, *Deputy Commissioner*
Department of Revenue

MEMO

To: Department of Law, State of Alaska
From: Spencer Hosie
Subject: ANS Royalty Litigation and Gross Versus Net Tax
Date: October 17, 2007

The Department of Law has asked for a brief memo summarizing why the *ANS Royalty Litigation* took near 20 years to resolve, and whether the State may expect similarly protracted, complex litigation with a "net" severance tax, *i.e.*, a tax based on revenues net of allowable costs. As we understand it, the concern is that a net tax will inject a multiplicity of complex factual issues, thereby leading to expensive and protracted litigation.

This memo first summarizes why the *ANS Royalty Litigation* took as long as it did. It then contrasts what we believe the State should expect in enforcing and collecting taxes under a net tax regime, and how this process will differ from the civil litigation in the *ANS Royalty Litigation*. Finally, the memo concludes with several concrete examples of recent State of Alaska cases which provide reasonable benchmarks of what the State is likely to experience in enforcing a net production tax.

I. THE ANS ROYALTY LITIGATION.

The State of Alaska filed what would become the *ANS Royalty Litigation* in 1977. The oil phase of the case was resolved in 1992; the gas liquids phase settled in 1995. All-in, the case took nearly two decades to resolve. Through the litigation, the State recovered significantly in excess of \$750 million and established going-forward royalty payment rules designed to either streamline or – preferably – eliminate prospective litigation, as discussed below.

There were four principal reasons why this matter took so long and cost so much. First, the State was not acting as a sovereign in the case, but rather as a party to a commercial contract; a litigant like any other. In that context, the State did not have the authority to serve and enforce subpoenas as sovereign, select an administrative judge, or rely on regulations to expedite dispute resolution. Instead, as in any private litigation, the State had to serve and enforce discovery through the civil discovery process, which can be (and was) extremely time consuming. This is very unlike the rights that legislation and regulations provide for enforcing a production tax, as set forth below.

Second, the *ANS Royalty* case involved numerous complicated legal questions of first impression. For example, did the DL-1 lease form permit the State to assess values in downstream markets, then netted back to Pump Station 1? Did the producers owe the State any duty above those owed to a private commercial party? How is market value to be determined under ¶ 15 of the lease, and what did the tripartite "proceeds" subparagraphs of ¶ 16 mean and require? These fundamental questions of contractual interpretation¹ required years of briefing, including discovery into the origin of other states' lease forms, leading to summary judgment decisions, all of which necessarily occurred before the State built its damage models. Put simply, even the basic royalty rules were not clear and had to be established through litigation.

Third, once having established that the State had the right to look to downstream markets to assess market value, and then to net back those values to derive a Pump Station 1 royalty value, the State literally had to track *every single barrel* of ANS previously produced to its market destination. Tracking many billions of barrels to myriad Lower 48 destinations over a near-15 year period proved a byzantinely complex and daunting task, one that took the State's

¹ In addition, the producers challenged venue in Alaska, arguing that every judge and juror in Alaska had a financial stake in the outcome given the Permit Fund Dividend. This issue was resolved only after two interlocutory appeals to the United States Court of Appeals for the Ninth Circuit.

outside accounting and economic experts years to complete. As part of this process, the State then had to assess the reasonable and actual transportation deduction for every barrel transported.

Fourth, the *ANS Litigation* involved all ANS producers and all were active in the litigation, even though the case focused on Exxon, Sohio, and Arco. The State had to conduct separate discovery of each producer within the context of a single case, and this substantially delayed completion of the lawsuit.

Finally, in the *ANS Royalty Litigation*, the State necessarily approached the ANS industry as a whole, *and* as a matter of first impression. In the 1980s, the State did not have deep institutional knowledge of how the ANS business worked, how the producers conducted business, what transportation costs were reasonable and what not, how the producers handled common (or "joint") cost accounting, and similar issues. In contrast, the State now has significant institutional expertise, having audited ANS producers for decades.

II. WILL A NET PRODUCTION TAX SPAWN MULTIPLE ANS ROYALTY-LIKE CASES?

Tax is not royalty. In enforcing its production tax statute and regulations, the State acts as a sovereign. The Legislature has authorized a regulatory structure that gives it the right to compel document production, to set a reasonable schedule, and to proceed under the functional equivalent of an Administrative Law Judge (hearing officer). These procedural differences are substantive and real. A single taxpayer case should proceed from audit to hearing in no more than two years, as described below. Two years is a long time, but a far cry from the two decades in *ANS Royalty Litigation*.

Second, unlike the royalty context, the basic tax rules will be set forth by statute, with the disputes on the margin, *e.g.*, wrong costs deducted, or costs inflated, etc.... In a tax context, the

basic structure and rules are a given; in the *ANS Royalty Litigation* case, these rules had to be established through hotly contentious litigation.

Third, presumably the State will vigilantly audit ANS taxpayers under any production tax, gross or net. *Audits should be conducted on a yearly basis, and if an issue arises, it should be dealt with promptly.* The *ANS Royalty Litigation* took decades in part because it involved decades of production by the time it was resolved; this will not be the case in the tax context.

Fourth, given taxpayer confidentiality, and the nature of the tax audit process, any tax proceeding would be taxpayer-specific. A single taxpayer proceeding should move much faster than a multi-party case such as the *ANS Royalty Litigation*.

Finally, and as noted above, the State now has deep institutional knowledge concerning the ANS business, including market values and transportation costs. This knowledge comes from the *ANS Royalty Litigation* itself, plus several follow-on cases (described below), and numerous tax audits and cases. The State now has accumulated decades of experience in auditing production and transportation costs, as well as a group of outside expert consultants who are well-versed in these matters.

To be clear, all else equal, a net tax will be more complex to administer and enforce than a gross tax. If the past is any guide, the taxpayers may well game costs, e.g., suddenly allocating an inappropriately large percentage of joint or common costs to their Alaska business. But the additional complexity should be manageable, and the State can discourage overly creative cost accounting by vigilantly auditing and enforcing the statute and regulations from the outside.

III. ROYALTY "REOPENER" CASES: A TAX PARADIGM.

The State recently had several "reopener" cases which serve as useful examples for what might be expected under a net production tax.

As part of the *ANS Royalty Litigation* settlement, the State and each of several producers agreed to formulas for future royalty payments, along with a short-fuse dispute resolution mechanism. That mechanism includes limited discovery, short deadlines, and a three-judge arbitration panel empowered to make a binding decision. If either party grows dissatisfied with the operation of the agreed royalty formula, it has the right (in certain general circumstances) to trigger a "reopener," which serves to start the dispute resolution process.

The State has had several such *ANS Royalty Litigation* "reopener" proceedings. Each has involved limited and manageable discovery, a relatively quick path to hearing, and a binding decision or settlement promptly after the arbitration hearing begun. On average, these matters have taken 20 to 22 months of active litigation, despite involving complex cost and revenue issues (and zealous producer counsel). For example, in the first of several reopeners, outside counsel became involved in August 2003, trial was in April 2005, a binding decision in the State's favor received in June 2005, and the State was paid promptly thereafter.

As noted, these "reopeners" are good models for what to expect under a net tax, as both involve: (1) established rules (by statute in tax); (2) streamlined administrative process; (3) company specific proceedings; and, (4) proceedings that benefit from State's historical, institutional knowledge.

Recruitment Period	Job Class	PCN(s)	Total Number of Applicants	Available Applicants that meet MQs	Appointment Made	Comments
10/12/07 - 10/17/07	Oil and Gas Revenue Auditor VII/III	04-3217 04-3272 04-3273 04-3274	4	4	No	Withdrawn due to pending legislation.
5/25/2007 - 6/4/2007	Oil and Gas Revenue Auditor IV	04-8023 04-3277 04-3276 04-3275	1	1	Yes (3 unsuccessful)	All State Employee recruitment
9/27/2007 - 10/17/2007	Oil and Gas Revenue Auditor IV	10-4233.	4	4	Pending	Alaska Resident only recruitment
8/4/2006 - 8/18/2006	Oil and Gas Revenue Auditor VII/III	10-4249.	21	19	Yes	Alaska Resident only recruitment
6/6/2006 - 6/16/2006	Oil and Gas Revenue Auditor VII/III	04-3262 04-3263	17	12	Yes (1 unsuccessful)	All Applicant recruitment
4/28/2006 - 5/30/2006	Oil and Gas Revenue Auditor III	10-4210.	3	1	Yes	Alaska Resident only recruitment
6/13/2006 - 6/23/2006	Oil and Gas Revenue Auditor III	04-8039.	2	1	No	All Applicant recruitment
3/9/2006 - 3/20/2006	Oil and Gas Revenue Auditor IV	10-4233.	5	4	Yes	All State Employee recruitment
6/8/2006 - 6/19/2006	Oil and Gas Revenue Auditor IV	04-8023. 04-3262 04-3263	2	2	No	All Applicant recruitment
8/10/2005 - 9/1/2005	Oil and Gas Revenue Auditor I/II	04-8022	13	11	Yes (2 unsuccessful)	All Applicant recruitment
9/29/2005 - 10/9/2005	Oil and Gas Revenue Auditor I	04-3262 04-3263 04-8023	1	1	Yes (one unsuccessful due to filling from previous recruitment)	All Applicant recruitment

Oil Gas Revenue Auditor Positions as of PPE October 15, 2007

PCN	Department	Class Title	Location	Employee Name	Unit	Rate	Grade	Salary
043271	Revenue	Oil and Gas Revenue Auditor I*	Anchorage		GG	18		
043272	Revenue	Oil and Gas Revenue Auditor I*	Anchorage		GG	18		
043273	Revenue	Oil and Gas Revenue Auditor I*	Anchorage		GG	18		
043274	Revenue	Oil and Gas Revenue Auditor I*	Anchorage		GG	18		
043262	Revenue	Oil and Gas Revenue Auditor II	Anchorage	BAYER,MELISSA A	GG	20	A	\$4,510.00
048022	Revenue	Oil and Gas Revenue Auditor II	Anchorage	STROMBERG,DESTIN M	GG	20	A	\$4,510.00
048028	Revenue	Oil and Gas Revenue Auditor II	Anchorage	MAINOR,JENNIFER L	GG	20	B	\$4,680.00
043049	Revenue	Oil and Gas Revenue Auditor III	Anchorage	RUSH,JOHN J	GG	22	M	\$7,354.00
043263	Revenue	Oil and Gas Revenue Auditor III	Anchorage	BOLAND,DANIEL T	GG	22	B	\$5,343.00
043230	Revenue	Oil and Gas Revenue Auditor IV	Anchorage	DOIEL,GW	GG	24	K	\$7,856.00
043275	Revenue	Oil and Gas Revenue Auditor IV	Anchorage	SMITH,CHRIS D	GG	24	D	\$6,561.00
043276	Revenue	Oil and Gas Revenue Auditor IV	Anchorage	WOOD,DONNA L	GG	24	A	\$5,901.00
043277	Revenue	Oil and Gas Revenue Auditor IV	Anchorage	MELENDEZ,FELIX F	GG	24	F	\$7,010.00
048023	Revenue	Oil and Gas Revenue Auditor IV	Anchorage		GG	24		
048038	Revenue	Oil and Gas Revenue Auditor IV	Anchorage		GG	24		
048044	Revenue	Oil and Gas Revenue Auditor IV	Anchorage	ROGERS,JENNY L	GG	24	K	\$7,856.00
043282	Revenue	Oil and Gas Revenue Specialist	Anchorage	LARSEN,JOHN M	GG	25	K	\$8,446.00
104249	Natural Resources	Oil and Gas Revenue Auditor II	Anchorage	COLLEY,ROGER L	GG	20	E	\$5,155.00
104115	Natural Resources	Oil and Gas Revenue Auditor III	Anchorage	WRIGHT,JACQUELINE	GG	22	J	\$6,585.00
104210	Natural Resources	Oil and Gas Revenue Auditor III	Anchorage	MAXWELL,BRENDA A	GG	22	B	\$5,343.00
104215	Natural Resources	Oil and Gas Revenue Auditor III	Anchorage	WERLE,SHAUN C	GG	22	D	\$5,712.00
104194	Natural Resources	Oil and Gas Revenue Auditor IV	Anchorage	JOHNSON,LESLIE K	GG	24	B	\$6,121.00
104233	Natural Resources	Oil and Gas Revenue Auditor IV	Anchorage		GG	24		

* Positions are flexed and may be filled at either the I, II or III level

Source: Vacancy:AllDept 071025

C:\Documents and Settings\snscsmi\Local Settings\Temporary Internet Files\OLK504\COPY of Oil Gas Revenue Auditors PPE 071015 DOP-071031

Prepared by: K. Nava, HR Tech I, DOPLR, EPIC

Cindy Smith

From: Iversen, Jonathan E (DOR) [jonathan.iversen@alaska.gov]
Sent: Sunday, October 28, 2007 3:01 PM
To: Cindy Smith
Cc: Davis, Marcia R (DOR)
Subject: Judiciary hearings

Cindy --

Marcia suggested I email you my questions regarding the hearing schedule.

A couple of questions for your for the next couple of days. I want to be sure to cover everything Sen. French wants covered and not let things get left in the dust as we proceed.

My first question is: how much flexibility do we have regarding the schedule?

I ask because our economics folks are preparing a presentation on the economics pieces that would cover the economic provisions including progressivity and floor portions on Wednesday's agenda. We would, however, ask to present that on Tuesday, so that we get the information into both bodies on the same day and have the time to do so.

I think we may be able to cover lots of ground on the issues identified on the schedule on Monday, perhaps even knocking some of Tuesday's out as well. Perhaps we could address any remaining non-economic issues after the gross versus net discussion on Wednesday?

There are a couple of additional administrative/legal issues the committee may want to address, that I think we could use some clarity on, that were deferred for discussion. I would like some guidance on when would be a good time to do that -- my intention here is to make sure that we are all on the same page. I could bring these up in the introduction or we can discuss later if the Senator feels appropriate. I don't think these will take much time. Regardless, I will attempt to make all of my discussions brief and to the point. These issues include:

1. the statement of intent in section 1 of the bill regarding the statute of limitations, and the statute of limitations issue
2. the importation of the Cook Inlet regulations into the language of the bill
3. the issue of tax exempt entities being allowed to obtain transferable tax credit certificates
4. the reduction of the rate for loss carry forward credits from 25% to 20%.

These issues may be non-issues, but I just wanted to confirm.

We have also asked Kathleen Strasbaugh from the AG's office, Kevin Brooks, Dep. Comm'r of Admin, and Personnel Director Nicki Neal to attend tomorrow's hearing for the discussion on personnel issues regarding auditors. I can field this from DOR's perspective, but these folks are the experts on the personnel side of things. We have notified DNR so that they can have someone attend regarding reasonable v. actual transportation costs and any discussion on Exploration Incentive Credits (55.025).

If you would like me to come over tomorrow morning for a chat before the hearing please let me know either via email, office phone 465-4340 or cell 223-2443.

Thanks,
Jon Iversen

Tax Interest and Penalties Under ACES and Current Law

Distributed by the Department of Revenue

October 29, 2007

Under AS 43.05.220, the state may levy three types of civil penalties for failure to file a return or report or pay the full amount of tax. These include a basic penalty for underpayment or failure to file, a penalty for negligence, and a penalty for fraud. All three are general provisions applying to all state taxes, including the oil and gas production tax. Penalties are calculated as a percentage of the tax deficiency and are cumulative, so that a fraudulent taxpayer, for example, could be assessed the fraud penalty, in addition to the negligence penalty and the basic failure to file or pay penalty.

Basic Penalty

The basic failure to file penalty arises when the taxpayer fails to file a return or report when required or pay the full amount due. Five percent of the unpaid balance of the tax liability is added to a tax for each 30 day period, or fraction of the period of noncompliance. This penalty may not exceed a total of 25% of the unpaid balance. The penalty may be forgiven if the taxpayer shows that the failure to file or pay is due to reasonable cause and not willful neglect.¹

Reasonable cause is not easy to show and the burden of proof lies with the taxpayer. The taxpayer must demonstrate in writing, and under penalty of perjury, that they acted in good faith to take all reasonable steps to ensure timeliness of the filing or payment. In determining whether the taxpayer has shown that the failure was due to reasonable cause and not willful neglect, the department considers the standards imposed by the Internal Revenue Code. Circumstances that may constitute reasonable cause include, acts of God, war, other disaster that made filing or delay unavoidable, or acts by another person beyond the control of the person required to file.²

Negligence Penalty

In addition to the basic penalty, if a deficiency is due to negligence or intentional disregard of a law or regulation, the department will, in its discretion, assess a penalty of 5% of the total amount of the deficiency. The penalty is calculated based on the total deficiency, even if only a part of the deficiency is due to negligence or intentional disregard. Negligence or

¹ AS 43.05.220(a). For more detail on failure to file and failure to pay penalties, see 15 AAC 05.210.

² 15 AAC 05.200.

Interest

The production tax currently requires monthly installment payments, in addition to annual payments and tax returns. The monthly payment is an estimate of 1/12th of the anticipated annual tax liability. The annual payment, which is accompanied by a return, requires payment of any difference between the estimated liability and actual liability during the 12 month period. The current production tax statute sets a generally lower interest rate for underpayments or overpayments of monthly installments of estimated tax due to the estimated nature of the monthly payment.

Interest on an unpaid amount of a monthly installment payment bears interest at the rate prescribed under the Internal Revenue Code, compounded daily from the date the installment is due until paid (if paid not later than when the annual return is due). That rate is currently at 8%. For corporate underpayments exceeding \$100,000, the rate increases to 10%.⁵

Overpayments of monthly installments also bear interest as stated in the Internal Revenue Code, generally at lower rates than those for underpayments. Overpayments bear interest at 8% (7% for corporations) and 5.5% for the portion of a corporate overpayment greater than \$10,000.⁶

Any portion of monthly installment payments that remains unpaid as of the annual filing date, as well as the interest accrued for those payments, is treated as a delinquent tax. Delinquent taxes are subject to a higher interest rate, currently 11% compounded quarterly.⁷

If the taxpayer has overpaid as of the annual return, the department has 90 days after the later of the date the return was filed or the due date of the return to refund the overpayment without incurring interest. After that, the state owes interest, currently 11% compounded quarterly.⁸

⁵ AS 43.55.020(g); 26 U.S.C. 6621.

⁶ AS 43.55.020(h); 26 U.S.C. 6621.

⁷ AS 43.55.020(g); 43.05.225.

⁸ AS 43.55.020(h); 43.05.225.

ACES Bill Version Comparisons

10/31/2007

		ACES	CS	CS
Administration Intent		Sec. 1. Confirmation of DOR's interpretation of statute of limitations for retroactive tax changes.	Deleted.	Deleted.
Information		Sec. 2. Amends AS 38.05.035(a). Adds authority for DNR to share oil & gas info with DOR.	CS Sec. 1. ACES language	CS Sec. 1. ACES language
Technical Amendments		Secs. 3-9. Conforming technical amendments.	CS Secs. 2-8. ACES language	CS Secs. 2-8. ACES language
Administration Auditors		Sec. 10. Amends AS 39.25.110. Adds exempt service for auditors.	CS Sec. 9. ACES language	CS Sec. 9. ACES language
Technical Amendments		Sec. 11. Amends AS 11.09.010(d). Conforming technical amendments.	CS Sec. 10. ACES language	CS Sec. 10. ACES language
Information		Sec. 12. Amends AS 43.05.230(a). Adds AS 43.55.890 (disclosure of tax info) as possible exception under AS 43.05.230(a) (unlawful disclosure).	CS Sec. 11. ACES language	CS Sec. 11. ACES language
Information		Sec. 13. Amends AS 43.05.230(h). Adds authority for DOR to share production tax info with DNR.	CS Sec. 12. ACES language	CS Sec. 12. ACES language
Administration Assessments		Sec. 14. Amends AS 43.05.260(a). Creates an exemption to allow DOR six years to conduct production tax assessments rather than three years.	CS Sec. 13. ACES language	Deleted.
Production Tax	AS 43.55.011(e). Sets the production tax rate at 22.5%	Sec. 15. Repeals & reenacts AS 43.55.011(e). Sets the production tax rate generally at 25%.	PPT	PPT
Production Tax Floor	AS 43.55.011(f). Sets a tax floor of not less than 4% of gross value when the average West Coast price is \$25 per barrel with step down factors.	Sec. 16. Repeals & reenacts AS 43.55.011(f). Sets a tax floor on legacy fields of 10% of the total gross value at the point of production; tax credits cannot reduce liability below floor.	PPT	PPT

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	CSHB 2001 (O&G)
Progressivity Slope	AS 43.55.011(g). Progressivity is triggered at \$40 net value with a .25% increase per dollar; 25% tax cap on progressivity rate.	Sec. 17. Repeals & reenacts AS 43.55.011(g). Progressivity is triggered at \$30 net value on an annual basis with 0.2% increase per dollar; 50% maximum tax rate (including progressivity).	Repeals AS 43.55.011(g) (PPT progressivity); adds new gross progressivity provision in sec. 17; AS 43.55.011(o).	PPT
Progressivity Trigger	AS 43.55.011(h). Establishes the price index for calculating progressivity on a monthly basis.	Sec. 18. Amends AS 43.55.011(h). Establishes price index for calculating progressivity on an annual basis	Repeals AS 43.55.011(h) (PPT progressivity calculation).	PPT
Progressivity Method	AS 43.55.011(h). Establishes the price index for calculating progressivity on a monthly basis.	Sec. 18. Amends AS 43.55.011(h). Establishes price index for calculating progressivity on an annual basis.	Repeals AS 43.55.011(h) (PPT progressivity calculation).	
Production Tax Cook Inlet	AS 43.55.011(j). Cook Inlet tax ceiling.	Sec. 19. Amends AS 43.55.011(j). Conforming technical amendment; deletes reference to AS 43.55.011(g) (progressivity) because reference is no longer applicable.	CS Sec. 14. ACES language Amends 43.55.011(j). Conforming technical amendment; deletes reference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	PPT
Production Tax Cook Inlet	AS 43.55.011(k). Cook Inlet tax ceiling.	Sec. 20. Amends AS 43.55.011(k) (Cook Inlet tax ceiling). Conforming technical amendment; deletes reference to AS 43.55.011(g) (progressivity) because reference is no longer applicable.	CS Sec. 15. ACES language Amends AS 43.55.011(k) (Cook Inlet tax ceiling). Conforming technical amendment; deletes reference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	PPT
Production Tax Cook Inlet	AS 43.55.011(l). Cook Inlet tax ceiling.	Repeals AS 43.55.011(l); conforming technical amendment.	CS Sec. 16. ACES language Amends AS 43.55.011(l). Conforming technical amendments; deletes reference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	ACES

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	PPT
Production Tax Cook Inlet	AS 43.55.011(m). Cook Inlet tax administration.	Sec. 21. Amends AS 43.44.011(m). Adds language to be consistent with sec. 55 (lease expenditures); deletes reference to AS 43.55.011(g) (progressivity) because reference is no longer applicable.	CS Sec. 17. ACES language Amends AS 43.55.011(m). Deletes language added in ACES; deletes reference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	PPT
Production Tax Progressivity			Sec. 18. Adds AS 43.55.011(o). Replaces ACES and PPT progressivity provisions with a new a new progressivity provision.	
Production Tax Mid-Alaska Tax Ceiling			Sec. 18. Adds AS 43.55.011(p). Extends Cook Inlet tax ceilings in .011(j) to gas outside Cook Inlet and outside the North Slope.	
Tax Payment	AS 43.55.020(a). Installment payments.	Sec. 22. Repeals & reenacts AS 43.55.020(a). Makes installment payment calculations consistent with changes to the production tax.	CS Sec. 19. ACES language with conforming ammendments.	PPT PPT
Tax Payment	AS 43.55.020(d). Royalty owner settlement deductions and installment payments.	Sec. 23. Amends AS 43.55.020(d). Conforming technical amendments; deletes reference to AS 43.55.011(g) (progressivity) because reference is no longer applicable.	CS Sec. 20. ACES language Conforming technical amendment; deletes reference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	PPT
Tax Payment	AS 43.55.020(g). Interest on unpaid installment payments.	Sec. 24. Amends AS 43.55.020(g). Conforming technical amendment.	CS Sec. 21. ACES language Amends AS 43.55.020(g). Conforming technical amendment.	PPT
Tax Payment	AS 43.55.020(h). Interest on overpayment of installment payments.	Sec. 25. Amends AS 43.55.020(h). Conforming technical amendment.	CS Sec. 22. ACES language Amends AS 43.55.020(h). Conforming technical amendment.	PPT
Tax Credits Capital Expenditures	AS 43.55.023(a). 20% tax credit for qualified capital expenditures and information requirements.	Sec. 26. Amends AS 43.55.023(a). Spreads use of tax credits over two years; moves and adds to info requirements; adds that legacy field tax credits may be applied only against legacy field taxes.	PPT	PPT

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CS 2007 (OSG)	CS 2007 (RES)
Tax Credits Capital Expenditures	AS 43.55.023(b). 20% of carried-forward annual loss credit allowed against deductible lease expenditures when use of the deduction would cause the production tax in a month to be less than zero.	Sec. 27. Amends AS 43.55.023(b). Matches carried-forward annual loss to production tax rate of 25%; adds that carried-forward annual losses may not be based on lease expenditures accrued in legacy fields.	PPT	PPT
Tax Credits Capital Expenditures	AS 43.55.023(d). Transferable tax credit certificates.	Sec. 28. Amends AS 43.55.023(d). Adds no transfer of tax credits earned on legacy fields, option to obtain cash payment, and more time for agency approval; requires annual reporting requirements; spreads use of tax credits over two years.	CS Sec. 23. ACES language Amends AS 43.55.023(d). Technical amendment to PPT provision.	PPT
Tax Credits Capital Expenditures	AS 43.55.023(e). Transfer of tax credits.	Sec. 29. Amends AS 43.55.023(e). Conforming technical amendment.	PPT	PPT
Tax Credits Capital Expenditures	AS 43.55.023(f). Cash refund of up to \$25,000,000 for small producer tax credits.	Repeals AS 43.55.023(f) (replaced with oil and gas tax credit fund).	PPT	PPT
Tax Credits Capital Expenditures	AS 43.55.023(g). Tax credit audits.	Sec. 30. Amends AS 43.55.023(g). Adds language to reflect DOR authority to purchase tax credits granted in AS 45.55.028.	PPT	PPT
Tax Credits Capital Expenditures	AS 43.55.023(i). Transitional investment expenditure (TIE) tax credits for qualified capital expenditures incurred after March 31, 2001 and before April 1, 2006.	Repeals AS 43.55.023(i).	CS Sec. 24. ACES language Amends AS 43.55.023(i). Changes application of TIE credits to qualified capital expenditures incurred after March 31, 2003 and before April 1, 2006.	CS Sec. 13. ACES language Amends AS 43.55.023(i). Limits TIE credits to taxpayers that did not have commercial production before January 1, 2008, and to 1/10 of qualified capital expenditures incurred after March 31, 2006 and before January 1, 2008.

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSRS 2001 (O&G)	CSRS 2001 (P&S)
Tax Credits Capital Expenditures		Sec. 31. Amends AS 43.55.023. Adds subsection (l) to make clear a tax exempt entity may not obtain a transferable tax credit.	CS Sec. 25. ACES language	Deleted.
Tax Credits Mid-Alaska	AS 43.55.024. Additional tax credit of \$6,000,000 for production from leases outside Cook Inlet and the North Slope for small producers.	Secs. 32 - 35. Amends AS 43.55.024. Subsection(a): technical correction; (b), (c), (e), (g): conforming technical amendments	PPT	PPT
Tax Credits Exploration	AS. 43.55.025. Alternative tax credits for up to 40% for oil and gas exploration.	Secs. 36 - 44. Amends AS 43.55.025 to clarify credit eligibility; extends eligibility for deliniation wells from 150 days to 540 days; requires additional information to be submitted to DOR; allows additional 5% credit for seismic exploration conducted before July 1, 2003 in exchange for seismic data.	PPT	PPT
Tax Credits Oil & Gas Tax Credit Fund		Sec. 45. Adds AS 43.55.028. Replaces PPT tax credit refund with an oil and tax credit fund funded by an appropriation of a percentage of production tax revenues.	PPT	PPT
Reporting Requirements		Sec. 46. Amends AS 43.55.030(a). Makes clear every taxpayer must file an annual return; expands info requirements.	CS Sec. 26. ACES language	CS Sec. 14. ACES language
Reporting Requirements Penalties		Sec. 47. Amends AS 43.55.030(d). Adds late filing penalty of \$1000/day for information required by the DOR.	Deleted.	CS Sec. 15. ACES language

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	CSHB 2001 (P&G)
Reporting Requirements		Sec. 48. Amends AS 43.55.030. Adds new subsections (e) - requires annual expenditure statement; and (f) - authorizes DOR to require monthly filing of info.	CS Sec. 27. ACES language	CS Sec. 16. ACES language
Reporting Requirements and Penalties		Sec. 49. Amends AS 43.55.040. Clarifies DOR has authority to require filing of reports necessary to forecast state revenue; adds additional penalties.	CS Sec. 28. ACES language Amends AS 43.55.040. Retains ACES authority clarification; deletes additional penalty.	CS Sec. 17. ACES language
Administration Statute of Limitations		Sec. 50. Amends AS 43.55. Adds a new section, AS 43.55.075, that expands statute of limitations for conducting tax assessments from three years to six years.	CS Sec. 29. ACES language	Deleted.
Administration Electronic Filing & Advisory Bulletins		Sec. 51. Amends AS 43.55.110. Adds new subsections (e) & (f) that authorize DOR to require electronic filings and payments; and (g) that gives DOR authority to issue advisory bulletins.	CS Sec. 30. ACES language	CS Sec. 18. ACES language
Tax Determination	AS 43.55.160(a). Determination of production tax value of oil and gas.	Sec. 52. Repeals and reenacts AS 43.55.160(a). Retains PPT principle that the taxable value is the gross value at the point of production minus lease expenditures; the changes are necessary to implement different tax treatments.	CS Sec. 31. ACES language Amends AS 43.55.160(a). Retains PPT language with conforming amendments.	PPT
Tax Determination	AS 43.55.160(b). Production tax value may not be less than zero.	Sec. 53. Amends AS 43.55.160(b). Conforming technical amendment.	PPT	PPT
Tax Determination	AS 43.55.160(e). Carried forward annual losses established when production tax value is less than zero.	Sec. 54. Repeals & reenacts AS 43.55.160(e). Provides explicit rules for calculating production tax values for oil and gas subject to different statutory provisions.	PPT	PPT

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (OSG)	CSHB 2001 (OSG)
Tax Determination		Sec. 55. Amends AS 43.55.160. Adds four new subsections related to allocations and calculations of adjusted lease expenditures.	Deleted.	Deleted.
Lease Expenditures	AS 43.55.165(a). Describes deductible lease expenditures for purposes of determining the net taxable amount; provides standards DOR shall consider for determining lease expenditures.	Sec. 56. Repeals & reenacts AS 43.55.165(a). Retains but rewords deductible lease expenditures description; adds requirement that deductible lease expenditures be affirmatively allowed through regulation; allows overhead expenses (moved from 165(b)); deletes standards (moved to 165(b)).	CS Sec. 32. ACES language PPT with conforming amendments.	Sec. 19. ACES
Lease Expenditures	AS 43.55.165(b). Lists direct costs that may be considered deductible lease expenditures; allows overhead expenses; and specifies allowed costs need not be physically located on lease.	Sec. 57. Amends AS 43.55.165(b). Retains PPT language; adds the standards DOR shall consider for determining lease expenditures (moved from 165(a) and (c)); deletes overhead expenses (moved to 165(a)).	PPT	CS Sec. 20. ACES language
Lease Expenditures	AS 43.55.165(c) and (d). Allows DOR to substitute costs that are billable or actually billed through unit operating agreements in place of the general lease expenditures standards.	Repeals AS 43.55.165(c) and (d).	ACES	ACES
Lease Expenditures		Sec. 58. Amends AS 43.55.165(e). Adds to the list of non-deductible lease expenditures, including costs incurred for violations of law and for repair, replacement or deferred maintenance in specified circumstances.	CS Sec. 33. ACES language	CS Sec. 21. ACES language

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	CSHB 2001 (ACES)
Lease Expenditures	AS 43.55.165(h). Allocation of costs between oil and gas.	Sec. 59. Amends AS 43.55.165(h). Conforming amendment to be consistent with new AS 43.55.160 (production tax determination).	PPT	PPT
Lease Expenditure Adjustments		Sec. 60. Amends AS 43.55.170(a). Conforming amendment necessitated by repeal of AS 43.55.165(c) and (d) (determination of lease expenditures).	CS Sec. 34. ACES language	CS Sec. 22. ACES language
Information		Sec. 61. Amends AS 43.55. Adds new section AS 43.55.890; makes clear DOR may publish production tax info that is aggregated among at least three taxpayers.	CS Sec. 35. ACES language	CS Sec. 23. ACES language
Definitions		Sec. 62. Amends AS 43.55.900. Adds new definitions for "nonunitized reservoir;" "pool;" "producer;" and "unit."	CS Sec. 36. ACES language Amends AS 43.55.900. Retains ACES definitions for "producer" and "unit;" deletes "nonunitized reservoir" and "pool."	CS Sec. 24. ACES language Amends AS 43.55.900. Retains ACES definitions for "producer" and "unit;" deletes "nonunitized reservoir" and "pool."
Repeals	AS 43.55.023(f) Provides cash refund for small producer credits.	Sec. 63. Repeals	PPT	PPT
Repeals		Sec. 64. Repeals AS 43.55.165(c) and (d): determination of deductible lease expenditures using unit operating agreements.	CS Sec. 37. ACES language	CS Sec. 25. ACES language
Repeals		Sec. 65. Repeals AS 43.55.011(l); (order for applying Cook Inlet tax ceiling); AS 43.55.023(i) (transitional investment expenditures); and AS 43.55.160(c) (determining tax value under AS 43.55.011(g) (progressivity)).	CS Sec. 38. ACES language Adds repeals of AS 43.55.011(g) and (h) (progressivity); retains ACES repeal of AS 43.55.160(c) (determining tax value); deletes repeal of AS 43.55.011(l) and AS 43.55.023(i).	CS Sec. 26. ACES language Retains ACES repeal of AS 43.55.011(l); deletes other repeals.

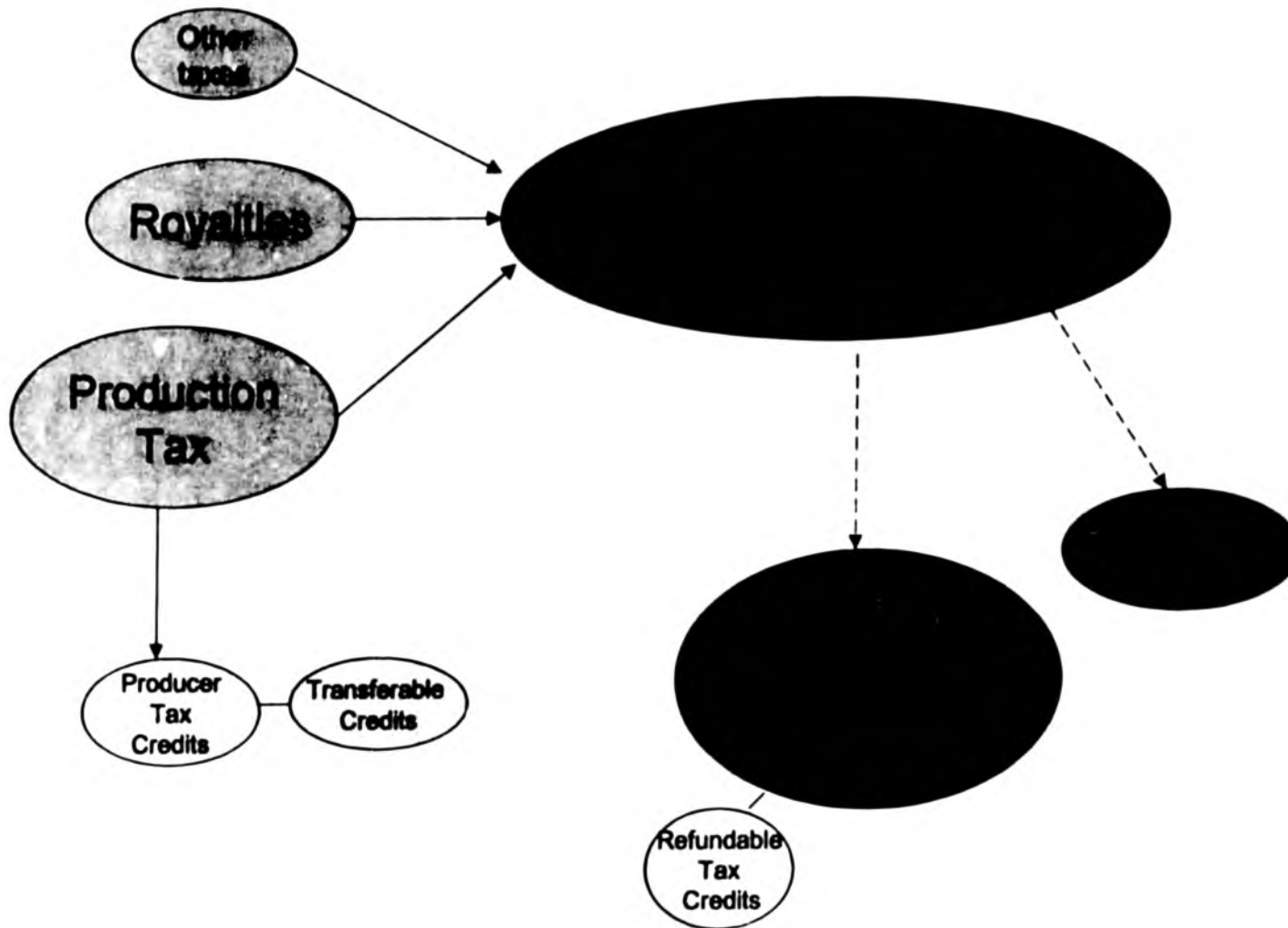
ACES Bill Version Comparisons

10/31/2007

Subject	PPF	ACES	CSRS 2001 (O&G)	CSRS 2001 (D&N)
Applicability		Sec. 66. Applicability of specified sections.	CS Sec. 39. ACES language No change to applicability of retained ACES sections.	CS Sec. 27. ACES language No change to applicability of retained ACES sections.
Transition Auditors		Sec. 67. Allows current oil and gas auditors to opt to remain in classified service.	CS Sec. 40. ACES language	CS Sec. 28. ACES language
Transition Regulations		Sec. 68. Allows regulations adopted by DOR and DNR to be applied retroactively to the applicability date of the statutory provisions being implemented.	CS Sec. 41. ACES language (with changed section numbers)	CS Sec. 29. ACES language (with changed section numbers)
Transition Pending Applications		Sec. 69. Provides for the treatment of pending applications for transferable credits and the refund of credits under AS 43.55.023.	Deleted.	Deleted.
Transition Regulations		Sec. 70. Authorizes DNR and DOR to proceed with adopting regulations.	CS Sec. 42. ACES language	CS Sec. 30. ACES language
Retroactivity		Sec. 71. Provides for the retroactivity of certain provisions.	CS Sec. 43. ACES language No change to retroactivity of retained ACES sections.	CS Sec. 31. ACES language No change to retroactivity of retained ACES sections.
Effective Dates		Secs. 72 and 73.	CS Sec. 44 & 45. ACES language No change to effective dates of retained ACES sections.	CS Secs. 32 & 33. ACES language No change to effective dates of retained ACES sections.

Current PPT Payment of Tax Credits

Blue=Revenue
Green=Fund
Orange=Budget
Yellow=Payment
Red Dotted Line=Appropriation



ACES Proposal Payment of Tax Credits

Blue=Revenue
Green=Fund
Orange=Budget
Yellow=Payment
Red Dotted Line=Appropriation

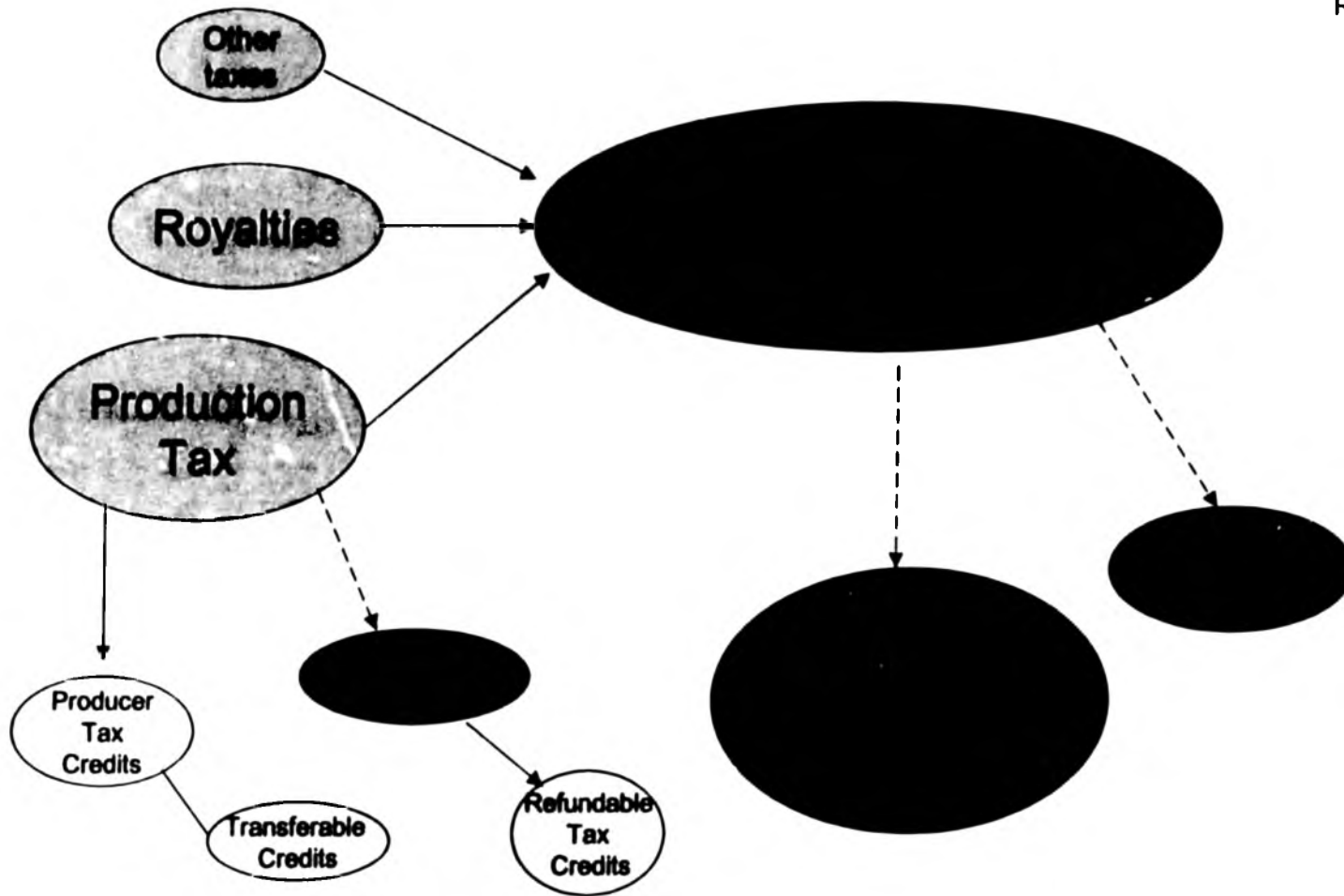
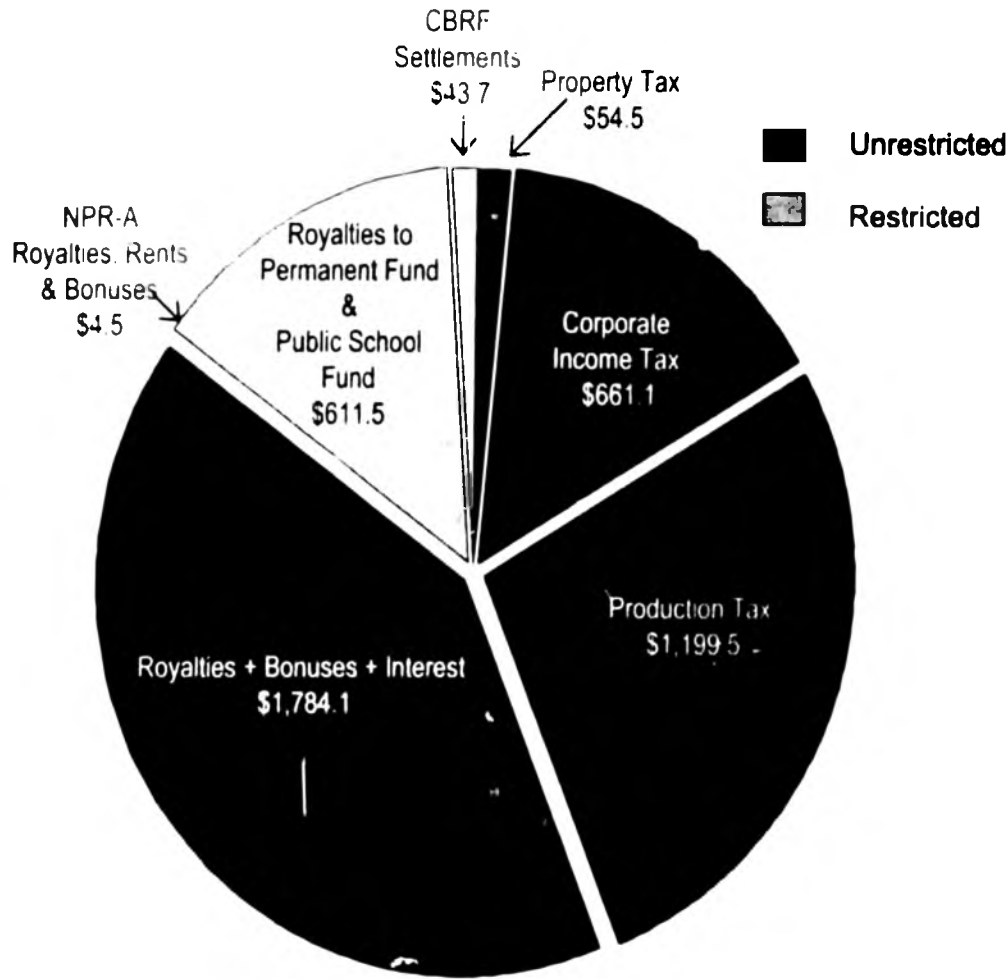


Figure 4-3. FY 2006 Oil Revenue by Category, \$4,359 million



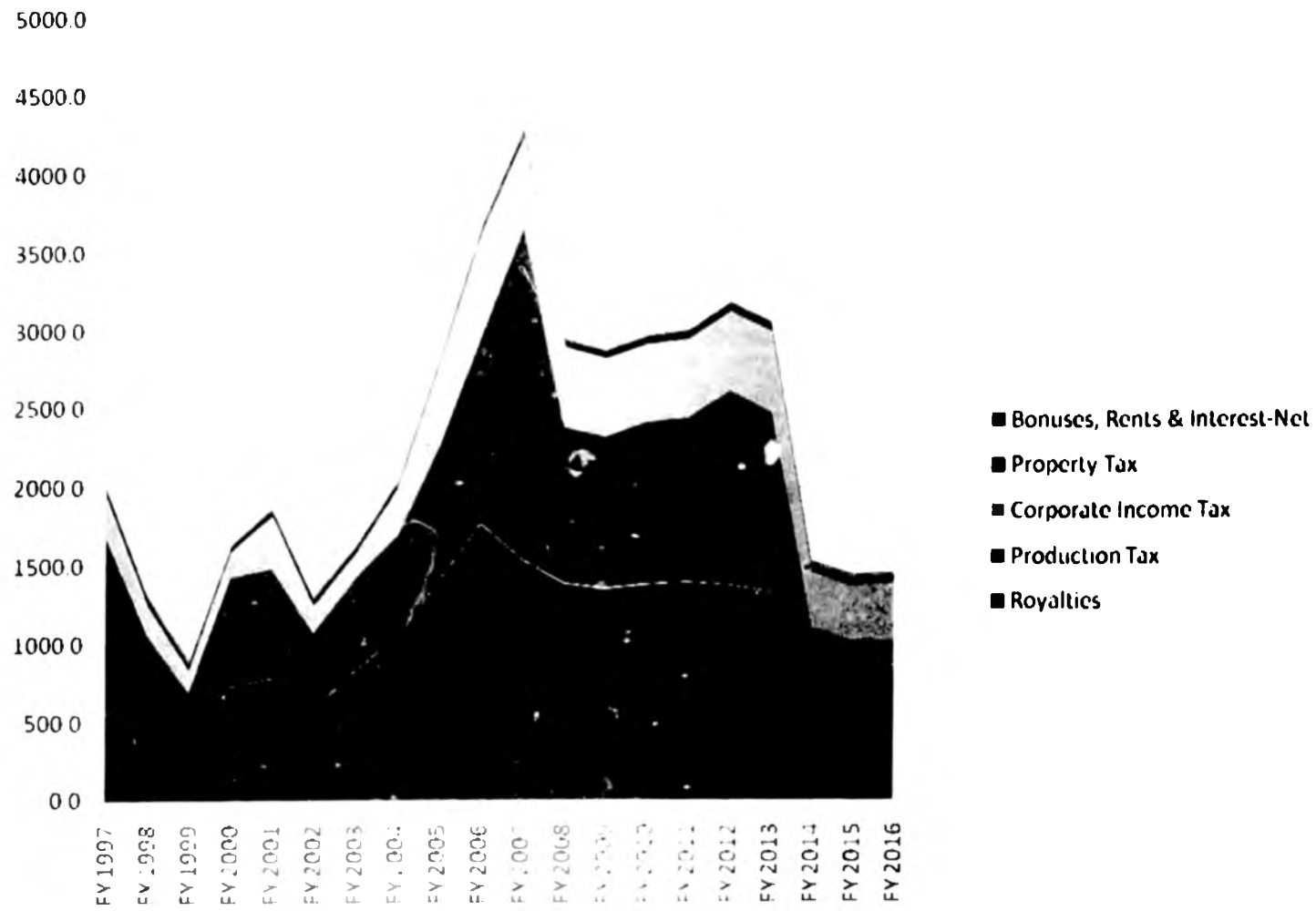
Unrestricted Oil Revenue

Figure 4-4. Unrestricted Oil Revenue Forecast, FY 2007-2016

Fiscal Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Property Tax	52.0	53.2	52.7	52.1	51.7	51.2	50.1	48.7	47.2	46.5
Corporate Income Tax	565.1	512.1	502.2	497.8	502.5	513.2	519.9	361.1	370.7	380.2
Production Tax	2,124.6	995.4	965.4	1,034.6	1,048.1	1,237.3	1,142.6	216.5	145.4	160.0
Royalties-Net ⁽¹⁾	1,583.0	1,406.4	1,373.0	1,398.2	1,413.5	1,390.0	1,348.8	902.2	882.6	869.0
Total Oil Revenues	4,324.7	2,967.2	2,893.3	2,982.7	3,015.7	3,191.7	3,061.4	1,528.5	1,466.0	1,455.7

Increase/Decrease from Prior Period	625.5	(1,357.5)	(73.8)	89.4	33.0	175.9	(130.3)	(1,532.8)	(82.5)	9.7
% Change from Prior Period	16.9%	-31.4%	-2.5%	3.1%	1.1%	5.8%	-4.1%	-50.1%	-5.4%	0.7%

⁽¹⁾ Includes Bonuses and Interest.





**BUILDING
TOMORROW**

A PLAN to secure Alberta's future

■ THE
**New Royalty
Framework**

OCTOBER 25, 2007





A message from Premier Ed Stelmach

*“I made
a commitment
and I delivered.”*

I am proud to deliver *The New Royalty Framework* to Albertans. I know it is the right plan to secure Alberta's future. I made a commitment and I delivered.

The New Royalty Framework gives future generations of Albertans a fair share from the development of their resources. It gives stability and predictability to the oil and gas industry. And it assures investors that Alberta will remain an internationally competitive and stable place to do business.

The New Royalty Framework furthers my plan for Alberta's future — a plan to build communities, green our growth and create opportunity.

Together, we're building tomorrow.

PREMIER ED STELMACH

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5	Background GUIDING PRINCIPLES
7	Government Decision Summary
13	Implications
14	Next Steps
15	Glossary
16	APPENDIX ONE <ul style="list-style-type: none">• A Summary of Decisions in comparison with the Alberta Royalty Review Panel's Recommendations

Executive Summary

The New Royalty Framework is the culmination of detailed study and analysis, extensive consultation, thoughtful deliberation, and political commitment.

It fulfills the promise Premier Ed Stelmach made to Albertans to review Alberta's royalty structure for oil and gas and ensure Albertans are getting a fair return on their resources. The Premier initiated this review in February. It is a key element of his plan to build a stronger Alberta.

The New Royalty Framework is the right plan – it increases royalty rates while allowing industry to remain competitive. It recognizes that a vibrant energy sector provides jobs and tax revenue as well as royalties. The *Framework* will ensure Albertans continue to receive all of these benefits.

The *Framework* represents fundamental and necessary change to current royalty structures. It creates a system that is more sensitive to market value, and also one that better reflects the growing importance of unconventional oil and gas resources to the future prosperity and economic development of the province.

Through vigorous and sometimes tough debate, the Stelmach government used three principles to guide decision-making on Alberta's royalties:

- support sustainable economic development that contributes to a high quality of life for all Albertans now and into the future
- support a fair, predictable and transparent royalty regime
- align Alberta's royalty regime with overall government objectives.

The Stelmach government has taken action and kept the promise. Government analysts project royalties will increase approximately \$1.4 billion in 2010, an increase of 20% over revenues forecast for that year under the current regime.

All changes take effect January 2009 unless otherwise noted.

Here are the major changes to Alberta's royalty regime:

Conventional Oil

The government will simplify royalties for conventional oil, eliminating specialty royalty programs and "old and "new" tiers. Royalties will be set by a single sliding rate formula containing separate elements that account for oil price and well production. The formula will be applied monthly to match current royalty reporting.

Overall, royalty rates will increase from the current maximums of 30% and 35% for old and new tiers. The new rates will range up to 50%, and rate caps will be raised to Cdn \$120 per barrel.

Natural Gas

As with conventional oil, natural gas royalties will be set by a single sliding rate formula sensitive to price and production volume. Royalty rates, currently 5% to 35%, will range from 5% to 50%, with rate caps at Cdn \$16.59/GJ (gigajoule).

Some members of the Alberta Royalty Review Panel have conceded their report erred by not mentioning Alberta should keep a benefit for deep wells with high drilling costs. The Alberta government will retain and revamp the Deep Gas Drilling Program and will apply lower royalty rates over a wider price range for wells with less productivity. Although government royalties from these sources will be lower, overall benefits to the economy will be higher, as production from marginal wells creates more jobs and benefits Alberta's businesses and communities.

The government will eliminate "old" and "new" tiers, but will retain the Otherwise Flared Solution Gas Royalty Waiver Program (OFSG), which improves air quality through solution gas conservation.

Oil Sands

The government supports increasing Albertans' share of revenues from the oil sands. It will do so by increasing royalty rates rather than by imposing an industry-wide tax on oil sands production.

Currently, the base or startup royalty rate for oil sands is 1%. While the Alberta Royalty Review Panel supported keeping this rate, Alberta's new royalty regime will ensure Albertans get a greater share of oil sands revenues right from the start. Under the new system, the base rate will start at 1%, and increase for every dollar oil is priced above \$55 per barrel, to a maximum of 9% when oil is priced at \$120 or higher.

The net royalty, applied post-payout is currently 25%. In the future, it will start at 25% and increase for every dollar oil is priced above \$55 per barrel to 40% when oil is priced at \$120 or higher.

The government will not grandfather existing oil sands projects. The government is in discussions with Syncrude and Suncor, whose Crown agreements expire in 2016, to participate in the new oil sands royalty regime. The transition details will be worked out over the next 90 days. In the event the agreement cannot be reached, the government will take other measures to ensure a level playing field for all industry stakeholders.

The government will adopt a permanent generic "bitumen valuation methodology" by June 30, 2008, after consulting with stakeholders and independent advisors. It will apply to projects with insufficient third party sales of bitumen.

Value Added

The Alberta government recognizes that to build a stable and prosperous future, the province must get the best economic return on the development of its energy resources. Alberta needs to add value to its exports and expand its economy by upgrading resources here in Alberta. By doing so, we will secure jobs and prosperity for future generations of Albertans.

The Alberta Royalty Review Panel recommended an upgrader credit of 5% as an incentive for industry to upgrade and refine in Alberta. Government analysis indicates the 5% credit would be ineffective. The government will consider other options, such as taking bitumen in kind rather than cash. Bitumen could then be used strategically to supply potential upgraders and refineries in Alberta.

Accountability

The government will assess and make improvements in the systems, structures and resources supporting the collection, verification and reporting of provincial revenues arising from conventional oil, natural gas and oil sands.

Former Auditor General Peter Valentine will lead this project and will report to Premier Stelmach. The project will begin in November 2007 and will be completed by March 31, 2008.

Background

The current royalty regime for oil and natural gas was developed in the early 1970s, and substantial changes were made in 1994.

Over the years, both the typical geology of pools being discovered and the way prices move in the world market have changed. A system that worked extremely well for oil prices up to \$30 per barrel and natural gas up to \$4/GJ (gigajoule) will not work as well for prices that can vary from \$5/GJ to \$14/GJ, and oil prices up to \$90/barrel. Costs have also changed over time as smaller and smaller pools tend to be found.

In 1997 the oil sands generic regime was created to encourage investment in the oil sands. This policy, along with higher prices and improvements in technology, has attracted close to \$60 billion of investment, and billions more in economic activity and tax revenue have benefited all Albertans.

But times change. A policy of lower royalties to maintain a minimum level of investment is no longer needed to attract investment to Alberta.

In February of this year, Premier Stelmach appointed the Alberta Royalty Review Panel. Premier Stelmach wanted to ensure Albertans are receiving a fair share from energy development and asked the Panel to provide advice. Premier Stelmach made the report public as soon as he received it, so it could receive the widest possible public debate.

Almost 9000 Albertans posted, faxed, phoned and e-mailed their views to the Government of Alberta. The Alberta Royalty Review Panel has had more than 640,000 hits to its website. Premier Stelmach appointed Ron Stevens, Deputy Premier and Minister of Justice, to meet with energy industry officials to ensure a shared understanding of the government's review process and give them an opportunity to provide their analysis of the impacts of the Panel's recommendations. Energy Minister Mel Knight led a technical analysis of the Panel's report to help decision-makers better understand the implications of their decisions.

All these pieces — the Alberta Royalty Review Panel Report, the Auditor General's Report, further public and industry feedback, as well as the technical analysis — were considered by government in this report.

Guiding Principles

The government used three principles to guide its decision-making:

- 1. Support sustainable economic development that contributes to a high quality of life for all Albertans now and into the future.**

Alberta's new royalty regime is a key element of Premier Stelmach's plan to build a stronger Alberta. The revenues generated from increased royalty rates will benefit current and future Albertans – one-third will go to provincial savings, with the remainder allocated to infrastructure and maintenance. The Framework encourages prosperity for Albertans in the long term and ensures that those who come after us receive a fair share of a well-managed and vigorous energy sector.

- 2. Support a fair, predictable and transparent royalty regime.**

The new royalty framework will help Alberta plan for a secure future by providing stability and predictability to business, and time to adjust to royalty changes.

Companies are investing billions of dollars in Alberta; they need to have a reasonable set of rules to play by if they are to compete internationally and contribute to the Alberta economy. Such rules require clear accountability and sound stewardship by government. This principle also supports fairness in sharing costs and benefits between owners and producers.

- 3. Align Alberta's royalty regime with overall government objectives.**

Premier Stelmach outlined the government's priorities in his television address *Alberta: A Plan for the Future: building communities, greening our growth, and creating opportunities for long-term prosperity*.

Alberta's jobs and prosperity will increasingly depend on the development of new sources of energy such as the oil sands and coal-bed methane. This Framework also supports the government's objective of maximizing recovery of existing known oil and gas resources.

Government Decision Summary

The following is a summary of the government's new royalty regime. A complete listing of the Alberta Royalty Review Panel's recommendations, government response and rationale is attached in Appendix One.

Conventional Oil

Price-sensitive and volume-sensitive conventional oil royalty rates will become separate elements within a single sliding rate formula. New royalty rates will range from 0% to 50%, up from the current maximums of 30% and 35% for new and old vintages.

Royalties will be calculated on a monthly production rate as is done currently and as collected, reported and used by industry.

To simplify the royalty system, several special royalty programs will be eliminated:

- Third Tier Exploratory Well Royalty Exemption
- Re-activated Well Royalty Reduction
- Low Productivity Well Royalty Reduction
- Horizontal Re-entry Well Royalty Program
- Experimental Project Petroleum Royalty

The new royalty formula will effectively deal with the economic issues these programs previously addressed. Oil project royalty programs like Enhanced Oil Recovery and the Innovative Energy Technology Program will be retained to encourage research and additional oil recovery.

The tiers in conventional oil that distinguish vintages based on the discovery date will be eliminated to simplify the system. Under current economic conditions the difference between tiers is no longer significant.

Rate caps on price will be raised for conventional oil to \$120 per barrel to ensure that the royalty system is sensitive over a broader range of prices. Currently maximums are reached at around \$30 per barrel for conventional oil. The new cap balances the royalty reductions at the low end of the production and price curve, thus contributing to a stable fiscal system.

Natural Gas

Price-sensitive and volume-sensitive gas royalty rates now become separate elements with a single sliding rate formula. New royalty rates range from 5% to 50%, up from ranges of 5% to 30% for new and 5% to 35% for old vintages. Changes to the price point at which lower royalty rates apply provide better protection to low productivity wells, also contributing to a more stable fiscal system.

For gas processing facilities, the government will move from using corporate effective royalty rates (CERR) to calculate costs of the Crown's share of capital to establishing facility effective royalty rates (FERR). This will improve the link of capital costs for natural gas to a particular facility. The Alberta Royalty Review Panel had recommended going to deemed or set fees, an approach tried before in Alberta, but it does not recognize significant actual cost differences in processing plants. While the FERR may initially be more administratively onerous on industry, it has the advantages of:

- not creating a disconnect with actual costs that are typical in a deemed fee system
- requiring less modification to the existing system
- moving cost calculations to the facility level.

For gathering and compression in Alberta, however, the government will continue to use set fees which do recognize actual costs.

The government will eliminate the tiers in conventional natural gas that distinguish vintages based on the discovery date to simplify the system. Under current economic conditions the difference between tiers is minimal.

The government will retain the Otherwise Flared Solution Gas Royalty (OFSG) Waiver Program and extend it to bitumen wells. This program was developed in consultation with industry and environmental stakeholders. It encourages solution gas conservation, rather than venting the gas, resulting in improved air quality. The OFSG program is part of an overall program that has contributed to about a 70% reduction in flaring across Alberta. Extending the OFSG program to bitumen wells makes the program more equitable and is consistent with the environmental intent of the program.

As well, the government will revamp the Deep Gas Drilling Program. Some members of the Alberta Royalty Review Panel have conceded their report erred by not mentioning Alberta should keep a benefit for deep wells with high drilling costs. Support for deep gas drilling is instrumental to the viability of gas development in Alberta. These deeper reserves are ten times the volume of natural gas reserves and remain to be developed.

The government will raise rate caps on the price of natural gas to Cdn \$16.59/GJ. The cap will ensure the royalty system is sensitive over a broad range of prices. Currently maximums are reached at around \$3.70/GJ for natural gas.

Royalties for natural gas liquids will now be set at 40% for pentanes, a change from 22-50% for old tiers and 22-35% for new. The new royalties for butanes and propane will be 30%, up from 15-30%.

The government will eliminate the option to use the Corporate Average Price (CAP) to determine natural gas royalties. CAP is a labour-intensive manual process used only by a small number of royalty payers. Natural gas can be reflected by a single reference price since it is processed to become relatively homogeneous. Use of the single reference price will provide an administrative saving to both industry and government.

Enhanced Oil and Gas Production

In 2005-06 the province's revenue from natural gas was 58% of total energy revenues.

Currently, new reserves of natural gas that can be easily developed form only 20% of Alberta's potential future production. The rest require enhanced means of development, such as deep or horizontally drilled wells. They are found in special formations, such as coal beds and shale. These reserves tend to have low productivity, but represent the future of the natural gas industry in Alberta. In the coming decades, jobs and prosperity will increasingly depend on unconventional oil and gas sources.

To encourage exploration and production, the Alberta government will apply somewhat lower royalty rates over a wider price range to low productivity reserves. As well, as noted previously, the government will revamp the Deep Gas Well Drilling Program.

The government will implement "shallow rights reversion" to maximize extraction of the resource. Under this policy, mineral rights to shallow gas geological formations that are not being developed would revert back to the government and be made available for resale.

Oil development has the potential for similar opportunities. Currently we leave 70% of oil in the ground. Government will continue to support investment in new technologies, such as using carbon dioxide to recover oil. This would not only benefit the economy, but carbon dioxide capture and sequestration would enhance the environment.

In the short term, there is a cost to supporting enhanced oil and gas production, but in the long term it will bring jobs and business opportunities to Alberta, securing our future and giving Albertans a bigger piece of an even bigger pie.

Oil Sands

Rather than impose a new tax, government will increase base and net royalty rates to achieve similar results.

Currently, the base or startup royalty rate for oil sands is 1%. While the Alberta Royalty Review Panel supported keeping this rate, Alberta's new royalty regime will ensure Albertans get a greater share of oil sands revenues right from the start. Under the new system, the base rate will start at 1%, and increase for every dollar oil is priced above \$55 per barrel, to a maximum of 9% when oil is priced at \$120 or higher.

The net royalty, applied post-payout is currently 25%. In the future, it will start at 25% and increase for every dollar oil is priced above \$55 per barrel to 40% when oil is priced at \$120 or higher.

The government will not grandfather existing oil sands projects. The government is in discussions with Syncrude and Suncor, whose Crown agreements expire in 2016, to participate in the new oil sands royalty regime. The transition details will be worked out over the next 90 days. In the event that agreement cannot be reached, the government will take other measures to ensure a level playing field for all industry stakeholders.

The government will eliminate the provincial portion of the Accelerated Capital Cost Allowance (ACCA) for oil sands projects, consistent with the federal government's recent elimination of the allowance.

The government will adopt a permanent, generic bitumen valuation methodology (BVM) after consulting with stakeholders and independent advisors. This methodology will be determined by June 30, 2008, and will be used wherever there are non-arm's length transactions. Where there are arm's-length sales at market price that price will be used. The development of the valuation method will include consideration of methods to deal with commodities that trade in markets that are not well functioning.

The government already has comprehensive rules and enforcement procedures for oil sands projects and eligible expenditures. However, the government will review and, if required, improve procedures. This policy aligns with others already being pursued by the government for enhanced cost and operating reporting requirements.

Value Added

The Alberta government recognizes that to build a stable and prosperous future, the province must get the best economic return on the development of its energy resources. Alberta needs to add value to its exports and expand its economy by upgrading resources here in Alberta. By doing so, we will secure jobs and prosperity for future generations of Albertans.

The Alberta Royalty Review Panel recommended an upgrader credit of 5% as an incentive for industry to upgrade and refine in Alberta. Government analysis indicates the 5% credit would be ineffective. The government will consider other options, such as:

- taking bitumen in kind rather than cash. Bitumen could be used strategically to supply potential upgraders and refineries in Alberta. The Crown would share in potential gains (and risks) in the upgrading, refining and petrochemical markets, and optimize its royalty share.
- advocating for adjusting pipeline toll differentials that currently may have an effect of subsidizing bitumen exports.
- expediting conditional regulatory approvals for projects with value-added content, while maintaining our strong environmental controls.

- investing in specific infrastructure projects, including investments in infrastructure for regional industrial development, and potentially carbon dioxide removal and storage.

Freehold Mineral Rights Tax

The government will review the federal mineral rights tax to ensure it is fulfilling its intended objectives. Freehold mineral rights for these reserves are held by individuals not the province. Current taxes cover the province's cost of administering the regulatory system.

Accountability

The government is determined that royalties will be collected within an equitable, flexible and competent administrative framework. It will initiate a project to assess and make improvements in the systems, structures and resources supporting the collection, verification and reporting of provincial revenues arising from conventional oil, natural gas and oil sands.

This initiative will:

- provide clarity on the goals of the province's non-renewable resource revenue regime.
- ensure the government has the systems and processes in place to assess the performance of royalty policy and collection for non-renewable resources.
- ensure complete and timely reporting to Albertans on royalties collected.

Former Auditor General Peter Valentine will lead this project and will report to Premier Stelmach. The project will start in November 2007 and will be completed by March 31, 2008.

This initiative will fully respond to the recommendations made by Alberta's Auditor General in his recent report.

Expenditures on Environmental Protection

Any discussion of programs and policies in the energy sector cannot be made without considering the environment. The Alberta government is committed to greening our growth:

- Alberta already is the first jurisdiction in North America to place real and measurable limits on large industrial plants that produce about 70% of greenhouse gas emissions.
- Recently, the government announced that instead of looking at the environmental impacts of industrial development on a project by project basis, for the first time, it will assess the overall impacts to land, air and water and set regional limits.
- Alberta has a comprehensive strategy for protecting our water, and we will soon be introducing a framework to better manage the competing demands on Alberta's landscape.
- And earlier this year, Premier Stelmach asked the Minister of Energy to develop a comprehensive energy strategy, one which will ensure the sustainable development of the province's resources in an environmentally responsible manner, making full use of innovations such as near zero-emission coal.

To encourage responsible resource management, the government will continue to assess and recognize any new environmental fees or levies as an eligible cost of doing business, and therefore deductible in determining royalties on oil sands projects.

Implications

The estimated increase in royalties will be \$1.4 billion dollars, a 20% increase over royalty revenues projections under the current system. These projections are based on the same assumptions the Alberta Royalty Review Panel used to reach its 2010 projections.

Yearly royalty revenues can be volatile, and are solely dependent on price and production levels for each of the commodities. Revenues could be higher or lower than the levels projected for 2010.

The recommendations will decrease royalties on 88% of conventional gas wells at a price of \$6.00/mcf (compared to 82% based on the Panel recommendations). The 57% of conventional oil wells paying less remains unchanged from the Panel recommendation.

In 2010, additional revenues from the government's new royalty program are forecasted to be:

Gas	\$470 million
Conventional oil	\$460 million
Oil sands	\$470 million
TOTAL	\$1,400 million

Government forecasts are less than those projected by the Alberta Royalty Review Panel for natural gas because of changes to encourage production from low producing gas wells and revamping of the Deep Gas Royalty Program. In the short term, there is a cost to such support, but in the long term it will bring jobs and business opportunities to Albertans, securing our future and giving Albertans a bigger piece of an even bigger pie.

Former Auditor General Peter Valentine will establish government benchmarks as part of his review of Alberta's accountability systems.

Corporate and personal tax implications were not estimated by the Alberta Royalty Review Panel and have not been estimated by the government at this time. However, we anticipate there will be reduced tax revenues from corporate income in the short term.

Currently low natural gas prices are causing a modest slowdown in economic growth and some job loss. The government does not expect any significant immediate economic impacts from its royalty changes. Industry has over a year to adjust its operations and address implementation issues.

Next Steps

As the title of this report indicates, this is a framework for Alberta's new royalty regime. As the government further develops the new royalty regime, adjustments may be made to ensure there are no unintended consequences to its decisions. Both the public and stakeholders will be consulted should significant adjustment be necessary. This is in keeping with Premier Stelmach's commitment to open, transparent government.

The new royalty regime takes effect in January 2009. A lead time of one year is required to ensure the appropriate legal framework and administrative systems are in place, and new accountability measures are identified. Changes to numerous pieces of legislation are required including the Mines and Minerals Act, the Petroleum Royalty Regulation, the Oil Sands Royalty Regulation, and the Natural Gas Royalty Regulation, to name a few. Government information systems, administrative procedures and audit functions will need substantial changes to accommodate the new royalty regime.

The accountability review will begin in November 2007 and be completed by March 31, 2008. Implementation of the new accountability initiatives is set to begin in May 2008.

Glossary

Bitumen Valuation Methodology (BVM)

a formula used to calculate the value of bitumen for the purposes of calculating royalties.

Bitumen

the heaviest, thickest form of petroleum as found in Alberta's oil sands.

Coal-bed Methane

natural gas found in coal seams. It is still in the early stages of development in Alberta and may help meet the growing demand for natural gas.

Conventional crude oil

petroleum found in liquid form, which can be pumped without processing or dilution.

Deep gas

refers to natural gas from wells drilled to depths greater than 2,500 metres.

Freehold Mineral Tax

is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands

Natural Gas Liquids (NGLs)

liquids obtained during production of natural gas comprising ethane, propane and butane.

Ring fence

refers to the definition of an oil sands project and the eligible expenditures deemed necessary for operation.

Royalties

the price that the owner of a natural resource charges for the right to develop the resource.

Royalty-in-Kind

refers to the Crown receiving resources, such as bitumen, in lieu of cash royalties.

Synthetic Crude

a product similar to crude oil, created by upgrading bitumen from oil sands.

Payout

in reference to oil sands projects, the point when the developer has recovered capital costs plus 6% return on the investment.

Primary wells

refers to wells producing heavy oil in areas designated as oil sands.

Value added

the upgrading or refining of resources into products of a higher value (e.g. synthetic crude, petrochemicals, plastics)

Vintage

refers to the date of discovery which is used to determine how conventional oil and natural gas royalties are calculated under the province's current system. Also referred to as "tiers."

APPENDIX ONE

A Summary of Decisions in comparison with the Alberta Royalty Review Panel's Recommendations

PANEL RECOMMENDATION	GOVERNMENT DECISION	RATIONALE
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Implementation

1. Implement Recommendations in July 2008	Reject Implement in January 2009	A lead time of one year is required to ensure the appropriate legal framework, administrative and accountability systems are in place.
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Conventional Oil

<p>2. Royalty rates are determined by a single sliding rate formula with separate elements sensitive to price and production volumes. New royalty rates range from 0% to 50%</p> <p>Royalties are calculated on a daily production rate.</p>	<p>Accept with modification This is a change from current royalty rates.</p> <p>Reject Royalty will be calculated on a monthly production rate instead of the daily rate suggested by the Panel.</p>	<p>Albertans will receive a greater royalty share at higher oil prices.</p> <p>Moving to a per day calculation would add administrative complexity and cost with no apparent benefit. Information is currently collected on a monthly basis.</p>
<p>3. Several special royalty programs be eliminated.</p>	<p>Accept Eliminate the following well-based oil royalty programs:</p> <ul style="list-style-type: none"> • Third Tier Exploratory Well Royalty Exemption • Re-activated Well Royalty Reduction • Low Productivity Well Royalty Reduction • Horizontal Re-entry Well Royalty Program • Experimental Project Petroleum Royalty. 	<p>Simplifies the current royalty system.</p> <p>The government's new royalty formula will effectively deal with the economic issues addressed by these programs.</p> <p>Oil project royalty programs like, Enhanced Oil Recovery and the Innovative Energy Technology Program will be retained to encourage research and additional oil recovery.</p>
<p>4. Eliminate the tiers in conventional oil that distinguish "vintages" based on discovery date.</p>	<p>Accept</p>	<p>Simplifies the current royalty system. Allows officials to focus on more value-added activities.</p> <p>Under current economic conditions the difference in royalties between tiers is no longer significant.</p>
<p>5. Rate caps on price be raised for conventional oil to Cdn \$120/barrel.</p>	<p>Accept Ensures the royalty system is sensitive over a broad range of prices.</p> <p>Current maximums are reached at around \$30 per barrel.</p>	<p>Improves Albertans' share at higher prices.</p>

Natural Gas

<p>6. Royalty rates are determined by a single sliding rate formula with separate elements sensitive to price and production volumes. New royalty rates range from 2% to 50%.</p>	<p>Accept with modification New royalty rates will range from 5% to 50%.</p>	<p>Significantly increases the government take at higher gas prices.</p> <p>Coal bed methane, tight gas, and shale gas represent important future gas resources for Alberta, but they are not highly productive. These wells will be subject to lower royalties at a wider price range to ensure the continued development of these unconventional gas reserves.</p>
<p>7. Crown deem a fee for processing to apply to all gas processing facilities in the province, with adjustments for different types of plant production (e.g., wet, dry, sweet)</p>	<p>Reject Establish a facility effective royalty rate (FERR) rather than the recommended deemed fee. The current system uses a corporate effective royalty rate (CERR)</p>	<p>Moves cost calculations to the facility level, better connecting costs to facility. Requires less modifications to the existing system.</p>
<p>8. Eliminate the tiers in conventional natural gas that distinguish "vintages" based on discovery date.</p>	<p>Accept</p>	<p>This change simplifies the system. Under current economic conditions the difference in royalties between tiers is minimal.</p>
<p>9. No panel recommendation on shallow gas.</p>	<p>The government will implement "shallow rights reversion" to maximize extraction of the resource. Under this policy, mineral rights to undeveloped geological formations above zones that are being developed would revert back to the government and be made available for resale.</p>	<p>This change would allow for development of currently undeveloped resources consistent with government's objective of maximizing recovery of known gas resources. This would allow for capture of increased royalty revenues for Albertans.</p>
<p>10. Several special royalty programs be eliminated.</p>	<p>Accept A number of well-based oil royalty programs will be eliminated. The following gas royalty programs will be retained and revamped:</p> <ul style="list-style-type: none"> • Otherwise Flared Solution Gas Royalty Waiver Program. It will be extended to bitumen wells. • Deep Gas Drilling Program. Some revisions will be required to the current program to reflect the change in the royalty formula. 	<p>The OFSG program was developed in consultation with industry and environmental stakeholders. It encourages solution gas conservation, rather than venting the gas, resulting in improved air quality. The OFSG program is part of an overall program that has contributed to a 70% reduction in flaring across Alberta. Extending the OFSG program to bitumen wells makes the program more equitable and is consistent with the environmental intent of the program</p> <p>The deep gas drilling program is instrumental to the viability of gas development in Alberta. Although royalties from unconventional gas will be lower, overall benefits to the economy will be higher, as production from marginal wells creates more jobs and benefits Alberta's businesses and communities.</p>
<p>11. Rate caps on price be raised for natural gas to Cdn \$16.59/GJ.</p>	<p>Accept Currently the maximum rate is reached just above \$3.70/GJ.</p>	<p>Improves Albertans' share at higher prices.</p>
<p>12. Treating natural gas liquids (propane, butanes, pentanes plus) as oil. Treat ethane as natural gas.</p>	<p>Reject Maintain the status quo for ethane and apply fixed royalty rates for propane, butane and pentanes to maximize their economic contribution to Alberta.</p>	<p>Ethane is already treated as natural gas.</p> <p>The panel recommendation is not justified by current drilling economics. Implementation would result in a considerable revenue loss for Alberta. There is no logical tie between the production and markets for oil and natural gas liquids.</p>
<p>13. Eliminate option to use Corporate Average Price (CAP) to determine natural gas royalties.</p>	<p>Accept</p>	<p>This is a minor change from the existing system. It is a labour-intensive manual process. Its elimination will result in administration savings to both industry and government.</p>

Oil Sands

14. Base Royalty rate to remain at 1%.	<p>Reject Implement a sliding rate structure where the base rate increases from 1% when the West Texas Intermediate (WTI) price is at \$55 per barrel to 9% when WTI reaches \$120.</p>	<p>At high prices the province will receive higher revenues from oil sands development. Albertans will receive a greater share from oil sands development.</p> <p>Ensures all components of the royalty system are price sensitive</p>
15. Increase net royalty rate from 25% to 33%.	<p>Reject Implement a sliding rate structure where the net royalty rate increases from 25% when WTI price is at \$55 per barrel to 40% when WTI reaches \$120.</p>	<p>Albertans will receive a greater share from oil sands development.</p> <p>Ensures all components of the royalty system are price sensitive.</p>
<p>16. Implement a new Oil Sands Severance Tax:</p> <ul style="list-style-type: none"> • 0% for price less than \$40/ bbl • 1% at \$40/ bbl • Increase by 0.1% for each dollar per barrel increase • Maximum of 9%. 	<p>Reject Royalties are a right of ownership. Other jurisdictions use severance taxes to meet their revenue need because they do not own the resources. Alberta's fair share is not based on revenue needs, but ownership rights.</p>	<p>By introducing a price sensitive base royalty rate, Alberta can obtain more revenue upfront, especially at high prices.</p>
17. Recognize any environmental fees or levies as eligible cost of doing business.	<p>Accept</p>	<p>Government already allows this for costs directly related to oil sands projects.</p>
<p>18. Introduce a tradable royalty credit at a rate of 5% of eligible capital expenditures on additional upgrading capacity in Alberta:</p> <ul style="list-style-type: none"> • Requires EUB approval. • Requires that a new Bitumen Valuation Methodology be in place. • Credit is transferable. 	<p>Reject Implement royalty in kind for bitumen (rather than cash). Continue work on the Value-Added Strategy to determine most effective tools to encourage value-added product development in Alberta. Upgrader credit may be one option to consider within this review.</p>	<p>Other tools may be more effective at encouraging value-added activity in Alberta</p> <p>Upgrading may be less critical than expanding refining or other value added activities.</p> <p>Numerous upgrading projects are already likely to go ahead in Alberta without the need for the special incentive, particularly if independent bitumen supply is available.</p>
19. Elimination of Accelerated Capital Cost Allowance (ACCA) for oil sands projects.	<p>Accept</p>	<p>The government will eliminate the provincial portion of the ACCA for oil sands projects, consistent with the federal government decision.</p>
<p>20. Adopt permanent, generic "bitumen valuation methodology" (BVM) by June 30, 2008 to replace all other BVMs and alternative valuations.</p> <p>All bitumen to be subject to this valuation system. Consult independent advisor.</p>	<p>Accept with Modification Accept the use of a formula-based approach as an option for the permanent BVM.</p> <p>Reject the application of the permanent BVM to all bitumen produced in the province.</p>	<p>A formula based approach is only required for non-arm's length transactions. Where there are arm's length sales at market price, the market price will be used.</p>

continues

Oil Sands *continued*

<p>21. Cost Rule Clarification Encourage the Government of Alberta to comprehensively and extensively review and tighten, if required, current rules and enforcement procedures to ensure that absolutely clear, transparent, auditable and appropriate definitions exist for projects and eligible expenditures.</p>	<p>Accept</p>	<p>Aligns with initiatives/policies already being pursued by government for enhanced cost and operating reporting requirements.</p>
<p>22. Recommendation against grandfathering on the grounds of fair treatment for all participants</p> <p>The panel did not make a specific recommendation on the treatment of the Crown Agreements, which it felt was "beyond the scope of the Panel's work."</p>	<p>Accept</p>	<p>This ensures a level playing field for all industry stakeholders.</p> <p>The government is in discussions with Syncrude and Suncor, whose Crown agreements expire in 2016, to participate in the new oil sands royalty regime by 2009. The transition details will be worked out over the next 90 days. In the event agreement cannot be reached, the government will take other measures to ensure a level playing field for all industry stakeholders.</p>
<p>23. Eliminate the option to elect oil sands administrative status for primary wells in certain areas.</p>	<p>Reject</p>	<p>For many heavy oil projects in the region, the economics and development conditions are similar to oil sands, and primary wells may become part of a project that is in-situ. Conventional rates are not appropriate for these situations and would not improve recovery efficiency. The generic royalty regime encourages enhanced recovery from primary wells.</p>
<p>24. The existing schedule of escalating rentals begin in the sixth year of any agreement (lease or license) and that no deductions be allowed in the calculation of escalating rentals.</p>	<p>Reject</p>	<p>Six years is a short time frame for evaluating, planning, obtaining regulatory approvals and developing complex projects. The shortened time frame could lead to acceleration of activity and further strain Alberta's infrastructure.</p>

Freehold Mineral Rights Tax

<p>25. Flat 6% tax apply regardless of level of production. Retain the base exemption of \$1,600</p>	<p>Reject</p>	<p>The Panel did not provide any significant rationale for moving to the flat tax system. Freehold mineral rights are owned by individual Albertans not the Crown. Royalties recover Albertans' share of Albertans' resources. Current taxes cover administrative costs of managing the process. Elimination of low productivity rate reductions could lead to well abandonment and oil and gas being left behind that could have been extracted.</p> <p>The government will review the freehold mineral rights tax to ensure it is fulfilling its intended objectives.</p>
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Accountability

<p>26. Royalties are collected within an equitable, flexible and competent administrative framework.</p>	<p style="text-align: center;">Accept</p> <p>Initiate a review to improve the systems and structures used to collect, verify and report non-renewable resource revenues received by the Province of Alberta.</p>	<p>Government is committed to a sound, accountable system for collecting royalties.</p>
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